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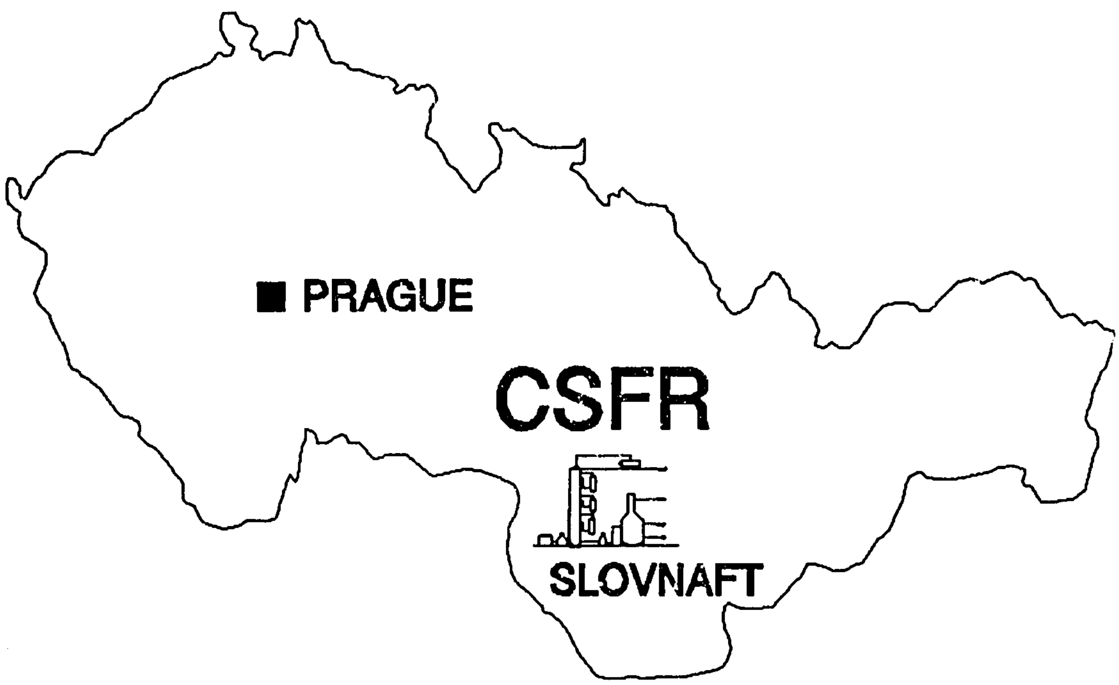
EVALUATION AUDIT REPORT
CZECHO-SLOVAKIAN PETROLEUM REFINERY
SLOVNAFT, BRATISLAVA

A SELECTIVE REFINERY ANALYSIS FOR:
OPERATION, ENERGY USE, ENVIRONMENTAL IMPACTS AND IMPROVEMENT OPPORTUNITIES

MAY, 1992



PREPARED BY: DAVY MCKEE CORPORATION, CHICAGO, IL USA

U.S. EMERGENCY ENERGY PROGRAM FOR EASTERN AND CENTRAL EUROPE

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
BUREAU FOR EUROPE
WASHINGTON, D.C. 20523

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REFINERY EVALUATION AND AUDIT
SLOVNAFT REFINERY, BRATISLAVA, CZECHOSLOVAKIA

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EXECUTIVE SUMMARY

Early in the year 1991, the United States Agency for International Development (USAID) retained the Chicago office of Davy McKee corporation (DMC) to perform a technical study of the seven refineries that constitute the Petroleum Refining Industry of Czecho-Slovakia (CSFR). The results of the study are presented on two levels: refinery characterization and selected refinery evaluation.

This report covers the results of an audit and evaluation of the Slovnaft Petroleum Refinery in Czecho-Slovakia. The Kaucuk Refinery in Kralupy and the Chemopetrol Refinery in Litvinov were also selected for audit and evaluation. A separate report covers the characterization of the petroleum refining industry. Also, a separate report covers the structure and use of a computerized data base, which has been prepared from the data in the response to a DMC questionnaire issued before the beginning of the field work.

The project started with meetings in early December 1990, between the United States and CSFR energy officials. During the meetings, a plan and schedule were developed for participation by the CSFR in the U.S. Emergency Energy Program. The goals of the program were to provide a data base for future planning activities in Eastern Europe to improve the viability of the petroleum sector, support the achievement of improved energy consumption efficiency and support alleviation of adverse environmental impact. The Scope of Work, or Terms of Reference for this project may be found in Appendix B of this report.

The study then addressed the potential of achieving substantial improvement in energy efficiency and disposal of solid liquid and gaseous effluents - both by reduction in volume and method of handling. Order-of-magnitude capital requirements and return on investment associated with identified opportunities form part of these evaluation reports.

The objective of this report is to present opportunities for energy improvement and reduction of emissions from the Slovnaft Refinery in Bratislava, Czechoslovakia. The Slovnaft Refinery is a large petrochemical complex, with selected refining units providing feed materials for the production of petrochemicals, motor fuels, lube oils, fuel oils and greases, primarily for the domestic market. The refinery is an initial part of the complex, and was constructed in the period between 1960-1970. The technological level of the units at this time is viewed as adequate. Over the years, some of the processing units were modified to better fit new product specifications and/or reduce energy consumption.

At the outset of the project, teams were organized for both the characterization and evaluation efforts and consisted of professionals with many years of experience in their respective engineering disciplines. The technical disciplines represented within the team were process, environmental, mechanical, electrical, and instrumentation engineering.

The data for preparation of the evaluation report may be considered divided into three stages:

- Initially there was a preliminary or reconnaissance visit to the CSFR, during which a rather detailed questionnaire was furnished to the refinery managers.

- The second stage brought the DMC team into Chicago for a week of orientation. The in-country consultant also participated in the discussions.

- The third stage of the evaluation and audit effort consisted of data collection through meetings with operating managers and engineers of individual units within the refinery.

It should be noted that Slovnaft required DMC to sign a Secrecy Agreement prior to release of information. Further, a similar agreement was executed with UOP of Des Plains, IL. Each organization required review and approval of a draft report. Such review and approval has occurred.

The refinery consists of three crude distillation units with a capacity of approximately 2.2 million tonnes per year each. The distilled products (naphtha, kerosene and gas oils) are desulfurized and treated to meet corresponding product specifications. One of these crude units (AVD 6) is associated with a vacuum tower. The vacuum distillates are furfural-extracted, dewaxed, and after hydrofinishing, blended to commercial lube oils.

There is production of light fuel oil (distillate) with low sulfur content and heavy fuel oil (residual) with a sulfur content up to 3% by weight. The atmospheric residue from Atmospheric Distillation Units 4 and 5 is fed to the hydrocracker vacuum tower.

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The Davy McKee evaluation of the selected part of the Slovnaft refinery took place over a three-week period, from 20 May 1991 to 8 June 1991. As primary suppliers and users of energy, electrical generation and other utility systems were reviewed in parallel with the process units. The environmental areas and the pollution control units were studied. The basis for selection of specific operating units was driven by a need to perform a useful and meaningful study within the established schedule and team composition, and included those units that were felt to be representative or typical (AVD #6 is similar to AD #4 and AD #5). Other units were selected for study where management felt they were especially troublesome with respect to operations and/or experienced high energy utilization. The new Dewaxing Unit #3 was chosen for this reason; it is reported to use many times the energy per metric ton of feed compared with the older Dewaxing Unit Number 2. The Hydrodesulfurizers #5 and #6 were selected as typically representative of other HDS units within the refinery. The lube oil train (furfural, dewaxing and hydrofinishing units) was chosen for review as the refinery recognized the need to upgrade the older lube oil system, due to perceived increasing market demands. The gas separation, gas desulfurization and sulfur plants, in addition to rounding out the review by including the gaseous product facilities, also represent the opportunity to consider the effect of changes to light end processing as it effects sulfur emissions.

The field activities consisted of process reviews of each of the selected units, with members of the refinery engineering, operation, management and economics analysis staff. Additionally, each unit was visually inspected by team members, with respect to their are of expertise. Refinery counterparts were made available to each of the team members as-needed. In addition to a "process unit" or systems approach to analysis, the DMC team viewed the refinery from an overall mechanical, electrical and instrumentation perspective, reviewing areas such as: pumping systems, fired heaters, steam and electrical generation, heat exchange, and acquisition of process variables (temperature, pressure, etc.) for data collection purposes.

For the most part, the team relied on data obtained or provided by the refinery staff or through refinery reports and operating logs. They did, however, request and observe the measurement of excess oxygen and resulting furnace efficiencies for selected fired heaters. Specifically, field data was obtained for fired heaters in Atmospheric Distillation #4 and #5 and Furfural Unit #2. As is shown substantially in the main report, opportunities exist to achieve energy savings through reduction in excess air and improved burner operation.

State-of-the-art portable gas analyzers were locally available through the refinery inspection department. As a standard practice, these units are used by the refinery to periodically monitor fired heater operations. Despite this activity, fire controls were not adjusted to reduce excess air in fired heaters, let alone to approach the levels seen in US refineries.

As was mentioned, the selection of units was oriented to areas where problems have been observed from the viewpoint of energy consumption, process flexibility and product quality. The evaluation took place in cooperation with the technical and operating personnel of the plant and following the general outline listed below.

- Physical inspection of facilities and operating units
- Twelve-months history (review material processed and energy utilized) of the units
- Process flow sheet and operations review

- Energy conservation possibilities
- Determination of environmental impact of the unit and opportunities for reduction
- Development of recommendations for improvements

Outside battery limits facilities reviewed in varying levels of detail were:

- Power Station
- Water Treatment Plant
- Warehousing/Maintenance/Fabrication Equipment and Repair
- Oil Movements Facilities
- Main Distribution Substation
- Analyzer/Advance Control Group Facilities

Part of the refinery production is shipped by product pipeline, the rest by railroad or truck. Shipping product by barge via the Danube River is an option available for product movement and is used for shipment of a portion of the production.

Crude oil is supplied by pipeline from the USSR. Slovnaft has a power station and other facilities necessary for full utility supply as well as waste treatment. In addition, effluent wastes are treated at the refinery site prior to discharge to the atmosphere or receiving waters.

X

It should be noted that the Slovnaft Refinery is designed to handle crudes with a sulfur content in the 1.5 wt% range, which results in (3 wt%) sulfur in the heavy fuel oil, and other products meet or exceed sulfur content specifications. Acquisition of lower sulfur crudes may be attractive, but we should not lose sight of the refinery's sulfur handling capability, which includes distillate HDS units, gas and liquid LPG desulfurizers and sulfur plants. In addition, the options offered by deeper bottoms processing are under evaluation by the refinery staff.

The Energy Division has various plants throughout the Slovnaft Refinery/Chemical Plant complex, and supplies electricity, steam, plant air, instrument air, cooling water, chemical water/demineralized water for high pressure steam and softened water.

The power station contains eight high pressure 96 atm (1 400 psi) boilers. Their normal operating procedure is to swing two boilers and base load the rest. They try to base load the most efficient boilers, but the desire to swing only two boilers makes it necessary to base load the small boilers in order to have enough swing capacity.

The Slovnaft Refinery/Chemical Plant Complex co-generates approximately 50% of its power usage. The power station has four turbo-generators (24MW, 25MW, 25MW and 29MW). The additional power needed is obtained from the national grid. The primary distribution voltages are 110 kV and 6 KV. Emergency power is available from the grid at a reduced MW level.

The Slovnaft Refinery's control instrumentation is generally pneumatic, except for the Polish electronic analog controllers on the Dewaxing unit 3 and a small distributed control system (DCS) of American manufacture. The newer controllers are mostly of Czech and Polish manufacture with a small amount of Russian equipment. Instrumentation installation details generally approximate U.S. practices. The refinery's instrument maintenance facilities are very extensive with almost all work being done in-house.

The process review concentrated on the AVD #6 (atmospheric and vacuum distillation), as it is the key unit for lube oil production and anticipated changes in crude supply would have a significant impact on the entire lube oil processing train.

During the evaluation process, discussion with refinery personnel revealed the following problems:

- Increase of AVD #6 unit capacity is desirable because the downstream lube units have the capability of processing larger quantities of feed.

- Better fractionation (to reduce overlapping) between kerosene and gas oil may help to alleviate difficulties in the Molex process. The reduction of overlapping of vacuum distillates (20 to 60 °C) would improve the quality of lube oils produced.

- Inability to heat the crude to the design fired heater inlet temperatures through the crude oil heat exchange train. (Design temperature of the inlet to the furnace is 245 °C, whereas actual temperature at the time of the visit was about 205 °C.) Subsequent correspondence with the refinery states that this temperature is now up to 225°C. For AVD #6, the operating cost reduction due directly to reduction in the amount of fuel fired is $20 527/yr per °C rise in crude temperature into heater caused by improved heat recovery. At 75% heater efficiency, the savings become $12 632/yr for each degree heater inlet temperature is raised.

The lube oil production units are not in optimal balance and Dewaxing Unit No.3 is in need of major engineering and revamp efforts to improve operations and energy efficiency. The overall economics of lube products is directly coupled to optimizing lube train operations and improving/revamping Dewaxing Unit #3.

The furfural extraction system is the limiting section of the lube oil train. Raffinate yields are in the order of 50 weight %, based on feed. The refinery is in the process of installing a "pseudo-raffinate" processing unit, which will increase overall yields. Conversion to NMP solvent extraction from furfural is a possibility which would increase capacity and reduce energy consumption. It should be noted, however, that NMP is an expensive energy, price-sensitive, imported product. Further, NMP is more corrosive than furfural and new corrosion resistant equipment would be necessary in a conversion process. Furfural, on the other hand, is produced in-country from renewable agricultural by-products and does not require hard currency as payment. Nevertheless, we do recommend a technical/economic study of switching to NMP as the increased cost of solvent may be more than offset by increased capacity and energy reduction. Since the extraction units are the limiting sections of the lube train, debottlenecking studies should be undertaken as part of the solvent change review.

Significant changes in crude oil specifications my have an influence on lube oil production. The additive package dose rate, blending formulations, and lube oil operations are directly coupled to years of experience with the Soviet crude oil. Also, different crudes will very likely have not only different yields of lube oil base stocks, but their chemical composition and lubricating qualities will also change. The complexity involved with changing crudes within multiple processing units in the lube oil train (furfural, dewaxing and hydrotreating) is such that a dedicated study of the effect of such changes upon final lube product quality is strongly recommended. It is strongly recommended that the current Russian crude continue to be used, at least in AVD #6, and subsequent lube train, until such time as a full evaluation of the effect of changing crudes is performed.

The facility design basis and current feedstock is crude oil from the USSR, supplied by an existing pipeline. Other crude sources are being evaluated but their transportation means into the refinery is contingent upon a variety of new pipeline possibilities.

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A computer simulation was performed for the AVD #6 crude unit based on data supplied by the refinery. Computer-aided chemical engineering operations simulations are a necessary tool in today's refinery engineering department. The speed of calculation of complex problems and relationships allows the refiner to model and analyze operating variables and options very rapidly. The use of computer simulation as a tool for Slovnaft would allow the technical staff to sort through a large number of operating options with multiple variables, thus providing management with more optimal solutions. Changing crude supplies, which is likely, will enhance the need for simulating crude unit and subsequent downstream operations. Highlights of the alternate crude feed simulations are as follows:

- A lighter feed, 38.7 °API, results in 35% less flow to the vacuum unit, which reduces flow through the lube oil train.

- The crude column should be able to handle either a 29.2 °API or a 38.7 °API crude feed. It is to be noted that the simulation shows that the top pump-around section of the tower operates at 83% of flood in the 38.7 °API case.

- The crude column overhead condenser middle pump-around exchanger duties are about 20% higher than the base case, which likely means increased surface area or a rearrangement among existing units, should this option take place.

- Light end product rates for the lighter crude are also greater, which would likely require rearrangement of the heat exchange train.

Additionally, the effect of different crudes processed in AVD #6 has also been simulated.

Energy improvement opportunities, as determined by the evaluation team in conjunction with the refinery staff, fall into the following areas:

- Improve operating practices in furnace burner operation and maintenance. There are a large number of multiple-burner furnaces. Training in efficient operating techniques would be an aid to energy reduction.

- Improve processing unit energy consumption measurement to allow unit supervisors and operators to better control total energy use and thus costs.

- Gain better understanding of corrosion through non-destructive testing or monitoring which will lead to longer on-stream time, a safer work place and improved profitability.

- Install oxygen analyzers of high reliability on all fired heaters. Add automatic damper controls (as can be justified economically) to keep excess air within desired limits, thus reducing fuel use.

- Addition of heat exchangers in selected areas to recover heat now lost to air and/or cooling water.

- Modify equipment to improve operational throughput or product quality. Change from bubble caps to valve trays, consider structured packing, etc.

- Study modifications of operating units to reduce unit energy consumption and thus total refinery energy consumed. For example, evaluate switching from furfural to NMP as an extractive solvent and combining dewaxing units 2 and 3 into one unit. Improved lube oil blending facilities may also be an attractive project.

- Start a maintenance history system. This would aid in determining failure frequency. Utilization of this information in repair/replacement decisions will lead to improved on-stream time.

- Add in-line blending of gasoline. Improved and tighter control of octane number will yield considerable savings.

- Study options for vacuum bottoms processing such (to increase yield of higher quality and thus more profitable products) as thermal cracking, visbreaking or partial oxidation in addition to a hydrocracker.

A summary of problems and potential emission improvements are as follows:

- Based on the calendar 1990 rate of processing 1.5 wt% sulfur crude oil, a total of over 18 000 tonnes of SO_2 is released to the atmosphere from refinery complex firing of the processed heavy fuel oil with a sulfur content of 3 wt%.

- Approximately five-sixths (5/6) of this fuel oil is burned at the main power plant. The refinery is considering scrubbing for SO_2 removal at the power plant; if this comes to pass, a reduction of 14 500 tonnes per year of SO_2 emission could be achieved. This still leaves about 3 500 tonnes per year of SO_2 emitting from refinery fired heaters. Note that the refinery is continuing its program to switch from fuel oil to natural and refinery gas firing.

- Replacement of existing fuel oil burners with staged combustion low NOx units could reduce NOx emission by 50 to 70%.

- Covering the API separator and installing a refrigerated condenser unit would reduce emission of volatile organics.

While a few of the environmental improvements can be implemented quickly, a considerable amount of capital must be invested for the majority of the needed work.

One must balance the capital investment to achieve environmental goals on one hand, with respect to at least SOx emissions, against the increment cost of lower sulfur crudes. Typically, refiners have opted for low sulfur crude.

It is important to note that disposal of flue gas desulfurization solid waste is a problem in Czechoslovakia. The ground is granular in nature, and simple burial is not a solution due to leachate problems. The cost of special landfill linings (or other solutions) must be added to the investment to account for this problem. Flue gas desulfurization processes that generate sulfuric acid have been considered in the country's desulfurization program.

Overall, the refinery is aggressively pursuing positive changes in energy operational environmental areas. Many of the recommendations made by the DMC team have taken place or are in progress. Further, the Slovnaft technical staff should be complemented on their on-going energy saving efforts and operational changes to improve environmental conditions. They are well trained and technically competent to address continuing opportunities for improvement.

A. INTRODUCTION

ACKNOWLEDGEMENTS

The Davy McKee Evaluation Team would like to express its gratitude to the management and staff of the Slovnaft Refinery for their excellent cooperation and assistance. Special thanks are due also to the following individuals and all personnel in their department.

Jozef Cimbora	General Director
Jozef Mlynar	Technical and Investment Director
Boris Nikolov	Head of the Process Department
Ilja Tesar	Chief of the Chemical Engineering Department
Vlasta Pastusakova	Environmental Protection Manager
Vratko Kassovic	Director of Production
Miroslav Kovac	Head of the Technology Department Oil Production Plant

1. OBJECTIVES

This report and the work entailed to produce it were performed as part of the USAID Emergency Energy Program for Central and Eastern Europe.

It is the objective of this report to present opportunities for energy improvement and reduction of emissions for the Slovnaft refinery in Bratislava, Czechoslovakia. Other defined and specified goals of the study include a consideration of refinery operating flexibility, an evaluation of fuel switching including the use of coal as a substitute for energy supply, and an observation of the plants general condition and of its maintenance practice for its effect on operations. It is a further objective to characterize the modifications for achieving expected benefits in accordance with the magnitude of effort and capital requirements anticipated.

A summary of the stated USAID objectives of this study is as follows:

- To identify changes in operating practices and low-cost modifications to equipment that can be immediately implemented to increase the efficiency of energy utilization, to conserve energy by avoiding unjustified use, and to reduce as far as practical undesirable gaseous, liquid, and solid effluents.

- To identify, characterize, and recommend more-extensive changes in practices, equipment and modifications to the process units, which appear justifiable but at the same time require further study possibly with inputs that may not yet be available.

- To assist the management of each refinery selected in each country, as needed, in the implementation of the changes identified above through on-the-spot assistance (including training sessions for refinery personnel).

This report details the results of the Evaluation & Audit Study. The recommendations of this study to improve energy utilization operations (yields, practices, etc.) and environmental conditions are categorized as follows:

1. Immediate minimum cost recommendations: This category covers zero cost to low cost modifications to the refinery that will be relatively inexpensive and easy to implement. The refinery can normally implement the recommendations with its internal resources.

2. Short term intermediate cost recommendations: This category includes modifications and/or additions to the refinery that will be characterized by costs related to equipment purchases, and/or changes to process operating conditions that could be considered significant. Implementation normally requires outside resources and appropriate justification.

3. Long-term substantial cost recommendations: This category characterizes primarily by significant modifications to current processing capabilities, or installation of additional process units to improve the refiner's competitive refining position into the 21st century. Implementation of this type of recommendation would normally be expensive and time consuming. Implementation requires outside resources and justification.

The recommendations of opportunitiess to improve environmental conditions are categorized as follows:

1. Immediate minimum cost recommendations: This category covers zero cost to low-cost modifications to the refinery that will be relatively inexpensive and easy to implement. The refinery can normally implement the recommendations with its internal resources.

2. Short-term intermediate cost recommendations: This category includes modifications and/or additions to the refinery that will be characterized by costs related to equipment purchases and/or changes to process operating conditions that could be considered significant. Implementation normally requires outside resources, technical and financial, in order to implement for compliance with environmental regulations.

3. Long-term substantial cost recommendations: This category is characterized primarily by significant modifications to current processing capabilities, or installation of additional process units to improve the refiner's competitive refining position in the 21st century. Implementation of this type of recommendation would normally be expensive and time consuming.

   Implementation would require outside technical and financial resources, but compliance could be complicated by the presence of other major polluters in the area and priorities for implementation need to be taken in the context of a complex system. Governmental regulatory policy may be an important input here.

2. BASIS FOR SELECTION

Selection of the Slovnaft facility in Bratislava, Czechoslovakia for Evaluation and Audit study was set by USAID agreement in December 1990, based on a representative and proper geographic balance within the country. The facility, one of the largest in the country, is a refining and petrochemical complex. Refinery management selected specific processing units for review based on a variety of variables, the primary being perceived need for improvement.

Units selected for review included the following; listed in order of mutually agreed upon priorities, as shown in Table A.2.1.

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TABLE A.2.1 - REFINERY UNITS EVALUATED

UNIT	CAPACITY (Tonnes/Year)
Atmospheric Distillation #6 (AVD#6)	2 200 000
Furfural Extraction Unit #2	200 000
Dewaxing Unit #2	110 000
Dewaxing Unit #3 (RP #3)	150 000
Hydrofinishing Units (2) (HRO)	110 000 Total
Gas Oil Hydrodesulfurizer #5 (HDS #5)	600 000
Kerosine Hydrodesulfurizer #6 (HDS #6)	600 000
Gas Desulfurization #2	130 000
Gas Separation #2	200 000
Sulfur Units (2)	24 000 Total

The basis for selection of specific operating units was driven by a need to perform useful and meaningful study within the established, schedule and team composition, included those units that were felt to be representative or typical (AVD #6 is similar to AD #4 and AD #5). Other units were selected for study where management felt they were especially troublesome with respect to operations and/or experienced high energy utilization. The new Dewaxing Unit #3 was chosen for this reason; it is reported to use many times the energy per metric ton of feed compared with the older Dewaxing Unit Number 2. The Hydrodesulfurizers #5 and #6 were selected as typically representative of other HDS units within the refinery. The lube oil train (furfural, dewaxing and hydrofinishing units) was chosen for review as the refinery recognized the need to upgrade the older lube oil system, due to perceived increasing market demands. The gas separation, gas desulfurization and sulfur plants, in addition to rounding out the review by including the gaseous product facilities, also represent the opportunity to consider the effect of changes to light end processing as it effects sulfur emissions.

As primary suppliers and users of energy, the electrical generation and other utility systems were reviewed in parallel with the process units. The environmental areas and the pollution control units were also studied.

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3. SUMMARY OF FIELD ACTIVITIES

The Davy McKee evaluation of the selected part of the Slovnaft refinery took place over a three-week period, from 20 May 1991 to 8 June 1991. The refinery management requested the team to direct its activities toward those units within the complex that were the most troublesome or were believed to be prime candidates for improvement. Specifically, these units were as follows (see Table A.2.1).

- Atmospheric Distillation Unit #6, which included the crude oil atmospheric section, the vacuum distillation unit, the naphtha re-run column, and the gas stabilizer.
- The lubricating oil production train, which consists of furfural extraction, the dewaxing system and hydrofinishing.
- Two (2) hydrotreaters, one for kerosene and the other for gas oil.
- A gas desulfurization unit.
- A gas separation (LPG) plant.
- Two (2) sulfur plants.

The evaluation team consisted of four members, each representing a different engineering discipline: Thomas Dempsey, Electrical and Instrumentation; George Hamilton, Mechanical; Jan Zapletal, a Czech consultant with extensive in-country refinery experience who also provided translation where needed; and Robert Jurish, Refinery Process Engineer and evaluation team leader. In addition, Environmental Engineer, Charles Best, the Team Leader for CSFR, P.D. Agrawal, Project Manager, and Eva Kostelkova a Czech consultant who provided administrative and translation services, spent one week at Slovnaft conducting the environmental site survey and evaluation.

The field activities consisted of process reviews of each of the selected units, with members of the refinery engineering, operation, management and economics analysis staff. Additionally, each unit was visually inspected by team members, with respect to their area of expertise. Refinery counterparts were made available to each of the team members as-needed. In addition to a "process unit" or systems approach to analysis, the DMC team viewed the refinery from an overall mechanical, electrical and instrumentation perspective, reviewing areas such as: pumping systems, fired heaters, steam and electrical generation, heat exchange, and acquisition of process variables (temperature, pressure, etc.) for data collection purposes.

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For the most part, the team relied on data obtained or provided by the refinery staff or through refinery reports and operating logs. They did, however, request and observe the measurement of excess oxygen and resulting furnace efficiencies for selected fired heaters. Specifically, field data was obtained for fired heaters in Atmospheric Distillation #4 and #5 and Furfural Unit #2. As will be shown subsequently in the later section of this report, opportunities exist to achieve energy savings through reduction in excess air and improved burner operation.

State-of-the-art portable gas analyzers were locally available through the refinery inspection department. As a standard practice these units are used by the refinery to periodically monitor fired heater operations. Despite this activity, fire controls were not adjusted to reduce excess air in fired heaters, let alone to approach the levels seen in US refineries.

As was mentioned, the selection of units was oriented to areas where problems have been observed from the viewpoint of energy consumption, process flexibility and product quality. The evaluation took place in cooperation with the technical and operating personnel of the plant, following the general outline as listed below.

- Physical inspection of facilities and operating units
- Twelve months history (review material processed and energy utilized) of the units
- Process flow sheet and operations review
- Energy conservation possibilities
- Determination of environmental impact of the unit and opportunities for reduction
- Development of recommendations for improvements

The process review concentrated on the AVD #6 (atmospheric and vacuum distillation), as it is the key unit for lube oil production and anticipated changes in crude supply would have a significant impact on the entire lube oil processing train.

During the evaluation process, discussion with refinery personnel, revealed the following problems:

- Increase of AVD #6 unit capacity is desirable, because the downstream lube units have the capability of processing larger quantities of feed.

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- Better fractionation (to reduce overlapping) between kerosene and gas oil may help to alleviate difficulties in downstream processes. The reduction of overlapping of vacuum distillates (20 to 60 °C) would improve the quality of lube oils produced.

- Inability to heat the crude to the design fired heater inlet temperatures through the crude oil heat exchange train. (Design temperature of the inlet to the furnace is 245 °C, whereas actual temperature at the time of the visit was about 205 °C.) Subsequent correspondence with the refinery states that this temperature is now up to 225°C.

A computer simulation was performed for the AVD #6 crude unit based on data supplied by the refinery. Computer aided chemical engineering operations simulations are a necessary tool in today's refinery engineering department. The speed of calculation of complex problems and relationships allows the refiner to model and analyze operating variables and options very rapidly. The use of computer simulation as a tool for Slovnaft would allow the technical staff to sort through a large number of operating options with multiple variables, thus providing management with more optimal solutions. Changing crude supplies, which is likely, will enhance the need for simulating crude unit and subsequent downstream operations. Highlights of the alternate crude feed simulations are as follows:

- A lighter feed, 38.7 °API, results in 35% less flow to the vacuum unit, which reduces flow through the lube oil train.

- The crude column should be able to handle either a 29.2 °API or a 38.7 °API crude feed. It is to be noted that the simulation shows that the top pump around section of the tower operates at 83% of flood in the 38.7 °API case.

- The crude column overhead condenser middle pump around exchanger duties are about 20% higher than the base case, which likely means increased surface area or a rearrangement among existing units, should this option take place.

- Light end product rates for the lighter crude are also greater, which also likely would require rearrangement of the heat exchange train.

Additionally, the effect of different crudes, processed in AVD #6 has also been simulated.

The lube oil production units are not in optimal balance and dewaxing unit No.3 is in need of major engineering and revamp efforts to improve operations and energy efficiency. The overall economics of lube products is directly coupled to optimizing lube train operations and improving/revamping of dewaxing unit #3.

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The facility design basis and current feedstock is crude oil from the USSR, supplied by an existing pipeline. Other crude sources are being evaluated but their transportation means into the refinery is contingent upon a variety of new pipeline possibilities.

The power station and maintenance system were reviewed and areas of possible improvements are suggested with this report, such as establishing a historic maintenance data base.

4. REFINERY DESCRIPTION

The Slovnaft Refinery is a large petrochemical complex, with selected refining units providing feed materials for the production of petrochemicals, motor fuels, lube oils, fuel oils and greases, primarily for the domestic market. A Block Flow Diagram, (Figure 1) illustrates the relationship of various process units. The refinery is an initial part of the complex, and was constructed in the period between 1960-1970. The technological level of the units at this time is viewed as adequate. Over the years, some of the processing units were modified to better fit new product specifications and/or reduce energy consumption. The refinery consists of three crude distillation units with a capacity of approximately 2.2 million tonnes per year each. The distilled products (naphtha, kerosene and gas oils) are desulfurized and treated to meet corresponding product specifications. One of these crude units (AVD 6) is associated with a vacuum tower. The vacuum distillates are furfural extracted, dewaxed and after hydrofinishing blended to commercial lube oils.

There is production of light fuel oil (distillate) with low sulfur content and heavy fuel oil (residual) with a sulfur content up to 3% by weight. The atmospheric residue from AD 4 and 5 is fed to the hydrocracker vacuum tower.

Outside battery limits facilities reviewed in varying levels of detail were:

- Power Station
- Water Treatment Plant
- Warehousing/Maintenance/Fabrication Equipment and Repair
- Oil Movements Facilities
- Main Distribution Substation
- Analyzer/Advance Control Group Facilities

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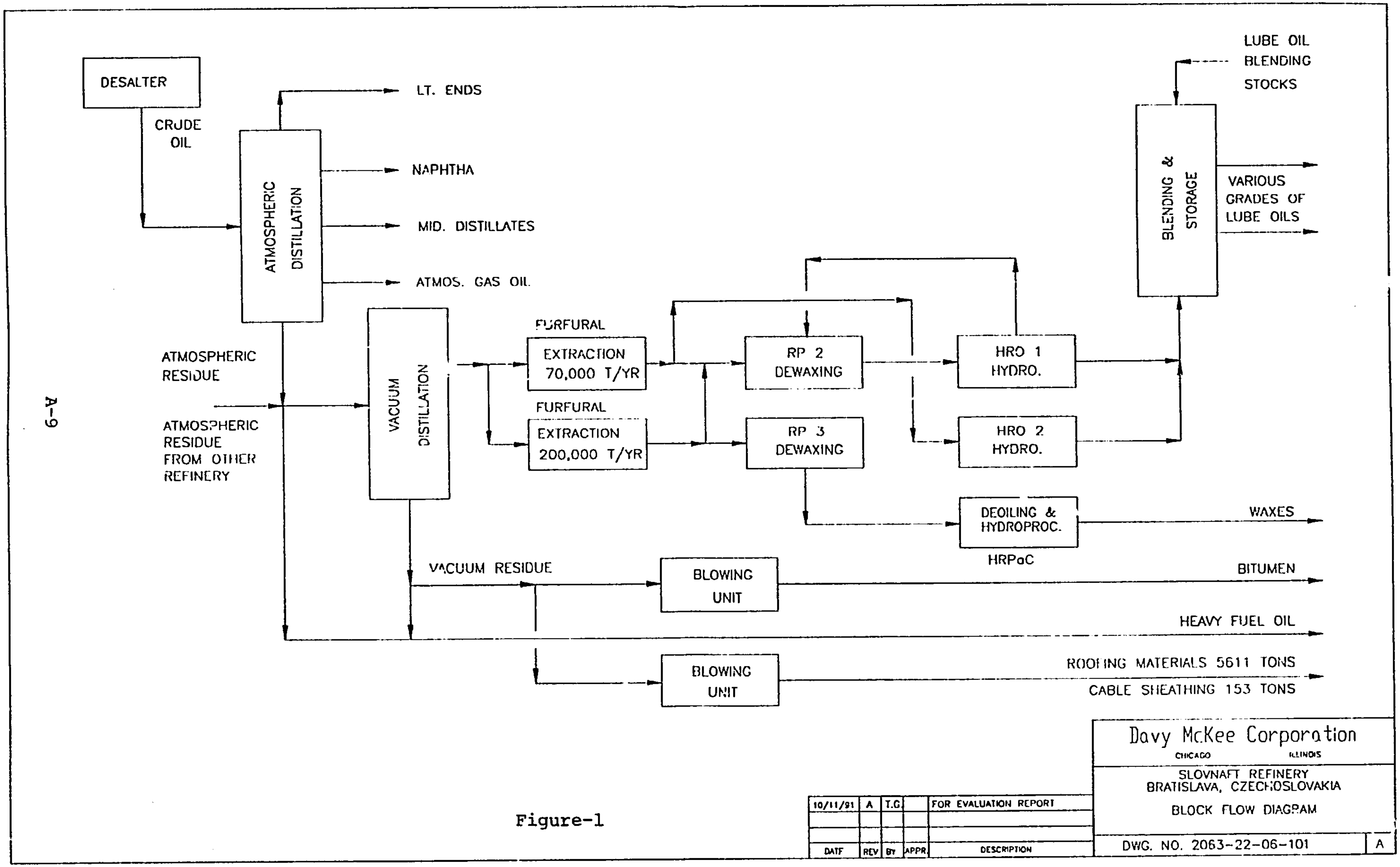
DESALTER
CRUDE OIL
ATMOSPHERIC DISTILLATION
LT. ENDS
NAPHTHA
MID. DISTILLATES
ATMOS. GAS OIL
ATMOSPHERIC RESIDUE
ATMOSPHERIC RESIDUE FROM OTHER REFINERY
VACUUM DISTILLATION
FURFURAL EXTRACTION 70,000 T/YR
FURFURAL EXTRACTION 200,000 T/YR
RP 2 DEWAXING
RP 3 DEWAXING
HRO 1 HYDRO.
HRO 2 HYDRO.
DEOILING & HYDROPROC.
HRPaC
LUBE OIL BLENDING STOCKS
BLENDING & STORAGE
VARIOUS GRADES OF LUBE OILS
WAXES
VACUUM RESIDUE
BLOWING UNIT
BITUMEN
HEAVY FUEL OIL
BLOWING UNIT
ROOFING MATERIALS 5611 TONS
CABLE SHEATHING 153 TONS
Davy McKee Corporation
CHICAGO ILLINOIS
SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA
BLOCK FLOW DIAGRAM
DWG. NO. 2063-22-06-101
A
10/11/91 A T.G. FOR EVALUATION REPORT
DATE REV BY APPR DESCRIPTION

Figure-1

Part of the refinery production is shipped by product pipeline, the rest by railroad or truck. Shipping product by barge via the Danube river is an option available for product movement, and is used for shipment of a portion of the production.

Crude oil is supplied by pipeline from the USSR. Slovnaft has a power station and the facilities needed to supply the necessary utilities as well as waste treatment for the complex. In addition, effluent waste are treated at the refinery site prior to discharge to the atmosphere or receiving waters.

It should be noted that the Slovnaft Refinery is designed to handle crudes with a sulfur content in the 1.5 wt% range, which results in 3 wt% sulfur in the heavy fuel oil. Other products meet or exceed sulfur content specifications. Acquisition of lower sulfur crudes may be attractive, but one should not lose sight of the refinery's sulfur handling capability, which includes distillate HDS units, gas and liquid LPG desulfurizers and sulfur plants. In addition, the options offered by deeper bottoms processing are under evaluation by the refinery staff.

5. TYPES OF ENERGY IMPROVEMENT OPPORTUNITIES

Energy improvement opportunities, as determined by the evaluation team, in conjunction with the refinery staff, fall into the following areas:

- Improve operating practices in furnace burner operation and maintenance. There are a large number of multiple-burner furnaces. Training in efficient operating techniques would be an aid to energy reduction.

- Improve processing unit energy consumption measurement to allow unit supervisors and operators to better control total energy use and thus costs.

- Gain better understanding of corrosion through non-destructive testing or monitoring which will lead to longer on-stream time, a safer work place and improved profitability.

- Install oxygen analyzers of high reliability on all fired heaters. Add automatic damper controls as can be justified economically to keep excess air within desired limits, thus reducing fuel use.

- Addition of heat exchangers in selected areas to recover heat now lost to air and/or cooling water.

- Modify equipment to improve operational throughput or product quality. Change from bubble caps to valve trays, consider structured packing, etc.

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- Study modifications of operating units to reduce unit energy consumption and thus total refinery energy consumed. For example, evaluate switching from furfural to NMP as an extractive solvent and combining dewaxing unit 2 and 3 into one unit. Improved lube oil blending facilities may also be an attractive project.

- Start a maintenance history system. This would aid in determining failure frequency. Utilization of this information in repair/replacement decisions will lead to improved on-stream time.

- Add in-line blending of gasoline. Improved and tighten control of octane number will yield considerable savings.

- Study options for vacuum bottoms processing such (to increase yield of higher quality and thus more profitable products) as visbreaking or partial oxidation in addition to a hydrocracker. Put coker back on stream.

6. TYPES OF ENVIRONMENTAL EMISSIONS IMPROVEMENT

Section K of this report lists specific emission based on reported observations in section I. A summary of problems and potential emission improvements are as follows:

- Based on the calendar 1990 rate of processing 1.5 wt% sulfur crude oil, a total of over 18000 tonnes of SO_2 was released to the atmosphere from refinery complex firing of the processed heavy fuel oil with a sulfur content 3 wt%.

- Approximately five sixths (5/6) of this fuel oil is burned at the main power plant. The refinery is considering scrubbing for SO_2 removal at the power plant; if this comes to pass, a reduction of 14500 tonnes per year of SO_2 emission could be achieved. This still leaves about 3500 tonnes per year of SO_2 emitting from refinery fired heaters. Note that the refinery is continuing its program to switch from fuel oil to natural and refinery gas firing and the fired heater SO_2 emissions are falling.

- Replacement of existing fuel oil burners with staged combustion low NOx units could reduce NOx emission by 50 to 70%.

- Covering the API separator and installing a refrigerated condenser unit would reduce emission of volatile organics.

While a few of the environmental improvements can be implemented quickly, a considerable amount of capital must be invested for the majority of the needed work.

One must balance the capital investment to achieve environmental goals on one hand, with respect to at least SOx emissions, against the increment cost of lower sulfur crudes. Typically, refiners have opted for low sulfur crude.

It is important to note that disposal of flue gas desulfurization solid waste is a problem in Czechoslovakia. The ground is granular in nature, and simple burial is not a solution due to leachate problems. The cost of special landfill linings (or other solutions) must be added to the investment to account for this problem. Flue gas desulfurization processes that generate sulfuric acid have been considered in the country's desulfurization program.

B. REFINERY ENERGY SYSTEMS AND CONSUMPTIONS

1. OPERATING UNIT ENERGY USE

The stated intent of the USAID Implementation/Evaluation effort was to review selected refinery process units, and specific equipment categories with a high potential for energy conservation such as fired heaters and/or utility systems including, but not limited to, electrical and steam generation and cooling water.

As has been noted elsewhere in this report, Slovnaft management specifically requested the evaluation team to concentrate its efforts in the refinery areas that it had pre-determined to have the greatest potential for improvement or that were viewed as being troublesome from an operations point of view. Accordingly, a detailed analysis/review of overall refinery consumption is not part of this report. Table B.1.1 shows energy and utility consumption for selected refinery units.

The decreasing and irregular supply of crude oil and the effects of more energy intense processing requirements for production of feedstock for plastics, reduction of naphtha imports and hydrocracker start-up, resulted in a slight increase of fuel and energy costs in 1990 as compared to 1989.

When energy use is measured in terms of Energy Units (BTU or Joules) per tonne of crude oil processed, an increase is noted from 1989 to 1990. However, through cost effective selection of fuels and efficient scheduling and utilization of production facilities, the cost of fuel and energy to total material expenditures was kept essentially flat for 1989 and 1990. This effect is dramatically demonstrated by noting that April 1990 to April 1991 total energy costs increased by 113%, while total energy cost to total value of products increased only 30%. As noted above, however, the yearly version of the latter value (energy cost to total product value was essentially the same. Table B.1.2A is included to provide a view of selected energy data and production ratios from the 3 year 1989 to 1991 time frame.

As of 15 January, 1991, liberalized pricing in the CSFR has allowed price changes not only in crude oil, but monthly regulated changes in product prices as well.

Cost rates per energy unit used in internal energy accounting have changed rapidly in the last year (1990 to 1991) as the refinery moves to align its internal energy prices to nominal world values. Table B.1.2.B provides a 3 year picture of selected utility costs.

Note that the 0.4 MPa steam of AVD6 is generated internally within the unit. It is included in the table to facilitate an understanding of total steam need/consumption. It should be understood that the energy content of the fuel fired in AVD6 is responsible for generating this low pressure steam (and/or resultant superheat) through heat recovery from product streams within the unit.

Utility data from evaluated units other than those in Table B.1.1 were not available in the detail needed to be useful.

Table B.1.3 is included to show and compare major utility costs used by the refinery to such typical values currently in use in the U.S. in preparing non-site specific Order of Magnitude Economic Analyses.

Utility data from evaluation units other than those in Table B.1.1 were not available.

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TABLE B.1.1 - ENERGY AND UTILITY CONSUMPTION FOR SELECTED REFINERY UNITS

Unit Name	Data Basis	Throughput Basis	Electrical Consumption (kWh)	Fuel (tonnes)	1.2 MPa Steam (tonnes)	0.6 MPa Steam (tonnes)	Cooling Water (m^3)	Comments
Atmospheric Distillation Unit #6	for calendar year 1990 (actual)	2 102 567 tonnes crude oil	13 442 469	26 461	47 602	49 725	10 368 563	reduced capacity in Feb and March '90
Furfural Unit #2	for calendar year 1990 (actual)	191 322 tonnes of feed	2 058 716	4 534	24 383	19 270	5.4×10^6	reduced capacity in Feb and March '90
Dewaxing Unit #3	last half calendar year 1990 (actual)	37 185 tonnes of feed	30 711 972	1 934	20 252	3 477	0.12×10^6	data for last 6 mo of '90, which reflect start-up period
Gas Oil Desulfurization Unit #5	calendar year 1990 (actual)	701 792 tonnes of feed	13 500 000	4 132 (oil) 3 167 (gas)	5 700	5 386	actual n.a. design 4.95×10^6	434 hours of downtime in '90
Kerosene Desulfurization Unit #6	calendar year 1990 (actual)	341 432 tonnes of feed	56 60 000	2 507	1 812	1 723	actual n.a. design 3.54×10^6	807 hours of downtime in '90

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Table B.1.2.A
SELECTED FUEL AND ENERGY DATA

	1989	1990	1991
Crude Processed Millions of Tonnes	7.836	6.19	4.969

The following data is a ratio (Kcs/Kcs)of the indicated utility cost to total refinery material costs.

Electric Power	18.096	17.182	19.4
Water	6.477	5.204	5.525
Natural Gas	16.017	22.996	23.094
Fuel Oil Production	71.732	76.369	74.019
Fuel and Energy	115.328	124.574	124.236

Table B.1.2.B
AVERAGE ENERGY PRICES*

	1989	1990	1991	Dec 1991
Elect. Power Kcs/MWh	460	460	1100	1300
Fuel Gas Kcs/Tonne	1770	1770	4900	4900
Water, Kcs/M^3x10^3	460	460	950	950
Heavy Fuel Oil, Kcs/Tonne	1430	1440	2250	2200
Natural Gas, Kcs/M^3x10^3	1530	1530	3200	2900 (1)

* Conversion rates at the time of this report were in the range of 28 to 30 Kcs/U.S. dollar.
(1) 1 Sept 91 to 31 Dec 91, temporary decrease.

Table B.1.3.
COMPARISON OF SLOVNAFT APRIL 1991
UTILITY RATES TO TYPICAL UTILITY UNITS USED FOR
REFINERY ECONOMIC ANALYSIS

Utility	Slovnaft		Typical
	Kcs/unit	\$/unit[1]	
Electricity	1 134.77 Kcs/MWh	0.0378 \$/kWh	0.06 \$/kWh
Cooling Water	0.92 Kcs/m^3	0.12 \$/mgal	0.10 \$/mgal
Fired Fuel	Basis 2 200 Kcs/tonne "External Price"	\$1.92/million BTU	\$3.00/million BTU

(1) At 30 Kcs/US\$ (Kcs is the abbreviation for the local unit of currency, the Koruna or Crown)

Energy consumption per ton of feedstock within the dewaxing unit #3 (RP#3), which was designed and built by the Russians, is reported to be much greater than that of the older unit (RP#2). It was obvious that RP#3 offered a high potential for substantial energy reduction. The complete analysis and solution to the problem, is however, a complex task, beyond the scope of, and time available to the evaluation team. Refer to the energy improvement opportunity section of this report for a few specific recommendations regarding imorovements to the Slovnaft dewaxing operations.

The refinery is considering the addition of a hot separator to desulfurizer unit #6 and adding two heat exchangers in order to improve energy efficiency. We concur with these changes. The refinery also is planning to replace the reactor on HDS #5; the proposed increase in reactor volume would allow a lower reactor inlet temperature, thus requiring less heat input to the fired heater. It was felt that since the reactor is reportedly due for replacement because of maintenance/age reasons; that a replacement unit with a larger volume would be appropriate. Note that historical maintenance data was not available to support the reported equipment condition.

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2. FUEL SYSTEM

2.1. Fuel Sources

Fuel gas and fuel oil is used throughout the refinery. No coal firing is utilized. The fuel gas consists of a mixture of refinery gases (produced in the various process units) and imported natural gas. The fuel gas characteristic data is presented in Table B.2.1.

The refinery has been planning to use vacuum residual as a supplemental fuel. The characteristics of this residual and fuel oil pool data are presented in Table B.2.2. Sulfur levels of 3 wt% are high and pressure exists to reduce SOx emissions. The residual fuel oils produced by the various bottoms processing units are presumably blended in tankage. This was not verified.

2.2. Fuel Distribution

The refinery gas and imported natural gas are blended and distributed throughout the refinery fuel system. Day tanks are used to measure fuel oil feed to fired heaters and in the case of the furfural unit, extract is fired directly, with the remainder flowing to the fuel oil pool. It should be noted that when available, fuel gas is the preferential fuel for fired heaters.

2.3. Fuel Users

Fuel gas and fuel oil is utilized throughout the complex in various fired heaters. It appears that refinery gas and residual refinery liquid materials are fired preferentially. These liquid product fuel sources are those naturally (as by-product) produced by the processing unit for which there is little demand or economic incentive to process further, but usually contain considerable amounts of sulfur.

The objective, therefore, is to use the bottoms materials and other refinery lower value products of the complex as a fuel and minimize the import of natural gas from outside. However, because of the need, and refinery managements desire, to reduce total site SOx emissions and because they represent single source, significant contributors to the total site SOx emission, some of the refinery heaters now use only natural gas as a fuel source.

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TABLE B.2.1. - FUEL GAS DATA

PROPERTY	SOURCE	
Composition (Volume %)	REFINERY	IMPORTED
H_2S	0 - 0.6	
H_2O		
CO		
CO_2		0.1 - 0.5
O_2		
N_2		0.8 - 0.9
H_2	8 - 30	
C_1	20 - 60	96 - 98
$C_2=$		
C_2	5 - 30	0.7 - 1.4
$C_3=$	4 - 20	
C_3	4 - 12	0.2 - 0.4
$C_4=$		
C_4		0.1 - 0.2
i-C_4		
n-C_4		0.1 - 0.2
$C_5=$		
i-C_5	1 - 4	
n-C_5	1 - 4	0.02 - 0.04
C_6+	1 - 8	0.02 - 0.04
MERCAPTANS		
TOTAL	100%	100%

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TABLE B.2.2. - FUEL OIL DATA

TYPE	HEAVY FUEL OIL
Distillation, Volume 10% 90%	-- --
Viscosity at 80°C, mm^2/sec	57 to 100
Flash Point, °C	140
Pour Point, °C	40
Sulfur, %wt.	3.0
Carbon Residue %	15
Ash, % wt.	--
Corrosion, Copper Strip	--

3. STEAM SYSTEM

3.1. Steam Generation

The Energy Division has various plants throughout the Slovnaft Refinery/Chemical Plant complex, and supplies electricity, steam, plant air, instrument air, cooling water, chemical water/demineralized water for high pressure steam, and softened water.

The power station contains eight high pressure 9.6 MPa (1 400 psi) boilers. Their normal operating procedure is to swing two boilers and base load the rest. They try to base load the most efficient boilers, but the desire to swing only two boilers makes it necessary to base load the small boilers in order to have enough swing capacity. There are ten boiler-feed water pumps, seven with electrical drives and three are steam turbine driven.

The steam ratings of the power station's four turbo-generators are:

- One 29 MW machine, extraction at 0.6 MPa, exhaust at 0.12 MPa.
- One 24 MW machine, extraction at 1.2 MPa, exhaust at 0.6 MPa.
- Two 25 MW machines, extraction at 1.2 and 0.6 MPa, partial condensing.

The inlet pressure to these machines is about 9.6 MPa. The turbines were domestically manufactured by Prvni Brnenska Strojirna and the generators by PLZEN (Skoda). There is a 10% service factor on the generators. The power station, viewed on the inside, resembled that of a large U.S. refinery doing steam turbine cogeneration (Rankin cycle).

The steam side control room is large (15 meter square) with Czechoslovakian manufactured miniature (6"x6") board mounted control instruments and recorders. For the past year, the steamside has been controlled by a Foxboro I/A Distributed Control System (DCS). The Foxboro I/A is "state-of-the-art" control equipment.

Their Distributed Control System (DCS) has one floor-type operator's console and two separate color monitors, along with controls mounted into the control panel. They are using a boiler monitoring computer program, which runs in English and was developed by Foxboro, Netherlands to do continuous boiler monitoring.

About 10% of the 9.6 MPa. steam is desuperheated, while the rest is expanded through the turbines. The horizontal surfaces in the control room and power station were covered with a gritty dust. A good industrial vacuum cleaner is needed; this poor housekeeping practice has the potential to damage the computer and instrumentation.

There are four small boilers outside of the power station, built in 1976 producing 25 tonnes/hr each of 1.2 MPa steam. These boilers are fired with natural gas or fuel oil (combination oil burners) and normally operated only during winter months. There are automatic start-up and shut-down controls on each boiler. Fuel is metered by twin ITT turbine motors mounted in series for each burner. Within the last several years, because of the energy conservation program the steam consumption was reduced to the point that these boilers are now used very rarely (in emergency cases only).

Steam is also generated and/or superheated in the convection section of various refinery furnaces and in the refinery furnace flue gas waste heat boiler AD-4.

The water for the various boilers and waste heat unit is furnished from a water treatment plant which is supplied with Danube River water. Two high quality streams from this unit are used for steam.

- Softened water (used in boilers 0.4 MPa. and under)
- Demineralized water (used in boilers over 0.4 MPa)

3.2. Steam Levels

The four steam pressures produced in the complex's power station are:

- 9.6 PMa (1410 psi) delivered to turbines and desuperheaters only
- 3.5 PMa (512 psi) by extraction and desuperheating
- 1.2 PMa (176 psi) by extraction and desuperheating
- 0.6 PMa (88 psi) by extraction and turbine back pressure
- 0.4 PMa steam is the pressure level generated within the local waste heat units.

Steam conditions are shown in Table B.3.2. and direct costs (budget) for the steam at Slovnaft refinery in 1991 are shown in Table B.3.3.

Table B.3.2. - STEAM CONDITIONS

System Identification	Pressure - Atmospheres				Temperature - °C			
	Min.	Norm.	Max.	Design	Min.	Norm.	Max.	Design
9.6 PMa.	80	90	98	93	578	535	540	535
3.5 PMa.	34.5	35	35.5	35	330	350	380	350
1.2 PMa.	9.0	10.2	12.0	11.8	280	290	300	290
0.6 PMa.	3.5	4.5	6.0	5.0	190	210	230	210

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Table B.3.3. - 1991 Steam Costs

Steam Pressure PMa.	Produced at (location)	Price Kcs/Tonne
3.5	Waste heat boiler	254
1.2	Power station	344
1.2	Waste heat boiler	250
0.6	Power station	327
0.6	Waste heat boiler	237
0.4	Power station	318
0.4	Waste heat boiler	231

For April 1991, steam costs for the refinery averaged about 68.3 Kcs/GJ, which is about $2.40 US/million BTU's. Steam prices for the refinery have risen dramatically the past couple of years and the trend to increase is expected to continue (although not as rapidly) as energy prices rise to match free market values.

3.3. Steam Users

Steam at the various pressure levels is metered using annubars (averaging Pitot tubes), as it leaves the power station (Energy Division) and goes to the refinery. It is metered again at the process units.

The refinery uses steam for the following purposes:

- Process heating as in reboilers
- Process stripping steam
- Motive power for steam turbines and direct acting steam pumps
- Atomizing steam for furnace burners using heavy fuel oil
- Equipment and line heating for freeze protection and heat maintenance
- Building heating and potable hot water

4. ELECTRIC POWER SYSTEM

4.1 Electricity Sources/Generation

The Slovnaft Refinery/Chemical Plant Complex co-generates approximately 50% of its power usage. The power station has four turbo-generators (24MW, 25MW, 25MW and 29MW). The additional power needed is obtained from the national grid. The primary distribution voltages are 110 kV and 6 kV. Emergency power is available from the grid at a reduced MW level.

A control room, about one half a kilometer (1/2 km) away from the steamside control room, controls the power station electrical side, the complex's electrical distribution system and the tie to the national power grid (110 kV). The electrical control room is spacious and wood paneled. About one quarter (1/4) of the control panel is devoted to the four turbo generators, another quarter (1/4) section to the National Grid Tie and the remaining half (1/2) to the complex's distribution system. Nine sets of dual 110 kV radial feeders leave the power station switching yard and go to the nine main substations located throughout the refinery / chemical plant complex. The 6 kV feeders leaving the main substations are controlled and monitored on the control panel.

The power factor for the electricity coming in on the National Grid is 0.83. The power factor for Slovnaft is 0.80. The electrical capacity of the grid tie is 63 MVA. The electrical system is able to start Slovnaft's largest motor (10.8 MW/14 500 HP) across-the-line.

4.2. Electric Distribution System

At the power station, electric power is generated at 6 kV and transformed up to 110 Kv for distribution. The 25 MVA transformers used have efficiencies that normally run about 99.95%. In the Slovnaft complex, the furthest main distribution station has a 110 kV cable run under 3 km. At 110 kV the line losses (I^2R) are at a reasonable low level. From the main substation to the motor control centers (MCCs) the distribution voltage is 6 kV and the distances under 1 km also holding line losses to low levels. At the MCCs, located adjacent to the process units they serve, some of the 6 kV power is transformed down to 380/220 volts for power and lighting. Motors 160 KW (215 hp) and over are powered at 6 kV. This practice helps to minimize motor line losses as well as voltage regulation problems.

Slovnaft utilizes an extensive electrical tray systems to carry power and data signals throughout the Petrochemical complex. For this tray system, they have developed a standard module that is used throughout the plant. This module is a bridge-like structure that is 5 m wide, 4 m high, and 20 m long. In cross-

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section, there is a walkway, two banks of trays, another walkway and one more bank of trays. The tray banks are 0.5 m across and six trays high. The bridge tray module is covered with a heavy corrugated, galvanized metal roof. The system appears to be about 40% loaded.

A pair of columns are installed, every 20 m, to support the bridge sections. The distance from grade to the bottom of the tray bridge is about 13 m. A caged ladder leading up to the walkways is installed every 100+ m. The steel structure looks adequate enough to support the system even if all the trays were filled with large conductor, lead-shielded cables.

One of the Slovnaft Complex's main substations lies just north of the main crude unit AVD-6. This substation is a quite large three story reinforced concrete building. The substation is fed by two 110 kV feeders, each consisting of three single phase conductors. Each feeder was connected to the primary side of a Skoda built 110 kV/6 kV 20 MVA oil filled transformer. The transformers are rail mounted outside the substation in three sided reinforced concrete vault type structures. The front side consists of a center opening, tall wire mesh gate with the rail track running down the center and about 12 m outside the gate. The transformers can be quickly disconnected and pulled along the rail outside the vault to a paved drive for a fast change out.

The substation building structure contains two sets of mirrored 6 kV equipment for 32 'A' feeders and 32 'B' feeders. The 'A' equipment is fed by one transformer and the 'B' equipment by the other. Each feeder is housed in a vault, consisting of three concrete sides and a steel mesh front panel. The equipment is basically air-break outdoor equipment, installed indoors, with bus bar for connections. The feeders start in vaults on the first floor with fuses, a pneumatically operated switch and connecting bus bar. The feeders continue up through the ceiling in insulator bushings to a second floor vault where current transformers (CTs), kWh meters and protective metering are installed. The feeders then continue through insulating bushings to a vault on the third floor. There connections are made to the feeders cables which leave the substation in the overhead bridge tray system.

The substation is a little over two years old. The housekeeping was immaculate and neither any equipment being worked on or needing to be worked on was seen.

The electrical system's reliability has been enhanced by a high degree of redundancy. As an example, dual 110 kV feeders transmit power from the power station to the main substations and then feed dual stations buses. From the main substations, dual 6 kV feeders distribute power to the motor control centers

(MCCs)/substations feeding their split buses. Slovnaft's cable is either in a secure cable tray system or routed underground. With Slovnaft's electrical distribution system high redundancy and minimal line losses no economical suggestions to minimize these losses can be made at this time.

4.3. Electrical Power Users

The voltage level from the main distribution centers to the process unit MCCs is at 6 kV. Oil filled transformers, when used, are located outside the MCCs in concrete vaults. Air cooled dry transformers, when used, are located inside the MCCs in steel cubicles. The MCC at AVD-6 has three power and one lighting transformer outside the MCC in three side vaults and the secondary is fed into the MCC by bus bar. Each rack of the 380 volt motor starters was double ended fed. The starters are domestically made, they use fuses for instantaneous protection, current transformers (CTs) to keep heater current down and supply current to ammeters and an elapsed time meter to supply motor run time. Each cubicle had two to eight starters, depending on motor size. There was also a cubicle rack with a capacitor bank, switches and a power factor controller.

The 6 kV and some 380 V motors were fed underground, but the majority of AVD-6's 380 volt equipment and the 220 V lighting was fed by overhead trays. Slovnaft says that their present design standard is to route all electrical cables overhead. Also, in areas outside Div.I and Div.II, (API RP-500A), aluminum is used for cost savings. On the process units, copper conductors are used.

The lighting transformer fed a 380/220 V cubicle rack. The 380/220 V power was fed, from fused switches in the cubicles, to lighting distribution panels on the unit. Emergency lighting (220 V) was fed from a battery bank. Safety lighting at 24 V is supplied from special 220/24 V transformers.

The 6 kV electrical equipment is housed separately from the 380 and 220 V switch gear and serviced by the company electricians. The incoming cubicle in a typical 6 kV switch gear line-up contains the following equipment: current and potential transformers, an instantaneous current relay, differential current relay, overload current relay, ground fault relay, crude unit fire detection sensor (to remove power upon detection), voltmeter and ammeter. The motor starter cubicles contain current transformers, instantaneous relay, time over current relays, and ammeters. The transformer cubicles have current transformers, an instantaneous current relay, ground fault relay, time over current relay and a high pressure oil-filled breaker.

5. COOLING WATER SYSTEM

Two batteries of mechanically drafted and dedicated cooling towers were surveyed at the #2 and #3 dewaxing units. The cooling tower at the #2 dewaxing unit was in a state of disrepair, although it was in constant use. The cooling tower at the #3 dewaxing unit located some 100 m from the one at #2 unit, was built about 1990 and is used intermittently. The refinery has already identified the poor condition of the older unit and has tentative plans to more fully utilize the new battery with possible abandonment of the old facility.

Chilled water from the #2 dewaxing unit is used in the wax pelletizing machine at the product packaging facility.

Basically, the best of the cooling water system is a "once-through" draw from the Danube River and refinery cooling is not differentiated from the total plant cooling effort. A small portion, less than 5% of the cooling water for the plant is obtained from a well.

Water flow control is accomplished by individual manual valves needing operator attention. Since it is felt that water-side fouling is affected by water flow rate, adjustments are not often made.

It was recommended that, due to the cooler temperatures, the cooling tower flow rates could be reduced in the winter, thus saving some pump and fan energy costs. Additives to minimize fouling were discussed and Slovnaft has talked to Nalco, but no action has been taken to date. Water-in-line cleaning of fouling is done on the water side of the cooling water system and the refinery personnel stated that it works well.

6. AIR COOLERS

Air coolers were not examined or reviewed from a process heat viewpoint due to lack of time and other priorities. However, it was noted that two speed fans were not in use; an option that should be considered.

Additionally, examination of air coolers that were out of service for repair showed an obvious air flow pattern that was not uniform. The result of the non-uniform flow is reduced cooler efficiency. One solution to the uneven flow pattern is to individually adjust the louvers, rather than have them operate in tandem.

Slovnaft utilizes air coolers for unit product cooldown and trims the outlet temperature with water. The refinery needs to install start/stop buttons for all the air cooler fans on the unit control boards/DCSs so as to be able to easily and selectively shut down fans during rainstorms and cold weather.

The refinery also mentioned that they believed that they had problems with blade/shroud clearance. They thought that on some coolers they had too large a cap resulting in turbulence and bypassing at the blade tip. One of the team members suggested a method used by some US refiners. That was to spray urethane foam on the shroud and use the blade to cut it, normally resulting in "form-to-fit" clearances.

7. ENERGY RECOVERY SYSTEMS

Slovnaft has been on an energy recovery program for sometime, but has been limited by capital availability. The following energy recovery systems were observed.

Furnace air preheaters

Ljungström air preheaters were installed on the combined flue gas of the atmospheric and vacuum tower furnaces on AVD-6, the combined flue gas of the heaters on HDS-5 and HDS-6 and the combined flue gas of the hydrocracker furnaces.

Waste heat recovery units

Waste heat boilers were installed on the flue gas from the furnaces on both AD-4 and AD-5, generating 0.6 MPa steam. A waste heat boiler on AVD-6 used atmospheric tower bottoms, vacuum tower bottoms and vacuum tower side streams for heating media. This boiler generated 5 tonnes/hr of 0.4 MPa and 4 tonne/hr of 0.2 MPa steam. Also, most process furnaces had steam coils in their convection sections.

Product heat recovery

The refinery has made extensive use of product to feed, overhead condensing to feed, pump-around to tower feed and product to tower feed heat exchangers.

Power recovery turbine

On the hydrocracker, a power recovery turbine is used to recover energy from the high pressure reactor effluent stream.

Low quality heat recovery

Low pressure steam and hot water are used to provide hot water and heat for the refinery's buildings and the extensive employee housing that surrounds the refinery.

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C. SELECTED PROCESS UNIT REVIEW AND EVALUATION

1. OVERVIEW

The calendar 1989 operating rate of the Slovnaft crude distillation units was 8 million tonnes/yr. In 1991, they expect to run 6 million tonnes due to reduced crude supplies. Each of the operating crude units (4, 5 and 6) is rated at 2.2 million tonnes/yr of feed capacity. A fourth unit, AD-3 (since shut down), was operating in 1980.

The refinery is having difficulty obtaining sufficient crude to operate at capacity. The existence of three crude units (4, 5 and 6) does allow for flexibility in economical and efficient operation. In the recent past, Slovnaft has received approximately 90% of its total crude from the Soviet Union via the Druzba pipeline. The remaining oil (Iranian and North African) was received mixed with the Russian crude via the Druzba connection to the Adria pipeline. The Russian crude, now in declining supply, is also reported to show increasing salt and sulfur content, which results in higher processing costs and product quality problems.

If sulfur levels continue to increase, it will be necessary to add a third sulfur plant. The need for sulfur plant tail gas processing is also near. An additional sulfur plant and larger tail gas unit (to also take care of the two existing units) is likely in the near future, especially as local environmental regulations regarding SO_x emissions, become more stringent.

A computer simulation of the crude unit AVD 6 on a heavier(29.2 °API) and lighter (38.7 °API) feed indicates ability to handle either crude with minimal modification. However, subsequent downstream units need to be checked. The heavier crude shows an increase of 8% crude bottoms. The vacuum unit may be at its upper capacity at the present time. The lighter crude shows reduction in vacuum tower feed (35%) in which case, a shortfall in lube unit feed is predicted.

2. ATMOSPHERIC VACUUM DISTILLATION UNIT 6 (AVD 6)

2.1 Process Flow Diagram

The process flow diagram of AVD # 6 is as shown in Figure 2 which consists of the crude heat exchange train, the desalter, pre-flash column, fired heater (for crude and vacuum), crude distillation, vacuum distillation, naphtha re-run column, gas stabilizer and waste heat steam production units. It should be noted that the salt content of the Russian crude steadily increased during the 1990 calendar year. Prior years averaged 25 to 30 mg/l salt; a value of 50 mg/l was noted in December 1990.

C-2

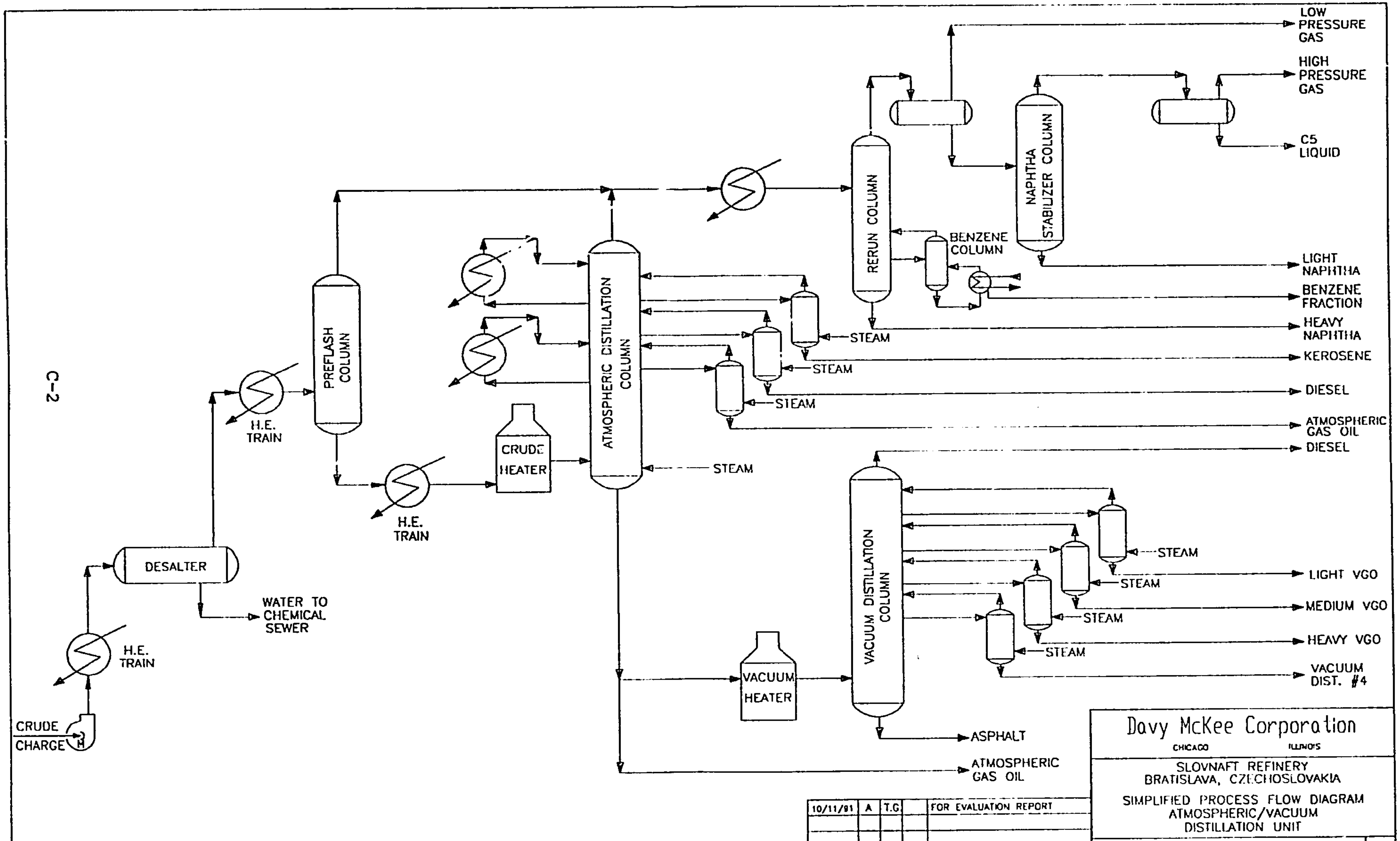

Figure-2

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2.2 Feedstock

The refinery currently processes a 32.0 °API crude supplied by pipeline from Russia (analytical data contained in the simulation section of the appendix). Standard analysis reports indicate sulfur at 1.5 weight %. Calendar year 1990 experienced sulfur content of the crude increasing to the 1.8 to 1.9 weight percent range. The Russian crude accounted for up to 90% of the calendar 1990 feed, with the balance from Iran and North Africa. These other crudes were received mixed with the Russian material via the Adria pipeline. It was therefore not possible to run these crudes through the system independently, and obtain the appropriate operating data on unit flexibility. With respect to increasing sulfur content, the existing hydrodesulfurization units were able to handle the changes without an increase in sulfur content of the products. The major problem is with the fuel oil quality, in that the refinery is at the limit of 3 wt% sulfur in the heavy fuel oil, which is the local specification on sulfur content.

2.3 Unit Flexibility

Slovnaft, the largest refinery in Czechoslovakia, processed crude oil amounting to 8 million tonnes in 1989, and during 1991, throughput is expected to be 6 million tonnes. As noted in the characterization report there are three crude units (Nos. 4, 5 & 6) in the refinery complex, each with a capability of processing approximately 2.2 million tonnes/yr of Soviet crude. Flexibility in crude processing capability is therefore quite good. The crude column of AVD 6 has been run between 232 to 270 tonnes/hour, while the vacuum unit has operated between 106 to 134 tonnes/hour. A crude unit computer simulation was prepared and run by DMC based on an actual operating case. The simulation model showed good agreement with the actual data. Table C.2.1. below summarizes the comparison between actual observations and simulation results. Flow sheet, Figure 3, shows base case conditions compared to simulation results.

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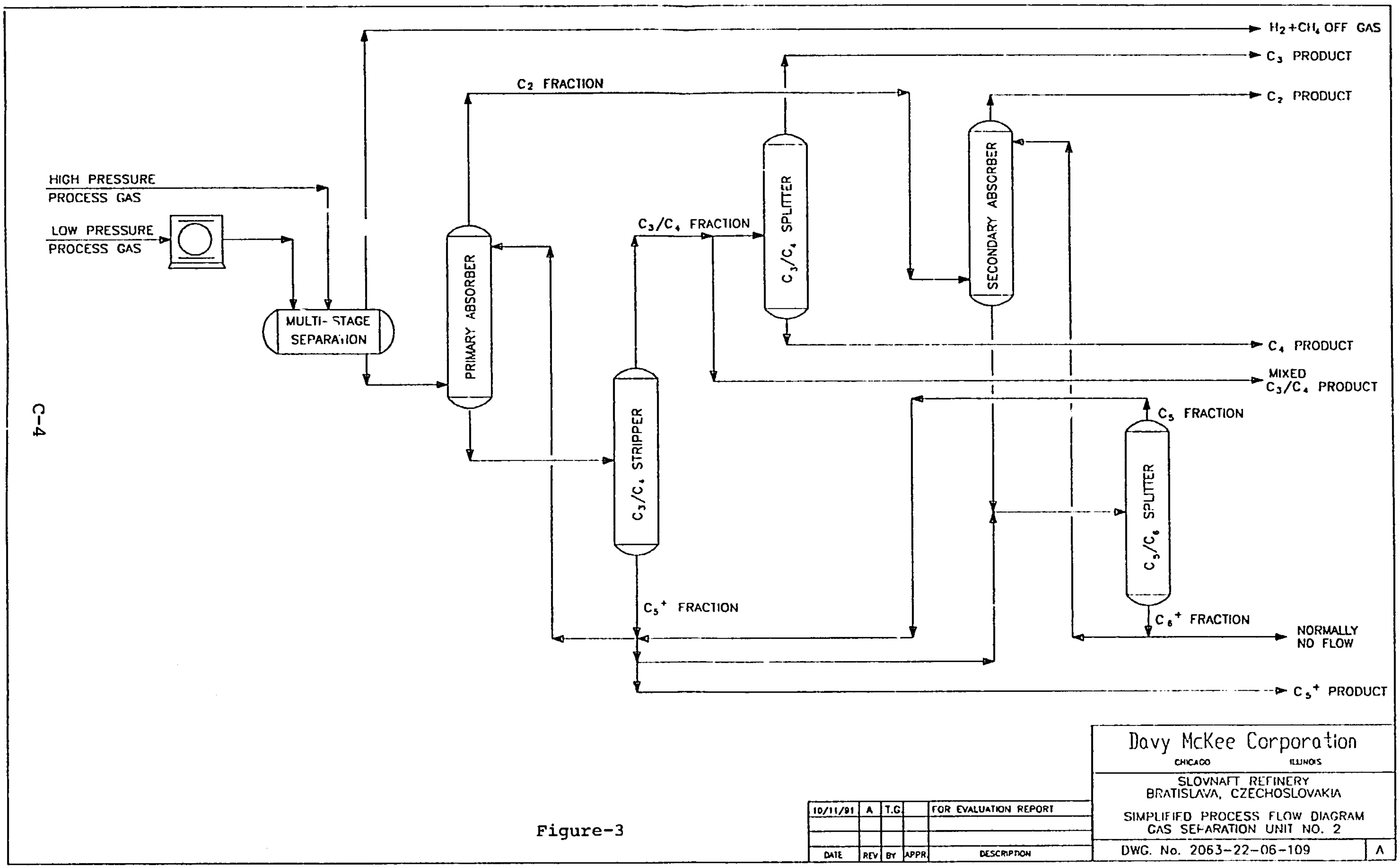

H_2+CH_4 OFF GAS
C_3 PRODUCT
C_2 FRACTION
C_2 PRODUCT
HIGH PRESSURE PROCESS GAS
LOW PRESSURE PROCESS GAS
MULTI- STAGE SEPARATION
PRIMARY ABSORBER
C_3/C_4 FRACTION
C_3/C_4 SPLITTER
SECONDARY ABSORBER
C_4 PRODUCT
MIXED C_3/C_4 PRODUCT
C_5 FRACTION
C_3/C_4 STRIPPER
C_5/C_6 SPLITTER
C_5^+ FRACTION
C_6^+ FRACTION
NORMALLY NO FLOW
C_5^+ PRODUCT
Davy McKee Corporation
CHICAGO ILLINOIS
SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA
SIMPLIFIED PROCESS FLOW DIAGRAM
GAS SEPARATION UNIT NO. 2
DWG. No. 2063-22-06-109 A
10/11/91 A T.G. FOR EVALUATION REPORT
DATE REV BY APPR DESCRIPTION

Figure-3

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TABLE C.2.1.
SUMMARY SIMULATION RESULTS
ACTUAL / SIMULATION COMPARISON

Variable	Observed Data	Simulation Results
Pre-Flash Column		
Tower Top Temp., °C	136	138
Condenser Temp., °C	48	46
Tower Bottom Temp., °C	170	164
Atmospheric Column		
Tower Top, °C	141	137
Top PA Draw, °C	148	154
Middle PA Draw, °C	238	247
Light Fuel Oil/Bottom PA Draw, °C	310	320
Overhead Condenser Duty, 10^6 Kcal/Hr.	8.4	9.5
Top PA Duty, 10^6Kcal/hr	9.3	9.6
Middle PA Duty, 10^6Kcal/hr	7.9	8.0
Product Gaps		
Kerosene/Naphtha, °C	17	11
LGO/Kerosene, °C	-23	-25
LFO/LGO, °C	-81	-80
Bottom/LFO, °C	-99	-102
Top Reflux, kg/hr	0.0	10
LFO Stripping Steam, kg/hr	0.0	7

The complete simulation run may be found in Appendix E of this report. The 170°C actual flash column bottoms temperature is believed to be an error perhaps an anomaly in the instrumentation/data gathering activity since the pre-flash feed is 163 °C. The crude tower top reflux and light fuel oil stripping steam simulation rate is essentially zero, but set at nominal low value to facilitate convergence of the model. Note that the simulation indicated a 2.9% volume overflash; lowering the overflash to 2% would reduce fired heater fuel usage. The model, now tested against actual data, was used to simulate two additional two crude oil cases, Brega Blend at 38.7°API and 29.2°API Arabian light. A summary of the simulation results is as shown in table C.2.2, below. It is important to note that these simulations have not been optimized, they have been run only to determine directional trends in equipment processing capability and limitations.

TABLE C.2.2. - SUMMARY CRUDE CHANGE SIMULATION RESULTS

	Existing Case	Heavier Crude	Lighter Crude
Feedstock	Russian	Arabian Light	Brega Blend
Gravity °API	32	29.2	38.7
Feed Rate, kg/hr (BBL/day)	275 000 (47 900)	280 100 (47 900)	263 600 (47 900)
Naphtha Slops Feed, kg/hr (BBL/day)	20 800 (4 200)	20 800 (4 200)	20 800 (4 200)
Preflash Column			
Flash Vapor, kg/hr	1 550	600	4 600
Overhead Liquid, kg/hr	23 490	23 190	32 490
Overhead Condenser Duty, 10^6 kcal/hr	3.2	3.1	4.1
Fired Heater Duty, 10^6 kcal/hr	36.8	32.5	35.4
Crude Column			
Overhead Condenser Duty 10^6 kcal/hr	9.5	10.9	10.3
Top Pa Duty, 10^6 kcal/hr	9.3	8.0	10.3
Middle PA Duty, 10^6 kcal/hr	7.9	8.3	9.8
Stream Rates			
Overhead Decant Water, kg/hr	5 100	8 400	5 100
Naphtha, kg/hr	52 201	53 200	60 800
Kerosene, kg/hr	30 000	27 500	30 800
Light Gas Oil, kg/hr	42 800	43 200	54 900
Light Fuel Oil, kg/hr	12 900	8 300	13 800
Bottoms, kg/hr	134 000	145 000	87 200
Total Stripping Steam, kg/hr	3 100	8 500	5 200

The unit feed rate was kept constant on a volumetric basis, at 47 900 Bbl/day of crude oil, since equipment capacity is a function of volume, not mass. Stripping steam was increased in the two simulation cases in order to maintain desired product ASTM (D-86) 5%-95% gaps. The significant variations between the base or existing case and the simulation runs occur in the lighter Brega blend. This lighter crude yields considerably more gas product from the pre-flash column overhead, over 16% more Kerosene, 28% more gas oil, and 35% less bottoms. The size of the pre-flash tower appears adequate to handle the lighter crude.

It should be noted that significant changes in crude oil specifications may have an influence on lube oil production. The additive package dose rate, blending formulations, and lube oil operations are directly coupled to years of experience with the Soviet crude oil. It is important to keep in mind that different crudes will very likely have not only different yields of lube oil base stocks, but their chemical composition and lubricating qualities will also change. The complexity involved with changing crudes within multiple processing units in the lube oil train (furfural, dewaxing, and hydrotreating) is such that a dedicated study of the effect of such changes upon final lube product quality is strongly recommended.

2.4 Operational Sensitivity

See comments under flexibility and operating practices.

2.5 Product Specifications

Product quality specifications for the crude and vacuum columns are as shown in Table C.2.3 and C.2.4. Table C.2.5 shows the difference between desired 5% - 95% ASTM D86 gaps and measured values.

TABLE C.2.3 - PRODUCT QUALITY- CRUDE COLUMN

Value	Light Naphtha	Gasoline Cut	Heavy Naphtha	Kerosen e	Gas Oil	Light Fuel Oil	VGO
IBP °C	30	65	90	170-175	180	-	267
95% °C	100	90	175	255-265	-	-	-
End Point °C	120	92	185	270-278	360		360 50%
Density kg/m^3	680	-	750	800-805	850	980	880
Flash Point °C	-	-	-	35	60-70	90	120
Pour Point °C	-	-	-	-	-12	+24	10

TABLE C.2.4. - PRODUCT QUALITY - VACUUM COLUMN

Value	#1. Vacuum Distillation	#2. Vacuum Distillation	#3. Vacuum Distillation	#4. Vacuum Distillation	Vacuum Residue
Flash Point °C	188	212	230	248	240
Viscosity at 50 °C mm^2/sec	19	42	67 (60 °C)	135 (60 °C)	-
Color ASTM	2.0	1.5	5	7.5	-

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TABLE C.2.5 - PRODUCT GAP DATA

Products	Desired	Measured Spring, 1991	Measured Feb., 1991	Simulation
Crude Column				
Kerosene/Naphtha°C	17	17	-15 to -20	11
LGO/Kerosene, °C	-28 (Max 50)	-23	-30 to -35	-25
LFO/LGO, °C	-58 (Max 55)	-81	-70	-80
LGO/Bottoms °C	-99 (Max 100)	NA	-180	-102
Vacuum Column				
VGO/VD#1, °C	0	63	16 to 40	
VD#1/VD#1, °C	50 max.	46	60	
VD#2/VD#3, °C	60 max.	95	110	
VD#3/VD#4, °C	80 max.	100	110	

AVD No. 6 product quality, especially the vacuum column, is important to lube oil manufacturing. As will be noted in the Furfural extraction unit discussion, the average lube yield is about 50%. The top vacuum gas oil cut from the vacuum column is used for transformer oil production, with vacuum column side draw No. 3 as the main feedstock for lube oil. There is increasing lube market demand for narrower cuts from the vacuum unit.

2.6 Unit Yields

The yearly product breakdown of AVD No. 6 is as shown in table C.2.6 below.

TABLE C.2.6. - 1990 PRODUCT BREAKDOWN

Product	Wt%
Gas & LPG	1.60
Naphtha	17.70
Kerosene	11.85
Gas Oil	17.30
Light Fuel Oil	4.20
Atmospheric Residue	4.05
Vacuum Gas Oil	6.45
Vacuum Distillation #1	3.90
Vacuum Distillation #2	3.00
Vacuum Distillation #3	7.80
Vacuum Distillation #4	2.60
Vacuum Residue	19.20
Losses	0.34
Total	100.00

2.7. Unit Modification Potential

Within the last several years, AVD 6 has been modified to reduce energy consumption. The installation of Ljungström air preheaters and addition of heat transfer surface to the crude heat exchange train are examples of the refinery staff and management efforts to reduce energy use and keep costs under control. Several examples of areas that have promise for continued improvement are as follows:

- Increase efficiency of the crude heat exchange train to bring crude oil closer to the design fired heater inlet temperature [current values are 205 °C (Feb 92 reports a value of 225°C] compared to a design of 245°C). Shell side fouling is causing problems and improved cleaning methods have been suggested. The DMC team provided specific details to Slovnaft as part of the immediate implementation effort. The close spacing of tubes makes it difficult to effectively utilize high pressure water on the interior part of the tube bundle. Tubes are 20 mm ID, 2.5 mm wall thickness with a 7mm spacing between tubes on a triangular pitch. Examination of open heat exchanger bundles shows bowed tubes in some cases, making jet water cleaning difficult. Detergent reportedly was not being used. The local staff also reports no change in crude train performance after cleaning. Analysis of the efficiency of the heat exchanger design may yield additional answers to the performance deficiency. An integrated simulation of the complete AVD 6 unit, focusing on the heat exchange issue would be useful in order to optimize operations.

- The use of structured packing instead of valve trays should be investigated as a means to reduce product overlapping and improve product quality.

- The use of a demister pad above the crude column flash zone should be considered.

- The use of automatic control of excess air to the fired furnaces of AD 4 and 5 is under current evaluation by the refinery staff.

- Utilization of a simulation model would greatly facilitate unit modification and improvement studies by quickly and easily identifying equipment bottlenecks.

- Examination of an air cooler bundle suggests that optimization of the air flow pattern would improve air cooling efficiency. Louvers adjusted individually rather than in tandem would give a better (more complete and uniform) air flow distribution. Measuring air velocity over the cross section area of the air cooler as an aid in adjusting louvers was suggested to the plant staff as an immediate energy savings means.

2.8 Capacity Increase Potential

The use of a simulation model would be an invaluable aid in determining system and equipment bottlenecks for capacity increase studies and evaluation of changes in crude oil feedstock.

2.9 Operating Practices

The AVD #6 unit consists of eight sub-sections, as follows:

- Crude Heat Exchange
- Pre-Flash Tower
- Fired Heater
- Atmospheric Crude Distillation Column
- Vacuum Column
- Naphtha Re-Run Column
- Gas Stabilizer
- Waste Heat Steam Generation

The AVD #6 system is heat integrated, that is crude tower bottoms flow directly to the vacuum unit heater and the use of product-to-feed heat exchangers is extensive. As of May, 1991, the refinery's expectation was to run 6 million tonnes of crude oil. utilizing crude units 4,5 and 6. As stated earlier, each of these plants are rated at 2.2 million tonnes/yr. At the time (late May, 1991) of the evaluation team visit to Slovnaft, unit No. 6 was down for maintenance, while unit 5 was not running due to reduced crude supply. AD unit No. 4 operates on a two year shutdown cycle for turnaround purposes.

The desalter of AVD 6 operates at 110 °C. The Russian crude is somewhat desalted by the supplier before it is sent down the pipeline. Inlet conditions are 50 to 80 ppm salt and 0.2% weight water. Desalter outlet is 5 ppm salt and less than 0.1% weight water. Salt content of the Russian crude was reported to increase steadily beginning during 1990, from about 20-25 ppm to over 50 ppm.

The crude heat exchange train does not perform as designed. Inlet to the pre-flash tower is running at 2.3 atm and 170 °C rather than the desired/designed temperature of 200 °C. Inlet to the AVD 6 crude unit fired heater is at 205 °C (more recently, 225 °C) rather than 245 °C. The crude H.E. train performance and suggested improvements are discussed in the unit modification section of this report; also refer to the recommendation pages for additional comments regarding this issue.

The operation of the pre-flash tower crude unit, naphtha re-run column, stabilizer and steam generation sections are reported to be satisfactory.

Gas from the overhead receivers in AVD 6 flow to the gas desulfurization for H_2S removal. As may be expected, summer cooling of the tower overheads is less efficient than during the winter season. Cooling water in this unit, as is the case with most of the refinery units is once through water from the Little Danube

River. Summer temperatures reported to be 18 °C, winter 6 °C. While summer cooling water temperatures are higher than the winter case, the value of 18 °C (64 °F) is far better than those achievable with a cooling tower circuit. This situation needs to be watched, should heat sink limits be placed on cooling water return to the river.

The AVD 6 crude unit fired heater outlet temperature is in the range of 340 to 350 °C, with four process lines in the heater and two transfer lines to the crude column. The Ljungström air pre-heater, which is combined with the vacuum unit fired heater results in an overall heater efficiency of 89 to 90%. The heater efficiencies are checked quite often with receipt of a new state of the art portable analyzer. The crude column is steam stripped, but not all side cut strippers utilize steam. The steam stripping operations for AVD 6 crude column side cut strippers are shown in Table C.2.7.

TABLE C.2.7. - STEAM STRIPPING

Product	Steam Stripped
Kerosene for Alkane Production	Yes, Normally
Diesel (Gas Oil)	Not Stripped
Gas Oil	No, unless fed to an HDS Unit.
Light Fuel Oil	Not Stripped

The IBP of Light fuel oil is reported to increase 80 °C when steam stripped. Steam stripping of Diesel is avoided due to the reported "cloudy" appearance of the product. We suggested the continuation of stripping, either using steam and a salt drier to remove traces of water or use of a reboiler. Stripping, of course would improve product quality, product gaps etc. The crude column overhead reflux is not used, reflux is provided instead by a top pump around which is used to transfer heat to the incoming crude feed. Crude column operating pressures are reported to be 28KPa (gauge) at the top and 52.5KPa (gauge) just below the flash zone. In the case where the crude column is operated at maximum rates, (270 metric tonnes/hour), the light fuel oil draw is very dark. The use of structured packing or demister pads above the flash zone as well as management of overflash was suggested as a means to minimize the problem.

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With respect to the vacuum column, the fired heater outlet is at 400 °C and top of column pressure is 40 mm Hg absolute. Although 5 cuts are possible from the vacuum column, only 4 are used; the bottom most side draw is reported to be "too black." Product overlaps of +80 to +100 °C cause problems in the finished product lube quality. For production of transformer oil, the vacuum gas oil cut is routed to the hydrofinisher and then to extraction and dewaxing. Vacuum oil cut No. 3 is the main feed for the lube units, with extraction, dewaxing and hydrofinishing as the route used for processing. The vacuum column operation needs study, as it is the basis for lube oil base stock production. Increasing market demand for narrower cuts, the potential for changing crude feedstock and several reported anomalies in operation strongly suggest simulation analysis of the vacuum system. Vacuum column bottoms are sent directly to asphalt blowing, by passing storage as a heat conservation method.

During shutdowns unprocessed material is sent to a slops tank. Liquids from subsequent steam cleaning is sent to waste water treatment. With respect to the naphtha re-run column, there has been some difficulty in vaporizing the reboiler; a change from kerosene to gas oil as heating medium is under consideration.

2.10 Replacement / Shutdown Observations

At the present time there is no need to consider replacement / shutdown of AVD 6 and associated units.

3. HYDRODESULFURIZATION UNITS 5 AND 6

Process Flow Diagram

The process flow diagrams for hydrodesulfurization 5 (gas oil) and 6 (kerosene) are as shown in Figures 4 and 5.

3.2 Feedstock

The two units associated with this study, number 5 and 6, receive their feed from the atmospheric crude columns of AD4 and 5 and AVD no. 6. Kerosene destined for alkane productions is steam stripped as well as gas oil bound for the HDS units. Diesel (gas oil) is not steam stripped due to reports of product cloudiness from the presence of water. Make-up hydrogen is from the refinery catalytic reformer. Feedstock specifications are shown in table C.3.1.

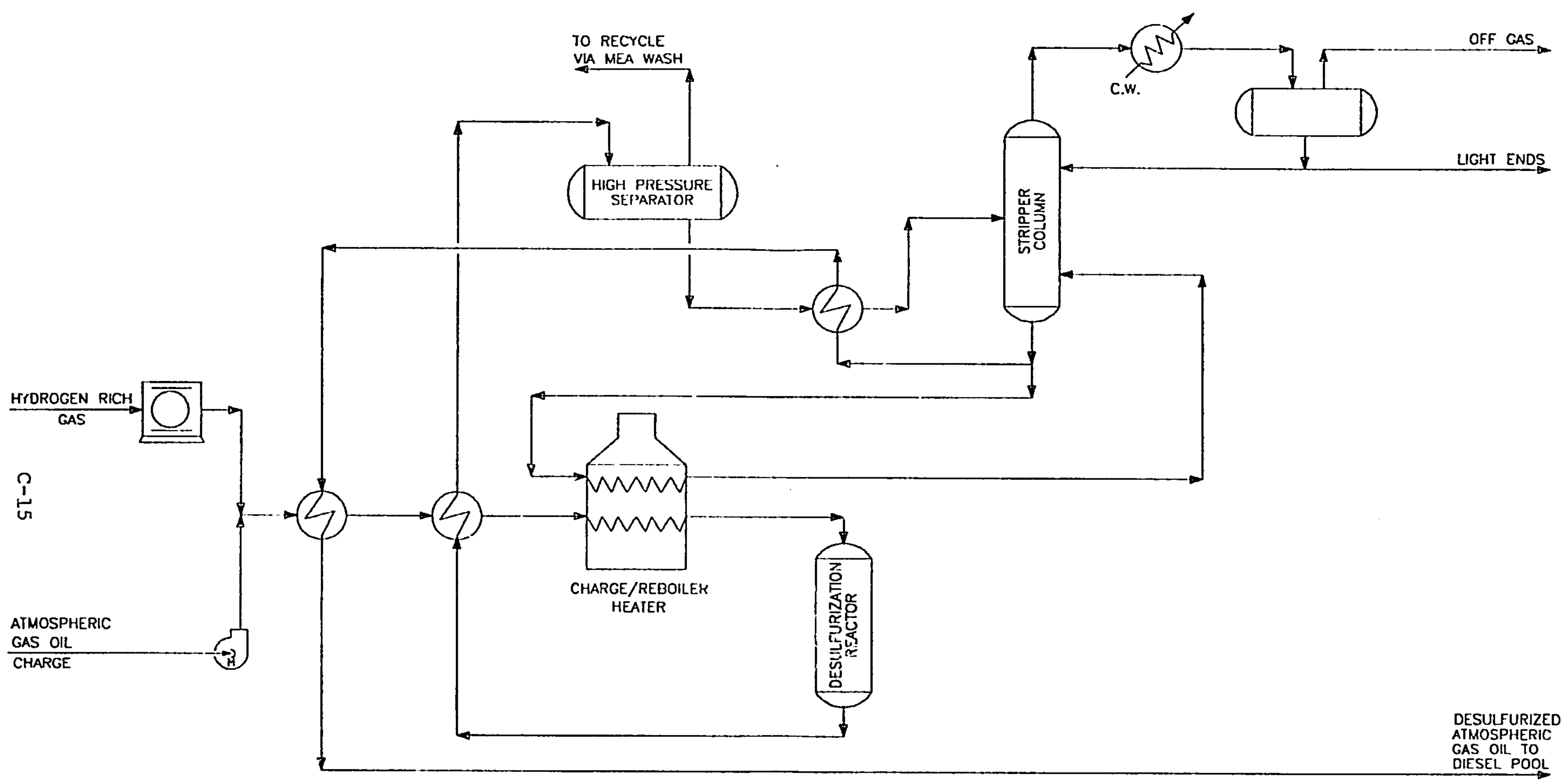

Figure-4

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Davy McKee Corporation
CHICAGO ILLINOIS

SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA

SIMPLIFIED PROCESS FLOW DIAGRAM
ATMOSPHERIC GAS OIL
DESULFURIZATION UNIT HDS-5

DWG. No. 2063-22-06-103 A

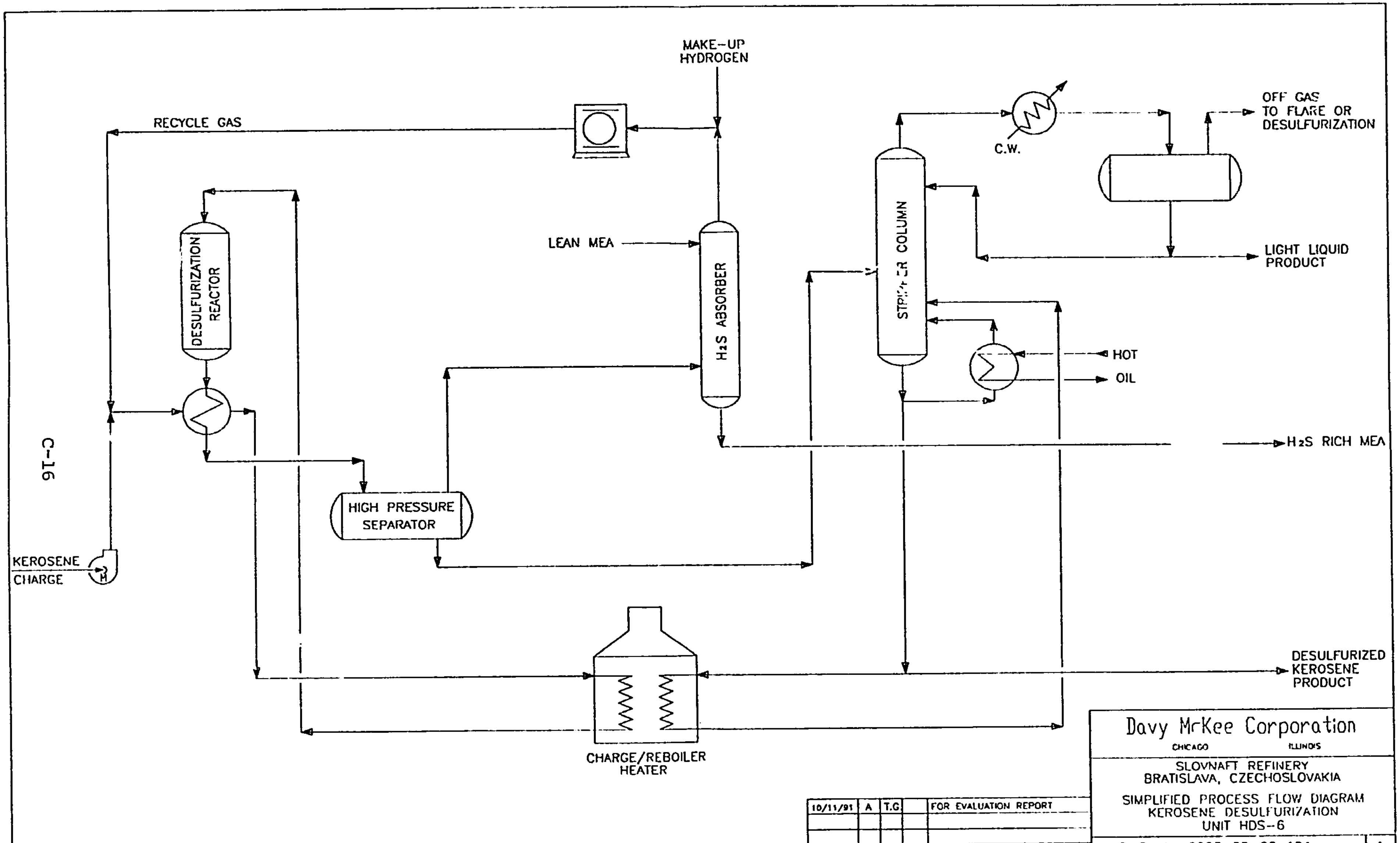
MAKE-UP HYDROGEN
RECYCLE GAS
OFF GAS TO FLARE OR DESULFURIZATION
C.W.
DESULFURIZATION REACTOR
LEAN MEA
H_2S ABSORBER
STRIPPER COLUMN
LIGHT LIQUID PRODUCT
HOT
OIL
H_2S RICH MEA
HIGH PRESSURE SEPARATOR
KEROSENE CHARGE
DESULFURIZED KEROSENE PRODUCT
CHARGE/REBOILER HEATER
Davy McKee Corporation
CHICAGO ILLINOIS
SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA
SIMPLIFIED PROCESS FLOW DIAGRAM
KEROSENE DESULFURIZATION
UNIT HDS-6
DWG. No. 2063-22-06-104 A
10/11/91 A T.G. FOR EVALUATION REPORT
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Figure-5

3.3 Unit Flexibility

In calendar year 1990, unit No. 5 averaged 1928 tonnes/day of gas oil feed (702 000 tonnes/yr). Product (diesel) average rates were 1883 tonnes/day (685 000 tonnes/yr). Maximum/minimum daily feed rates as reported were 2 500/1 300 tonnes and maximum/minimum daily product rates were reported at 2 400/1 200 tonnes. Yearly average product rate was 1 883 tonnes/day. Note that there are a total of 6 HDS units in the refinery, with a total capacity of over 2 000 000 tonnes/yr.

3.4 Operational Sensitivity

Diesel product specification call for 0.15% sulfur by weight; the unit can achieve a 0.05 weight% level which is the coming U.S. standard. Diesel fuel now contains about 20% aromatics; the start-up and operation of the new hydrocracker will improve diesel quality.

TABLE C.3.1. - HDS NO. 5 FEED (GAS OIL) SPECIFICATIONS

PROPERTY	VALUE
Density	852 kg/m^3
Sulfur	0.97 wt%
Bromine Number	6.83 g Br/100g
DISTILLATION	
IBP	192 °C
5%	238 °C
10%	251 °C
30%	277 °C
50%	296 °C
70%	317 °C
90%	347 °C
FBP	360 °C
Amount Distilled	94%

If gas oil feed is too heavy, (defined as 95% less than 360 °C), there is a problem with higher (more than 10ppm) levels of H_2S in the product (stripping column bottoms). The problem traces back to the crude column gas oil/heavy gas oil separation. The stripping column overhead pressure has been reduced to "spring" H_2S from the product. This test however caused excessive gas generation, loss of gas through flaring and reduced flow to the desulfurization unit due to low pressure.

3.5. Production Specifications

TABLE C.3.2. - GAS OIL PRODUCT SPECIFICATIONS

PRODUCT	VALUE
Density	846 kg/m^3
Sulphur	0.12 wt%
Bromine number	1.86 gmBr/100g
IBP	224 °C
5%	245 °C
10%	258 °C
30%	279 °C
50%	296 °C
70%	316 °C
90%	346 °C
FBP	360 °C
Amount Distilled	95%

3.6. Unit Yields

From average rate data, HDS 5 unit yield is calculated to be 97.7 wt% of desulfurized gas oil.

3.7 Unit Modification Potential

The refinery staff is considering the addition of two heat exchangers to the feed stream of the HDS 5 unit. Heat that is now removed by cooling water would instead be transferred to the inlet feed stream. The implementation team was asked to review the calculations. A computer simulation of the system indicates that 1 677 780 kcal/hr of fuel would be saved which is equivalent to just over $100 000/yr.

The two reactors of HDS 5 are old and replacement is under consideration. Installation of a single unit with a greater catalyst volume is planned. A 20 °C lower reactor outlet temperature would result with an estimated savings of about 1 880 000 kcal/hr or just over $113 000/yr. Additionally, the new reactor will lower product H_2S as well as increase operating time by 8 days per year as a result of longer operations between regenerations. The saving from these last two items are supportive of the reactor change-out activity.

Despite the existence of air preheaters, the fired heater efficiency is lower than optimum. Better control of excess air is necessary.

The basis of the cost saving calculations is as follows:

Heating value of fuel: $9\,600 \frac{\text{Kcs}}{\text{Tonne}}$

Internal cost of fuel: $2\,200 \frac{\text{kcal}}{\text{Tonne}}$ (heavy fuel oil basis, April, 1991)

Efficiency of fired furnace 85%
Conversion rate 30 Kcs/U.S. $
Operating time 330 days/yr

Note that internal energy prices have risen in the recent past. Economic justification calculations may be best made using western European free market equivalents.

3.8. Capacity Increase Potential

No observations, or calculations were made regarding system bottlenecks or capacity increase potential.

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3.9. Operating Practices

The following operations take place in the hydrotreating unit:

- Gas oil is mixed with recycled hydrogen, heated by product/feed heat exchange and fired heater and fed to the reactor over a CoMo catalyst.
- Under moderate Hydrogen pressure, the sulfur compounds are converted to H_2S in the reactor.
- The reactor product is cooled through heat exchange with the feed and water and liquid is separated from the gas.
- The recycle gas stream is passed through a MEA wash where H_2S is removed. Make-up hydrogen is added to the recycle gas.
- Liquid from the separator is preheated through feed/bottoms exchange and the light ends removed through a distillation step.
- A hot separator vessel has been added to the HDS 5 reactor gas effluent as an energy reduction measure.

The material and utility balance for gas oil HDS No. 5 is shown in table C.3.3.

TABLE C.3.3. - MATERIAL/UTILITY CONSUMPTIONS

Material/Utility kg/tonne feed	Summer	Winter
H_2	9.8	9.8
Low press. rich gas (stripper Ovhd Rcvr gas to gas desulfur.)	9.1	9.1
H_2S	9.1	9.1
Product	974.8	974.8
Losses	1.5	1.5
Naphtha Slop	15.15	15.15
Fuel gas	4.65	4.85
Fuel oil	5.45	5.65
Electricity kWh	19.2	19.2
Steam 0.6 MPa	6.36	8.79
Steam 1.2 MPa	4.29	4.80
Water m^3	14.5	14.5
Nitrogen m^3	0.02	0.02
Instr. air m^3	969	969

During regeneration 2 140 tonnes of 12 atm steam, 60 000 m^3 of instrument air and 343 tonnes of fuel oil are used.

The combined fired heater gaseous effluent from HDS units 5 and 6 flow through a Ljungström air preheater. Overall fired heater efficiency is in the order of 82 to 85%. Heater flue gas outlet temperatures runs at 185 °C with heavy fuel oil feed and 170 °C when utilizing natural gas. Corrosion is observed on the cooler end

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of the pre-heater. The team suggested that both the water and sulfuric acid dew points be checked and that operations be adjusted accordingly. It was further suggested that the top four (4) feet of stack be made of stainless steel with a temperature sensing element located just below the stainless section.

Fuel gas flow to the heaters is measured by use of an orifice plate, while fuel oil is measured by use of a day tank and dip-stick method.

There is no on-line measurement of flue gas excess oxygen. With tighter operation of the system (including the pre-heater) coupled with appropriate in-line analyzers (2), it is expected that an additional 1 240 000 crowns ($41 000) can be saved per year.

3.10. Replacement / Shutdown Observations

The HDS units 5 and 6 operate well and replacement / shutdown was not considered. See, however, plans to replace the reactors in HDS-5.

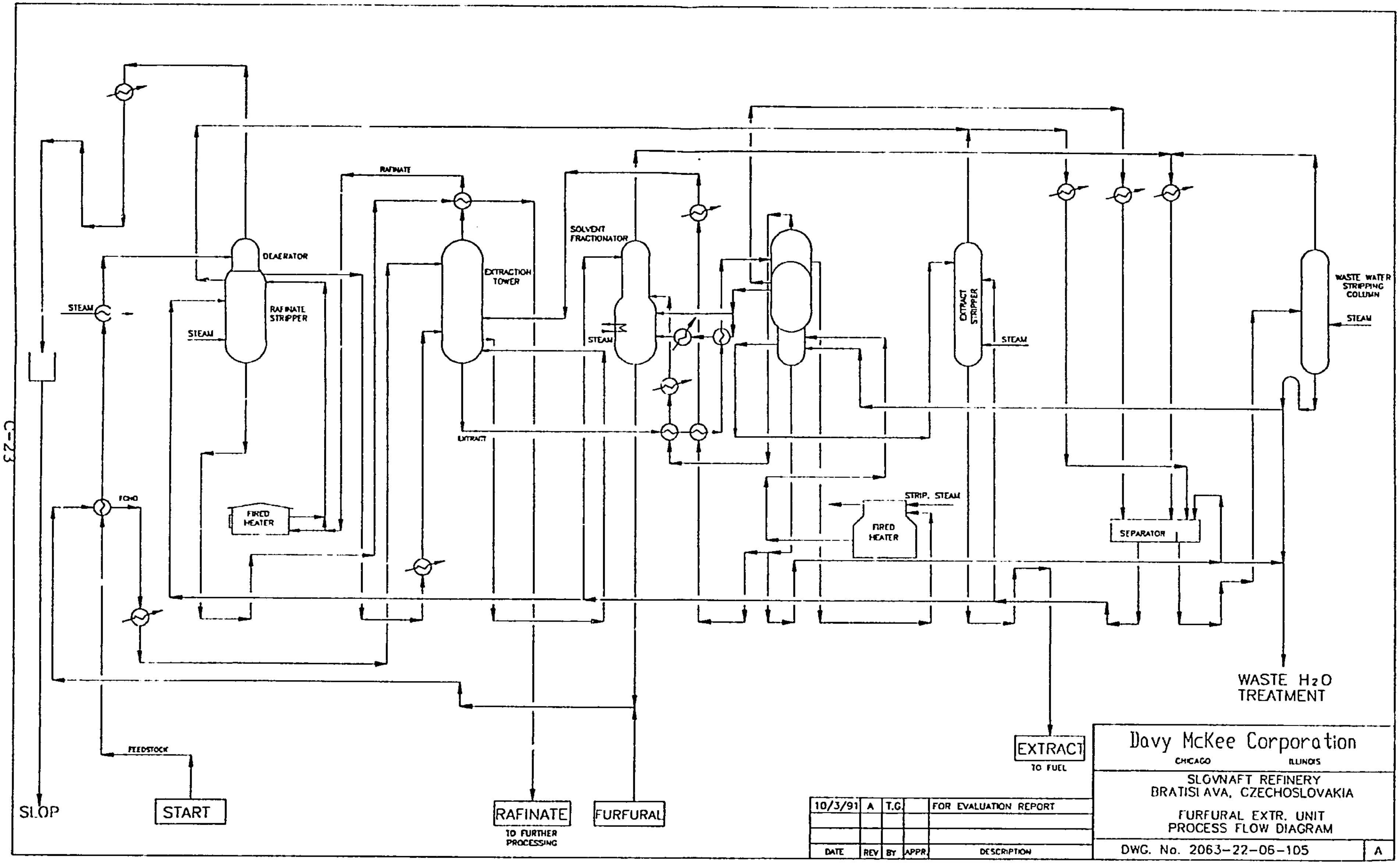
4. FURFURAL EXTRACTION UNIT

4.1 Process Flow Diagram

The process flow diagram for the furfural extraction unit No. 2 is as shown in Figure 6.

4.2 Feedstock

The main feedstock for furfural extraction is from vacuum unit cut No. 3, with additional amounts coming from propane deasphalting and vacuum column cut No. 2. Additionally, vacuum column gas oil, which is used for transformer oil production is first sent through hydrofinishing, before furfural extraction.


RAFINATE
DEAERATOR
RAFINATE STRIPPER
STEAM
STEAM
EXTRACTION TOWER
EXTRACT
SOLVENT FRACTIONATOR
STEAM
EXTRACT STRIPPER
STEAM
WASTE WATER STRIPPING COLUMN
STEAM
FIRED HEATER
FIRED HEATER
STRIP. STEAM
SEPARATOR
WASTE H_2O TREATMENT
FEEDSTOCK
SLOP
START
RAFINATE
TO FURTHER PROCESSING
FURFURAL
EXTRACT
TO FUEL
Davy McKee Corporation
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SLOVNAFT REFINERY
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FURFURAL EXTR. UNIT
PROCESS FLOW DIAGRAM
DWG. No. 2063-22-06-105
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Figure-6

4.2 Unit Flexibility

There are two furfural extraction units: No. 1 rated at 70 000 tonnes/yr and No. 2 rated at 200 000 tonnes/yr. The units work in parallel and capacity is based on feed. Unit No. 2 was reviewed in the evaluation process. Minimum flow of unit No. 2 as observed by the operating group has been 450 tonne/day when using only 1 RDC column. The maximum capacity is reported to be 650 tonne/day with both RDC columns in operation. The limiting piece of equipment on minimum flow is the extract furnace, at 10 m^3 per hour (normal flow rate to the furnace is 20 m^3 per hour and includes the furfural component). The Rotating Disc Contactor (RDC) column, furnaces and coolers are limiting for the maximum capacity case.

4.4 Operational Sensitivity

There are a wide range of products with different viscosity indices. Unit capacity varies as a function of final product specification. No special operational sensitivity issues arose during the evaluation discussions and process review.

The experience base in utilizing and processing the Russian crude within the refinery is an important factor when considering a change to different crude feedstock. The entire lube oil train, furfural, hydrofinishing, dewaxing, blending and additive formulation is based on the chemistry and processing nature of the Russian crude. An extensive reassessment of all units within the lube oil train is needed to adequately address the impact of different crude oil feeds. It is strongly recommended that the current Russian crude continue to be used, at least in AVD #6 and subsequent lube train until such time as a full evaluation of the effect of changing crudes is preformed.

4.5 Product Specifications

The product specification of the Furfural Extraction Unit is broad. There are four different feed materials from the vacuum column and a fifth from the propane deasphalting unit.

6V

TABLE C.4.1. - TYPICAL PRODUCT CONTROL

Value	Vac Dist 3 To V1 80	Vac Dist 2 to V1 90	Vac Dist #2 to V1 95	Vac Dist #1 to V1 95
Density at 20 °C kg/m^3	886	-		
Viscosity at 50 °C mm^2/sec	-	-	23.5	13.55
Viscosity at 60 °C mm^2/sec	33.6	-	-	-
Viscosity at 100 °C mm^2/sec	9.7	7.7	5.8	4.05
Viscosity Index	84	90	95	95
Color ASTM	2.5	2.0	3.5	0.5
Flash Point °C	252	242	216	200

4.6 Unit 2 Yields

Typical yields are as shown in table C.4.2., below:

TABLE C.4.2. - FURFURAL UNIT TYPICAL

	Vac. Distill. 1	Vac. Distill. 2	Vac. Distill. 3
Raffinate wt%	55.8	49.4	41.7
Extract wt%	44.2	50.6	58.3

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Overall operations of furfural extraction unit No. 2 for the 1990 calendar year shows production of 50.4 weight % raffinate and 47.0 weight % extract with a 2.6 weight percent loss. Just over 191 000 tonnes of feed was processed in the No. 2 unit in calendar 1990.

4.7 Unit Modification Potential

The furfural extraction system is the limiting section of the lube oil train. Raffinate yields are in the order of 50 weight %, based on feed. The refinery is in the process of installing a "pseudo-raffinate" processing unit, which will increase over all yields. This additional processing step takes the extract from the RDC column bottoms, and through adjustment of solvent selectivity, an additional quantity of useable oil (cable oil as final product) is obtained. Overall process yield increases approximately 10% through this step.

Conversion to NMP solvent extraction from furfural, is a possibility, which would increase capacity and reduce energy consumption. It should be noted however that NMP is an expensive energy price sensitive imported product. Further, NMP is more corrosive then furfural and new corrosion resistant equipment would be necessary in a conversion process. Furfural on the other hand is produced in-country from renewable agricultural by-products and does not require hard currency as payment. Nevertheless, we do recommend a technical/economic study of switching to NMP as the increased cost of solvent may be more than offset by increased capacity and energy reduction.

Reduction of excess air in the furnace (there was more than 11% oxygen in the flue gas during the implementation study) was recommended as an immediate fuel savings activity. Fuel oil measurement is now by the "day tank dip stick method." Instrumentation for measurement of fuel and control of fuel/air ratio would also be an advantage.

4.8 Capacity Increase Potential

The comments made in the preceding section regarding the "pseudo-raffinate" system and switching to NMP as a solvent also apply to this section. Since the extraction units are the limiting sections of the lube train, debottlenecking studies should be undertaken as part of the solvent change review.

4.9 Operating Practices

Both units 1 and 2 are of Czechoslovakian design. The distillates from AVD #6 (vacuum oils and propane deasphalting) are solvent extracted with furfural in a rotating disc contactor to separate the low viscosity index fraction (extract) from the desired higher viscosity oils (raffinate). The mixture of extract and furfural is heated and furfural recovered by steam stripping and subsequently purified by distillation and then recycled back to the RDC column. The high viscosity index product is heated and furfural recovered through steam stripping and distillation. Unit No. 2 utilizes two (2) parallel RDC units.

Furfural losses are reported to be between 2.4 kg/tonne of feed to 4.2 kg/tonne, the latter figure for light vacuum gas oil feed. A rate of 1.0 kg/tonne of oil charged for a treatment rate of 2.5 furfural to oil is considered acceptable for optimum operations. Furfural loss is accelerated by high temperatures, acidity and the presence of oxygen. All three of these factors lead to furfural auto-oxidation and polymer formation. The refinery staff was asked to operate the deaerator (a visiting U.S. oil company to Slovnaft had earlier made the recommendation), check for and eliminate air leaks, and keep system acidity low through use of neutralizing agents. The operating staff stated that tar and coke formation on pump mechanical seals had failed to the point that they have now switched to the use of packing for shaft sealing. The recommendations made here on minimizing furfural auto-oxidation should alleviate the problem. These polymers will also coat out on heat transfer surfaces, the result of which is increased energy utilization. Following the steps for minimizing auto-oxidation is strongly recommended.

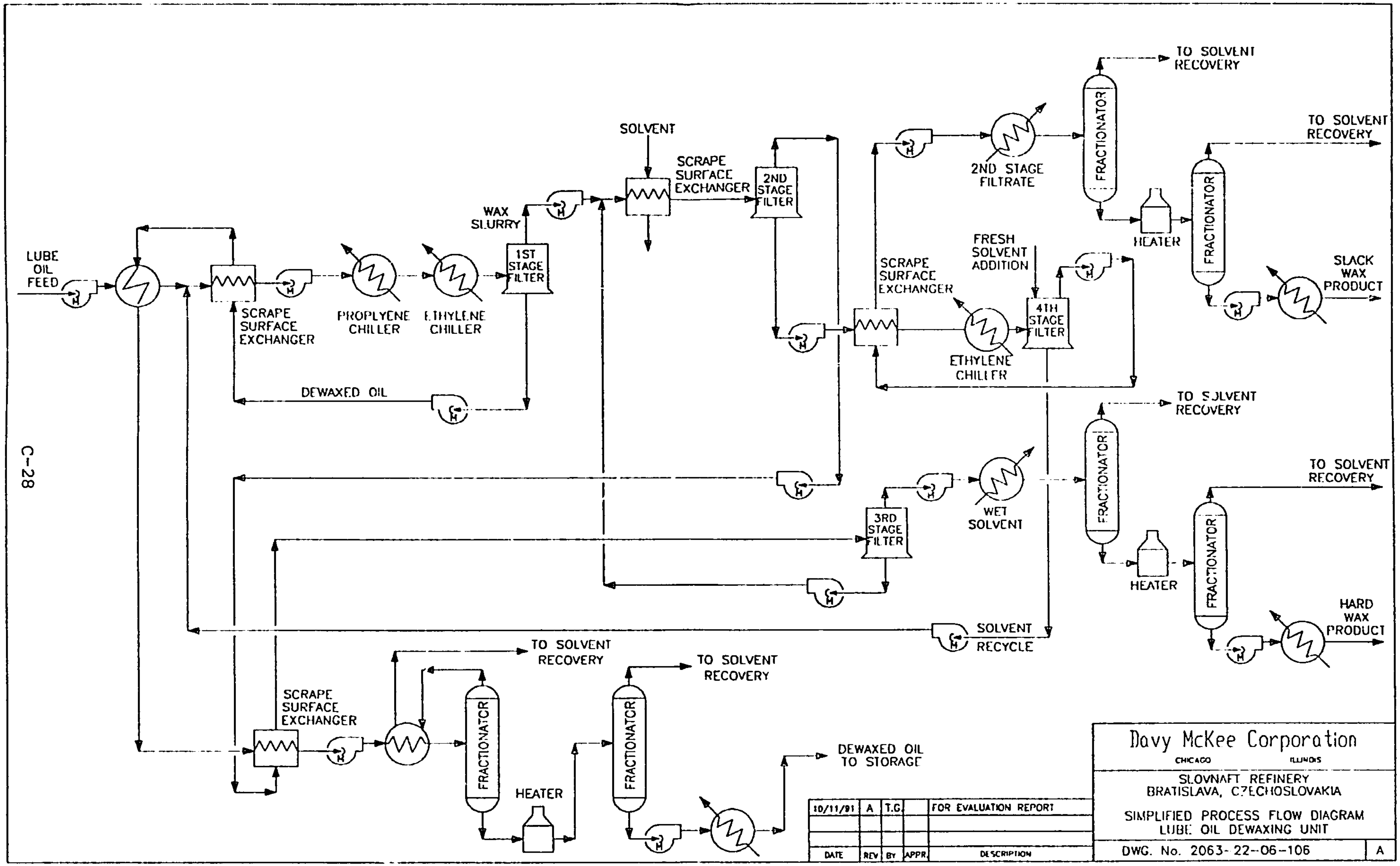
4.10 Replacements/Shutdown Observations

The units operate reasonably well and no replacement / shutdown comments are appropriate. However, should conversion to NMP prove attractive, it would be done by converting unit No. 2 and shutting down unit No. 1. Shutdown of unit 1 would occur only if lube train capacity remains essentially the same. The furfural unit is the current "bottleneck" in the lube system. The converted unit capacity would be about 250 000 tonnes/yr.

5. DEWAXING UNIT NO. 3

5.1 Process Flow Diagram

The process flow sheet of Dewaxing Unit No. 3 is as shown in Figure 7.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PROPYLENE CHILLER
ETHYLENE CHILLER
WAX SLURRY
1ST STAGE FILTER
DEWAXED OIL
SOLVENT
SCRAPE SURFACE EXCHANGER
2ND STAGE FILTER
2ND STAGE FILTRATE
FRACTIONATOR
TO SOLVENT RECOVERY
HEATER
FRACTIONATOR
TO SOLVENT RECOVERY
SLACK WAX PRODUCT
SCRAPE SURFACE EXCHANGER
FRESH SOLVENT ADDITION
4TH STAGE FILTER
ETHYLENE CHILLER
TO SOLVENT RECOVERY
FRACTIONATOR
WET SOLVENT
3RD STAGE FILTER
TO SOLVENT RECOVERY
HEATER
FRACTIONATOR
HARD WAX PRODUCT
SOLVENT RECYCLE
SCRAPE SURFACE EXCHANGER
TO SOLVENT RECOVERY
FRACTIONATOR
HEATER
TO SOLVENT RECOVERY
FRACTIONATOR
DEWAXED OIL TO STORAGE
Davy McKee Corporation
CHICAGO ILLINOIS
SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA
SIMPLIFIED PROCESS FLOW DIAGRAM
LUBE OIL DEWAXING UNIT
DWG. No. 2063-22-06-106 A
10/11/91 A T.G. FOR EVALUATION REPORT
DATE REV BY APPR. DESCRIPTION

Figure-7

5.2 Feedstock

The dewaxing unit receives its feed from the furfural extraction units. There are two dewaxing units in the refinery. Unit No. 2, built in 1964, utilizes an acetone/toluene solvent and is rated at 110 000 tonnes/yr. The newer No. 3 unit, which began operations in the summer of 1990, uses a MEK/toluene solvent and is rated at 150 000 tonnes/yr. Unit No. 3 was designed to take as feed its light vacuum gas oil to produce low pour point (-45 °C) transformer oils. For the transformer oil case the light vacuum gas oil is normally hydrotreated before furfural extraction. The product demand in the Czechoslovakian markets however, is for a product with a -15 °C pour point.

5.3 Flexibility

While unit No. 3 was designed to produce low pour point transformer oils (-45 °C), it has been run to make a variety of other products, including a -15 °C pour point oil. The energy consumption of this unit is very high and is an inappropriate operation when viewed from an economic viewpoint. The capacity of unit No. 3, at 150 000 tonnes/yr of low pour point transformer oils is a major portion of the world's demand. Unfortunately this demand is not supplied by unit No. 3, nor is it likely to do so at its current high energy consumption per tonne of product. The design capacity of units No. 2 and No. 3 far exceeds the capacity of both the upstream and downstream units. The current feed for the dewaxing units are distillates and furfural treated raffinates derived from AVD 6. Note that there is insufficient feedstock available from AVD 6 to allow simultaneous operation of both dewaxing units.

5.4 Operational Sensitivity

If the initial boiling point of the light vacuum gas oil is 300 °C or higher, transformer oil production can follow the normal extraction, dewaxing, hydrofinishing route rather than hydrofinishing, extraction and dewaxing.

5.6 Product Specifications

There are a wide variety of lube products produced. Typical product quality Specifications for unit No. 2 and 3 are as shown in table C.5.1. and C.5.2. Also, refer to the characterization report for lube oil product specifications.

TABLE C.5.1. - #2 DEWAXING UNIT PRODUCTS

Value	Vac. Distill. #1	Vac. Distill. #2	Vac. Distill. #3	Vac. Distill. #4
Density kg/m^2	-	-	-	-
Flash point °C	206	214	246	254
Pour point °C	-15	-15	-15	-12
Viscosity at /°C	-	-	-	-
Viscosity at 100 °C	-	-	-	-
Viscosity Index	-	-	-	-

TABLE C.5.2. - #3 DEWAXING UNIT PRODUCTS

Value	Vac. Distill. #1	Vac. Gas Oil	Vac. Gas Oil Treated
Density kg/m^2	912	857	855
Flash point °C	188	146	146
Pour point °C	-21	-50	-48
Viscosity at /°C	30.1/40	21.5/20	10.44/40
Viscosity at 100 °C	4.7	2.62	2.6
Viscosity Index	52	-	81.5

5.6 Unit Yields

Yields of the two units are shown in table C.5.3. and C.5.4. Production feed rates for unit No. 3 are shown in table C.5.5.

TABLE C.5.3. - DEWAXING UNIT NO. 2 YIELDS

No. 2	Vac. Distill. #1 (treated)	Vac. Distill #2 (treated)	Vac. Distill #3	Deasphalted Oil
Oil wt%	82.1	80.1	76.1	76.0
Slackwax wt%	17.8	19.8	23.8	23.9
Loss wt%	0.1	0.1	0.1	0.1

TABLE C.5.4. - DEWAXING UNIT NO. 3 YIELDS

No. 3	Vac. Gas Oil to low pour point	Vac. Distill. #1	Vac. Distill. #2
Oil wt%	74.95	83.00	83.00
Paraffin wt%	9.5	6.4	7.0
Slack Wax wt%	14.4	11.5	9.9
Loss wt%	0.1	0.1	0.1

TABLE C.5.5. - DEWAXING UNIT NO. 3 THROUGHPUT DATA

Product	%Throughput	Feed Rate
Transformer oil	12	20 Tonnes/hr
"620"	10	$18m^3/hr$
"333"	20	$16m^3/hr$
"650" (-15 °C pour point)	40	$15m^3/hr$
"331"	10	$18m^3/hr$
"631"	8	$20m^3/hr$

Product definition for Table C.5.5 is as follows:

- Transformer oil is vacuum gas oil that has been hydrotreated and furfural extracted prior to dewaxing.
- Product "620" is vacuum distillate No. 1 that has been furfural extracted and is of a lower viscosity than products 333, 331, 650 and 631.
- Product "333" is obtained straight from vacuum distillate No. 1 and is not furfural extracted.
- Product "650" is from vacuum distillate No.3 that has been furfural extracted.
- Product "331" is from vacuum distillate No. 1 and is not furfural extracted.
- Product "631" is a vacuum distillate No.1 that has been furfural extracted and has a higher viscosity than product 620.

10

5.7 Unit Modification Potential

The combined dewaxing units are oversized in comparison to other units in the lube oil train. That is, they have a combined capacity of 260 000 tonnes per yr compared to furfural extraction at 270 000 tonnes feed (with a nominal 50% yield) and hydrofinishing at 110 000 tonnes/yr. However, to use only the #3 unit for the production of base oils with a pour point of -15 °C is uneconomical. On the other hand the compressors (at least) in No. 2 unit need to be replaced in the near future. The dewaxing units should be revaluated in the context of the entire lube oil train capability, operating economics and the future of lube oil production/market demand in the projected Slovnaft marketing area. Unit No. 3 is uneconomical to operate due to its high energy costs as well as reflecting a design for a product that has minimal demand in the Slovnaft area. Also, as previously indicated, insufficient feedstock is available from AVD 6 to allow simultaneous operation of both dewaxing units. It is therefore recommended that a study be undertaken to either revamp unit No. 3 to a product design basis more suited for local markets (-15 °C pour point) and thus reduce energy and operating costs or combine operations and equipment of units 2 and 3 to achieve optimum operating costs.

Upon shutdown of unit No. 3, a event which occurred quite frequently in the last year, (the maximum run time has been 3 weeks) ethylene/propylene refrigerant gases are flared. About 30 tonnes of ethylene and 40 tonnes of propylene is lost at some of these times. Returning these gases back to the system, the ethylene cracker or refinery fuel system is a better alternative.

A hard wax with low oil content is produced and used for candle production. Food or medicinal grade wax is reported to be in demand with a good profit potential. Assistance is needed in providing manufacturing and market analysis. Slack wax could be processed through a mild hydrocracking step to produce a 130 viscosity index oil with quality similar to synthetic lubes. Further analysis is required. Changes in crude stock will, of course effect the dewaxing unit and an in-depth redesign is necessary to assess the impact of this change as well as determine new operation parameters and equipment modifications.

5.8 Capacity Increase Potential

The capacity of the two units exceeds that of both the feed and downstream units. Combination of the two units to a capacity of about 250 000 tonnes/yr is more appropriate, to match the lube oil train throughout.

5.9 Operating Practices

Unit No. 2, utilizing acetone and toluene as a solvent, has a minimum capacity of 100 000 tonnes/yr, a 75% yield and design basis to produce -15 °C pour point oils. Ammonia is used as a refrigerant. Plans are underway to replace the existing reciprocating Czech built ammonia compressors with turbo-compressors as the existing machines require increasing amounts of maintenance and spare parts are difficult to find as the models are no longer made.

Unit No. 3, which was reviewed in detail, is of Russian design, utilizes a MEK/toluene solvent and is rated at 150 000 tonnes/yr of very low (-45 °C) pour point oils. The unit is laid out in a very spacious fashion; a more compact design would have saved initial capital costs as well as minimized heat loss from extensive piping runs. This unit operates at temperatures down to -60 °C and the unnecessary heat losses increase operating costs.

The following operations take place within dewaxing unit No. 3:

- Feed material from furfural extraction is mixed with solvent (MEK-toluene), chilled and the wax components crystallized.
- Solid crystallized material is filtered and solvent washed on a rotary drum filter.
- The filter cake is recrystallized for paraffin production, filtered and washed again to reduce oil content to less than 0.5%.
- The solvent from the dewaxed oil, slack wax and paraffin is recovered through a distillation step.
- Solvent is dewatered, recovered and recycled.

The first six months of operation for this unit have been difficult, with many shutdowns and high operating cost. The following table C.5.6. illustrates utility trends.

AV

TABLE C.5.6. - DEWAXING UNIT NO. 3 - UTILITY TRENDS/TONNE OF FEED

Utility	Design Basis	Average of 1ST 6 months of operation	Unit No. 2 Data
Fuel (oil & gas)	61.5 kg	52 kg	None
Electricity	515 kWh	825 kWh	126 kWh
Cooling Water	2.5 m^3	3.25 m^3	21.9
0.6 MPa steam	90 kg	93.5 kg	1 060 kg
1.2 MPa Steam	355 kg	545 kg	1 060 kg
MEK	5 kg	NA	NA
Toluene	5.2 kg	NA	NA
Ethylene	0.535	NA	NA
Propylene	1.0	NA	NA

Start-up experience, as you go down the learning curve, is partially responsible for the higher utility utilization in the first six months of operation. However, high electric costs will continue due to refrigeration compression needs, as a function of the -60 °C cooling design for -45 °C pour point oils. Redesign of unit No. 3 to meet -15 °C or -25 °C pour points would result in considerable energy savings. It was suggested that the refinery shutdown the ethylene cooling system and run only the propylene coolant to about -30 °C or so as a means of achieving lower utility cost and yet meet specifications for -15 °C pour point oils. Although unit No. 3 is new, the Russian designed equipment was not made to U.S. or Western European standards and some difficulties with acquisition of spare parts has already occurred.

The operations staff reports that it takes up to 1.5 days of operating time to change products. The refinery tries to use this "in-between" material for blending industrial oils. Slops production is also enhanced by this problem. Increase in on-stream time is also a positive economic driving force for modifying the unit.

The last stage of the solvent recovery section is steam stripped, which introduces water into the system. The water ices up in the ethylene chillers and other low temperature equipment. It takes up to 1.5 hours of non-productive time to clear the system. Use of driers have been suggested. Lost production time is valuable, as noted above, and the increase in production can justify solutions. The frequency of the "ice" problem was reported to occur every 6 to 12 hours. Other operating difficulties include high solvent content in the nitrogen blanket recycle compressor and problems with filterability and high pressure drop in the second stage filtration due to formation of thin crystals.

5.10 Replacement / Shutdown Observations

There are plans to replace the ammonia compressors of unit No. 2 with turbo-compressors due to age, condition, ammonia leakage and lack of spare parts. As previously stated, an in-depth study should be made of the dewaxing operations at Slovnaft. Capacity of both units is not needed or useable now or in the foreseeable future.

The team discussed the possibility of redesigning unit No. 3 into two (2) parallel units designed for -15 °C or so pour points, and shutting down unit No. 2. The use of some of unit 2 systems in a redesigned combination facility, such as the solvent recovery section may be reasonable. The evaluation team strongly recommends the implementation of redesign activities for these units.

6. HYDROFINISHING

6.1 Process Flow Diagram

The process flow sheet of the hydrofinishing unit is as shown in Figure 8. There are two identical units, each with a capacity of 65 000 tonnes/yr. There is an additional unit of 15 000 tonnes/yr capacity which is used for paraffins.

6.2 Feedstock

Feed for these units is normally received from the dewaxing units, although as noted in other sections of this report, vacuum gas oil for transformer oil production is first hydrofinished before being sent through furfural extraction and dewaxing.

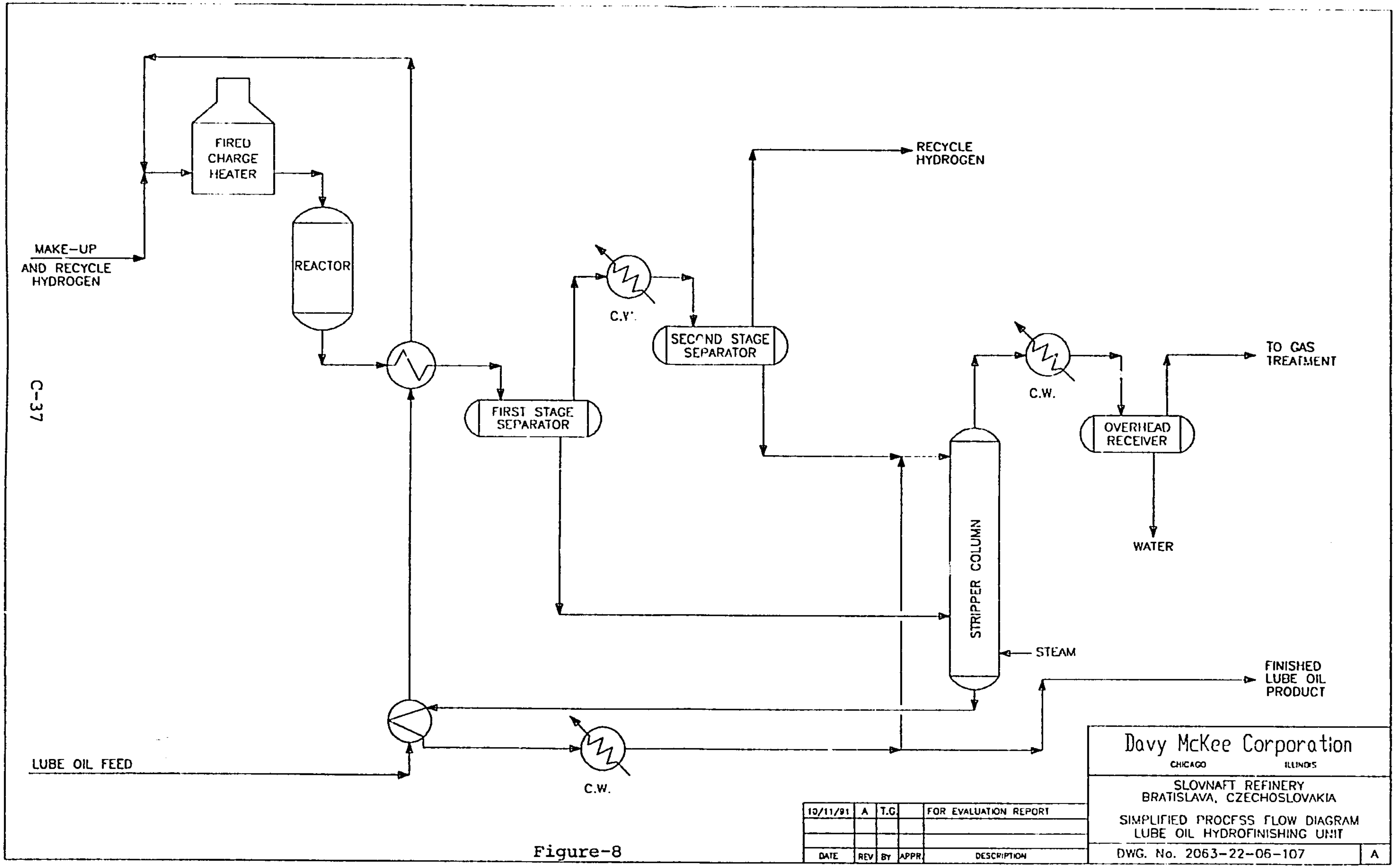

FIRED
CHARGE
HEATER
REACTOR
MAKE-UP
AND RECYCLE
HYDROGEN
C.W.
SECOND STAGE
SEPARATOR
RECYCLE
HYDROGEN
FIRST STAGE
SEPARATOR
C.W.
TO GAS
TREATMENT
OVERHEAD
RECEIVER
WATER
STRIPPER COLUMN
STEAM
FINISHED
LUBE OIL
PRODUCT
LUBE OIL FEED
C.W.
Davy McKee Corporation
CHICAGO ILLINOIS
SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA
SIMPLIFIED PROCESS FLOW DIAGRAM
LUBE OIL HYDROFINISHING UNIT
DWG. No. 2063-22-06-107 A
10/11/91 A T.G. FOR EVALUATION REPORT
DATE REV BY APPR. DESCRIPTION

Figure-8

6.3 Flexibility

This unit was not reviewed in sufficient detail, no comment

6.4 Operational Sensitivity

This unit was not reviewed in sufficient detail, no comment

6.5 Product Specifications

TABLE C.6.1. - HYDROFINISHING PRODUCT SPECIFICATIONS

Value	Vac. Distill. #1 (treated)	Vac. Distill. #2 (treated)	Vac. Distill. #3 (treated)	Wax
Pour Point°C	-23	-12	-15	62
Flash Point°C	272	228	256	240
Viscosity at 50 °C mm^2/sec	102.8	29.8	69.1	-
Viscosity at 100 °C mm^2/sec	15.2	6.63	11.4	-
Viscosity index	83	93	81.5	-
Color ASTM	2.5	1.0	2.0	-
Oil content wt%	-	-	-	0.66

6.6. Unit Yields

This unit was not reviewed in sufficient detail, no comment

6.7. Unit Modification Potential

This unit was not reviewed in sufficient detail, no comment

6.8. Capacity Increase Potential

This unit was not reviewed in sufficient detail, no comment.

6.9 Operating Practices

The summary of operations is as follows:

- Dewaxed oil is mixed with hydrogen recycle gas, heated through heat exchange and the fired heater and then fed to the reactor.
- After feed/bottoms heat exchange and cooling, the liquid product is separated in a flash drum and the gas phase hydrogen rich stream is recycled.
- Make-up hydrogen is added to the recycled gas.
- Liquid product is preheated and the light ends removed by distillation in order to reach the desired finished product flash point.

6.10. Replacement / Shutdown Options

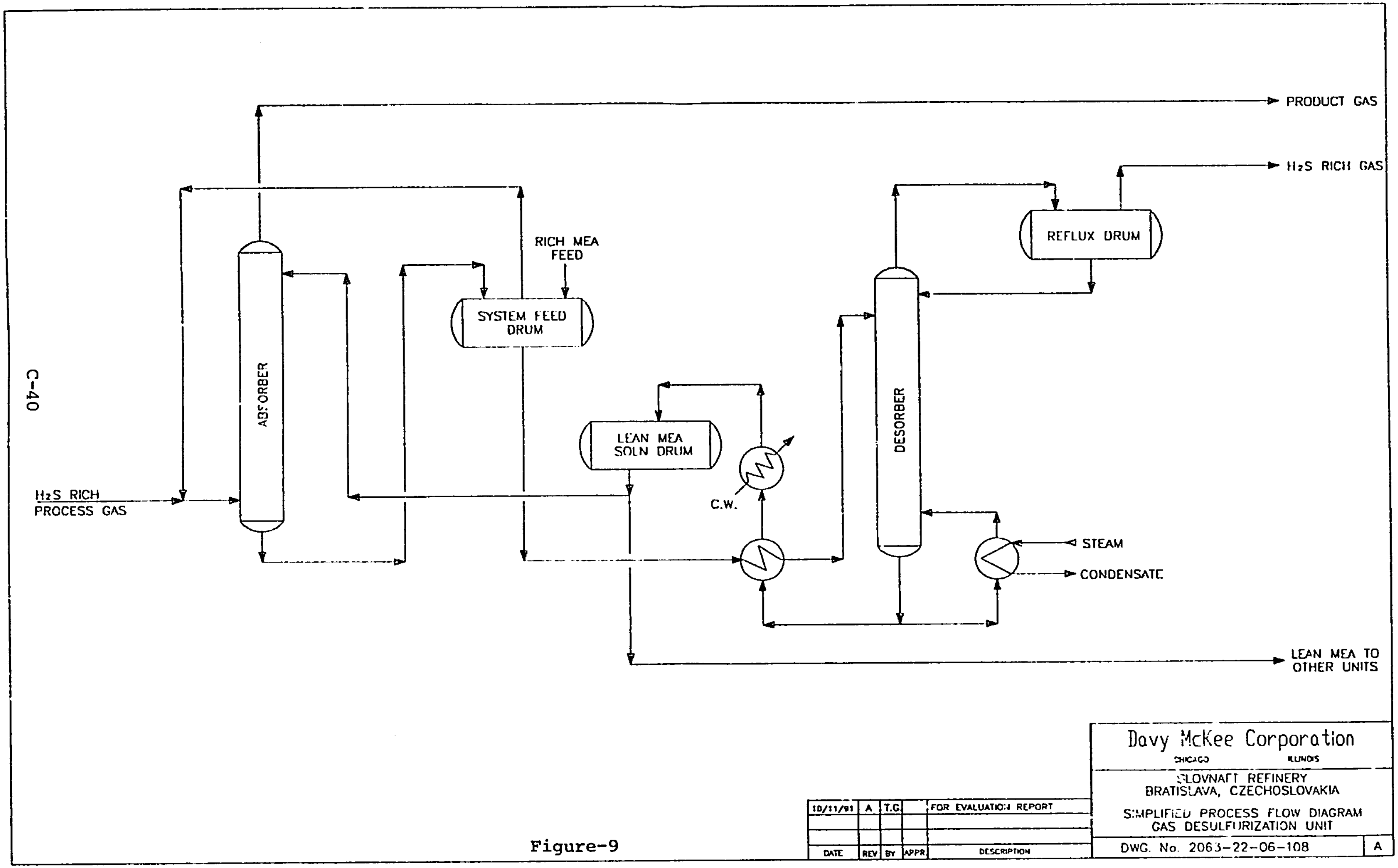
No comment.

7. GAS DESULFURIZATION UNITS NO. 1 AND NO. 2

7.1 Process Flow Diagram and Process Description

The Process Flow Diagram is as shown in Figure 9. This diagram is for gas desulfurization unit No. 2. For the gas phase units, low pressure gases containing hydrogen sulfide are compressed and sent to a column where the H_2S is absorbed before counter flow against a 10 to 15% MEA solution. The H_2S rich MEA is heated and H_2S removed from the solution in a desorber column.

'ch MEA, saturated with H_2S, from other sources in the refinery (hydrotreaters) is also processed in these units. The lean, or H_2S free MEA solution is then recycled back to its respective source.


PRODUCT GAS
H_2S RICH GAS
RICH MEA FEED
SYSTEM FEED DRUM
ABSORBER
REFLUX DRUM
DESORBER
LEAN MEA SOLN DRUM
C.W.
H_2S RICH PROCESS GAS
STEAM
CONDENSATE
LEAN MEA TO OTHER UNITS
Davy McKee Corporation
CHICAGO ILLINOIS
SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA
SIMPLIFIED PROCESS FLOW DIAGRAM
GAS DESULFURIZATION UNIT
DWG. No. 2063-22-06-108
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DESCRIPTION

Figure-9

7.2 Feedstock

H_2S bearing effluent gases from various refinery units (hydrodesulfurizers, hydrocracker, etc.) are processed in two (2) gas phase desulfurizers.

7.3 Unit Flexibility

The feed capacity of both gas phase units is approximately the same, however the H_2S production rate of unit No. 2 is about two times that of unit 1 due to a higher H_2S content of its inlet gas.

7.4 Operational Sensitivity

The number 2 gas desulfurization plant, which was built in 1982, uses valve type trays in the absorber and desorber columns. The efficiency of the No. 2 unit is reported to be better than the No. 1 unit, which was built in 1961.

7.5 Product Specifications

The lean or recycled MEA or in the case of unit No. 2, the LPG gas, is essentially free of H_2S after processing.

7.6 Unit Yields

The MEA solution (design basis) is approximately 15 wt% MEA, 85 wt% water. H_2S gas, which is sent to the sulfur plants, runs approximately 85 mol% H_2S and 11 mol% H_2O, with small amounts of CO_2 and CH_4 as the remainder.

7.7 Unit Modification Potential

Serious consideration is being given to changing from bubble cap to valve trays in Unit No. 1 to improve separation efficiency. We suggested switching from the current 10 to 15% (weight) MEA to a 20% MEA solution and addition of a filter to remove carbon particles, as a means to reduce steam consumption in the desorber columns. The refinery staff has considered utilizing a higher MEA concentration, but they are very concerned that they will experience product degrading, higher MEA consumption, foaming and corrosion. Additionally, a MEA reclaim unit and filter is needed to remove sludge products. Improved on line analyzers and desorber steam control is under review. The use of anti-foaming agents which are not now used, may improve operations.

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7.8 Capacity Increase Potential

Should the sulfur content of the crude oil increase (and in the case of Russian crude it indeed has increased over the last year), it will be necessary to debottleneck the units to increase capacity.

7.9 Operating Practices

Unit no. 2 processes sour gases from the refinery, and is rated at 130 000 tonnes/yr.
The refinery staff reports an occasional high concentration of Hydrocarbon (nC_4 from hydrotreating) appearing in the #2 unit desorber column overhead. The presence of this Hydrocarbon leads to minor undesirable, "Explosions," in the sulfur unit burners. High gas velocities (5m/sec) in the H_2S rich MEA desorber feed vessel, and low residence time, not allowing the hydrocarbons to drop out is believed to be the problem. Installation of a larger drum is under consideration.

7.10 Replacement / Shutdown Observations

These units operate satisfactorily and no replacement / shutdown comments are appropriate.

8. GAS SEPARATION UNITS

8.1 Process Flow Diagram

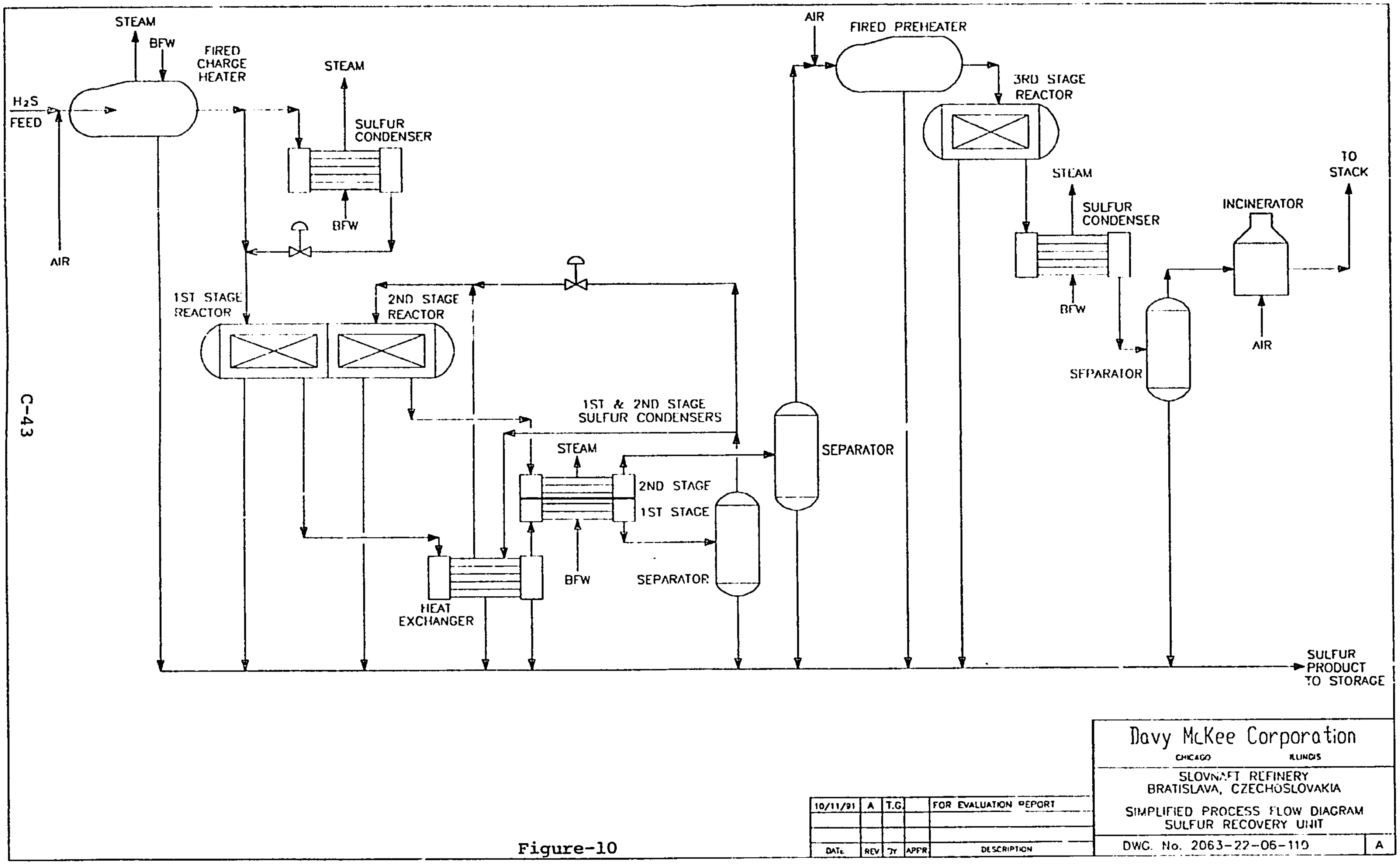
The process flow diagram of the gas separation Unit No. 2 is as shown in Figure 10.

8.2 Feedstock

The gas separation units receive their feed from the gas desulfurization units and streams of sweet gases from the reformer.

8.3 Unit Flexibility

There are two (2) units in use; unit number 1, built in 1961, is rated at 130 000 tonnes/yr gas phase and 40 000 tonnes/yr liquid phase, while unit 2, built in 1974, has a capacity of 200 000 tonnes/yr gas phase only. Additionally, unit number 1 contains the butane splitter, which also takes mixed butane feed from unit 2. Turn down to 40% of capacity is achievable.


STEAM
BFW
FIRED CHARGE HEATER
H_2S FEED
AIR
STEAM
SULFUR CONDENSER
BFW
1ST STAGE REACTOR
2ND STAGE REACTOR
1ST & 2ND STAGE SULFUR CONDENSERS
STEAM
2ND STAGE
1ST STAGE
BFW
SEPARATOR
HEAT EXCHANGER
SEPARATOR
AIR
FIRED PREHEATER
3RD STAGE REACTOR
STEAM
SULFUR CONDENSER
BFW
SEPARATOR
INCINERATOR
AIR
TO STACK
SULFUR PRODUCT TO STORAGE
Davy McKee Corporation
CHICAGO ILLINOIS
SLOVNAFT REFINERY
BRATISLAVA, CZECHOSLOVAKIA
SIMPLIFIED PROCESS FLOW DIAGRAM
SULFUR RECOVERY UNIT
DWG. No. 2063-22-06-110
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10/11/91 A T.G. FOR EVALUATION REPORT
DATE REV BY APPR DESCRIPTION

Figure-10

8.4 Operational Sensitivity

Unit number 2 is reported to be very reliable.

8.5 Product Specifications

Product streams from the operation include; ethane, propane, butane, pentane and a mixed propane/butane fraction. Product specifications are shown in Table C.8.1.

TABLE C.8.1. - LPG (LIQUIFIED PETROLEUM GASES)

Composition	Propane	Butane	LPG Summer/ Winter
Propane content wt%	95	0.2	30/55
C_2 and lighter wt% max	5.0	-	7.0
Butane and Heavier (LV% - max wt%)	5% max	97.4	60/40
Pentane and Heavier (LV% - max wt%)	-	1.0	3.0
Residual Matter	moisture and higher hydrocarbons		
Corrosion, Copperstrip (max)	-	-	-
Total Sulfur (ppmw)	3.0	200	200

8.6 Unit Yields

Products obtained from the facility and the associated weight percent distribution are shown in Table C.8.2.

TABLE C.8.2. - UNIT YIELDS

Product	No Individual C_3 or C_4 made	No C_3/C_4 mixture made
Ethane	30.8	29.5
Propane	-	31.8
Butane	-	30.3
Pentane	8.8	8.4
*Propane/butane Mixture	60.4	-

*Propane/butane may be taken as a product or be split into its respective components, in any proportion desired.

8.7 Unit Modification Potential

Even though the operation of the older unit number 1 is reported to be satisfactory, the refinery staff is undertaking a modernization program. A new compressor, column retraying and new pumps are planned. A combination of age, wear and difficulty in obtaining spare parts is the prime reason for the rotating equipment replacement. Expected improved efficiency is driving the column tray change out. The iso-butane splitter, currently one eighty tray bubble-cap type column, will be changed to either valve or sieve trays.

There is need to optimize column reflux through better, control in that the feed to the units is not constant. This would lead to smoother operations and directionary moves toward energy reduction.

8.8 Capacity Increase Potential

Bottlenecks and operational limitations were not discussed, however the unit No. 2 feed compressor, which serves both units, is fully loaded at 37.5 tonne/hr.

8.9 Operating Practices

Low pressure gases are compressed to approximately 1.8 MPa atmospheres then processed through multiple distillation and extraction steps where the ethane through pentane products are separated. The initial step is to separate a crude ethane stream (approximately 90% Ethane and 10% propane/butane) by pentane absorption, leaving a fraction consisting of propane, butane and pentane. The ethane is further purified in a heptane extraction cycle. The propane through pentane mixture is separated into a pentane product and propane/butane mixture. The propane/butane mixture can be a product as such or further processed into product quality propane and a mixed butane stream. The mixed butane either goes to LPG or the butane splitter.

The presence of pentane in the butane product is reported to cause problems when this stream is sent to the butane splitter. Operating personnel are sensitive to this potential and the plant is operated accordingly.

The recent start-up of the new hydrocracker caused a bit of a problem in that it introduces a lower MW gas to the gas separation plant, due to the presence of hydrogen. This reduces the capacity of the compressor in mass per hour, since the compressor is a volumemetric device. The local engineering staff is planning to alleviate the problem through a separate processing step for Hydrocracker gas or recycling the material back to its source. The higher H_2S content of gas from the hydrocracker does not yet present a capacity processing problem, but it is being watched closely.

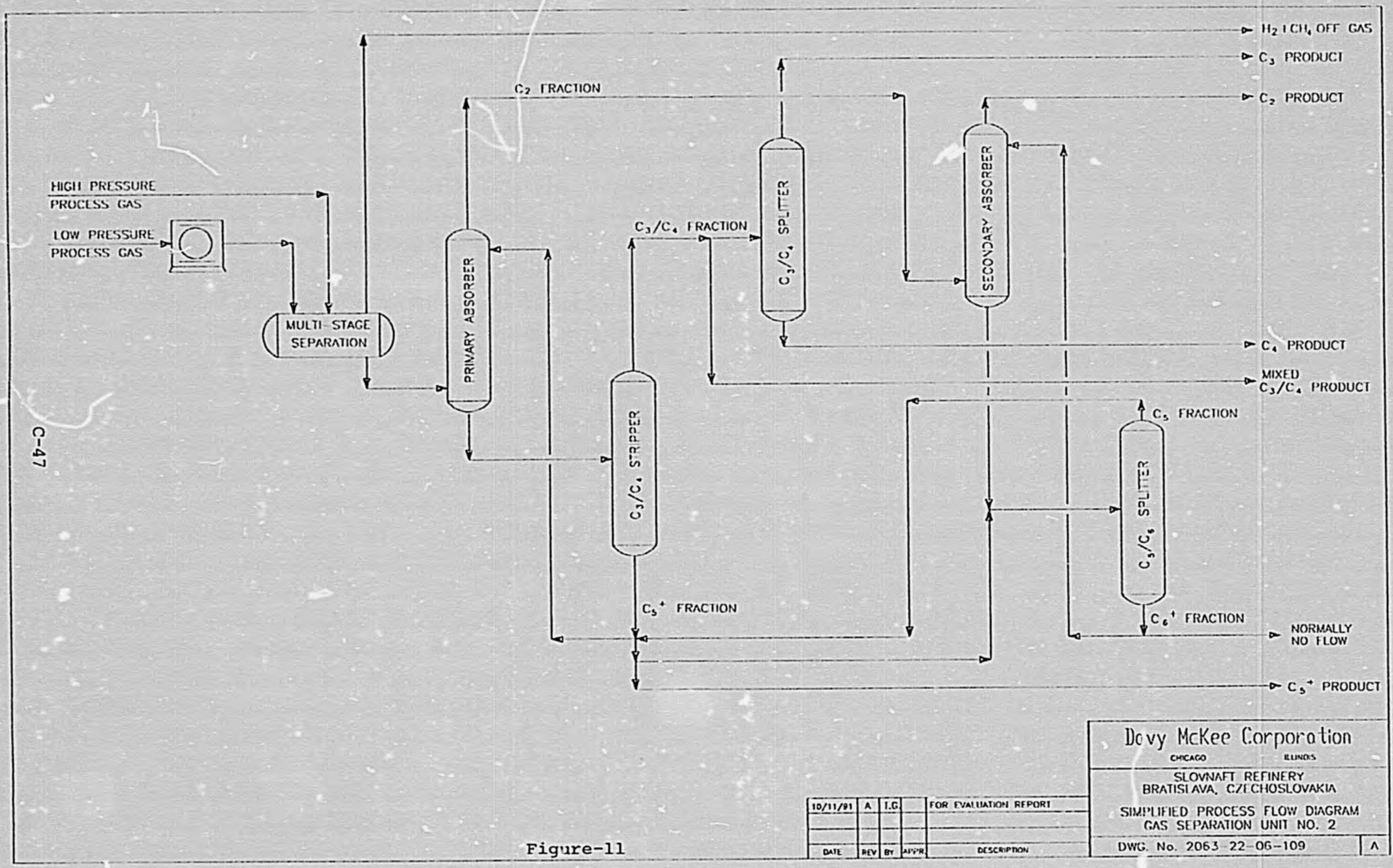
8.10 Replacement / Shutdown Observations

There appears to be no need to consider replacement or shutdown of the gas separation units at this time.

9. SULFUR PLANT

9.1 Process Flow Diagram

The process flow diagram of the two stage Claus sulfur plant(s) is as shown in Figure 11.



H2 / CH4 OFF GAS
C3 PRODUCT
C2 FRACTION
C2 PRODUCT
HIGH PRESSURE
PROCESS GAS
LOW PRESSURE
PROCESS GAS
MULTI-STAGE
SEPARATION
PRIMARY ABSORBER
C3/C4 FRACTION
C3/C4 SPLITTER
SECONDARY ABSORBER
C4 PRODUCT
MIXED
C3/C4 PRODUCT
C5 FRACTION
C3/C4 STRIPPER
C5/C6 SPLITTER
C5+ FRACTION
C6+ FRACTION
NORMALLY
NO FLOW
C5+ PRODUCT
Davy McKee Corporation
CHICAGO ILLINOIS
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BRATISLAVA, CZECHOSLOVAKIA
SIMPLIFIED PROCESS FLOW DIAGRAM
GAS SEPARATION UNIT NO. 2
10/11/91 A T.G. FOR EVALUATION REPORT
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DWG. No. 2063-22-06-109 A

Figure-11

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9.2 Feedstock

The sulfur plants receive their H_2S rich gas feedstock from the gas desulfurization facilities, which are described earlier in this report. Inlet gas runs at just over 70% weight H_2S.

9.3 Unit Flexibility

The sulfur plants are reported to have an operating range up to 120%. One of the lines has a smaller flexibility range limitation due to constraints placed on the system by the presence of ammonia in the feed gas.

9.4 Operational Sensitivity

It should be noted that there are two units, each with a sulfur capacity of 12 000 tonnes/yr. The two units are essentially identical, except that line 2 has been modified to accept feed gases that contain a small amount (1.7 wt%) of Ammonia. The modification consists of a custom built burner/furnace which converts the Ammonia to nitrogen under specially controlled conditions. The burner exit gas is kept below 100 ppm Ammonia to prevent harmful side reactions that could harm the units reactor catalyst.

9.5 Product Specifications and Unit Yields

Approximately 94% of sulfur is recovered on a weight basis. Product purity is 99.8% minimum with a maximum water content of 0.17%, weight basis.

9.7 Unit Modification Potential

To improve the sulfur recovery to 99% and decrease SO_2 emissions, a tail gas treatment unit is recommended.

9.8 Capacity Increase Potential

It is expected that the sulfur content of the refinery crude feedstock will increase in the future. Should this happen a third sulfur plant will be necessary to handle the increased sulfur load.

9.9 Operating Practices

With respect to operations, a DuPont Analyzer measures the H_2S/SO_2 content of the effluent stack gases and is used to control the amount of air added to the process. The gaseous inlet to the stack currently runs about one-half of the H_2S/SO_2 allowed by environmental regulations. Approximately 90% of the air inlet is added ratio wise, based on inlet gas composition and flows, with the remaining 10% admitted through the DuPont controller.

The only current operating problem reported by the refinery staff was with a "Damper", butterfly type valve used to control flow to the first section of the Claus unit reactor. Operating temperatures of 800 to 900 °C, results in valve distortion and the presence of SO_2 and H_2S gases causes corrosion which results in improper valve operations, poorer control, and maintenance downtime. The local staff requested suggestions for solutions to the problem.

While hard maintenance data was not presented the refinery staff commented about high rates of sulfur plant corrosion.

9.10 Replacement / Shutdown Observations

The refinery is considering the addition of a third sulfur line along with a tail gas treatment plant sized to take effluent from all three plants. The proposed sulfur removal efficiency would then be over 99%, compared to the current level of 94 to 96%.

10. PLANT LIMITATIONS

10.1. Unit Capacities

See section A-3, refinery description, for a list of units evaluated and their nominal rated capacities.

10.2. Product Requirements

Refer to the characterization report in the appendix for product quality specifications. Refer also to section C-2 for selected intermediate product specification.

10.3. Fuel System

Fuel system limitations were not addressed as such, with the exception of concerns over the 3 wt% sulfur in the heavy fuel oil. As local regulations change, either acquisition of lower sulfur crudes or desulfurization must take place. Refer to section B.2. for other fuel system data.

10.4. Steam System

Refer to sections B-3 and F4 for data on the steam system. Since the entire complex was not reviewed, no data on steam limitations was obtained. For the units reviewed steam availability was not a problem. Note also that not all steam boilers were running at the time of the evaluation as processing units were shutdown due to reduced crude supply.

10.5. Electric Power System

At the present time, the power station's electrical power output is limited by the Slovnaft complex's steam usage, since it is a cogeneration plant with very limited condensing. For any new electrical load, additional generating capacity would depend upon the additional steam load. Unless this steam load was very high, additional electrical power would be required from the state grid.

Considering its excellent design and its degree of redundancy, the electric distribution system should not limit any debottlenecking on the refinery units, replacement of existing units with larger units or new units. The plant distribution system is designed for a higher electrical load than is presently connected.

10.6. Tankage

Refer to comments in characterization report. There is limited heavy fuel oil storage, which presents a problem in the summer when fuel oil demand is low. Crude oil tankage is limited to a 12 day feedstock supply.

Additional crude oil tankage (agitated) is under construction in order to improve reserves and reliability of supply to the refinery.

10.7. Other Limitations

Addition of other crude oil pipelines into the refinery are under consideration. Currently crude is received via the Russian Druzba pipeline. The Adria pipeline (from Yugoslovaia) which connects to the Russian line some 150 km to the east has been used to bring in small amounts of Mid-East crude. Continued use of the Adria line is will depend upon settlement of the present Yugoslavian problems. Consideration is being given to bringing a 60 km crude supply line into Bratislava under the Danube river via the Schwechadt refinery in Austria.

D. HEAT CONSERVATION

1. HEAT TRANSFER PRACTICES

The refinery appeared to follow generally accepted good heat transfer practices, such as proper assignment of tube side / shell side flow, considering fluid flow characteristics. Fired heaters utilized convective sections, unlike heaters observed in some other eastern european countries.

It should be noted that the evaluation of specific applications did not occur, nor were any heat transfer practice issues raised during the implementation review, with the exception of the crude heat train performance.

The thermal and mechanical design of future exchangers should be checked against HTRI or similar program to assure installation of the most cost effective design. Such checking for proposed modifications of arrangement and service for existing units is also recommended.

2. UNIT ENERGY AND UTILITY CONSUMPTION

Energy and utility consumption for selected evaluation units, is as shown in Table B.1.1.

Utility data from evaluation units other than those in Table B.1.1., were not available.

3. HEAT TRANSFER EQUIPMENT ANALYSIS

3.1 Fired Heaters

A review of fired heaters, mainly within the selected units was undertaken during the evaluation. Portable combustion analyzers were used to determine flue gas composition and amount of excess air. The results of these measurements revealed high excess air, which would economically justify automatic fuel/air ratio control. Repeated measurements were made to assure a more accurate data base. The refinery has moved to reduce excess air in these units and improve the total heat economy of their furnaces.

AVD 6 Fired Heaters

A Ljungström air pre-heater has been installed in crude/vacuum heater No. 6 effluent gas lines, with overall efficiency reported to be in the 90-92% range. Modern, state of the art "ORSAT" type portable instruments are used to periodically check the accuracy of the on-line oxygen analyzer (KENT), which continuously monitors the excess air. The portable unit we saw in use was a Model 2000 P MSI analyzer of German manufacture. The unit determines and reports not only the heater efficiency but inlet air and flue gas temperatures as well as percent CO_2, O_2, CO, NO_x, SO_2 and excess air.

Furfural Unit No. 2

The fired heater efficiency of Furfural unit no. 2 was analyzed at the request of our team. An oxygen level of 11% was observed in the flue gas as sampled from the stack. These are older type furnaces, that are not sealed properly and additional air is introduced into the furnace chamber close to the sample port.

3.2 Heat Exchange Trains

Atmosphere Crude Unit No. 6

The refinery staff has analyzed the crude heat exchange train using pinch technology and report that the results were inconclusive.

It is important to note that many changes to the crude unit no. 6 heat exchange train have been made over the years, with several exchangers switched in service as the refinery staff worked to optimize heat recovery and maximize the inlet temperature to the fired heater. It should be understood that this is a dynamic system and changes were in progress as we met. As a consequence of this optimization, the inlet temperature into the heater has been increased from 205°C to 225°C (from May, 1991 to winter, 1991) but it's still lower than the desired design temperature (245°C). The use of a simulation analysis to analyze the heat exchange train within context of the whole AVD 6 unit is recommended.

3.3 Waste Heat Recovery

See Section B-7 for comments

3.4 Economics of Increasing Surface Area

The problems relating to the fouling, source of contaminants and potential solutions are contained in the mechanical section of this report (see also Section C.5.4, Limitations) Regular monitoring of the heat exchange of AVD 6 along with use of a heat exchange completed simulation is recommended. There were some investigations on the part of the refinery staff on HDS units related to increasing of heat exchange area and installation of a hot separator as energy saving means. One of the HDS units, in fact, has already seen installation of a hot separator. Refer to Appendix D for a calculation regarding the savings resulting from improved crude heat exchange heat transfer.

4. STEAM SYSTEM

4.1 Steam balance and utilization

Refer to Section B.3

4.2 Selection of Pressure Levels

Refer to Section B.3

4.3 Condensate System

Several years ago, Slovnaft management formed a team to address energy loss in the condensate system. Many areas have been improved since that time (implementation of proper steam trap sizing procedures, replacement and repair of faulty units, and the start of steam trap operation and maintenance training programs. A program is now in place that continuously monitors trap operation and records repair history.

There are still some problems (monitoring of the system, incorrect condensate line and slopes, corrosion and erosion) that need additional study.

4.4. Insulation

The insulation on the steam distribution system appeared adequate. The local staff is sensitive to good insulation practices and aware of the effect of rising energy prices.

4.5. Potential effect of energy savings projects to steam balance

Improved fired heater efficiency through reduced excess air flow, in situations where flue gas is used to generate low pressure steam, (AVD #4 for example) will result in reduced steam production from waste heat boilers. This steam must then be made up from increased production from the steam boiler system or concurrent reduction in consumption must occur.

5. HEAT REJECTION SYSTEM

5.1 Cooling Water Systems

Refer to Section B.5

5.2 Air Coolers

Refer to Section B.6 on air coolers.

5.3. Equipment, Piping and Stream Heat Losses

Refinery data exists to review and optimize heat recovery systems, to minimize stream heat losses. We did not evaluate this data in detail, as it appeared that the local staff was properly managing this area. We observed operating practices, such as by-passing storage and transferring hot streams (AVD 6 atmospheric column bottoms to vacuum tower feed) directly to the next processing unit, as means of conserving energy.

Note, however, that not all units were reviewed in this context.

5.4. Recovery Systems

Typical design practices to recover heat from hot product or process streams include process heat (feed to bottoms exchangers, pumparound to feed exchanger, etc) followed by waste heat boiler steam generation, then air coolers and use of water for final trim cooling.

See also comments in Section B.7.

5.5 Tracing and Temperature Maintenance Systems

At Slovnaft, steam is used as the heat media for both freeze protection and heat maintenance. No electrical tracing was observed, however suitable low heat density cal-rod type electrical heaters are used to heat some field mounted instrument enclosures.

Instrument tracing is usually 6 mm copper or steel. For heat maintenance on pipe (such as heavy fuel oil), 18 mm or 25 mm steel tubing is used. Freeze protection for some of the water lines also uses steel tubing. Insulation for these lines is one size larger than the nominal pipe size. No automatic temperature controls on either the heat maintenance or freeze protection tracing systems was observed.

6. USE OF HOT OIL LOOPS

The only use of hot oil loops that came to our attention was the system used in the Molex unit, which also was used in HDS No. 6. It is believed that others are in use in other parts of the complex but the units under evaluation did not utilize these systems.

E. MECHANICAL DRIVE SYSTEMS

1. COMPRESSORS / FANS

The only centrifugal compressors in the refinery, were on the newer Reformer unit and the Hydrocracker. The Reformers's compressors were induction motor driven and the Hyrdrocracker's both motor and turbine driven. The axial fans on the furnace air preheaters and the induced draft fans on the flue gas waste heat boilers, also had induction motor drives.

At the Instrument Air Plant, there are three 2-stage packaged screw compressors of which two are normally in use. Stainless steel piping is used, starting with the first stage outlet piping. Output air pressure is 5 atm. (nominal 75 psi) with a capacity of about 2 000 m^3/hr (1 177 SCFM). A silica gel system is used to dry the air with additional drying being done on the process unit. The target dew point after the first dryer is -27 °C (-16.6 °F) and -40 °C after the second unit.

All of the other refinery compressors are induction motor driven reciprocating machines. For additional information on reciprocating compressors see F.3.4 - Rotating Equipment.

2. SPECIAL PUMPS

There are liquid ring pumps furnishing the vacuum for the vacuum towers on AVD-6 and the Hydrocracker. On the MEA unit, there are reciprocating diaphragm pumps handling a two phase propane mixture. Also, on the furfural extraction units, there are a number of direct acting steam pumps, both simplex and duplex.

3. ELECTRIC MOTORS

Ninety percent of the refinery motors are manufactured domestically. The remaining 10% are from mostly Russian and German sources. All of the process unit mounted motors are totally enclosed fan cooled and explosion proof (TEFC EP). They are suitable for service in Div. I and Div. II group D areas as defined by API RP-500A.

Motors 160 kW (215 hp) and over are powered at 6 000 volts. Under 160 kW, they are powered at 380 Volts. For motors over 25 kW (34 hp), ammeters are mounted at the local push button.

As an energy reduction measure, the refinery is considering, either two speed motors or variable speed drives for the fan drives on the cooling towers. Also, for new motors, the economics of high efficiency motors will be evaluated.

4. STEAM TURBINES

Except for the power station and the hydrocracker, there are no steam turbine drives on the units reviewed by Davy McKee Corporation. At the Power Station, besides the turbo generators, there are turbine drives on some of the boiler feedwater pumps. This is done for safety reasons and continued production of steam upon electrical power failure. The power house turbines were domestically manufactured by Prvni Brnenska Strojirna. For further information on these machines see F.3.5 - Steam Systems.

Turbine drives are installed in the Petrochemical facility in critical applications.

5. SPECIAL EQUIPMENT

On the Hydrocracker, there is a hydraulic recovery turbine, utilizing the high pressure reactor effluent for the motive power, coupled to a motor driving one of the three feed pumps. On AVD-6, the original equipment vacuum steam ejectors are still used, to pull vacuum on unit start-up and as a spare to the liquid ring pump.

F. MAINTENANCE/MECHANICAL OBSERVATION

1. OVERALL IMPRESSIONS

The refinery was visited during the annual turnaround, which afforded the opportunity of directly observing the associated activities and the mechanical condition of at least one unit (AVD No. 6). While equipment inspection records are kept, especially as required by law or regulation, there was no easily accessible central historical data base to examine for trends in equipment failures, service intervals, etc. The Maintenance/ Mechanical Engineering Department exhibited strength in practical maintenance and a growing ambitiousness in mechanical engineering analysis of rotating equipment parts failures, vessel testing, and heat exchanger efficiencies. The Department actively sought to develop in-house programming to track inventory, streamline and prioritize work orders and begin a historical database. Further, there was great interest in entering into non-destructive testing and gaining the in-line and portable equipment necessary to maintain the program. Methods and new materials were of particular interest to the group.

Off-site warehousing, shop fabrication, and shop repair facilities were adequate, although it was volunteered that there were serious material shortages. Survival in the past accented self-reliance in fabrication as against purchasing. This was demonstrated in the scavenging and rebuilding of normally discarded parts and equipment. Labor costs were not maintained, although transfer of material and equipment from off-site warehousing was charged at cost without escalation or mark-up.

2. UNIT REVIEW

2.1. Hydrocracker

The Hydrocracker is Slovnaft's newest unit, and has been operating since January, 1991. It uses UNOCAL technology and was engineered by Snam Progetti. It was built to reduce Slovnaft's heavy gas oil output and increase gasoline and light distillate production. The unit has an associated hydrogen plant (other sources of hydrogen are available if needed), a vacuum tower to process the feed, a reaction section (three reactors) and a distillation section to separate the products.

The unit is controlled and monitored by a Foxboro Videospec II system. This system consists of three consoles, with each console having four color CRTs, an alarm panel and an operator interface keyboard. One console is for the hydrogen unit, one for the vacuum tower and reaction section, and the third for the distillation section. Data logging and monitoring was being done on a Fox-1A computer along with advance control schemes.

The Hydrocracker has most major pumps and compressors (however, there is only one main compressor) designed to have two driven units and one spare. Some of the compressors and pumps use a turbine for one of the drivers. One compressor has a turbine - motor - compressor train for one of the two normal drives, along with an electrical driven spare. Most of the equipment was domestically built, the small amount that was not domestically built was mostly Italian. The Hydrocracker appears to have been designed and constructed to the standards of a major U.S. refiner.

2.2. AVD-6 (Atmospheric Vacuum Distillation) Unit

The basic instrumentation on the AVD-6 (Atmospheric Vacuum Distillation) Unit is pneumatic. The original recording controllers are of Czechoslovakian manufacture. Polish manufactured pneumatic recording controllers were installed for the air preheater in 1988. The multi-point temperature recorders are potentiometric type and appear to be based on the old Honeywell/Brown design. Temperature measurement is mainly made with thermocouples (T/C), using J type (Iron-Constant) for most measurements and K type (Chromel-Alumel) for temperatures over 600°C (1 023°F). The thermocouples used are stainless steel sheath type and are manufactured in the refinery and are also sold outside the complex.

The Control Room is very large with a semi-graphic control board. The ceiling is four meters high and the semi-graphic unit representation extends two meters above the board instruments. The control board appears to be about 10 gauge steel and was manufactured in the refinery. The space behind the board is enclosed and is at least three times the area usually found in U.S. control rooms.

Heavy use is made of cascade loops, such as transfer line temperature setting the furnace gas flow. There are no advance controls operating at the present time, but combustion control and atmospheric tower draw-off decoupling schemes are expected to be implemented with the new Distributed Control System (DCS). The DCS is based on Foxboro's "Microspec" multiload controllers and a "Multi-Station" operator interface, and is now being commissioned on the unit. It consists of 87 control loops and 150 measurement points loops covering the unit's critical loops. This is approximately 60% of AVD-6's control and measurement loops. On the DCS, they will be implementing advance control strategies designed by Slovnaft's Advance Control Group and Foxboro, USA.

Signal conversion for the DCS is accomplished using P/I and I/P convertors located behind the control board. The corresponding pneumatic controllers on the control board serve as back-up for the DCS. Power for the DCS is provided by a uninterruptible power-supply (UPS).

2.3. Oil Movements

Gasoline blending is done by the batch method of mixing the components in a tank. Tank mixers are just now being installed. Mixing was previously done by pumping in and out of the tank.

The rail car loading was very modern and up-to-date. There were three loading stations with provisions for a fourth. One pumper operates two loading stations from one control center, while the other pumper operates a single station from the other control center, located 10 meters from the first. The tanker cars to be loaded are in a string and are positioned by the pumper, via a powered cable and pulley system over a scale, where a hydraulically operated 15 cm diameter loading arm is extended into the tank car. A DEC workstation size computer (one for each station) does the data logging, monitoring, fill computations, and accounting entries. When the fill point is reached, either the computer calculated weight fill or a high level shutdown on the loading arm, the fill is stopped by the computer and the loading nozzle is retracted. The next car is then brought into place and the cycle is repeated.

There are two product pipelines (P/Ls) leaving the refinery. The stations for both, within the Slovnaft complex, are about 150 meters apart, use domestically manufactured 6" x 6" miniature pneumatic instruments, are board mounted, and look like U.S. P/L stations built in the 1960's. One P/L runs into Moravia and the other P/L has two lines that serve Slovakia.

3. EQUIPMENT CONDITION SUMMARY

3.1 Fired Heaters and Boilers

Three heaters were inspected for maintenance, overall condition and an attempt was made to test efficiency using a portable Flue Gas Analyzer. Two fuel oil fired heaters located at ADU #4 equipment no.s F1/1 and F1/2, manually operated, induced draft, were measured and found to contain 9% to 10% oxygen in the flue gas. A visual survey of the skin and refractory found no major leaks nor hot spot anomalies. A third oil fired heater at the furfural unit was tested with similar results it was noted that fuel flow was not measured continuously. Fuel oil consumption was measured at the end of shift from a day tank volume change.

3.2 Heat Exchangers

Refer to Section D.3.2 for observations in relating to AVD 6 heat exchange train performance.

Heat exchangers and inter-connecting pipe were adequately insulated and without leaks, high pressure water jet cleaning was the only method observed during the turnaround of AVD#6.

3.3 Vessels

The country code permits operation of vessels to 100 000 hrs. The Slovnaft staff has requested information on methods and procedures for recertification of vessels.

3.4 Rotating Equipment

All pumps in AVD#6, and Dewaxing units #2 and #3 were examined to document particular problems. High failure rates on double sealed pumps have caused the refinery to eliminate double sealing practices and maintain only single seal installations. Other problems were related to aging and resultant leaking of furfural and NH_3. Most equipment sets were electric motor matched and spared. Past supply requirements have prevented equipment standardization. The Dewaxing Unit #2 is considered for replacement due to increasing difficulty in obtaining spare parts. Sealless pumps retrofitted or new are a recommendation for problems at #2 and #3 dewaxing units. See Section E Mechanical Drive Systems for more information on rotary equipment.

3.5 Steam System

Steam supply pipe was inspected in AVD #6 & AD #4. Condensate is collected and used as desalting water and waste heat boiler steam generation. The steam system grew in increments, responding to the demand of newly constructed units, in a period of time when close engineering, planning and design for steam services was thought to be a lower priority. All units need to have their steam consumption reexamined and evaluated. Steam traps have been and continue to be an inordinate problem. Insulation was an ongoing activity. Insulation jacketing was unpainted against corrosion.

All steam traps are examined during turn arounds. A report is issued covering the number of traps on the unit, the number found to be bad and the reasons why. Maintenance recommendations are made and bad traps are painted blue to make sure that they are changed out before start-up. A portable ultrasonic type leak detector (made in England) is used to detect traps that pass steam. The refinery is sensitive to energy loss and resultant savings through proper steam trap selection, installation, operation and maintenance. They are working with a major trap manufacturer in assuring proper training of staff in steam trap applications.

For trap repairs all the trap internals are replaced; a few of the replaced internals are kept for spares, but the normal practice is to do full replacement. Most trap failures are due to corrosion/sediment deposits on moving parts. There are no historical records for individual traps, but Slovnaft has started keeping a trap history by process unit.

3.6. Piping and Valves

The crude supply, product transfer, steam and condensate piping was inspected. Some minor leaks (pin hole size) were noted. In general the piping appeared to be in good shape, though some of the bents at the top of the pipe racks exhibited signs of erosion and corrosion.

During our visit AVD-6 was shutdown. Observations made during this turn around, indicated that the major and minor pipe spool replacement was about normal for a medium sulphur crude unit.

Valve inspection of the crude delivery and the product transfer lines for AVD-6 and AVD-4 showed no major value problems, though about 2% of the valves had limited seepage at the valve flanges. The inspections of the steam and condensate valves also showed no major problems, but here the leakage was about 4% and almost all of it, in the steam system.

The facilities for testing and maintenance of pressure safety valves (PSVs) were inspected and found to be more than adequate. The plant has an excellent system of tagging, witnessed bench testing, follow-up maintenance and record keeping for PSVs. The refinery's normal practice is during a turn arounds to inspect, do any necessary maintenance and bench test all the unit's PSVs. A historical record is kept for each PSV. A very adequate set of spares are kept for the refinery's PSVs.

3.7. Instrumentation

The Slovnaft Refinery's control instrumentation is generally pneumatic, except for the Polish electronic analog controllers on the Dewaxing unit 3 and a small distributed control system (DCS) of American manufacture. The newer controllers are mostly of Czech and Polish manufacture with a small amount of Russian equipment.

Instrumentation security is very high. All controller front doors, unit instrumentation shops, analyzer buildings and back-of-the-control board areas are kept under lock and key.

Instrumentation installation details generally approximate U.S. practices. The refinery's instrument maintenance facilities are very extensive with almost all work being done in house. However, the work is done by a number of distinct separate groups such as the general instrument maintenance group, an analyzer group, a turbine/compressor monitoring group, a computer/digital logic group and an energy group. Work is also received from outside the Slovnaft Refinery/Chemical complex. Slovnaft does the service work for Foxboro and its Polish licensee for all of Czechoslovakia. Some instrumentation manufacturing is also done in complex.

The prevailing wind is from the Northwest. Accordingly Slovnaft designs its units with the furnace in the northwest corner of the unit. On their Russian designed MEK unit, the refinery was unable to get the design changed to install the furnaces in the Northwest corner. The refinery therefore installed a steam ring about six inches above grade, drilled at the top and bottom to provide a steam curtain under emergency hydrocarbon leakage conditions.

The number of flow meters on the Slovnaft units appears to be less than that which would be found in a US Major's refinery. For example, for control purposes on AD-4, gas flow is inferred from the gas burner header pressure at the atmospheric tower charge furnace. Most meter-runs for the office plate meters are inadequate for good flow measurement and are mostly under ten pipe diameters (D). U.S. standards follow a Spinks' Table in his"Principles of Flow Meter Engineering" which calls for a minimum length of 14D for liquids and 17D for gases when the upstream disturbance is a simple 90° bend and 30D for liquid and 44D for a complex disturbance, of the normal cross-sectional velocity distribution, such as a control valve just upstream of the office plate.

On the pipe stills, AD-4, AD-5 and AVD-6, the crude input and the product outputs are measured with Hungarian manufactured turbine meters or German PD meters. The refinery installation practices for these instruments were very good. On the crude metering, to get the high flow velocities (N_{RE} 500 000) necessary for turbine metering crude, the crude lines were reduced two line sizes for the 20D meter-runs. Also, large basket-type filters were installed upstream of the meter-run. The product metering installations were basically the same, except that most meter runs were reduced one pipe size with the remainder being the same line size. On AVD-6, the ammonia injection stream was also turbine metered.

The Slovnaft complex has a large three story well equipped instrument maintenance shop. On the bottom floor are facilities for repairing control valves and bending and breaking sheet steel to fabricate enclosures and control boards. Thermowells are also fabricated on this floor. On the second floor, there were facilities for testing, calibrating and repairing pressure gauges, DPs, displacement level controllers and other pneumatic instruments. PD and turbine meters were also repaired here. Foxboro pneumatic instruments for all of Czechoslovakia are also repaired on this floor. The third floor was devoted to electronic repair. Their were 15 electronic technicians, about one third were female. Slovnaft's philosophy for electronic repair, is to do board and or module replacement except for domestic products, where the basis is element replacement. Foxboro "Spec Zoo" equipment is repaired here for all of Czechoslovakia. Foxboro DCS equipment is repaired elsewhere in the complex.

They prioritized their work as follows:

1. Critical
2. Important, but not critical
3. Neither of the above two

Category '1' is done in house whenever possible. When overloaded, such as during large turn-arounds, personnel are borrowed from other refineries and/or work is sent out starting with category '3'.

The Slovnaft Analyzer and Advance Control Group is presently staffed as follows:

1. Process Analyzer Maintenance - 10 technicians
2. Technical Service Lab Analyzer Maintenance - 5 technicians
3. Analyzer and advance control design - 5 engineers

The technicians are selected personnel who are trained in both electronics and chemistry. Besides doing analyzer maintenance for the Slovnaft Refinery/Chemical plant complex, the group also designs, procures, installs, implements and maintains advance control systems. They also do system work for Foxboro.

The Slovnaft complex contains approximately 800 analyzer loops, mainly consisting of gas chromatographs, end point, density, O_2, CO, CO_2, SO_2, NO_x, combustion, BOD, phenol, oil-in water, dissolved O_2 and pH among others.

Slovnaft has a Signal 821/850 gas divider and blender, which it utilizes to make most of their calibration gases. They also manufacture a stack gas oxygen analyzer and probe. These instruments are used only for indication and recording. For control purposes, Kent analyzers are used.

Separate maintenance records are kept for each analyzer and also computer entered. In addition, for each analyzer, a maintenance schedule with the recommended periodic maintenance listing is kept, along with calibration records such as sample gas traces.

Advance Controls

With the implementation of distributed control systems (DCS) on their process units, the opportunity for a greatly increased use of advance controls and stratagems dawned for US refineries. It became apparent to many of these refineries that the increased profits from advance controls would quickly payout on analog instrumented process units, the costs of a DCS and the advance controls. One US major decided to convert all its refinery process controls to DCS; their experience was that four (4) to twelve (12) months of the new control's operations to recovered the DCS/Advance control costs for almost all units.

With the implementation of DCSs, the following unit advance controls should be considered:

- Crude Units

  * Decoupling the side draws- This control allows the board operator to increase / decrease a product draw (changing that product's IBP and EBP) without upsetting the other product sidedraws.

  * Cutpoint calculation- This control replaces an expensive high maintenance analyzer. Calculating and inferring boiling point measurements such as 95% point from tower measurements. This measurement can then be used for tower control.

  * Pumparound control- This control looks at the pumparound flows, temperature, energy use and heat transfer and determines the economics of increasing/decreasing pumparound to increase/decrease products flow.

- Reformer Units

  * Reactor optimization- Controls reactor temperatures to optimize the catalyst life vs octane number output.

  * Prefractionator control- Sharpens fractionation so as to minimize catalyst poisoning heavy ends and non-reactable light components in the reactor feed, thereby increasing the reformer's octane barrel output.

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- Hydrogen Desulfurizers

  * Hydrogen control- Ratio hydrogen to feed to smooth flow, enhance the desulfurization reaction and extend catalyst life.

- Furnace/Heaters

  * Furnace air control- Regulate the combustion air to minimize excess air and prevent smoke formation.

When starting an advance control project, a 'process audit' covering those areas that the advance controls will impact, needs to be made. This audit should show all pertinent data such as flows, process condition, energy usage, product quality and stream values. This establishes the baseline. Later, three (3) to four (4) months after implementation of the advance controls a final process audit needs to be taken. This audit collects the same data that was taken for the starting audit. With the data from the two audits, a final report can be issued showing the actual savings vs the estimate savings and reasons for any differences. Besides establishing credibility for the project estimate and payouts, it also provides the feedback necessary to improve the savings estimating.

Ideal members of this final audit team are the advance control engineer, the process unit operations engineer and one of the consulting engineers, if used. With the high degree of savings seen on advance control projects, there is usually a push for their rapid implementation. This push, plus a lack of availability and/or expertise in the advance control area being implemented, generally makes it prudent to hire outside expertise, i.e. consultant. This an opportunity to upgrade the facilities staff expertise. A staff advance control engineer/s should be assigned to work with and monitor the consultant. On later projects, this will allow more (or sometimes all) of the same type of work to be done in-house.

3.8. Electrical Equipment

General

The Slovnaft Refinery/Chemical Plant Complex co-generates approximately 50% of its power usage. The power station, has four turbo-generators, with a total generation capacity of 104 MW. The additional power needed is obtained from the national grid. The primary distribution voltage is 110 kV and 6 kV. Emergency power is available from the grid at a reduced MW level. The power factor is high, 0.80 at AVD-6 unit. Automatic power factor correction is distributed through out the complex. Safety lighting is at 24 volts, normal lighting is at 220 volts.

For motors over 25 kW (33.5 hp), ammeters are mounted at the local push button. Throughout the refinery chemical plant complex, there is a very elaborate and extensive electrical tray system, mounted 10 meters (33 ft) above grade. This tray system appears to be about 40% loaded. It is used for power distribution and to bring data signals back to a central computer for accounting and balancing purposes. Factory motors are of 90% domestic manufacture, the remaining being of Russian and German manufacture. Motors 160 kW (215 hp) and over are powered at 6 000 volts. Motor repairs are made in the Slovnaft electrical motor shop.

Electrical heat tracing is almost non-existent. The complexes electrical systems are well grounded with the central ground system being slightly less than one ohm to earth. On the separate ground systems, Slovnaft has been able to maintain two to five ohms to earth.

The electrical safety practices as a general rule are not as strict in Slovnaft as they are in U.S. refineries, OSHA is probably the main reason. However, electrical equipment, is to a higher degree, under lock and key. On the crude unit AVD-6, on the top of the electrical desalters spheres, the 33 000 secondary voltage used for desalting, is exposed to possible personnel contact on the bus bar connection and insulator tops from the desalting transformer to the sphere penetrating bushing. Personnel safety is acnieved by installing a gate on the stairway to the danger and an interlock that removes power from the desalter and alarm, when the gate is opened.

The Slovnaft electrical craftsman are an entirely separate group from that of the power station. The latter's electricians maintain the electrical equipment in the power system of the complex and the electrical distribution system through the main substations.

Motor repair shop

Slovnaft operates a large electrical motor repair shop located just outside the refinery/petro-chemical plant complex. The facility is composed of a number of buildings surrounding a central paved courtyard. One building is devoted to offices, armature winding, coil forming and winding assembly into the stator. There are two Austrian manufactured hydraulic coil formers for fabricating windings for non-random wound machines. Eight armature winder operators were counted.

Another building housed varnish dipping tanks and a baking oven. The remaining building which was the largest, held a German manufactured dynamometer test stand, rated to 250 kW, and a German built balancing machine. Only electrical rotors being balanced and waiting to be balanced, were observed, no mechanical assemblies were in sight. There was also a large assembly, aligning and testing area in the building . This facility is capable of repairing Slovnaft's largest motor, 10 800 kV (14 500 hp).

3.9 Corrosion

Corrosion and erosion continue to preoccupy the turn around planners in the maintenance and mechanical engineering groups. Presently they have no non-destructive test coupons nor portable equipment to indicate metal thickness and corrosion. Inhibitors were being added in the normal manner, however, there was no historical data to review to determine their effectiveness.

3.10 Insulation Condition

Replacement and repair of insulation at the #3 Dewaxing unit was observed in progress and found to be equal to the design specification. Specifications were also being adhered to on vessels, process and steam pipe. Insulation stripped during turn arounds seemed to wait an inordinate period of time before repair.

3.11 Specialty Items

4. MAINTENANCE

4.1. Policies

The maintenance policy of Slovnaft has, to a larger degree, been severely affected by the plant organization, past budgetary procedures, and a lack of software to plan, schedule, interface inventories and collect equipment historical data. Organization of refinery maintenance is at the unit, multi-unit and plant levels. The unit operator has a lead mechanic with direct report for shift repairs. The chief mechanical engineer organizes his work at the level of several units and solves technical problems which the unit lead mechanic. Supervision and craft labor is pooled at the plant level, making for "discovered" matrix management and difficulty in setting priorities. Further, warehousing, purchasing and shop services are also organized at the plant level, complicating authority and responsibility.

4.2. History

Refer to Section F-1

Historical maintenance data exists on steam traps, safety valves, instrumentation, high pressure steam boilers, electrical equipment, pressure vessels, natural gas and the refinery gas system. Some of this data is as required by local laws and regulations.

4.3. Current Practices

Since our visit, Slovnaft reports the installation of a system for maintenance planning and control with spare parts inventory capability. We do not know the specific details regarding the program, but are encouraged that the refinery is moving forward in this area.

G. ENERGY LOSS MONITORING SYSTEM

On the newer process units, most product streams are metered by turbine or PD meter. Some of the furnaces/heaters inspected by the team did not meter gaseous fuel although day tanks were used in the case of oil fired units. The refinery needs to review its orifice plate metering techniques making sure the meter run lengths are long enough to insure accurate measurement.

Also needed are reliable oxygen analyzers to measure the oxygen in furnace/heater flue gas. An "In Situ" type oxygen analyzer, where the measuring cell is placed in the firebox, such as a "Zirtek", should provide the accuracy and reliability needed. It will also provide high and low alarms and most of all a reliable signal for an advance control furnace control and monitoring system.

Slovnaft is extensively gathering data from the process units into its computer system. The measurements for a reliable energy use data base are for all intents either already in system or easily added. What is needed is to extract this data from the system in a meaningful timely manner. The problem energy uses and losses and significant energy trends can then be identified and programs established to start minimizing these losses.

Energy use monitoring should allow charging the process units, on some calendar basis, for their various energy usages. Accountability for the efficient usage of the refinery energy then needs to be established, so that goals to reduce energy use can be set and monitored.

Slovnaft has implemented a distributed control system (DCS) on the hydrocracker and a partial system on AVD-6. The refinery now needs to upgrade its obsolete pneumatic control systems with DCSs thereby bringing the control systems to what is rapidly becoming the standard in western refineries. This will then allow real time tracking of energy usage and with the implementation of advance controls, methods to minimize the energy per tonne of crude processed.

In summary, Slovnaft needs to improve its metering techniques, setup a system to obtain timely energy usage data, install DCSs, on appropriate refinery units and implement advance control schemes. Then the data obtained and equipment installed can be used to identify energy loss problems, energy use charges and energy usage trends and also be available for energy minimization advance controls.

The refinery is managing energy loss through a variety of approaches. First, and most importantly, management has established an energy management group, whose purpose is to seek out and implement energy saving opportunities. These activities may generate projects that range from re-arrangement of the crude heat exchange train to changing reactor operating conditions and outlet temperature, yet maintaining yields and throughput, thus saving fired fuel usage.

Several state of the art portable combustion gas analyzers have been acquired. These units are used by the local staff to periodically test fired heater flue gas for CO, SO_2, NO, O_2 and CO_2. The unit also indicates heater efficiency. The information is used to check in-line oxygen analyzers, but more importantly, estimates of fuel lost based the new data are forcing positive changes in operating practice. Economically justifiable projects to control excess air are now coming forward for management approval. The problem so far in reducing excess air to fired heaters has been convincing the operating staff to utilize analyzer data to adjust burners.

Several years ago, a team was created to examine heat loss due to steam trap operation. A strong program has been carried out to insure that a strict inspection of all traps occurs during each shutdown, as well as during normal operations. This team, in addition to its steam trap work, is now focusing on condensate systems, steam trap sizing practices and operator training.

A difficulty in implementing energy saving projects is availability of funds, not opportunities or solutions to problems. Capital budgeting practices may need review. The previously mentioned problem of effecting change in the operating staffs attitude in adjusting burners is an example of the type of staff motivation problems that must be addressed.

This is not to leave the impression that all is perfect. Much work remains to be done. Two of the team members shared their training and experience in motivation techniques with the Slovnaft management. This was done in response to a question of how to motivate people to be sensitive to save energy. Ideas shared included setting objectives with mutual agreement between management and staff, accountability, ownership, rewards and ability of the staff to control the variables that effect their objectives. Many of the concepts shared were already in practice.

In summary, much good work has been done by the Slovnaft staff to reduce energy consumption and we are sure that their continued efforts will insure future success.

H. FUEL SWITCHING / UTILIZATION

1. REFINERY FUEL SYSTEM

Refer to section B.2. for a description of the refinery fuel system.

2. GENERAL REVIEW OF COAL USE IN REFINERY SERVICE

The availability of native coal makes a review of coal as an energy source of interest to the national economy. A study on the use of coal as an adjunct or substitute for hydrocarbon fuel streams is, therefore, included in this evaluation.

Heat is provided by burning a variety of fuels in directly fired heaters. Generally the fuels are a collection of effluent streams from the various operations around the refinery complex in both gaseous and liquid forms.

Coal is frequently used in industry as a fuel source. Generally it is used on large capacity boiler units. There are significant base investment and operating costs and activities associated with feed and ash handling equipment, sulfur removal, etc. that can be charged out over large installations, but prove too inhibitive in the economics of small units.

There are many ways of utilizing coal as a fuel. Probably the most applicable to the situation at hand are discussed below. The first two, direct coal firing and coal gasification, are discussed in some detail. Several others, such as coal liquefaction, coal-oil mixtures, coal fired gas turbines and coal gasification / fuel cells are touched upon briefly.

Coal usage in existing refinery process heaters would most likely be restricted to one of the methods in which a product fuel can be produced in one location and piped to the various users. Plot space in the vicinity of the existing furnaces along with safety considerations typically does not allow for coal and ash storage and handling facilities within the refinery processing area. Also existing equipment is not designed for the particulate loading experienced in the flue gas with coal firing. In addition, any required sulfur removal equipment would have to deal with flue gas clean-up on an individual process heater basis if there were not a central coal processing facility.

The entire refinery energy and equipment picture dictates if coal could be incorporated into the refinery as a acceptable energy source. If a new process heater or utility boiler would be needed and the fuel balance allows for another fuel source, then the use of coal may be justified and the new coal technologies would be worth looking at. If the residual fuel picture changes because of modifications to the refinery, coal usage may be justified. For Slovnaft, however, the potential for use is negligible.

2.1 Direct Coal Firing

Coal usage is not a simple thing anymore. Gone are the days of stoking the fire by shovelful of run-of-mine coal and just letting it burn. Coal may need to go through physical cleaning, sizing and drying just to get it to the furnace. Burners are specially designed to achieve optimum efficiency and low NOx emissions. Additives are injected to reduce ash sticking to heater tubewalls, reduce SO_2 in the flue gas, etc. Flue gas may be subjected to further treatment such as wet scrubbing to reduce SO_2 to tighter levels of environmental acceptance.

Traveling grate burners bring the coal automatically to the burning chamber where the coal is combusted. Coal with a moisture content much above 30% must be dried before burning, so lignite / brown coals would most likely need pre-combustion drying. Hot under grate air can be used for this purpose. Ash builds up on the grate until it drops into a hopper. The ash is later removed from the hopper. Sulfur, however, must typically be dealt with after combustion if its' removal as sulfur oxides is necessary. Add on SO_2 equipment adds significant cost to a unit.

Modern direct coal burning systems include atmospheric and pressurized fluidized bed combustion (AFBC and PFBC) units that provide for gas burning, clean-up and heat recovery all in one unit. Limestone is used as part of the fluidizing medium and the calcium present in it reacts with the SO_2 before it is able to escape from the combustion chamber. The result is a non-toxic disposable by-product.

FBC technology is applicable to a wide variety of fuels including a wide range of coals, residual oil, petroleum coke, etc. AFBC technology for boilers is available commercially from a large number of licensors, while PFBC technology is still considered to be in the development stages. The application of FBC technology to a process heater may be possible, but it would require extensive pilot test runs and special considerations in equipment design.

2.2 Coal Gasification

Coal gasification has been utilized for a long time and there are several companies (Texaco, Lurgi, IGT, KRW, etc.) that have commercialized processes. The product from the gasification (H_2, CO, CO_2, +others) can be used as a chemical feedstock or a fuel gas. To produce a fuel gas of medium range heating value (9.3 -18.6 MJ/m^3 or 250 - 500 Btu / SCF) suitable for burning in a process heater, oxygen must be used in the gasification. Because of the reducing conditions present in the gasifiers, most of the sulfur in the coal is converted to H_2S. H_2S can reliably removed from the gas stream by a number of available processes. In addition, it can further be turned into elemental sulfur.

Development work is being done for in-situ desulfurization in a fluidized bed coal gasifier. This process is much the same as the PFBC except that the product is a gas with a heating value instead of combustion product gases. It is also similar to the FBC technology in that it can utilize a wide variety of fuels, such as the sour residual oil produced within the refinery.

Fuel gas produced in this way can be piped into a plant fuel header and used anywhere around the facility. The attractiveness of this option is that the coal usage would be in one central location, while the fuel users could be in many different locations.

Another possible use of the gas produced via gasification could be as a fuel to a gas turbine The gas turbine could be used to generate electricity or to provide a direct large capacity mechanical drive such as a compressor. The thermal efficiency of a gas turbine is typically raised by using the turbine exhaust gas to raise steam in a waste heat boiler, in a co-generation system.

Given the availability of coal in Czechoslovakia, coal gasification technology should be watched closely and given full consideration at such time that energy economics dictate its use. The selection of the proper technology to best fit the local brown coal characteristics should be kept in mind. In-country technical experts, we understand, are very well aware of the various technologies and are keeping abreast of current developments. Initial investment cost is high and although a project may be justified from a DCF or NPV basis, a shortage of hard currency may delay or defer action.

The cheapest source of fuel at this time is Russian natural gas. Alternate sources of fuel will not come to fruition until it is economical to do so.

2.3 Other Technologies

Coal liquefaction

Production of liquid fuels from coal can be either indirect or direct. In indirect liquefaction, the synthesis gas produced in a gasification step is further reacted to produce a readily burnable fuel (i.e., via the Fischer Tropsch process to naphtha, diesel and waxes or via syngas to methanol to gasoline). Since the gasification product would be an adequate fuel for the heaters on the refinery, there would be no need to go beyond that step to liquid fuels.

Direct liquefaction producing a No. 2 type fuel oil would be more applicable to the fuel needs in the refinery. Several processes have been developed since the 1960's including H-Coal, SRC-I, Exxon Donor Solvent, SRC-II, etc. (in the U.S.). The high cost and inefficiency associated with these processes led to the cutback of further development of the technologies as they stood. The early processes have been modified and further developed by the United States Department of Energy (U.S. DOE) and industrial partners into two-stage liquefaction processes. These processes are still not available on a large commercial scale. Estimates are that the cost of a barrel of oil produced by coal liquefaction using such methods might approach $25/barrel by the late-1990's.

Coal oil / water mixtures

The use of coal slurried with oil or water to produce a usable fuel is also the subject of numerous studies and optimizations. There are even annual conferences on "Coal & Slurry Technology" sponsored by the Coal & Slurry Technology Association and the U.S. DOE's Pittsburgh Energy Technology Center (PETC). Coal water mixtures can be prepared with up to 70% solids, while current technologies and pilot plant results show coal oil mixtures are limited to 30 - 50% solids. Coal-oil mixtures could be prepared in one location and pumped around the plant to the various process heaters, however, emissions in terms of SO_2, NOx and particulates would be a problem at each furnace.

Coal-fired gas turbines

Direct coal-fired gas turbines are being developed and improved by General Electric, Westinghouse, United Technologies, etc. The use of gas turbines in this manner on the refinery would most likely be restricted to electricity generation. Solids and impurities deposition on blades and casings would likely require frequent cleaning and duplication of equipment would be required to even out loads. Environmental control requirements would also likely limit the application of this technology to high quality coals.

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Fuel Cells

The combination of coal gasification and emerging fuel cell technology presents an attractive high efficiency electronic and heat energy generation possibility. Current projections, based on work sponsored by the US Department of Energy, indicate an efficiency between 45 and 55% in converting hydrocarbons directly to electricity. The H_2 and CO rich fuel from coal gasification is suited to fuel cell use, with CO_2 used in the cathode side of the cell.

Of the four major fuel cell technologies, two are worthy of mention here, phosphoric acid and molten carbonate. Phosphoric acid fuel cells are at a more advanced state, however, they operate in the range of 400 °F compared to molten carbonate cells at 1 200 °F.

The molten carbonate fuel cell is best suited for use with coal gasification in applications where there is need for good quality heat. The exhaust gas temperature of 1 200 °F is useful in the generation of high quality steam for process purposes. The use of bottoming cycles further enhances the system. Overall efficiencies, electrical and utilization of exhaust gas to generate steam, are in the order of 80%. The Department of Energy is sponsoring Sub-megawatt tests of commercial sized units; these tests are scheduled for the 1993 calendar year.

While the technology is not quite ready for commercial use, it is attractive and should be watched closely.

3. COAL AT THE SLOVNAFT REFINERY

3.1 Availability and Characteristics of Coal

Coal is not available in the Bratislava area, however it is available in the Northwest area of the country. Two types of coal analyses are as shown in table H.3.1.

Table H.3.1 - Typical Czechoslovak Coal Analysis

Component	At Kraiupy	At Litvinov
C	33.3	29.3
H_2	3.8	3.3
Combustible Ash	1.0	-
N_2	0.5	0.4
O_2	10.7	10.5
Total Sulfur	1.1	1.0
H_2O	27.0	24.3
Ash	23.7	31.2

The heating value of coal at Litvinov is reported to be 10.82 GJ/tonne with a delivered cost of 260 Kcs/tonne in August, 1991.

3.2 Potential for Use

It is reported that only a 30 year supply of coal is left in Czechoslovakia. The country is building nuclear power stations for future electrical needs. The coal reserve will be used to feed existing power stations, not refineries. Therefore, at this point in time the potential for coal use is extremely low. Refinery fuel fired equipment can easily use natural gas or fuel oil. Modification for coal use reflects a major capital investment that is unlikely to occur.

3.3 Economics of Use

High sulfur fuel oil is a product that does not have much demand, especially in the summer. Its use as a refinery fuel is a convenient way to utilize the material. Switching to coal would present an over supply of fuel oil. The availability and current price of natural gas at about \$3.00/1 000 ft^3, coupled with a high capital investment required to utilize coal leads to the observation that coal is not an attractive alternative for Slovnaft.

Frankly speaking, burning coal for Slovnaft would not be allowed by environmental authorities, unless desulfurization and particulate removal would be especially efficient.

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I. REFINERY EMISSIONS

1. SUMMARY OF ENVIRONMENTAL SURVEY

1.1 Refinery Sulfur Balance

The current crude contains 1.5 wt% sulfur. Based upon a crude oil throughput of 5.7 million tonnes per year yields the following:

TABLE I.1.1 - SULFUR BALANCE

Source	Tonnes/year
Total Sulfur In Feed	85 604
Sulfur Recovered	11 231
Sulfur In Product	65 365
To Atmosphere	
Claus Unit	557
Fuel Oil Fired	8 410
Refinery Fuel Gas	41
Subtotal, To Atmosphere	9 008
Total Sulfur Out	85 604

The 9 008 tonnes/yr of sulfur to the atmosphere generates a total of 18 016 tonnes/yr of SO_2. This level of release will cause health hazards during any non-ventilating day. The facility is currently investigating installing SO_2 scrubbing for the main power plant. The amount of fuel oil fired at the power plant is approximately five sixths (5/6) of the oil fired at the complex. Therefore, if a SO_2 flue gas scrubbing system is installed for the power plant, approximately 14 000 tonnes/yr of SO_2 could be removed. Other means of control would be to collect and scrub the process heaters, solid waste incinerator and chemical sludge incinerator stack gases and remove the SO_2 from these flue gases. A more efficient method of SO_2 control would be to use a low sulfur fuel in the process heaters.

1.2 Air Emissions

Emission data was available for the power house boiler and certain process heaters. Based upon these stack gas analysis it is evident that an excess of SO_2 and NOx is being emitted. The plant could undertake a four year plan to replace existing fuei oil burners with staged combustion low NOx burners. The amount of NOx emitted could be reduced by approximately 50 to 70% by this substitution.

Data was not available as to the amount of loss from the process tank. It was determined that the higher pressure storage tanks were protected with pressure relief valves and rupture discs, which vented to a steamer-no-smoke flare system. The atmospheric storage tanks were equipped with flame arresters on the breathing nozzles. A target for reducing the volatile organic chemical (VOC) loss is to install vapor recovery units on each of the atmospheric tanks.

Options under consideration to reduce VOC emission from these sources include connecting tank vents to a common header for recovery and/or installation of a double seal floating roof on selected vessels. The refinery management expects to meet local environmental regulations, in this respect, by the year 2000. With the proper design of the recovery system, the VOC loss could be reduced by 90%.

The refinery API separator could be covered. This would reduce the total VOCs emitted. The actual pounds of VOCs that would be prevented from evaporating from the API cannot be determined. The current practices in the USA is to require the covering of the API. The head space between the liquid level and cover must be vented to either a flare system or to a vapor condensing system.

1.3 Water Quality

The facility has three water discharges. Two cooling and storm water outlets flow to the Little Danube River. Both of the discharges pass through API type oil/water separators. The API separators are equipped with flight collectors for both the sludge and floating oil. The sludges are periodically removed from the API and deposited on sand drying beds. The dewatered oils/sludge is collected from the sand bed and transported to the solid waste incinerator. The floating oil in the API separator is pumped into a slop oil tank adjacent to the crude oil storage tanks. The slop oil is dewatered and blended into the crude oil before refining processing.

The chemical sewer effluent from the petro-chemical complex is treated in an above ground API type separator. The collection sewer terminates at a pump station sump. The waste water is pumped to the forbay of the separator. The separator is equipped with sludge and floating foam collection flights. Both the foam and sludges are pumped to the sludge incinerator for disposal. The partially treated water is then pumped to the final stage wastewater treatment plant.

The chemical sewer effluent from the refinery is treated in the same manner as the petrochemical oil prior to pumping the wastewater to the combined treatment plant.

The combined wastewater treatment plant has two parallel trains. Both trains consist of:

- Two compartment API type separators
- Flocculation/mixer tank
- Recycle and waste activated sludge pumps
- Chemical feed for ammonia and phosphate
- Clarifier with floating and settled sludge collectors
- Fixed platform slow speed aerators
- Activated sludge clarifier
- Chemical feed building
- Dissolved air recycle pump and air dissolving tank

The units are concrete above ground construction.

The flow from both the refinery and the petrochemical plants are combined before flowing into the API type separators. The collected float and sludge are moved and pumped to the sludge incinerator. The effluent flows to the flocculation/mixer tank. The flocculation/mixer tank is equipped with a slow speed top mounted paddle. The paddles are to ensure proper mixing of chemical additives and the wastewater. No chemicals are currently being added. The plant operators are capable of meeting the wastewater discharge standards most of the time without the added chemicals. A portion of the wastewater flow from the flocculation/mixer is pumped into an air dissolving tank.

The air dissolving tank receives water from a pressurizing water pump. Compressed air is provided by air compressors. The compressed air caused air to be dissolved in the water. The water with the dissolved air mixed with the flow from the flocculation/mixer tank. The combined flow is released at the center of the clarifier unit. The circular clarifier is equipped with a float collector and a bottom sludge collector. Both the float and sludge is pumped to the sludge incinerator. The clarified water flows to the pump station supplying the aeration basins.

The aeration basin is constructed with two trains of aeration compartments. The design allows for parallel flow through six aeration units or a combination of up to twelve units in series. The plant is currently operating eleven in series and using one aeration compartment for activated sludge re-aeration. The wastewater from the clarifier and the re-aerated activated sludge is mixed in the first of the eleven aeration compartments. The mixed wastewater then flows through the remaining ten aeration compartments. From the final compartment, the waste mix flows to the circular activated sludge clarifier.

The clarifier is equipped with both a float and settled sludge scraper mechanism. The float is pumped to the sludge incinerator. The settled activated sludge is pumped to either recycle to the re-aeration tank or to the sludge incinerator. The clarified water then flows to a final complete mix aeration lagoon. The lagoon is equipped with eight floating aerators. The lagoon overflows to the Danube River. This lagoon also functions as a fire water pond.

The treated effluents standards and actual effluent are:

TABLE I.1.2 TREATED EFFLUENT STANDARDS

Description	Standards	Effluent
pH	6.5-8.5	7.98
SS (mg/l)	< 30	15.90
BOD (mg/l)	< 20	28.70
Phenol (mg/l)	< 0.1	0.054
PO_4 (mg/l)	-	2.64
Flow (m_3/hr)	3 600 Design	1 350 Actual

It is to be noted that only one train was operating. Therefore, there appears to be excess capacity available at the present crude run. The effluent BOD is larger than the standard. this could probably be reduced with the adjustment of pH, additives or a flocculent and polymer in the chemical flocculent/mix tank. Other modifications could be considered and raise the mixed liquor suspended solids. This evaluation would require additional testing and sampling.

The ground water under the sample has become contaminated. The plant has conducted a ground water survey and developed a program to contain and remove the contaminated water. If the sources of contamination are removed, oil lagoons, leaky contaminated soil from previous spills, the existing system should eliminate the ground water contamination within 5 to 10 years.

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1.4 Solid Waste

As mentioned previously, various floats and settled solids are incinerated in the chemical incinerator. The chemical incinerator consists of the following:

TABLE I.1.3 - CHEMICAL INCINERATOR

Quantity	Description of Item
2	Circular sludge thickener tanks
3	Rotary vacuum filters for the chemical sludge (6 000 tonnes/yr)
2	Squeeze two belt filters for biological sludge (6 000 tonnes/yr)
2	Chemical feed/mix systems for polymer feeding to the sludge
2	Vertical rotary hearth incinerator
2	Spray scrubbers
2	Bottom ash slurry systems
1	Slurry holding tank

One incinerator was operating and one was being repaired at the time of the visit. The concrete slurry holding tank was designed to hold the estimated quantity of dust that would be generated in 10 years. The incinerator has been operating 7 years. A near future disposal problem will exist due to the amount of leachable materials in the dry flue ash and bottom ash. Two other solid waste incinerators are installed at the facility. Both are installed at the same location and the exit gases discharge through a common boiler and stack.

The first incinerator is a rotary kiln type. The solid waste is fed by a grab bucket into a feed chute. The feed chute feeds the solid waste through a double slide feeding chamber, the solid waste being fed at the high end of the inclined rotary drum. Waste oil or heavy oil is fired at the low end. The waste, oil and solid are combusted as the material travels from the high end to the ash discharge at the low end. The hot combustion gas flows into a boiler for heat recovery.

The second incinerator is of the chamber type, where the waste to be incinerated is placed on a slide platform. A door is opened to the combustion chamber by a ram, the ram is withdrawn and the door is closed. Waste or heavy oil is fired to burn the materials in the chamber. The hot gas, as it flows from the combustion chamber, is not completely oxidized. Therefore, a secondary combustion chamber is installed. Additional waste or heavy oil is burned in the secondary chamber to combust the flue gas. The hot gas from the secondary chamber can flow into a steam boiler for heat recovery or to a wet scrubber for stack gas clean-up. The scrubber has not been operated for a few years. The boiler exit flue gas passes through a multicyclone particulate separator located upstream of the induced draft fan. The induced fan discharges to the stack.

During start-up on the morning of Friday, 24 May 1991, a distinct black plume was observed. This is typical for start-up using heavy oil in a cold combustion chamber without natural gas warm-up.

The various solid waste material observed were:

- Plastic bags of paper refuse
- Drums of off-spec plastics
- Drums of oily substances from various sources
- Open piles of scrap plastic
- Concrete holding tank full of heavy oil used for fuel

The capacity of the incinerator is uncertain because of the type of material fed into it. The combustion chamber is 1.5 m x 3 m x 4 m high. The bulk density of the material and flammability are both highly variable; therefore, burning capacity is variable.

The solid waste, lime sludge, from the lime softening plant is collected and disposed of as an agricultural supplement. In 1990, they shipped approximately 9000 tonnes.

1.5 Impact of Maintenance Practice in Generating Emissions

The operation of the environmental control system was limited due to the lack of spare parts.

The systems that were observed that could reduce emissions by making available the spare parts and maintenance personnel are: VOC, H_2S, oil loss, particulate and acid gas, effluent water quality and solid waste disposal. The total VOC emission could be moderately reduced by improving the maintenance of the flange gaskets, pump seals, compressor seals, and the valve glands in those systems that are processing VOC material.

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It is important for the refinery to assure continuous maintenance of H_2S analyzers around the amine strippers and Claus unit. Proper attention to the maintenance of the air pollution controls at the dual solid waste incinerators and oil skimmer/sludge separator is necessary to assure continuous, proper equipment and systems operation in order to meet environmental emission standards.

1.6 Evaporation Losses

Part of Item 1.2.

1.7 Loss of Products to Solvents

Not observed or investigated.

2. HANDLING OF MATERIALS

2.1 Tetra-ethyl lead (TEL)

Not observed or investigated.

2.2 Aromatics

Not observed or investigated.

2.3 Solvents

Not observed or investigated.

2.4 Halogenated Hydrocarbons

Not observed or investigated.

2.5 Heavy Metals Management

The observed potential sources of heavy metals were:

- Basic Sediment and Water (BS and W)
- Desalter Water
- Oily Sludges

ND

- Combustion of Heavy Oils
- Combustion of Water and Wastewater Sludges

The tank bottoms from storage tanks, process units or the API separators are sources of accumulated heavy metals. These wastes were typically burned in the rotary kiln incinerator. The hot gases exited the heat recovery boiler without any particulate control. Therefore, the volatile heavy metals would exit the stack. The non-volatile heavy metals would remain with the bottom ash. The bottom ash is currently being stored in a large concrete-lined pit. No ultimate disposal plan has been developed.

The burning of the vacuum unit bottoms in the power plant and process heaters release heavy metals to the flue gases. Currently no control devices are installed on either the boilers or the process heaters. If a flue gas desulfurization (FGD) system is installed for the boilers, a major portion of the heavy metals in the flue gas will be captured in the sulfur scrubbing material. The FGD sludge will then have to be managed to prevent environmental pollution.

The crude oil storage tank water drainage and the water from the desalter will contain heavy metals. Both of the waters are routed to the wastewater treatment plant. Some of the heavy metals will settle in the API and enter the environment by being burned in an incinerator. A portion of the remaining heavy metals will be accumulated by the biological sludge in the activated sludge treatment system. The bio-accumulated heavy metals in the waste activated sludge will be released to the environment by either the incinerator stack gas or in dust removed from the flue gas by the cyclones. The dust from the cyclones is currently being stored in a large concrete tank. An ultimate disposal plan has not been developed.

Any heavy metals that come into the facility in the raw water would be removed in the softening process. The sludge from this process is de-watered and burned in the same incinerator as the waste activated sludge. The heavy metals will have the same fate as the burning of the waste-activated sludge.

As stated in Section 1.9.3, Solid Waste, the spent catalyst and fines are currently being stored in piles above-ground. Some of the fines become airborne and migrate throughout the environment. Any rainwater falling on the dust could leach heavy metals to either the river or groundwater. A plan for the ultimate control of this source has not been developed.

2.6. Sulfur

The liquid sulfur from the Claus plant is pumped to above ground storage tank. The storage tank are steam heated and insulated. The liquid sulfur is pumped into steam located railroad cars or tank tracks.

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2.7 H_2SO_4, HF

The refinery unit does not have an alkylation unit.

2.8 Combustion Products

The only combustion products that are handled are the ashes from the three incinerators discussed in section 1.4 - solid waste.

2.9 Tars

Not observed or investigated.

3. MEASUREMENT OF EMISSIONS

No measurements of emissions were taken. It was noted that the power house had orsat measurements of the flue gas but were not recorded. Also the Claus plant stack had H_2S monitors, but no data was recorded.

4. SPECIFIC RECOMMENDATIONS

The proposed installation of centrifuges by the refinery to separate the oily phase from oil sludge is supported by the DMC team.

Institute a program to determine what process unit is losing hydrocarbons to the oily water sewer. The proposed oil in water portable monitor will aid in this program.

Replace the covers on the petro-chemical API separator, and cover the refining API separator. Both should be equipped with a ventilation system, with capture or destruction of the VOC removed.

Install a pH control system at the beginning of the mechanical sector of the combined WWTP to adjust the incoming pH to 6.5 to 8.0 units.

Initiate a program of observing the dissolved oxygen level in each of the various ashes from the incinerators to determine the potential of recycling. If they cannot be recycled to a reproductive use, they should be stabilized to prevent leaching of heavy metals.

Install a vapor recovery system on tanks containing volatile materials.

Institute a program of monitoring the flanges, valves, gaskets, and seals of equipment processing volatile materials. Repair or replace any item showing excessive VOC leaks.

Establish a plan to install a more efficient pollution control system for the sludge incinerator.

Improve the sulfur management program by implementing a combination of the following:

- Install Flue Gas Desulfurization (FGD) Systems
- Install tail gas clean-up units on the Claus units.
- Addition of bottoms processing to improve yield of lighter products and reduce sulfur content of fuels.

J. ENERGY EFFICIENCY IMPROVEMENTS

1. IMMEDIATE OPPORTUNITIES

The evaluation team made several recommendations of an immediate implementation nature. These were:

- To seek out and eliminate air leaks into the furfural units. The refinery staff pointed out that there was excessive maintenance on Furfural unit pump mechanical seals. The team pointed out that sections of the unit operate under vacuum and that air leaks into equipment must be eliminated. The reason for this statement is that furfural rapidly oxidizes in the presence of oxygen and high temperatures to form tars and polymers. It is very likely these tars and polymers cause pump mechanical seal problems, with resultant loss of production due to maintenance downtime as well as contributing to the loss of furfural. Additionally these tars and polymers cause increased fouling on heat transfer surfaces, with a resultant increase in energy consumption. We should also note that Texaco Corporation, in a recent visit to the refinery, strongly recommended that the furfural unit feed deaerator be put back into operation. The Davy team strongly concurred with this recommendation. The local staff stated that they would put the deaerator into operation and that they would check for and eliminate air leaks.

- It is recommended that the refinery check fin-fan air cooler air flow patterns, as we did observe clean/dirty patterns on the finned surface of units down for maintenance, that indicated poor air distribution. Air louvers should be altered so that they can be operated independently, rather than in tandem and portable air velocity meters should be used as an aid to make the adjustments.

- Two of the team members shared their training in current U.S. motivation practices, with respect to a question by refinery management on how to get people to be sensitive to the need to save energy. We reviewed setting mutually agreed to objectives, accountability and the ability of the staff to control the variables that effect their objectives and a reward structure for good performance. The local staff is already doing many of the items that were suggested. We were unable to determine if any of our comments resulted in changes in managements strategy to effect change, but overall the team felt it was a very useful discussion.

- The refinery asked the implementation team to take part in a panel discussion on the topic of the USAID Energy Improvement program. About 40 local refinery engineers and supervisors attended. After a brief presentation by the Davy team, we then spoke for about two hours on topics varying from staffing size, maintenance practices and current U.S.

refinery developments. Our sharing was well received with many people remaining behind to discuss a wide variety of issues. Additionally, we spent much of the next morning in continuing discussions, based on comments made the previous afternoon. It is difficult to access the nature of the economic benefit of this activity, but the implementation team felt it might have been the best part of our effort at Slovnaft, based on the response from the local staff.

- Based on our observations of the furfural units fired heater operations, we requested the local instrument group to do an excess air/furnace efficiency analysis. The results indicated an oxygen value in the flue gas of about 10%. We recommended that the refinery first line operating supervision become more active in getting operators to pay attention to excess air analysis and adjust the air dampers and burner air registers properly.

- We did offer to provide information on different types of tube bundle cleaning equipment, solutions and practices. This was based on queries from the local staff, as it related especially to the crude heat exchange train.

- We believe that in this new era of openness in Eastern Europe, that encouraging refinery participation in API or NPRA or similar meetings is essential for the working staff to come up to speed with regard to current, modern refinery practices. Further, the one-on-one sharing and mutual problem solving that goes on as a programmed activity and especially, after hours or coffee break discussions, is worth many times the price of admission.

  USAID sponsorship of API membership for selected staff is recommended.

- Two of the team members participated in a review of HDS unit no. 6 distillation column downcommer collapse problem. The combined team, Davy McKee, tray manufacturer, and local refinery staff examined the column and damaged downcommers, as well as held interviews with operations and maintenance and reviewed design and recent historical operating data. It was determined that sludge build-up at the bottom of the downcommers in question prevented liquid flow, with a resultant partial vacuum formation, the forces of which caused the downcommer to expand outward. It was decided that improved cleaning practices and sensitivity to sludge presence would prevent further occurrences.

2. MEDIUM TERM OPPORTUNITIES

Improvement projects of a medium range/cost nature are as follows:

- The acquisition and subsequent utilization of on line/in line non-destructive testing equipment would be valuable.

  The time between shutdowns for normal maintenance has been substantially increased in U.S. refineries. This has resulted from the use of on-line monitoring equipment (sonagram, x-ray etc.) and the proper placement and utilization of in-line corrosion monitoring equipment. Extending operations for an additional 3 years is not uncommon. The increased revenue from reduced downtime (more onstream operation time per year and lower yearly average maintenance costs) more than pays for the monitoring costs. This activity cannot be achieved immediately, however. The gathering of good historical data on corrosion is necessary in order to determine corrosion "metering" locations. Also, additional equipment will have to be installed and/or changed out to reduce equipment failures and allow more on-stream maintenance repairs.

  Existing local laws also present a barrier to this potential cost improvement. Some equipment must be shutdown and inspected periodically (yearly in some cases) by governmental agencies. However, changing laws where questions of safety, injury and human life are raised, is difficult. But US and Western European experience in achieving longer safe running times through proper attention to potential areas of failure, coupled with improved local practices could result in regulation modification. Also, the monitoring equipment and longer turn around periods bring some safety benefits of their own. This is a long term, but very worth while objective.

J. **ENERGY EFFICIENCY IMPROVEMENTS**

1. IMMEDIATE OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Purchase attendance to a John Zink seminar covering furnace burner maintenance and operation (alternately, bringing a Zink seminar to the refineries or locally conducted activities may be a more efficient approach).	$5 000.00, plus travel.	Immediate
Benefit:	Allows technology, burner selection, and furnace operating practices review for improved efficiency. Strongly recommended. A consumption of approximately 400 000 tonnes of fuel oil is projected for 1991. At 2 200 Kcs/tonne and assuming a saving of only 1%/yr, would yield a payback of about $290 000/yr.		
Supplier:	John Zink, Tulsa, OK. or equivalent		

Davy

1. IMMEDIATE OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Purchase one thickness/corrosion gauging package for non-destructive testing of pipe and vessels.	$2 945.00	Improved on-stream time.
Benefit:	Allows maintenance crews the opportunity to plan turnaround work in advance of shutdown. In the long run, proper awareness of corrosion problems, and changes to manage these problems (change in metallurgy or operating practices), will result in improved on-stream time and thus profitability.		
Supplier:	Krautkramer Branson P.O. Box 350 Lewistown, Pennsylvania 17044		

2. MEDIUM TERM OPPORTUNITIES

	Description	Cost	Pay-Off
Action:	Provide a review of and training in capital budgeting practices.	$25 000 Estimated	Improved return on invested capital.
Benefit:	Allocation of capital funds in a business must be based on maximizing financial return. A portion of available funds are needed for maintenance, environmental and safety purposes. However discretionary capital should be allocated on a sound technical/economic basis. Refinery management needs the tools and understanding to recognize and support projects that minimize costs (in many cases energy savings) and thus maximize profits. Yield improvements, labor reduction, new products, new business lines, etc., also fall into this category.	Follow-up, $15 000	
Supplier:	To be determined. Business schools or individuals from project justification/financial analysis areas are possible sources. Groups specializing in management training, such as the AMA are another source.		

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2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Acquire suitable refinery linear program (LP) software such as "PIMS" to enable the reliable modelling of the refinery and eventually the total complex. When complete (allow 6 months) the model will permit a systematic approach to optimizing operations with regard to feedstock / processing costs and product marketing realities.	Budget: Software:$50 000 Staff: 2 man yrs Say $100 000	Undetermined, but at 6 000 000 tonnes/yr crude throughput at $140 tonne = $824 million/yr
Benefit:	As experience is gained, the model can be utilized to study and identify: 1. Areas of existing deficiencies 2. Means of maximizing product profitability 3. Analyzing optimum modernization possibilities		$100 000 represents 0.01% of crude cost. Experience indicates average improvements of 10% in operational profitability can be achieved using LP techniques.
Supplier:	To be determined. (The refinery reports, in February, 1992, that an LP System has been acquired)		

2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Accurately meter all energy into, generated on (i.e., refinery gas) or leaving each process unit. Then make all process unit superintendents accountable for a yearly improvement (a decrease) in the joules per tonne (Btus/barrel) needed to process the feed through the unit. Preferably, this goal should be calculated weekly and sent to the refinery and process division managements monthly. At year's end, it should be one of the factors, in the unit superintendent's yearly performance evaluation. Other than crude costs, energy costs are the major variable costs in operating a refinery.	$0 - 100 000 Negligible if all the energy is now metered on the process units. Otherwise, the cost of installing those meters.	Immediate Also provides a baseline for further yearly improvements. Major US refiners have reduced their energy usage per barrel of crude run by over one third during the past 17 years. They are now averaging about a 1 to 2% reduction per year.
Benefit:	Significantly lower refinery energy costs. The unit superintendent must be involved; they will then involve all under their supervision on the unit.		
Supplier:	Objectives by refinery management. Equipment by Competitive Supplier		

2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	HDS#5 (hydrodesulfurizer). Slovnaft plans to install two heat exchangers to recover heat from the reactor effluent (in conjunction with an already added hot separator), heat that is now lost to cooling water.	Using a 3 year payout as a rough guideline for project justification, yields a capital cost of $315 000. It is believed the cost of this project is below this value.	$105 000/yr.
Benefit:	1950 kW of fuel would be saved, or $105 000 / yr., at a fuel oil cost of 2 200 kcs/tonne.		
Supplier:	As competitively determined by the Slovnaft project execution staff. Subsequent correspondence with the refinery indicates that this installation has taken place and is in operation.		

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2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	It is recommended that the internals in the vacuum column be replaced with structured (Sulzer or Norton) packing. #6 AVD (atmospheric and vacuum unit). The gas oil cuts from the vacuum unit are not of good quality, as they are overlapping. These cuts are the feed to the lube oil plant, and have too high a light end content.	To be determined	To be determined
Benefit:	Lube oil quality will need to undergo re-evaluation to be acceptable in Western European Markets. This will result in lower vacuum column pressure drop and better product separation with resultant improved lube oil quality.		
Supplier:	Sulzer or Norton		
	The refinery stated in Feb, 1992 that this activity is in progress.		

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2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Purchase integrated software package to organize: • maintenance, inventory procurement and allow planning and scheduling, cost tracking and maintenance historical.	$220 800	Indeterminant
Benefit:	Allows system approach and collection of database to initiate preventive maintenance program.		
Supplier:	Bonner & Moore Consulting 2727 Allen Parkway Houston, Texas 77019		

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2. MEDIUM TERM OPPORTUNITIES

Description	Cost	Pay-Off
Action: Sponsor a study to evaluate process engineering simulation programs, including heat exchanger network pinch analysis. **Benefit:** Provide ability to simulate and/or calculate complex refinery chemical engineering operations. To simulate crude and vacuum columns with different crude oils; to simulate and optimize operating conditions, to use high speed computer calculations of unit operations to quickly understand and solve operating problems. **Supplier of Simulation:** "Hysim" - Hyprotech, Chem Share, Aspen, Sim-Sci or equivalent. **Supplier of Study:** Engineering design firm of appropriate background. John Brown/Davy McKee would be pleased to be considered for this program.	Study Cost- $110 000	Immediate

3. LONG TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Reformulation of gasoline A study is needed to address the coming elimination of lead content and the reduction of aromatic levels in gasoline. Improving octane value through MTBE, alkylation and/or a CCR reformer needs to be evaluated.	$250 000 to 300 000	Environmental improvement
Benefit:	The proper economic choice of replacing lead and aromatics is necessary to meet environmental goals.		
Supplier:	Engineering design firm of appropriate background. John Brown/Davy McKee would be pleased to be considered for this program.		

3. LONG TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Study to optimize dewaxing operations. The No. 3 dewaxing unit, besides being greatly oversized, was designed to provide transformer oils with a pour point of -45°C. Existing markets in the Slovnaft area require only -15 °C or so pour point oils. A study is needed to combine units 2 and 3 into one unit which produce products suited to the characteristics of the Czech and nearby markets.	To be determined	To be determined
Benefit:	Substantial energy reduction per tonne of product produced and reduced losses of product and refrigerant. See comments in dewaxing section of this report.		
Supplier:	To be determined. Feb, 92 input from the refinery insists that an energy reduction program for this unit is underway.		

3. LONG TERM OPPORTUNITIES

Description		Cost	Pay-off
Action:	Study the following options: <u>Vacuum Bottoms Processing</u> Some of the options for vacuum bottoms processing are as a follows: • Burn as preferred fuel in the boilers and treat the flue gas for SO_2 removal. • Thermal cracking or visbreaking. • Partially oxidize to produce syn gas which can be converted to hydrogen, methanol, ammonia or gasoline.	$500 000	To be determined
Benefit:	Needs further study.		
Supplier:	The refinery has undertaken studies in this area (Feb, 92)		

3. LONG TERM OPPORTUNITIES

Description		Cost	Pay-off
Action:	Contract design/construct firm to install a large activated carbon filter in and/or reclaim system in MEA units. (Amine acid gas removal units).	Not to exceed $100 000	To be determined
Benefits:	Allows increase of wt% MEA solution up to 20%, lowering energy consumption by up to 30%.		
	The reclaim system would reduce corrosion, foaming, and keep gas absorption capacity at design rates.		
Supplier:	Competitive		

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3. LONG TERM OPPORTUNITIES

Description		Cost	Pay-off
Action:	Study of Sulfur Plant Slovnaft needs tail gas treatment units on the existing sulfur plants, for improving the efficiency from 94% to 99% and also for environmental reasons. Slovnaft will also need a third sulfur plant should crude sulfur levels increase.	To be determined	To be determined
Benefit:	Improve Efficiency to 99%.		
Supplier:			

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3. LONG TERM OPPORTUNITIES

Description		Cost	Pay-off
Action:	Commission a study to improve the lube oil blending system. State of the art in-line or automatic batch blending and pigging technology is needed.	$250 000 - $300 000	Two (2) to three (3) years payout of total installed cost is likely.
Benefit:	Improved lube oil blending would reduce spills, keep losses below 1% of material processed and reduce processing costs through improved manpower utilization.		
Supplies:	Mid-America Engineers 101 North Wacker Chicago, IL 60606 Art Smith, VP Eng. Larry Hamilton, Sales Ed Barth, VP (312)346-0700		

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3. LONG TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Add in-line blending of gasoline including two knock-test engines and software for octane control.	US $640 000	1 year US 670 000/yr
Benefit:	In-line blending should allow Slcvnaft to lower their blending target to +0.5 RON (octane giveaway). This will be especially important in meeting the increased octane demands of unleaded gasoline. There should also be a reduction in tankage needed for finished gasoline product.	19.2 M kcs* 30 kcs = 1 USD US $640 000 *from refinery estimate	20.1 M kcs* 30 kcs = 1USD US $670 000/yr *from refinery estimate
Supplier:	Foxboro 1901 South Busee Road Mount Prospect, IL 60056 ATTN: F. Gatter		

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K. ENVIRONMENTAL EMISSIONS REDUCTIONS

The recommendations presented herein are to improve air quality and bring other effluent streams in compliance with local regulation. These projects are not economically justified, but are recommended on the basis of improving the environment and preventing possible regulatory fines or actions.

There are a variety of options available to reduce SO_2 emissions from the refinery. The largest source of SO_2 is from fuel oil consumption in the boilers at the power plant. If fuel gas scrubbing is utilized to alleviate this problem, it is estimated that approximately 14 000 tonnes per year of SO_2 could be removed (assuming current operating schemes, fuel oil utilization and crude throughput). The refinery is considering options and will opt for the most economical path to achieving attainment of environmental goals. It should be noted that many refinery furnaces have been changed from high sulfur content fuel oil firing to natural gas fuel, thus reducing SO_2 emissions.

K. ENVIRONMENTAL EMISSIONS REDUCTION

1. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Cover refinery API separator, 4 units at 3 m x 33 m, including a vapor condenser.	\$272 000 30 000 \$302 000	Air quality improvement. Recover VOCs
Benefit:	Improvement of air quality.		
Supplier:	To be determined.		

2. MEDIUM TERM OPPORTUNITIES

Description		Cost		Pay-Off
Action:	Complete installing covers to the API separator at the petrochem unit. (This unit is within 100 meters of the refinery API Separator and has very high volatile organic vapors above the unit). A refrigerated condenser unit will condense the VOC's from a blower stream of 25 Atm. per basin. Collected VOC's could be recycled or used as fuel at one of the waste incinerators.	Covers Condenser Units Total	$25 000 $30 000 $55 000	Air quality improvement. Recover VOC's
Benefit:	Air quality improvement.			
Supplier:	To be determined.			

2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Repair the 4 traveling bridge scraper mechanisms at the waste water treatment plant clarifiers.		Save an annual clarifier cleaning estimated at 5 000 - $10 000 per cleaning
	4 - electrical system check-out with new relays, limit switches	$20 000	
	4 - Scum pumps	16 000	
	4 - Sludge pumps	12 000	
	16 - Scraper boards	4 800	
		$52 800	
Benefit:	Reduce the carryover of oil material to the DAF unit could save 5 000 - $10 000 of chemicals per year.		
Supplier:	To be determined		
	The refinery reports that this project has been implemented and the equipment is operational. (Feb, 92)		

2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Reduce VOC loss at rotary kiln incinerator and:		Improved air quality.
	Cover oil sump 3 m x 3 m	$5 300	
	Add oil feed pump to incinerator	$48 000	
	Enclosed solid waste/slop oil feed pit at rotary kiln feed end.	$2 000	
Benefit:	Reduce VOC's at incinerator. Reduce VOC's at slop pit.	$55 300	
Supplier:	To be determined		

2. MEDIUM TERM OPPORTUNITIES

Description		Cost	Pay-Off
Action:	Eliminate oil dewatering lagoons @ the storm water API area. Replace with a 5 meter dia. x 6 meter high carbon steel oil decant tank. Provide booster pumps at API, pipeline to crude storage area dike area, pump-out pumps and pipe lines to slop tanks and sewer. Clean-up one foot depth of oil contaminated soil.	$55 000	Improved air quality.
Benefit:	Estimated to reduce the VOC's lost to the atmosphere.		
Supplier:	To be determined		
	Installation of centrifuges and appropriate ancillary equipment to achieve this objective is underway.		

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APPENDIX A. EXCERT FROM CHARACTERIZATION REPORT

6. SLOVNAFT REFINERY AND PETROCHEMICAL COMPANY - BRATISLAVA, CSFR

Address:

Slovnaft s.p. Bratislava
Vlcie Hrdlo
82412 Bratislava
CSFR

Telephone: (42-7) 283 635
Telefax: (42-7) 246 829

Contact: Mr. Boris Nikolov

6.1 Summary Description of Refinery

Slovnaft s.p. Bratislava is a refinery and petrochemical complex. For this characterization effort, only the refinery was selected, although it is closely integrated with the rest of the complex. The refinery is located adjacent to the Danube River, close to Bratislava, about 20 kilometers from the Austrian border.

The rated processing capacity of Slovnaft refinery is 6.6 million tonnes/y of the USSR export blend crude oil. Figure 8 shows the processing units in the refinery. Table C.6.1.1 indicates the various units that make up the refinery along with each unit's original start-up date and the contractor. Table C.6.1.2 lists the overall material balance for the refinery during 1990. Tables C.6.10.1 - C.6.10.10 indicate the feeds to and product slates from the refinery. Following is a description of the major process units in the refinery.

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AP-λ-2

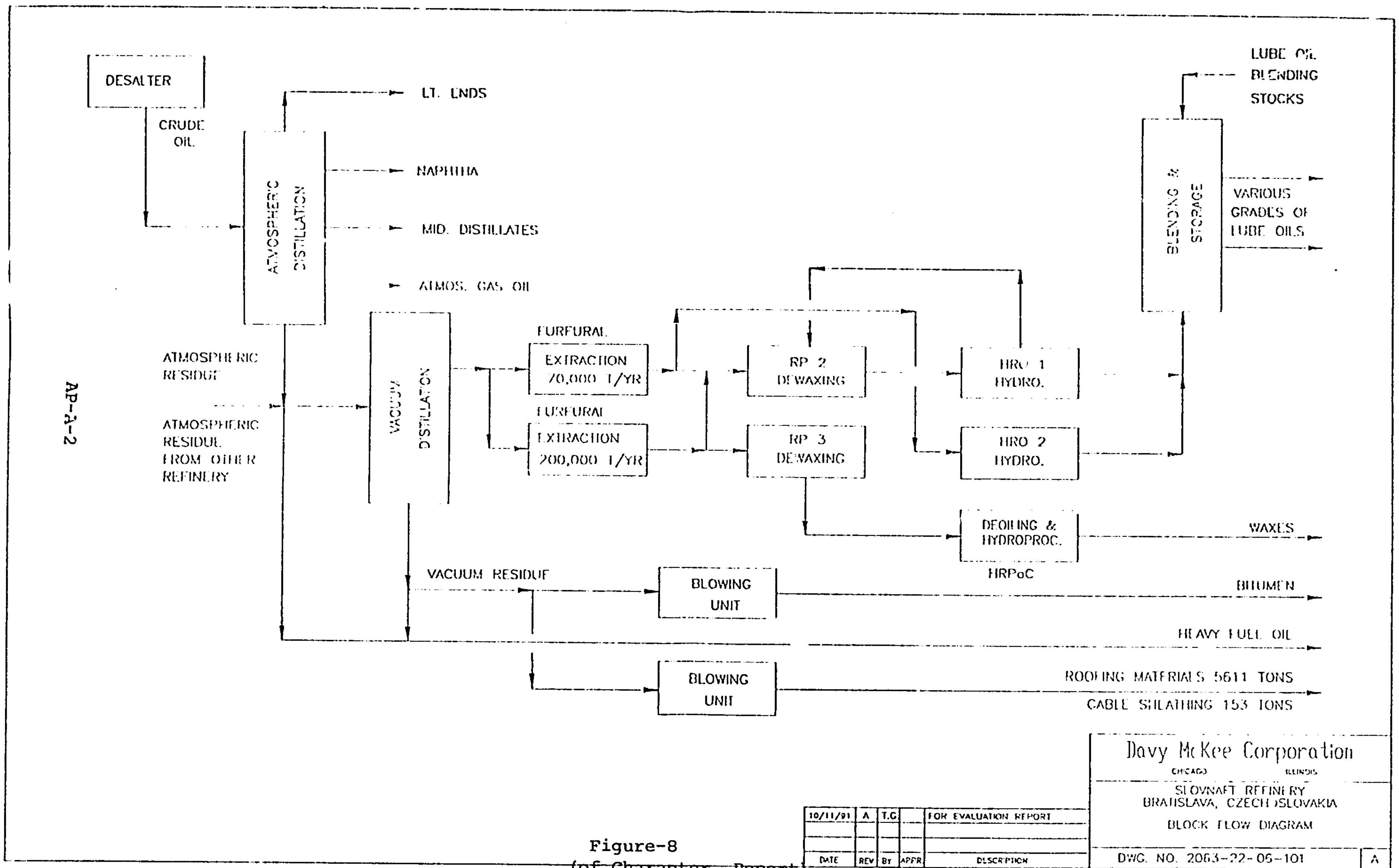

Figure-8
(of Character. Report)

Table C.6.1.1 - REFINERY UNITS

UNIT	Start-up Date	Contractor
Atmospheric Distillation #4	1963	Kralovopolska Stojirna Brno
Atmospheric Distillation #5	1967	Kralovopolska Stojirna Brno
Atm. and Vacuum Distillation #6	1971	Kralovopolska Stojirna Brno
Catalytic Reformer #3	1969	Kralovopolska Stojirna Brno
Catalytic Reformer #4	1973	Kralovopolska Stojirna Brno
Redistillation of Heavy Gasoline	1972	Kralovopolska Stojirna Brno
Aromatic Extraction	1972	Linde, Ger.
Aromatic Solvent Plant	1963	Kralovopolska Stojirna Brno
Pyrolysis gasoline redistillation	1971	Kralovopolska Stojirna Brno
Hydrotreater #1 Gas Oil	1963	Kralovopolska Stojirna Brno
Hydrotreater #2 Gas Oil	1964	Kralovopolska Stojirna Brno
Hydrotreater #3 Jet Fuels	1964	Kralovopolska Stojirna Brno
Hydrotreater #4 BTX Fraction	1964	Kralovopolska Stojirna Brno
Hydrotreater #5 Gas Oil	1969	Kralovopolska Stojirna Brno
Hydrotreater #6 Kerosene	1974	Kralovopolska Stojirna Brno
n-Alkanes (Molex)	1980	Chisso, Japan
Hydrocracker	1991	Snam Progetti
Gasoline and Diesel Pool	1957	Kralovopolska Stojirna Brno
Fuel Oil Pool	1957	Kralovopolska Stojirna Brno
Gas Desulfurization #1	1963	Kralovopolska Stojirna Brno
Gas Desulfurization #2	1982	Kralovopolska Stojirna Brno
LPG Plant #1	1963	Kralovopolska Stojirna Brno
LPG Plant #2	1974	Kralovopolska Stojirna Brno
Sulfur Plant	1983	Kralovopolska Stojirna Brno
Sodium Sulfide Plant	1970	Kralovopolska Stojirna Brno
Solvent Extraction #1	1961	Kralovopolska Stojirna Brno
Solvent Extraction #2	1970	Kralovopolska Stojirna Brno
Dewaxing Unit #2	1964	Kralovopolska Stojirna Brno
Dewaxing Unit #3	1989	USSR
Oil and Wax Hydrotreater	1964	Kralovopolska Stojirna Brno
Semioxidation Asphalts	1987	Slovnaft
Propane Deasphalting	1963	Kralovopolska Stojirna Brno

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Crude distillation units

There are three crude oil distillation units. Each crude unit has a crude desalter that reduces the salt content to under 5 ppm to reduce corrosion of the equipment. Two of the crude units are atmospheric distillation only, while the third is a combined atmospheric/vacuum unit. The vacuum distillate constitutes the lube oil stock. There is also a vacuum tower to process the atmospheric residual (partly) from the atmospheric towers. This vacuum tower provides feed to the hydrocracking unit.

The furnaces of the atmospheric vacuum distillation unit have flue gas/combustion air heat exchangers.

Light ends processing

Sour gases from the tops of the crude towers and from the HDS units are collected and desulfurized using MEA treating. There are two lines for gas desulfurization. Sweet gas is mixed with LPG streams from the reformer units and sent to the gas separation plant. There are also two lines for gas separation. Compressed gases are washed, using a C_6 cut as an absorbing medium. Lighter components, including ethane, are separated in a gaseous form and sent to the refinery fuel gas system. Propane, butane and pentane are selectively desorbed. Individual components are then mixed to produce a controlled composition commercial product (LPG). The remainder of the recovered gases are used as feed for the steam cracker. The absorption medium is recycled.

Light and heavy naphtha processing

Naphtha is used partly as a feed to the ethylene plant and partly for gasoline production. For the gasoline production, straight run naphtha is hydrotreated and rerun to remove light ends. Bottoms product from this rerun column is sent to the reformer unit to increase the octane number. Liquid product from the reformer is the high octane component of the gasoline pool. Two principle grades of gasoline are produced: a 91 octane grade leaded with 0.15 cubic centimeters TEL/liter and a 95 octane grade, also leaded, with 0.15 cubic centimeters TEL/liter. A small amount of 95 octane lead free gasoline is also produced. The quality of the gasoline is indicated in Table 6.10.6.

Distillate processing

Kerosene and gas oil are hydrotreated to remove sulfur. Standard medium pressure hydrodesulfurization is used. Kerosene is used for jet fuel production and as feed to a Molex unit for the production of straight chain alkanes C_{10}'s - C_{13}'s and C_{14}'s - C_{18}'s. The kerosene remaining is blended into the diesel pool. In all cases it is possible to meet product specifications.

The quality of the diesel pool is improved by the gas oil from the hydrocracking unit, as it is practically free of sulfur.

No. 2 fuel oil is the next heavier fraction and goes off directly as product fuel oil.

Vacuum distillates

The total capacity of the vacuum distillation units is about 2.5 million tonnes/y of atmospheric bottoms. The average yield of vacuum residue is 42.3%. Vacuum distillates are used for lube oil production (380 300 tonnes/y), for hydrocracking and finally any remaining is sent to fuel oil blending.

Vacuum distillates from AVD-6 are the preferred feed for the lube oils production. Part of the distillates is furfural extracted to increase the viscosity index or directly dewaxed. Excess of these distillates over that needed to meet lube oil production schedules is sent to the hydrocracking unit for fuel oil production and as cutterstock in semi-blowing of bitumen. Vacuum bottoms is partly used in bitumen production and partly blended in the fuel oil pool.

Another vacuum distillation unit feeds the hydrocracking unit. That vacuum residue is handled solely by being blended in the fuel oil pool.

Lube oil processing

Vacuum distillates are extracted with furfural in rotating disc extractors, where the low viscosity index portion is dissolved. The solvent from the refined product and extract is recovered by distillation and recycled. There are two units of 70 000 tonnes/y and 200 000 tonnes/y feed capacity. The product yields vary between 50 to 60%, depending on the viscosity index desired in the product. The extract is mainly directed to fuel oil blending.

Dewaxing units

There are three dewaxing units in the refinery. No. 2 has a capacity of 120 000 tonnes/y and No. 3 has a capacity of 150 000 tonnes/y. Dewaxing unit No. 1 was permanently shut down after the startup of the No. 3 unit.

Dewaxing Unit No. 2 uses a mixture of acetone and toluene as the solvent. Ammonia is used as a cooling agent. The pour point of dewaxed oil is about -12 °C. No deoiled solid paraffins are produced.

Dewaxing Unit No. 3 was designed by and equipment supplied from the USSR. The unit was put into operation during July 1990. This unit was designed for very low pour point oil production - namely for transformer oil production. A methylethylketone (MEK) and toluene mixture is used as a solvent. Propylene is used as a cooling medium in the first stage and ethylene in the second stage of cooling. The equipment is not standardized and therefore requires a large inventory of spare parts.

The design pour point of the dewaxed oil is -45 °C. CSFR consumption of transformer oil is about 13 000 tonnes/y and there is no clear opportunity to export low pour point oils.

To run the unit for the normal lube oil production (pour point of dewaxed oil is about -15°C) causes trouble in some parts of the filtration section and in the cooling system.

Lube oil and paraffin hydrofinishing unit

After dewaxing, the oils are hydrofinished in a medium pressure process over Co-Mo catalyst. There are two lines with a total capacity of about 130 000 tonnes/y and 1 line for paraffin hydrofinishing with a capacity of about 20 000 tonnes/y.

Blending unit

Different kinds of lube oil products are blended batchwise in tanks with agitators. An adequate quantity of components and additives is mixed together and the mixture is analyzed.

Hydrogen production

Sufficient quantity of hydrogen for the hydrotreating units is produced within the refinery from the heavy naphtha reformer. There is hydrogen production within the two ethylene plants in the complex and in a natural gas steam reforming plant that produces hydrogen for the hydrocracking unit.

Sulfur recovery

Sulfur is removed from the LPG in various hydrotreating units. H_2S is burned catalytically to produce elemental sulfur in the Claus unit. There are two lines of 12 000 tonnes/y sulfur each. One of these lines has been modified to be able to burn H_2S with some NH_3 content from the hydrocracking unit. The total efficiency of the two stage Claus unit is 94 - 96% sulfur removal. The remainder of the sulfur is emitted in the tail gas.

Table C.6.1.2 - MATERIAL BALANCE 1990

INPUTS	tonnes/y	TOTAL tonnes/y
Crude Oil	6 190 472	
Imported Blending Stocks		
Naphtha from USSR	164 623	
Naphtha from other sources	13 333	
LPG from Kralupy	22 164	
Aromatics from Litvinov	1 138	
Nonparaffins from Koramo	667	
Nonparaffinic Oil from Koramo	1 503	
Mixed Xylenes from Litvinov	8 376	
	211 804	
MTBE	15 602	
TEL	207	
	15809	
TOTAL INPUTS		6 418 085
OUTPUTS		
Gaseous Products		
LPG	47 336	
Propane - Butane	1 820	
i-butane	2 931	
n-butane	1 305	
	53 392	
Regular Gasoline		
BA 91C	327 004	
Premium Gasoline		
BA 96C	159 231	
BA 95D	2 131	
	161362	
Solvents		
Nonaromatic Solvents	29 081	
Technical Naphtha	17 643	
	46 724	

Table C.6.1.2 (cont'd.)

OUTPUTS (cont'd.)	tonnes/y	TOTAL tonnes/y
Feed to the Aromatic Complex		
BTX from Refinery	174 455	
BTX from Hydrocracker	119 160	
	293 615	
Feed to the Petrochemical Complex		
Gas	130 174	
Naphtha	586 873	
	717 047	
Aviation Fuels		
PL-6	118 092	
Kerosene		
PS-2	23 891	
Diesel Fuels		
Diesel fuel	1 625 114	
Diesel EX	337	
Component for MN 35	4 797	
	1 630 248	
Heating Oils	357	
Industrial Fuels		
VOTL	322 627	
VONS PH	38 069	
VOTM	1 673 171	
Oxidized Products	138 513	
	2 172 380	
Lube Oils		
Heavy Oils + Raffinate	143 685	
Paraffins	2 667	
Greases		
Heavy Greases	8 102	
PEKOL	114	
	8 216	
Asphalt		
Primary Asphalt	32 381	
Oxidation Products + Road Asphalt	328 372	
	360 753	

Table C.6.1.2 (cont'd.)

OUTPUTS (cont'd.)	tonnes/y	TOTAL tonnes/y
Coke	0	
Sulfur Products		
Sodium Sulfide 25%	5 051	
Sodium Sulfide Scale	6 300	
Sodium Hydrosulfide	1 029	
Sulfur	8 773	
(Neglect in Balance)	21 153	
Alkanes		
n-alkanes C10 - C13	28 018	
n-alkanes C14 - C18	2 917	
	30 935	
Naphtha for Pyrolysis	41 225	
TOTAL PRODUCTS (1)		6 152 746

CLOSURE = 95.9%

Note (1) Fuel consumption and losses are not included.

6.2 Utilities, Services and Offsites

Electricity and steam generation and distribution

There are four (4) turbogenerators at Slovnaft (29 MW, 24 MW and two 25 MW machines). Steam is extracted from the turbines at 3.5 Mpa, 1.2 MPa and 0.6 MPa levels in quantities needed to supply the plant. The remaining steam is condensed through turbines to complete the steam balance.

About 50% of the power is produced inside the plant, the rest is supplemented from the national grid.

Condensate collection

Only a fraction of the steam condensate is returned to the boilers (waste heat boiler).

Fuel supply

Part of the plant fuel gas is imported as natural gas containing 96 - 98% methane. The rest of the fuel is off gases from the refinery units.

Fresh water supply

The facility obtains plant water from the Danube River. The water supply pump station is rated at 22 420 m^3/h. This supplies the once-through cooling water, makeup for the cooling towers, feedwater for the boilers and various service water uses. Drinking water is supplied by the city of Bratislava. Untreated water is used for once-through cooling water, fire water and general washdown.

Cooling water system

Cooling water is basically once-through. There are a few local cooling towers for individual units. Within the refinery, there is a forced draft cooling tower and cooling water circuit for the dewaxing units.

Crude oil receiving

Crude oil, known as Russian Export blend, is delivered by pipeline and is about 99% East Siberian in origin.

Product blending and shipping

All product blending is done in tankage. Gasoline and diesel fuels are shipped mainly by pipeline. Heavier products are shipped by railcars and trucks.

Tank farm

Crude Oil:	12 @ 20 000 cubic meters with 12 days operating capacity
Product/intermediate:	126 varying in size up to 10 000 cubic meters

The crude oil and lighter product tanks have floating roofs; others are fixed roof tanks. In the future, the plant plans to replace the crude oil storage tanks with 50 000 cubic meters tanks.

Flares

Elevated flares are used.

Fire protection

The fire protection, process water intake and wastewater are combined, therefore, the following applies to both the oil refinery and the petro-chemical complex. The refinery and petro-chemical complex has a fire protection system that consists of water ponds, pump house, Danube river water intake and a pipe distribution loop. The fire water pond serves a dual function. It is the final aerated lagoon after the activated sludge waste water treatment, as well as the fire water pond. The pond is 186 meters wide by 6 meters deep and holds approximately 117 850 cubic meters of water (18 622 000 gallons). It was reported that the system was recently upgraded.

6.3 Chemicals and Catalysts Use

The majority of catalyst usage is within the hydrotreating, hydrofinishing and reforming units. Most of the catalysts are imported.

6.4 Previous 12 Month Operating History

In 1990, the refinery was not fully loaded because it lacked crude oil, as indicated in the overall material balance information presented in Section 6.1.

6.4.1 Recent Modifications

The major factor that modified refinery production was the startup of the hydrocracking unit. Existing plants have been modified primarily to reduce energy consumption (air preheat, hot separator in HDS) and to improve product quality. Dewaxing Unit No. 3 was put into operation in the lube oil train.

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Sourcing and pricing

Since 1 January 1991 a free market pricing system has been in effect. This system does not, however, apply to the refinery product prices which are still under control. Product prices have been following crude oil prices and are approaching world market prices.

6.4.2 Crude Oil Supply

Crude oil, processed in the Slovnaft Refinery during 1989 - 1990, was 99% East Siberian (USSR) and delivered via the pipeline. Less than 1.0% of other crudes were used. Delivery varied, but the average for the period was 774 tonnes/h.

In addition to the crude pipeline from the USSR, the ADRIA pipeline from the Adriatic Sea via Yugoslavia and Hungary is connected to the Russian pipeline. CSFR participated financially in the construction of this pipeline, but it has not been used by the CSFR in a very long time, and the contract has since expired. The Hungarians have similar problems with the supply of Russian crude, and have chosen to use the ADRIA pipeline for their own supply. The ADRIA Pipeline could potentially transport 3 - 4 million tonnes/y of crude to the CSFR.

Other alternatives being considered are the extension of the pipeline from the Schwechat Refinery to Slovnaft (about 60 km), and a pipeline (about 360 km) from the TAL pipeline in Germany to Litvinov and Kralupy.

Crude oil characterization / properties

The Slovnaft Refinery was designed to process Russian crude oil. Russian crude is relatively light, 32 °API gravity, and the naphtha cut has sufficient naphthenes to reform to a relatively high octane level. It is also considered to be a medium sulfur crude, 1.5 wt%, although the sulfur content has risen this year to 1.9 wt%. The Slovnaft Refinery has been designed to resist the corrosive effects of sulfur, and the plant also has the facilities to recover elemental sulfur and to produce sodium sulfide (Na_2S) as a valuable by-product. Desalters treat the incoming crude to reduce the corrosive chloride content to an acceptable level. See Sections 6.10. and D for the crude oil properties characterization curves.

API Gravity	32.1 °API
Viscosity, Cst	5.4 - 5.9 @ 50 °C
Sulfur, wt%	1.5
Watson K	11.91

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6.4.3 Operating experiences

The refinery is offsite and the utility facilities experience frequent shutdowns; the on-stream factor for the year was 0.91. The operating staff is skilled and the technicians are on a good level, although compared to western practices, the refinery appears overstaffed.

There are some problems with spare parts. Some of the equipment is old and spare parts are no longer produced. Also some of the equipment has been supplied from western countries and there are problems in procuring spare parts in a timely manner.

The power station, located in the plant, supplies about 50% of the required electric power. It is backed up by the national grid. Overall, electric power is very dependable. Only two outages (both of short duration) were experienced due to power failures in 1990.

Some 760 hours (one month) of operating time were lost last year due to lack of crude supply and turnarounds. The Gulf War resulted in a sharp decline in the amount of crude available and a large price increase. This weakness is a result of being dependent on one crude source. USSR had its supply of foreign crude reduced during the war and used more of its own production internally instead of exporting it.

6.4.4 Impact of Crude Oil Changes

The refinery is designed to process mainly Russian Export Blend crude oil. The refinery is capable of producing a full product slate at its full capacity of 6.5 million tonnes/y. The refinery is flexible and has eliminated the need to import naphtha from the USSR. Materials used in the construction of the refinery are capable of handling crude oil with as much as 1.9 wt% sulfur. Slovnaft is considering future processing of crude oils from Iran, Syria and Saudi Arabia.

In the U.S., most crude units are designed to process three types of crude oils. These are light, medium and heavy, ranging in gravity from 40 - 50, 30 - 40 and 20 - 30 °API. The crude oil properties which determine the product slate are: gravity (density), characterization (UOP or Watson K) and the slope of the crude distillation curve. The gravity and slope of the crude distillation curve determine the number of products that can be obtained from a given crude. The other crude oil properties affecting the refinery configuration and design are salt, naphthenic acid, sulfur and metals (Ni + Va) content. The sulfur and sometimes naphthenic acids content affect the metallurgy of refinery equipment.

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As mentioned before, Slovnaft crude units are designed to process only the Russian export crude (around 32 °API gravity). It is also apparent that, to some extent, the equipment does have additional capacity/capability.

The best way to evaluate an existing crude unit when considering a new crude oil or a blend of crude oils as a feedstock, is to simulate the unit using existing operating conditions. This is done to establish capacities, limitations and bottlenecks. Then through further simulation with a new feedstock, the operating conditions, production rates, pumparound duties, flash zone conditions, crude heater duty, crude column tray loadings and capacities of the downstream equipment are determined. All this is done by using sophisticated process simulation software and appropriate high speed computers.

6.4.5 Impact of Product Market Changes

Refinery production is oriented to the domestic market. Some excess products have been exported. Recently, due to crude oil reduction, some products (gasoline) have been imported. In the near future, it is reasonable to expect stronger competition even in the domestic market (at least with some products). For the refinery, this means that the ability to produce competitive products at competitive prices and still make a profit will become very important.

6.4.6 Impact of Legislation and Social Changes

The impact of legislation and social changes, presumably toward a market oriented system, is expected to profoundly change the mode of operation for the refinery. It is safe to predict that within the next few years, based on the present environmental restrictions in other countries, tetraethyl lead in the CSFR will no longer be acceptable as a gasoline additive and that the aromatics content in gasoline will be strictly limited. The tolerances for sulfur in the fuel oils and diesel will also be reduced and the tail gas from the Claus unit will require further treatment. This will dictate the need for other processing units at Slovnaft, such as a CCR reformer, an alkylation unit and a butane isomerization / MTBE plant to produce the present gasoline grades without the additive values of the TEL and aromatics. Each of these factors will affect the refinery and must be solved soon.

6.5 Environmental Considerations

6.5.1 Quality of Local Environment

The Slovnaft Refinery is located adjacent to Bratislava near the confluence of the Danube River and the Little Danube River. The river water receives numerous discharges of industrial waste as evidenced by the chemical and biological composition. The water must be treated before any use other than once-through cooling.

The ground water is quite high in dissolved salts (500 to 1000 ppm) which is typical for Eastern Europe. The well water is normally softened and chlorinated before use.

The topography in the area of the city and plant is flat, consisting of old flood plains of the Danube River. The land a few kilometers away from the river bed is comprised of rolling hills. The hills are 200 - 700 meters in height. This topography causes the refinery and other industries located along the river to raise air pollution levels along the flat lands following the river bed. The industries currently have no, or few, control systems for SOx, NOx, VOC's and particulate matter.

6.5.2 Current Emissions Controls

Gaseous effluents

Combustible gaseous emissions are being released to the atmosphere from storage tanks, process units (leaks), API separators and water treatment units. A major part of the gaseous emissions are flue gases from different furnaces, three incinerators, power station boilers containing SO_2, NOx, and particulate matter.

Liquid effluents

The refinery has three water discharges: two are cooling and storm water outlets to the Little Danube River. Both pass through API type oil/water separators. The third effluent is from the combined wastewater treatment plant, which is discharged to the Danube River. The design and actual quality of treated wastewater is as follows:

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Table C.6.5.1 - TREATED WASTEWATER QUALITY

ITEM	DESIGN	ACTUAL
pH	6.5 - 8.5	7.98
TSS (mg/liter)	<30	15.9
BOD_5 (mg/liter)	<20	28.7
Phenol (mg/liter)	<0.1	0.054
PO^3 (mg/liter)	--	2.64
Flow (cubic meters/h)	3 600	1 350

Solid waste

Solid wastes are generated from water treatment, sludge incineration and the various processes in the form of spent catalysts, molecular sieves and drying bed materials. The spent catalysts are reprocessed to recover metal and the rest of the materials are dumped. Ash from two solid waste incinerators is dumped into a dry concrete lined pit. Ash from the multihearth incinerator is pumped to a concrete storage tank.

Sulfur management

Based on the 1990 production and Soviet crude oil analysis of 1.5 wt% sulfur, the refinery received 85 604 tonnes of sulfur. Of this amount, 11 231 tonnes (13%) were recovered in the Claus Unit, 65 365 (76%) tonnes were shipped offsite in various products and 9008 tonnes (11%) were released to the atmosphere.

Volatile organic compounds (VOC) management

The only observed VOC management program is the use of floating covers in 39 storage tanks.

Heavy metals management

The potential sources of heavy metals were: sludge materials from wastewater treatment and bottom materials from crude oil distillation. Burning or incineration of these materials produces ash or dust containing heavy metals. This ash and materials containing leachable metals are currently stored in a large concrete lined pit.

General health and safety

The major effort in general employee safety has been the emphasis on fire prevention, ventilation of confined areas before entering and teaching proper burning or cutting methods.

6.6 Refinery Specific Potential and Opportunities for Improvement

Short Term Improvements:

Steam trap maintenance and condensate return to boiler

Slovnaft has in place a program for steam trap evaluation and maintenance. They have to seriously implement the program and maximize the condensate returned to the boiler.

Computer software and hardware

Slovnaft needs a sophisticated process simulation program.

Slovnaft is in the process of acquiring PIMS, an LP model marketed by Bechtel.

Slovnaft can use a PC based maintenance planning and spare parts inventory program.

Improvement of efficiency of furnaces

For AD#4 (Atmospheric Distillation #4) and AD#5 furnaces, the calculated combustion efficiencies are around 70 - 75%. Better flue gas analysis and combustion air control, in addition to an air preheater, are recommended. Flue gas from the #6 A\" furnace contains about 8 - 9% oxygen, which is rather high.

Similarly, all furnaces in the lube oil processing plant require better flue gas analysis and air control.

Hydrodesulfurizer #6 (HDS #6)

Slovnaft plans to install a hot flash drum in HDS #6. This is a sound idea, as the hot flash drum will improve the energy efficiency.

Reformer feed / effluent exchanger

The efficiency and capacity of the reformer can be improved by replacing the existing shell and tube exchangers with a single vertical shell and tube exchanger or a welded plate type exchanger.

In-line gasoline blending

Currently, Slovnaft conducts gasoline blending operations batchwise. A more efficient in-line blending system is recommended.

In-line lube oil blending plant

Slovnaft is planning to market its products throughout Europe. The refinery will definitely need an in-line lube oil blending facility.

#6 AVD (Atmospheric and Vacuum Distillation Unit)

The vacuum gas oil cuts from the vacuum unit overlap and thus are not of good quality. These cuts are the feed to the lube oil plant. It is recommended that the internals in the vacuum column be replaced with structured (Sulzer or Norton) packing. This will result in a lower pressure drop and better separation.

Amine acid gas removal

All the amine units in the refinery are operating with 15 wt% MEA solution. Today, most MEA units operate with around 30 wt% solution. However, in order to control degradation of the solution, a large activated carbon filter and reclaim unit is required. The higher solution concentration should reduce the energy consumption by one half.

Secondary sealing of tanks

The secondary sealing of floating roof type storage tanks will save products lost to the atmosphere.

Long Term Capital Improvements:

Lube oil processing

There are two very old furfural units. In most modern refineries, the furfural has been replaced with NMP. However, given the cost of importing NMP and the fact that furfural is available in-country, and the ease of operating furfural units the decision to change should be evaluated closely.

The No. 3 Dewaxing Unit was designed to produce transformer oils (w/ -45 °C pour point) for the lube oil blending. A revamped unit for base oils would result in considerably higher energy efficiency.

Sulfur plant

Slovnaft needs tail gas treatment units in the existing sulfur plant for improving efficiency to 99% and also for environmental reasons. A third sulfur plant may be needed to cover the increased capacity.

Vacuum bottoms processing

Some of the options for vacuum bottoms processing are as follows:

1) Incinerate in the boilers and treat the flue gas for SO_2 removal.

2) Thermal cracking or visbreaking.

3) Partially oxidize to produce synthesis gas which can be converted to hydrogen, methanol, ammonia or gasoline.

Gasoline reformulation

Slovnaft is negotiating an MTBE and alkylation project with OMV in Austria. The project also includes pipelines for crude oil and products.

6.7 Refinery Specific Problems and Trends

The refinery needs to adapt to competitive markets and changing social and economic conditions. Refinery management is aware of these problems and is continuously seeking solutions. Many of the specific problem areas are discussed in Section C.6.6 where possible solutions are specified. Further detailed evaluations are recommended. Priorities will have to be established based on financial realities.

6.8 Methodology of Data Collection

This report describes refinery operations and lube oil sections as of June 1991. It does not cover the petrochemical section, but details the production of raw materials employed in the petrochemical section. A questionnaire, sent to the refinery before the team's visit, furnished the basis for much of the data gathered by the Davy McKee team during their stay at the refinery.

6.9 Evaluation of Results Achieved by/for Data Base

Data gathered in the field, pertinent parts of which are the subject of a separate report, have been applied to the formation of a computerized data base.

6.10 Supporting Plant Data

Product specifications are indicated in the following tables:

C.6.10.1	LPG (LIQUIFIED PETROLEUM GASES)
C.6.10.2	GASOLINES
C.6.10.3	JET FUEL (AVIATION FUEL)
C.6.10.4	DIESEL FUEL
C.6.10.5	FUEL OIL
C.6.10.6	LUBE OIL

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Table C.6.10.1 - LPG (LIQUIFIED PETROLEUM GASES)

Composition	Propane	Butane	LPG
Vapor Pressure at 100°F (MPa)	95.0	0.2	30/55
Volatile Residue (ppm)	5.0	-	7.0
Butane and Heavier (LV% - max.)	5.0	97.4	60/40
Pentane and Heavier (LV % - max.)	-	1.0	3.0
Residual Matter	moisture and higher hydrocarbons		
Corrosion, Copperstrip (max)	-	-	-
Total Sulfur (ppmw)	30.0	200.0	200.0

Table C.6.10.2 - GASOLINES

Type	91C Regular	96C Premium	95D Natural
Density @ 20°C, kg/cubic meters	736	742	748
Octane Number RON MON	 91 82	 96 87	 95 85
Distillation Volume 10% 50% 90% EP	 65 115 180 215	 65 80 - 115 180 215	 65 110 - 115 180 215
Distillation Residue (wt%)	2	2	2
RVP (at 38 °C, kPa)	40 - 70	40 - 70	40 - 70
Sulfur Content (wt%)	0.01	0.01	0.01
MTBE Content (vol%)[1]	10	10	-
TEL Content (g/liter)	0.15	0.15	-

[1]MTBE is supplied by Kaucuk

KW

Table C.6.10.3 - JET FUEL (AVIATION FUEL)

Type	
Density @ 20°C, kg/cubic meters	788
Distillation Volume IBP 10% 50% 90% EP	 135 °C 180 °C 225 °C 270 °C 280 °C
Viscosity (mm^2/s) 20 °C	2
Crystallization Point (°C)	-55
Flash Point (°C)	38
Smoke Point (mm)	23
Net Heat of Combustion (kJ/kg)	42 800
Acidity (mg KOH/100 cubic centimeters)	0.50

Table C.6.10.4 - DIESEL FUEL

Type	Winter MN 22B	Summer MN 4B
Density at 20°C (kg/cubic meters)	855 - 835	810 - 850
Distillation Volume IBP °C 50% °C EP °C	 175 - 205 - 355	 175 - 215 260 360
Viscosity @ 20°C (mm^2/sec)	2 3 - 5.0	2.3 - 5.0
Pour Point (°C)	-22	-4
Flash Point (°C)	56	60
Sulfur Content (ppmw)	0.15	0.15
Carbon Residue (wt%)	0.01	0.01
Ash (wt%)	0.01	0.01
Water and Sediment (vol%)	none	none
Cetane Number (min)	42	45
Filterability	-15	0
Acidity (mg KOH/g)	0.01	0.01

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Table C.6.10.5 - FUEL OIL

Type	Heavy	Light
Gravity @ 20 °C (kg/cubic meters)	961	886
Distillation Volume % vol at 350 °C	-	20
Viscosity (mm^2/sec)	57 at 100 °C	2.5 - 12.6 at 50 °C
Flash Point (°C)	140	66
Pour Point (°C)	13	0/-5
Sulfur (wt%)	3.0	2.0
Carbon Residue (wt%) CONRADSON	15	0.5
Ash (wt%)	-	0.002

Table C.6.10.6 - TYPICAL QUALITY OF LUBE OILS PRODUCED

Type	MD Motor Oils			Motor Oils	
	M7AD SAE10W40	M3AD SAE10W30	M6AD SAE30	M6A	M9A
Viscosity at 100 °C, mm^2/sec	14.5 - 17	10 - 12	12 - 13.5	10 - 12	13 - 15
Viscosity Index	170	150	90	85	80
Pour Point, °C	-30	-30	-25	-25	-10
Flash Point, °C	210	205	225	220	225
Ash, wt%	-	0.40	0.45	-	-
Color ASTM max.	4.5	2.5	6.0	6.5	8.0
Viscosity at -18 °C, MPa/sec	3 000	4 000	-	-	-
Carbon Resid. minus ash, wt% (max)	0.3	0.2	0.4	0.3	0.4
Oxidation Test (CSN 656335)	-	-	-	-	-
Increase of Viscosity at 50 °C, %	5	10	15	15	15
Increase of Carbon resid., %	0.3	0.4	0.6	0.9	1.0
Reaction of Water Extract	Neutral or Alkaline			Neutral or Alkaline	
Viscosity at 20 °C, mm^2/sec	-	-	-	-	-
Viscosity at 50 °C, mm^2/sec	-	-	-	-	-
Acid No., mg KOH / g	-	-	-	-	-

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Table C.6.10.6. (cont)

Type	Bearing Oils					Compressor Oils		
	B1	B2	B4	B5	B7	K-8	K-12	K-18
Viscosity Index at 100 °C, mm^2/sec	-	-	-	-	-	11	15	19
Viscosity Index	-	-	-	-	-	80	80	80
Pour Point, °C	0	0	0	0	0	-12	-8	-8
Flash Point, °C	135	150	170	175	180	230	240	260
Ash, wt%	-	-	-	-	-	0.02	0.02	0.02
Color ASTM max.	-	-	-	-	-	7	8	8
Viscosity at -18 °C, MPa/sec	-	-	-	-	-	-	-	-
Carbon Resid. minus ash, wt% (max)	-	-	-	-	-	-	-	-
Oxidation Test (CSN 656335)	-	-	-	-	-	-	-	-
Increase of Viscosity at 50 °C, %	-	-	-	-	-	20	20	15
Increase of Carbon resid., %	-	-	-	-	-	-	-	-
Reaction of Water Extract	-	-	-	-	-	Neutral		
Viscosity at 20 °C, mm^2/sec	-	-	-	-	-	-	-	-
Viscosity at 50 °C, mm^2/sec	-	16-22	30-35	45-53	60-75	76	114	175
Acid No., mg KOH/g								

Appendix B

ABBREVIATIONS

°API	deg API (gravity of oil fractions, defined by API)
°C	degree Celsius
°F	degree Fahrenheit
%	per cent
/	per (e.g., tonnes/day)
A	ampere
ACFM	actual cubic feet per minute
AFBC	Atmospheric Fluidized Bed Combustion
API	American Petroleum Institute
ASTM	American Society of Testing Materials
BACT	best available control technology
BFW	boiler feed water
BOD	biological oxygen demand
BPCD	barrels per calendar day
BPSD	barrels per stream day
BS&W	Basic, Sediment and Water
BTX	benzene toluene xylene
Btu	British thermal units
C.F.	characterization factor
CCR	continuous catalyst regeneration
COD	chemical oxygen demand
CV	calorific value (heat of combustion)
DCS	distributed control system
DEA	Diethanolamine
EP	end point
EPA	Environmental Protection Agency (U.S.)
FBP	final boiling point
FCC	fluid catalytic cracking
FGD	flue gas desulfurization
FOE	fuel oil equivalent
G	giga(10^9)
GCV	gross calorific value
GJ	giga joules
HC	hydrocarbons
HDS	hydrodesulfurization
HP	high pressure
Hg	mercury
Hz	hertz

IBP	initial boiling point
IGT	Institute of Gas Technology
ISBL	inside battery limit
J	joule
KRW	Kellogg Rust Westinghouse
LHSV	Liquid Hourly Space Velocity
LP	linear programming/low pressure
Lube	Lubricating
M	mega(10^6)
MEA	Monoethanolamine
MEK	methyl ethyl ketone
MHC	mild hydrocracking
MON	motor octane number
MPa	Megapascal, a unit of pressure
MSW	municipal solid waste
MTBE	methyl tertiary butyl ether
MVA	mega volts ampere
MVAR	mega voltampere reactive
MW	mega watts
NAAQS	National Ambient Air Quality Standards
NCV	net calorific value
NO_x	Oxides of Nitrogen
NPDES	National Pollutant Discharge Elimination System
OSBL	outside battery limit
OVA	Organic Vapor Analyzer
PFBC	Pressurized Fluidized Bed Combustion
PONA	Paraffins, Olefins, Naphthanes and Aromatics
Pa	pascal, a unit of pressure
RCC	reduced crude conversion
RON	research octane number
RTD	Resistance Temperature Detector
RVP	Reid Vapor Pressure
S.R.	Straight Run
SCFD	standard cubic feet per day
SCFH	standard cubic feet per hour
SCFM	standard cubic feet per minute
SG	specific gravity
SO_x	Oxides of sulfur
SRC	solvent refined coal
T	tera (10^{12})
TBP	true boiling point
TDS	total dissolved solids

TEFC	totally enclosed fan cooled
TEL	tetraethyl lead
TOC	total organic carbon
TSS	Total Suspended Solids
UOP K	UOP Characterization Factor
V	volt
VOC	volatile organic compound
WWTP	wastewater treatment plant
WATSON K	Watson Characterization Factor
XP	explosion proof
atm	atmosphere or atmospheres
bar	bar
cP	centipoise
cSt	centistokes
cal	calorie
cm	centimeters
cps	cycles per second
day	day
ft^3	cubic feet
ft	feet or foot
g	gram
gal	gallons
gpm	gallons per minute
h	hour
hp	horse power
in	inch or inches
k	kilo
kA	kiloamperes
kPa	kilo pascal, a unit of pressure
kV	kilovolts
kWh	kilowatt hour
kcal	kilo calories
kcal	kilo calories
kg	kilogram
kg/cm^2	kilogram per square centimeter
lb	pound or pounds
liter	liter or litre
m	meter or metre
max.	maximum
mg	milligram
mi	mile
million	million(10^6)

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min	minute
min.	minimum
mm	millimeters
mol	mole
n	normal
ohm	ohm
pH	pH, a measure of acidity or strength of a base.
percent	percent(or %)
phase	phase (electrical)
ppm	parts per million
ppmv	parts per million (volume)
ppmw	parts per million (weight)
ppb	parts per billion
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
ptb	pounds per thousand barrels of oil
rpm	revolutions per minute
sec	seconds
tonne	metric ton
tonnes	metric tons
vol	volume
wt	weight
y	year

TERMS OF REFERENCE

DESCRIPTION/SPECIFICATIONS/WORK STATEMENT

Component #2: A PETROLEUM REFINERY EFFICIENCY IMPROVEMENT ENERGY CONSERVATION PROGRAM

1. BACKGROUND

The petroleum sectors of Bulgaria, Czechoslovakia, Poland, Romania, and Yugoslavia (as well as that of Hungary) are emerging from a 40-year period of centrally-planned crude supplies and centrally-controlled markets. Practically all of the petroleum refineries in these six countries were built, or modernized, during this period.

Among the five countries, it appears that Bulgaria has three separate refineries having an aggregate throughput of 300,000 B/D; Czechoslovakia has seven aggregating 455,000 B/D; Poland nine with an aggregate throughput of 385,000 B/D; Romania thirteen aggregating 617,000 B/D; and Yugoslavia seven with an aggregate capacity of 609,135 B/D. Now, these refineries face changing circumstances.

First, it is likely that the existing refineries were designed to process a narrow slate of crude oils supplied from the USSR. Now, crude supply options have broadened so that supplies can be bought on the world market through spot and contract purchases. The USSR appears to be phasing out as a primary crude supplier to these countries. Accordingly, potential future crude oil slates can have a much broader range of physical and chemical characteristics than has heretofore been the case.

Second, market conditions for the refinery product slates have been based on the principles of a centrally-planned national economy. Expectations, because of the shift to democratic pluralism in these countries, are for a higher standard of living for the populations, for a greater awareness of the need for environmental protection, and for shifts in refinery-product slates that will occur because of these. The capabilities of the mix of processing units in the refineries in each country to adjust simultaneously to changing crude slates and product slates will be brought into question.

Third, greater public awareness of preserving environmental quality and of the environmental deterioration that has occurred during the past forty years are likely to force major changes in refinery design and operating practices to reduce noxious gaseous, liquid, and solid waste emissions. This awareness is likely to emphasize production of unleaded gasolines and alcohol additives, and perhaps also the exploration of neat alcohol and compressed natural gas alternatives. At the same time, changes in refinery operations will be demanded to reduce noxious emissions to the extent practical.

Finally, tightened economic conditions will force refinery managements to improve operations through introducing more efficient internal utilization of energy and through implementing opportunities for energy conservation. These improvements will have to occur while anticipating changing crude and product conditions and with an inventory of processing units in the refineries that in all likelihood has a limited flexibility to adapt to changes. The roles for alternative fuels could emerge here also.

Compounding the problem of managing change are shortages of foreign exchange, increases in foreign exchange demands because of purchase of crude oil supplies on the open market at now greatly increased price levels, and demands on investment capital that will be generated by the political and economic changes in these countries. Foreign investment by international oil companies in petroleum-sector investment opportunities could bring needed foreign exchange and could potentially lead to new refinery construction at strategic locations and the scrapping of some existing refineries.

The complexity of the relationships within the petroleum sector system is somewhat illustrated in Figure 1 of this Appendix.

Obviously, managing the process of change will take some time. The inputs for analysis are not yet completely available. Economic benefits will depend on national policies, formed or as yet unformed. The current crude supply and pricing picture is an unstable one. Foreign investor interest in the five countries probably varies among the countries and perhaps is not yet well focused on the petroleum sector.

Nevertheless, a start in an analysis to improve the situation can be made provided the focus of initial efforts is on a rationalization of the petroleum-system situation in each of the five countries. Rationalization intends (a) efficient, effective, and environmentally-acceptable improvement in the production of petroleum products to serve current domestic markets, (b) adaptation of current operating practices to serve emerging domestic markets from expected, cost-attractive, crude-oil slates, and (c) identification of the improvements in terms of consistency with the privatization policies in each of the five countries.

2. GOAL AND OBJECTIVES

Accordingly, the generic goal of the work is to begin a process that ultimately can lead to such rationalization of the petroleum sectors in each of the five countries. The end results for the work at this time are

a. an organized data base comprising available data and information relevant to producing inputs for later use by others (when sufficient data and information for the

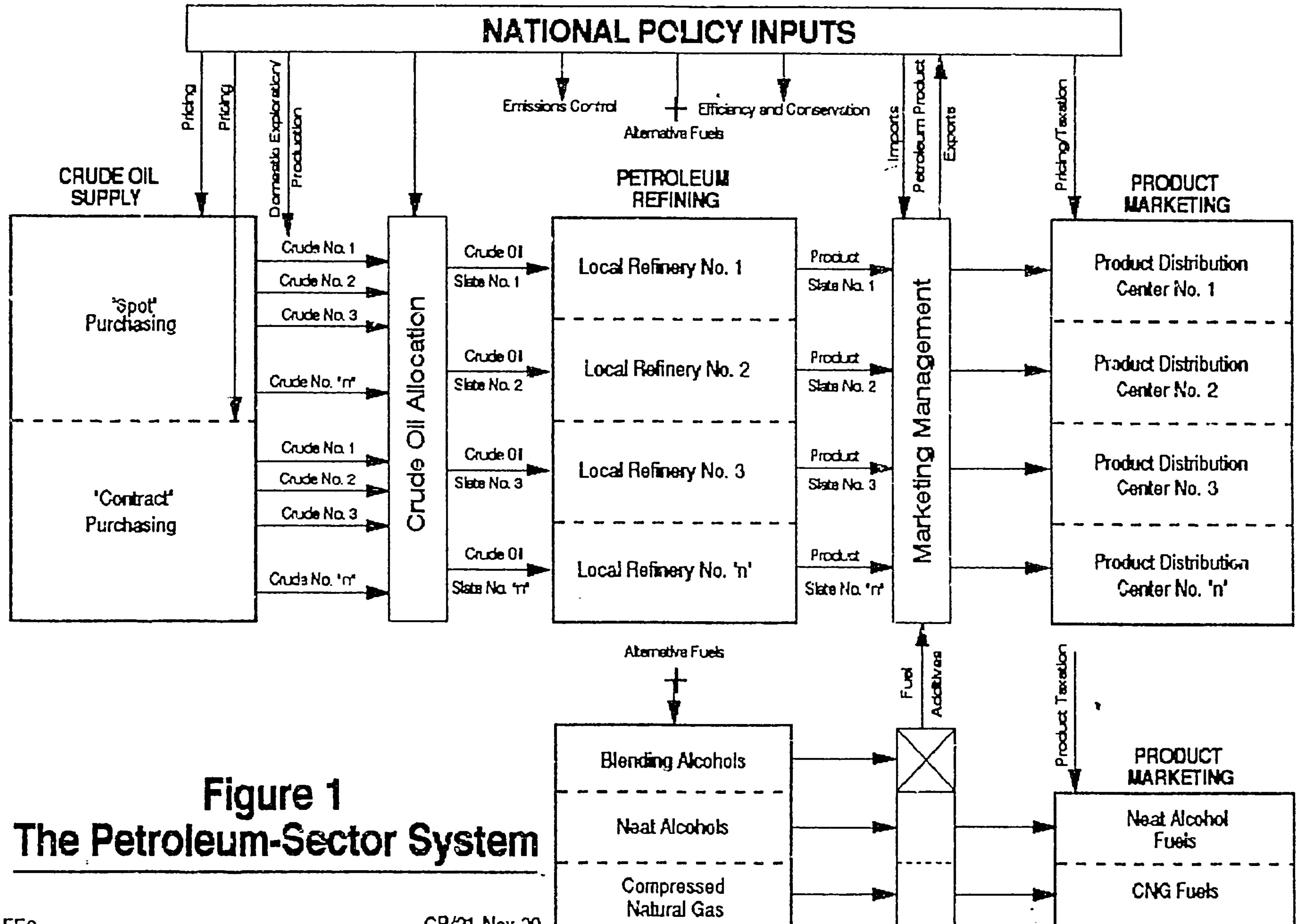

Figure 1
The Petroleum-Sector System

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various components of the petroleum system, such as is shown in Figure 1, become available) in a commercial linear programming model to optimize the petroleum system in each country,

b. low-cost improvements in the energy efficiency and environmental impact of selected refineries producing the current product slates that have been implemented during the course of the Contractor's work, and

c. the identification of further improvements which can only be implemented at a later time by others through making a significant investment that needs to be justified.

Accordingly, the objectives of the work focus on the five countries and are

a. for the refinery sector in each country and to the extent that relevant information is available, to describe the process mix in each refinery, the technical capabilities, and current operating practices in a form that (1) provides a data base for undertaking further and future work by others aimed at optimizing the petroleum system in each country and (2) more specifically for the present, enables at least qualitative judgments to be made of effects of changing crude-oil slates on refinery product slates;

b. for a sample of two refineries each in Czechoslovakia, Poland, and Yugoslavia and one refinery each in Bulgaria and Romania, to identify changes in operating practices and low-cost modifications to equipment that can be immediately implemented to increase the efficiency of energy utilization, to conserve energy by avoiding unjustified use, and to reduce as far as practical undesirable gaseous, liquid, and solid effluents;

c. for the same refinery selection in each country, to identify, characterize, and recommend more-extensive changes in practices and equipment and modifications to the process units, which appear justifiable but at the same time require further study possibly with inputs that may not yet be available; and

d. to assist the management of each refinery selected in each country, as needed, in the implementation of the changes identified in b. above through on-the-spot assistance (including training sessions for refinery personnel).

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3. APPROACH

This work statement is intended to be generic and applicable in each of the five countries. The intent is to undertake the work with two separate teams of specialized personnel operating in parallel. One team will undertake the work in three countries sequentially and the other in the two remaining countries sequentially. The two teams will be supported as appropriate by a home-office team. The work of the three teams will be coordinated by a program director.

In order to permit pragmatic planning for efficient accomplishment of the work, the first activity will be a reconnaisance in the five countries, probably lasting five weeks, during which needed technical and administrative inputs will be developed and needed local support arranged for. In order to gauge the effectiveness of the work, the final activity will be return visits to the five countries, probably over a two week period when the final reports have been submitted, for the purpose of discussing the results and answering questions that may arise.

The expectations are that considerable data and information will be collected for the countries and for the operating oil refineries. Also, expectations are that this data base, aside from the needs of the Contractor's work program and even after the completion of his work, can provide continuing inputs to other efforts aimed at improving operations in the non-refinery components of the petroleum-sector system (see Figure 1) or to follow-on efforts aimed at implementing the longer-term improvement opportunities identified in the work. Therefore, data and information collection is to be computer oriented with programs organized to be user-friendly and documented accordingly in the Contractor's final reports.

Furthermore, in the identification of improvement opportunities relevant to achieving the objectives of the work, expectations are that benefit/cost estimates will be prepared and/or evaluations performed as far as practical. Estimates and calculations will, with little doubt, require assumptions to fill in for a lack of data. Therefore, estimate preparation and evaluation of opportunities is also to be computer-oriented and user-friendly with programs designed to permit asking "what if" questions, with documentation incorporated in the Contractor's final reports.

Petroleum refineries and petrochemical manufacturing plants are closely linked both physically and through refinery products that become petrochemical feedstocks. The work shall be confined to petroleum refineries only. For this purpose the refinery shall be defined as comprising all installations that pertain to the receipt of the crude oil through to processing and storage of the refinery's primary products. A primary product shall be defined as one that has been fully processed so as to be marketable. On-site facilities to blend different gasoline streams, produce, and process them to final specifications are refinery units. Refinery gas and/or liquid streams that are delivered to other units for further processing, such as to ethylene, ammonia, or aromatic extraction, are to be considered as finished products.

Equipment purchases (both for test work and for permanent installation) needed for the implementation of short-term improvements shall be defined and justified. A brief report shall be submitted for A.I.D. approval before committing to purchase.

4. TASKS

The following tasks are foreseen for the work.

a. Refinery Characterization

The work is technically oriented. It involves preparing for each refinery in each country, a block flow diagram showing the processing units and the support facilities between receipt of the crude oil slate and the dispatch of the product slate to market. The depth of detail for this characterization will provide

1) a description as far as practical of the capability of each processing unit in terms of feedstocks and feedstock variability and product yields and specifications; of the operating conditions, age, mechanical condition of the processing units; of the consumption of utilities (electricity, water, catalysts, chemicals, etc.); and of the quantities and characteristics of the effluents.

2) a description as far as practical of the support facilities in terms of crude and product storage capacity, fire protection and personnel safety provisions, and methods for segregation, collection, treatment, and disposal of solid, liquid, and gaseous effluents.

3) a written operating history of a refinery for the previous 12-month period emphasizing crude-oil receipts and specifications, product slates produced, unusual operating experiences, routine maintenance performed, and emergencies encountered during operations.

4) a description of the method of electricity supply, whether entirely purchased, self-generated, or a combination of both; and a technical description of the design and operation of the power house (if any) in terms of energy balance and heat rate.

b. Refinery Financial Structure

The objective in this task will be to collect data on local practices from the refinery management and/or from other appropriate sources that can be evaluated to establish the basis whereby the cost of each improvement opportunity can be pragmatically estimated and attractiveness of the opportunity determined. The expectation is that attractiveness will be based in part on (a) the magnitude of the capital requirement, including the foreign exchange component, and (b) the period of time within which the cost of the improvement can be recovered through savings in operating costs achieved. Attractiveness shall refer also to quantification (if practical) of benefits from reduced emissions of objectionable effluents. No need exists to relate emissions for compliance with any existing standards.

c. Selection of the Refineries

The refineries to be subjected to more detailed study, in order to meet Objectives b, c, and d above, shall be selected during the reconnaisance period by mutual agreement between the Contractor and the host-government agency concerned. For Contractor's guidance, the main criterion for selection should be based on achieving a maximum efficiency/environmental improvement impact for a minimum effort and cost in a minimum time frame. However, the selection shall be subject to A.I.D. concurrence.

d. Refinery Housekeeping

For each country and for each selected refinery, the work involves observation over a period of time of the refinery operations in order to detect opportunities to improve operating and maintenance practices, such as by

1) eliminating the presence of leaky valve-stems and steam traps,

2) incrementally insulating excessively hot surfaces,

3) avoiding poor combustion conditions (high oxygen content in chimney gases because of excessive excess air beyond combustion needs and/or leaky furnace settings),

4) avoiding excessive carbon monoxide in chimney gases (poor combustion, inadequate mixing of fuel and air),

5) increasing the frequency with which heat transfer surfaces are cleaned of fouling deposits,

6) reviewing whether rotating machinery is adequately maintained in terms of lubrication and condition of bearings, and

7) reviewing whether plant instrumentation is adequate and/or well-enough maintained to provide accurate readings of operating conditions and is appropriately configured to permit efficient operation.

e. Heat Conservation

The work involves observations over a period of time to evaluate the adequacy of provisions to recover heat that otherwise is wasted. The best example is a lack of airheaters to recover heat from hot chimney gases in refinery furnace equipment. Another example is the design of feedstock preheat heat exchanger trains and the opportunity to introduce an additional heat exchanger that can be justified now because of higher energy prices.

f. Process Unit Operating Conditions

The work involves analyzing the operating conditions and control systems installed for each processing unit in a selected refinery in order to determine whether these are appropriate for the products from the feedstock. This analysis can be particularly significant if current feedstocks and/or product slates have changed from the conditions on which the original design of the processing unit was based.

g. Refinery Energy Balance

The work involves analysis of the flows of energy among the different processing units comprising each selected refinery as well as within the processing units themselves in order to identify opportunities for energy-efficiency improvement in the short term and long term.

The analysis should attempt to provide a data base to assist others to foresee the longer term opportunities for a more efficient energy balance through review of the market demand, future crude oil supplies, and the design and applicability of the processing units themselves. Ultimately, the product of such analysis by others could be decisions to abandon certain units, modify others, or add new units, all providing for greater thermal efficiency.

Accordingly, the Contractor shall attempt to foresee as far as practical the prospect that such future analysis could invalidate the benefits perceived for an identified long-term opportunity from a presumption that a substantial remaining useful life for the process unit exists.

h. Fuel Switching

For each selected refinery, the work shall include comment and expert opinion on the practicality of replacing petroleum hydrocarbon fuels with indigenous coal. Refinery furnaces have in the past been fired with coal. Fuel switching to coal to save on oil imports could be a viable option. However, the Contractor shall focus on a different technical option for coal utilization, in order to reduce investment, by considering high fuel-density, coal/water slurry fuels as a direct replacement for fuel oil with minimum retrofit. Sootblowers could handle the higher ash content.

Consideration of such an option should be limited to assessing its practicality in terms of coal supply and characteristics, the state-of-the-art of fuel formulation, and adaptability to existing combustion equipment.

i. Refinery Emissions

For each selected refinery, the work involves preparing a survey of all solid, liquid, and gaseous refinery effluents in terms of sourcing, probable quantities, and chemical analyses, and suggesting practices to be employed in the refinery for control to reduce such emissions that reflect experiences elsewhere where emission control laws are in effect. There is no need to relate this task to showing compliance of emissions with standards that may be established by the World Bank or the U.S. Environmental Protection Agency.

j. Data Evaluation

The work involves computer-oriented organization of the data and information collected, evaluation of the data and information, compiling cost estimates, performing financial calculations, ranking opportunities in terms of the adopted criteria, and preparing final reports to meet the objectives of the work.

APPENDIX D. ECONOMIC ANALYSES

Crude Heat Exchanger Train

The economic driving force to improve heat transfer within the crude heat exchange train is as follows:

Basis:		
	Unit Feed Rate	261 tonnes crude/hour
	Enthalpy of Crude	0.6 kcal/Kg -°C
	Fuel Oil Heating Value	9 600 kcal/Kg

$$261\ \frac{\text{tonnes}}{\text{hr}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{0.6\ \text{kcal}}{\text{Kg - °C}} \times \frac{1\ 000\ \text{kg}}{\text{tonne}} = 3.76\ \frac{\times 10^6\ \text{kcal}}{\text{°C - day}}$$

At 90% heater efficiency and operating time of $\frac{330\ \text{days}}{\text{yr}}$

we have

$$\frac{3.76 \times 10^6\ \text{kcal}}{\text{°C - day}} \times \frac{\text{kg}}{9\ 600\ \text{klm}} \times \frac{2.2\ \text{kcs}}{\text{Kg}} \times \frac{1}{0.90} \times \frac{330\ \text{days}}{\text{yr}}$$

$$= 315\ 810\ \frac{\text{kcs}}{\text{yr - °C}} \quad \text{or} \quad \frac{\$10\ 527}{\text{yr - °C}} \qquad \left(\text{at } \frac{30\ \text{kcs}}{\$}\right)$$

Achievement of these savings may be possible through improved heat exchange design, minimization of fouling and optimization of the heat exchange train system.

i.e. the operating cost reduction due directly to a reduction in the amount of fuel fired is $10 527/yr per °C rise in crude temperature into heater caused by improved heat recovery. At 75% heater efficiency, the savings becomes $12 632/yr for each degree the heater inlet temperature is raised.

HDS Unit No. 5 Heat Exchanger Addition

Savings resulting from addition of heat exchangers (2) to HDS No. 5 reactor effluent, recovering heat now lost to cooling water.

$$\text{Savings} = 1\,950 \text{ kw} \times \frac{14.34 \text{ kcal}}{\text{kw min}} = 27\,963 \frac{\text{kcal}}{\text{min}} \times 60 \frac{\text{min}}{\text{hr}} = 1\,677\,780 \text{ kcal/hr}$$

$$1\,667\,780 \frac{\text{kcal}}{\text{hr}} \times \frac{24 \text{ hrs}}{\text{day}} \times \frac{330 \text{ days}}{\text{yr}} = 1.3288 \text{ kcal/yr} \times 10^{10}$$

at 9600 kcal/kg fuel oil heating valve.

$$1.3288 \times 10^{10} \frac{\text{kcal}}{\text{yr}} \times \frac{\text{kg}}{9\,600 \text{ kcal}} \times \frac{2.2 \text{ kcs}}{\text{kg}} = 3\,045\,170 \text{ kcs/yr}$$

at 30 kcs/$ = $104 506/yr

Installation of Zirtek "in situ" oxygen analyzers in furnace fireboxes

Note that the real issue here is proper control of excess air flow, not just the need for a better oxygen analyzer. Analyzers, in fact, exist in many cases. One was checked by the evaluation team and found to be reasonably accurate, but had a low operability factor. The proposed sensing element of the replacement unit is designed to be mounted in the firebox and will more accurately reflect actual combustion conditions. (The exiting unit is located in the flue gas duct and can read erroneously due to air leaks into the furnace. Also, the present analyzer has tended to be a high maintenance item).

Recommendation for two firebox oxygen analyzers

Three of four proposed vendors submitted proposals. An analysis of their bids shows the following costs for an operable system:

$13 030	Ametek (includes calibration kit)
$22 100	Datatest
$11 825	Zirtek

Shipping costs for Ametek and Zirtek are $100 plus freight costs to Czechoslovakia. Datatest shipping costs are $100 total.

Significant items to be considered for technical evaluation are:

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<u>Sample Gas</u>	Ametek requires sample gases. Datatest requires sample gases. Zirtek requires only instrument air.		
<u>In-Situ</u>	Ametek has measurement cells outside the firebox. Datatest has measurement cells outside the firebox. Zirtek has its measurement cell inside the firebox.		
<u>Firebox Temperature</u>	Zirtek provides a measurement of the firebox temperature.		
<u>Oxygen Measurement</u>	Ametek	-	0-1% to 0-100%
	Datatest	-	0-10% to 0-25%
	Zirtek	-	0.1-21%.
<u>Probe</u>	All three vendors use alumina probes		
<u>Accuracy</u>	Ameteck	-	±2% of measured value (MV)
	Datatest	-	±1% of full scale (FS) on either range
	Zirtek	-	±5% of measured value.
<u>Repeatability & Drift</u>	Ametek	-	repeatability: ±0.2% of MV, Drift: <0.1%/month
	Datatest	-	repeatability: ±0.5% of FS, Drift: not given
	Zirtek	-	stability: less than ± 1% over probe life without recalibration
<u>Alarms</u>	Ametek	-	2 high & 2 low oxygen
	Datatest	-	1 high & 1 low oxygen and error, back purging and calibration gas
	Zirtek	-	1 high & 1 low oxygen and 1 high & 1 low temperature
<u>Output</u>	All vendors	-	4 - 20 mA
<u>Probe Mounting</u>	All vendors	-	5 cm flange mounting.

Considering the above data gathered, the Zirtek is the overwhelming choice. It has the lowest cost, the simplest installation, easiest routine maintenance with no calibration gas and has firebox temperature indication and alarms. The only area where the Zirtek was less desirable than the other two vendors was accuracy of ±5% for the Zirtek and ±2% for the other two vendors. However, in the application the analyzers are being bought the ±5% accuracy is more than adequate. What is as important is the very good stability of the ±1% over the probe life without calibration.

A Zirtek installation was checked out at Amoco's Whiting Refinery (400 000 Bbl/day). The Whiting Refinery had recently installed 14 Zirtek O_2 analyzers (2 per firebox) on their UF-3 Reformer (22 500 Bbl/day) after having excellent results with 8 units installed on a crude unit. The unit operators said they had very good results with the analyzers and really like the firebox temperature readout and alarms. They said the low temperature alarm allowed them to catch burner problems much more quickly. Amoco's analyzer technician said of the 22 Zirtek analyzers they have, the only maintenance problem they had was when one analyzer failed a week after installation. Zirtek furnished a new probe on warranty and the unit has been operating 14 months without any further problems.

Cost accounting practices

We briefly reviewed refinery cost accounting and allocation practices to get a better understanding of the composition of the cost data used for project justification purposes. The system in use is similar to that used in the US. The various categories of cost used and the elements contained therein, for a process unit, are as follows:

- Raw Material - All feeds to the unit in question. For example, for diesel fuel product, all gas oil or kerosene from crude units 4, 5 and 6, from the hydrocracker and misc. streams from the chemical side of the complex.
- Hydrogen - If used, is listed separately.
- Direct Labor - Does not include supervision.
- Fuel - Refinery gas, natural gas, fuel oil.
- Energy - Electrical, steam by pressure level, cooling water, demineralized water, nitrogen, instrument air and catalyst (catalyst cost is estimated and allocated on a lifetime per tonne feed basis).
- Cost of purchasing allocated to the unit or product.
- Other direct costs, such as labor fringes and social security taxes (at 50% of salary).
- Depreciation straight line basis; equipment, 15 year life; civil/structure buildings at 50 year life.
- Maintenance - Material, labor, outside services.

- Other costs covering items of general consumption; paper, pencils, uniforms, etc.
- Overhead allocations, administrative and building maintenance, senior management, area management, engineering, supervision and their fringes.
- Marketing and sales costs.
- Transportation.
- Overhead costs are allocated on the basis of an overhead to total direct cost ratio.
- Sales and marketing wgts are allocated in a similar manner; i.e. total sales cost divided by overhead and direct costs.

APPENDIX E. CRUDE UNIT PROCESS SIMULATION

Process simulation

The general overall benefit of process simulation is that it is the most cost effective approach to process prediction and evaluation. Refiners can evaluate process changes without physically doing it in the plant.

Process simulation can be done on virtually any process. However, the following are common examples.

Tower and flash drums

Distillation towers are probably the most frequent simulated process. Commercial simulation programs such as Simulation Sciences-PROCESS/PRO-II, Chemshare, HYSIM, and Aspen all have elaborate thermodynamic data bases and prediction procedures to yield accurate vapor and liquid separation and therefore, distillation results. Examples of common owner simulation are as follows:

Crude atmospheric and vacuum towers

These simulations can determine the expected yields from various crude blends. These crude change simulations can highlight areas of concern in downstream processing. Many times these simulations not only include pumparounds, but also side steam strippers so detailed product specifications and tower loadings can be accurately checked. With an anticipated crude blend and/or rate change, the refiner can determine:

- Product yields
- Pumparound duty requirements
- Flash zone temperatures
- Column section loadings
- Vacuum system requirements
- Stripping steam requirements (in the main column and side stream strippers)

Since these variables can affect each other, the simulation allows the refiner to recheck and reoptimize all variables simultaneously.

The tower simulation can also be used to evaluate possible cost effective efficiency improvements (even if crude rates and/or blends remain the same). For example, the economics of adding a preflash tower (the preflash tower vessel and main fractionator costs versus energy savings) can be evaluated. Another example is a vacuum tower transfer line redesign and its energy and yield benefits.

Fluid catalytic cracking unit columns

The FCCU main fractionator tower and Vapor Recovery Unit towers: Absorber-Stripper, Depropanizer, etc., are simulated for similar reasons as crude unit towers, but not as often. Pumparound duties are once again important variables in determining absorption & product yields and tower loadings.

Other product separation and stabilization

There are many other refinery columns that frequently can be simulated to determine tower capacity, separation effectiveness, energy improvements, control optimization, etc. These include:

- Lube Oil Vacuum Towers
- Coking Unit Combination Towers
- Naphtha Splitters
- Gasoline, or other product, Stabilizers
- Debutanizers
- Depropanizers
- Deethanizers
- Propane-Propylene Splitters

Many times these columns have stringent separation requirements necessitating high reflux ratios to achieve product specifications. Simulation models can assist in balancing these reflux ratios with condenser duties, reboiler duties, tray/packing loads, intermediate heat removals, and tower hydraulics.

Often, tower pressure drops can markedly affect K-values. Thus, the tray-by-tray calculations of a tower simulation program not only achieve accurate separation results, but also can be used to predict tower delta P effects.

If these tower simulations show an area of concern (tower loading, product specification, etc.), the refiner can again use the tower simulation program to see:

1) if any adjustment in pumparound duties, tower conditions (pressure and temperature) stripping steam, and/or product yields and specifications can be used to solve the problem

2) how much reduction in capacity would be required to remove the problem(s).

3) the effect of a possible capital addition, such as more pumparound duties, bigger columns, deeper vacuums, and/or a change in tower internals.

Many times refiners see a range of possible tower feeds. The simulation model can be used to evaluate the extremes. Perhaps, the simulation results may highlight ways to improve day-to-day operations. For example, this approach may show the refiners the best tray (the tray with greatest temperature change) to control the tower heat balance (i.e., reboiler duty).

Heat exchange network

Heat exchange network units are prime candidates for frequent simulations to evaluate:

1) the most efficient way to exchange heat between streams in new processes, and;

2) heat integration improvement ideas in existing processes.

Examples of these heat exchange networks are:

- Crude Unit Preheat Trains
- FCCU Main Fraction Pumparound Circuits
- Coking Unit Combination Tower Pumparounds

Simulation Sciences HEXTRAN program and the Linhoff-March Pinch Technology (available in the Aspen simulation program) are used for this purpose.

It is important to note that these heat exchange network simulations should be used along with the main tower simulation until duties, rates, and temperatures are consistent in both models (to accurately evaluate the process).

Many times refiners monitor heat exchange performance with/against network simulations on a regular basis to establish exchanger cleaning schedules and benefits.

Reactor simulations

Simulations to predict reactor yields are being used more often these days. These reactor models include: Hydrotreaters, Cokers, FCCU's, Reformers, Alkylation Units, and Sulfur Plants. Although the catalyst and/or technology companies still provide the expected and guaranteed yields, refiners are seeing the need to evaluate day-to-day changes in feed rate and composition in these reactors to anticipate problems and operate efficiently.

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For example, several factors affect the amount of propylene sent to alkylation, if any. These factors include:

1) The market for chemical-grade and polymer-grade propylene.

2) The propane/propylene yield.

3) The propane/propylene splitter capacity.

An alkylation model would allow the refiner to evaluate the effects before doing it in the field. Another example is the expected FCCU yields from varying amounts of residual cracking.

The Simulation Sciences-PROCESS/PRO-II and Chemshare programs allow users to specify reactors in different ways:

- plug flow and stirred-tank models, with in-line Fortran for the kinetics;
- equilibrium reaction equations and approach to equilibrium relationships, and;
- simpler conversion versus temperature relationships.

Refiners are also using reactor model simulations to more accurately time and justify catalyst change outs.

Piping networks

Piping network simulations are used to determine new and/or evaluate existing system hydraulics. This is especially important when evaluating/designing unit expansions.

It is often wise to use a piping network simulation program along with a heat exchange network for complex preheat trains with multiple parallel paths. Inaccurate pressure designations on streams in heat network programs will produce inaccurate heat network solutions.

Detailed equipment programs

Simulation Sciences-PROCESS/PRO-II, Chemshare, Aspen, and HYSIM programs all have equipment modules that allow users to model: pumps, compressors, heat exchangers, coolers, heaters, drums, etc.

These models afford accurate heat exchange, pressure drop, heat of compression, energy usage, etc., process calculations. One such example is interstage cooling economics for multi-stage compressors. A simulation model can be used to determine the heat exchange, knock out drum, and piping requirements (capital costs) of interstage cooling/separation versus compressor horsepower savings to determine an energy efficient compressor design or revamp.

These equipment modules, however, are not made for detailed mechanical design of equipment. There are many separate detailed equipment design programs that exist. These Rating and/or Design Programs include:

- Tower Trays and/or Packing
- Fired Heaters and Boilers
- Heat Exchangers
- Shell & Tube
- Plate & Frame
- Core
- Air Coolers
- Cooling Towers
- Pumps and Compressors
- Relief Valves

These can be accessed, if needed for specific problems.

Other uses

These simulation models are also used for non-simulation tasks, as well. For example, stream heating/cooling curves and physical properties can be generated for input to detailed equipment sizing software and/or specifications. Another common use is reconciling inconsistent field data by the use of material and energy balance algorithms.

Summary

The keys to using a simulation program effectively are:

- Understand how equipment is modelled in the program.

- Know that the simulations results are only as accurate as the input information (feed characterization and process specification).

- Confirm the model with existing operation, if possible.

- Invest the time to develop a model for future, as well as current studies. An accurate model is always used for more than its original intention.

Slovnaft crude unit simulation

The beginning of this section highlighted the benefits of process simulations. The evaluation of the Slovnaft crude unit via computer simulation was basically accomplished in two steps:

- Base case Simulation Development - This step involved first using the physical unit information to develop the basic computer model using the Simulation Sciences, Inc. (SSI) Process program. The physical unit information included: the number of trays in towers, the locations of tower feed and products, pressure drops, and enthalpy changes. A known crude (a 32 °API Russian blend) was then input into the model to "tune" the simulation to match performance data for that crude. This effort included adding or removing a theoretical tray, adjusting stripping steam rates, slight changes in tower temperature and/or pressure profiles, etc. This effort also revealed a few inconsistent and/or erroneous data which were returned to Slovnaft for confirmation.

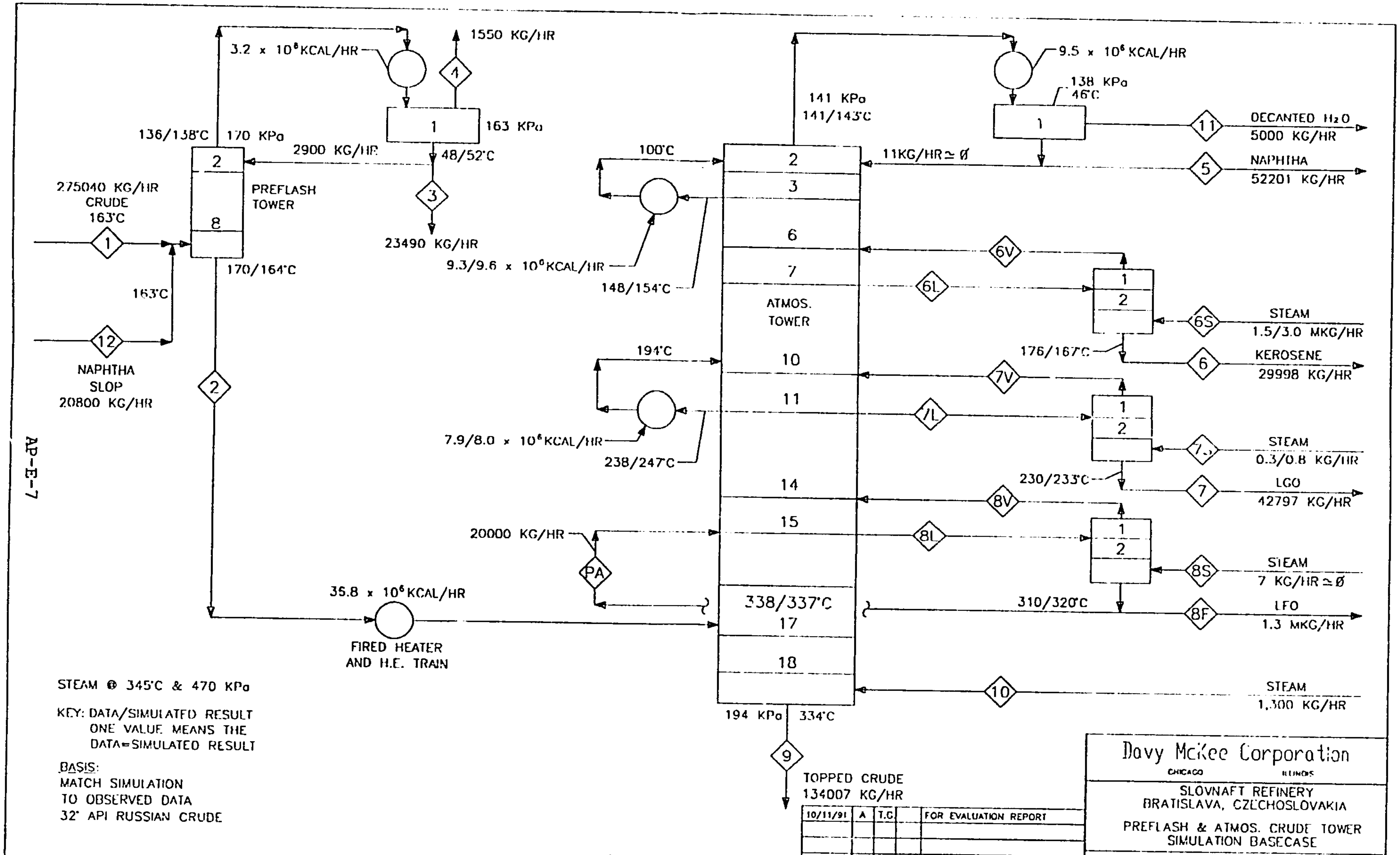
- Other Crude Blend Evaluation - Once the model matched the observed data, the simulation model was then ready to be used to predict results on other crude blends. For Slovnaft, a lighter crude, 38.7 °API Brega blend and a heavier crude, a 29.3 °API Arabian light blend were evaluated.

Base case simulation

Figure No. 12 is a summary of the base case simulation. As shown in the summary, 8 theoretical stages for the preflash tower, 18 for the main tower, and 2 for each side stream stripper were specified. Since the main atmospheric tower overhead condense was a subcooled total condense (as required to match the data), this first specified theoretical stage did not really act as a theoretical stage.

The attached summary drawing highlights the actual plant data along with the simulated results. 275040 kg/hr of Russian crude enter the preflash tower at 163 °C along with 20 800 kg/hr of naphtha slop. The crude was characterized (by the simulation program) by combining the 32 °API gravity, with the graphical TBP and GC light ends given in Appendix F. The naphtha slop was assumed to be 100% naphtha.

As shown in the tables following, the preflash towers simulation matched data well. The pressure profile and overhead vapor and liquid rates were specified. The temperature profile, reflux, condenser data, and tower fraction were allowed to vary. For this topic, a basic familiarity with the concept and operation of simulation programs is assumed.



Davy McKee Corporation — CHICAGO ILLINOIS
SLOVNAFT REFINERY BRATISLAVA, CZECHOSLOVAKIA
PREFLASH & ATMOS. CRUDE TOWER SIMULATION BASECASE
DWG. No. 2063-22-06-112 — A

DATE	REV	BY	APPR	DESCRIPTION
10/11/91	A	T.C.		FOR EVALUATION REPORT

Figure-12

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As the following shows, the temperature profile matched well:

	DATA	SIMULATION
Overhead Condenser Temp., °C	48	53
Tower Top Temp. °C	136	138
Bottom Temp. °C	170 (suspect)	164

The preflash tower bottoms temperature of 170 °C was suspect considering the feed temperature was only 163 °C and the tower had no reboiler. The resulting reflux rate was 2.9 Mkg/hr. The preflash tower bottoms was fed to the atmospheric tower.

The atmospheric tower was simulated in a similar manner. The pressure profile, product rates, pump around duties, and flash zone were specified. A 10 kg/hr reflux (representing zero reflux) was also specified. The temperature profile, condenser duty, tower fractionation and overflash were allowed to vary. The enthalpy needed to achieve flash zone conditions was also determined by the simulation model.

Because the 5/95 gap simulation results did not totally match the data, the stripper steam rates were varied. A comparison of the gaps and steam rates required to achieve those gaps are summarized as follows:

5/95 GAPS, °C	DESIRED	ACTUAL DATA	SIMULATION
Kero/naph	10	17	11
LGO/Kero	-28	-23	-25
LFO/LGO	-58	-81	-80
Btm/LFO	-99	NA	-102

STRIPPING STEAM RATES, MKG/HR	ACTUAL DATA	SIMULATION
Kero Stripping Steam	1500	3000
LGO Stripping Steam	300	800
LFO Stripping Steam	0	7
Main Tower Bottoms	1300	1300

Adding one more tray to each of the top two sections of the towers (in lieu of the additional stripping) did not improve the gaps enough. Thus, the stripping steam changes were kept for the base case simulation.

The resulting temperature profile matched well:

TEMPERATURES	DATA, °C	SIMULATION, °C
Top Condenser	46	46
Tower Top	141	137
Top PA Draw	148	154
Kero Prod.	176	167
Middle PA Draw	238	247
LGO Prod.	230	233
LFO Prod/Bot PA	310	320
Flash Zone	338	337
Bottoms	334	334

The overhead condenser duty was 9.5 million Kcal/hr. and the water decant rate was 5000 kg/hr. Also, 24.6 million Kcal/hr. of enthalpy from the preheat train was needed to preheat the feed up to the preflash tower and 36.8 million Kcal/hr (from the preheat train and furnace) was needed for feed to the main tower.

A later section of this simulation study summarizes tower loadings. Theoretical trays 2 and 11 were the most loaded sections mainly as a result of the pumparounds through those sections. The model calculated PA rates based upon tower temperature profile, PA duty, and inputed PA return temperature. Because of the actual vs. theoretical tray temperature differences, the PA rate had to be corrected before calculating the tray loading. For instance, the top PA rate was about 10% higher with a 148 actual vs. 154 °C simulated draw temperature.

<u>Other crude blends</u>

Figure 13 summarizes the results of simulating the same base <u>volume</u> of a lighter 38.7 °API Brega crude blend. Figure 14 summarizes the results of simulating the same <u>volume</u> of a heavier 29.3 °API Arabian Light crude blend. The 1.9 wt% of light ends for the Arabian Light blend was characterized by ratioing down the 3.1 wt% light ends composition of the base case or Brega blends.

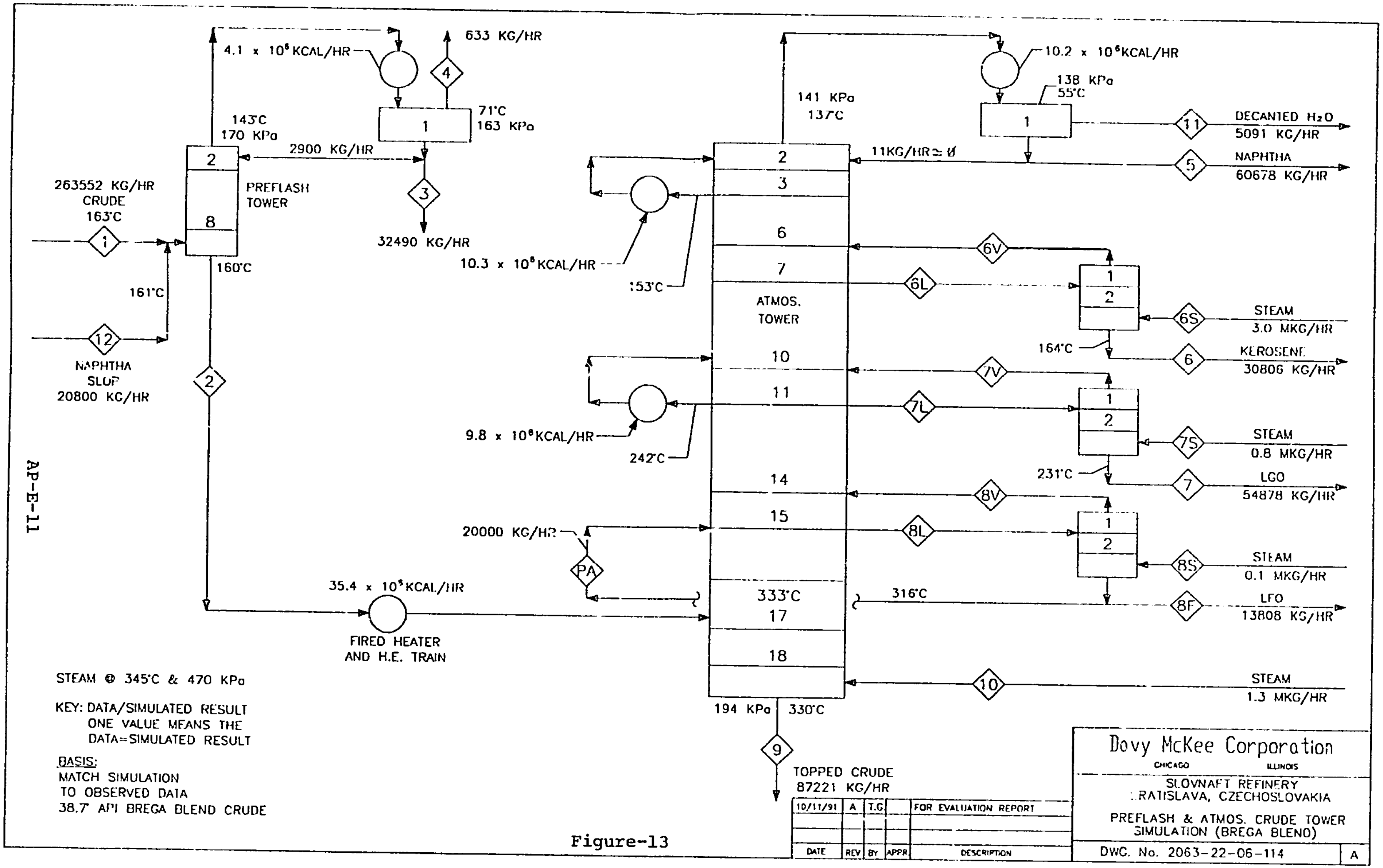

Figure-13

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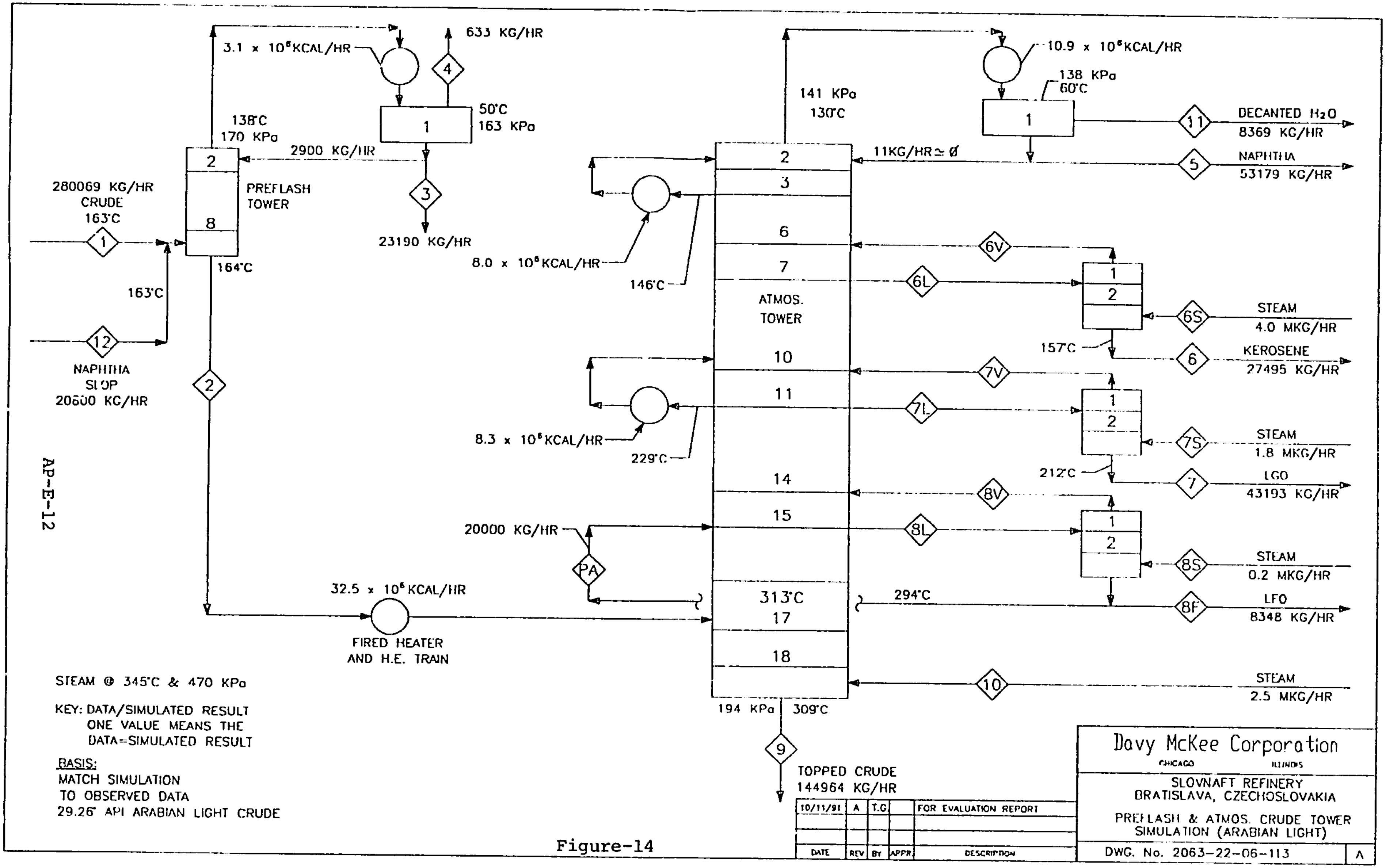

Figure-14

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The same amount of naphtha slop (as the base case) was added for both new crude cases. Also, the same base case enthalpy (24.6 million Kcal/hr. was added to the feed (crude and slop) before entering the preflash tower.

The preflash tower for both cases was simulated by specifying the same pressure profile and reflux rates as the base case. The condenser temperatures were set based upon approximately the same condenser performance as the base case. For the lighter Brega crude, the amount preflashed overhead was of course more than the base case. The average vapor load increased about 40% (over the base case). The average liquid load was about 6% less. For the heavier Arabian Light crude, the amount preflashed overhead was less. The average vapor load was about 6% less and the average liquid load was about 2% more. The top of the preflash tower was the most loaded section. Based upon a quick sizing method developed by Koch Engineering Company, the approximate preflash tower % of flood determinations for the three cases are as follows:

SIMULATION	PREFLASH TOWER % OF FLOOD
Base case	65%
Brega Blend	79%
Arabian Light Blend	62%

For the main column simulation, the pressure profile from the base case was assumed for both new cases. However, product rates were not specified for these runs. Instead, the following product ASTM D86 cut points. Obtained from the base case simulation were specified:

Naphtha	95% PT - 176°C
Kero	EP - 275°C
LGO	95% PT - 346°C
LFO	95% - 435°C

In addition, a 2% overflash was also specified along with essentially no reflux (10 kg/hr). The preflash tower simulation, the subcooled (total) condenser duty and temperature was approximated based upon the base case performance.

Finally, the stripping steam rates were adjusted as required to meet the designed 5/95 gaps provided by Slovnaft. For the Brega case, all the steam rates were the same as the base case simulation with the exception of the LFO Stripper which was increased from 7 to 100 kg/hr to achieve the desired LFO/LGO gap.

For the Arabian Light blend case, all the stripping steam rates needed to be raised as follows:

STRIPPING STEAM	Base case, MKG/HR	ARABIAN LIGHT, MKG/HR
Kerosene	3000	4000
LGO	800	1800
LFO	7	200
Column Bottoms	1300	2500

The side stream stripping vapors loads were of course proportionately larger.

The resulting product gaps were:

5/95 GAPS, °C	DESIRED	BREGA SIMULATION	ARABIAN LIGHT SIMULATION
Kero/Naph	10	8	8
LGO/Kero	-28	-31	-32
LFO/LGO	-58	-59	-60
BTM/LFO	-99	-97	-103

The required pumparound duties and temperature profile were determined by the simulation. Therefore, the enthalpy added to the preflashed crude (to achieve flash zone conditions) was determined by the simulation. The comparison with the base case temperature profile and enthalpies follows:

TEMPERATURE PROFILE, °C	BASE CASE	BREGA BLEND	ARABIAN LIGHT BLEND
Top Condenser	46	55	60
Tower Top	141	137	130
Top PA Draw	148	153	146
Kero Prod.	176	164	157
Middle PA Draw	238	242	229
LGO Pro.	230	231	212
LFO Prod/Bot PA	310	316	294
Flash Zone	338	333	313
Bottoms	334	330	309

ENTHALPY CHANGE	Base case 10^6KCAL/HR.	BREGA BLEND 10^6KCAL/HR.	ARABIAN LIGHT BLEND 10^6KCAL/HR.
Preflashed crude to the flash zone	36.8	35.4	32.5
Top PA	9.6	10.3	8.0
Middle PA	8.0	9.8	8.3

A yield comparison is as follows:

	Base case 10^3 KG/HR	BREGA BLEND 10^3 KG/HR	ARABIAN LIGHT BLEND 10^3 KG/HR
FEEDS:			
Crude	275.0	263.6	280.6
Naphtha Slop	20.8	20.8	20.8
Stripping Steam	5.1	5.2	8.5
TOTAL FEEDS	300.9	289.6	309.3
PRODUCTS:			
OVHD Flash Vapor	1.6	4.6	0.6
OVHD Preflash liquid	23.5	32.5	23.2
Naphtha	52.2	60.8	53.2
Kerosene	30.0	30.8	27.5
LGO	42.8	54.9	43.2
LFO	11.9	13.8	8.3
Topped Crude	134.0	87.2	145.0
Decant H_2O	5.0	5.1	8.4
TOTAL PRODUCTS	301.0	289.7	309.4

It is important to note that the preheat train was not evaluated for these two new crude cases. As shown in the yield summary, there was more LFO and lighter product for the Brega blend than base case (as expected). The LFO and lighter yield for the Arabian Light blend was less than the base case. Thus, a detailed preheat train evaluation may determine that more preheat train surface is needed. However, the yields appear close enough that the existing preheat train or some swing service piping may be adequate. In other words, for a Brega run, some crude preheat surface in vacuum tower service may need to be switched to atmospheric tower service. For the Arabian Light blend, atmospheric tower preheat surface may need to be switched to vacuum tower service.

A detailed evaluation of the F-1 crude heater was also not done. In the base case, the F-1 heater added 31.0 million Kcal/hr. of enthalpy to the preflashed crude. Thus, 84% of the enthalpy added to the preflashed crude (before entering, the main column flash zone) was provided by F-1. Based upon the range in preflashed crude rates and temperatures for the three cases, the F-1 duty could provide approximately 31 $\pm$ 10% million Kcal/hr. Thus, the preflashed crude (PC) preheat train would have to provide enthalpy as follows:

CASE	PC ENTHALPY TO FLASH ZONE 10^6KCAL/HR.	APPROXIMATELY F-1 DUTY 10^6KCAL/HR.	REQUIRED PC PREHEAT 10^6KCAL/HR.
Base case	36.8	31.0	5.8
Brega Blend	35.4	31.0	4.4
Arabian Light Blend	32.5	31.0	1.5

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In terms of the average main column loadings, the Brega blend increase loads: the upper load averaged about 17% higher than base case and the liquid load was about 7% higher. On average, the Arabian light blend reduced the loads, the vapor load averaged about 4% lower and the liquid load about 8% lower. As mentioned already, the top and middle pumparound sections of the main column were the most loaded. The following summarizes the approximate % of the floods for the three cases (based upon the Koch quick sizing method):

SIMULATION	TOP PA SECTION % OF FLOOD	MIDDLE PA SECTION % OF FLOOD
Base case	77%	71%
Brega Blend	83%	79%
Arabian Light Blend	74%	73%

Finally, although the vacuum tower was not evaluated in this study, a Brega blend crude run would unload the vacuum tower. However, the required vacuum tower capacity would have to increase about 8% for an Arabian Light crude run. Thus, the vacuum tower and associated equipment would need to be evaluated and confirmed in detail for this crude.

APPENDIX F. CRUDE OIL ANALYSIS

TBP curves for Russian crude oil

Figure 15 - Temperature vs. Yield
Figure 16 - Temperature vs. Density
Figure 17 - Temperature vs. Sulfur Content
Figure 18 - Temperature vs. Viscosity
Figure 19 - Light End Analysis

Appendix F

Figure 15

TBP CURVES FOR SOVIET CRUDE OIL

TEMPERATURE VS. YIELD

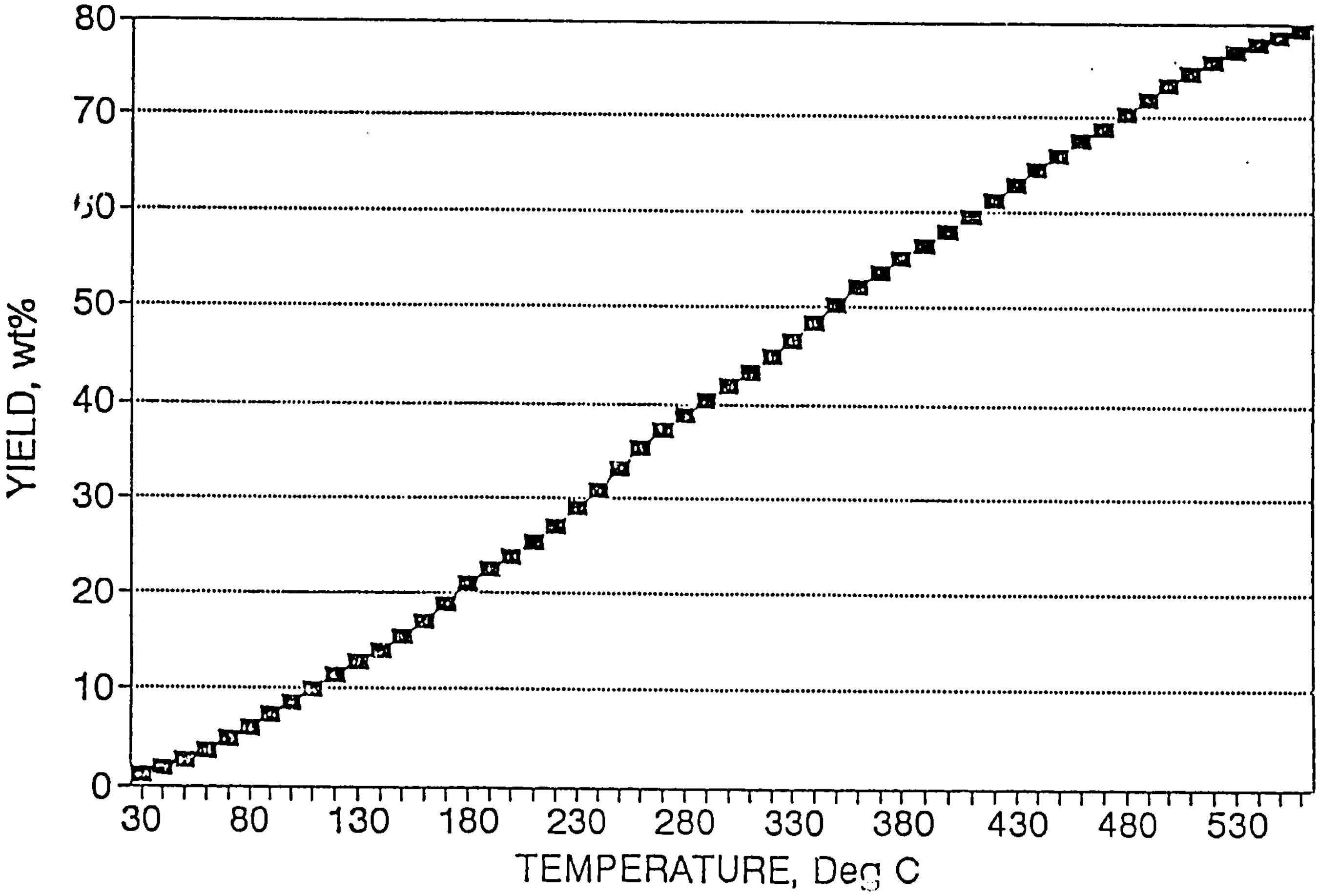

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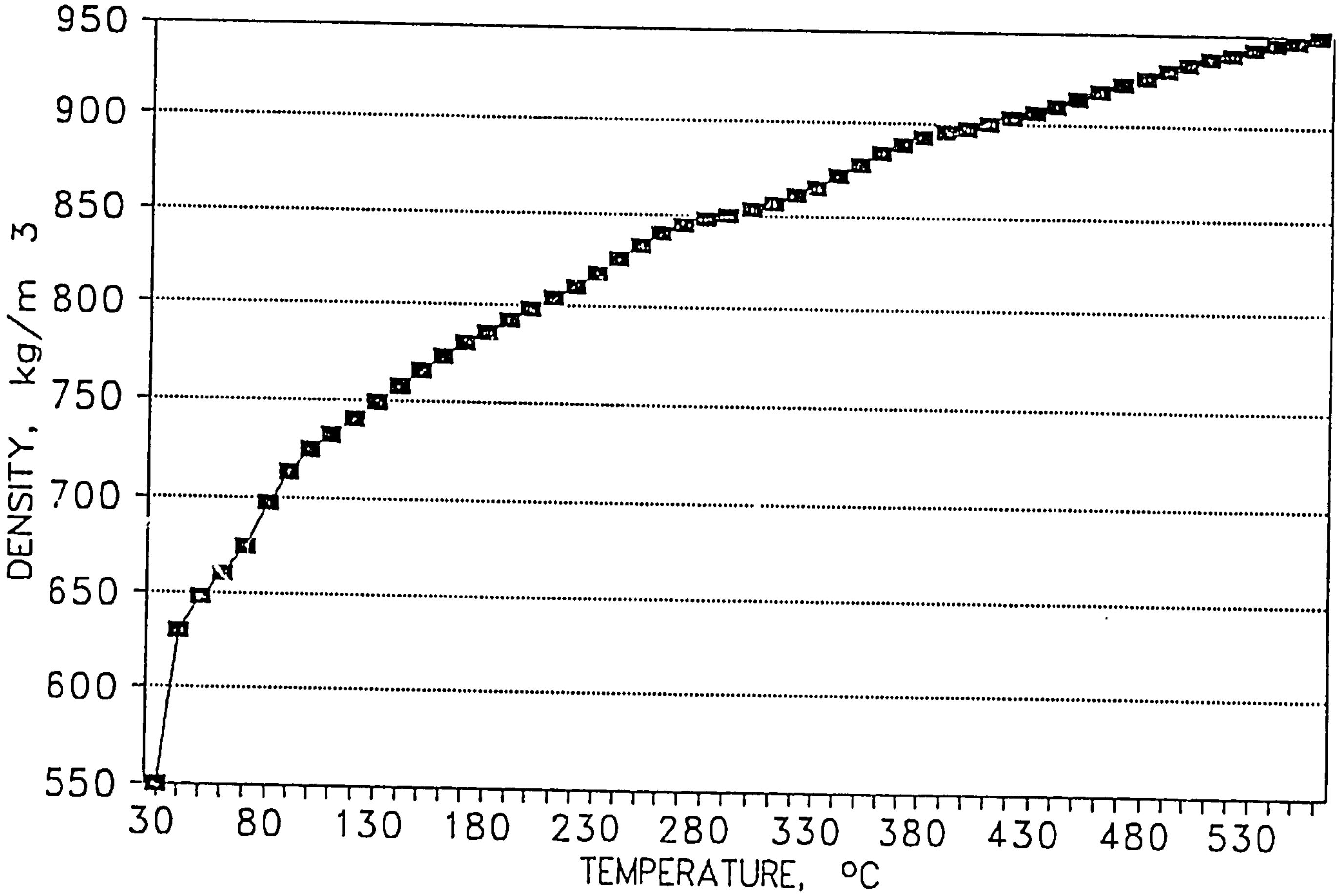
Figure 16

TBP CURVES FOR SOVIET BLEND CRUDE OIL

TEMPERATURE VS. DENSITY MID-POINT



2/19

Figure 17

TBP CURVE FOR SOVIET BLEND CRUDE OIL

TEMPERATURE VS. SULFUR CONTENT

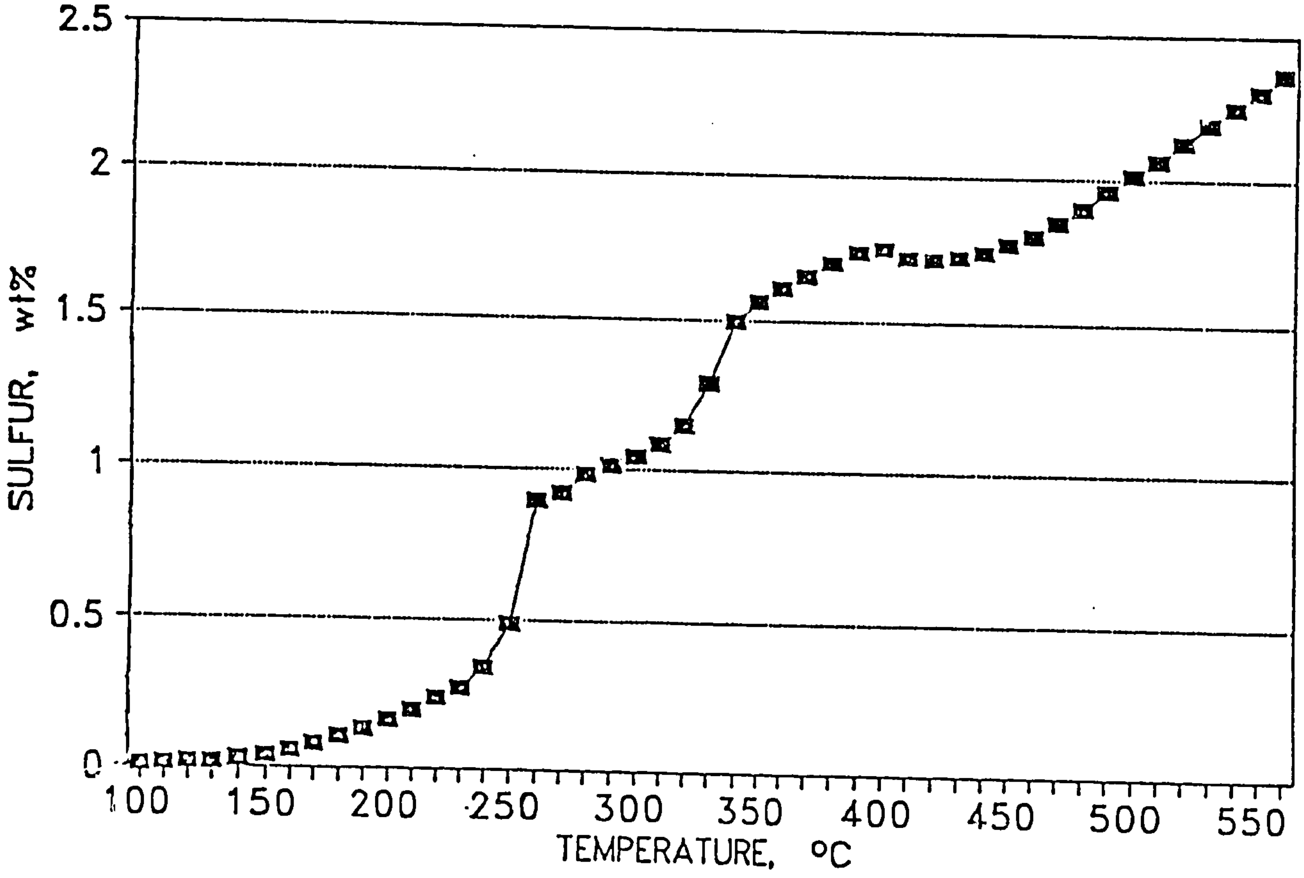


Figure 18

TBP CURVE FOR SOVIET BLEND CRUDE OIL

TEMPERATURE VS. VISCOSITY AT 20%

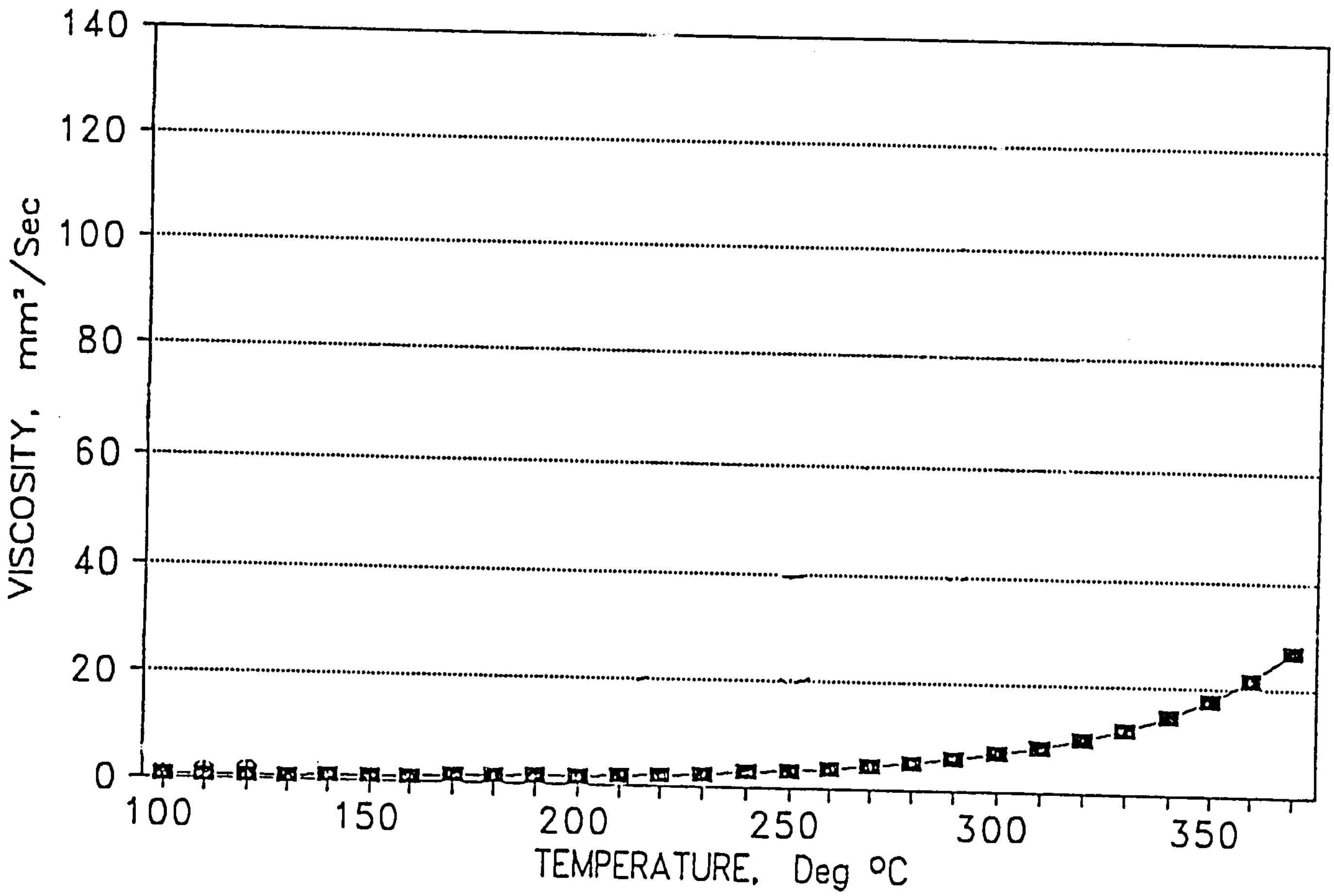


Figure 19

LIGHT ENDS ANALYSIS

COMPONENT	WT%
C_2H_6	0.06
C_3H_8	2.40
C_4H_{10}	19.55
C_5H_{12}	39.00
C_6H_{14}	34.53
C_6+	4.46
TOTAL	100.00