ALSANDS PROJECT GROUP

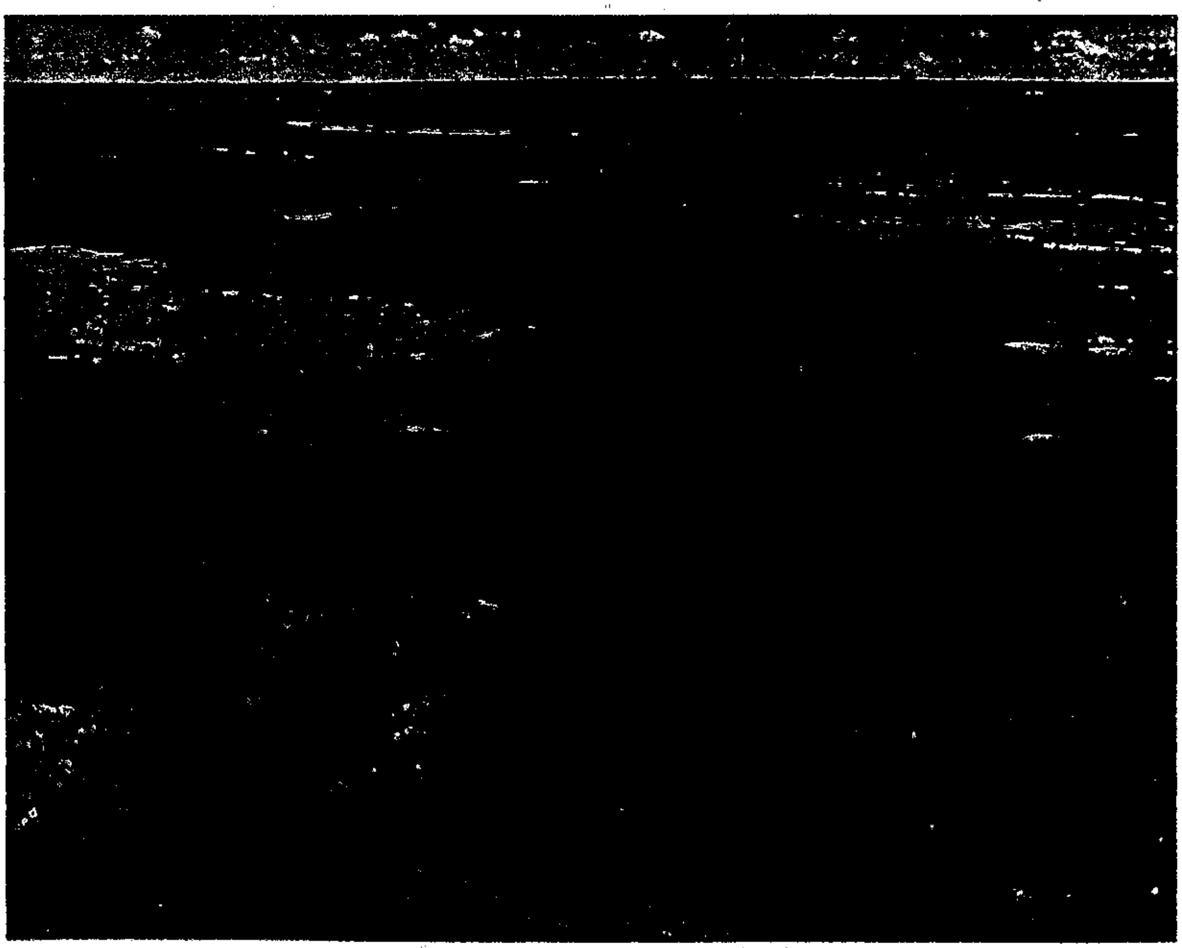
APPLICATION

to the

Alberta Energy Resources Conservation Board

for an

Oil Sands Mining Project



December 1978

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I Application

1. Amoco Canada Petroleum Company Ltd., Chevron Standard Limited, Dome Petroleum Limited, Gulf Canada Limited, Hudson's Bay Oil and Gas Company Limited, Pacific Petroleums Ltd., Petrofina Canada Ltd., Shell Canada Resources Limited and Shell Explorer Limited, (collectively called the "Applicant") hereby make application to the Energy Resources Conservation Board pursuant to Section 43(1) of The Oil and Gas Conservation Act for approval of a scheme or operation for the recovery of oil sands, crude bitumen and products derived therefrom within an area that comprises Bituminous Sands Leases No. 34, No. 96 and a portion of No. 0877080001 issued by Her Majesty the Queen in the right of the Province of Alberta.

2. The above noted companies formed a Consortium known as the Alsands Project Group to carry on negotiations with Governments on the commercial and fiscal terms and conditions necessary to an economically viable Project and to submit this Application. Each participant in the Alsands Project Group will be entitled to acquire an interest in the scheme or operation proposed in this Application equal to their respective interests in the Alsands Project Group which are presently as follows:

Amoco Canada Petroleum Company Ltd.	10 percent
Chevron Standard Limited	8 percent
Dome Petroleum Limited	4 percent
Gulf Canada Limited	8 percent
Hudson's Bay Oil and Gas Company Limited	8 percent
Pacific Petroleums Ltd.	9 percent
Petrofina Canada Ltd.	8 percent
Shell Canada Resources Limited	25 percent
Shell Explorer Limited	20 percent

3. The Applicant proposes to produce 22 250 m^3/d (140 000 B/D) of synthetic crude oil and LPG products. Subject to obtaining all necessary approvals and making satisfactory agreements concerning royalties, taxes and other matters by the third quarter of 1979, the Applicant intends to commence construction of the facilities by mid-1980. First production is scheduled to commence by the first quarter of 1986.

4. Bituminous Sands Lease No. 0877080001 is held by Shell Canada Resources Limited and Shell Explorer Limited in undivided shares. Bituminous Sands Leases No. 34 and No. 96 are held by Hudson's Bay Oil and Gas Company Limited, Murphy Oil Company Ltd., Pacific Petroleums Ltd., and Petrofina Canada Ltd. in undivided shares. The holders of the Leases have dedicated the lands described in Schedule "A" attached hereto to the scheme or operation proposed in this Application.

5. Particulars of the scheme or operation attached hereto form a part of this Application.

6. An Environmental Impact Assessment document prepared pursuant to Section 8 of The Land Surface Conservation and Reclamation Act is being filed for purposes of Section 43(1.1) of The Oil and Gas Conservation Act, and a Social Impact-Benefit/Cost document is being filed as requested by the Board.

7. The Applicant submits that approval of this project will facilitate the orderly development of the Alberta oil sands in a manner consistent with the exercise of sound conservation and environmental protection practices. This project will contribute significantly towards Canada's energy needs and will provide local, provincial and national economic benefits.

8. Communications relative to this Application should be directed to J.E. Czaja, Alsands Project Group, 22nd Floor, Shell Centre, 400-4th Avenue S.W., P.O. Box 2606, Station "M", Calgary, Alberta, T2P 3A9.

Dated at Calgary, Alberta, this 14th day of December, 1978.

Jones, Black & Company,
Counsel for the Applicant

Schedule "A"
Description of Lands

Portions of Bituminous Sands Lease No. 0877080001:

IN TOWNSHIP NINETY-FIVE (95), RANGE NINE (9), WEST OF THE FOURTH (4) MERIDIAN:

Sections Nineteen (19) to Twenty-one (21) inclusive, Lsd's 4, 5, 12 and 13 of Section Twenty-eight (28);

Sections Twenty-nine (29) to Thirty-two (32) inclusive, Lsd's 4, 5, 12, 13, 14, 15 and 16 of Section Thirty-three (33);

AND

IN TOWNSHIP NINETY-FIVE (95), RANGE TEN (10), WEST OF THE FOURTH (4) MERIDIAN:

Sections Two (2) to Five (5) inclusive;

Sections Eight (8) to Eleven (11) inclusive, N 1/2 of Section Twelve (12);

Sections Thirteen (13) to Seventeen (17) inclusive;

Those portions of Sections Six (6), Seven (7), Eighteen (18) and Nineteen (19) lying to the North and East of the right bank of the Athabasca River;

Sections Twenty (20) to Thirty-six (36) inclusive;

AND

IN TOWNSHIP NINETY-FIVE (95), RANGE ELEVEN (11), WEST OF THE FOURTH (4) MERIDIAN:

Those portions of Sections Twenty-Four (24), Twenty-five (25), Thirty-five (35) and Thirty-six (36) lying to the North and East of the right bank of the Athabasca River;

AND

All statutory road allowances and what would be statutory road allowances, if the lands were surveyed pursuant to The Surveys Act, lying within the outer limits of the above described lands.

Bituminous Sands Leases No. 34 and No. 96:

IN TOWNSHIP NINETY-SIX (96), RANGE NINE (9), WEST OF THE FOURTH (4) MERIDIAN:

Sections Four (4) to Nine (9) inclusive;

AND

IN TOWNSHIP NINETY-SIX (96), RANGE TEN (10), WEST OF THE FOURTH (4) MERIDIAN:

Sections One (1) to Twelve (12) inclusive;

AND

IN TOWNSHIP NINETY-SIX (96), RANGE ELEVEN (11), WEST OF THE FOURTH (4) MERIDIAN:

Sections One (1) and Twelve (12) and those portions of Sections Two (2) and Eleven (11) lying to the East of the right bank of the Athabasca River;

AND

All statutory road allowances and what would be statutory road allowances if the lands were surveyed pursuant to The Surveys Act, lying within the outer limits of the above described lands.

II Introduction and Project Summary

Overview

This Application describes a scheme for the recovery of 22 250 m^3/d (140 000 B/D) of synthetic crude oil and LPG, by mining of near-surface portions of the Athabasca Oil Sands deposit. It also includes summaries of an Environmental Impact Assessment, Social Impact-Benefit/Cost Analysis and Regional Socio-Economic Impact Assessment which are being filed in support of the Project.

Various members of the Alsands Project Group have been actively involved in oil sand mining developments for over 25 years. The Applicant submits that approval of this Project will continue orderly development of the Alberta Oil Sands, consistent with the objectives of best practical resource conservation and environmental protection practices. The Project contributes significantly towards Canada's domestic energy needs, and offers local, provincial and national economic benefits.

The most suitable areas of the Shell and AOP leases have been combined for this Project, and the best commercial technology currently available used for oil sands Mining, Extraction, and bitumen Upgrading. Significant improvements for Projects of this type have been made in resource conservation and emissions levels. The sponsoring companies collectively bring to the Project the financial resources, technological capability, and management expertise necessary for its implementation.

The synthetic crude output from this Project will add approximately eight percent to Canada's present potential producibility of crude oil and equivalent, rising to some 11 percent in 1985 when production begins (basis September, 1978 NEB predictions). The Project will come onstream at a time when supply from conventional crude oil sources will be in decline. National Energy Board projections anticipate that approximately 50 percent of Canada's crude oil production will come from oil sands and heavy oil sources by the mid-1990's. This Project would be a major contributor to that supply. It will have a positive impact on the Canadian balance of payments of $17.2 billion. This is mainly due to the replacement of imported crude by the synthetic crude oil production.

The Project will also support the specific objectives of creating new jobs (permanent employment will be provided for some 6500 people), developing Northeastern Alberta, diversifying the province's industrial base, and providing overall economic stimulus. It will generate continuing royalty payments at the Provincial level, and encourage the continuing growth of a major sector of the oil industry. Direct benefits will include the growth in Alberta of major project construction expertise, and of secondary industry.

In summary, the Project is considered to be of major benefit to Canada and to Alberta.

Location

Figure II-1 locates the Project Area with respect to Fort McMurray and other local surface features of interest.

The Project Lands include portions of Bituminous Sands Leases 34, 96 and 0877080001, and occupy all or parts of Townships 95 and 96, Ranges 9, 10 and 11 W4M. The total Project Area is some 17 000 ha (42 000 acres).

Leases 96 and 0877080001 were formerly known as Leases 12 and 13 respectively, and these former numbers are used throughout this Application.

Resource Description

The Athabasca Oil Sands, located at the northeastern updip edge of the Alberta Basin, contain the largest oil deposit in Canada. The bitumen occurs in the McMurray formation of Lower Cretaceous age. Associated with the bitumen bearing sands are barren silts and clays, which must be considered in the Mining and Extraction processes. Considerable water occurs under artesian conditions in aquifer sands associated with the bitumen bearing units. Such reservoirs must be depressured prior to mining.

The Project Area is situated in the northern portion of the Athabasca Oil Sands, where the thickest of the bitumen containing sandstones occur. It contains several orebodies centrally located within the relatively limited area where overburden thicknesses permit surface mining. Total reserves are estimated at 1300×10^6 m^3 (8100×10^6 Bbl) of bitumen in place. Of this total, 700×10^6 m^3 (4400×10^6 Bbl) are considered to be mineable.

Energy and material recoveries are outlined in the Resource Recovery section below for the 25 year life of this Project. The orebody being mined contains reserves sufficient for 55 years of production.

Project Facilities

The overall processing scheme for the mining Project is illustrated schematically in Figure II-2 and consists of the following major components:

* an open pit mine utilizing large dragline excavators and bucketwheel reclaimers
* an ore transportation conveyor belt system to move the ore to the Extraction Plant
* a hot water Extraction Plant to separate the bitumen from the oil sand
* an Upgrading Plant to convert the bitumen to a light, low sulphur synthetic crude oil
* a gas line to provide natural gas to the Project
* a power line for linking the Project to the Provincial power grid
* a Utilities Plant to supply the steam and electrical energy required to operate the complex
* supporting facilities such as tailings pond, river water pipeline and product storage, buildings, warehouses, etc.

Additional offsite facilities will include a pipeline to link the Project to existing crude oil distribution lines, and airport, highway and telecommunication and power line facilities.

Project Schedule

The Applicant plans to commence detailed engineering at the beginning of 1980 and to follow this closely with equipment selection. Engineering is expected to be 90 percent complete during the first half of 1983.

Plant site clearing and drainage will commence in late 1979. The installation of temporary construction facilities and site grading will commence during the second half of 1980; foundation work will begin mid-1981. The plant will be mechanically complete between mid and end 1985.

This timetable is based upon receiving appropriate approvals from Government regulatory agencies, and on receiving satisfactory agreements on royalties and taxes and other commercial terms by the third quarter of 1979.

Figure II-3 illustrates the Project schedule in summary form.

Resource Recovery

The orebody to be mined contains an estimated 323 $\times$ 10^6 m^3 (2030 $\times$ 10^6 Bbl) of bitumen in place. Bitumen mined will be 249 $\times$ 10^6 m^3 (1570 $\times$ 10^6 Bbl), which after Extraction will be Upgraded to 200 $\times$ 10^6 m^3 (1260 $\times$ 10^6 Bbl) of synthetic crude product plus saleable LPG.

Production of bitumen and synthetic crude oil over the 25 year Project life is shown in Table II-1, along with Material and Energy recovery factors. The Statistics in this table are based on the phased utilization of the coke produced by the Upgrading process, as described in following sections of this Application.

Figures II-4, 5 and 6 illustrate the major stream flows in summary form. The three cases illustrated relate respectively to proposed initial operation, the alternative of initial natural gas usage for Hydrogen Plant feed, and the Gasification of Fluid Coke for Hydrogen production.

Construction Labour Force

The site construction labour force is estimated to peak at 6700 people in 1984 plus an additional peak of 1100 people (in 1983) at a marshalling yard in Edmonton. An estimated 35 million construction manhours will be required for the Project, including modularization and preassembly work at the Edmonton marshalling yard. The Applicant expects the majority of the work force to come from Alberta, and will work with native and appropriate Government agencies to ensure native participation.

Transportation Facilities and Infrastructure

LIVING ACCOMMODATION

Numerous studies conducted by consultants for the Applicant and for Government agencies have concluded that because of the excessive commuting distance between Fort McMurray and this Project and other potential developments in the area, a new town is preferred to serve the northern portion of the Athabasca region. The presently proposed town site is located between McClelland Lake and the Athabasca River (Figure II-1).

The Applicant is prepared to work closely with appropriate Government agencies to ensure that the necessary planning and agreements for living accommodation are put in place in a timely manner.

UTILITY CORRIDOR

The Applicant proposes that all of the utilities required for both the plant and the proposed town be located in a narrow corridor near the top bank of the Athabasca River valley. The corridor will contain a highway, synthetic crude pipeline, gas pipeline, power line and water line. A bridge across the Athabasca River will also be required, and would carry the gas and synthetic crude pipelines.

The corridor concept will be used in order to minimize environmental impact by careful selection of a single route for all facilities needed to service the plant and proposed town site.

AIR ACCESS

During the initial construction phase, an existing 1200 m (4000 ft) long airstrip 4 km (2.4 miles) south of the plant site will be utilized.

To service the long-term needs of the Project, a new 1800 m (6000 ft) airstrip capable of handling large aircraft such as the Boeing 737 or Hercules, will be required.

TRANSPORTATION

The Applicant has made preliminary investigations into the optimum modes of transportation for equipment, materials and people. Freight will be carried to the job site primarily via truck. Rail facilities will be used as far as Fort McMurray for some large loads.

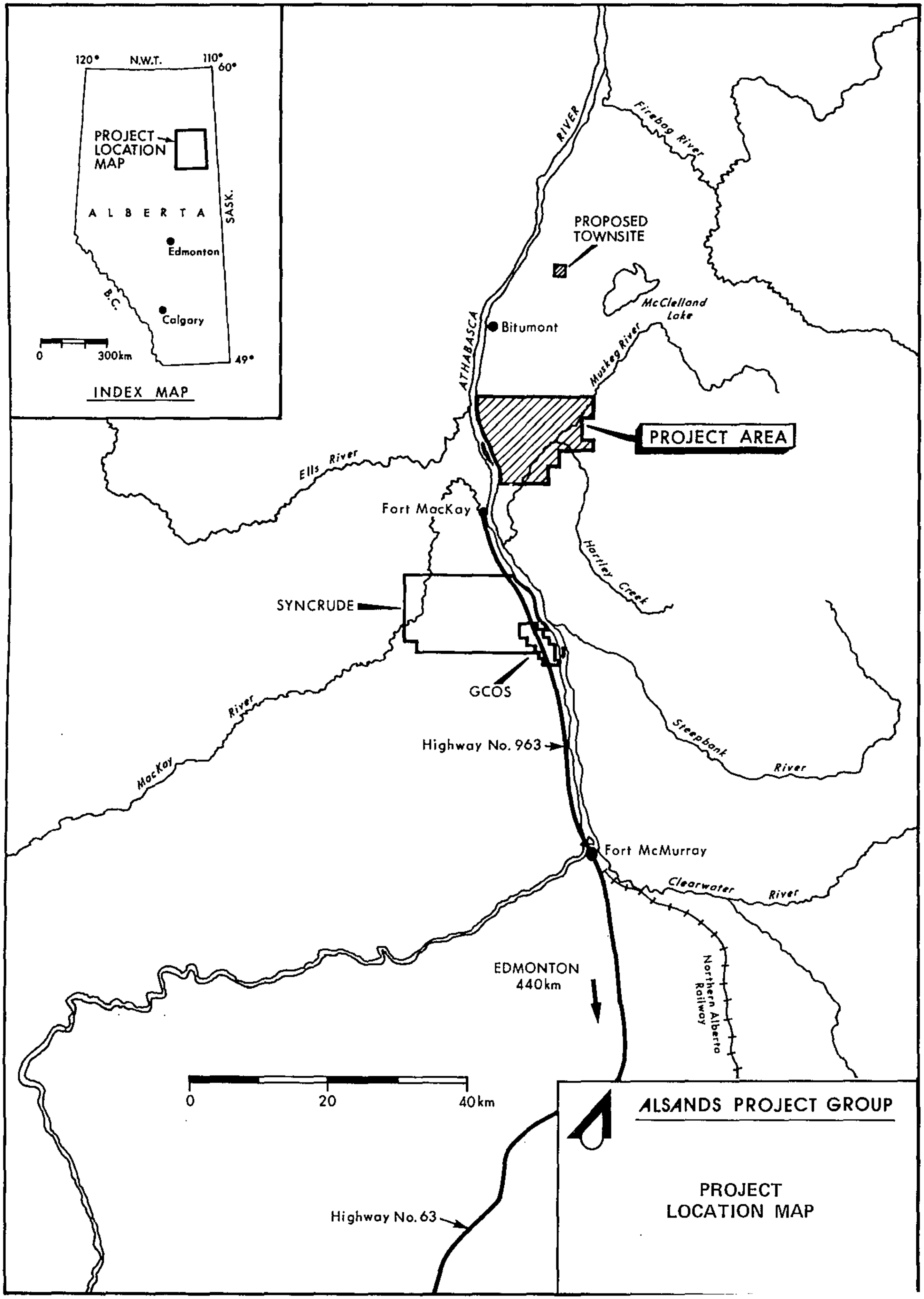
The transportation network from Fort McMurray to the plant site prior to completion of the bridge across the Athabasca River is expected to include a combination of road, river ferry barge, ice bridge and air, depending on the season. Transport of people to the job site will be primarily by aircraft or by ice bridge until the highway bridge is completed.

TABLE II-1

MATERIAL AND ENERGY RECOVERY
PROJECT LIFE BASIS (25 YEARS)

		RECOVERIES	
A. VOLUME	**10^6 m^3**	**INDIVIDUAL**	**CUMULATIVE**
Inplace Bitumen	323	1.00	1.00
Mined Bitumen	249	0.771	0.771
Extracted Bitumen	228	0.916	0.706
Upgraded Product	200	0.877	0.619
B. MASS	**10^6 t**	**INDIVIDUAL**	**CUMULATIVE**
Inplace Bitumen	326	1.00	1.00
Mined Bitumen	251	0.771	0.771
Extracted Bitumen	230	0.916	0.706
Upgraded Product	167	0.726	0.513
C. ENERGY	**10^3 TJ**	**INDIVIDUAL**	**CUMULATIVE**
Inplace Bitumen	12 490	1.00	1.00
Mined Bitumen	9 630	0.771	0.771
Extracted Bitumen	8 830	0.916	0.706
Upgraded Bitumen	7 130	0.807	0.570

Note: Extraction Plant Diluent losses are included in the Upgrading figures.


120°
N.W.T.
110°
60°
PROJECT LOCATION MAP
ALBERTA
SASK.
Edmonton
B.C.
Calgary
0
300km
49°
INDEX MAP
RIVER
Firebag River
PROPOSED TOWNSITE
McClelland Lake
ATHABASCA
Bitumont
Muskeg River
PROJECT AREA
Ells River
Fort MacKay
Hartley Creek
SYNCRUDE
GCOS
River
Steepbank
River
Highway No. 963
MacKay
Fort McMurray
Clearwater
River
EDMONTON 440km
Northern Alberta Railway
0
20
40km
ALSANDS PROJECT GROUP
PROJECT LOCATION MAP
Highway No. 63

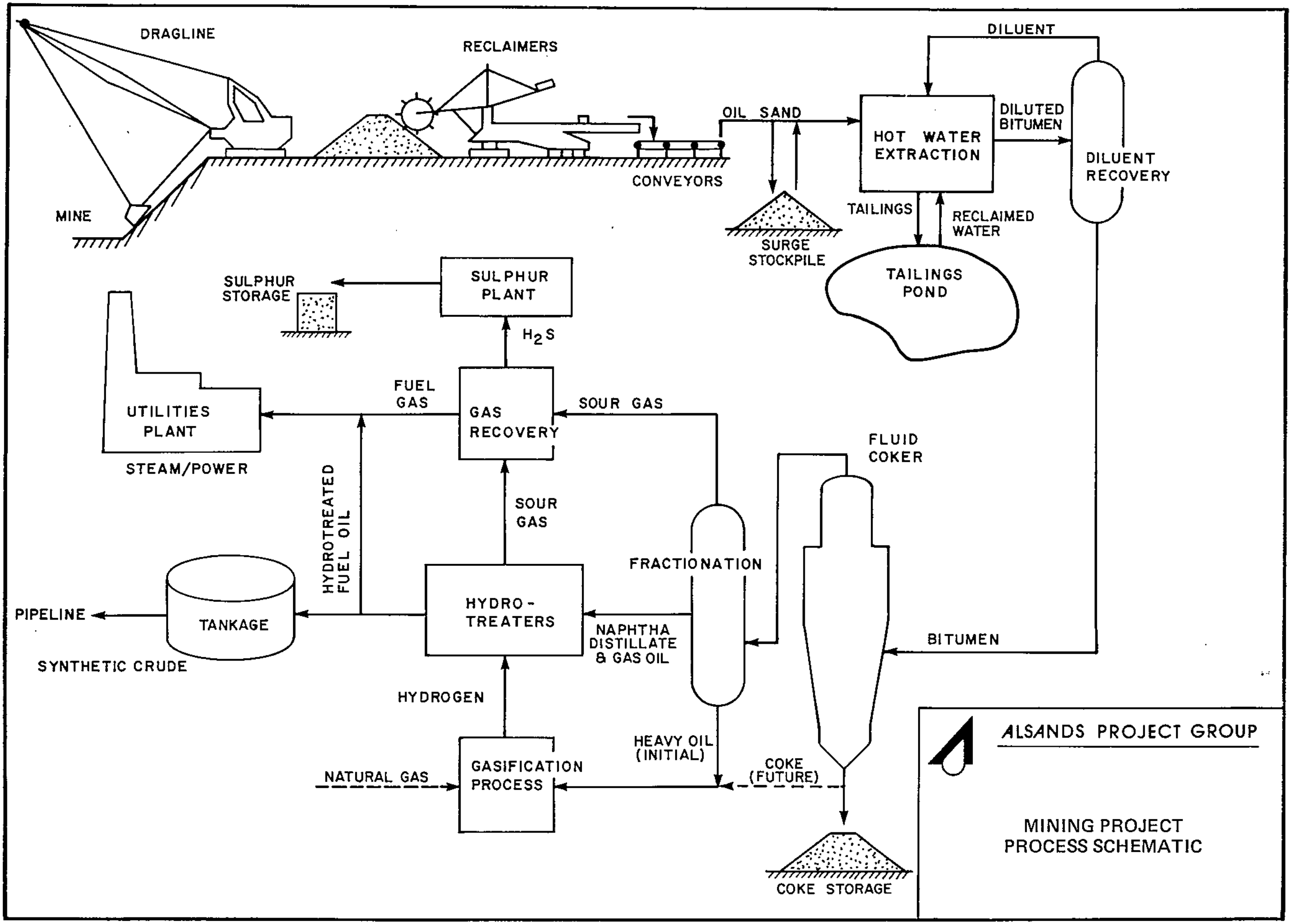
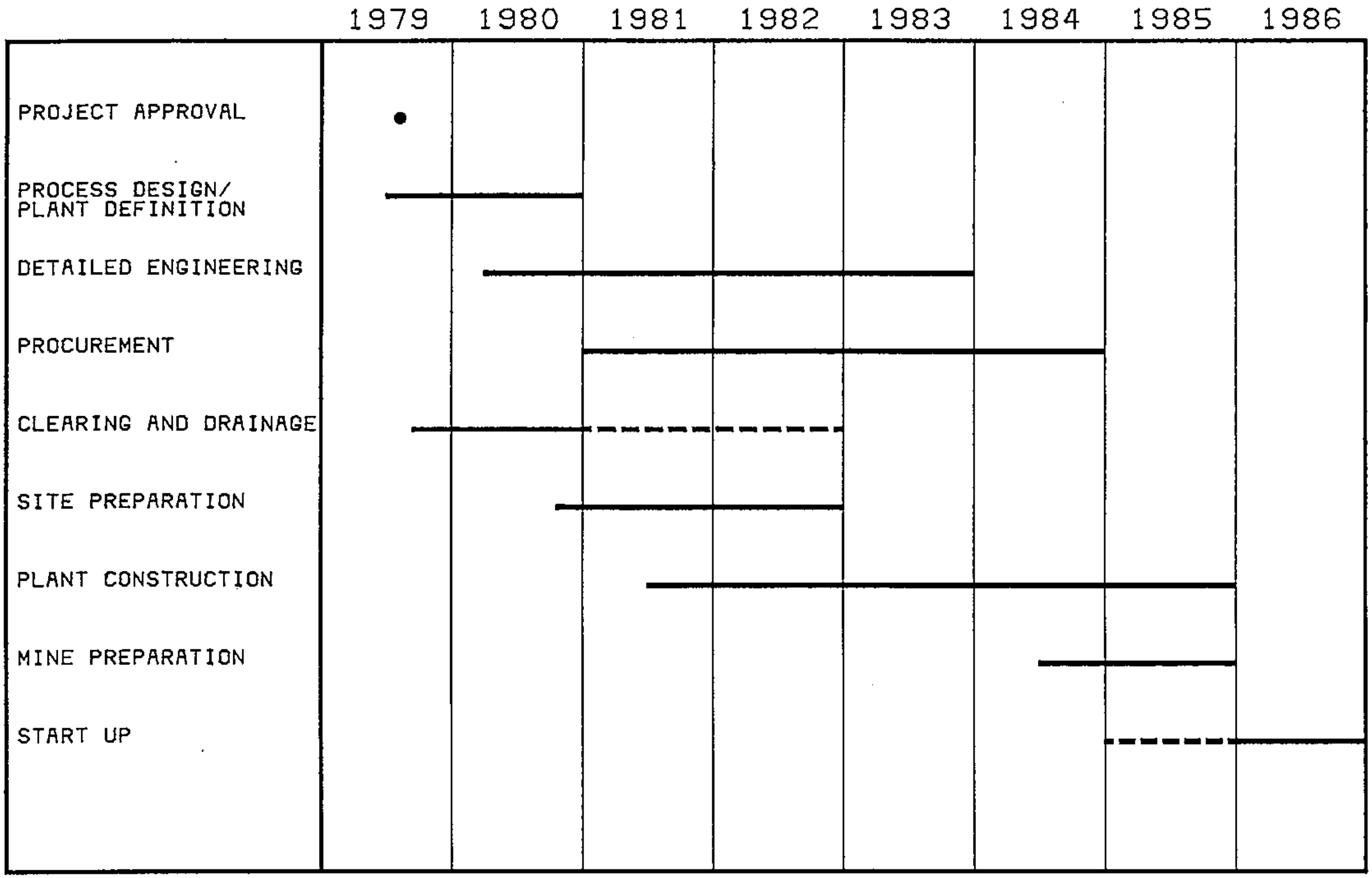

DRAGLINE
RECLAIMERS
DILUENT
OIL SAND
HOT WATER EXTRACTION
DILUTED BITUMEN
DILUENT RECOVERY
MINE
CONVEYORS
TAILINGS
RECLAIMED WATER
SURGE STOCKPILE
TAILINGS POND
SULPHUR STORAGE
SULPHUR PLANT
H_2S
UTILITIES PLANT
STEAM/POWER
FUEL GAS
GAS RECOVERY
SOUR GAS
FLUID COKER
HYDROTREATED FUEL OIL
SOUR GAS
FRACTIONATION
PIPELINE
TANKAGE
HYDRO-TREATERS
NAPHTHA DISTILLATE & GAS OIL
BITUMEN
SYNTHETIC CRUDE
HYDROGEN
HEAVY OIL (INITIAL)
COKE (FUTURE)
NATURAL GAS
GASIFICATION PROCESS
COKE STORAGE
ALSANDS PROJECT GROUP
MINING PROJECT PROCESS SCHEMATIC

FIGURE II-2



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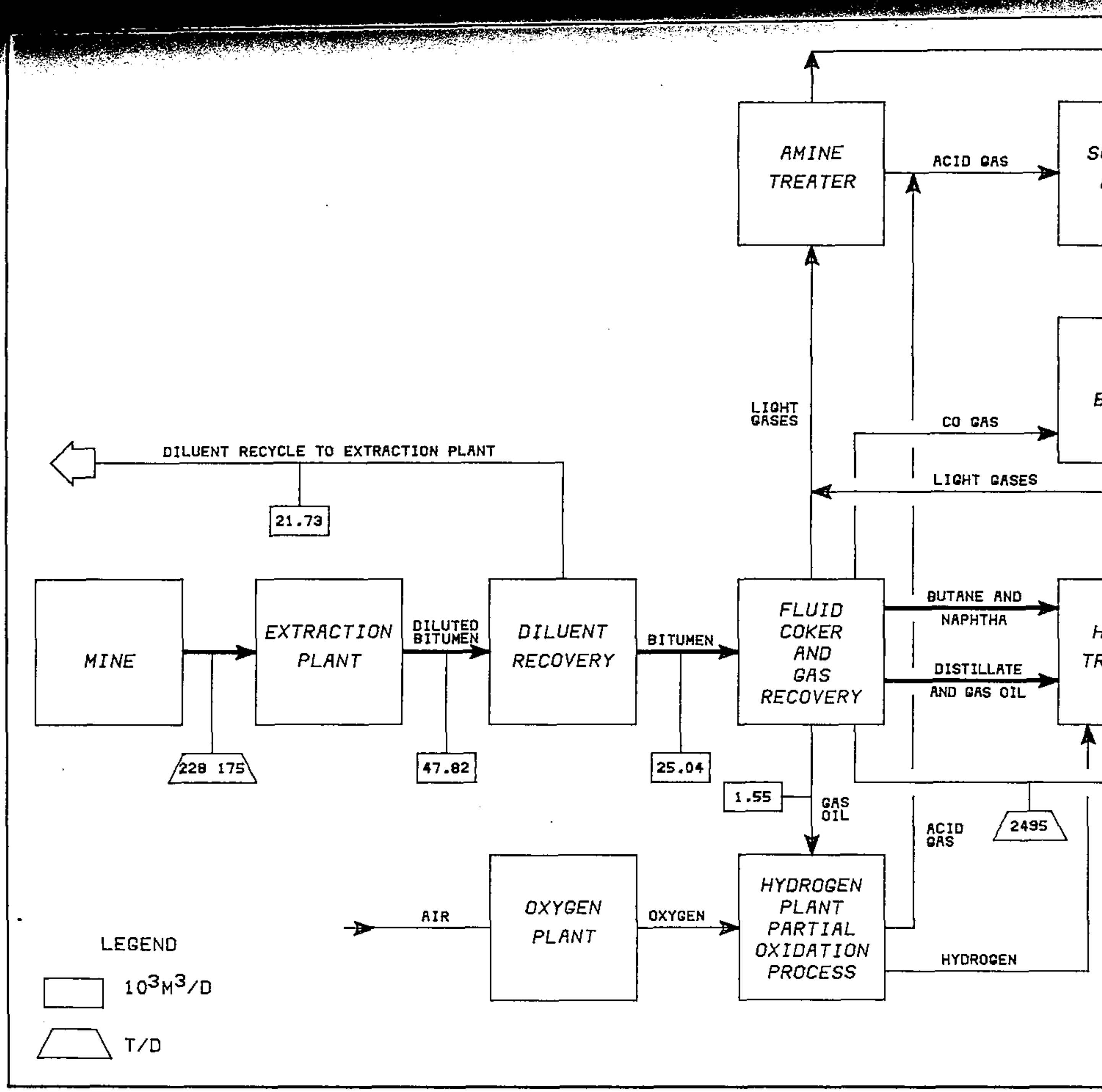
PROJECT SCHEDULE

FIGURE II-3



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PROJECT FLOW SUMMARY
INITIAL OPERATION WITH
HYDROGEN FROM GAS OIL

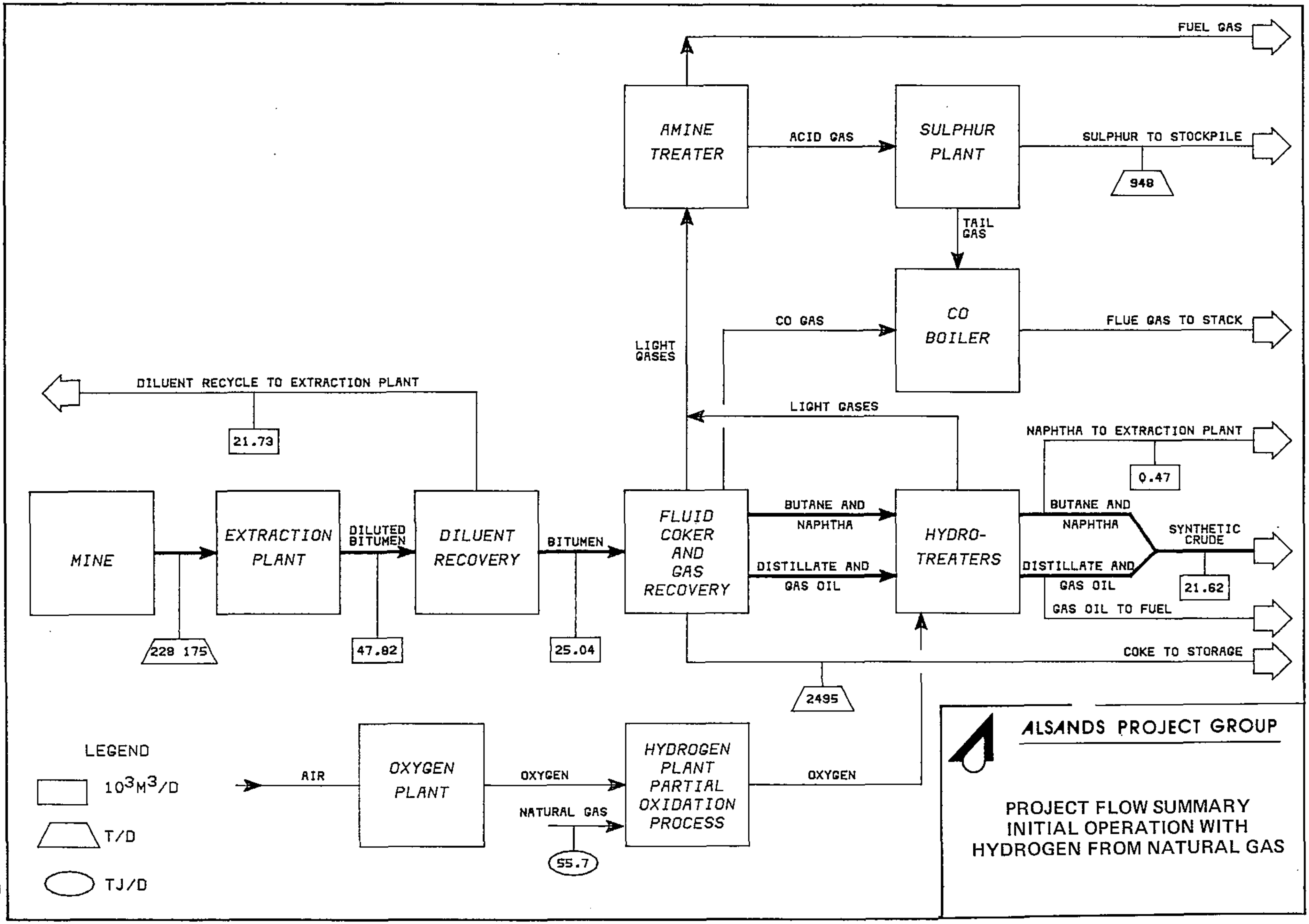
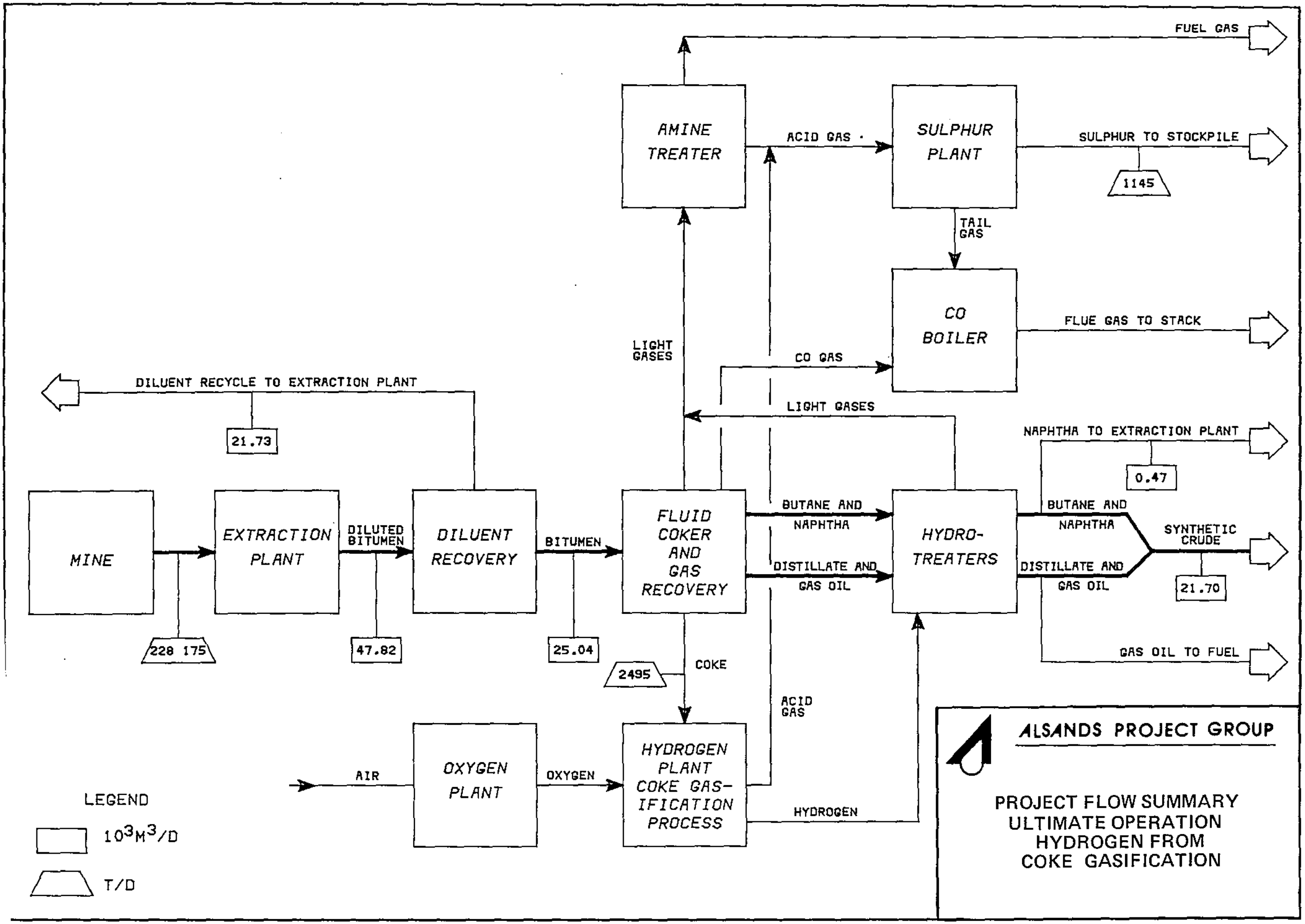

FUEL GAS
AMINE TREATER
ACID GAS
SULPHUR PLANT
SULPHUR TO STOCKPILE
948
TAIL GAS
CO BOILER
CO GAS
FLUE GAS TO STACK
LIGHT GASES
LIGHT GASES
DILUENT RECYCLE TO EXTRACTION PLANT
21.73
NAPHTHA TO EXTRACTION PLANT
0.47
MINE
EXTRACTION PLANT
DILUTED BITUMEN
DILUENT RECOVERY
BITUMEN
FLUID COKER AND GAS RECOVERY
BUTANE AND NAPHTHA
DISTILLATE AND GAS OIL
HYDRO-TREATERS
BUTANE AND NAPHTHA
DISTILLATE AND GAS OIL
SYNTHETIC CRUDE
21.62
GAS OIL TO FUEL
COKE TO STORAGE
228 175
47.82
25.04
2495
LEGEND
$10^3M^3/D$
T/D
TJ/D
AIR
OXYGEN PLANT
OXYGEN
NATURAL GAS
55.7
HYDROGEN PLANT PARTIAL OXIDATION PROCESS
OXYGEN
ALSANDS PROJECT GROUP
PROJECT FLOW SUMMARY
INITIAL OPERATION WITH
HYDROGEN FROM NATURAL GAS

FIGURE II-5


FUEL GAS
AMINE TREATER
ACID GAS
SULPHUR PLANT
SULPHUR TO STOCKPILE
1145
TAIL GAS
CO BOILER
FLUE GAS TO STACK
LIGHT GASES
CO GAS
DILUENT RECYCLE TO EXTRACTION PLANT
21.73
LIGHT GASES
NAPHTHA TO EXTRACTION PLANT
0.47
MINE
EXTRACTION PLANT
DILUTED BITUMEN
DILUENT RECOVERY
BITUMEN
FLUID COKER AND GAS RECOVERY
BUTANE AND NAPHTHA
DISTILLATE AND GAS OIL
HYDRO-TREATERS
BUTANE AND NAPHTHA
DISTILLATE AND GAS OIL
SYNTHETIC CRUDE
21.70
228 175
47.82
25.04
2495
COKE
GAS OIL TO FUEL
ACID GAS
AIR
OXYGEN PLANT
OXYGEN
HYDROGEN PLANT COKE GAS-IFICATION PROCESS
HYDROGEN
LEGEND
$10^3M^3/D$
T/D
ALSANDS PROJECT GROUP
PROJECT FLOW SUMMARY
ULTIMATE OPERATION
HYDROGEN FROM
COKE GASIFICATION

III Geology and Resource Appraisal

Introduction

The Project Area is situated in the northern portion of the Athabasca Oil Sands, where the thickest of the bitumen bearing Cretaceous, McMurray sandstones occur. The Project area contains several orebodies, centrally located within the relatively limited area where overburden thicknesses permit surface mining. Ample area is available for the necessary support facilities such as plant site, tailings pond and utility corridor. The site is close to the Athabasca River. The bitumen in place to be covered by the surface facilities will be minimal. Sufficient mineable reserves are present within the Project Area for at least two projects, each producing an average of 22 000 m^3/d (138 000 B/D) of synthetic crude oil for 25 years.

Regional Geology

The Athabasca Oil Sands, located at the northeastern updip edge of the Alberta Basin, contain the largest oil deposit in Canada. The bitumen occurs in the McMurray formation of Lower Cretaceous age, where it constitutes the primary cementing agent in this predominantly deltaic sandstone sequence. Associated with the bitumen bearing sands, and which must be considered in the Mining and Extraction processes, are barren sands, silts and clays. Considerable water occurs under artesian conditions in aquifer sands associated with the bitumen bearing units and consequently such reservoirs must be depressured prior to mining.

The McMurray formation was deposited on the eroded surface of Upper Devonian carbonates and shales (Beaverhill Lake group) in environments ranging from terrestrial to marine. Toward the close of McMurray time, deeper water sedimentation took place followed by the more marine clays and silts of the overlying Clearwater formation.

Deposition of Cretaceous sediments, particularly the lowermost sediments (McMurray formation), appears to have been controlled to some extent by a regional structural depression caused by solution of Middle Devonian salt (Prairie Evaporite formation) with the subsequent collapse of overlying Middle and Upper Devonian strata. The axis of this major salt collapse feature, which represents the present day eastern limit of massive salt beds in the Middle Devonian, trends in a northwest-southeasterly direction to the west of the Athabasca River. At the northwest corner of the Project Area, a major structural feature known as the Bitumount Basin is believed to have been caused by post Devonian salt solution. The generally rugged nature of the Devonian paleotopographic surface, particularly to the east of the Athabasca, is undoubtedly related to salt solution, modified by subsequent post Devonian erosion processes. The presence of highly saline water in springs and in flowing wells along the Athabasca River suggests that the solution of the remaining salt to the west of the river is continuing today.

Project Area Evaluation

FIELD PROGRAMS

The geology of the Project Area leases has been interpreted primarily through the use of drilling data, and incorporates information from hydrological testing programs and from the excavation of a test pit on Lease 13.

Drilling

A total of 580 holes have been drilled in the Project Area – 400 on Lease 13 and 180 on Leases 12 and 34. Of these totals, 236 holes on Lease 13 are subsequent to those reported in the Shell Application (1973), and 39 are subsequent to those reported in the Application of the AOP Group relative to the Daphne area, in 1974. The pre and post Applications drilling programs are shown in Figure III-1, with the densely drilled test pit area shown in Figure III-2. Of the total drilling within the Project Area, approximately 70 percent of the holes are logged and 50 percent are cored. It was the Applicant's intent, in all of the evaluation drilling programs, to penetrate the entire potentially bitumen bearing section within the Cretaceous. Accordingly, virtually all of the holes shown on Figure III-1 were drilled either to the top of the Devonian or into the basal aquifer overlying the Devonian.

The post Applications drilling programs, which were completed in 1975, were designed to delineate orebodies and plant and tailings pond sites, and to provide more information on reserves, hydrology and stratigraphy for future mine planning. All of these holes were logged by Dual Laterolog and Gamma Ray and in addition, some of the programs included Compensated Density, Neutron Porosity, Borehole Compensated Sonic, Induction Electric and Caliper logs. In excess of one-third of the holes were cored and four were drilled to depths of 215 to 325 m (700 to 1075 ft) to the Middle Devonian and Precambrian.

The Applicant considers that the present drilling density within the Project Area is more than adequate for appraisal of the bitumen reserves, orebody limits and locations for tailings pond, plant site and other surface facilities. The well spacing within the 17 000 ha (42 000 acres) Project Area now averages 30 ha (75 acres) and ranges between 6 ha (16 acres) in the area of the proposed initial mining operations (Sec. 25 Twp 95 R. 10 W4M) and 65 ha (160 acres) in the surrounding areas. Statistical studies (Zwicky, 1977) have shown that the area of influence of each hole is about 475 ha (1170 acres) which indicates that the Project Area has been adequately appraised for the purpose of reserve determination. Further studies in the test pit area indicate that 10 to 15 ha (25 to 40 acres) spacing may be optimum for preliminary mine planning. On this basis, additional drilling will be required in the northern portion of the initial mine (Figure III-3). It is anticipated that further infill drilling will be required ahead of the actual mining operation.

In addition to the above drilling, 66 shallow holes were drilled to an average depth of 7 m (25 ft) for granular resources exploration and 56 holes (average depth 9 m) (30 ft) for soil testing. These holes were not wireline logged.

Test Pit

A test pit (Figure III-2) was excavated within the proposed mining area of Orebody No. 1 (Figure III-3) over a 12 month period in 1974-75. The test pit was excavated to a depth of 70 m (230 ft). The primary purpose of the test pit was to evaluate the feasibility of dragline mining. Specifically, slope stability, dewatering, mining equipment productivity and the effect of weathering on oil sand were investigated. In addition, the pit provided an opportunity for the first-hand examination of a portion of the stratigraphic section.

Hydrological Investigations

Shell continued field hydrological work at Lease 13 in each of the years 1973 through 1975 in order to determine aquifer characteristics and optimize future mine dewatering programs. This included the drilling of pump and observation wells in the vicinity of the mine, and the undertaking of an extensive dewatering program for the test pit. In addition, the Alberta Research Council has been monitoring three of Shell's hydrological holes in the test pit area, and in 1975 drilled new pump and observation holes at Lease 13 within a kilometre (0.6 mile) of the Project Area. The AOP group, in cooperation with the Research Council, initiated pump tests at two locations in Leases 12 and 34 in 1974. The locations of these programs are shown in Figure III-4.

PETROPHYSICAL STUDIES

Each of the Shell and AOP holes penetrating the McMurray formation within the Project Area has been evaluated by means of core analyses and/or wireline log data. These methods have been previously outlined in detail (pp 5 to 8, Shell, 1973). Based on data acquired since that time, however, the relationships of bitumen saturation and fines concentration to the wireline log values have been reviewed and updated.

Bitumen

A critical factor in the calculation of bitumen saturation from log resistivities is the resistivity of formation water. Extensive sampling of formation water resistivities has been carried out at Lease 13 in air drilled holes. Analyses of this data indicate both lateral and vertical variations in water resistivity. In general, resistivities tend to be higher in the eastern portion of the area, and in the shallower aquifers (reflecting fresher waters closer to recharge or source areas). For the purpose of log evaluation, resistivities were segregated into three categories related to depth:

* 1.5 to 5 ohm-m, mainly in the lower portion of the hole
* 6 to 14 ohm-m in the intermediate portion of the hole
* 15 plus ohm-m in the upper section.

Based on calibration with core analysis data, three relationships were developed for log resistivity vs percent bulk weight bitumen as shown in Figure III-5. In order to determine which of the relationships to use in a specific interval where water resistivity data was absent, a cross plot of gamma ray vs log resistivity was constructed (Figure III-6). This plot assumes that for comparable sand sections as delineated by the gamma ray curve that have constant bitumen saturation, any change in resistivity on the log is due to a change in the formation water resistivity. The position of a representative log interval on this plot then determined the appropriate resistivity vs bitumen relationship for the interval. The method was applied to all holes or intervals in the Project Area where core data was not available.

Figure III-7 illustrates a comparison of the percent bitumen as calculated from log data vs core analyses for all Lease 13 holes on which both types of analyses were available up to the winter 73/74 drilling program. This represents about 80 percent of the cored holes at Lease 13 and shows that the average bitumen content when determined by both log and core analyses, agrees within 0.4 percent bitumen. A comparison of log and core calculations in the Daphne area yielded similar results. The Applicant believes that this comparison of bitumen saturations in the mill feed on the basis of hole averages is justified because of the blending that will result from the mining, reclamation and transportation operations. In addition, it is evident because of the demonstrated consistency of results between the two techniques, that reserve estimations based on log data are essentially as reliable as those estimates based on core data.

Fines

Fines are defined as the clay and silt fraction less than 44 micrometres in size. The determination of fines in the mill feed is important because it affects the Extraction Plant utility requirements, recovery efficiency, and the bulking volume in the tailings pond.

The wet sieve analyses method has been found to be the most representative direct method for the measurement of fines. It is, however, very time consuming and therefore impractical for an overall evaluation. A fines to bitumen relationship (Figure III-8), is used to estimate fines concentration in the mill feed.

Local Geological Appraisal

The Applicant's interpretation of the geology in the Project Area is based primarily on the extensive drilling data, with an important contribution from observations in the test pit.

TEST PIT

The excavation of the test pit provided a unique opportunity to observe the upper 30 to 35 m (100 to 115 ft) of the McMurray formation in an area previously interpreted on the basis of well data.

Sedimentation

As observed in the exposures, and in the well data available in the test pit area, the upper 30 to 45 m (100 to 150 ft) of the geologic section consists of a series of thinly bedded oil sands and clays of 2 to 3 m (7 to 10 ft) in thickness. These units are relatively consistent in thickness and some are continuous over the entire 270 m (880 ft) length of the pit. An abrupt change in the sedimentary style takes place at the base of this interval where more massive and richer oil sands occur. Little of this lower section was observed because of talus buildup on the slope. The integration of the exposure and well data is shown on Figure III-9. Here, the deltaic environments of deposition range from inner fringe to lower deltaic plain in the lower 60 m (200 ft), with outer fringe to marine deposition in the upper 30 m (100 ft), perhaps separated by a disconformity. As would be expected, the average saturation in the bitumen bearing sands of the upper section is less than in the lower section (13 percent vs 15 percent total weight bitumen). In addition, it was found that bitumen saturation within individual beds is horizontally consistent in both sections within ± 1.5 percent. It has been concluded, therefore, that holes on a spacing of 10 to 15 ha (25 to 40 acres) apart are adequate for annual mine planning.

Structure

The predominant structure in the test pit is a contra-regional easterly dip of about five to eight degrees. No evidence of faulting was observed; however extensive jointing occurred in the oil sand layers as a result of stress release after excavation. The degree of jointing or fissuring did not appear to be a governing factor in the observed mode of slope failure. The geotechnical performance of the test pit slopes is discussed in Chapter V.

OTHER AREAS

Test pit observations and the study of well data in the pit area and in the remainder of the Project Area indicate that many individual oil sand units and clay layers of two or three metres (6 to 10 ft) in thickness are continuous for several hundreds of metres. This is illustrated in Figures III-10 and 11. Because of the complex nature of deltaic sedimentary processes, detailed examination of these individual units reveals multiple sand bodies with a variety of sedimentary structures. Although correlation of these smaller units would be difficult or impossible, the Applicant believes the thicker intervals cover extensive areas and therefore preliminary mine planning may be undertaken with confidence on the basis of the current evaluation.

Although regional dip is to the southwest, the attitude of the beds in the Project Area is controlled for the most part by the underlying Devonian paleotopographic surface, and perhaps to some extent, by a disconformity which underlies the upper, more marine section of the McMurray formation in most of the Project Area.

The rugged nature of the Devonian erosional surface in the Project Area is fundamentally controlled by the collapse of younger Devonian beds due to the solution of Middle Devonian salt. This salt solution is believed to have occurred in both Devonian and Cretaceous times, and has influenced the deposition of Cretaceous sediments. Six deep holes (total depths – 215 to 345 m) (705 to 1130 ft) have been drilled to the Middle Devonian and Precambrian within the Project Area (Figure III-4). Of the five holes drilled on Lease 13, one (No. 1717) was drilled on a Devonian high to investigate the possibility that this feature was caused by a remnant of Middle Devonian salt. As salt was not encountered at any of the locations, it is considered improbable that massive salt occurs within the Project Area.

Local Hydrological Appraisal

The primary aquifer in the Project Area is located at the base of the bitumen bearing interval in the McMurray formation (Figures III-9, III-10 and III-11). This reservoir is a medium to coarse grained, unconsolidated sand with minor bitumen content (generally less than three percent total weight). It occupies the lower 15 to 60 m (50 to 200 ft) of the McMurray with an average net sand development of about 15 m (50 ft). Its distribution is controlled primarily by the underlying eroded surface of the Devonian, which in this vicinity, consists of shale and limestone and may, itself, occasionally constitute an aquifer.

Because the basal aquifer contains significant volumes of water under artesian conditions, it must be depressured prior to mining. It was determined during the excavation of the test pit that this can be accomplished by means of pump wells, which will lower the hydrostatic head below the base of the mine. All of the Cretaceous waters are relatively fresh, generally having a total dissolved solids content of less than 4500 mg/L.

A shallow aquifer occurs in the surface sands and gravels. No problem is anticipated in dewatering this reservoir by means of drainage ditches. Minor aquifers occur in thin sand units interbedded with the oil sands. When these intra orebody aquifers are encountered during mining, the water will be allowed to run to the pit bottom where it will be removed by sump pumps.

The Middle Devonian Methy carbonates contain a major saline aquifer some 100 m (330 ft) below the top of the Devonian. The Methy reservoir reaches a maximum thickness of about 20 m (65 ft), capped by 30 to 40 m (100 to 130 ft) of impermeable Prairie Evaporite (anhydrite, gypsum, carbonate and shale), based on deep drilling on Leases 12 and 13. Consideration of all the geological, hydrological and geochemical data indicates that there is no hydraulic connection between the Cretaceous and Middle Devonian aquifers in the Project Area.

Further details on these aquifers as they relate to mining operations are given in Chapter V.

The following table summarizes aquifer water quality in the Project Area:

AQUIFER WATER QUALITY
Maximum Observed Concentrations (mg/L)

	CHLORIDE ION	TOTAL DISSOLVED SOLIDS
Shallow Aquifer	145	849
Intra Orebody Aquifer	67	2 148
Basal Aquifer	1 285	4 158
Methy Aquifer	10 947	22 544

TEST PIT DEWATERING PROGRAM

The hydrostatic head of the basal McMurray aquifer is within five metres (16 ft) of the surface. It was therefore necessary to depressure this unit prior to excavation of the test pit, to prevent an influx of groundwater and to assure bank stability. This was successfully completed over a period of 12 months with a maximum of six pump wells at a peak rate of 45 L/s (700 USGPM); however the major drawdown was accomplished with only three wells. During this time, the static head of the basal aquifer in the test pit area was lowered to below the base of the pit and maintained at that level for a period of five months to allow completion of the excavation. A drawdown of 30 m (100 ft) was observed 1220 m (4000 ft) north of the test pit. The fourteen observation wells indicated maximum drawdown of 70 m (230 ft) in the western portion of the area with a more limited effect to the east because of restricted aquifer development (Figure III-9). Drawdown in excess of 25 m (80 ft) has been observed over an area of at least 100 ha (250 acres) (Figure III-12). It has been shown that although the basal aquifer is not continuous, there are zones of sufficient permeability, perhaps associated with the underlying Devonian surface, that it may be considered hydraulically as a single aquifer over large areas.

The hydrostatic head of the Methy aquifer is 18 m (60 ft) below that of the basal McMurray aquifer, thus indicating there is no hydraulic communication. However, excavation of the test pit below the Methy head provided the opportunity for an influx of saline Devonian water, should fracturing or faulting have provided access through the otherwise impermeable sequence between the Methy and McMurray aquifers. No evidence of Devonian water has been observed during the extensive monitoring operations. In addition, piezometers installed in the Methy and observed continuously during the basal aquifer depressuring operations in the test pit area showed no response to pumping from the McMurray.

The Applicant has therefore concluded that there is little likelihood of an influx of water from the Middle Devonian into the proposed mining operations.

OTHER AREAS

The Alberta Research Council conducted drawdown tests at the Cretaceous — Devonian boundary in Lsd 2, Section 18, Township 95, Range 9, W4M, some 4 km (2.5 miles) southeast of the test pit (Figure III-4). This formed a part of the Council's regional observation well network. It was observed that when the basal McMurray aquifer was drawn down some 30 m (100 ft), a small drawdown (about 2 m — 7 ft) was observed in the Beaverhill Lake section at the top of the underlying Devonian. This tends to support the possibility of a more or less hydraulically continuous aquifer in the adjoining Cretaceous and uppermost Devonian sediments.

At two locations on Leases 12 and 34 (Figure III-4), the Research Council conducted pump tests in the basal McMurray aquifer. Observed salinities were in the range of those in the test pit area, 6.5 km (4 miles) to the south east (1750 to 2500 mg/L total dissolved solids), and were observed to be decreasing at the end of the pump tests. The Research Council concluded that the necessary drawdown to permit mining operations in the area could be accomplished in about one year (Hackbarth, 1974).

Resource Appraisal

OVERVIEW

The Project Area contains an estimated total of 1300×10^6 m^3 (8100×10^6 Bbl) of bitumen in place (to zero percent bitumen saturation), above the Devonian. Of this total, 700×10^6 m^3 (4400×10^6 Bbl) are considered to be mineable from three orebody complexes, based on current technology and assumed economics. The orebodies as defined are shown in Figure III-3. More detailed study of the orebody areas beyond the limits of the first mine, utilizing other mining methods or future technology and economics, may indicate higher mining recoveries. The amount of bitumen which may ultimately be recovered is primarily dependent on economic factors and is subject to the limitations of the recovery techniques and mining equipment used. A method of applying these considerations to the petrophysical data in order to obtain a detailed vertical and horizontal evaluation of the lease holdings has therefore been developed.

RESERVES EVALUATION METHOD

With the use of a computerized calculation method developed by Shell Canada Resources, which incorporates estimates of Mining and Extraction costs and equipment limitations, together with a forecasted synthetic crude oil price, the net value of the bitumen in each tar bearing interval has been calculated within a standard (200 m – 660 ft) grid. The value of each grid or cell may then be calculated, and the orebody areas defined by those groups of cells with positive values and comprising areas of sufficient size for mining operations. For details of this evaluation procedure, refer to Chapter V.

The size of an orebody and the mineable reserves will vary, dependent on the total project economics, and therefore the evaluation must be reviewed periodically.

The current evaluation is based on a combined one and two bench open pit dragline mining system as detailed in Chapter V.

RESERVE DETAIL

The application of the economic program to the individual well data is shown on Table III-1. This table lists all holes in the Project Area on which usable data is available, excluding certain duplicate holes. Thickness and bitumen grades are included for each of the major categories in a typical borehole, as follows:

Overburden – all material above the top of the economic orebody.

Mill Feed – all material economically mineable within the constraints of the planned mining system.

Centre Reject – all material below the overburden and above the base of the orebody that is not mill feed.

Residual Mill Feed – mill feed that lies below the maximum depth that can be reached with the planned mining scheme.

Bottom Reject – all non-economically mineable material which lies below the base of the orebody.

Waste/Ore Ratio – the volumetric ratio of overburden plus centre reject to the mill feed.

Value — the net value of the bitumen in the borehole, expressed as $/m², after deduction of all mining and extraction costs.

The various parameters from this table are illustrated on the following contour maps:

Figure III-13 — *Overburden Thickness*
Figure III-14 — *Mill Feed Thickness*
Figure III-15 — *Mill Feed Grade*
Figure III-16 — *Depth of Base Mineable*
Figure III-17 — *Waste/Ore Ratio*
Figure III-18 — *Value*

The individual well parameters were then combined into the grid system to define the orebody areas and reserves as shown in Table III-2 and outlined on Figure III-3.

The proposed initial Mine, Extraction Plant and support facilities have been designed to produce 25 040 m³/d (157 500 B/D) of bitumen to Upgrading for 25 years. As shown in Table III-3, the overall mining recovery of 77 percent volume is affected significantly by the relatively low recovery in Block 4 (57 percent) compared to the recoveries in the other blocks (78 to 89 percent). (See Figure V-3 for definition of blocks.) This is explained by the relatively large amount of bottom reject in Block 4 and the thinly bedded upper section as illustrated in Figure III-10. Many of these thin beds are not economically mineable due to the preponderance of intervening thick waste beds.

The bitumen losses within the area of the initial mine will occur in the following categories:

Overburden	7×10^6 m³	(45×10^6 Bbl)
Centre Reject	19×10^6 m³	(120×10^6 Bbl)
Residual Mill Feed	8×10^6 m³	(50×10^6 Bbl)
Bottom Reject	40×10^6 m³	(250×10^6 Bbl)

The in-place bitumen reserves underlying the plant site (28×10^6 m³ — 180×10^6 Bbl), under the tailings pond, (139×10^6 m³ — 870×10^6 Bbl), and in the planned utility corridor (5×10^6 m³ — 30×10^6 Bbl), are not economically mineable by any current or foreseeable method. These areas contain relatively low bitumen reserves with high waste/ore ratios (2.0-2.4).

The question of off-lease tailings disposal to areas devoid of bitumen has also been reviewed and is discussed in Chapter VII.

TABLE III-1-1

BORE HOLE DATA
MINE AREA — SINGLE BENCH

HOLE NO	LSD	SEC	TWP	RGE	MER	OVERBURDEN THK M	OVERBURDEN BIT %	MINE MILL FEED THK M	MINE MILL FEED BIT %	CENTRE REJECT THK M	CENTRE REJECT BIT %	RESIDUAL MILL FEED THK M	RESIDUAL MILL FEED BIT %	BOTTOM REJECT THK M	BOTTOM REJECT BIT %	WASTE/ORE RATIO (VOL)	VALUE $/M2
1014	13	25	95	10	4	10.0	.0	54.0	14.6	.0	.0	.0	.0	14.7	1.2	.18	54.7
1016	16	30	95	9	4	23.7	.0	26.0	11.3	.0	.0	.0	.0	42.0	.4	.91	10.3
1026	16	25	95	10	4	2.5	.0	58.2	14.9	9.2	1.0	13.7	9.6	33.4	2.0	.20	59.8
1032	16	35	95	10	4	18.5	.0	29.0	13.9	.0	.0	.0	.0	39.7	1.5	.63	23.4
1033	10	36	95	10	4	18.5	1.6	37.2	12.7	5.7	5.4	.0	.0	19.0	1.8	.65	20.4
1041	10	31	95	9	4	36.5	.2	9.0	10.0	.0	.0	.0	.0	67.2	1.4	4.05	-10.7
1052	14	25	95	10	4	9.2	.0	40.7	13.8	12.7	3.2	.0	.0	36.5	1.0	.54	29.9
1114	3	31	95	9	4	14.2	4.0	5.2	8.0	.0	.0	.0	.0	77.5	4.2	2.71	-2.7
1134	4	32	95	9	4	31.0	4.7	11.7	13.5	.0	.0	.0	.0	48.7	.3	2.63	1.6
1212	15	36	95	10	4	15.5	.0	41.7	13.0	.0	.0	.0	.0	9.2	.8	.37	30.8
1213	2	35	95	10	4	31.0	.3	21.5	13.4	7.5	5.3	.0	.0	13.2	3.1	1.79	-1.2
1227	8	36	95	10	4	17.0	.0	48.7	12.8	.0	.0	15.7	9.4	7.5	3.9	.34	33.0
1228	12	36	95	10	4	6.0	.0	49.7	11.6	4.5	6.0	.0	.0	11.5	3.7	.21	29.0
1229	10	35	95	10	4	9.2	.0	56.3	13.1	4.5	5.7	15.2	10.7	1.5	.0	.24	42.5
1320	14	30	95	9	4	24.7	.0	17.0	11.4	.0	.0	.0	.0	62.0	3.5	1.45	4.5
1321	6	31	95	9	4	5.0	6.4	29.2	11.3	17.2	4.4	.0	.0	10.0	5.7	.76	12.7
1322	8	31	95	9	4	6.0	.0	12.2	10.1	.0	.0	.0	.0	80.0	3.0	.49	3.2
1324	6	32	95	9	4	6.0	.0	28.5	12.8	11.2	3.8	.0	.0	67.0	.8	.60	18.5
1326	10	32	95	9	4	2.5	.0	33.2	14.4	.0	.0	.0	.0	15.5	1.9	. 7	33.7
1327	12	32	95	9	4	5.0	.0	5.2	10.8	.0	.0	.0	.0	92.5	3.2	.95	1.5
1328	14	32	95	9	4	6.0	.0	19.7	11.4	12.0	2.7	.0	.0	7.0	2.3	.91	8.1
1367	16	25	95	10	4	9.7	1.6	49.0	11.4	11.2	5.6	2.5	10.3	23.5	3.4	.42	18.9
1370	16	26	95	10	4	9.2	.0	54.2	11.0	4.5	4.0	.0	.0	13.5	1.9	.25	26.1
1371	1	35	95	10	4	21.0	2.4	40.2	13.1	.0	.0	.0	.0	2.2	.0	.52	27.2
1374	8	35	95	10	4	13.7	.0	51.7	10.3	.0	.0	.0	.0	12.2	3.1	.26	20.9
1375	9	35	95	10	4	3.0	.0	51.5	12.6	5.7	2.6	.0	.0	21.5	1.0	.17	38.1
1376	1	36	95	10	4	4.2	.0	55.7	11.4	10.0	3.2	15.2	10.0	19.0	4.2	.25	29.0
1377	2	36	95	10	4	12.7	.0	25.0	10.3	18.2	5.6	.0	.0	34.0	2.4	1.24	-2.1
1378	6	36	95	10	4	13.7	.0	40.2	12.1	6.7	2.9	.0	.0	21.0	1.5	.50	21.6
1379	10	36	95	10	4	8.2	.9	46.7	12.1	12.7	6.0	.0	.0	4.7	1.4	.44	24.0
1380	16	36	95	10	4	30.2	3.9	32.7	12.1	.0	.0	.0	.0	16.2	2.1	.92	8.4
1402	13	30	95	9	4	6.0	.0	22.7	12.1	22.2	3.2	.0	.0	58.0	3.1	1.24	6.6
1403	13	30	95	9	4	12.2	1.6	36.7	10.5	5.2	6.3	.0	.0	55.5	1.9	.47	12.7
1404	1	31	95	9	4	5.5	.0	6.0	10.8	.0	.0	.0	.0	110.5	4.3	.91	1.5
1405	2	31	95	9	4	7.5	1.0	18.2	11.4	13.5	3.3	.0	.0	59.7	3.7	1.15	6.0
1406	5	31	95	9	4	5.2	.0	40.2	11.7	24.5	4.1	3.2	9.2	15.2	2.5	.73	8.5
1407	7	31	95	9	4	6.7	1.6	34.0	11.4	9.0	5.9	.0	.0	33.5	1.2	.46	16.6
1408	11	31	95	9	4	3.0	.0	46.7	11.9	20.2	4.5	4.2	12.6	9.5	2.6	.49	19.1
1409	13	31	95	9	4	4.2	.0	47.7	11.9	17.5	5.9	.0	.0	14.2	2.8	.45	21.8
1410	14	31	95	9	4	1.7	.0	36.5	11.3	19.7	4.3	.0	.0	21.2	3.2	.58	14.3
1434	10	25	95	10	4	3.0	.0	42.7	11.0	24.2	5.4	11.0	8.9	16.5	1.7	.63	7.3
1436	11	25	95	10	4	16.2	3.4	43.2	10.9	5.7	5.7	.0	.0	7.2	3.2	.50	14.2
1437	12	25	95	10	4	7.2	.0	55.2	12.8	4.5	5.5	.0	.0	1.3	.0	.21	40.1
1438	13	25	95	10	4	4.2	.0	64.0	12.3	.0	.0	.0	.0	7.0	.0	. 6	44.6
1439	15	25	95	10	4	8.5	.0	56.7	12.5	.0	.0	10.5	10.7	17.0	4.2	.15	38.9
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4	5.0	.0	34.5	9.6	5.5	6.9	.0	.0	41.7	2.2	.30	8.5

TABLE III-1-i (cont'd)

BORE HOLE DATA
MINE AREA — SINGLE BENCH

HOLE NO	LSD	SEC	TWP	RGE	MER	OVERBURDEN THK M	OVERBURDEN BIT %	MINE MILL FEED THK M	MINE MILL FEED BIT %	CENTRE REJECT THK M	CENTRE REJECT BIT %	RESIDUAL MILL FEED THK M	RESIDUAL MILL FEED BIT %	BOTTOM REJECT THK M	BOTTOM REJECT BIT %	WASTE/ORE RATIO (VOL)	VALUE $/M2
1441	15	25	95	10	4	6.0	.0	45.7	11.6	18.2	5.0	10.5	9.6	17.0	2.1	.53	15.3
1461	1	35	95	10	4	16.5	.0	39.5	12.5	.0	.0	.0	.0	12.5	2.5	.41	25.2
1464	7	35	95	10	4	26.2	1.9	33.0	11.1	.0	.0	.0	.0	18.5	1.6	.79	7.4
1466	9	35	95	10	4	24.7	2.7	30.7	13.7	.0	.0	.0	.0	22.2	1.4	.80	19.6
1469	16	35	95	10	4	21.0	2.5	23.5	10.8	.0	.0	.0	.0	41.7	2.7	.89	7.4
1470	13	35	95	10	4	8.5	.0	48.2	12.1	13.2	1.8	5.0	9.7	16.5	2.0	.45	22.8
1471	1	36	95	10	4	5.5	.0	55.2	12.0	9.2	2.6	25.7	11.6	6.3	.0	.26	33.2
1472	1	36	95	10	4	5.5	.0	64.5	11.5	.0	.0	9.2	13.4	15.2	1.0	. 8	37.5
1473	3	26	95	10	4	8.0	.0	39.7	10.2	17.2	6.0	.0	.0	23.5	2.6	.63	5.0
1474	3	36	95	10	4	8.5	.0	53.5	11.3	4.5	5.6	.0	.0	20.2	1.6	.24	27.3
1475	4	36	95	10	4	5.5	.0	57.2	12.0	5.0	7.3	.0	.0	7.0	.0	.18	36.4
1476	6	36	95	10	4	5.2	3.0	4.5	9.5	.0	.0	.0	.0	77.0	4.6	1.16	.1
1477	7	36	95	10	4	14.2	2.6	38.0	11.9	17.7	5.0	13.7	13.3	3.8	.0	.84	6.8
1479	8	36	95	10	4	4.2	1.8	36.2	10.7	29.5	3.2	18.5	12.2	4.5	.0	.93	-2.0
1481	11	36	95	10	4	5.7	.0	34.0	12.8	12.0	5.1	.0	.0	37.5	1.9	.52	23.0
1484	16	36	95	10	4	25.0	4.7	39.0	12.2	.0	.0	.0	.0	9.2	3.7	.64	18.2
1497	7	36	95	10	4	20.5	3.0	27.0	12.4	5.5	6.3	.0	.0	21.7	2.8	.96	11.6
1498	7	36	95	10	4	4.2	.0	47.7	12.6	18.0	3.7	13.0	12.3	3.5	.0	.46	26.5
1510	10	25	95	10	4	9.2	.0	43.0	10.6	17.7	2.4	7.5	11.6	20.0	2.0	.62	6.1
1518	15	26	95	10	4	25.0	1.2	36.0	11.6	.0	.0	.0	.0	12.7	1.3	.69	11.9
2309	2	2	96	10	4	8.5	.0	57.0	12.0	4.5	3.6	18.8	9.5	15.5	2.5	.22	34.6
2310	2	1	96	10	4	7.2	.0	51.2	11.2	4.5	6.1	.0	.0	8.2	1.4	.22	26.5
2311	4	6	96	9	4	8.5	.4	46.0	11.7	4.7	6.6	.0	.0	6.3	.0	.28	26.1
2312	2	6	96	9	4	8.0	.0	40.0	10.9	16.2	4.5	.0	.0	8.2	.0	.60	10.2
2313	4	5	96	9	4	8.5	.0	38.7	11.1	4.7	5.6	.0	.0	27.7	2.1	.34	18.9
2314	2	5	96	9	4	12.2	.0	13.5	9.8	11.5	3.6	.0	.0	30.0	4.0	1.75	-.6
2315	12	1	96	10	4	6.0	.0	41.7	13.6	22.2	1.5	13.2	8.5	38.2	1.6	.67	22.9
2316	12	6	96	9	4	8.5	.6	38.5	12.1	9.7	3.0	.0	.0	4.7	.0	.47	22.3
2317	12	5	96	9	4	8.8	.0	18.2	13.2	15.7	3.7	.0	.0	31.0	4.4	1.34	10.2
2322	2	7	96	9	4	11.5	.3	26.2	11.2	10.5	.1	.0	.0	40.2	2.6	.83	9.9
2323	4	8	96	9	4	12.7	.0	33.0	10.7	11.5	3.9	.0	.0	43.8	2.8	.73	7.9
2324	2	8	96	9	4	10.2	.0	9.2	11.5	.0	.0	.0	.0	108.2	4.7	1.10	3.0
2418	10	2	96	10	4	11.5	.1	4.5	7.5	.0	.0	.0	.0	113.7	3.4	2.55	-2.2
2953	6	1	96	10	4	32.5	1.2	32.5	13.0	.0	.0	.0	.0	3.2	.1	1.00	9.8
2954	6	6	96	9	4	19.7	.1	11.7	10.8	4.5	2.3	.0	.0	3.0	.0	2.06	.4
2966	1	12	96	10	4	14.7	.1	10.2	10.9	.0	.0	.0	.0	51.2	.2	1.43	2.1

TABLE III-1 (cont'd)

BORE HOLE DATA
MINE AREA — DOUBLE BENCH

HOLE NO	LSD	SEC	TWP	RGE	MER	OVERBURDEN THK M	OVERBURDEN BIT %	MINE MILL FEED THK M	MINE MILL FEED BIT %	CENTRE REJECT THK M	CENTRE REJECT BIT %	RESIDUAL MILL FEED THK M	RESIDUAL MILL FEED BIT %	BOTTOM REJECT THK M	BOTTOM REJECT BIT %	WASTE/ORE RATIO (VOL)	VALUE $/M2
1027	6	26	95	10	4	9.5	.0	32.2	12.6	25.0	2.7	.0	.0	12.0	.3	1.07	-.8
1051	6	25	95	10	4	3.0	.0	51.5	12.5	19.7	1.4	.0	.0	32.5	1.7	.44	29.2
1119	2	26	95	10	4	38.7	.7	15.7	12.4	19.7	.8	.0	.0	10.7	2.2	3.71	-24.4
1180	2	25	95	10	4	1.5	.0	56.5	11.8	14.7	3.1	.0	.0	18.8	2.7	.28	29.1
1181	12	24	95	10	4	8.5	.0	48.7	11.5	16.2	1.1	.0	.0	18.0	1.4	.50	16.5
1182	9	26	95	10	4	11.5	.0	52.0	12.7	.0	.0	.0	.0	17.0	3.5	.22	27.7
1233	10	25	95	10	4	5.5	.0	50.2	10.8	29.5	4.3	.0	.0	2.2	.0	.69	6.7
1234	10	25	95	10	4	9.7	.0	52.7	11.6	10.7	5.9	.0	.0	15.2	3.1	.38	15.0
1235	10	25	95	10	4	5.5	.0	41.7	10.8	29.0	3.3	.0	.0	18.2	4.8	.82	3.6
1359	14	24	95	10	4	4.5	.0	38.2	9.8	23.0	3.3	.0	.0	20.7	1.9	.71	-1.6
1362	4	25	95	10	4	4.2	.0	42.5	13.5	.0	.0	.0	.0	34.0	1.1	.10	32.2
1363	5	25	95	10	4	13.5	3.3	56.3	12.3	.0	.0	.0	.0	6.3	2.9	.24	28.0
1364	9	25	95	10	4	9.2	.0	64.2	11.6	10.5	5.7	.0	.0	12.0	1.8	.30	24.6
1365	10	25	95	10	4	3.0	.0	46.7	11.5	20.0	3.7	.0	.0	24.2	2.0	.49	16.5
1366	12	25	95	10	4	8.2	3.4	53.2	13.1	11.0	2.6	.0	.0	7.0	.0	.36	33.3
1368	10	26	95	10	4	14.0	3.4	49.2	11.3	.0	.0	.0	.0	8.0	.0	.32	13.6
1401	12	30	95	9	4	3.0	.0	43.2	11.6	.0	.0	.0	.0	45.2	2.8	.6	22.7
1411	15	23	95	10	4	1.3	.0	59.5	13.2	15.2	3.8	.0	.0	9.7	.0	.27	32.7
1412	16	23	95	10	4	37.2	.9	31.7	13.3	.0	.0	.0	.0	18.8	3.6	1.17	-3.6
1416	13	24	95	10	4	9.2	.0	44.2	12.5	22.0	3.4	.0	.0	19.0	1.8	.70	17.1
1417	13	24	95	10	4	4.2	.0	61.0	12.7	10.2	3.0	.0	.0	19.0	2.8	.23	37.2
1418	14	24	95	10	4	4.2	1.9	58.7	9.9	15.7	3.1	.0	.0	1.0	.0	.34	7.1
1419	15	24	95	10	4	5.5	.0	41.2	11.1	28.0	2.9	.0	.0	13.7	3.1	.81	6.5
1421	2	25	95	10	4	2.5	.4	50.7	11.5	32.7	3.6	.0	.0	2.5	.0	.69	12.5
1422	1	25	95	10	4	8.5	2.7	59.7	12.1	4.5	6.9	.0	.0	5.5	2.0	.21	31.2
1423	2	25	95	10	4	4.2	.7	57.2	11.6	11.7	4.1	.0	.0	10.0	4.4	.27	26.7
1424	3	25	95	10	4	9.7	3.8	38.5	11.2	22.5	2.5	.0	.0	22.2	2.2	.83	2.8
1425	3	25	95	10	4	5.5	.0	58.7	12.8	8.2	5.6	.0	.0	16.0	.9	.23	37.0
1426	4	25	95	10	4	5.0	.0	48.0	11.2	22.5	3.8	.0	.0	13.0	1.3	.57	11.4
1427	4	25	95	10	4	6.0	.0	61.2	13.0	5.0	5.6	.0	.0	14.5	1.0	.18	40.0
1428	5	25	95	10	4	2.2	.0	59.2	13.1	.0	.0	.0	.0	10.2	.0	. 3	43.4
1429	6	25	95	10	4	4.5	.0	58.7	12.4	13.5	3.4	.0	.0	16.2	.7	.30	31.4
1430	6	25	95	10	4	3.0	.0	54.7	11.9	23.2	4.3	.0	.0	6.7	.0	.47	21.5
1433	8	25	95	10	4	3.8	.0	70.5	12.5	5.5	6.2	.0	.0	11.7	.2	.13	41.4
1435	11	25	95	10	4	19.5	3.1	52.5	12.6	.0	.0	.0	.0	10.2	1.1	.37	23.2
1442	1	26	95	10	4	11.5	5.4	62.2	11.7	5.5	2.2	.0	.0	14.7	1.6	.27	24.9
1447	7	26	95	10	4	15.7	2.9	51.2	12.8	.0	.0	.0	.0	10.7	.0	.30	24.0
1448	8	26	95	10	4	6.7	.0	66.5	13.2	11.5	3.7	.0	.0	5.2	.0	.27	45.2
1449	8	26	95	10	4	2.2	2.7	68.8	12.5	9.2	5.5	.0	.0	5.0	.0	.16	41.6
1485	12	25	95	10	4	17.0	.0	51.7	13.7	9.0	2.3	.0	.0	2.7	.4	.50	29.3
1489	16	23	95	10	4	36.5	1.6	36.2	13.1	8.2	5.7	.0	.0	.0	.0	1.23	-4.0
1490	10	25	95	10	4	9.2	.0	57.7	12.0	7.0	5.0	.0	.0	5.7	1.9	.28	23.0
1491	10	25	95	10	4	12.7	3.6	56.7	11.7	5.2	6.3	.0	.0	22.7	2.2	.31	21.3
1492	10	25	95	10	4	13.7	1.2	76.0	12.5	.0	.0	2.0	10.0	5.5	.0	.18	41.8
1493	9	25	95	10	4	5.5	.4	58.2	13.7	7.0	5.0	.0	.0	8.5	.1	.21	41.1
1494	9	25	95	10	4	2.7	.4	66.0	12.3	6.0	4.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

BORE HOLE DATA
MINE AREA — DOUBLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
						THK	BIT	THK	BIT	THK	BIT	THK	BIT	THK	BIT	RATIO	VALUE
HOLE NO	LSD	SEC	TWP	RGE	MER	M	%	M	%	M	%	M	%	M	%	(VOL)	$/M2
1495	10	25	95	10	4	5.2	1.1	51.7	12.2	13.7	5.5	.0	.0	13.0	4.9	.36	21.5
1511	10	25	95	10	4	9.2	.0	57.7	10.8	6.7	7.4	.0	.0	17.5	1.7	.27	12.0
1512	10	25	95	10	4	9.2	.0	53.7	10.6	14.5	5.4	.0	.0	14.2	2.3	.44	8.4
2320	2	11	96	10	4	7.5	.0	41.2	13.5	25.5	5.4	.0	.0	44.0	1.8	.80	13.4
2321	2	12	96	10	4	6.0	.0	63.2	12.4	4.5	6.0	.0	.0	16.2	.0	.16	36.8
2327	12	12	96	10	4	11.0	.0	61.2	12.6	.0	.0	4.5	7.3	44.2	3.3	.18	35.0
2328	12	7	96	9	4	9.2	.0	47.2	11.3	28.0	5.1	.0	.0	35.5	1.9	.78	7.0
2413	1	11	96	10	4	35.7	2.1	37.0	14.5	.0	.0	.0	.0	11.2	.3	.96	7.5
2928	6	12	96	10	4	18.2	.0	37.0	13.0	16.5	1.3	.0	.0	2.5	3.6	.93	9.9

TABLE III-1-ii

BORE HOLE DATA
OTHER OREBODY #1 — SINGLE BENCH

HOLE NO	LSD	SEC	TWP	RGE	MER	OVERBURDEN THK M	OVERBURDEN BIT %	MINE MILL FEED THK M	MINE MILL FEED BIT %	CENTRE REJECT THK M	CENTRE REJECT BIT %	RESIDUAL MILL FEED THK M	RESIDUAL MILL FEED BIT %	BOTTOM REJECT THK M	BOTTOM REJECT BIT %	WASTE/ORE RATIO (VOL)	VALUE $/M2
1015	3	33	95	10	4	25.0	.0	45.0	12.7	.0	.0	1.3	7.7	6.7	2.6	.55	20.3
1022	11	22	95	10	4	11.5	1.1	34.0	10.9	16.7	5.0	.0	.0	9.7	.9	.83	4.7
1037	16	20	95	9	4	3.0	.0	28.5	12.1	25.0	2.9	.0	.0	33.5	.2	.98	8.4
1042	9	32	95	9	4	2.5	.0	38.5	12.8	15.7	3.3	.0	.0	6.0	.0	.47	26.2
1054	2	29	95	9	4	3.0	.0	42.2	11.3	19.0	2.5	.0	.0	74.5	.1	.52	15.2
1131	2	30	95	9	4	12.0	2.7	24.7	11.5	12.7	1.3	.0	.0	42.0	1.0	1.00	8.9
1132	10	29	95	9	4	22.5	.3	24.2	9.9	.0	.0	.0	.0	14.2	3.1	.92	3.8
1133	2	32	95	9	4	4.0	.0	28.0	11.8	4.5	6.1	.0	.0	24.5	3.6	.30	16.6
1171	2	20	95	9	4	25.5	.0	21.5	14.5	.0	.0	.0	.0	41.7	4.9	1.18	16.2
1192	12	29	95	9	4	11.5	1.4	51.5	12.8	5.0	5.2	.0	.0	23.5	.0	.32	35.6
1211	4	35	95	10	4	12.5	.0	39.5	10.7	18.0	4.7	.0	.0	8.2	1.0	.77	2.5
1223	4	20	95	9	4	17.7	.0	23.7	11.1	.0	.0	.0	.0	43.0	4.0	.74	9.0
1224	12	20	95	9	4	22.7	.0	24.0	11.5	4.5	6.0	.0	.0	34.7	3.1	1.13	5.3
1225	10	20	95	9	4	25.5	2.1	33.0	12.4	11.5	.4	.0	.0	6.0	2.9	1.12	3.0
1226	14	35	95	10	4	1.5	.0	43.8	13.6	24.7	4.3	4.7	9.8	8.5	5.8	.60	25.5
1311	4	29	95	9	4	17.2	.0	28.2	12.2	.0	.0	.0	.0	39.7	.1	.61	16.7
1312	6	29	95	9	4	15.2	.0	22.2	12.4	.0	.0	.0	.0	64.5	3.7	.68	13.6
1313	14	29	95	9	4	28.7	2.4	39.5	11.8	.0	.0	.0	.0	4.0	.0	.72	10.4
1314	16	29	95	9	4	17.5	.0	30.0	10.7	10.7	4.4	.0	.0	33.2	.6	.94	3.3
1317	8	30	95	9	4	14.7	.5	42.5	12.8	.0	.0	.0	.0	32.7	2.4	.34	30.6
1318	10	30	95	9	4	7.2	.0	27.0	11.2	20.0	5.6	.0	.0	37.2	5.1	1.00	5.8
1323	12	31	95	9	4	19.7	.0	44.0	12.0	6.3	4.1	9.0	13.1	4.7	.0	.59	16.6
1325	8	32	95	9	4	11.2	.0	30.7	11.0	19.0	1.6	.0	.0	25.7	3.1	.98	2.9
1330	12	33	95	9	4	19.2	.0	20.0	10.7	.0	.0	.0	.0	5.7	4.5	.96	5.8
1369	13	26	95	10	4	31.5	1.4	38.0	13.2	.0	.0	.0	.0	5.5	1.3	.82	15.3
1372	5	35	95	10	4	16.2	2.1	4.7	10.6	.0	.0	.0	.0	66.7	4.7	3.42	-1.4
1373	6	35	95	10	4	42.7	2.4	21.5	13.7	.0	.0	.0	.0	8.2	2.3	1.98	-5.0
1443	3	26	95	10	4	31.0	2.7	13.5	13.5	.0	.0	.0	.0	40.7	5.1	2.29	2.7
1454	14	26	95	10	4	7.0	4.4	51.2	11.4	4.5	7.1	.0	.0	9.0	3.3	.22	27.9
1462	3	35	95	10	4	19.7	.0	35.7	12.1	4.5	6.8	.0	.0	17.7	1.9	.67	15.7
1463	5	35	95	10	4	2.5	.0	40.2	11.7	27.2	3.2	2.0	10.2	10.2	.8	.73	8.9
1465	7	35	95	10	4	9.7	.5	49.0	14.5	.0	.0	.0	.0	14.5	.1	.19	48.0
1467	11	35	95	10	4	15.7	2.6	45.7	11.0	8.5	2.0	2.0	7.9	18.0	3.2	.53	11.5
1468	12	35	95	10	4	1.5	.0	39.0	12.2	29.5	4.1	9.2	8.6	10.7	3.4	.79	10.2
1478	7	36	95	10	4	5.5	.0	39.2	13.3	25.2	3.4	11.0	13.0	7.5	2.2	.78	16.7
1480	9	36	95	10	4	39.0	2.0	25.5	13.5	4.5	5.1	.0	.0	31.5	3.6	1.70	-4.2
1506	8	27	95	10	4	8.8	2.0	45.5	13.1	12.7	3.3	.0	.0	7.2	2.8	.47	29.4
1507	5	34	95	10	4	15.7	1.7	36.7	10.9	17.5	4.3	13.2	15.0	8.2	.4	.90	-.1
1517	11	26	95	10	4	27.5	1.9	26.7	12.7	9.2	5.1	.0	.0	13.5	1.0	1.37	.3
1520	8	34	95	10	4	31.0	3.7	39.0	12.3	.0	.0	7.5	12.3	9.7	.0	.79	10.5
1521	16	22	95	10	4	22.0	1.1	45.7	12.6	.0	.0	.0	.0	10.0	.0	.48	25.0
1522	16	27	95	10	4	22.0	1.6	16.5	11.1	.0	.0	.0	.0	44.0	6.1	1.33	3.8
1717	4	23	95	10	4	30.5	.8	33.0	12.4	.0	.0	.0	.0	6.5	.4	.92	8.8
1723	13	33	95	10	4	10.2	.0	49.0	13.4	10.7	1.6	3.2	13.7	10.5	.0	.42	32.3
1724	15	33	95	10	4	20.7	1.8	23.2	9.7	4.7	.6	.0	.0	47.7	3.5	1.09	1.8
1725	[illegible]	34	95	10	4	9.7	.0	23.7	11.5	17.0	4.7	.0	.0	45.5	3.2	1.12	5.4

BORE HOLE DATA
OTHER OREBODY #1 — SINGLE BENCH

HOLE NO	LSD	SEC	TWP	RGE	MER	OVERBURDEN THK M	OVERBURDEN BIT %	MINE MILL FEED THK M	MINE MILL FEED BIT %	CENTRE REJECT THK M	CENTRE REJECT BIT %	RESIDUAL MILL FEED THK M	RESIDUAL MILL FEED BIT %	BOTTOM REJECT THK M	BOTTOM REJECT BIT %	WASTE/ORE RATIO (VOL)	VALUE $/M2
1726	15	34	95	10	4	2.5	.0	49.5	10.9	18.0	5.2	6.5	14.5	8.8	2.7	.41	15.6
2204	16	9	96	10	4	32.5	.1	37.5	13.3	.0	.0	15.2	11.7	19.2	2.6	.86	14.4
2209	9	8	96	10	4	28.0	.0	42.0	12.9	.0	.0	15.0	12.4	16.2	2.6	.66	19.1
2210	11	9	96	10	4	25.5	.1	41.5	10.8	.0	.0	22.7	10.6	55.0	.5	.61	8.9
2213	6	9	96	10	4	20.5	.1	49.5	11.1	.0	.0	19.5	13.2	60.5	.1	.41	18.0
2214	6	10	96	10	4	16.5	.1	53.5	13.7	.0	.0	20.7	14.2	7.0	1.3	.30	43.9
2221	10	4	96	10	4	35.0	.1	30.5	14.7	4.5	4.0	6.7	13.1	52.7	.5	1.29	8.6
2227	6	3	96	10	4	22.0	.1	29.0	12.0	.0	.0	.0	.0	46.7	2.0	.75	15.5
2239	14	9	96	10	4	30.7	.0	39.2	13.1	.0	.0	17.5	11.5	68.0	.1	.78	16.0
2305	9	8	96	10	4	17.7	.5	47.7	13.4	4.5	6.6	14.0	14.6	69.0	2.0	.46	31.9
2306	9	9	96	10	4	8.2	.0	53.5	12.2	8.2	3.8	13.0	12.7	64.5	1.5	.30	32.2
2307	11	10	96	10	4	8.5	.0	57.0	14.3	.0	.0	24.0	11.7	55.5	2.5	.14	56.2
2308	12	3	96	10	4	10.0	1.5	51.2	12.0	.0	.0	4.5	8.6	67.2	.6	.19	32.5
2325	4	9	96	9	4	12.2	.0	7.2	9.7	.0	.0	.0	.0	100.2	4.3	1.69	-.4
2326	2	9	96	9	4	6.0	.0	49.5	9.4	14.5	3.4	1.3	9.1	.0	.0	.41	6.2
2329	10	9	96	9	4	15.2	.8	54.7	11.4	.0	.0	8.8	8.6	39.4	2.2	.27	27.1
2335	13	9	96	9	4	9.5	.0	34.0	9.8	9.2	6.5	.0	.0	69.7	4.4	.55	8.0
2412	6	7	96	9	4	8.2	.0	12.5	8.5	.0	.0	.0	.0	102.5	3.5	.66	.4
2778	12	4	96	10	4	17.0	3.4	41.0	11.9	4.7	7.0	.0	.0	63.5	.1	.53	19.5
2779	4	9	96	10	4	27.2	3.2	33.0	10.8	.0	.0	22.7	12.1	13.5	1.7	.82	5.1
2801	14	4	96	10	4	6.0	.1	36.7	11.5	26.7	2.7	.0	.0	8.2	.6	.89	3.8
2803	12	4	96	10	4	19.0	2.0	43.8	11.2	.0	.0	.0	.0	10.7	.0	.43	19.5
2804	13	4	96	10	4	32.0	4.0	38.0	11.2	.0	.0	16.7	11.4	3.8	.1	.84	3.6
2805	4	9	96	10	4	20.0	.3	41.0	10.6	9.0	6.9	21.5	14.2	1.5	.1	.70	3.5
2806	5	9	96	10	4	18.0	.0	52.0	11.8	.0	.0	8.8	14.8	8.9	2.3	.34	26.6
2807	12	9	96	10	4	24.7	.1	40.7	12.5	4.5	4.9	10.2	13.7	7.5	.0	.71	14.7
2809	5	9	96	10	4	32.2	1.5	37.7	11.3	.0	.0	2.5	10.2	23.0	2.1	.85	3.3
2819	9	9	96	10	4	12.2	.1	57.7	14.0	.0	.0	1.7	14.4	17.2	.8	.21	54.0
2820	9	10	96	10	4	21.2	.1	16.7	10.4	.0	.0	.0	.0	23.0	2.3	1.26	2.9
2821	1	9	96	10	4	19.7	.1	45.7	12.6	4.5	5.7	24.0	12.0	2.2	1.2	.53	23.8
2822	9	4	96	10	4	23.5	.1	42.0	11.7	4.5	4.9	8.2	13.2	3.5	.1	.66	11.6
2823	3	10	96	10	4	18.2	.1	49.5	14.4	.0	.0	4.5	8.2	16.2	1.0	.36	44.5
2916	13	9	96	10	4	35.2	.9	34.7	12.9	.0	.0	19.5	13.9	8.0	.1	1.01	7.2
2917	9	9	96	10	4	22.7	.0	34.2	13.8	13.0	1.3	.0	.0	24.7	.0	1.04	13.2
2918	13	10	96	10	4	27.5	.1	42.5	13.3	.0	.0	18.0	10.0	6.7	.7	.64	22.9
2937	4	10	96	10	4	21.2	.1	40.7	12.7	8.0	3.0	13.0	16.3	4.2	.8	.71	15.8
2938	1	10	96	10	4	29.7	.1	40.2	14.7	.0	.0	3.2	8.5	4.5	4.3	.73	26.2

TABLE III-1-ii (cont'd)

BORE HOLE DATA
OTHER OREBODY #1 — DOUBLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
HOLE NO	LSD	SEC	TWP	RGE	MER	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	RATIO (VOL)	VALUE $/M2
1024	3	24	95	10	4	9.2	.0	22.7	12.0	41.7	.4	.0	.0	27.2	1.2	2.24	-11.5
1116	4	30	95	9	4	4.0	.0	47.5	11.7	26.2	3.2	.0	.0	14.5	6.4	.63	18.7
1118	10	24	95	10	4	11.2	.4	49.2	12.1	19.2	2.1	.0	.0	10.5	.2	.61	17.5
1358	8	24	95	10	4	6.0	.0	63.2	10.9	4.5	4.4	.0	.0	5.5	.0	.16	22.7
1360	16	24	95	10	4	25.5	1.3	51.7	11.7	.0	.0	.0	.0	4.0	.0	.49	9.8
1361	1	25	95	10	4	4.2	4.5	67.0	11.2	5.5	1.8	.0	.0	5.5	.0	.14	28.7
1400	5	30	95	9	4	2.2	.4	40.0	12.0	29.0	2.8	.0	.0	11.0	2.3	.78	11.5
1413	6	24	95	10	4	3.0	.0	50.0	11.2	21.2	4.2	.0	.0	5.0	.0	.48	10.2
1414	11	24	95	10	4	3.0	.0	54.0	11.3	16.7	3.0	.0	.0	10.0	.0	.36	14.9
1420	1	25	95	10	4	2.2	.0	40.0	10.8	38.5	3.2	.0	.0	25.7	2.4	1.01	-.3
1431	8	25	95	10	4	4.2	2.3	63.0	11.2	15.7	4.7	.0	.0	4.5	4.2	.31	19.5
1432	8	25	95	10	4	3.8	.0	59.2	11.9	9.5	7.2	.0	.0	11.2	.0	.22	27.2
1602	10	25	95	10	4	8.8	.1	50.7	12.2	14.0	5.3	.0	.0	13.2	2.0	.44	18.1
1614	10	25	95	10	4	11.5	.0	42.2	12.5	21.0	4.7	.0	.0	25.2	1.0	.76	11.9
1615	10	25	95	10	4	10.0	.3	54.7	12.0	11.7	6.5	.0	.0	19.7	.4	.39	20.7
1616	10	25	95	10	4	14.7	1.6	57.7	12.8	12.7	4.9	.0	.0	14.7	1.1	.47	22.0
1617	10	25	95	10	4	12.0	.0	67.5	13.6	10.5	5.4	.5	14.0	9.2	.8	.33	40.2
1618	10	25	95	10	4	14.7	.7	57.0	12.4	6.3	6.1	.0	.0	21.0	1.5	.36	20.4
1619	10	25	95	10	4	14.0	.4	57.2	12.0	10.7	5.7	.0	.0	10.2	2.3	.43	16.7
1631	10	25	95	10	4	8.5	.8	39.0	10.9	16.7	3.6	.0	.0	27.7	2.2	.64	1.0
1633	10	25	95	10	4	9.2	1.5	46.5	11.0	15.0	7.2	.0	.0	11.7	.5	.52	5.5
1652	9	25	95	10	4	8.5	.0	59.0	11.9	5.0	7.6	.0	.0	4.5	.0	.22	23.7
1751	10	25	95	10	4	6.7	.0	42.2	11.3	23.7	.1	.0	.0	21.7	1.5	.72	9.2
1752	10	25	95	10	4	6.0	.0	46.0	12.1	22.7	.7	.0	.0	22.7	1.3	.62	18.9
2330	13	12	96	10	4	12.2	.0	64.0	13.3	.0	.0	.0	.0	45.0	.7	.19	42.2
2331	15	12	96	10	4	12.2	.0	44.5	13.7	11.7	4.5	.0	.0	7.5	.1	.53	22.2
2332	13	7	96	9	4	8.2	.0	55.2	11.9	23.7	3.7	.0	.0	33.2	3.8	.57	14.1

BORE HOLE DATA
OREBODY #2A — DOUBLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
HOLE NO	LSD	SEC	TWP	RGE	MER	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	RATIO (VOL)	VALUE $/M2
2201	15	12	96	11	4	31.0	.1	22.5	12.9	.0	.0	.0	.0	8.5	.1	1.38	-8.9
2206	11	12	96	11	4	34.2	.1	43.2	12.9	12.0	4.6	.0	.0	24.0	.1	1.06	1.4
2207	9	12	96	11	4	18.5	.5	54.5	11.8	16.5	3.6	5.7	12.5	12.7	.5	.64	8.5
2211	7	12	96	11	4	22.5	.1	49.2	12.6	16.7	.8	.0	.0	16.0	.1	.79	13.3
2219	9	1	96	11	4	19.2	.0	64.5	13.0	5.2	.8	.0	.0	2.2	.0	.38	33.6
2224	5	6	96	10	4	37.5	.1	33.5	12.6	17.0	2.0	.0	.0	9.0	.1	1.62	-10.3
2229	3	6	96	10	4	21.7	.1	50.0	15.1	12.0	1.7	.0	.0	5.5	.2	.67	32.8
2230	3	6	96	10	4	22.7	.0	50.5	13.5	6.3	1.8	.0	.0	3.0	.0	.57	22.6
2236	14	12	96	11	4	14.0	.1	42.5	12.7	.0	.0	.0	.0	35.5	.1	.32	19.5
2301	11	1	96	11	4	8.2	.0	47.0	13.5	22.7	2.5	.0	.0	11.2	.4	.66	27.1
2302	1	1	96	11	4	9.5	1.0	36.5	13.2	41.2	2.4	.0	.0	30.5	2.4	1.39	-1.4
2303	11	7	96	10	4	26.7	.0	56.7	12.8	6.5	.6	8.2	13.7	55.7	.1	.58	17.9
2394	6	6	96	10	4	13.7	2.6	65.2	11.6	11.0	6.4	1.5	8.0	1.3	.0	.37	19.3
2647	10	12	96	11	4	36.5	3.2	38.2	11.6	.0	.0	.0	.0	4.0	.0	.95	-8.1
2780	12	6	96	10	4	9.7	.1	66.2	13.4	14.0	2.9	.8	10.7	3.8	.0	.35	44.1
2781	4	7	96	10	4	8.5	.0	73.5	13.4	6.0	.2	.0	.0	2.2	.0	.19	53.0
2811	4	7	96	10	4	25.2	1.7	51.5	12.2	13.2	2.6	1.3	10.4	.8	.0	.74	9.5
2812	8	12	96	11	4	12.2	.4	57.0	11.6	18.2	5.1	.0	.0	1.5	.0	.53	15.2
2814	2	12	96	11	4	9.2	4.5	73.7	12.5	7.0	.1	.3	12.0	.3	.0	.22	43.0
2815	15	1	96	11	4	12.2	.1	35.5	13.4	17.5	2.3	.0	.0	.0	.0	.83	15.6
2816	10	1	96	11	4	3.8	.0	67.2	12.6	14.0	5.5	.0	.0	2.5	1.6	.26	39.8
2817	8	1	96	11	4	8.2	.1	46.5	10.6	24.0	2.2	.0	.0	13.5	2.2	.69	-3.0
2818	12	6	96	10	4	20.5	1.3	54.2	13.6	13.7	.7	.0	.0	4.2	.0	.63	26.9
2910	13	12	96	11	4	36.2	.6	45.5	12.2	.0	.0	.0	.0	15.7	.1	.79	.3
2911	16	12	96	11	4	41.5	2.1	42.2	12.5	5.5	6.2	.0	.0	9.2	.8	1.11	-2.7
2912	13	7	96	10	4	31.7	.0	58.0	12.5	.0	.0	2.7	10.9	4.2	4.9	.55	13.8
2921	9	12	96	11	4	42.7	.1	46.7	12.7	.0	.0	.0	.0	2.5	.0	.91	3.7
2946	6	1	96	11	4	26.7	.1	32.0	11.5	17.7	3.4	.0	.0	.0	.0	1.39	-10.7
2957	4	6	96	10	4	12.2	.1	45.0	12.2	27.2	2.0	.0	.0	8.5	.6	.87	6.4

BORE HOLE DATA
OTHER OREBODY #2B — SINGLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
HOLE NO	LSD	SEC	TWP	RGE	MER	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	RATIO (VOL)	VALUE $/M2
1285	15	19	95	10	4	4.2	.0	47.7	12.1	10.7	.0	.0	.0	3.0	.0	.31	30.3
1289	7	30	95	10	4	22.0	1.9	16.0	11.0	.0	.0	.0	.0	26.0	3.8	1.37	3.7
1294	16	25	95	11	4	22.5	.6	16.0	11.6	.0	.0	.0	.0	17.5	.7	1.40	5.1

TABLE III-1-iv

BORE HOLE DATA
OREBODY #3 — SINGLE BENCH

HOLE NO	LSD	SEC	TWP	RGE	MER	OVERBURDEN THK M	OVERBURDEN BIT %	MINE MILL FEED THK M	MINE MILL FEED BIT %	CENTRE REJECT THK M	CENTRE REJECT BIT %	RESIDUAL MILL FEED THK M	RESIDUAL MILL FEED BIT %	BOTTOM REJECT THK M	BOTTOM REJECT BIT %	WASTE/ORE RATIO (VOL)	VALUE $/M2
1011	5	2	95	10	4	12.2	.0	6.7	11.8	.0	.0	.0	.0	14.7	.0	1.81	1.9
1012	14	11	95	10	4	9.2	.0	14.2	11.7	.0	.0	.0	.0	13.5	1.5	.64	7.3
1017	4	8	95	10	4	3.0	.0	27.0	10.0	19.0	2.8	.0	.0	13.5	1.0	.81	6.9
1121	10	15	95	10	4	27.2	.0	33.5	11.7	9.0	5.1	.0	.0	4.5	1.4	1.08	.3
1123	4	10	95	10	4	11.2	.8	23.2	11.3	.0	.0	.0	.0	5.0	.4	.48	11.2
1124	2	10	95	10	4	1.5	.0	27.7	12.7	.0	.0	.0	.0	5.0	7.0	. 5	21.4
1125	10	10	95	10	4	2.5	.0	21.2	12.1	.0	.0	.0	.0	21.0	1.3	.11	14.1
1126	4	14	95	10	4	6.5	.0	16.2	13.3	4.5	5.7	.0	.0	20.0	3.2	.67	11.7
1127	2	14	95	10	4	1.0	.0	12.0	9.3	.0	.0	.0	.0	23.5	2.7	. 8	3.6
1186	4	13	95	10	4	5.7	.0	32.7	11.7	.0	.0	.0	.0	9.7	2.7	.17	19.0
1191	10	13	95	10	4	12.0	1.3	25.0	10.7	16.7	5.2	.0	.0	37.7	1.0	1.15	1.8
1197	2	13	95	10	4	12.7	.0	21.5	11.9	18.8	4.1	.0	.0	11.0	4.9	1.46	1.7
1216	6	4	95	10	4	10.0	.0	17.7	12.3	.0	.0	.0	.0	16.7	.9	.56	10.5
1218	4	11	95	10	4	3.0	.0	12.5	11.5	.0	.0	.0	.0	27.5	.7	.24	6.6
1221	11	14	95	10	4	13.7	.0	39.2	11.4	12.5	3.8	.0	.0	10.5	.1	.66	11.3
1265	3	8	95	10	4	2.2	.0	12.5	11.0	19.5	1.4	.0	.0	26.0	1.6	1.74	1.5
1266	14	5	95	10	4	2.2	.0	12.0	11.9	22.2	2.9	.0	.0	3.0	.0	2.04	2.6
1271	4	8	95	10	4	10.2	.6	29.2	9.8	5.5	.0	.0	.0	.8	.0	.53	7.1
1274	3	8	95	10	4	1.7	.0	11.2	10.5	14.2	.5	.0	.0	4.5	2.7	1.42	1.7
1278	3	8	95	10	4	1.5	.0	9.7	10.1	10.5	2.5	.0	.0	13.2	.9	1.23	1.3
1279	1	8	95	10	4	13.0	2.7	27.0	12.3	.0	.0	.0	.0	.3	.0	.48	16.9
1334	15	4	95	10	4	14.7	.0	22.7	11.3	.0	.0	.0	.0	22.0	.4	.64	9.9
1336	8	10	95	10	4	2.5	.0	13.7	9.3	4.5	3.8	.0	.0	25.0	2.0	.50	2.8
1337	14	10	95	10	4	9.2	.0	18.2	11.3	4.5	7.0	.0	.0	38.0	1.3	.75	7.5
1338	16	10	95	10	4	3.8	.0	23.0	12.0	.0	.0	.0	.0	12.2	.8	.16	15.2
1339	6	11	95	10	4	9.2	.0	11.5	11.2	4.5	2.7	.0	.0	2.2	.0	1.19	3.5
1340	12	11	95	10	4	10.2	2.7	4.5	10.7	.0	.0	.0	.0	14.2	.3	2.27	.1
1341	14	11	95	10	4	13.5	.0	14.2	11.1	.0	.0	.0	.0	18.0	1.5	.94	4.8
1342	6	13	95	10	4	9.7	.0	25.2	12.0	7.0	3.0	.0	.0	43.8	2.0	.66	12.9
1344	9	13	95	10	4	9.5	1.2	21.7	9.4	4.5	3.9	.0	.0	43.5	.1	.64	3.7
1345	14	13	95	10	4	7.7	.0	9.7	9.9	4.5	4.8	.0	.0	83.5	4.9	1.25	1.0
1347	3	14	95	10	4	11.0	4.7	8.2	8.8	.0	.0	.0	.0	25.7	3.9	1.33	-.6
1348	6	14	95	10	4	22.5	1.4	34.0	11.9	.0	.0	.0	.0	18.8	2.4	.66	16.3
1349	8	14	95	10	4	14.7	1.7	29.5	13.6	.0	.0	.0	.0	7.0	1.3	.50	24.1
1353	2	15	95	10	4	10.0	.0	13.2	9.0	.0	.0	.0	.0	45.7	4.6	.75	1.0
1354	8	15	95	10	4	19.2	.0	41.0	12.9	.0	.0	.0	.0	8.2	.0	.47	27.8
1509	12	15	95	10	4	9.5	.9	46.5	10.4	14.0	3.5	4.2	13.4	8.0	.7	.50	9.2
1706	8	9	95	10	4	23.7	1.0	26.2	10.7	6.0	3.2	.0	.0	21.5	.3	1.13	.1
1707	3	9	95	10	4	12.5	1.1	25.0	9.4	11.2	5.2	.0	.0	31.7	1.9	.95	2.0
1709	4	15	95	10	4	26.2	2.7	9.0	11.4	.0	.0	.0	.0	50.7	2.9	2.91	-.5

BORE HOLE DATA
TAILINGS POND — DOUBLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
HOLE NO	LSD	SEC	TWP	RGE	MER	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	RATIO (VOL)	VALUE $/M2
1020	10	16	95	10	4	86.0	1.1	.0	.0	.0	.0	.0	.0	.0	.0		-59.6
1021	7	21	95	10	4	14.7	.0	30.5	11.8	25.2	1.1	.0	.0	7.2	4.3	1.31	-9.8
1050	10	28	95	10	4	46.0	.0	14.2	10.7	.0	.0	.0	.0	11.7	1.7	3.22	-25.6
1053	2	29	95	10	4	33.5	1.2	17.5	10.5	13.5	5.0	.0	.0	5.5	2.9	2.68	-24.2
1055	1	20	95	10	4	28.7	.0	43.2	11.4	.0	.0	.0	.0	11.2	.4	.67	-1.7
1056	10	20	95	10	4	16.7	.0	40.5	10.1	17.5	3.3	.0	.0	10.2	1.1	.84	-6.8
1219	16	16	95	10	4	33.0	.0	25.7	12.9	4.7	4.4	.0	.0	3.8	.0	1.46	-9.0
1282	3	20	95	10	4	33.5	2.2	22.5	11.5	9.2	.3	.0	.0	7.0	.0	1.90	-18.1
1283	11	20	95	10	4	28.7	2.0	13.5	8.7	22.2	3.8	.0	.0	6.7	1.9	3.77	-27.9
1284	9	19	95	10	4	12.2	.8	17.2	8.6	19.7	1.6	.0	.0	20.7	2.4	1.85	-18.7
1286	1	30	95	10	4	69.2	1.0	.0	.0	.0	.0	.0	.0	.0	.0	.	-39.8
1291	15	30	95	10	4	32.0	2.7	26.5	11.0	9.2	4.9	.0	.0	3.0	.0	1.55	-16.4
1292	13	29	95	10	4	48.2	.7	5.5	9.8	.0	.0	.0	.0	6.5	.0	8.77	-31.2
1293	7	31	95	10	4	56.0	2.2	.0	.0	.0	.0	.0	.0	.0	.0	.	-35.0
1355	14	15	95	10	4	50.5	1.3	16.0	12.2	.0	.0	.0	.0	15.7	4.6	3.15	-22.7
1508	16	28	95	10	4	27.5	3.7	27.5	12.0	8.5	2.8	.0	.0	15.5	2.1	1.30	-9.4
1513	1	21	95	10	4	34.7	1.2	24.5	14.2	17.5	2.7	.0	.0	8.5	.6	2.13	-10.6
1702	11	16	95	10	4	29.2	2.2	23.7	13.9	11.5	1.2	.0	.0	25.5	2.0	1.71	-6.4
1703	7	28	95	10	4	49.0	2.4	20.0	9.4	.0	.0	.0	.0	10.5	2.2	2.45	-28.1
1704	1	29	95	10	4	36.7	2.0	21.5	11.6	8.2	4.2	.0	.0	5.2	.0	2.09	-19.7
1705	8	32	95	10	4	48.2	3.9	26.5	11.9	.0	.0	.0	.0	8.8	.0	1.82	-16.4
1711	6	16	95	10	4	2.5	.0	26.5	10.7	30.2	3.5	.0	.0	44.5	1.7	1.23	-11.3
1713	5	21	95	10	4	39.0	1.5	20.7	10.4	12.2	3.9	.0	.0	13.2	.0	2.47	-25.8
1714	13	21	95	10	4	47.0	.6	11.5	8.5	.0	.0	.0	.0	26.7	3.1	4.08	-31.0
1715	4	22	95	10	4	37.7	2.7	11.7	13.0	.0	.0	.0	.0	32.5	4.9	3.21	-21.0
1716	13	22	95	10	4	14.2	3.8	37.2	11.2	21.7	6.1	.0	.0	11.2	.0	.96	-7.3
1718	3	28	95	10	4	56.5	1.1	10.0	12.8	.0	.0	.0	.0	18.8	2.7	5.65	-27.8
1719	13	28	95	10	4	49.5	2.7	20.0	12.6	.0	.0	.0	.0	9.7	3.1	2.47	-19.7
1720	16	29	95	10	4	36.0	2.4	22.5	12.0	12.7	1.9	.0	.0	14.0	1.3	2.16	-19.4
1721	16	32	95	10	4	13.2	1.1	28.2	12.2	36.0	1.4	.0	.0	13.0	.7	1.74	-11.9
2231	1	6	96	10	4	71.0	.9	7.2	10.3	.0	.0	.0	.0	6.5	.8	9.79	-41.2
2232	3	5	96	10	4	39.2	.0	29.2	10.9	8.0	.5	.0	.0	8.0	.0	1.61	-18.4
2249	1	6	96	10	4	57.5	.0	21.7	11.1	.0	.0	.0	.0	.5	.0	2.64	-24.1
2959	4	5	96	10	4	55.2	.6	21.2	12.4	.0	.0	.0	.0	7.2	.1	2.60	-20.0

TABLE III-1-vi

BORE HOLE DATA
PLANTSITE — DOUBLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
HOLE NO	LSD	SEC	TWP	RGE	MER	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	RATIO (VOL)	VALUE $/M2
1030	16	32	95	10	4	32.2	.0	20.0	10.5	24.0	2.8	.0	.0	17.0	1.5	2.81	-24.7
1031	16	34	95	10	4	51.7	.0	19.0	13.4	.0	.0	.0	.0	54.2	2.6	2.72	-17.9
2223	10	3	96	10	4	52.7	.3	19.0	11.3	4.5	6.2	.0	.0	11.7	.1	3.01	-25.1
2233	3	4	96	10	4	56.5	.0	4.5	8.0	.0	.0	.0	.0	60.2	.0	12.55	-34.7
2250	1	4	96	10	4	41.5	.0	33.0	12.4	4.5	2.7	.0	.0	2.7	.0	1.39	-9.3
2251	3	3	96	10	4	38.7	.0	29.0	13.5	9.2	4.3	.0	.0	3.8	.0	1.65	-7.7
2417	8	3	96	10	4	31.5	2.1	39.0	13.1	5.7	1.6	.0	.0	7.0	.1	.95	2.8
2777	5	4	96	10	4	18.5	3.2	34.2	12.9	26.5	2.2	.0	.0	3.0	2.0	1.31	-1.9
2802	5	4	96	10	4	42.2	1.7	35.0	11.9	4.5	3.6	.0	.0	3.0	.0	1.33	-10.5
2961	1	4	96	10	4	39.2	.1	25.5	11.0	14.0	1.5	.0	.0	3.8	.0	2.08	-21.5
2962	4	3	96	10	4	48.2	.1	26.5	12.1	.0	.0	.0	.0	2.7	.0	1.82	-15.6
2963	1	3	96	10	4	121.0	.9	.0	.0	.0	.0	.0	.0	.0	.0		-100.6

BORE HOLE DATA
OTHER AREAS — DOUBLE BENCH

HOLE NO	LSD	SEC	TWP	RGE	MER	OVERBURDEN THK M	OVERBURDEN BIT %	MINE MILL FEED THK M	MINE MILL FEED BIT %	CENTRE REJECT THK M	CENTRE REJECT BIT %	RESIDUAL MILL FEED THK M	RESIDUAL MILL FEED BIT %	BOTTOM REJECT THK M	BOTTOM REJECT BIT %	WASTE/ORE RATIO (VOL)	VALUE $/M2
1019	4	16	95	10	4	5.5	.0	35.0	11.1	9.5	5.4	.0	.0	23.5	2.9	.42	3.9
1023	10	23	95	10	4	54.0	1.7	21.2	12.6	.0	.0	.0	.0	10.0	.9	2.54	-18.5
1028	6	27	95	10	4	33.2	.0	20.7	11.3	24.2	4.7	.0	.0	10.5	.0	2.77	-23.6
1034	13	17	95	10	4	39.0	2.1	16.2	10.0	10.5	3.1	.0	.0	15.2	.0	3.04	-27.6
1035	4	15	95	10	4	17.7	1.5	16.5	8.6	29.7	3.9	.0	.0	13.7	.0	2.87	-24.4
1115	12	30	95	9	4	11.5	.0	20.5	9.3	14.7	3.1	.0	.0	45.2	1.4	1.28	-16.2
1120	2	23	95	10	4	54.7	1.9	25.7	11.1	.0	.0	.0	.0	5.7	.0	2.12	-20.8
1122	12	10	95	10	4	20.2	3.5	4.5	9.1	10.2	.5	.0	.0	8.2	.0	6.77	-26.8
1128	12	13	95	10	4	15.0	3.5	36.5	11.0	27.7	4.3	.0	.0	1.7	.0	1.17	-6.2
1130	4	19	95	9	4	20.0	1.8	20.7	8.8	37.2	.8	.0	.0	10.0	2.7	2.75	-28.4
1165	10	21	95	9	4	13.0	.0	25.2	10.7	35.0	4.4	.0	.0	18.2	.4	1.90	-18.9
1166	2	21	95	9	4	20.0	1.7	19.0	9.6	28.7	5.7	.0	.0	23.7	.5	2.56	-24.2
1176	10	12	95	10	4	65.5	3.0	.0	.0	.0	.0	.0	.0	.0	.0		-37.4
1217	6	3	95	10	4	15.2	.0	4.5	8.7	15.2	1.1	.0	.0	1.0	.0	6.77	-25.4
1261	5	8	95	10	4	23.7	.3	20.2	10.4	4.7	4.6	.0	.0	2.5	.0	1.40	-13.1
1262	11	8	95	10	4	22.7	1.0	18.8	9.5	11.0	5.3	.0	.0	6.7	1.0	1.80	-20.0
1263	10	8	95	10	4	20.0	.0	10.5	10.5	4.5	4.2	.0	.0	17.7	3.8	2.33	-20.9
1264	2	8	95	10	4	33.5	1.3	.0	.0	.0	.0	.0	.0	.0	.0	.	-28.4
1267	4	8	95	10	4	21.5	1.1	9.0	9.1	4.5	4.9	.0	.0	10.0	2.5	2.88	-23.0
1268	5	8	95	10	4	33.0	1.3	2.0	10.5	.0	.0	.0	.0	19.7	2.1	16.50	-32.2
1269	15	8	95	10	4	31.0	2.5	2.0	8.0	.0	.0	.0	.0	.0	.0	15.50	-26.1
1270	2	17	95	10	4	37.2	2.1	11.0	12.4	.0	.0	.0	.0	2.0	.0	3.38	-22.6
1272	5	8	95	10	4	28.2	.9	13.5	10.4	.0	.0	.0	.0	5.2	4.6	2.11	-18.6
1273	6	8	95	10	4	24.0	1.3	11.0	10.1	.0	.0	.0	.0	15.2	2.6	2.18	-20.4
1276	5	8	95	10	4	15.2	.0	12.2	8.9	7.5	1.7	.0	.0	12.5	4.5	1.85	-20.2
1277	6	8	95	10	4	4.2	.0	5.7	11.6	20.5	1.3	.0	.0	.0	.0	4.30	-17.5
1280	4	9	95	10	4	31.7	1.5	9.7	12.1	.0	.0	.0	.0	1.0	.0	3.28	-20.6
1281	8	8	95	10	4	27.7	1.2	12.5	10.2	.0	.0	.0	.0	10.5	6.1	2.24	-18.8
1288	10	19	95	10	4	59.7	.3	.0	.0	.0	.0	.0	.0	.0	.0	.	-36.0
1290	13	19	95	10	4	22.7	1.8	21.0	10.0	16.0	.5	.0	.0	1.5	.0	1.84	-19.4
1295	5	31	95	10	4	49.0	1.1	.0	.0	.0	.0	.0	.0	.0	.0	.	-33.2
1296	16	36	95	11	4	31.7	3.0	28.7	10.2	9.2	6.6	.0	.0	4.0	.0	1.42	-18.4
1297	14	36	95	11	4	27.2	6.2	12.2	10.1	23.7	2.9	.0	.0	7.2	.0	4.16	-24.7
1315	3	30	95	9	4	5.5	.4	26.0	9.0	22.2	4.6	.0	.0	55.7	.9	1.06	-14.1
1316	6	30	95	9	4	30.5	1.6	16.7	10.4	22.7	1.2	.0	.0	29.0	3.0	3.17	-24.6
1319	11	30	95	9	4	28.5	3.8	10.0	10.4	22.7	3.0	.0	.0	37.2	1.6	5.12	-27.2
1329	4	33	95	9	4	28.0	3.1	20.7	11.1	.0	.0	.0	.0	45.0	1.1	1.36	-13.1
1335	6	10	95	10	4	37.5	.4	.0	.0	.0	.0	.0	.0	.0	.0	.	-30.3
1350	13	14	95	10	4	22.5	.0	43.0	12.1	19.5	3.2	.0	.0	1.3	.0	.97	.0
1351	14	14	95	10	4	37.2	1.6	39.7	11.0	.0	.0	.0	.0	3.8	.8	.93	-10.3
1352	16	14	95	10	4	30.5	1.6	18.8	11.5	17.5	1.7	.0	.0	5.5	.0	2.56	-19.0
1356	9	23	95	10	4	52.0	2.1	29.0	12.7	.0	.0	.0	.0	11.2	1.0	1.79	-12.4
1357	5	24	95	10	4	48.2	.8	11.0	10.5	.0	.0	.0	.0	18.5	2.2	4.38	-27.9
1415	12	24	95	10	4	23.7	3.4	10.5	9.8	19.7	1.9	.0	.0	36.0	2.2	4.14	-25.5
1505	14	23	95	10	4	37.7	2.4	24.7	13.6	9.7	1.4	.0	.0	31.5	1.7	1.91	-11.2
1515	1	22	95	10	4	34.2	2.0	29.5	12.1	12.5	1.0	.0	.0	19.7	1.8	1.58	-13.5

TABLE III-1-vii (cont'd)

BORE HOLE DATA
OTHER AREAS — DOUBLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
						THK	BIT	THK	BIT	THK	BIT	THK	BIT	THK	BIT	RATIO	VALUE
HOLE NO	LSD	SEC	TWP	RGE	MER	M	%	M	%	M	%	M	%	M	%	(VOL)	$/M2
1516	10	23	95	10	4	54.7	1.3	17.7	11.1	.0	.0	.0	.0	9.7	.7	3.08	-25.4
1519	5	27	95	10	4	44.2	2.0	24.7	12.9	.0	.0	.0	.0	10.2	.0	1.78	-12.4
1523	14	27	95	10	4	28.0	2.4	30.0	11.6	16.7	3.4	.0	.0	10.0	2.2	1.49	-12.0
1701	9	9	95	10	4	39.0	1.7	4.5	8.7	.0	.0	.0	.0	13.7	1.5	8.66	-29.9
1708	12	9	95	10	4	34.7	2.7	4.7	10.1	6.3	4.2	.0	.0	56.0	1.6	8.63	-29.3
1710	7	16	95	10	4	88.5	1.3	.0	.0	.0	.0	.0	.0	.0	.0	.	-62.5
1712	8	17	95	10	4	28.0	2.5	16.0	11.4	18.2	3.9	.0	.0	42.2	1.0	2.89	-20.6
1722	8	33	95	10	4	16.2	2.9	43.0	11.6	18.8	4.6	.0	.0	7.2	.0	.81	-.1
2202	16	7	96	10	4	38.5	1.4	38.0	11.4	12.2	1.1	.0	.0	2.5	.0	1.33	-12.9
2203	16	8	96	10	4	43.2	.1	36.7	12.0	5.0	.0	.0	.0	26.5	1.5	1.31	-8.7
2205	14	10	96	10	4	31.7	.1	47.7	12.0	10.5	.3	.3	8.0	15.7	.0	.88	1.2
2208	11	7	96	10	4	50.5	.1	18.0	13.4	.0	.0	.0	.0	2.7	.0	2.80	-18.2
2212	6	7	96	10	4	43.2	.1	25.7	12.6	4.5	3.8	.0	.0	2.0	.0	1.85	-14.0
2215	3	7	96	10	4	44.2	.1	13.0	11.4	12.0	4.1	.0	.0	5.0	1.0	4.32	-27.9
2216	2	9	96	10	4	33.2	1.1	35.2	11.3	12.5	4.0	.0	.0	12.0	2.6	1.29	-12.1
2217	15	4	96	10	4	45.7	.1	40.7	11.6	.0	.0	.0	.0	8.0	.1	1.12	-8.4
2225	7	6	96	10	4	54.0	.1	36.0	13.7	.0	.0	7.7	10.7	.0	.0	1.50	-2.6
2226	6	4	96	10	4	65.0	.1	14.7	14.4	.0	.0	.0	.0	6.0	.2	4.40	-25.0
2235	3	7	96	10	4	42.2	.1	15.0	12.1	.0	.0	.0	.0	4.5	3.8	2.81	-21.4
2237	14	7	96	10	4	33.5	.1	22.7	12.1	26.0	2.3	.0	.0	3.0	.0	2.61	-20.8
2238	14	8	96	10	4	33.2	.1	31.5	13.4	19.2	1.0	.0	.0	71.7	.1	1.66	-6.5
2241	9	7	96	10	4	47.2	.6	22.5	12.6	.0	.0	.0	.0	1.3	.0	2.10	-16.2
2242	6	8	96	10	4	54.7	1.9	33.0	12.8	.0	.0	.0	.0	49.7	.0	1.65	-9.7
2243	1	7	96	10	4	52.0	.1	26.0	12.6	12.0	.8	8.2	11.4	1.5	.0	2.46	-23.1
2244	9	6	96	10	4	66.5	.1	22.7	12.5	.0	.0	.0	.0	4.7	3.2	2.92	-27.9
2245	10	5	96	10	4	41.2	.1	19.0	11.8	.0	.0	.0	.0	.0	.0	2.17	-19.5
2246	8	6	96	10	4	103.2	.2	.0	.0	.0	.0	.0	.0	.0	.0	.	-79.9
2247	6	5	96	10	4	77.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.	-48.9
2304	11	6	96	10	4	38.5	1.3	32.5	12.5	19.0	1.0	5.5	12.4	11.5	.4	1.76	-13.2
2318	12	4	96	9	4	34.7	2.7	11.0	10.8	.0	.0	.0	.0	22.0	1.3	3.27	-24.6
2319	10	4	96	9	4	28.0	2.4	11.5	8.8	.0	.0	.0	.0	38.2	3.7	2.43	-21.6
2333	15	7	96	9	4	11.5	.5	39.2	10.7	29.5	.8	.0	.0	12.7	3.2	1.04	-8.4
2334	13	8	96	9	4	14.7	.0	4.5	10.0	15.7	4.2	.0	.0	100.2	4.5	6.77	-38.9
2418	6	2	96	10	4	11.5	.1	18.2	12.3	35.2	.6	.0	.0	64.7	2.7	2.56	-17.3
2810	3	8	96	10	4	24.5	.1	29.7	13.2	32.0	1.4	.0	.0	6.0	5.2	1.89	-10.4
2913	16	7	96	10	4	31.5	.1	19.7	11.8	.0	.0	.0	.0	5.7	.2	1.60	-14.7
2914	13	8	96	10	4	38.0	.1	22.5	13.8	29.5	3.6	2.0	13.5	5.7	.2	3.00	-25.1
2915	16	8	96	10	4	32.5	.1	32.0	12.2	17.5	3.6	.0	.0	31.5	.7	1.56	-10.2
2919	16	10	96	10	4	47.0	.1	35.0	13.6	.0	.0	.0	.0	2.7	.0	1.34	-2.4
2923	9	7	96	10	4	39.5	.1	25.5	13.1	4.5	7.3	.0	.0	3.2	.0	1.72	-11.4
2927	11	11	96	10	4	76.5	2.2	.0	.0	.0	.0	.0	.0	.0	.0	.	-48.3
2930	6	8	96	9	4	51.2	.5	4.5	11.8	.0	.0	.0	.0	42.5	.2	11.38	-31.1
2933	2	7	96	10	4	48.2	.1	30.5	11.3	.0	.0	.0	.0	6.5	.2	1.58	-16.6
2934	4	8	96	10	4	50.0	.1	13.0	12.6	.0	.0	.0	.0	46.7	3.3	3.84	-24.1
2935	1	8	96	10	4	40.0	1.2	23.7	11.6	17.0	3.4	.0	.0	26.2	1.2	2.40	-21.6
2942	13	5	96	10	4	48.2	.1	29.5	11.3	.0	.0	.0	.0	3.8	.0	1.63	-17.1

BORE HOLE DATA
OTHER AREAS — DOUBLE BENCH

						OVERBURDEN		MINE MILL FEED		CENTRE REJECT		RESIDUAL MILL FEED		BOTTOM REJECT		WASTE/ORE	
HOLE NO	LSD	SEC	TWP	RGE	MER	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	THK M	BIT %	RATIO (VOL)	VALUE $/M2
2958	2	6	96	10	4	41.2	.3	25.0	11.7	16.5	2.1	.0	.0	4.0	.5	2.31	-20.4
2960	1	5	96	10	4	51.5	.1	25.5	10.8	.0	.0	.0	.0	7.0	1.1	2.02	-22.1

OREBODY PARAMETERS AND RESERVES

	Area ha	Over-burden Thickness m	Millfeed Thickness m	Millfeed Grade %	Centre Reject Thickness m	W/O Ratio (Mass)	Millfeed Fines %	Depth to Base Mineable m	Bitumen In Place $10^6 m^3$	Mineable Bitumen $10^6 m^3$	Life Index yrs. 25 040 m^3/d Bitumen
OREBODY AREAS											
1. Initial Mine	2,720	13	38	12.1	10	0.59	14.5	60	323	249	25
Other Mineable	3,380	19	38	12.2	11	0.76	14.5	67	380	307	30
TOTAL OREBODY NO. 1	6,100	16	38	12.2	11	0.68	14.5	64	703	556	55
2. a.	530	22	49	12.6	13	0.69	13.8	85	77	69	7
b.	280	22	22	12.0	5	1.15	15.0	49	19	14	1
3.	1,940	12	19	11.5	4	0.76	16.0	36	94	73	7
TOTAL OREBODIES	8,850	17	37	12.2	10	0.70	14.5	63	893	712	70
FACILITIES											
Plantsite	350					1.96			28		
Tailings Pond	2,050					2.41			139		
Utility Corridor	40					2.17			5		
Total Facilities	2,440					2.31			172		
OTHER AREAS (Non Mineable)	5,485					2.25			230		
TOTAL PROJECT AREA	16,775								1,295	712	70

TABLE III-3

OVERALL MINING RECOVERY IN PROPOSED AREA

	Block 1		Block 2		Block 3		Block 4		Total Mine	
	10^6m^3 Bitumen	%	10^6m^3 bItumen	%	10^6m^3 Bitumen	%	10^6m^3 Bitumen	%	10^6m^3 Bitumen	%
Millfeed	95.8	78.2	49.0	88.6	69.3	82.5	34.9	57.0	249.0	77.1
Overburden	3.0		1.3		1.8		0.9		7.0	2.2
Center Reject	6.3		3.1		5.4		4.2		19.0	5.9
Total Waste	9.3	7.6	4.4	8.0	7.2	8.6	5.1	8.3	26.0	8.1
Residual Millfeed	7.0	5.7	0.0	—	1.0	1.2	0.0	—	8.0	2.4
Bottom Reject	10.4	8.5	1.9	3.4	6.5	7.7	21.2	34.7	40.0	12.4
TOTAL RESERVE	122.5	100.0	55.3	100.0	84.0	100.0	61.2	100.0	323.0	
Percent Recovery (Overall)	78.2		88.6		82.5		57.0		77.1	
Life (yrs)	9.6		4.9		7.0		3.5		25.0	

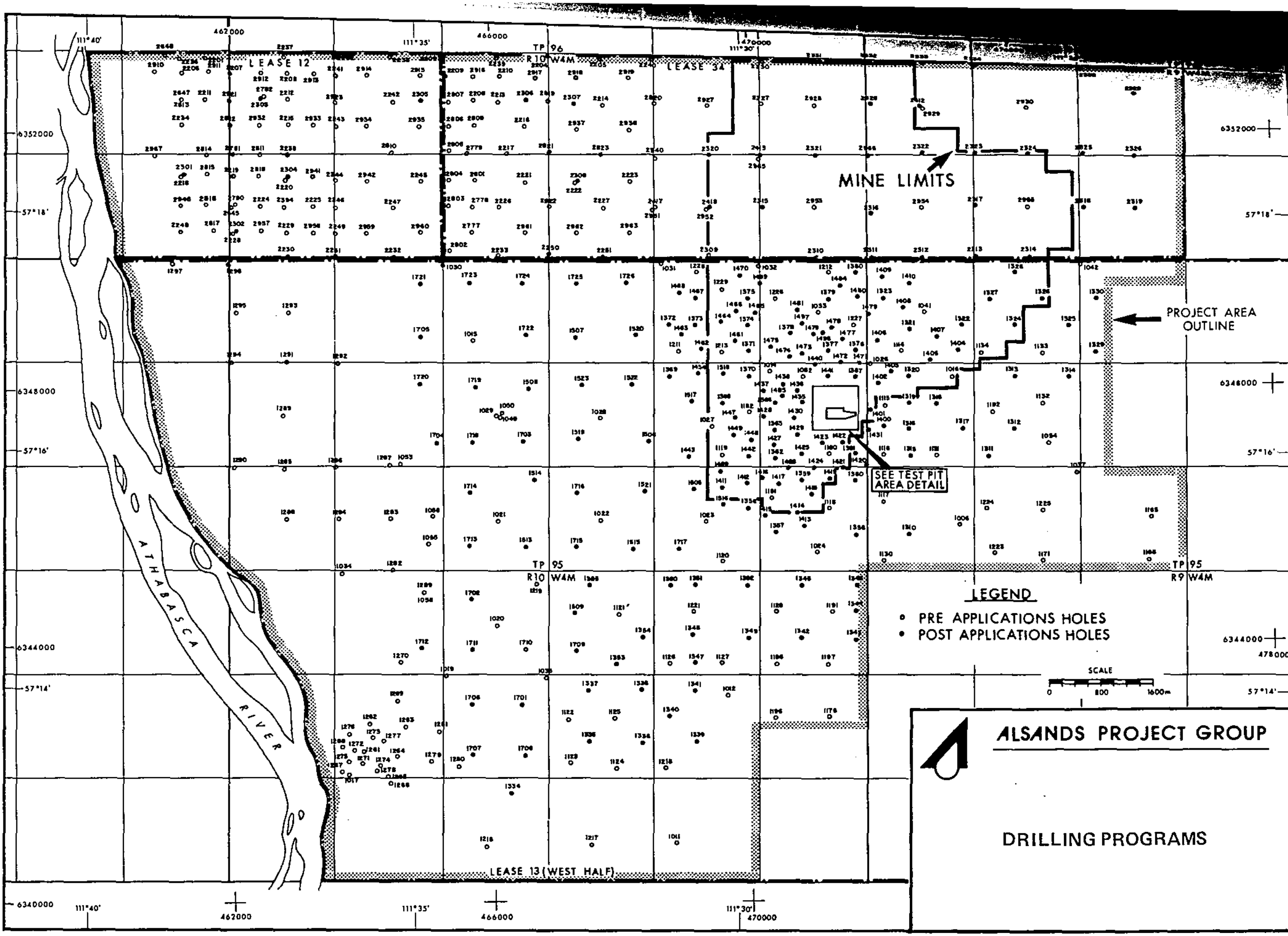
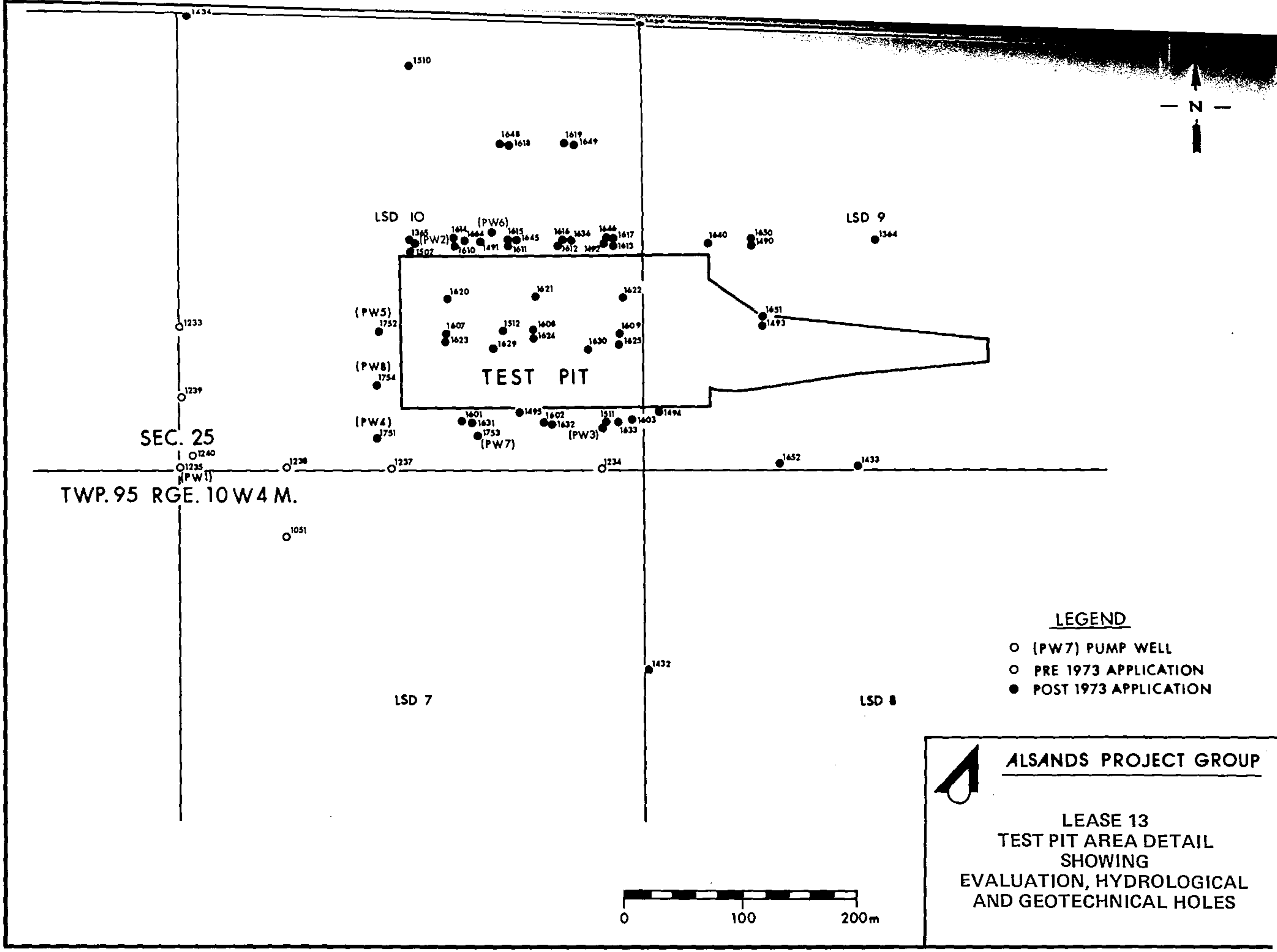
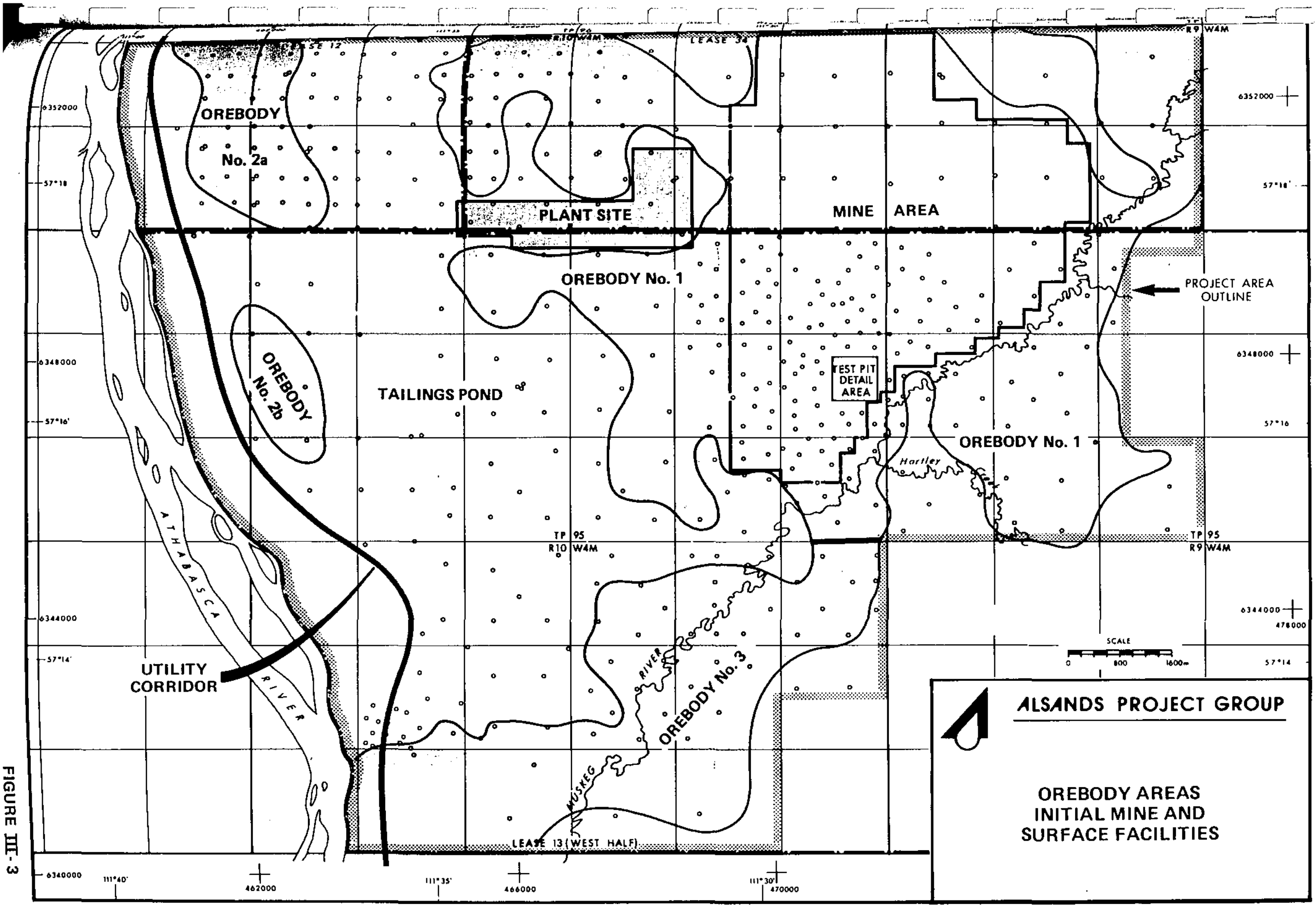

LEASE 12
LEASE 34
TP 96
R10 W4M
R9 W4M
MINE LIMITS
PROJECT AREA OUTLINE
SEE TEST PIT AREA DETAIL
TP 95
R10 W4M
R9 W4M
ATHABASCA RIVER
LEGEND
PRE APPLICATIONS HOLES
POST APPLICATIONS HOLES
SCALE
0
800
1600m
LEASE 13 (WEST HALF)
ALSANDS PROJECT GROUP
DRILLING PROGRAMS
462000
466000
470000
478000
6352000
6348000
6344000
6340000
111°40'
111°35'
111°30'
57°18'
57°16'
57°14'

FIGURE III-1



N
LSD 10
LSD 9
LSD 7
LSD 8
TEST PIT
SEC. 25
TWP. 95 RGE. 10 W 4 M.
(PW1)
(PW2)
(PW3)
(PW4)
(PW5)
(PW6)
(PW7)
(PW8)
LEGEND
(PW7) PUMP WELL
PRE 1973 APPLICATION
POST 1973 APPLICATION
0
100
200m
ALSANDS PROJECT GROUP
LEASE 13
TEST PIT AREA DETAIL
SHOWING
EVALUATION, HYDROLOGICAL
AND GEOTECHNICAL HOLES

FIGURE III-2



ALSANDS PROJECT GROUP
OREBODY AREAS
INITIAL MINE AND
SURFACE FACILITIES
OREBODY No. 2a
OREBODY No. 2b
OREBODY No. 1
OREBODY No. 3
PLANT SITE
MINE AREA
TAILINGS POND
TEST PIT DETAIL AREA
PROJECT AREA OUTLINE
UTILITY CORRIDOR
ATHABASCA RIVER
MUSKEG RIVER
Hartley Creek
LEASE 12
LEASE 34
LEASE 13 (WEST HALF)
R10 W4M
R9 W4M
TP 95
R10 W4M
TP 95
R9 W4M
SCALE
0
800
1600m
6352000
6348000
6344000
6340000
57°18'
57°16'
57°14'
111°40'
111°35'
111°30'
462000
466000
470000
476000

FIGURE III-3

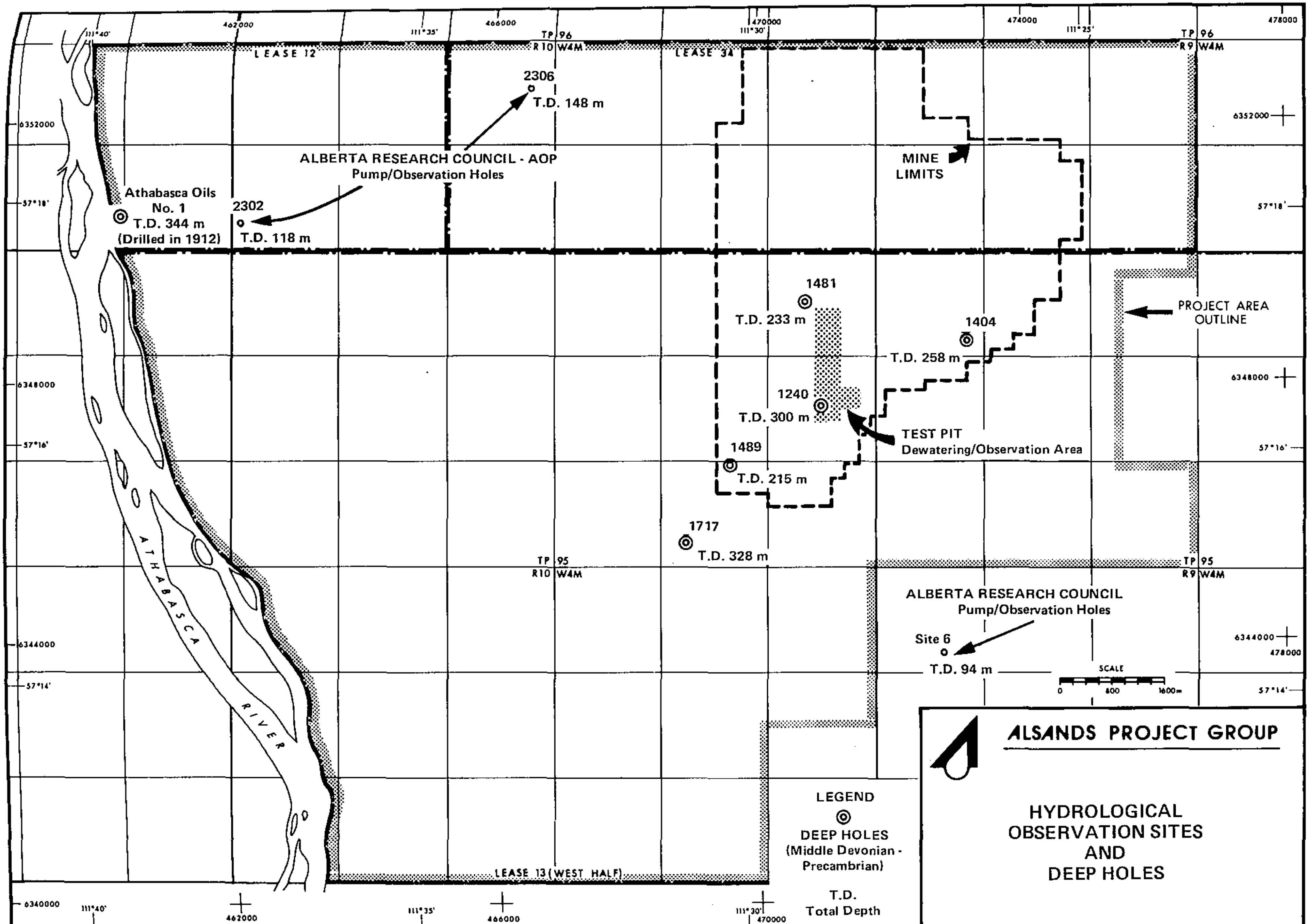
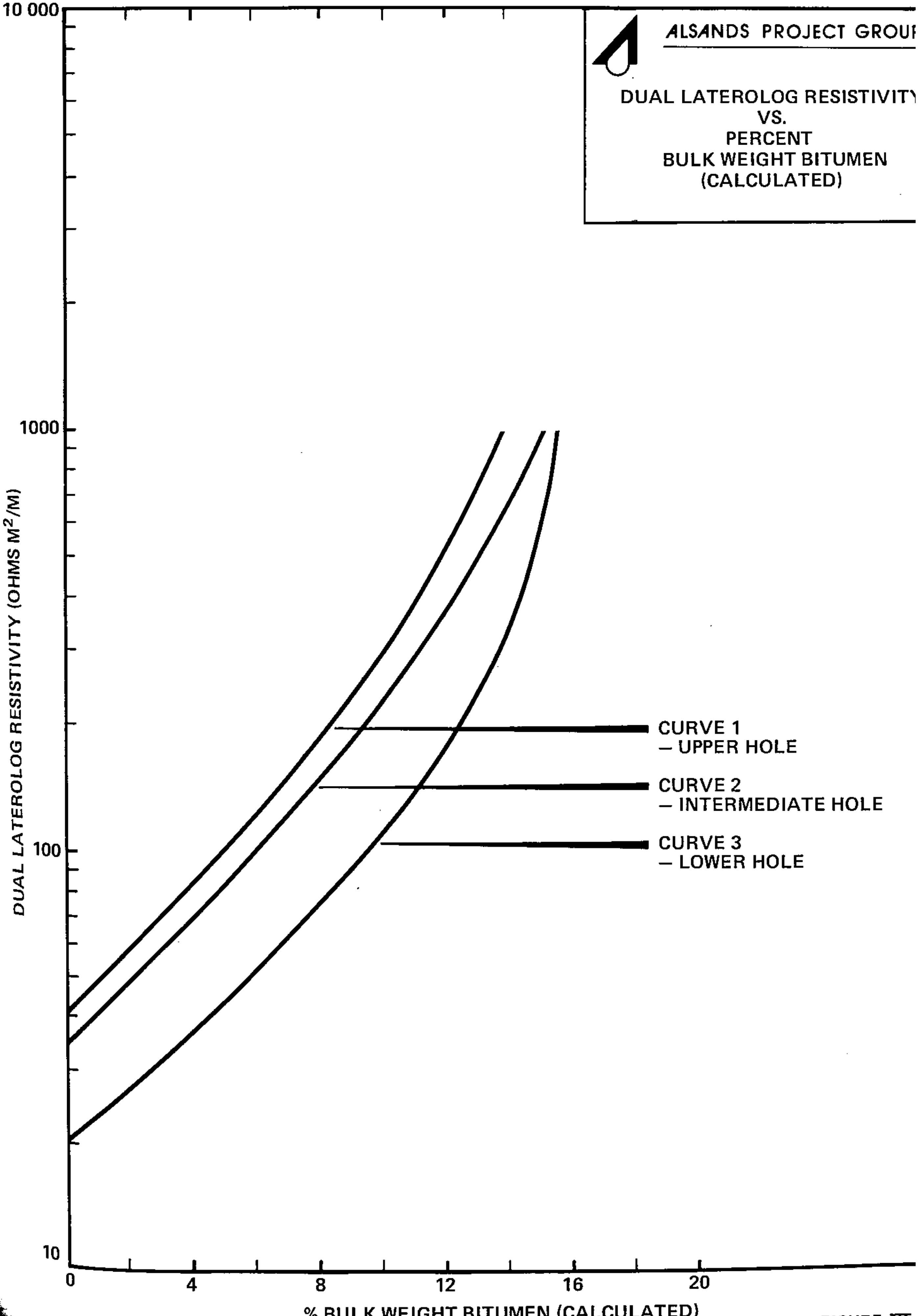

LEASE 12
LEASE 34
LEASE 13 (WEST HALF)
TP 96
R10 W4M
TP 96
R9 W4M
TP 95
R10 W4M
TP 95
R9 W4M
2306
T.D. 148 m
ALBERTA RESEARCH COUNCIL - AOP
Pump/Observation Holes
Athabasca Oils
No. 1
T.D. 344 m
(Drilled in 1912)
2302
T.D. 118 m
MINE
LIMITS
1481
T.D. 233 m
1404
T.D. 258 m
1240
T.D. 300 m
TEST PIT
Dewatering/Observation Area
1489
T.D. 215 m
1717
T.D. 328 m
PROJECT AREA
OUTLINE
ALBERTA RESEARCH COUNCIL
Pump/Observation Holes
Site 6
T.D. 94 m
ATHABASCA RIVER
SCALE
0 800 1600m
462000
466000
470000
474000
478000
6352000
6348000
6344000
6340000
111°40'
111°35'
111°30'
111°25'
57°18'
57°16'
57°14'
LEGEND
DEEP HOLES
(Middle Devonian - Precambrian)
T.D.
Total Depth
ALSANDS PROJECT GROUP
HYDROLOGICAL
OBSERVATION SITES
AND
DEEP HOLES

FIGURE III-4



ALSANDS PROJECT GROUP
DUAL LATEROLOG RESISTIVITY
VS.
PERCENT
BULK WEIGHT BITUMEN
(CALCULATED)
10 000
1000
100
10
DUAL LATEROLOG RESISTIVITY (OHMS M^2/M)
CURVE 1
– UPPER HOLE
CURVE 2
– INTERMEDIATE HOLE
CURVE 3
– LOWER HOLE
0
4
8
12
16
20
% BULK WEIGHT BITUMEN (CALCULATED)

FIGURE III-

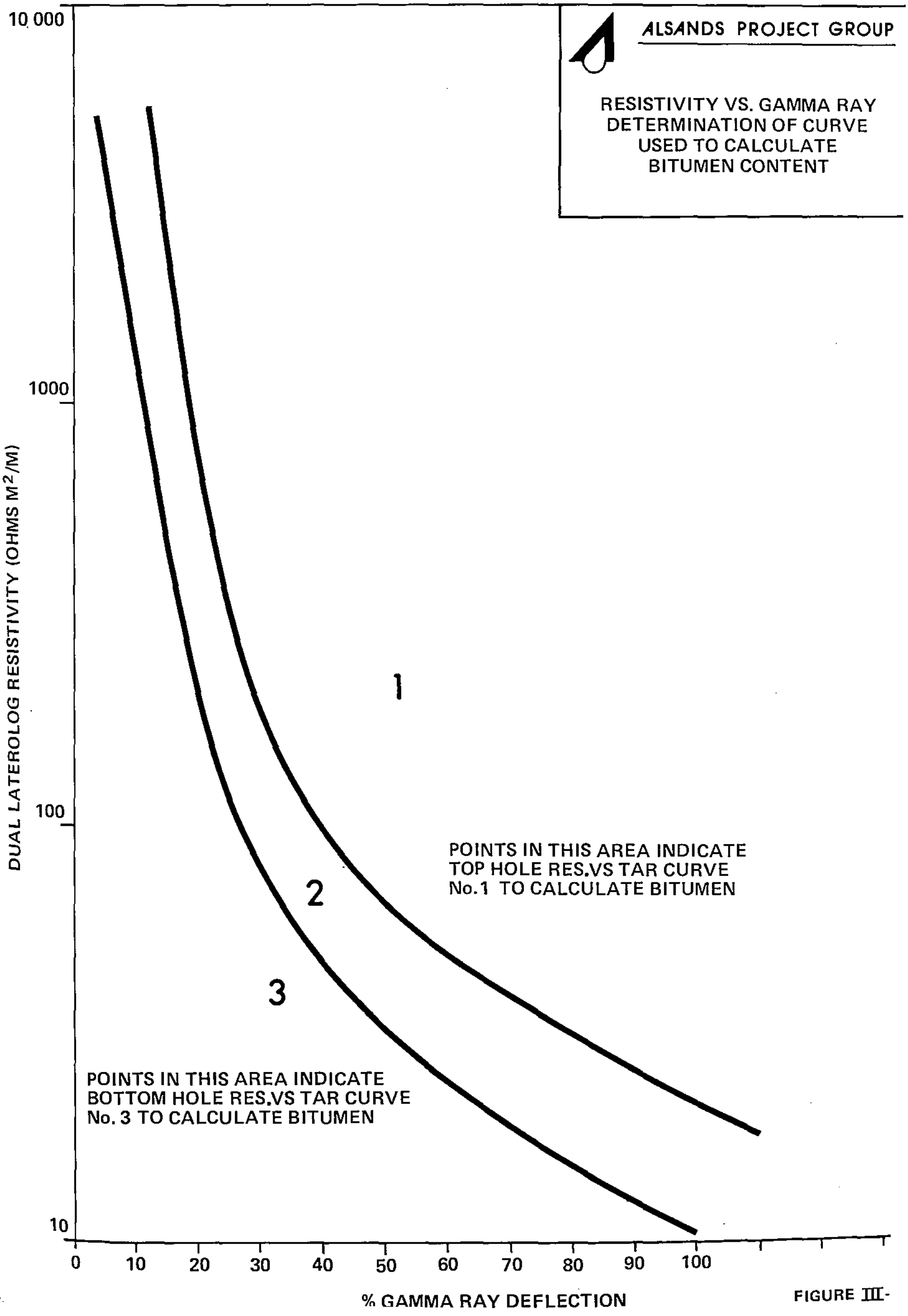
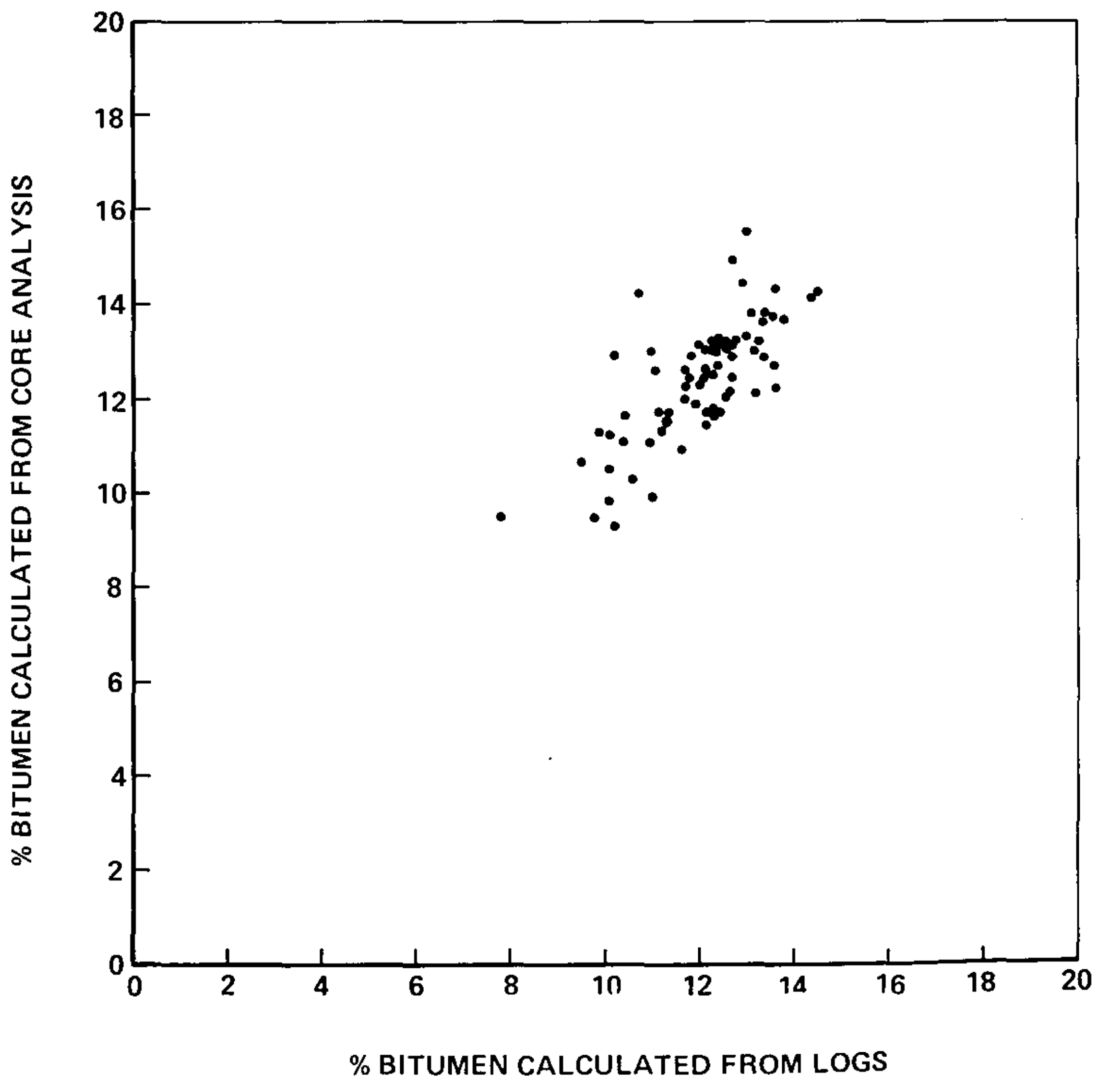

ALSANDS PROJECT GROUP
RESISTIVITY VS. GAMMA RAY DETERMINATION OF CURVE USED TO CALCULATE BITUMEN CONTENT
10,000
1000
100
10
DUAL LATEROLOG RESISTIVITY (OHMS M2/M)
1
2
3
POINTS IN THIS AREA INDICATE TOP HOLE RES.VS TAR CURVE No.1 TO CALCULATE BITUMEN
POINTS IN THIS AREA INDICATE BOTTOM HOLE RES.VS TAR CURVE No. 3 TO CALCULATE BITUMEN
0
10
20
30
40
50
60
70
80
90
100
% GAMMA RAY DEFLECTION

FIGURE III-

ALSANDS PROJECT GROUP

COMPARISON
OF THE AVERAGE BITUMEN
CALCULATED FROM
CORE ANALYSIS
VS.
LOG ANALYSIS



DATA FROM CORED HOLES UP TO
73/74 PROGRAM

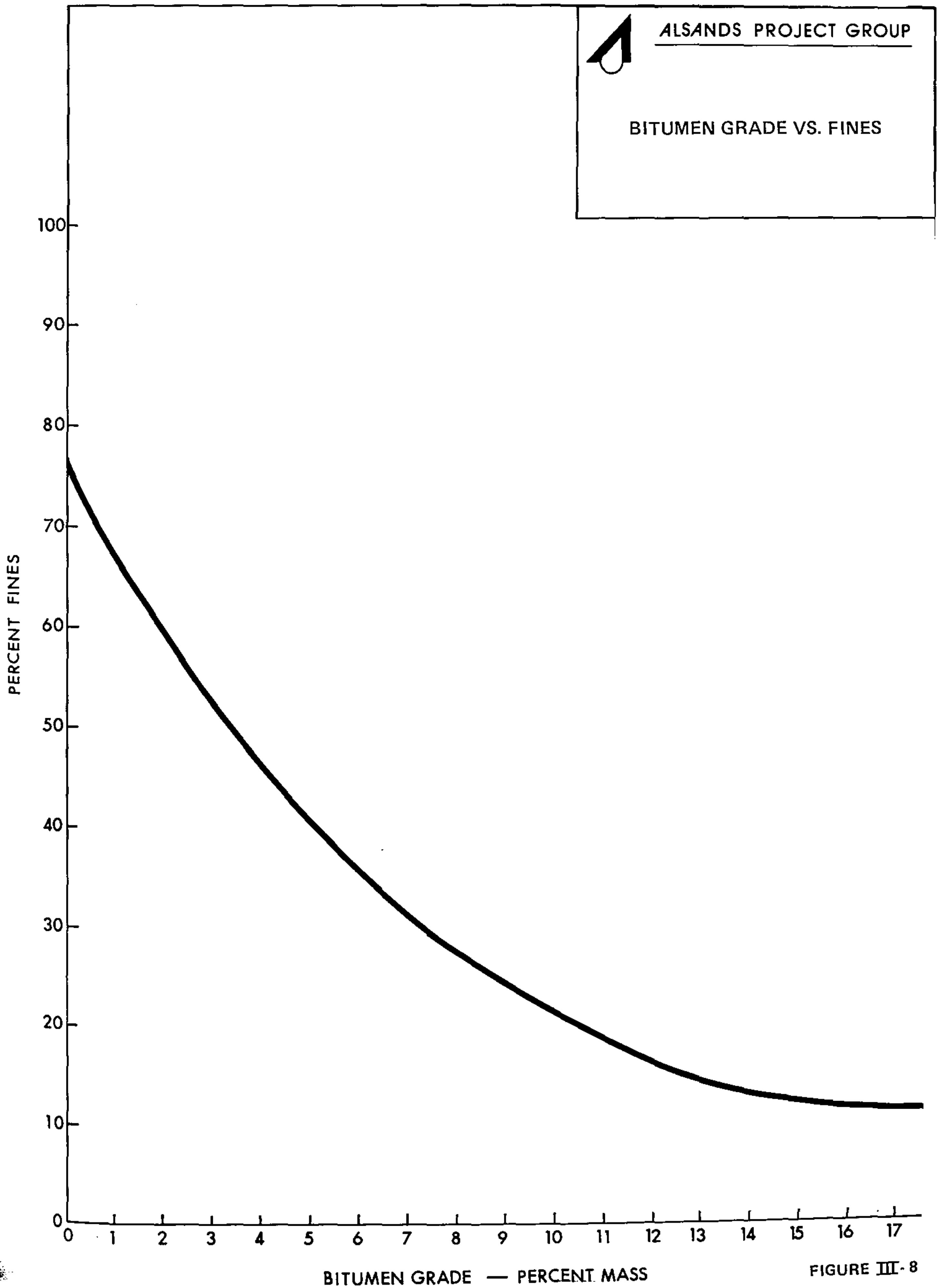
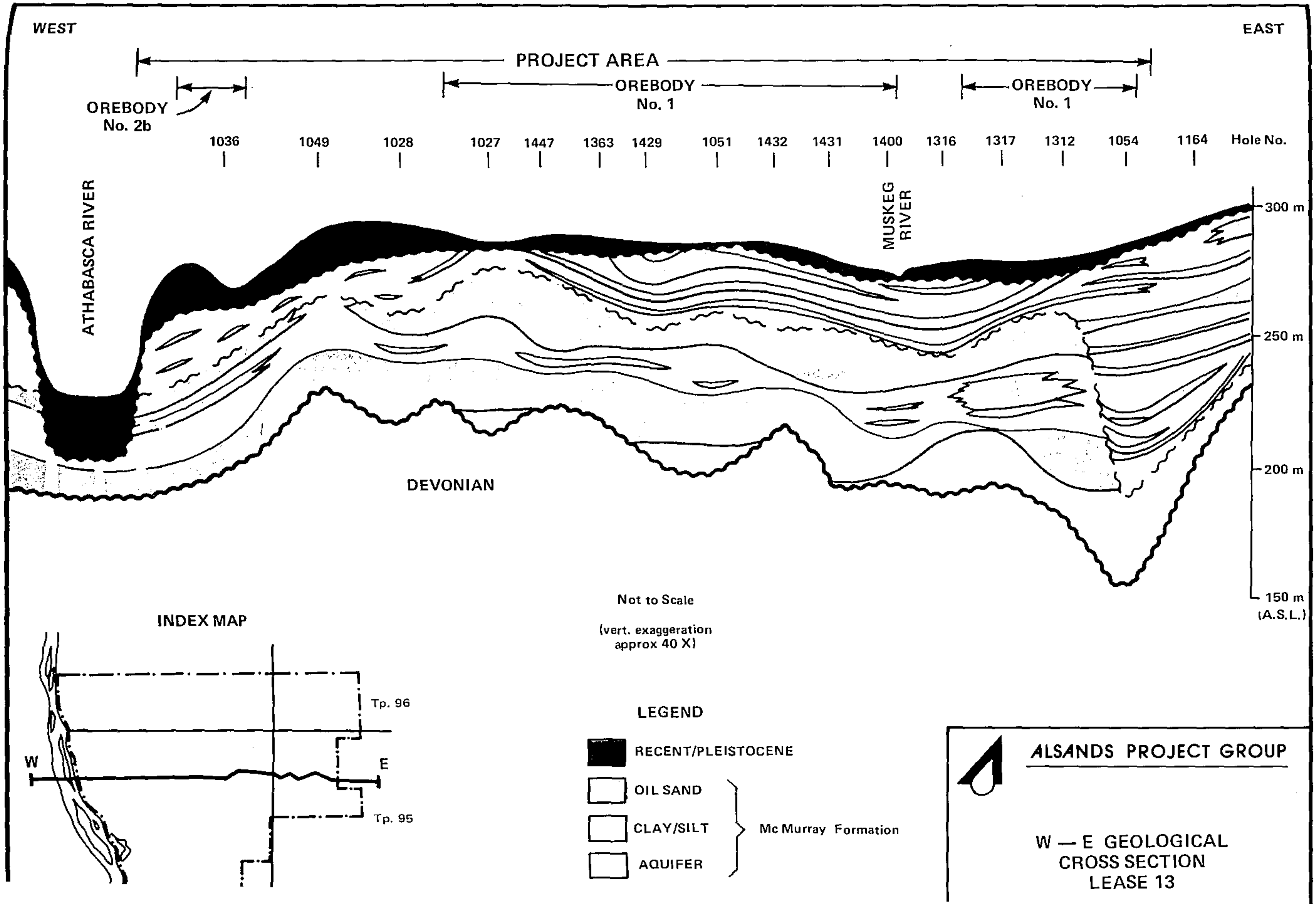

ALSANDS PROJECT GROUP
BITUMEN GRADE VS. FINES
PERCENT FINES
100
90
80
70
60
50
40
30
20
10
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17
BITUMEN GRADE — PERCENT MASS

FIGURE III - 8


WEST
EAST
PROJECT AREA
OREBODY No. 2b
OREBODY No. 1
OREBODY No. 1
1036 1049 1028 1027 1447 1363 1429 1051 1432 1431 1400 1316 1317 1312 1054 1164 Hole No.
ATHABASCA RIVER
MUSKEG RIVER
300 m
250 m
200 m
150 m (A.S.L.)
DEVONIAN
Not to Scale
(vert. exaggeration approx 40 X)
INDEX MAP
Tp. 96
Tp. 95
W
E
LEGEND
RECENT/PLEISTOCENE
OIL SAND
CLAY/SILT
AQUIFER
Mc Murray Formation
ALSANDS PROJECT GROUP
W — E GEOLOGICAL CROSS SECTION LEASE 13

FIGURE

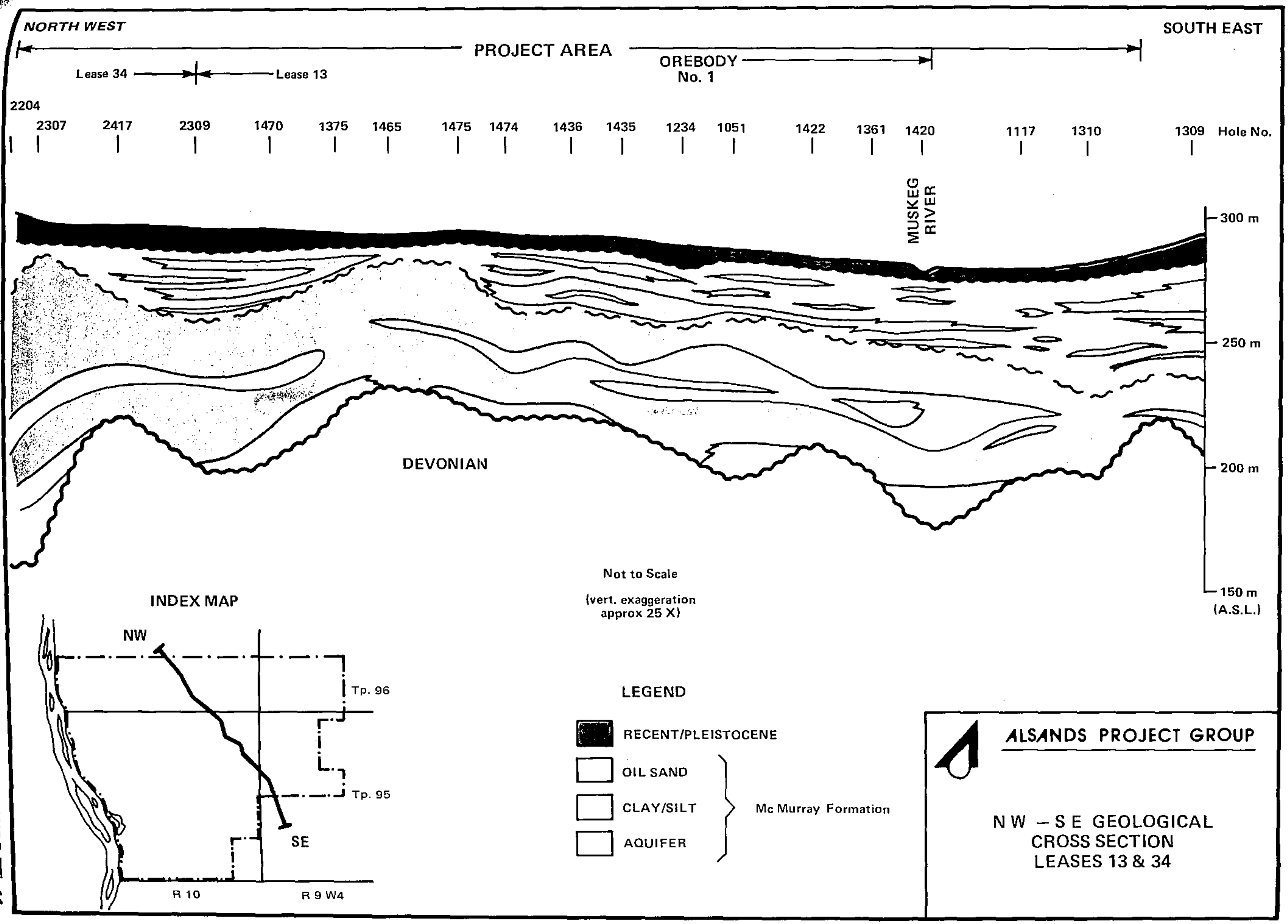
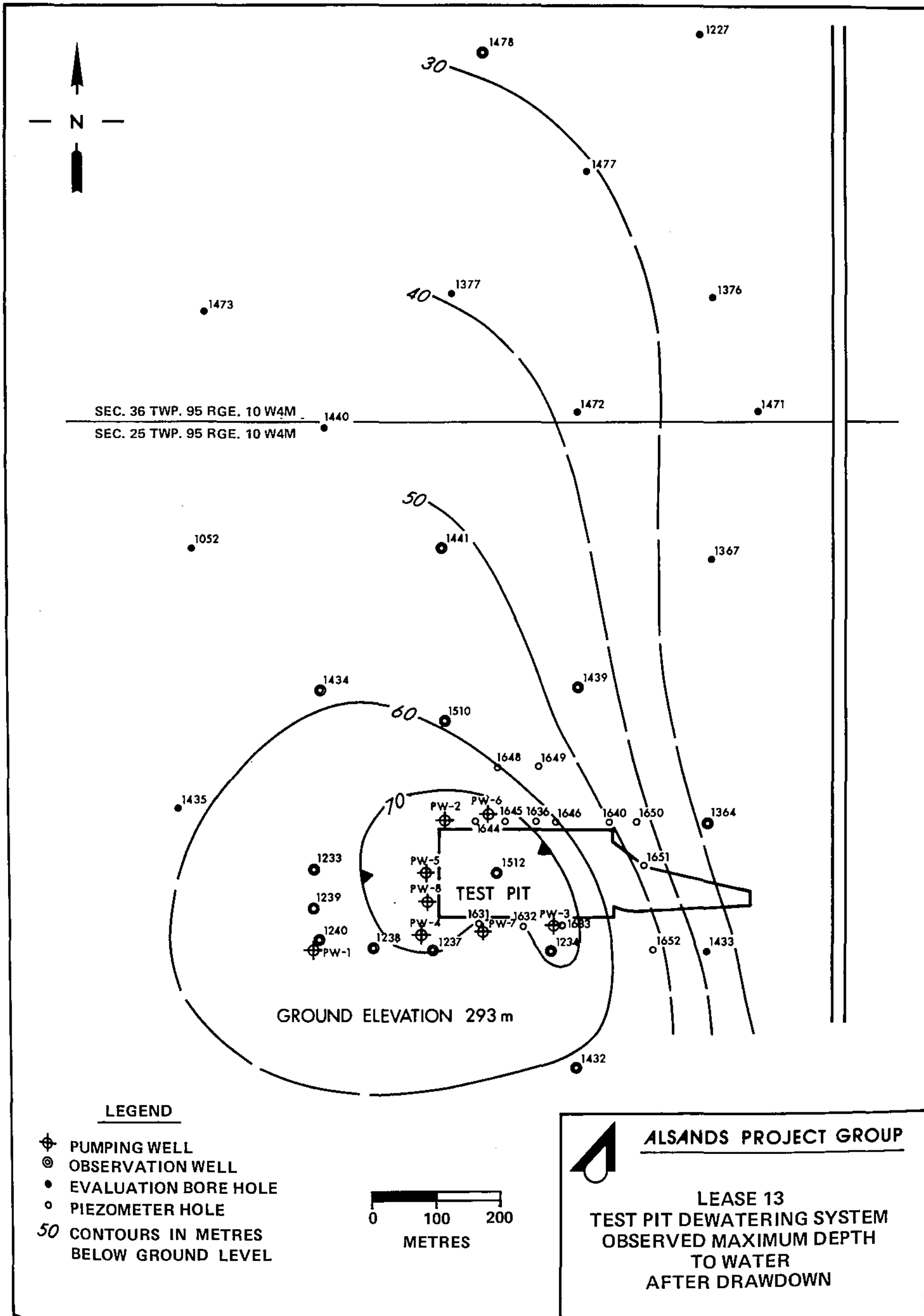


FIGURE III-11



ALSANDS PROJECT GROUP

LEASE 13
TEST PIT DEWATERING SYSTEM
OBSERVED MAXIMUM DEPTH
TO WATER
AFTER DRAWDOWN

FIGURE III- 12

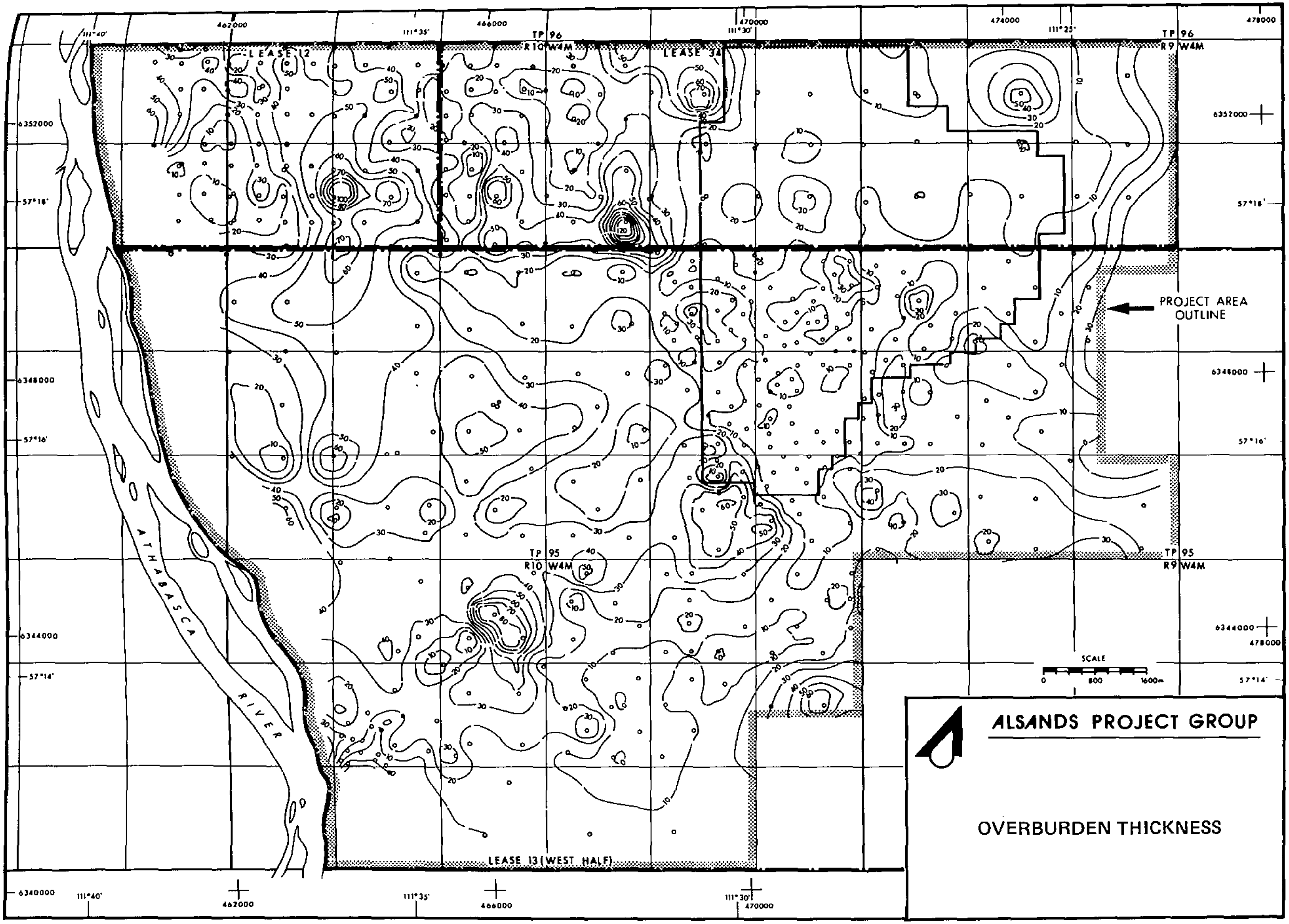


FIGURE III-13

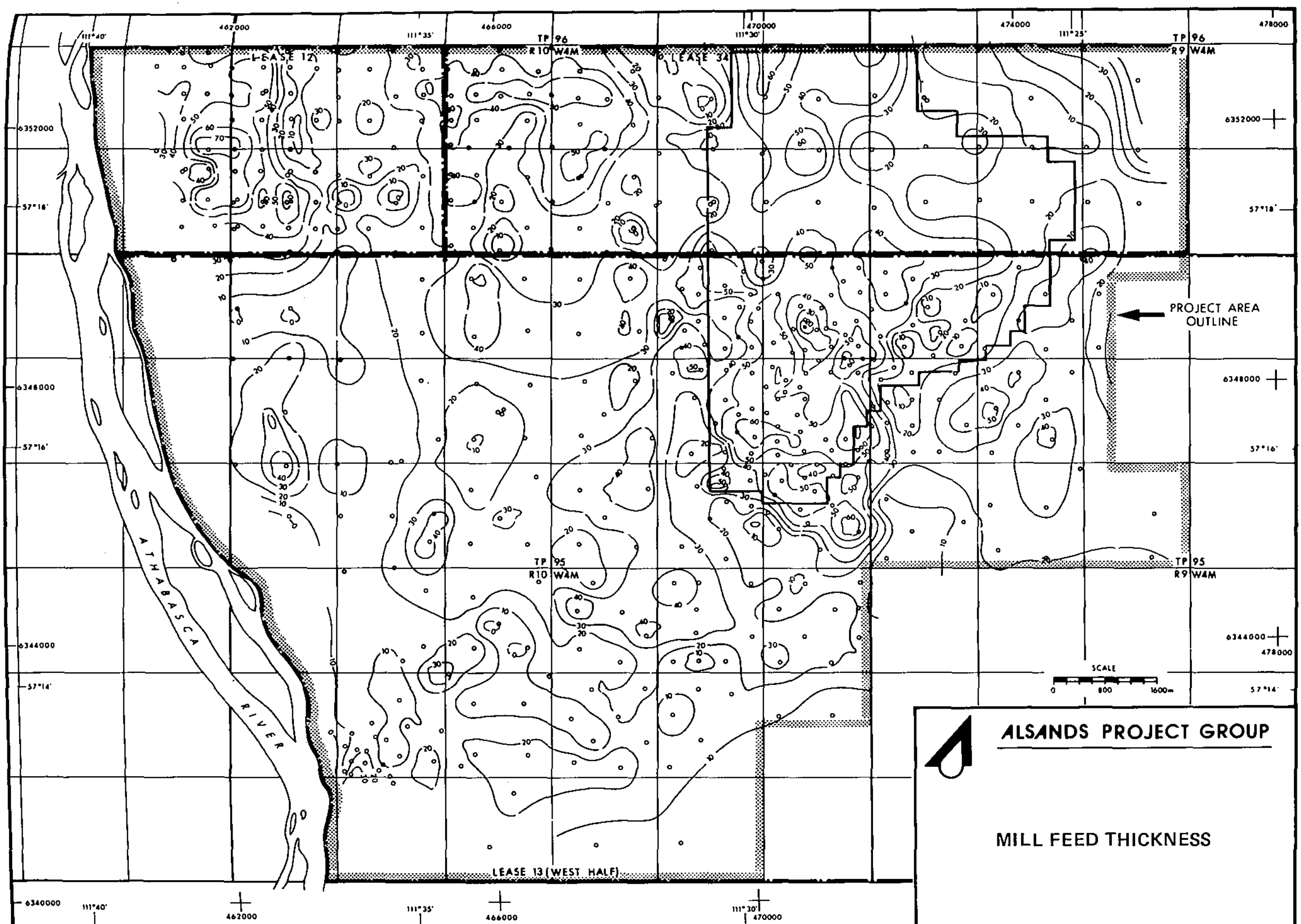
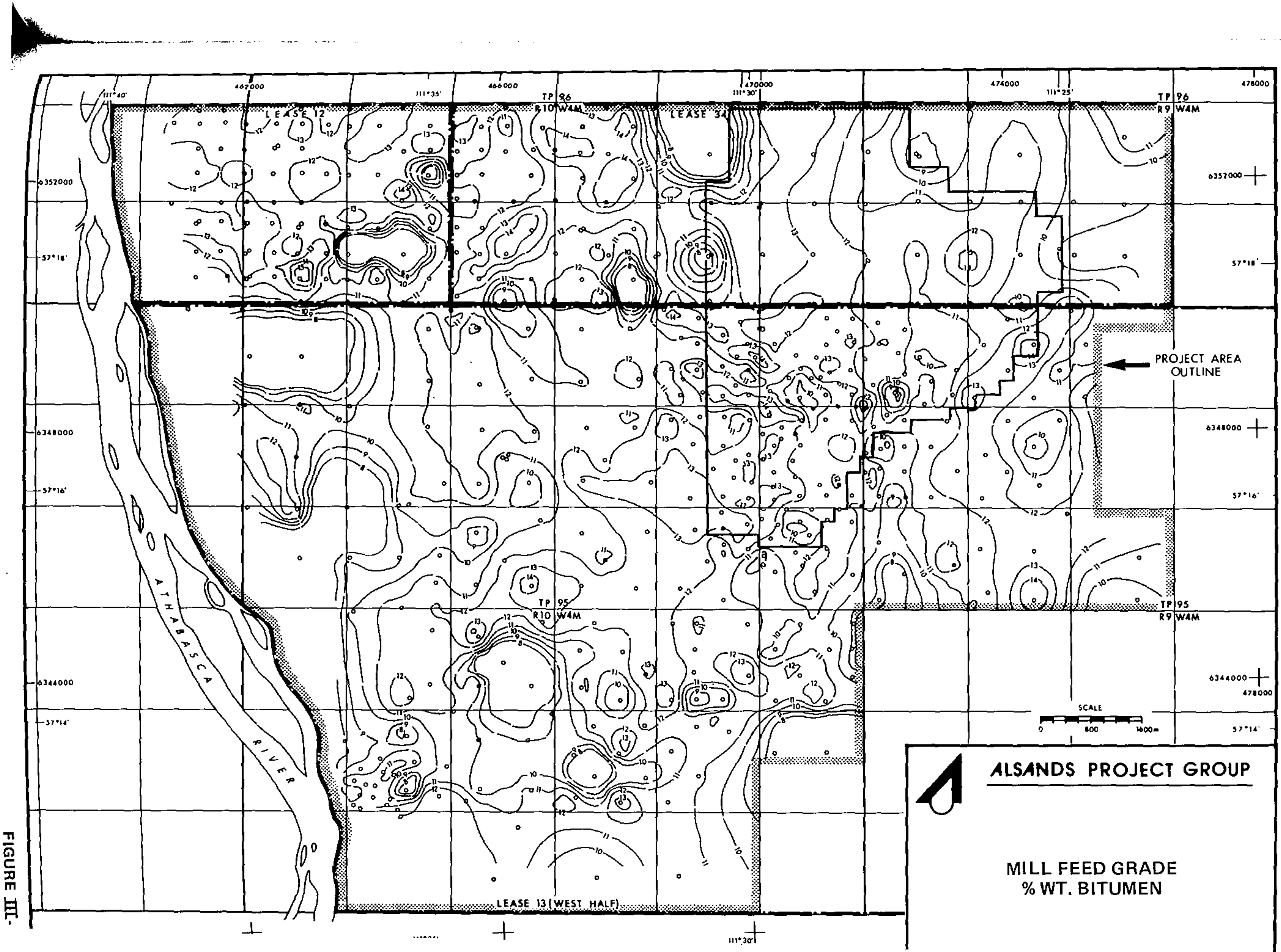


FIGURE III-14



LEASE 12
LEASE 34
LEASE 13 (WEST HALF)
TP 96 R10 W4M
TP 96 R9 W4M
TP 95 R10 W4M
TP 95 R9 W4M
PROJECT AREA OUTLINE
ATHABASCA RIVER
462000
466000
470000
474000
478000
111°40'
111°35'
111°30'
111°25'
6352000
6348000
6344000
57°18'
57°16'
57°14'
SCALE
0
800
1600m
ALSANDS PROJECT GROUP
MILL FEED GRADE
% WT. BITUMEN

FIGURE III-

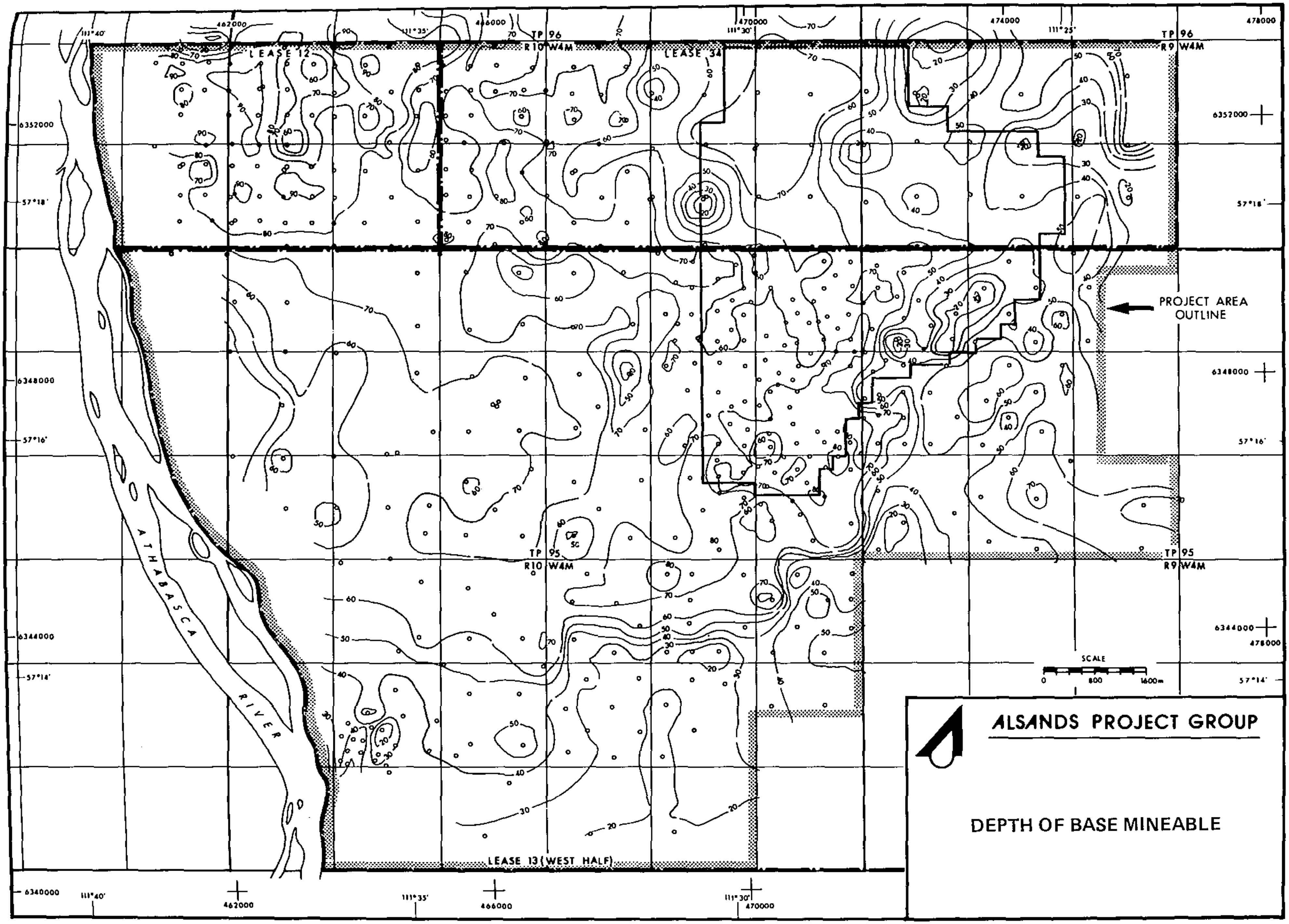


FIGURE III-16

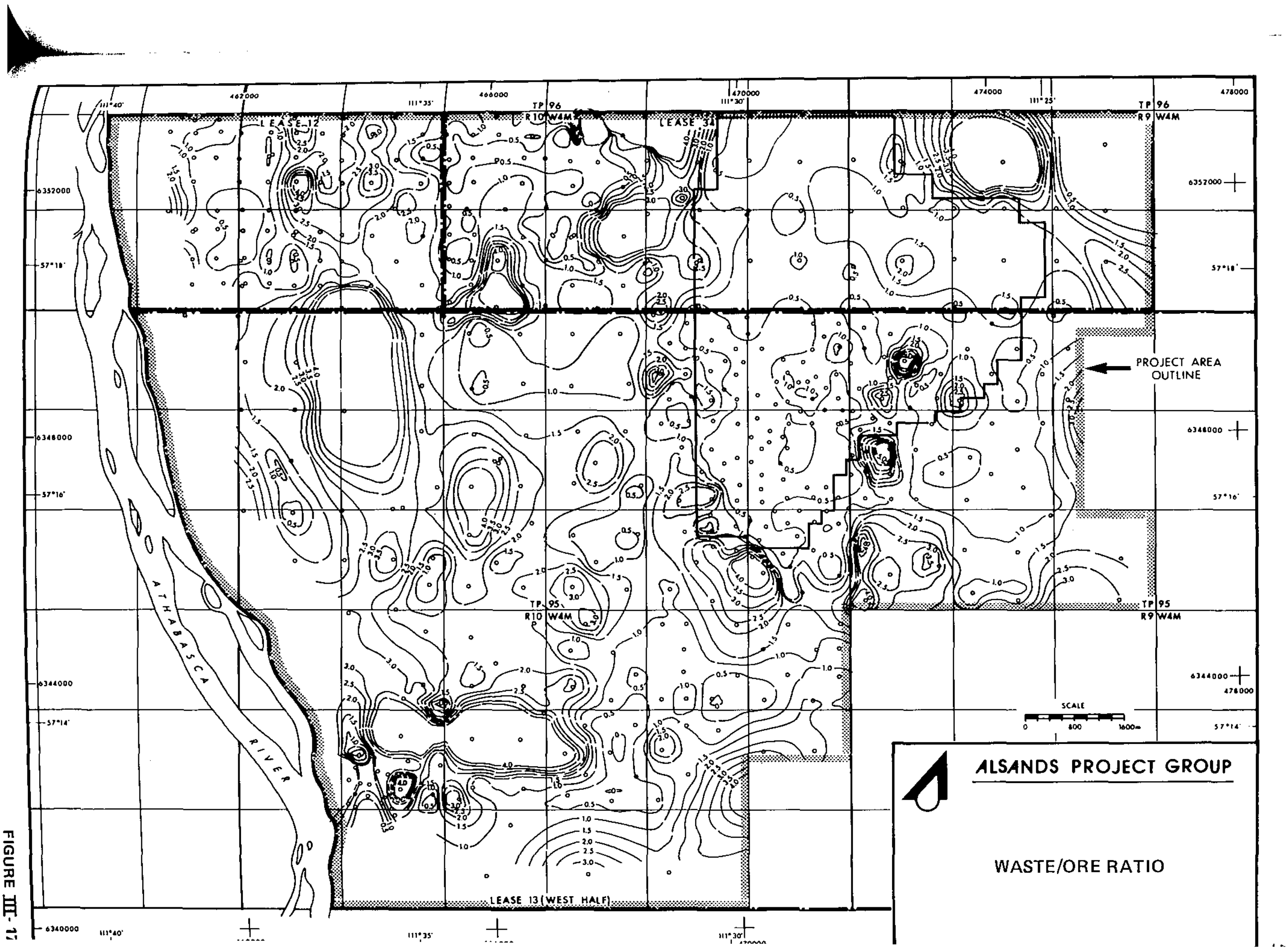
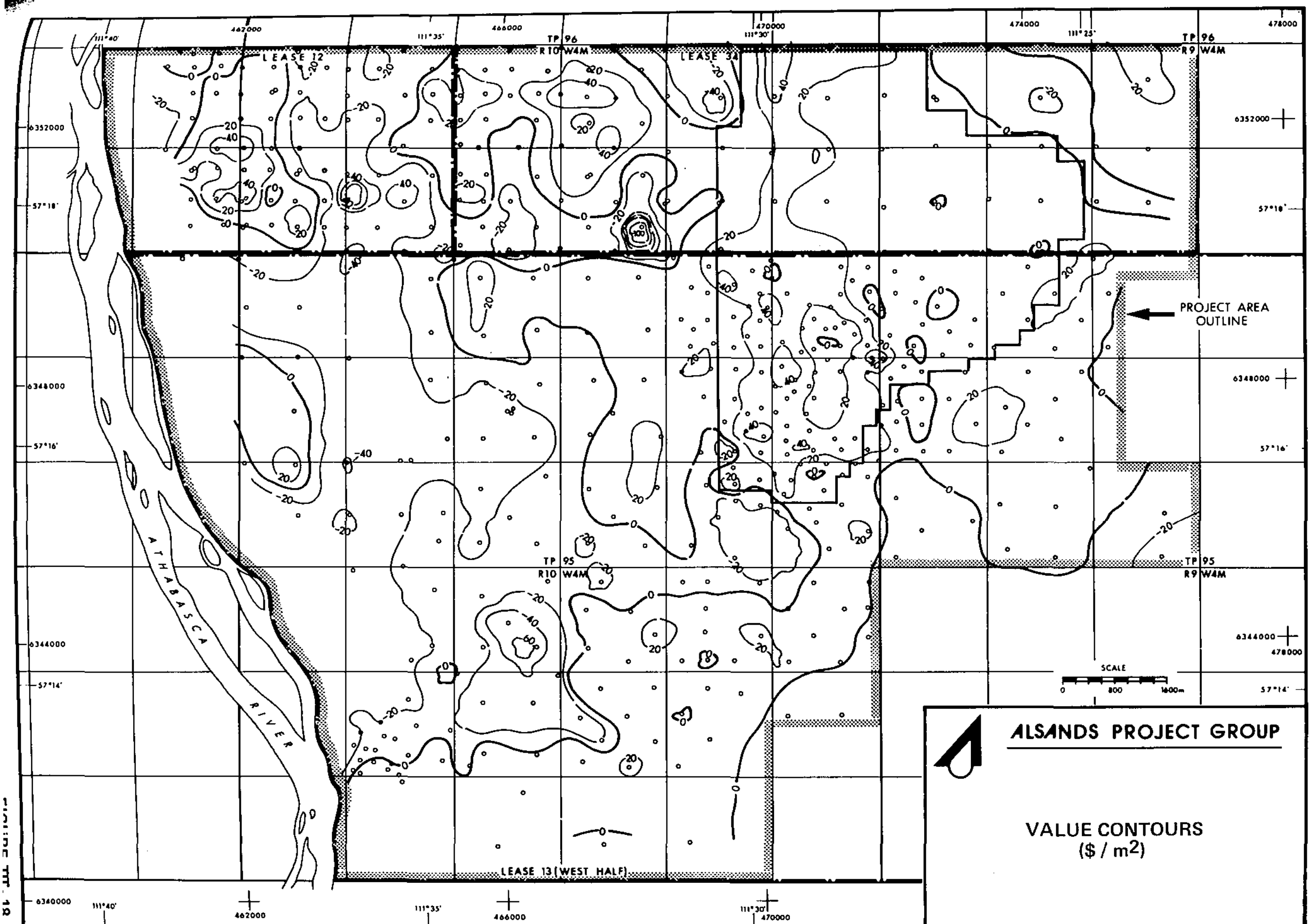


FIGURE III-17



VALUE CONTOURS
($ / m²)

FIGURE III.18

IV Site Preparation

General

Site preparation will consist of four major activities:
clearing
surface drainage
muskeg removal
final site preparation

The plant site and 5 year mine plan, as shown in Figure IV-1, will initially be prepared for construction and mining activities. After startup the mine area will be prepared as indicated in Table IV-1. The mine area is prepared generally 4 to 5 years in advance of mining to allow sufficient time for surface and near surface drainage and for muskeg removal.

Areas to be developed will be cleared. Merchantable trees will be identified and removed. Bush and other non-merchantable growth which predominate in the area will be arranged in windrows and burned.

Surface water will be drained from the plant and mine areas through a series of shallow ditches to the surrounding muskeg and ultimately to the Muskeg River. Early drainage of the plant site area is planned to serve as a pilot program for the much larger mining area program. Data will be gathered on drainage rates, water quantity and quality, and required spacing of ditches. Additional interceptor ditches around the entire site will be used to prevent water in the adjacent muskeg from entering the dewatered areas.

After drainage muskeg will be removed during the winter using trucks and front end loaders. An estimated 9×10^6 m^3 (12×10^6 yd^3) of muskeg must be removed initially from the plant site and the first 5 years of mine area. In total approximately 42×10^6 m^3 (56×10^6 yd^3) of muskeg will be removed.

The 9×10^6 m^3 (12×10^6 yd^3) of muskeg will be stored within containment dykes located in a natural depression approximately 3 km (2 miles) south of the plant site. The estimated 3×10^6 m^3 (4×10^6 yd^3) of borrow material required to construct the dyke will be obtained from the external tailings pond area or from the mine area as prestripped overburden.

Final site preparation in the plant area will involve further grading and possible excavation in order to ensure proper equipment foundations. A detailed geotechnical survey of the proposed plant site for foundations design will be completed when the plot plan has been finalized.

Final preparation of the mining area will involve the installation of the subsurface dewatering wells and the possible prestripping of overburden. Overburden will be prestripped along the initial mine face if detailed site investigations indicate that draglines may have stability problems on the surface material.

Granular Resources

The Project will require approximately 5×10^6 m^3 (6.5×10^6 yd^3) of granular material for concrete foundations, roads and general site preparations.

Site investigations of an area south of the mine (Figure IV-1) indicate reserves of sand and gravel of 9 to 17×10^6 m^3 (12 to 22×10^6 yd^3). Preliminary test borings carried out in 1978 indicated a potential granular source within 2 km (1 mile) northwest of the proposed plant site. Additional closely spaced test holes and pits will be required at both locations in order to detail the quality and quantity of the reserves, determine the preferred site, and define the pit layout.

The total area required for gravel pit development is estimated at 50 ha (125 acres). The largest portion of this will be opened and operated during the construction phase of the project, after which the land will be contoured and revegetated. A smaller gravel pit operation will be needed after the construction period, primarily to supply material for maintenance of roads on the lease. Again, reclamation would follow use of each pit area.

TABLE IV-1

TIMETABLE AND EXTENT OF SURFACE DEWATERING AND MUSKEG STRIPPING

AREA	HECTARES	YEAR CLEAR AND DEWATER	MUSKEG REMOVAL
Plant Site	270	1979	1980
Permanent Camp	48	1979	1980
Temporary Camp and Construction Area	500	1979	1980
Stockpile Area	16	1979	1980
Coke Storage	80	1979	1980
Mine Area			
Years 1-5	420	1980	1982
Years 6-10	540	1986-90	1988-92
Years 11-15	380	1991-95	1993-97
Years 15-25	660	1995-2005	1997-2007
Years 18-25	720	1998-2005	2000-2007

V Mining

Introduction

The selected mining area is suitable for mining by large draglines and contains reserves necessary to supply an oil sand Extraction Plant at a throughput rate of 25 040 m^3/d (157 500 B/D) of bitumen for 25 years. The outlined mining area is contained within Orebody No. 1 on Bituminous Sands Leases 13 and 34. Figure IV-1 shows the location of the mine area.

In order to supply feed with an overall average grade of 12.1 percent bitumen to the Extraction Plant at the rate noted above, an average mine output of 109 000 bank m^3/d (143 000 yd^3/d) of oil sands is required. This necessitates the movement of an average of some 176 000 bank m^3/d (230 000 yd^3/d) of total material within the mine area.

The mining technique selected by the Applicant for development of the orebody incorporates four large draglines in the 61 to 76 m^3 (80 to 100 yd^3) capacity class, as primary excavating equipment, with four bucketwheel reclaimers, one per dragline, for transferring material stockpiled by the draglines onto a conveyor transportation system.

The draglines will selectively mine beds of ore and waste material to an average minimum bed thickness of 4.5 m (15 ft). Ore will be transported either directly into the Extraction Plant or to a stockpile system ahead of the plant depending on plant requirements. Waste material will either be cast directly back into the mined areas by the dragline, or if insufficient storage volume is accessible, rehandled by the bucketwheel reclaimers and transferred via the conveyor system to the mined out areas. Single bench and double bench mining configurations have been developed to enable the draglines to mine to full orebody depths in the outlined mine area while applying the geometric constraints on highwall depth and slope angle imposed by geotechnical consideration for safe mining practice. These criteria were developed during the excavation of a test pit with a small dragline on Lease 13.

Extensive and contiguous single bench and double bench mining areas have been identified within the mine area. An orebody mining sequence, initiating in a single bench mining area will be implemented. The mining sequence recognizes the need to provide feed at a consistent bitumen grade to the Extraction Plant, this is accomplished in the later stages of the Project by blending material from two separate mining areas.

Equipment productivities developed by the Applicant indicate a need for supplementary capacity for waste removal in four years of the total operation. It is proposed to supply this capacity by utilizing front end loaders and trucks. This requirement will be reviewed once projected machine productivities can be confirmed.

Selection of Mining System

Two basic systems have been considered by the Applicant in developing a suitable economic method of excavating oil sand for feed to the Extraction Plant. The chosen method must fulfill the following requirements:

* utilize equipment of present technology,
* have proven capabilities of mining to the full depth of the orebody,
* allow a safe working environment.

The two mining systems considered were:

* a bucketwheel mining scheme utilizing bucketwheel excavators as primary excavating equipment with conveyors for ore and waste transportation,

* a dragline mining scheme utilizing large draglines as primary excavatir equipment, bucketwheel reclaimers for reclaiming mined oil sand and exce waste materials with conveyors for material transportation.

The dragline mining scheme is the preferred system for the followir reasons:

* the Applicant considers the dragline system to be a more economic minin scheme and therefore one which allows more oil sand to be economicall recovered. The increase in the combined present value (at 10 percent) of dire mine operating and capital costs for the bucketwheel excavator scheme estimated at 15 percent over the dragline scheme.
* the dragline is considered better able to mine selectively interbedded waste an oil sand materials.
* due to its ability to be selective, the dragline scheme reduces Extraction Plar feed for the same bitumen production rate, thereby requiring an Extraction Plar and supporting facilities with a lower capacity and less area for external tailing disposal. This reduces the present value (at 10 percent) of total Mining capit cost over the bucketwheel scheme by an estimated 12 percent.
* following the excavation of a test pit using a small dragline and the in-dept geotechnical studies associated with this test, the Applicant is confident that wit necessary monitoring of high wall slope performance, a dragline operation can b safely carried out to the depths anticipated with the constraints on minin configuration outlined in this Application.
* the proposed dragline mining scheme does not require equipment to work on mining bench formed on dewatered basal aquifer sands and clays as would b necessary on the lowest bench of a bucketwheel mining scheme. These materials particularly during and directly after rains would provide both difficult anc hazardous operating conditions.

Orebody Analysis and Reserve Estimation

GENERAL

An in-house developed automatic data processing system called TOBYS (Tarsand Orebody Evaluation System)has been used to locate target orebodies by analyzing the boreholes contained in the Alsands Project leases.

The TOBYS contains a cost model which with imposed constraining equipment and geotechnical parameters from the Project conceptual design defines waste and millfeed sections at each borehole. Critical parameters from this analysis, such as millfeed and waste thickness, millfeed grade and "value function" are then extrapolated to a uniform surface grid so that ore volumes and quality characteristics can be calculated over selected areas. Target orebodies are then delineated by the inclusion of all areas within the zero "value function" contours. Reserves and average orebody characteristics are computed for these areas. External constraints are then imposed on the target orebodies and the Project life area selected. Conventional mine planning techniques are applied to the Project life orebody to determine an operating sequence.

BOREHOLE DATA

The two major characteristics that determine oil sands quality are bitumen saturation (percent mass bitumen) and fines concentration (percent mass minus 44 micrometre material). This information has been obtained from analysis of cores and/or log data. These grade and fines data for each sample interval (0.25 m – 0.82 ft) in the boreholes are entered into the TOBYS system.

COST MODEL

The TOBYS cost model determines the value and depth of ore in a borehole by:
* calculating the grade value of each 0.25 m (0.82 ft) interval
* bedding the intervals by applying a mining equipment selectivity constraint
* calculating the value of ore for each borehole by subtracting the cost of waste removal
* applying dragline geometric constraints to determine the amount of waste which must be rehandled and adjusting the total value function accordingly to obtain a net value for each borehole.

Grade Value

The following equation is used to calculate the grade value of each interval:

$$Vg = [\ (G)\quad (Vb)\quad (R)\ ] - Cme$$

where Vg = grade value of interval ($/t)
G = observed grade of interval (mass fraction)
Vb = value of bitumen ($/t)
R = Bitumen recovery factor as a function of fines (fraction)
Cme = mining, transportation and extraction operating costs ($/t)

Vb, the value of a unit of bitumen required at the Extraction Plant gate to realize a specific rate of return on investment is calculated by subtracting all amortized project capital costs, royalties, taxes and Upgrading and Utilities operating costs from a projected plant gate price of synthetic crude.

R, the bitumen recovery factor is calculated from a curve of fines to bitumen recovery (Extraction Figure VI-2) and a value is assigned for each sample interval.

If the grade value Vg, as calculated above is positive, the interval is considered as containing potential economically mineable ore. Conversely, if the value is negative the interval may become part of a waste bed.

Interval Bedding

Since the mining scheme proposed cannot selectively mine beds of the thickness of the sample interval (0.25 m — 0.82 ft), the entire section must be "bedded". The criteria for bedding the section is that beds of potentially mineable ore or waste must have a thickness equal to or greater than the minimum thickness that the prime excavator is able to mine selectively (in this case 4.5 m — 15 ft).

The sample intervals are classified as potentially mineable ore or waste by calculating a bed "aggregate grade value" down the hole. In this way, the bed thicknesses of potentially mineable ore are maximized.

The result of applying the selectivity constraint is a sequence of beds, a minimum of 4.5 m (15 ft) thick, classified as potentially mineable or as waste.

Borehole Value

Once the hole has been bedded, the cost of removing waste is calculated by substituting a single average cost for the previously defined grade values in the waste beds and summing this cost for each waste bed in the hole (Figure V-1). Since the ore beds have already been assigned some positive value, the function is calculated by algebraically accumulating the ore bed value minus waste cost down the hole. The bottom of the deepest ore bed at which this function is positive is defined as the economic depth cutoff and hence the bottom of the mine. The assigned magnitude of this value function (called *Value* and expressed as dollars per square metre) at this point is an indication of the relative value of the ore intersected by the borehole.

Geometric Constraints

Consideration is given to the geometry of dragline operations during the borehole analysis in order to approximate the effects of a finite maximum digging depth and waste volume to the volume accessible for direct casting of waste into the mine.

In the conventional single bench scheme, the dragline sits on the highwall, casts waste back into the previously mined-out cut and stockpiles millfeed on the highwall. When the waste volume is less than the spoil space available, waste is charged at a simple cast cost. Should the waste from the current panel exceed the spoil space available, some portion of the waste must be rehandled. In areas of orebody depth requiring two bench operations, both millfeed and waste from the top bench are stockpiled on the highwall. In this case all the waste from the top bench must be considered as rehandle. The bottom bench analysis is conducted in the same manner as the single bench mode.

The cost of rehandling waste material is subtracted from the value function calculated above to obtain the net value for the borehole.

Selection of the Initial Mine Area

An initial mine area containing twenty-five years of bitumen reserve at a production rate of 25 040 m^3/d (157 500 B/D) of bitumen, suitable for dragline mining has been outlined and is shown in Figure IV-1.

The mine area was selected on the basis of its suitability for being economically mineable utilizing a dragline mining scheme; that being the mining scheme considered by the Applicant to be most suitable for oil sand mining to an orebody depth of 90 m (295 ft), as detailed under Selection of Mining System. However, the selected mine area has not been constrained to this depth limitation.

In selecting the initial mine area consideration was given to the following parameters:

orebody depth
overburden thickness
waste to ore ratio
economic value

OREBODY DEPTH

The chosen mine area is one of comparatively shallow ore depth in which the amount of potentially economic recoverable tar sand remaining after mining due to depth constraints imposed by the dragline mining scheme has been minimized.

OVERBURDEN THICKNESS AND WASTE TO ORE RATIO

Overburden in this context is defined as all material above the economic orebody.

The waste to ore ratio is defined as the mass ratio of total waste material (including both overburden and waste material which can be selectively mined from within the orebody) to the total ore recoverable by the proposed dragline mining scheme.

The mine area has been selected as an area of relatively shallow overburden, typically less than 20 m, and of low waste to ore ratio, averaging 0.59 by mass for the mine area. This minimizes both the amount of necessary nonproductive dragline mining, and the necessity for rehandling waste material where the amount of waste material requires more in pit storage volume than is available for direct casting by the dragline. In pit storage volume will be constrained in single bench mining by shallow highwall slope angles and a limited dragline dumping radius.

VALUE

Value as defined in the section above on Orebody Analysis and Reserve Estimation has been used in the selection of the initial mine area. Areas indicated to be economic have a positive value.

The chosen mine area encompasses mostly areas of positive value but does, however, contain areas showing negative value which would be impractical to mine selectively as orderly mining progresses.

Mining limits have been restricted to the east and southeast by the Muskeg River. The environmental ramifications of diverting the river to release potential bitumen reserves make the development of these reserves undesirable at this time.

Northern mining limits are restricted by an oil sand lease boundary; however it is the intention of the Applicant to negotiate with the lease holder at an appropriate time for rights to continue mining to the economic limits of the orebody, which constitutes a further 2.5 years of orebody life at a rate of 25 040 m^3 /d (157 500 B/D) bitumen production.

Excavation Plan

GEOTECHNICAL PERFORMANCE OF OIL SAND MINING SLOPES

One of the major concerns of utilizing large draglines for mining oil sand formation has been the predicting of the performance of steep angled highwall slopes of this material.

In order to obtain the geotechnical information necessary to predict the performance of highwall slopes excavated in oil sand formations, the Applicant has excavated a test pit, utilizing a 9.2 m^3 (12 yd^3) capacity dragline on Lease 13. A geotechnical consultant was retained during excavation to monitor the performance of the highwall slopes and to provide design recommendations for full scale mining.

The observed mode of failure is considered to have the greatest impact on the design slopes incorporated in the excavation plan described under the Primary Excavation Section and is described in detail below.

The effect of the McMurray basal aquifer and its associated hydrostatic pressures on slope stability are discussed under the Dewatering Plan Section.

Mode of Failure

The predominant mode of failure of pit highwalls in oil sand formations is by slabbing (the peeling of material from the highwall in layers ranging from centimetres to metres in thickness). Slabbing occurs preferentially in layers of high grade oil sand. Once initiated, slabbing may continue upward toward the crest of the highwall resulting in continued retrogression of the highwall until a stable slope configuration is attained. The stable slope configuration is one of a steep angled highwall (70 degrees) buttressed by a talus slope covering up to 80 percent of the total highwall. Figure V-2 shows schematically the observed slope failure.

Slabbing is minimal to mining depths of between 35 m and 45 m (115 ft and 150 ft) with slope angles up to 70 degrees, with no retrogression of the highwall crest. At greater mining depths while retaining highwall slope angles of 60 to 70 degrees, the rate of slabbing increases and retrogression of the highwall crest occurs. When the highwall slope angle is limited to 45 degrees or less the rate of slabbing is greatly reduced and retrogression of the highwall crest is minimized or non-existent.

The Applicant acknowledges that although conditions did not occur during the excavation of the test pit to precipitate rapid full face failure of the mined slopes, there can occur during the course of mining unfavourable geologic conditions which may cause such a failure (for example, steeply dipping bedding surfaces or the presence of slickensided highly plastic basal clay strata). Such conditions have not been identified within the proposed mine area, however, the Applicant will carry out sufficient exploratory drilling and slope monitoring ahead of mining to identify these conditions. Any necessary modifications will then be made to the mining plan to ensure a safe mining operation and maximize reserves recovered.

Slope Monitoring

Highwall slope performance will be monitored ahead of dragline mining in oil sand to provide adequate warning of possible hazardous mining conditions. This is particularly necessary during the initial excavation of the mine since it is during this period that conditions behind the mine faces are least stable.

Based on the experience gained during the excavation of the test pit, slope monitoring with piezometers, slope indicators and conventional surface surveys together with continuing visual field observations and geological assessment for detection of unfavourable detail will have the capability of ensuring safety to personnel and equipment with regard to the stability of mine faces. These systems are mutually supporting and have the capability of providing sufficient advance warning of potentially unstable conditions to permit any necessary corrective measures to be taken.

The Applicant will use those monitoring techniques outlined above and any other techniques which may be considered necessary to ensure safety of mining operations.

Surficial Deposits

The problems associated with the operation of large draglines and bucketwheel reclaimers through incompetent surficial deposits is recognized. It is proposed to carry out a detailed assessment of the surficial deposits in the outlined mine area to define those materials which could effect the safe operation of large mining equipment. Incompetent materials of low bearing strength will be removed ahead of mining and disposed of in mined out areas or used if required for reclamation purposes.

DEWATERING PLAN

Four distinct water bearing zones have been identified:
* shallow aquifer
* intra-orebody aquifer
* basal aquifer
* Methy aquifer

Dewatering of the shallow aquifer and depressurization of the basal aquifer are required prior to mining.

Surface water from natural runoff will be prevented from entering the mining area by perimeter ditching. These ditches will form an integral part of the surface aquifier drainage system.

Shallow Aquifer

A water bearing zone is contained within the surface sands and gravels that comprise a portion of the mine overburden (Chapter III). The zone ranges from 3 to 5 m (10 to 16 ft) in thickness in the initial mine area. Dewatering will be carried out by a system of drainage ditches as part of site preparation.

Dewatering of this zone is necessary to improve the competency of the Pleistocene material and to prevent surface water from being channelled into the working areas of the mine.

The water contained within this shallow aquifer has a low chloride content and is considered fresh. The table in the Local Hydrological Appraisal section in Chapter III shows maximum chloride levels measured on the Applicant's leases. Disposal of the water will be into existing natural drainage systems.

Intra-Orebody Aquifers

Thin discontinuous artesian water bearing zones occur within the McMurray formation. These aquifers are encountered during the normal course of mining and are slowly dewatered by natural seepage out of the mine faces. Water flows experienced during the excavation of the test pit were minor and there was no evidence of interconnection with the major basal aquifer at the base of the McMurray formation.

No slope stability problems are anticipated from these aquifers.

Water accumulations at the base of the mining faces will be removed as required by sump pumping; disposal of this water will be into the tailings disposal pond.

Basal Aquifer

A thick (5 to 30 m – 16 to 100 ft) extensive artesian water bearing zone has been identified at the base of the McMurray sands (Chapter III).

Detailed hydrological studies on this aquifer have been carried out by the Applicant prior to and during the excavation of the test pit. From this work it was determined that the piezometric head in the aquifer will be within 5 m (15ft) of the natural ground surface. Since the oil sand formation is virtually impermeable, the lowering of the piezometric head within the aquifer does not reduce the pore pressures within the tar sand formation.

It is the opinion of the geotechnical consultants retained by the Applicant during the excavation of the test pit, that depressurization of the basal aquifer will not affect the stability of a mine face as long as the governing mode of failure is retrogression of the face by slabbing. It will, however, be essential to depressurize the aquifer to prevent failure of the pit floor in areas where the thickness of formation is less than that required to contain the pressure within the aquifer. If failure of the pit floor occurs, piping of the aquifer may result in undercutting of the mine face and could cause block or full face failure.

It is the intention, therefore, of the Applicant to depressurize this aquifer ahead of mining. This was successfully accomplished during the excavation of the test pit by deep well pumping, and it is intended to use this method, utilizing the well completion techniques developed by the Applicant, during the initial phases of full scale operation.

Pump wells will be completed and developed in favourable thick aquifer regions and not necessarily on a regular grid pattern. Available gamma and resistivity logs of holes will be used for locating the favourable aquifer regions. Where aquifer conditions cannot be adequately defined, pilot holes will be drilled and logged before pump wells are drilled. The effectiveness of the pumping system will be verified by well observation before deep excavation begins.

Alternate methods of aquifer depressurization such as a passive system incorporating perforated pipes placed in grade control holes ahead of mining may be investigated as mining progresses. Sump pumping of accumulated water at the base of the mining face would then be required.

WATER QUALITY AND DISPOSAL

The basal aquifer water has a total dissolved solids content less than 4500 mg/L mostly consisting of sodium chloride (approximately 1800 mg/L). and sodium bicarbonate (approximately 1500 mg/L). Table V-1 gives a typical analysis of the discharge water from the basal aquifer taken during the excavation of the test pit. The water from the test pit was passed through a settling pond to remove suspended solids and then filtered through straw to remove any entrained bitumen traces prior to discharge into the Muskeg River.

Depressurization of the McMurray basal aquifer will begin 18 months prior to mining. Disposal of the water during the opening cuts of the mine prior to the development of the external tailings pond, estimated at 115 L/s (1800 USGPM), will be into the Muskeg River via a settling pond and filtering system. The Applicant will monitor discharge and river water quality on a continuous basis. If it is found that there is insufficient dilution of chlorides during low flow periods of the river, the water will be contained on the lease and disposed of only during periods of high flow.

When external tailings pond facilities are adequately developed, disposal of aquifer water will be into this system where it will be recycled for use in the Extraction Plant.

Methy Aquifer

The Methy reef, occurring within the Middle Devonian carbonate section contains a saline aquifer approximately 100 m (330 ft) below the basal aquifer (Chapter III). The measured piezometric head of this aquifer is some 20 m (66 ft) below ground surface, i.e., 18 m (59 ft) below that of the McMurray basal aquifer.

Observation wells completed in the Methy aquifer have shown no response to pumping tests carried out by the Applicant in the McMurray basal aquifer. It has been concluded from the substantial amount of data obtained from these tests that no hydraulic connection exists between the two aquifers, through the approximately 100 m (330 ft) of competent impermeable Devonian formation by which they are separated.

The Applicant will however, monitor aquifer conditions within the Methy reef during the planned deep well pumping of the McMurray basal aquifer prior to and during mining operations.

Methy aquifer water under the mine area has a total dissolved solids content of up to 22 500 mg/L, mostly consisting of sodium chloride (17 700 mg/L). In the unlikely event of connection occurring between the McMurray and Methy aquifers, indicated either by a drop in piezometric head within the Methy aquifer or a substantial increase in the chloride level of the water pumped from the basal aquifer, the effects on mining and water disposal will be assessed at that time. Water at this salinity could not be discharged into surficial water bodies or into the tailings system for eventual use in the Extraction Plant. Therefore acceptable disposal of saline water into a suitable subsurface formation would be carried out as required to ensure a safe mining operation.

MINING STRATEGY

A mining strategy has been developed which outlines the overall sequence of excavation of the initial 25 year mine area.

The overall strategy sets out mining areas which will be mined either by a single or two bench operation. The overall depth of the orebody within a particular area determines the choice of mining configuration. Single bench mining is carried out to a total mining depth of 70 m (230 ft); thereafter two bench mining is required to depths of 90 m (295 ft).

The development of the mine strategy was also based on the following premises:

* mining would begin in areas of relatively shallow ore depth to facilitate the initial use of single bench mining. This enables definite operating practices to be developed with regard to highwall slope geometry.
* mining would begin in areas of relatively shallow overburden and minimal centre reject to reduce both the non-productive output of the draglines and the surface requirements for initial waste stockpiling.
* mining would start close to the bitumen extraction facilities to reduce initial transportation requirements.
* lower grade ore from the eastern portion of the orebody would be blended with ore from other areas to provide a consistent grade of feed to the Extraction Plant in order to maximize bitumen recovery.
* the orientation of the mining faces would preferably be in directions which would minimize adverse effects on highwall stability from factors such as unfavourable inclination of geologic strata or increased rate of spalling due to the thermal effects of direct sunlight on the mine face.
* mining would progress in a manner to facilitate the early disposal of tailings within the mined out areas.

Based on the above premises the preferred mining strategy is shown in Figure V-3, indicating the sequence and direction of mining. Blocks 3 and 4 will be mined concurrently to provide a consistent blended Extraction Plant feed grade.

Average orebody characteristics have been calculated for each block, based on 200 m (660 ft) grid values developed from the TOBYS program. These average characteristics are shown in Figure V-3.

PRIMARY EXCAVATION

The Applicant proposes to use four electric walking draglines of the 61 - 76 m^3 (80-100 yd^3) capacity class as prime excavators for both overburden stripping and oil sand mining. These draglines have the following general specification. Operating radius 103.6 m (340 ft); boom length 109.7 m (360 ft); boom angle 30.5 degrees; digging depth 60 m (200 ft); tub diameter 24.4 m (80 ft); ground bearing pressure 124.1 kPa (18 psi). As noted above, both single and double bench mine configurations have been developed to ensure that these machines can mine to the full depth of the orebody.

Selective Mining

The Applicant proposes to selectively mine interbedded waste and oil sand materials within the orebody.

Based on trials carried out during the excavation of the test pit a bed thickness of 4.5 m (15 ft) is considered the average minimum bed thickness that can be selectively mined with the dragline at the mining depths anticipated. The Applicant recognizes that beds less than 4.5 m (15 ft) thick could be selectively mined at the top of an individual dragline panel. However, it is considered that the degree of selective mining achieveable at the base of an individual dragline panel would be in excess of 4.5 m (15 ft).

The ability to mine selectively beds within the orebody with the dragline is dependent on such factors as face height, panel length, and the ability to define the spacial position of particular beds ahead of mining.

Thicknesses and depths of geological beds ahead of mining will be identified by exploratory drilling – initially one hole per dragline mining panel. Final drilling density will be dependent on the ability to correlate geological bedding accurately. From this definition reject beds will be separated during mining according to thickness and depth below the crest of the mining face.

Single Bench Mining

Single bench mining will be carried out to a maximum depth of 70 m (230 ft) incorporating a maximum chopcut of approximately 15 m (50 ft) and a main face height of 55 m (180 ft).

The maximum height of the main mining face is constrained to 55 m (180 ft) by the ability of the dragline to reach the toe of the mining face. This ability is largely dependent on the highwall slope angle and the operating radius of the dragline. At a depth of 55 m (180 ft) a highwall slope angle of 45 degrees is considered necessary to limit slabbing failure on the highwall face, as discussed previously under the Geotechnical Performance of Oil Sand Mining Slopes Section. The operating radius of 103.6 m (340 ft) is the maximum available utilizing the longest dragline boom (109.7 m) (360 ft) presently manufactured.

A chopcut is incorporated in the mining configuration to enable the dragline to reach greater overall ore depths with a single pass operation and thereby maintain the direct casting of waste material into the mined out area.

However, the operation of chopcutting with a dragline is inefficient and reduces the overall productivity of the machine. Based on North American mining practice and the average depth of overburden a maximum chopcut depth of 15 m (50ft) been imposed.

Figure V-4 shows cross-sectional representations of highwall configurations which would be used in varying orebody depths utilizing a single bench operation. These configurations are based on the geotechnical observations made during the test pit operation, and would limit slabbing failure as discussed under the Geotechnical Performance of Oil Sand Mining Slopes Section. These configurations will be reviewed as operating experience is obtained.

The limiting of highwall slope angles to 45 degrees at mining depths greater than 52.5 m (172 ft) severely restricts the amount of waste material that can be stockpiled into the mined out area. An estimated 16 per cent of waste material will need to be rehandled during single bench operations. In developing estimates of in-pit stockpile volumes and quantities of materials to be rehandled, a material swell factor of 1.35 has been used. This is based on a measured in-situ density of 2040 kg/m^3 (127 lbs/ft^3) and a loose density of 1510 kg/m^3 (93.8 lbs/ft^3) measured from dragline stockpiles during the excavation of the test pit.

Figures V-5 and V-6 show in plan and cross-section mining configurations and stockpile locations for single bench mining in blocks 1 and 4 of the mining strategy.

During single bench mining operations the four draglines will advance along a staggered single cut. Each dragline will operate one quarter of the full cut length. The minimum cut length per dragline will be approximately 750 m (2500 ft).

Two Bench Mining

A two bench mining scheme will be used to mine areas of ore depth greater than 70 m (230 ft).

In this scheme the upper mining bench will be taken to a depth of 35 m (115 ft) with a steep highwall slope (up to 70 degrees). The lower mining bench will be mined to a depth of 55 m (180 ft) with a highwall slope of 45 degrees. Figure V-4B outlines this general configuration.

Two draglines will operate on the upper bench stockpiling both oil sand and waste on the same level as the dragline. Two draglines will operate on the lower bench and will stockpile only oil sand, casting waste material directly back into the mine.

During two bench mining operations the draglines on the upper bench will require an operating radius of 91.4 m (300 ft), rather than 103.6 m (340 ft), for casting waste material or for reaching the toe of the mining face. Therefore during the two bench mining the boom angle on these machines will be increased to permit the use of larger bucket sizes, thereby increasing their productivity. The machines on the lower bench will continue to require an operating radius of 103.6 m (340 ft).

Waste material stockpiled on the upper bench will be transferred by bucketwheel reclaimers onto the conveyor system which will transport the material to a stacker for placement into the mined out area.

Figure V-7 shows, in plan and cross-section, mining configurations and stockpile locations for two bench mining in blocks 2 and 3 of the mining strategy. Waste and oil sand stockpiles on the upper bench are interchanged to optimize cycle times depending on the respective quantities of oil sand and waste in the mining panel.

Equipment Productivity

Since the operation of draglines for oil sand mining is quite different from coal stripping applications for which dragline production rates are readily available, the Applicant has determined production rates from calculated cycle times for given mining face configurations.

Dragline productivity has been calculated for each of the average mining configurations anticipated in the individual mining blocks outlined in the mine strategy.

Productivity penalties were applied to the machines when mining frozen material (winter conditions), and when chopcutting, based on experience derived from the excavation of the test pit and in operating mines. Parameters such as swell factors and bucket fill factors for varying types of material were also based on test pit experience.

Anticipated production rates per machine for the size of draglines specified range from 40 000 to 55 000 bank m^3/d (52 000 to 77 000 yd^3/d)for single bench mining and 44 000 to 83 000 bank m^3/d (58 000 to 109 000 yd^3/d) for two bench mining. The high production rates in two bench mining are from draglines working the upper bench.

Based on the dragline productivities calculated by the Applicant, four draglines of 61 to 76m^3 (80 to 100 yd^3) capacity are required for most years of the Project life. In four years of Project life extra waste stripping capacity will be required. It is proposed in these years to utilize front end loaders and trucks when necessary to prestrip overburden ahead of the dragline operation. The need for excess stripping capacity will be reviewed once anticipated dragline production rates can be confirmed.

ORE RECLAMATION AND TRANSPORTATION

Ore and Waste Reclaiming

Oil sand material selectively mined by the dragline is stockpiled on the highwall. The stockpile base will have been prepared to minimize dilution and provide a competent working surface for reclaiming equipment.

Transfer of the stockpiled material to the ore transportation system will be by bucketwheel reclaimer with connecting conveyor bridge. Four such machines will be used, one per dragline.

Each bucketwheel reclaimer will be capable of an overall feed rate of 4230 loose m^3/h (5500 yd^3/h).

In areas requiring rehandling of reject material, i.e., two bench mining areas and deep single bench areas where all waste material cannot be cast directly into

the mine, the reclaimers will reclaim waste material in addition to oil sand. T
face stockpiling layouts are shown in Figures V-5 to V-7.

Materials Transportation

Bucketwheel reclaimers transfer oil sand to 1800 mm (6 ft) wide face conv which then transport the material to one of two 2400 mm (8 ft) wide conveyors.

The oil sand is then transported on the trunk conveyors either directly Extraction Plant or to stockpiles ahead of it. Each trunk conveyor is capal handling 100 percent of the Extraction Plant feed requirements.

When necessary, waste material rehandled by the bucketwheel recla is also transported by the face conveyors to the trunk conveyor system. The conveyor not already handling oil sand, will transport the waste material tripper station where it will be redirected to an overburden conveyor and st which will place it in the mined out area to be utilized for in-pit tailings s dykes.

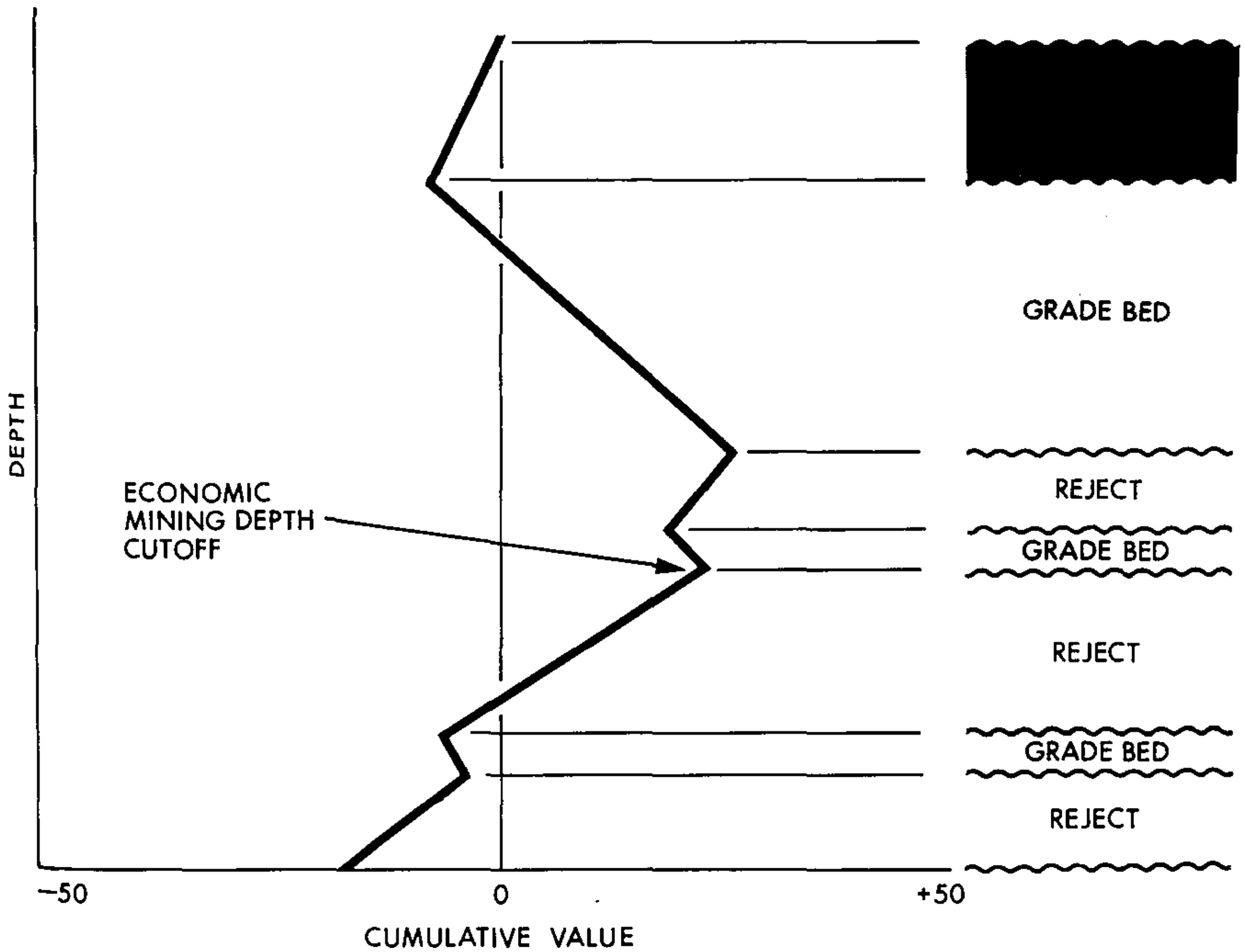
Figures V-8 to V-10 show typical conveyor layouts during the Projec

Reclamation and revegetation planning is discussed in the Environm Impact Assessment filed in support of this Project.

TABLE V-1

CHEMICAL ANALYSIS OF TEST PIT OF DICHARGE WATER FROM McMURRAY BASAL AQUIFER

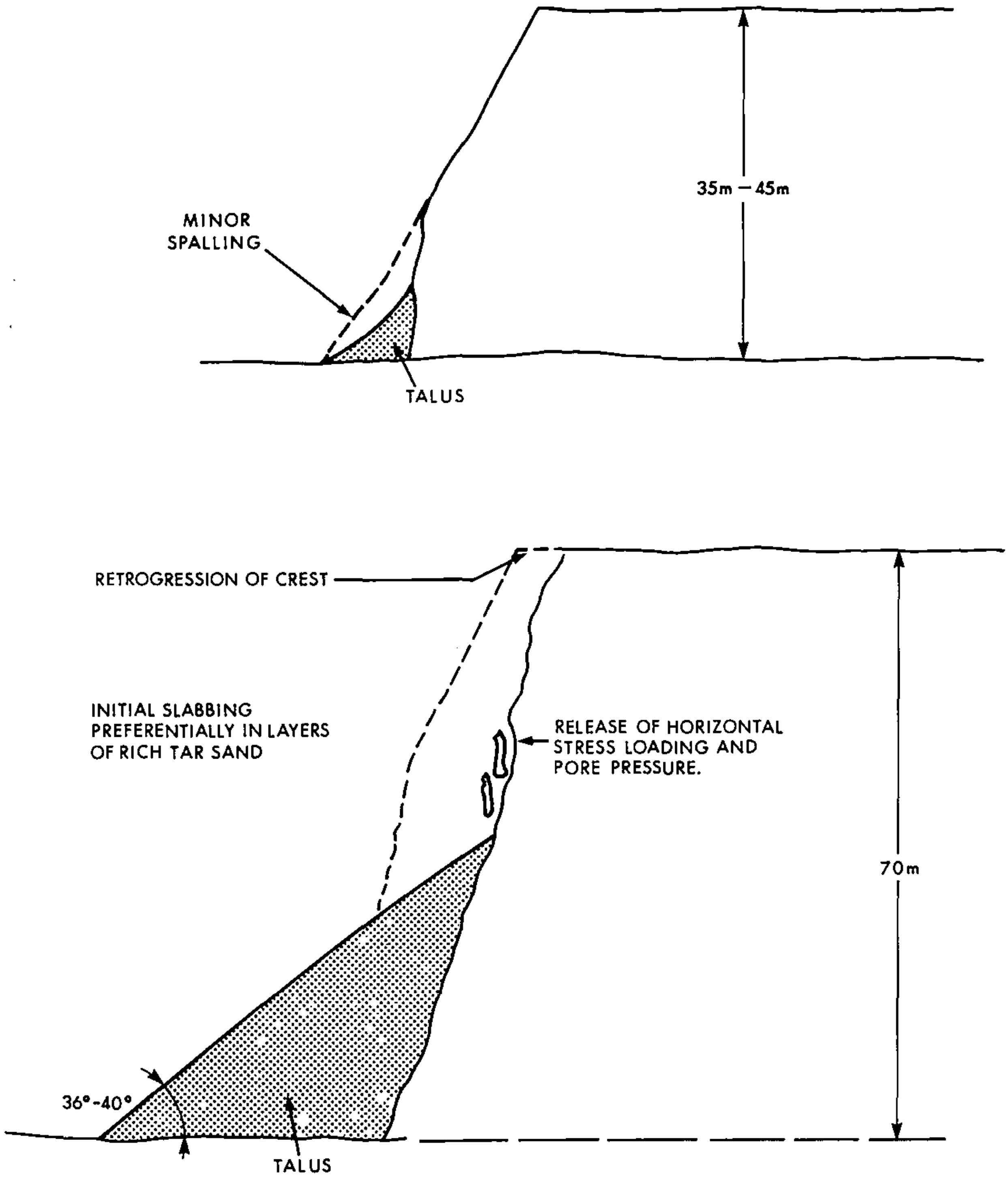
ph	7.4
Specific Gravity	1.005
MAJOR COMPONENTS (mg/L)	
Sodium	1137
Calcium	55
Magnesium	30
Chloride	1061
Bicarbonate	1440
Sulphate	55
Carbonate	0
Hydroxide	0
TOTAL DISSOLVED SOLIDS	3778
OTHER COMPONENTS (mg/L)	
Barium	0.9
Iron	0.5
Sulphide	23.5



ALSANDS PROJECT GROUP

GRAPHICAL PRESENTATION
OF GRADE VALUE BEDDING

FIGURE V-1



ALSANDS PROJECT GROUP

TEST PIT
GOVERNING MODE OF FAILURE

FIGURE V-2

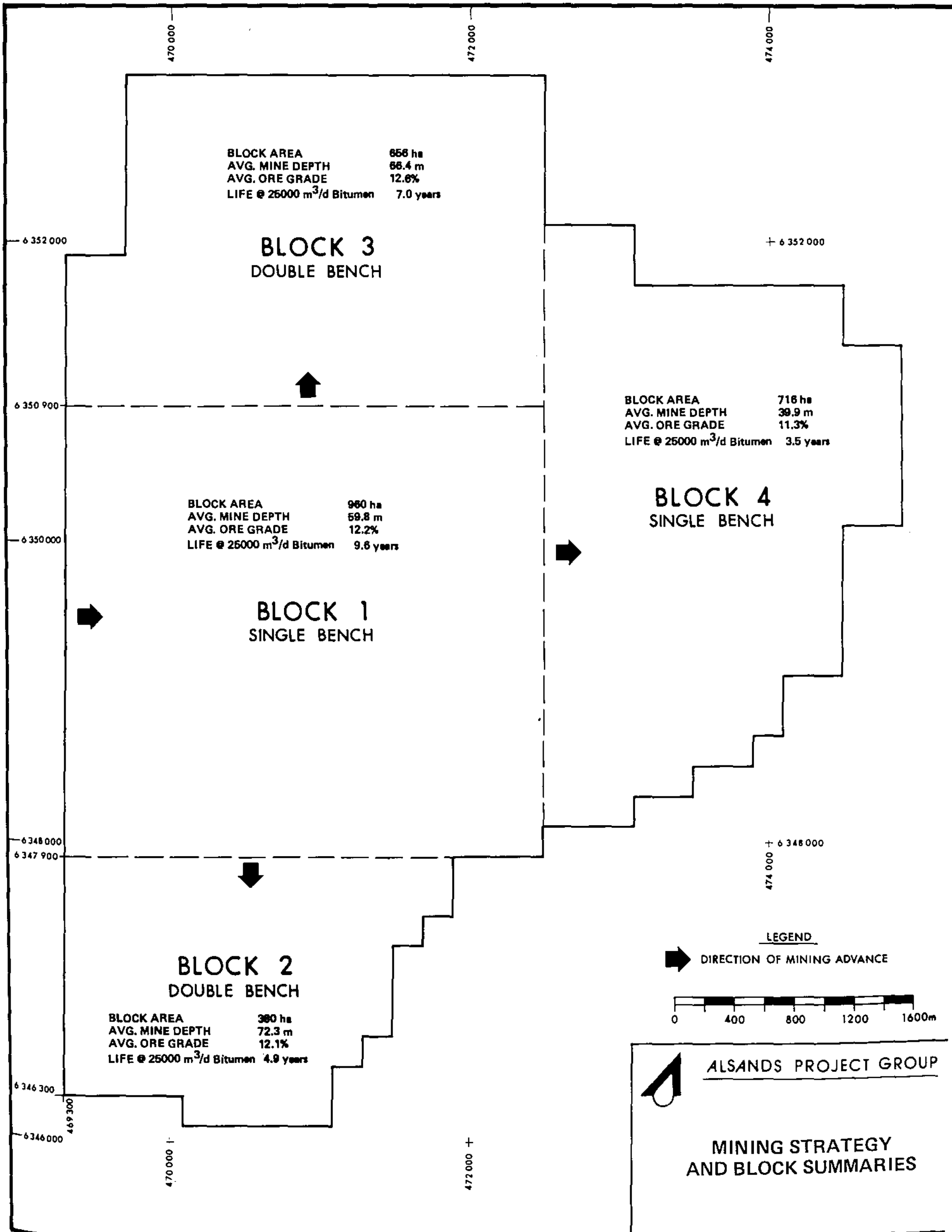

470 000
472 000
474 000
6 352 000
6 350 900
6 350 000
6 348 000
6 347 900
6 346 300
6 346 000
469 300
BLOCK AREA 656 ha
AVG. MINE DEPTH 66.4 m
AVG. ORE GRADE 12.6%
LIFE @ 25000 m³/d Bitumen 7.0 years
BLOCK 3
DOUBLE BENCH
BLOCK AREA 960 ha
AVG. MINE DEPTH 59.8 m
AVG. ORE GRADE 12.2%
LIFE @ 25000 m³/d Bitumen 9.6 years
BLOCK 1
SINGLE BENCH
BLOCK AREA 716 ha
AVG. MINE DEPTH 39.9 m
AVG. ORE GRADE 11.3%
LIFE @ 25000 m³/d Bitumen 3.5 years
BLOCK 4
SINGLE BENCH
BLOCK 2
DOUBLE BENCH
BLOCK AREA 380 ha
AVG. MINE DEPTH 72.3 m
AVG. ORE GRADE 12.1%
LIFE @ 25000 m³/d Bitumen 4.9 years
LEGEND
DIRECTION OF MINING ADVANCE
0 400 800 1200 1600m
ALSANDS PROJECT GROUP
MINING STRATEGY
AND BLOCK SUMMARIES

FIGURE V-3

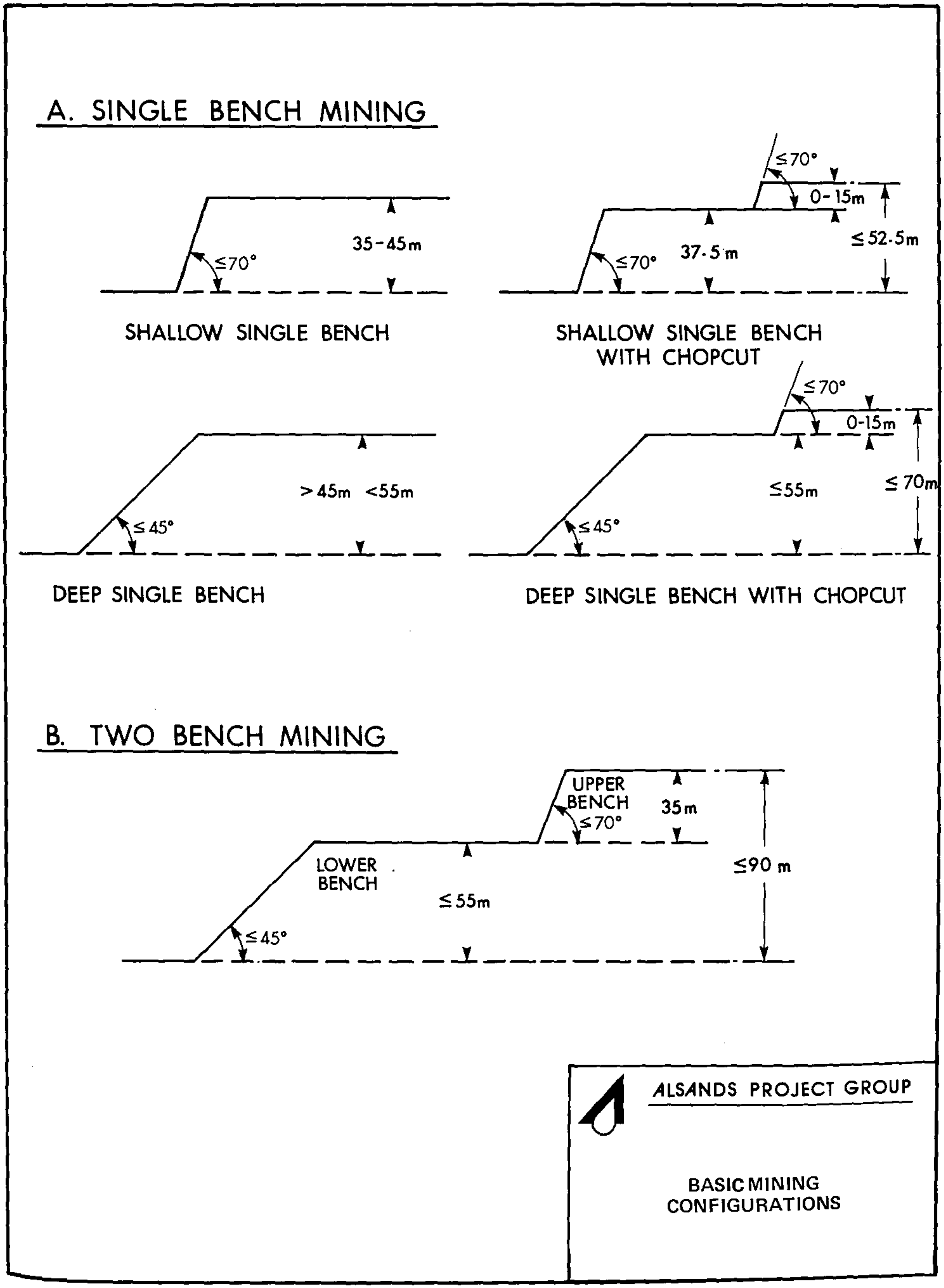

A. SINGLE BENCH MINING
35-45m
≤70°
SHALLOW SINGLE BENCH
≤70°
0-15m
≤52.5m
37.5m
≤70°
SHALLOW SINGLE BENCH
WITH CHOPCUT
>45m <55m
≤45°
DEEP SINGLE BENCH
≤70°
0-15m
≤55m
≤70m
≤45°
DEEP SINGLE BENCH WITH CHOPCUT
B. TWO BENCH MINING
UPPER
BENCH
35m
≤70°
≤90 m
LOWER
BENCH
≤55m
≤45°
ALSANDS PROJECT GROUP
BASIC MINING
CONFIGURATIONS

FIGURE V-4

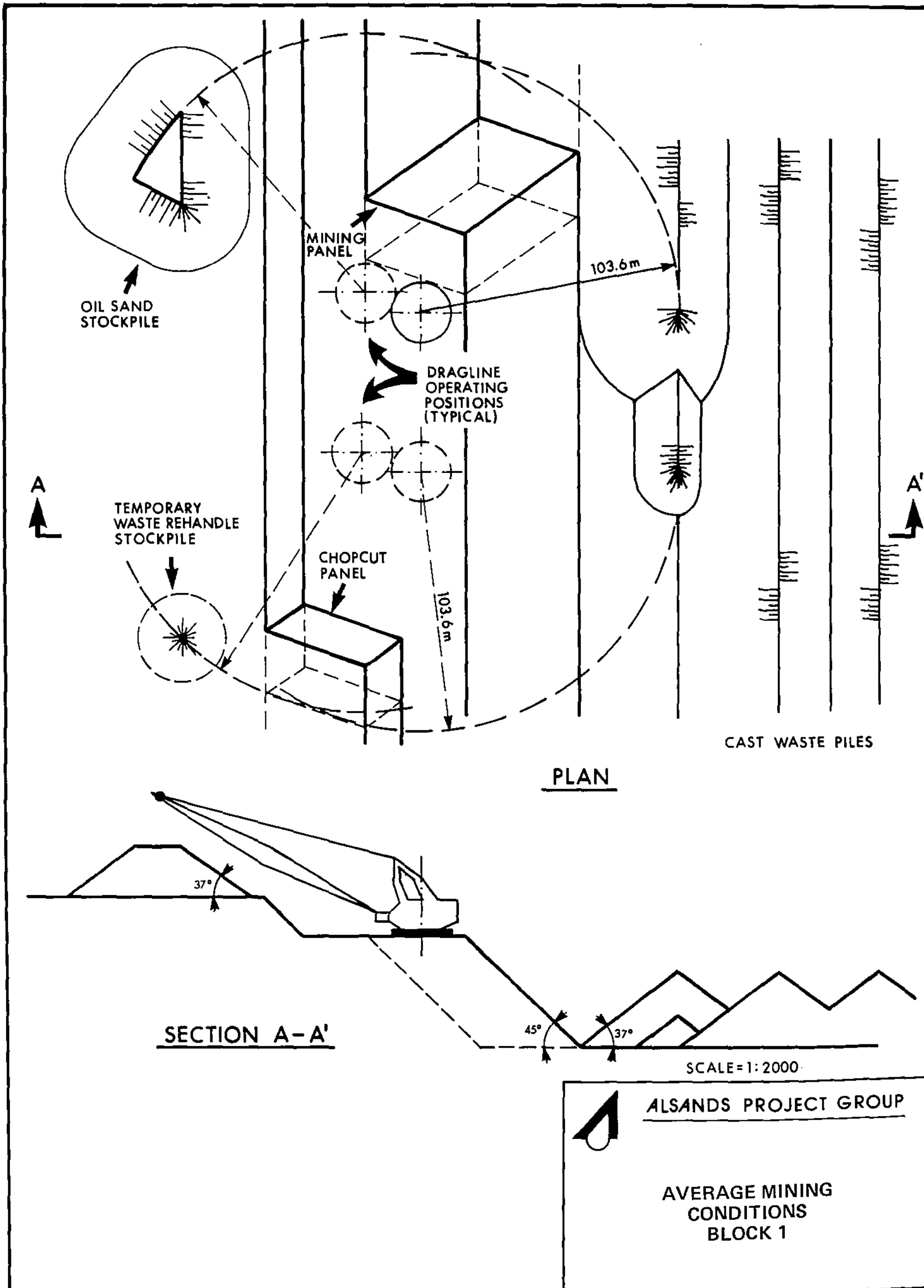
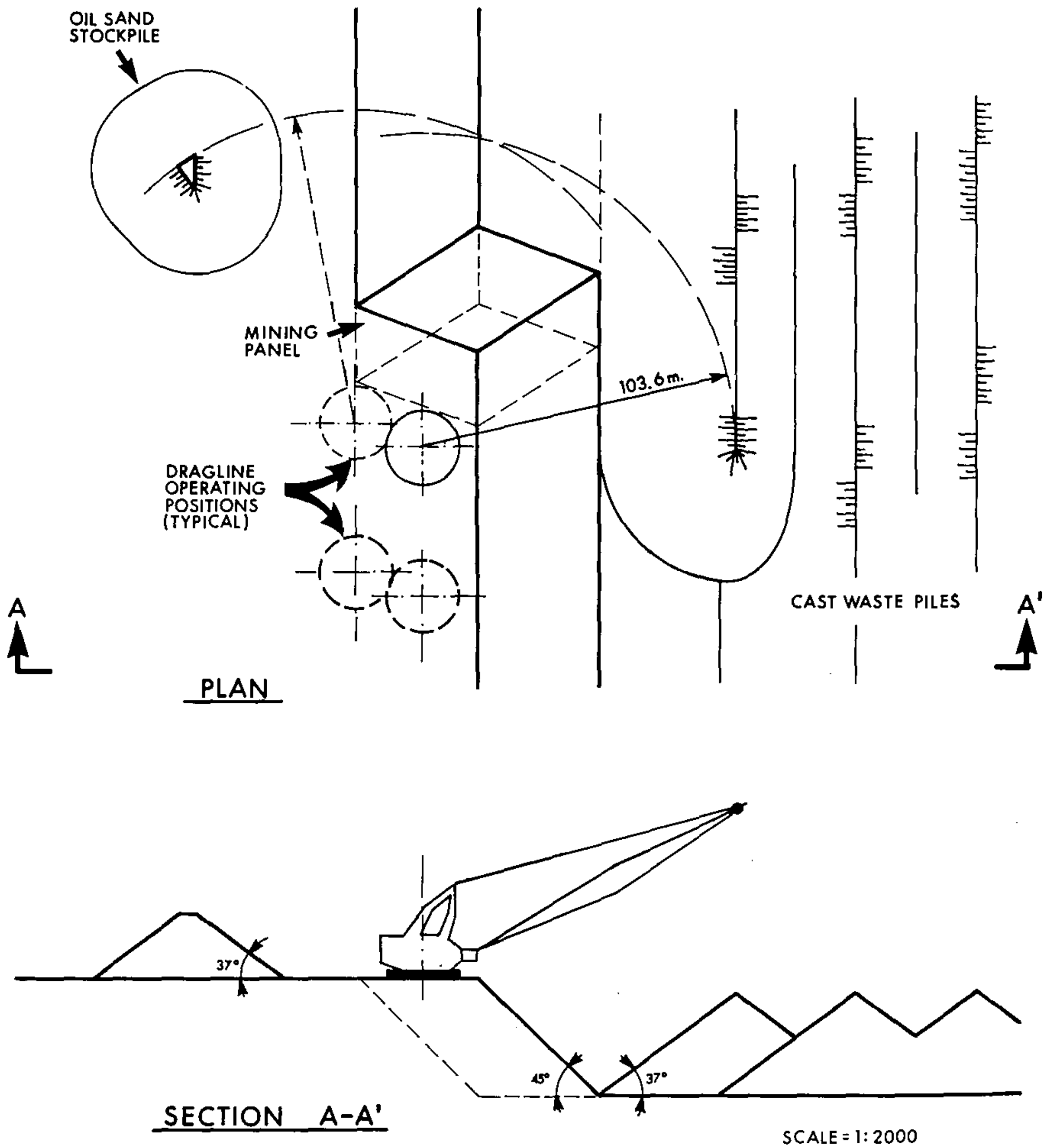

MINING PANEL
OIL SAND STOCKPILE
103.6m
DRAGLINE OPERATING POSITIONS (TYPICAL)
A
A'
TEMPORARY WASTE REHANDLE STOCKPILE
CHOPCUT PANEL
103.6m
CAST WASTE PILES
PLAN
37°
SECTION A-A'
45°
37°
SCALE=1:2000
ALSANDS PROJECT GROUP
AVERAGE MINING CONDITIONS BLOCK 1

FIGURE V-5



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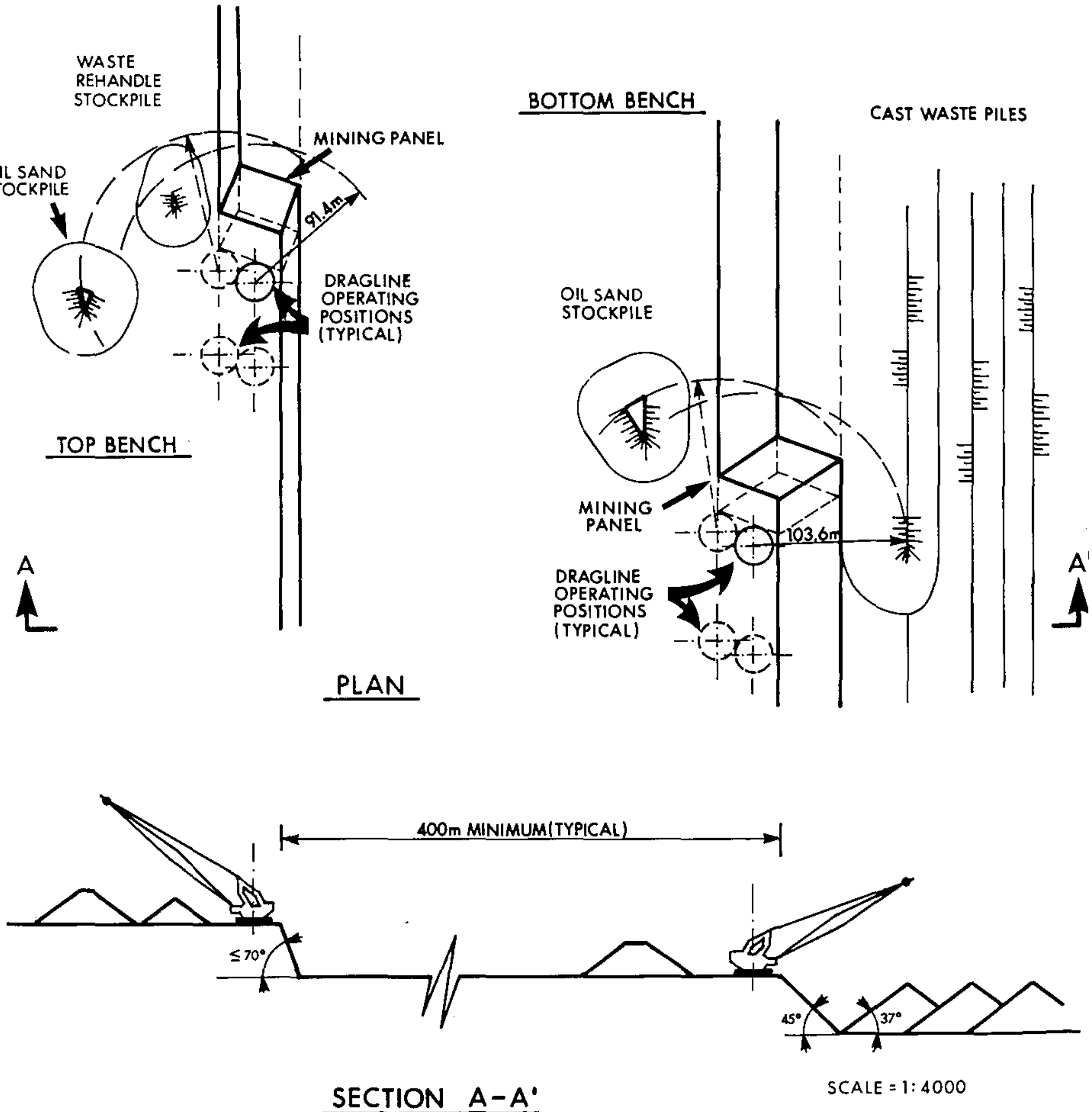
AVERAGE MINING
CONDITIONS
BLOCK 4

FIGURE V-6



ALSANDS PROJECT GROUP

AVERAGE MINING CONDITIONS BLOCK 2 & 3

FIGURE V-7

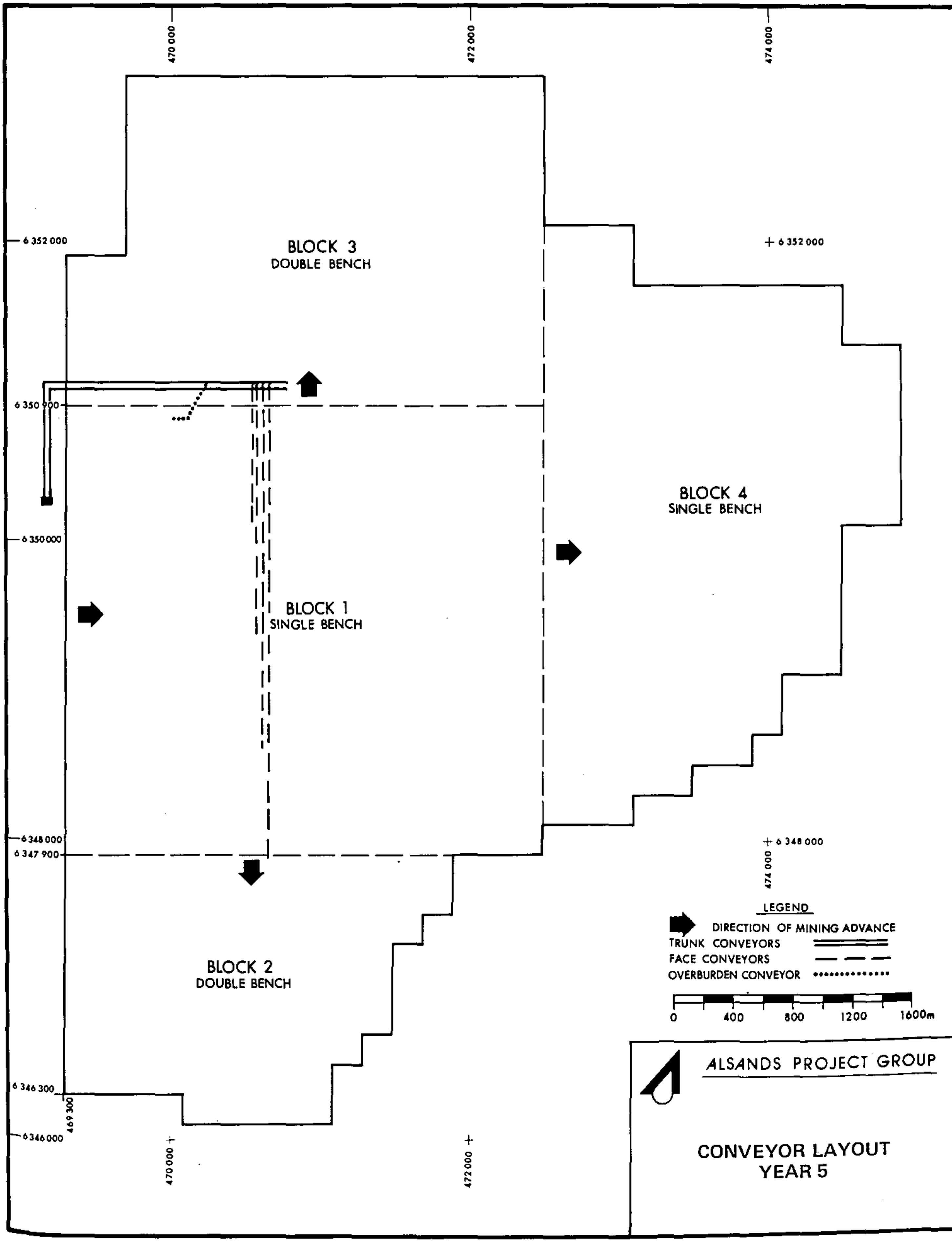
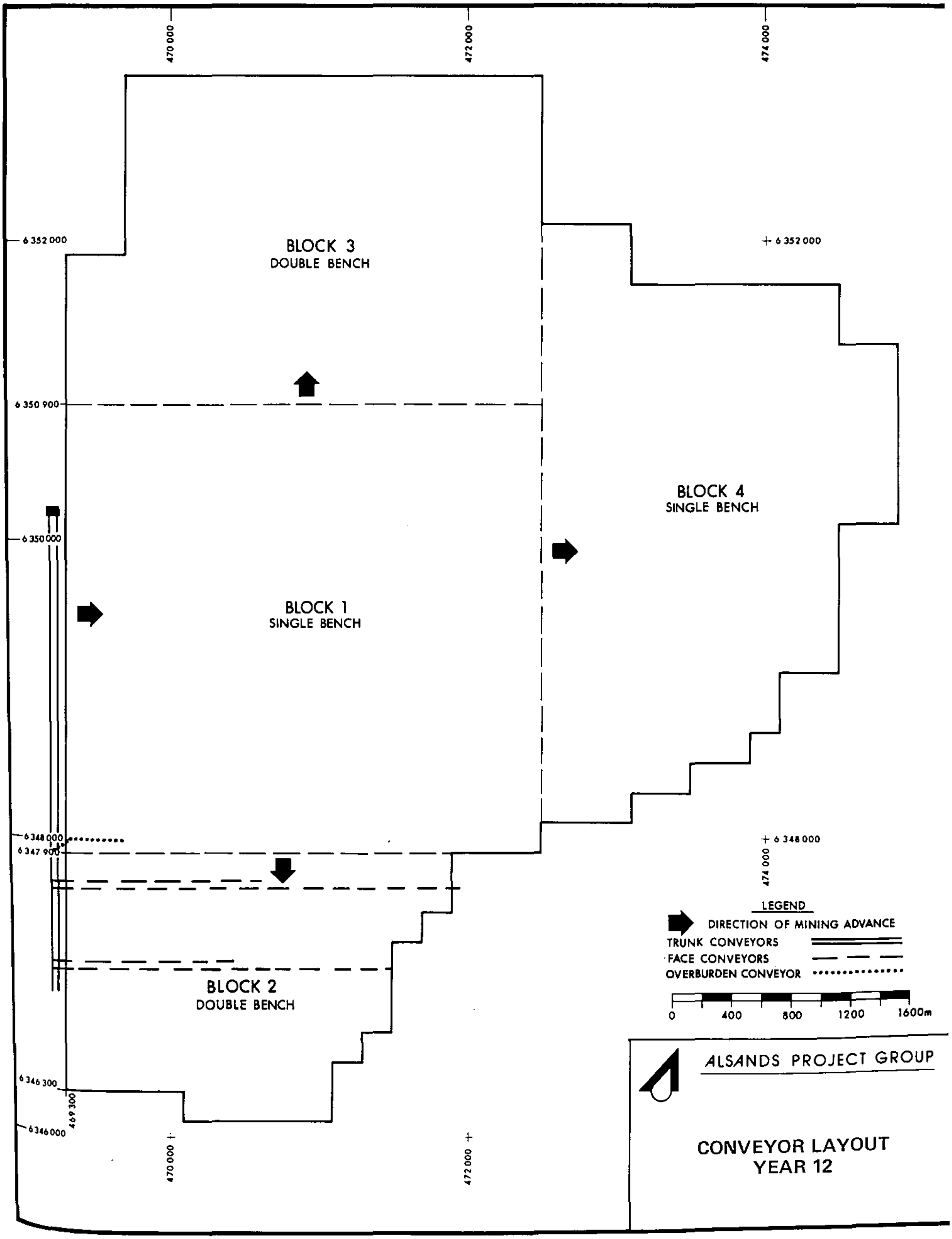

470 000
472 000
474 000
6 352 000
6 350 900
6 350 000
6 348 000
6 347 900
6 346 300
6 346 000
469 300
BLOCK 3
DOUBLE BENCH
BLOCK 4
SINGLE BENCH
BLOCK 1
SINGLE BENCH
BLOCK 2
DOUBLE BENCH
LEGEND
DIRECTION OF MINING ADVANCE
TRUNK CONVEYORS
FACE CONVEYORS
OVERBURDEN CONVEYOR
0
400
800
1200
1600m
ALSANDS PROJECT GROUP
CONVEYOR LAYOUT
YEAR 5

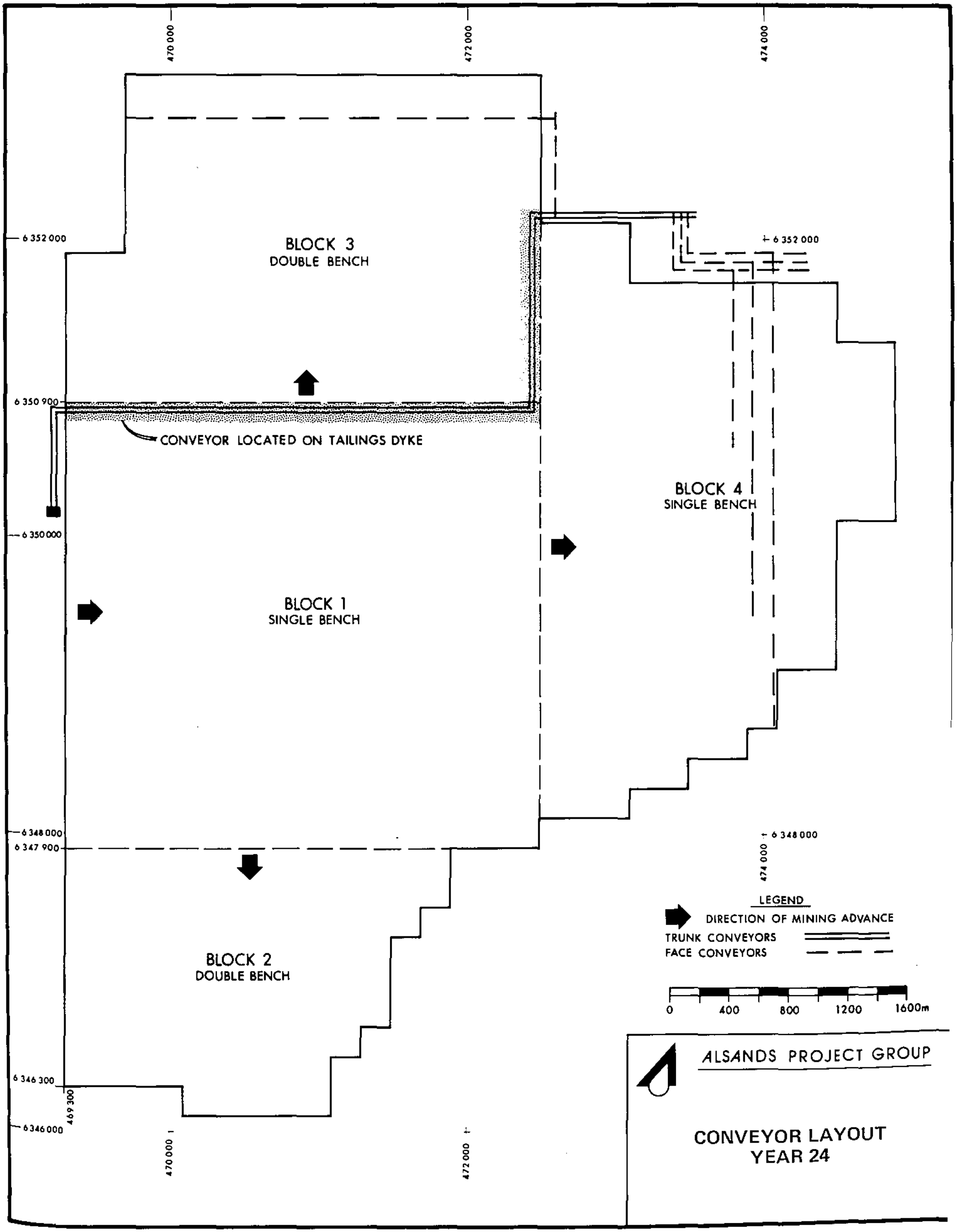
FIGURE V-8



ALSANDS PROJECT GROUP

CONVEYOR LAYOUT
YEAR 12

FIGURE V-9



CONVEYOR LAYOUT
YEAR 24

FIGURE V-10

VI Extraction

Introduction

To extract bitumen from the oil sand, the Applicant proposes to use the K.A. Clark Hot Water Process with recent technological improvements which are cost/benefit effective. Many aspects of this process are patented and rights to use these aspects will have to be negotiated. The selection of this process recognizes the present proven technology demonstrated by Great Canadian Oil Sands Limited for the past ten years, and recent utilization of this process by Syncrude Canada Limited. The Applicant has examined other separation techniques and believes that this process offers the only commercial means of reliably extracting bitumen from the oil sand. Bench scale pilot testing of oil sand from Lease 13 indicates that this material is readily amenable to hot water extraction.

Fundamentally, the process utilizes hot water, caustic and steam to condition oil sand for gravity separation. Froth flotation and dilution centrifuging are used to provide a suitable Upgrading plant feed stock.

Alternative Extractive Processes

The Applicant has reviewed several of the process concepts that are available to extract bitumen from the mined oil sand. It has been concluded that these concepts which are still being developed will not be commercially proven in time for use with the Project.

A logical development sequence for any process concept usually involves the following steps:

Confirmation of the concept on a bench scale unit

Definition of yields, heat and material balances in a pilot plant or small scale type demonstration unit

Development and installation of a commercial scale unit. Such a "semi works" or prototype plant usually uses feedstock from an operating commercial unit. From this prototype unit, full commercial scale estimates are developed for capital and operating costs, yields, product quality, heat balances, process flexibility and stability, and off-site requirements.

Construction of a commercial scale unit with appropriate peripheral facilities

Successful operation of the commercial unit to confirm the capital and operating costs, equipment reliability, yields, product quality, heat and material balances and peripheral requirements

In cases where the scale up risks are high it may be necessary to include another pilot stage prior to the commercial pilot.

These processes can be divided into two basic types of schemes: *thermal anhydrous*, and *solvent extraction.*

THERMAL ANHYDROUS

Three thermal anhydrous processes at various developmental stages are:

Taciuk Process – Developed by UMATAC Industrial Processes.

Lurgi-Ruhrgas Process – Developed by Lurgi Mineraloletechnik GmbH.

Anhydrous Extraction Process – Developed by the University of Calgary.

In all three processes, mined oil sand is retorted by burning the residual coke produced from coking of the bitumen, and some degree of Upgrading of the bitumen is achieved.

The Applicant considers the Taciuk and Lurgi-Ruhrgas Processes to be in the pilot plant stage and the Anhydrous Extraction Process to be in the laboratory scale stage and therefore concludes that none of the thermal anhydrous processes will have demonstrated their commercial viability in time to be incorporated the current design and engineering schedule.

SOLVENT EXTRACTION

Solvent extraction methods piloted by Shell Canada Limited in 1971 were reje because solvent losses rendered the processes uneconomic. However, four solvent extraction concepts utilizing innovative techniques in various stage development are:

* RTL Oil Sands Process – Developed by RTR SA-Rio Tinto RTL.
* Solvent Agglomeration Process – Developed by the National Rese Council.
* Magna Oil Sand Extraction – Developed by the National Research Council Magna International.
* Dravo Process – Developed by Dravo Corporation.

In the Applicant's view the RTL, Solvent Agglomeration and Ma Processes are in the pilot plant stage and the Dravo Process is at the labora stage. Large demonstration type units will have to be piloted continuousl demonstrate fully the commercial feasibility and reliability of these processes p to implementation in a full scale project. Again, in the Applicant's view, tl processes will not be commercially proven in time to meet the current enginee and design schedule.

Potential Technological Improvement to Hot Water Process

The Applicant proposes to evaluate and if attractive, pilot an electrical dehydra This process could possibly replace the dilution centrifuging section of the Water Extraction Process. It might also be used to recover bitumen and dilu from the centrifuge plant tailings, or for further removal of water and clay fr bitumen product. It is anticipated that with the first two innovations noted abc diluent losses could be reduced and the bitumen recovery efficiency furt improved.

Process Description – Hot Water Process

GENERAL

The proposed Extraction Process is essentially the K.A. Clark Hot Water Proc whereby the bitumen in the oil sand is separated into a form suitable Upgrading. The process is shown schematically in Figure VI-1 and is compri of the following major steps:

* plant stockpile and feed system,
* conditioning,
* primary separation,
* scavenging, and
* froth treatment.

PLANT STOCKPILE AND FEED SYSTEM

A stockpile and reclaim system is provided in front of the Extraction Pla primarily as a surge to delink the Mine and Extraction Plant operations.

Oil sand delivered from the mine by the conveyors is either stockpiled stackers at the entrance to the Extraction Plant or delivered directly to a surge b as plant feed. The oil sand stored in the stockpile will be reclaimed by bucketwheel reclaimer to supplement the Extraction Plant feed during perio when feed requirements exceed mine output. The material in the bin is discharg onto apron feeders, weighed and fed by four inclined conveyors into four parall processing lines for extraction.

The average oil sand feed rate to the extraction facilities will be 227 300 t/d (250 600 ST/D) of 12.1 percent weight bitumen. At this grade the average fines content will be 14.5. percent.

CONDITIONING

In the conditioning step, oil sand is combined with hot water at 85 degrees C (185 degrees F) and agitated in rotary drums to ablate the oil sand lumps. Caustic is added to control the alkalinity of the pulp at a pH of 8 to 8.5 and steam is injected to increase the temperature of the oil sand to about 85 degrees C. The conditioned pulp is screened at the discharge end of the drum to separate the oversize material, consisting essentially of clay lumps and rocks, from the dispersed bitumen, sand, clay and water. The oversize reject is transported to the mined-out area or the tailings pond for disposal.

PRIMARY SEPARATION

Separation of the dispersed bitumen from the conditioned pulp is accomplished in a separation cell by diluting the pulp with hot water and recycled middlings (the central layer in the separation cell), then holding it in a quiescent state. The use of middlings recycle reduces the hot water make-up requirement, which is governed by the amount of fines in the oil sand feed. The water rate is adjusted to control the middlings density/viscosity. The coarse sand particles rapidly settle to the conical bottom of the separation cell while the bitumen rises forming a frothy layer on top of the cell. This layer, referred to as primary froth, is skimmed off and pumped to the froth treatment plant. The sand in the cell bottom is continuously raked to a central discharge cone from where it is pumped after dilution to the tailings pond.

The fines, consisting essentially of silt and clays from the oil sand, do not settle out and tend to accumulate in the middlings. This accumulation increases the viscosity in the cell and retards the rate of rise of the bitumen flecks. The fines must be continually withdrawn from the central layer in the cell in the form of a dilute middlings slurry; otherwise accumulation of fines will cause the viscosity to build up until separation of the bitumen ceases. The middlings withdrawn contain significant quantities of bitumen which can be economically recovered in the scavenging circuit.

SCAVENGING

In the scavenging operation, conventional flotation cells are employed. Air is injected into the middlings which is further mechanically agitated to promote the formation of a bituminous froth. The recovered froth is sent to a settler to improve its quality, after which it is combined with froth from primary separation and sent to froth treatment.

Tailings from the scavenging operation are combined with the primary separation tailings for disposal to the tailings pond.

FROTH TREATMENT

In the Froth Treatment Plant, the combined froth from the primary separation and scavenging operations is treated to provide a suitable feedstock for the Upgrading Plant. The froth is first heated then deaerated prior to dehydration and demineralization by dilution centrifuging.

Dilution centrifuging utilizes naphtha, a recycle material, as a diluent to reduce the specific gravity and viscosity of the bitumen, with the result that the entrained solids and water, which are heavier than diluted bitumen, can be segregated.

The diluted bitumen is centrifuged in the primary solid-liquid separators or scroll centrifuges at relatively low gravitational forces to remove the larger mineral particles. The high energy secondary solid-liquid-liquid separators or noz: centrifuges further reduce the mineral and water content. Diluted bitumen is th stored in surge tanks prior to feeding it to the Upgrading facility.

The Froth Treatment Plant tailings will be pumped separately to a localiz area of the tailings ponds to permit skimming of floating diluted bitumen a segregate heavy minerals in the tailings. This will also maximize the residence tir of this stream so that more fines will settle prior to water recycle.

RECOVERY

The selection of the Hot Water Process is predicated on its commercial viabili and its reliability in recovering bitumen. The recovery efficiency is directly relat to the fines content of the plant feed as indicated in Figure VI-2. This relationsh is based on test work on material from Lease 13 and other published recove information. The Applicant estimates that the average recovery efficiency for tl Extraction Process will be 91.6 percent, excluding diluent losses, for an avera; fines content in mill feed of 14.5 percent. However, naphtha losses in tl centrifuge plant will reduce the total hydrocarbon recovery to 90.3 percent.

MATERIAL BALANCE

The material balance shown in Figure VI-3 gives the average calendar day flo rates to produce 25 040 m^3/d (157 500 B/D) of bitumen. It is based on a average mill feed grade of 12.1 percent bitumen, and an average fines content (14.5 percent.

Water Management

FRESH WATER REQUIREMENTS

The anticipated fresh water requirements average 2.02 m^3/s (32 000 USGPM in years one to three and 0.90 m^3/s (14 300 USGPM) in years four to twenty five. This is equivalent to 1.02 and 0.34 tonne water per tonne oil san(respectively.

During normal operation, after water recycle is established from the tailing pond, the fresh water requirement will be reduced to 0.34 t/t of oil sand feed.

These requirements are compared to Athabasca River flow rates ir Table VI-1.

FRESH WATER SOURCE

The fresh water requirements will be met by pumping water from the Athabasca River. The use of river water will be minimized by using local surface runoff and subsurface water and by maximizing tailings pond recycle water.

The river water supply system for the Project will consist of an intake situated on the river bank, a 40 ha (100 acres) settling reservoir adjacent to the Athabasca River, and high head pumps to lift the water to the plant site through a 12.5 km (8 miles), 1400 mm (56 in) water line. The pipeline will be routed to the plant along the proposed utility corridor as shown in Figure IV-1.

The water settling reservoir, required to remove suspended solids, will be formed by constructing a dam in an abandoned channel in the Athabasca River valley east of Ings Island as shown in Site Preparation Figure IV-1. The abandoned channel, now occupied by a crescent shaped muskeg flood plain, extends some 245 m (750 ft) along the river and has a maximum width of 1220 m (3700 ft). The valley wall bordering the flood plain rises abruptly about 52 m (160 ft). A natural levee rising as much as 2 m (6 ft) above the flood plain and carrying a heavy growth of mature trees, separates the river from the flood plain and will contribute to bank stability and provide protection against scour and ice erosion. A dam height of 7.5 m (23 ft), will provide a storage volume of approximately $1.8 \times 10^6\ m^3$ ($64 \times 10^6\ ft^3$).

The bank intake will be designed with both low and high level ports to minimize sediment intake to the system. The design will also incorporate Alberta Fish and Wildlife Division regulations for maximum intake velocity.

Design of the intake systems will require geotechnical and hydraulic investigations, with analysis of flows, sediment loads, river ice conditions and foundation conditions.

TAILINGS DISPOSAL

The Extraction Process produces two separate tailings streams, extraction tailings and froth treatment tailings. These streams will be pumped to the tailings pond in separate lines.

The extraction tailings containing sand, silt clay and residual bitumen will be a dense slurry with 45 to 50 percent solids by mass. This stream represents about 97 percent of the mineral from the Extraction Process. Four of the five primary extraction tailings lines provided will be capable of transporting the maximum amount of tailings produced.

Froth Treatment tailings will contain silt, clay, water, residual bitumen and naphtha. One froth treatment tailings line will be provided and it will transport tailings to one localized area of the main tailings pond.

The quantities of materials in the Extraction and Froth Treatment tailings are shown in Figure VI-3. The Extraction tailings will have approximately five times as much clay mineral as the Froth Treatment tailings.

Further details of tailings disposal and dyke construction is contained in Chapter VII.

WATER RECYCLE

Clarified water from the tailings pond with less than five percent solids, as dictated by process considerations, will be decanted by barge mounted pumps and stored in a recycle water basin within the plant site. This water will be mixed with recycle process water and river water as required and recycled for use in the Upgrading Process and Extraction Plant, and as sluicing water in the tailings system.

Tailings pond water recycle will commence approximately three years after plant start-up when adequate volumes of clarified water will be available. Process water will be recycled immediately after start-up.

After evaporation losses, entrainment in the sand dykes and retention of water in the sludge, the Applicant estimates that 65 percent of the water in the tailings will be available for recycle.

The tailings pond water balance is discussed in detail in the Tailings Management section.

OVERALL WATER BALANCE

Two overall water balances are presented. The balance in Figure VI-4 represents the average annual flow rates during the first three years of operation, when all the water requirements will be met from the Athabasca River because no recycle water will be available from the tailings pond.

The balance shown in Figure VI-5 represents the average annual flow rate for the rest of the Project life, when 65 percent of the tailings water will be available for recycle.

EXTRACTION PLANT EMERGENCY DUMP PONDS

Two emergency dump ponds will be provided in the plant area as shown in Figure VI-6 for collection and handling of pipeline and equipment drainage and spills. One pond will be dedicated for froth treatment tailings and the other for primary extraction and the tailings disposal system. The total capacity of the two ponds will be 100 000 m^3 (3.5×10^6 ft^3).

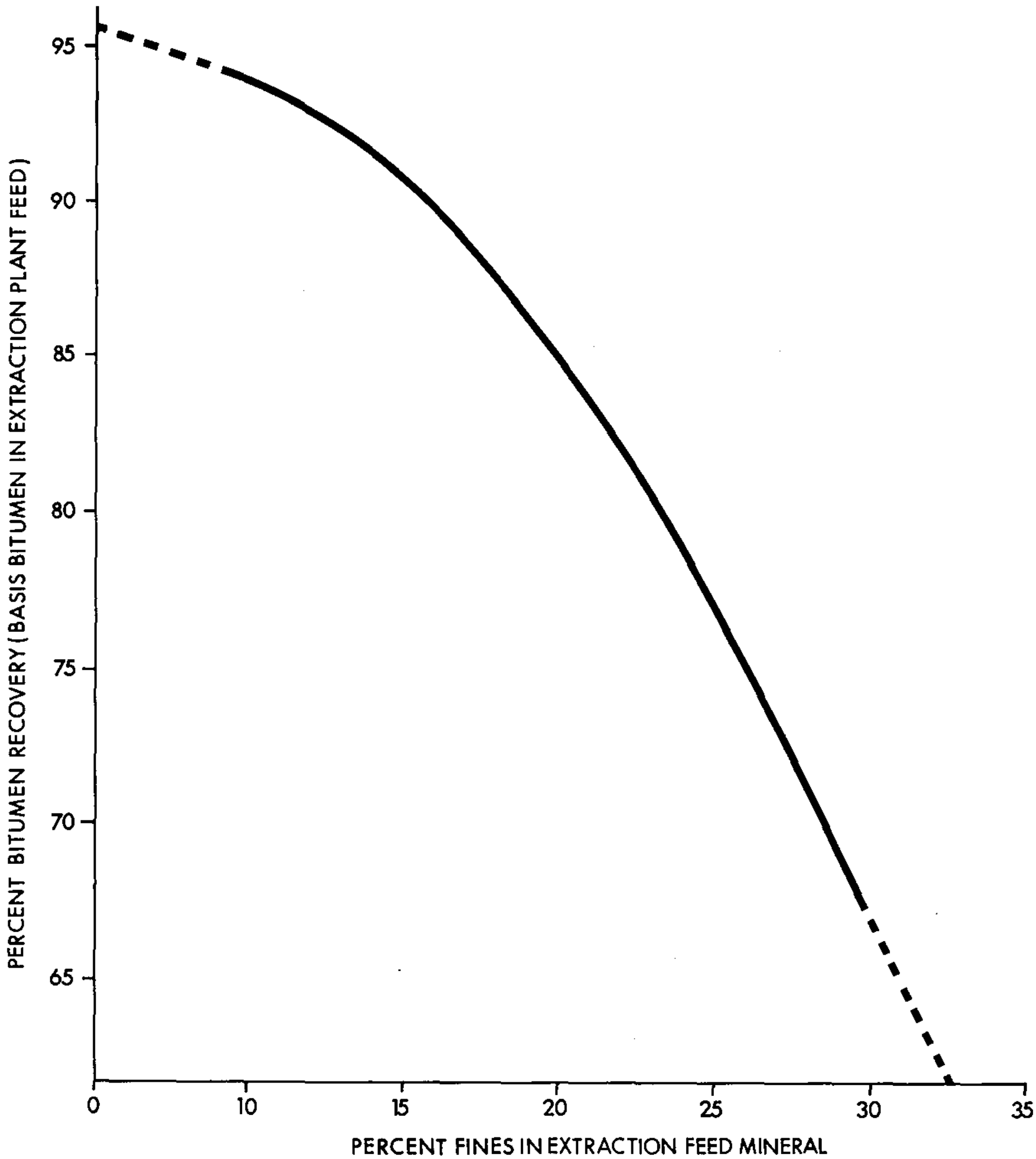
The emergency dump ponds will be provided with facilities to pump the contents to either conditioning, separation or tailings on a controlled basis to reclaim bituminous material or dispose of water and solids as required.

TABLE VI-1

FRESH WATER REQUIREMENT AS A FRACTION OF ATHABASCA RIVER FLOW RATE

PERIOD OF OBSERVATION	TOTAL RIVER FLOW	YEARS 1-3 USAGE		YEARS 4-25 USAGE		MAXIMUM USAGE	
	(m^3/s)	(m^3/s)	(% of flow)	(m^3/s)	(% of flow)	(m^3/s)	(% of flow)
Winter (Minimum)	97	2.02	2.08	0.9	1.0	2.80	2.8
Annual (Mean)	655	2.02	0.31	0.9	0.15	2.80	0.42
Breakup (Maximum)	4250	2.02	0.05	0.9	0.023	2.80	0.06

Note:
Athabasca River flows are based on data from Environment Canada Gauging Station No. 07DA001, below Fort McMurray, over the period 1958 to 1972.



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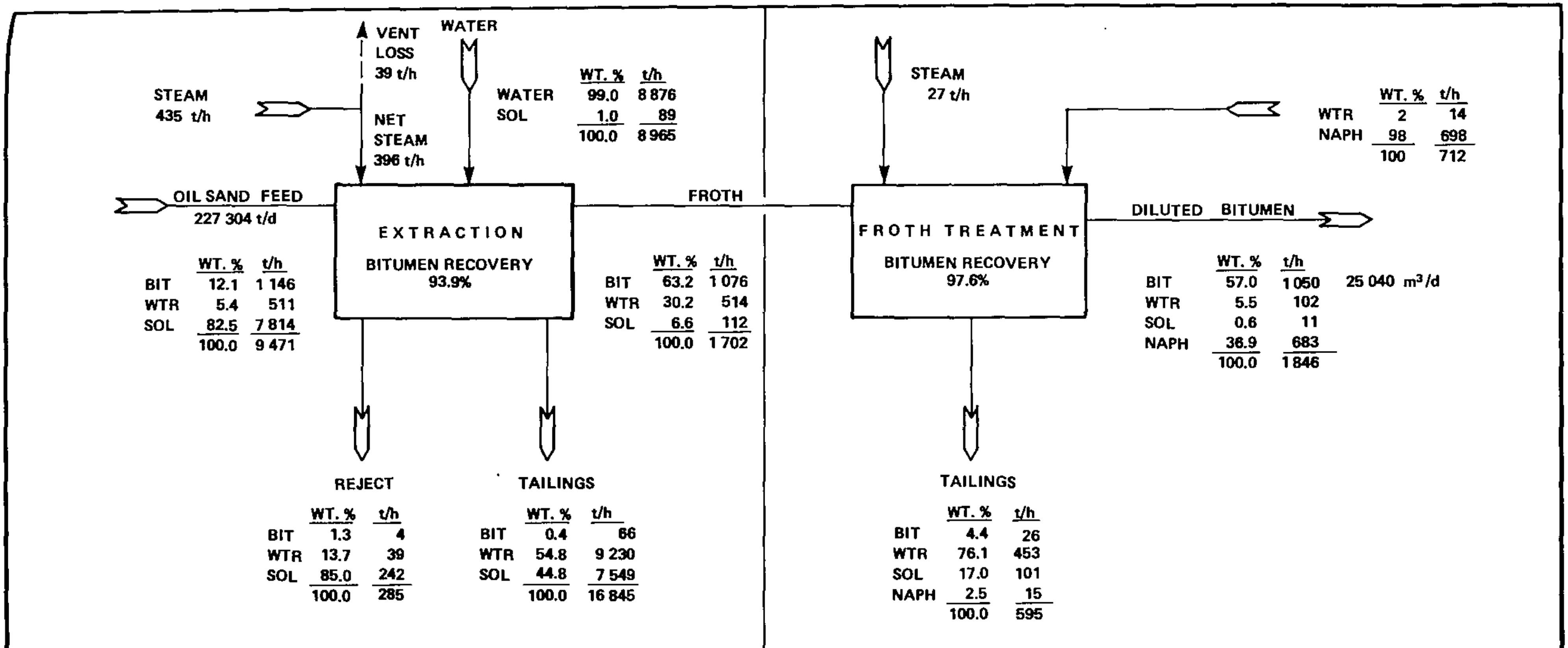
BITUMEN RECOVERY
VERSUS
FINES IN EXTRACTION
FEED MINERAL

FIGURE VI - 2



MATERIAL BALANCE EXTRACTION

	OIL SAND	STEAM	WATER	TOTAL IN	FROTH	TAILINGS	REJECT	TOTAL OUT
BIT	1 146	–	–	1 146	1 076	66	4	1 146
WTR	511	396	8 876	9 783	514	9 230	39	9 783
SOL	7 814	–	89	7 903	112	7 549	242	7 903
NAPH	–	–	–	–	–	–	–	–
TOTAL	9 471	396	8 965	18 832	1 702	16 845	285	18 832

MATERIAL BALANCE FROTH TREATMENT

	FROTH	NAPHTHA	STEAM	TOTAL IN	DILUTED BITUMEN	TAILINGS	TOTAL OUT
BIT	1 076	–	–	1 076	1 050	26	1 076
WTR	514	14	27	555	102	453	555
SOL	112	–	–	112	11	101	112
NAPH	–	698	–	698	683	15	698
TOTAL	1 702	712	27	2 441	1 846	595	2 441

t/h : TONNES PER CALENDAR HOUR

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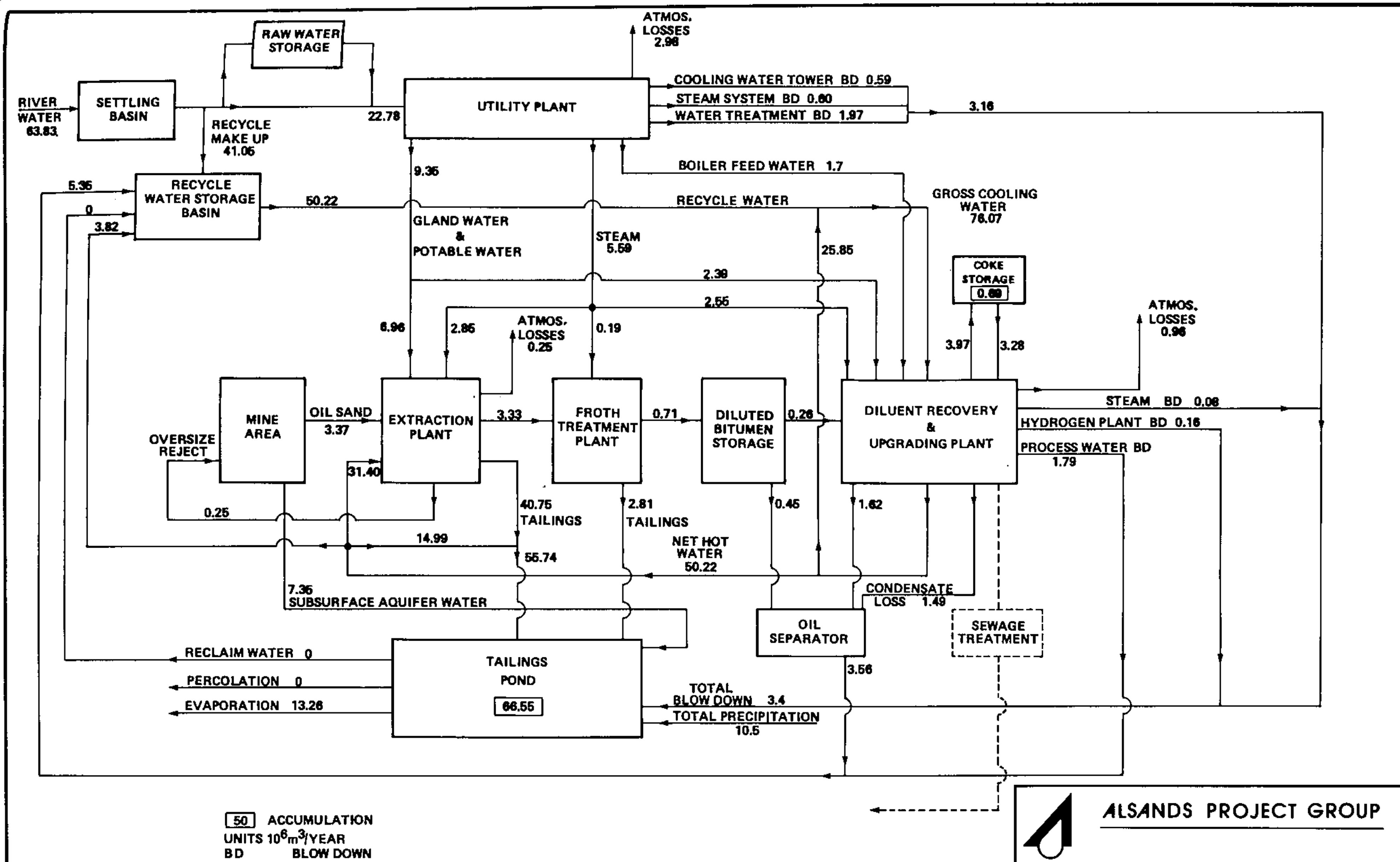
EXTRACTION & FROTH TREATMENT MATERIAL BALANCE

FIGURE VI-3



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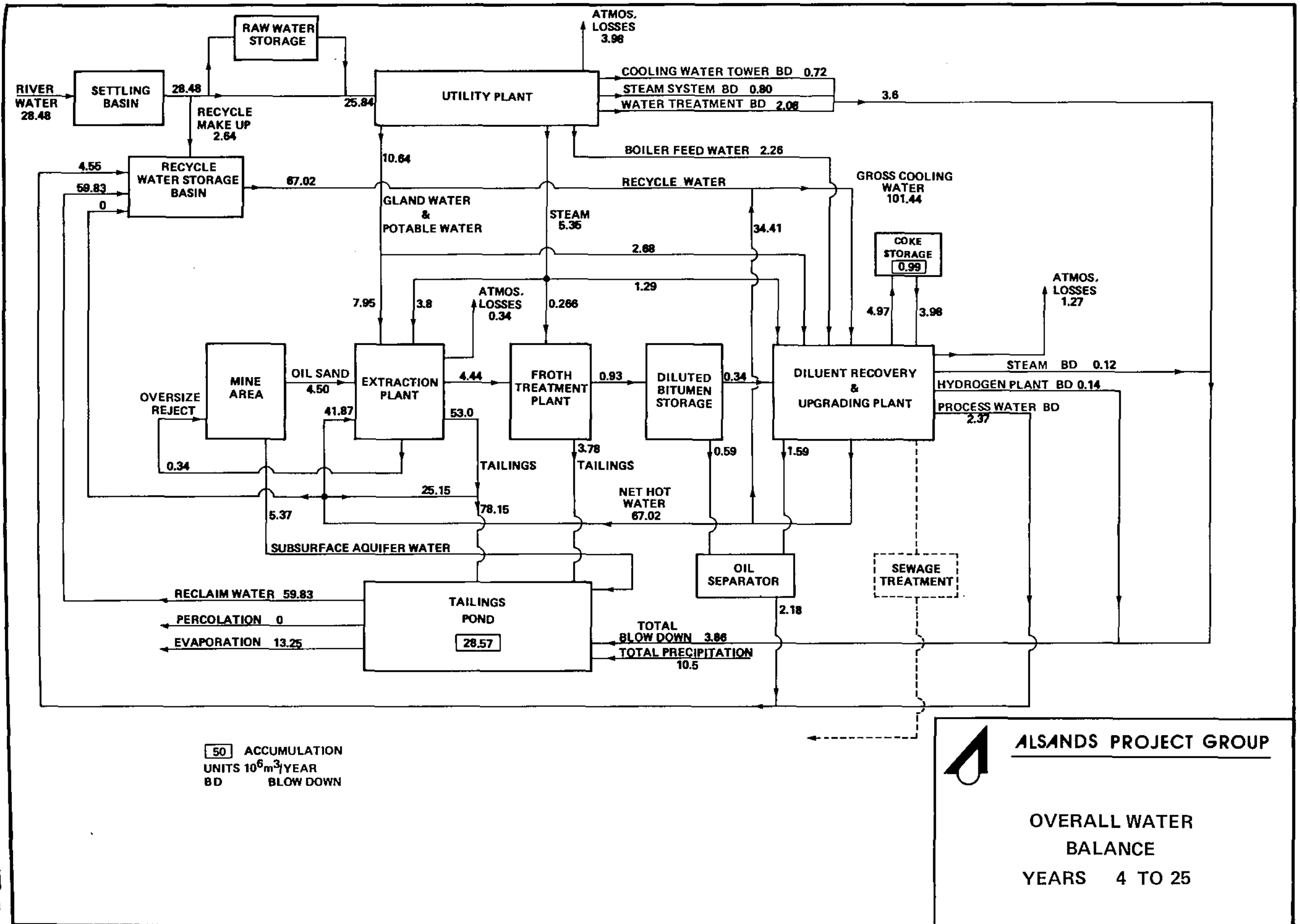
OVERALL WATER BALANCE

YEARS 1 TO 3


RIVER WATER 28.48
SETTLING BASIN
28.48
RAW WATER STORAGE
25.84
UTILITY PLANT
ATMOS. LOSSES 3.98
COOLING WATER TOWER BD 0.72
STEAM SYSTEM BD 0.80
WATER TREATMENT BD 2.06
3.6
RECYCLE MAKE UP 2.64
RECYCLE WATER STORAGE BASIN
4.55
59.83
0
67.02
10.64
BOILER FEED WATER 2.26
RECYCLE WATER
GROSS COOLING WATER 101.44
GLAND WATER & POTABLE WATER
STEAM 5.36
34.41
2.68
COKE STORAGE
0.99
1.29
ATMOS. LOSSES 1.27
7.95
3.8
ATMOS. LOSSES 0.34
0.266
4.97
3.98
MINE AREA
OIL SAND 4.50
EXTRACTION PLANT
4.44
FROTH TREATMENT PLANT
0.93
DILUTED BITUMEN STORAGE
0.34
DILUENT RECOVERY & UPGRADING PLANT
STEAM BD 0.12
HYDROGEN PLANT BD 0.14
PROCESS WATER BD 2.37
OVERSIZE REJECT
41.87
53.0
0.34
TAILINGS
3.78
TAILINGS
0.59
1.59
25.15
78.15
NET HOT WATER 67.02
5.37
SUBSURFACE AQUIFER WATER
OIL SEPARATOR
SEWAGE TREATMENT
RECLAIM WATER 59.83
PERCOLATION 0
EVAPORATION 13.25
TAILINGS POND
28.57
2.18
TOTAL BLOW DOWN 3.86
TOTAL PRECIPITATION 10.5
50 ACCUMULATION
UNITS 10^6 m^3/YEAR
BD BLOW DOWN
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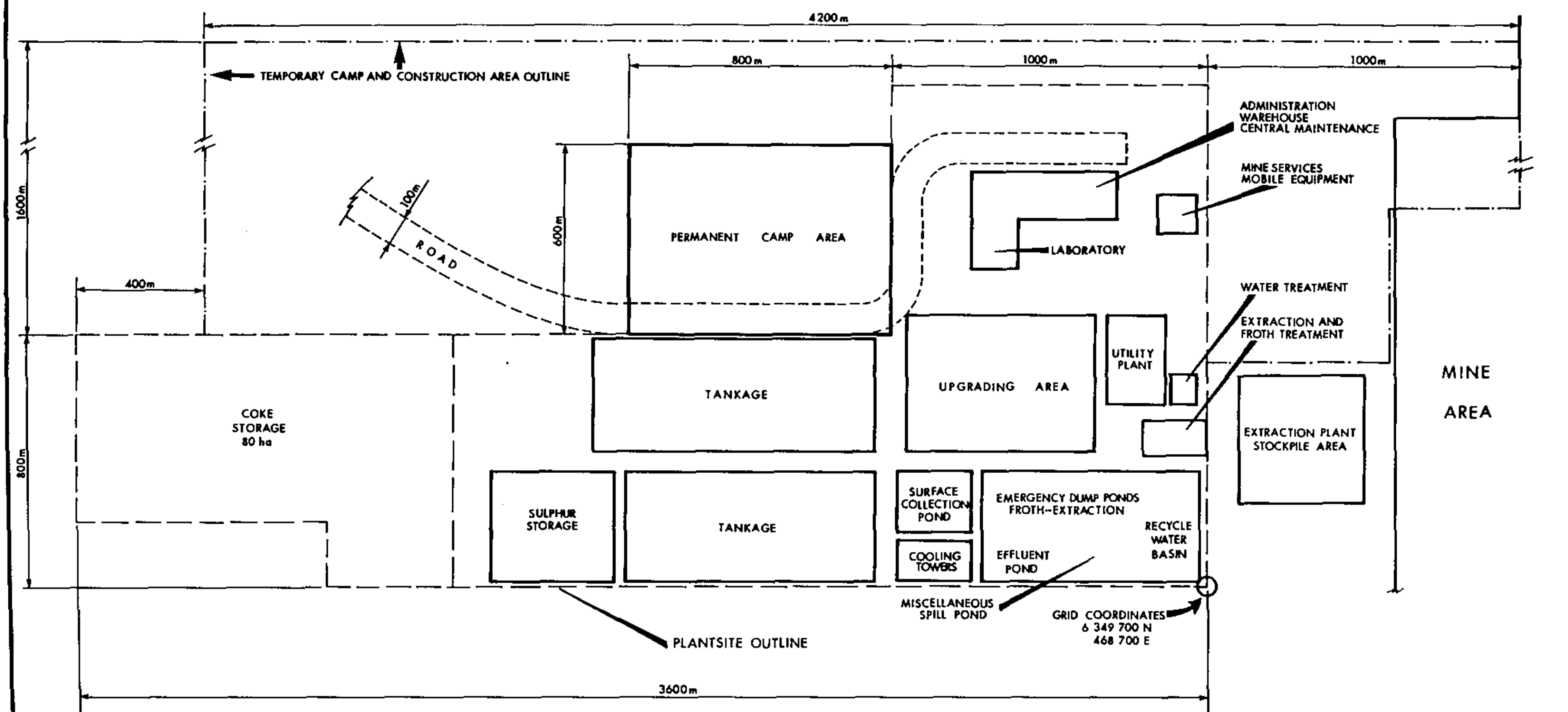
OVERALL WATER BALANCE
YEARS 4 TO 25

FIGURE VI-5



ALSANDS PROJECT GROUP

PROPOSED PLANTSITE
LAYOUT

FIGURE VI-6

VII Tailings Management

General

The hot water extraction process will produce 300×10^3 m^3/d (55 000 USGPM) of tailings which will be permanently stored except for the recycle water. In the storage of tailings, bulking of the solids by forty to fifty percent over the insitu volume must be accommodated. Initial storage is provided in an external pond located outside the economically mineable limits, and is followed by deposition into the mined-out pits.

Starter dykes for the external pond will be constructed with borrow material from within the area which will follow the tailings pond outline indicated in Figure III-3, encompassing approximately 2100 ha (5200 acres). The tailings slurry is comprised predominantly of water, sand and smaller amounts of silts and clays. When disposed of in the tailings pond the tailings forms two distinct phases consisting of a coarse sand deposit and a dilute silt/clay sludge. The coarse sand fraction will be used to raise the tailings pond dykes above the starter dykes to approximately 50 m (165 ft) above original ground elevation. The use of the upstream method of dyke construction will permit early reclamation of the outer slopes.

The timing for start of in-pit disposal is dependent upon the volume of storage that is developed in the mine. The in-pit tailings pond dykes will be constructed in a similar manner to the external tailings pond dykes, on top of the waste material which has been cast back into the pit. To permit reclamation of the entire surface of the filled mined-out area, the sludge and water fraction will be continuously dredged from the in-pit storage and pumped into the external tailings pond, leaving behind the pit filled with coarse sand.

Tailings Pond Site Selection

Two cases for site selection of the external tailings pond were investigated: off-lease and on-lease.

OFF-LEASE TAILINGS POND

The Applicant has reviewed alternate sites for off-lease tailings disposal and concludes the nearest potential site barren of reserves is approximately 20 km (12 miles) to the northeast of the plantsite.

An economic analysis has been conducted assuming transport of the total tailings stream to this site for a period of 8 years followed by transport of only the water and sludge fractions for the remaining 17 years. Water must be recycled from the tailings pond for the entire life of the project.

It is assumed that the cost of development and the cost of reclamation at this site would be the same as at the on-lease site.

The incremental capital required for off-lease tailings disposal at the above mentioned site, is \$250 million (1978) (a 25-30 fold increase over the on-lease case) with \$26 million (1978) per year in operating costs for the first 8 years of operation and \$10 million (1978) per year (a 6 fold increase over the on-lease case) for the remaining 17 years of service.

The Applicant has also estimated how great a real increase in the value of oil would be required to make recovery of the bitumen under the proposed on-lease tailings pond site economic. Using the same criteria for this site as was used for evaluation of the designated ore bodies, it would take a *real increase* of \$25/m^3 (\$4/Bbl) (27 percent increase) to the average value of the synthetic crude to make the bitumen in the proposed tailings pond site economic. (A *real increase* is an increase in the value (price) of the synthetic crude not reflected in the increase in the cost of producing it.)

The Applicant therefore concludes that the bitumen under the proposed on-lease tailings site is uneconomically recoverable with present technology. The incremental cost of off-lease tailings is a significant burden on the Project, and because of the high cost of recovering the bitumen covered by the proposed on-lease tailings pond, it is not warranted. The on-lease tailings disposal site is therefore proposed as discussed in the following sections.

ON-LEASE TAILINGS POND

The on-lease external tailings pond site location is located outside the economically mineable limits as shown on Figure III-3. Within this area the tailings pond has been located to maximize the use of borrow material from inside the pond, minimizing surficial land disturbance.

Tailings Pond Size

Sizing of the tailings pond is dependent upon the volume of tailings that must be stored external to the mined out pits. Based on the storage volume that is developed by mining and on geotechnical constraints on the rate of in-pit dyke construction, disposal into the pit is not practical until after 8 years of mining. Geotechnical consultants have recommended that the vertical rate of dyke construction be limited to 12 m (40 ft) per year to ensure a stable dyke design. Furthermore, sufficient volume is required for the storage of the liquid sludge in the tailings pond for the full 25 year mine life to permit surface reclamation of the mined out area following in-pit tailings disposal.

Consistent with the above conditions the proposed tailings pond will cover 2100 ha (5200 acres) of surface area, and dyke heights will range from 35 to 55 m (115 to 180 ft). A minimum of 8 years of mining is required to provide enough tailings sand to construct the containment dyke around the proposed pond area. A smaller external tailings pond would require additional sand for dyke construction because of the need for higher dykes. This would delay disposal of tailings into the mine area and reduce the amount of mined out area that would eventually be reclaimed.

Tailings Pond Construction

STARTER DYKES

Starter dykes will be constructed along the tailings pond outline indicated in Figure III-3. The maximum height will be approximately 15 m (50 ft) with an average of 7 to 8 m (23 to 36 ft). An estimated dyke length of 20 km (12 miles) will be required with a top width of 20 m (65 ft) and average side slopes of 3.5:1. Typical cross sections are illustrated in Figures VII-1 and VII-2, which show the construction technique for either muskeg or no muskeg foundation conditions. They differ only in slope angles required. Muskeg depths of 1.0 m (3 ft) and less will be removed prior to placement of the compacted fill. For muskeg depths exceeding 1.0 m (3 ft), stage loading methods of construction will be employed. Stage loading involves incremental placement of fill and provides time for drainage of water from the muskeg. After drainage the muskeg will consolidate, forming a competent foundation.

Sufficient quantities of starter dyke construction material are available from within the tailings pond area. These materials include outwash sands and gravels which make up the bulk of the required volume, eolian sands which occur mostly in the south half of the pond and lean oil sand which is available in most locations. It is estimated that 14×10^6 m^3 (18×10^6 yd^3) of borrow materials are required for starter dykes. The locations of these deposits are shown in Figure VII-3.

The main section of the dyke is composed of outwash sand and gravel combined with some eolian sand. These materials will provide a permeable, well drained downstream toe for the sand tailings dyke and will aid in controlling the direction of seepage in this dyke. A zone of lean oil sand will be used as a barrier to seepage on the upstream face of the starter dyke to permit the main section of the dyke to drain. A filter zone between the lean oil sand and the outwash gravel may be required. Information on the quality of outwash gravel remains to be confirmed.

TAILINGS SAND DYKE CONSTRUCTION

The design and construction concepts proposed for the sand dykes are similar to those being used for Great Canadian Oil Sands Ltd. (Mittal and Hardy, 1977) and Syncrude Canada Ltd. (Nyren, Haakonson, and Mittal, 1978) tailings ponds. The sand dykes will be constructed with side slopes ranging from 3:1 to 4:1 depending upon the existing subsoil conditions at the site.

The dyke section is designed as a hydraulic fill structure. To provide a stable section under all anticipated conditions, the structural portion of the dyke will be compacted to a minimum seventy percent relative density. To prevent the phreatic surface from exiting on the downstream slope, seepage control will be provided by internal drains. A typical design section is shown on Figure VII-4.

The construction of the dykes will be by an upstream method since the starter dyke will form the downstream toe of the final dyke section. The sand in the dykes will be placed by the hydraulic cell method. This procedure involves placement of tailings by hydraulic sluicing into cellular units usually but not necessarily parallel to the longitudinal axis of the dyke. These cells are about 30 to 90 m (100 to 300 ft) wide and 300 to 600 m (1000 to 2000 ft) long and are sloped away from the tailings discharge area. The cells are bounded initially by shallow sand dykes, about 1.5 to 2.0 m (5 to 7 ft) high, pushed up by dozers. The tailings stream is discharged into these cells, the coarse sand settles out by gravity and the fines fraction in suspension flows out through an overflow weir into the pond.

Dyke building experience indicates that the specified minimum densities of over 70 percent can be achieved by wide track dozers operating in the cells during hydraulic sluicing.

During the winter months the tailings will be discharged directly into the pond upstream of the compacted dyke section since cells cannot be constructed safely due to poor visibility during dozer operation. A beach of uncompacted sand is formed which abuts the compacted dyke section and extends into the pond on relatively flat slopes of 1:20. The sludge and water component of the tailings effluent will flow as a fluid to the low side or end of the tailings disposal area being developed at any particular time.

The tailings pond has been designed with a capacity to handle total tailings for the first 8 years of production and the sludge portion of the tailings for the remaining 17 years of the Project life. All clarified water will be recycled for re-use in the plant. Figure VII-5 shows the rise in pond elevation and dyke height with an ultimate dyke height of approximately 50 m (165 ft) above original ground level. In calculating the final height of the dyke, allowances were made for 3.5 m (10 ft) of free board.

SEEPAGE CONTROL

Some seepage will occur from the sand tailings dykes. The source of this seepage includes water from the clear water zone near the pond surface, minor amounts from the sludge as it consolidates, and sluicing water during hydraulic placement is mined out after 8 years, resulting in an average depth of 33 m (110 ft) below the original ground surface after the overburden and centre reject has been cast back into the pit. The total tailings stream is discharged into this area for 2.5 years until block 1B has been mined out. Mining then advances to block 2. Tailings continue to be discharged into block 1A concurrently with disposal into block 1B until the dyke heights of the two blocks are equal. The cross dyke between blocks 1A and 1B is abandoned. After 15.5 years of mining, block 2 has been mined out and is available to store tailings, and block 1 has been built up to an elevation of 7 m (23 ft) above the original ground surface elevation.

Since block 2 does not have sufficient areal extent to store the total tailings while restricting the rise in dyke height to below 12 m (40 ft) per year, a portion of the flow is discharged into block 1. This situation continues until year 21.5 when block 3A has been mined out and blocks 1 and 2 have been raised to an elevation of 17 m (55 ft) above the original ground surface. Reclamation of the top surface of blocks 1 and 2 can now commence. Systematic revegetation of in-pit dykes exterior slopes can begin in year 9 of operation. From years 21.5 to 25, the tailings are deposited into block 3A.

The end result is blocks 1 and 2 raised to 17 m (55 ft) above original ground level, block 3A raised to a height of 6 m (20 ft) above original ground level and blocks 3B and 4 left as a mined out pit at average depths of 30 m (100 ft) and 18 m (60 ft) respectively. Blocks 3B and 4 will either provide storage for a post 25 year mining project or be left as an open water body.

This in-pit disposal scheme allows reclamation of approximately 70 percent of the surface of the mined out area with the remaining area left as a lake.

Tailings Pond Water Balance

The major stream flow discharged into the tailings pond is the Extraction Plant tailings, consisting of a slurry of water, sand, and sludge at 45 to 50 percent solids by mass. When discharged into the pond, a portion of the water becomes trapped in the interstices of the sand and sludge. The amount of water trapped in the pore spaces in the sludge and sand is estimated to average 10.6×10^6 m^3/a (2800×10^6 USG/yr) and 18.0×10^6 m^3/a (4800×10^6 USG/yr) respectively.

As the depth of the sludge layer increases, consolidation takes place, releasing a portion of the trapped water. Most of this released water eventually becomes part of the clear water zone but a small portion migrates downwards to the foundation soils. This percolation is negligible and is not presented in the pond water balance in Table VII-1 because it has been included in the estimate of trapped water.

After approximately 3 years of operation a mature tailings pond will be developed with a zone of clarified water at the surface which is of suitable quality for recycle. It is envisaged that the mature pond will consist of a 3 m (10 ft) depth of clarified water overlying a 4 m (13 ft) deep transition zone of fines in suspension which in turn overlies the accumulating sludge layer.

The other streams discharged into the tailings pond such as mine drainage water and process water from Upgrading and Utilities will form part of the recycle water.

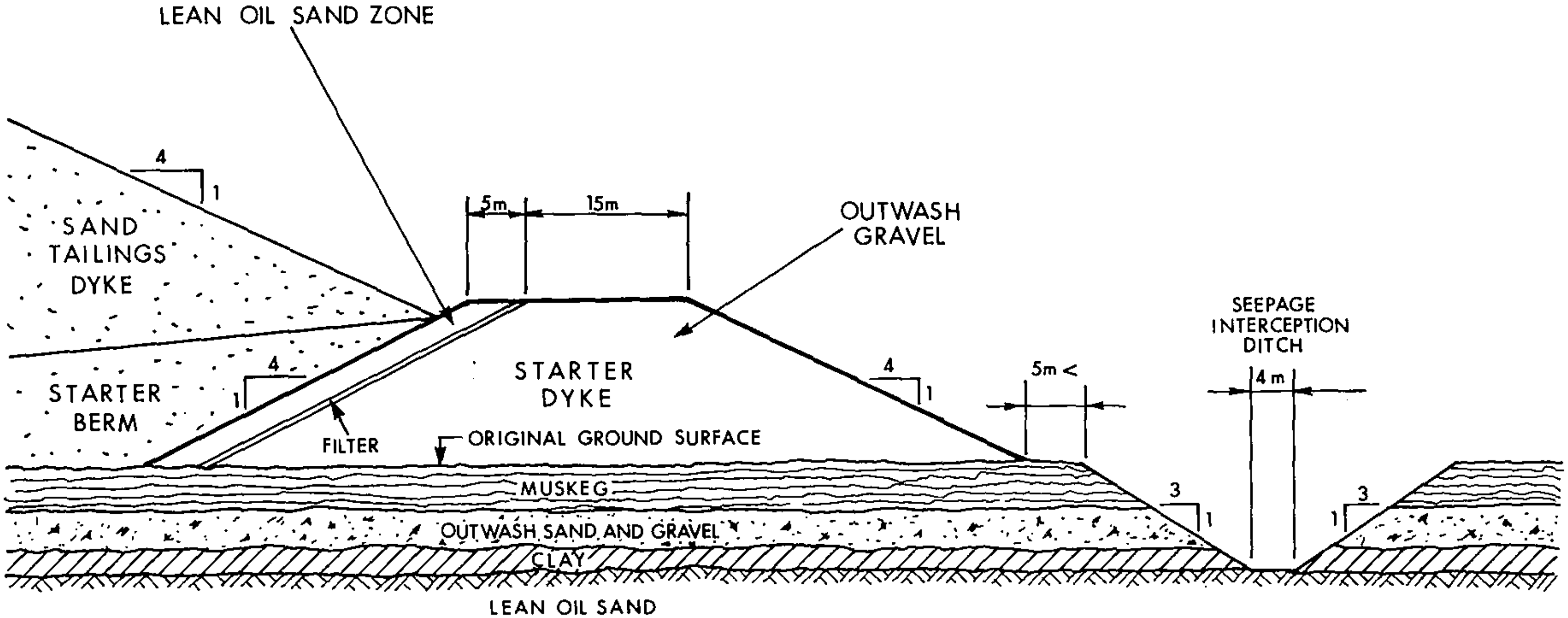
The average total tailings pond water balance during full scale operation is presented in Table VII-1.

TABLE VII-1

TAILINGS POND WATER BALANCE

IN	WATER ($10^6 m^3/a$)
Extraction Tailings	78.15
Froth Treatment Tailings	3.78
Mine Drainage Water	5.36
Process Water from Upgrading and Utilities Plant	3.96
Precipitation[1]	10.50
TOTAL	101.75
OUT	
Water trapped in sand voids	18.03
Water trapped in sludge voids	10.64
Evaporation[2]	13.25
Recycle[3]	59.83
TOTAL	101.75

Notes:
1. Based on annual precipitation of 450 mm.
2. Based on annual evaporation of 640 mm.
3. 65 percent of water in the tailings.

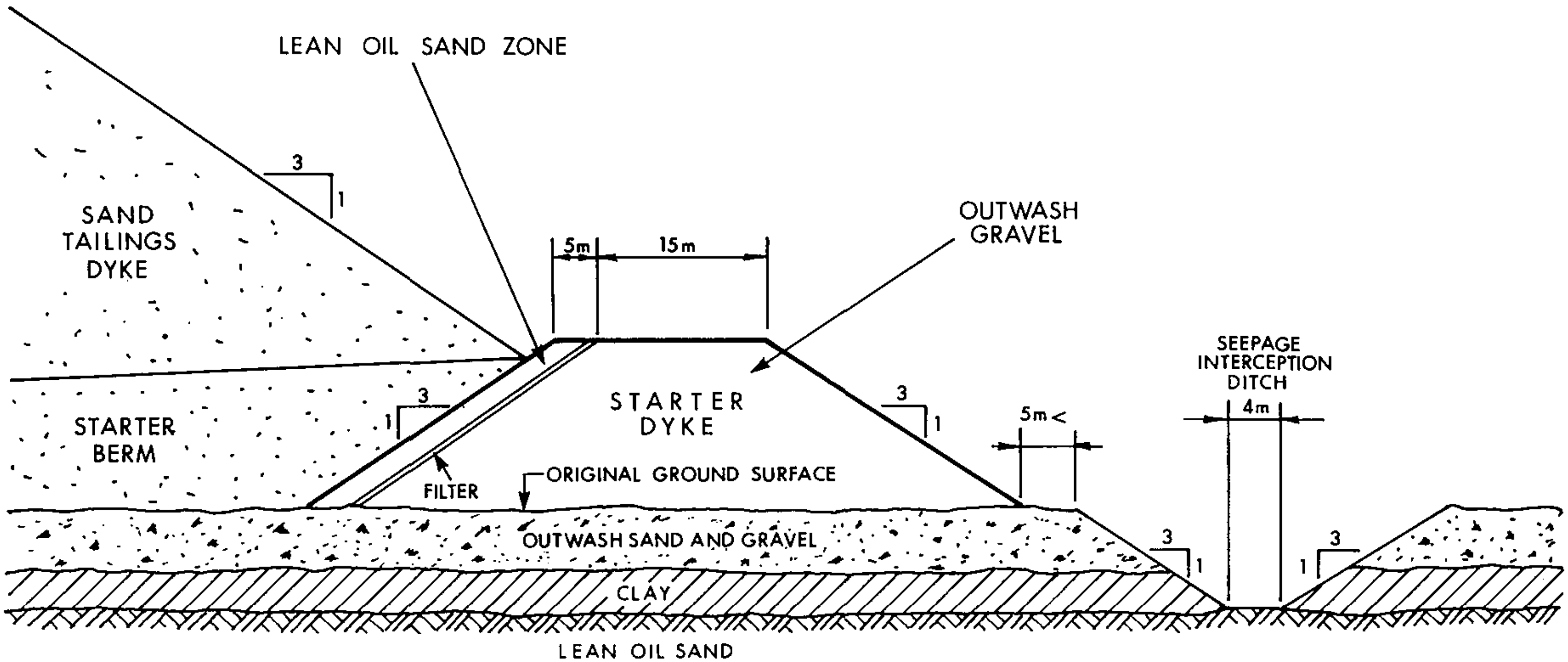


TYPICAL SECTION THROUGH STARTER DYKE

ALSANDS PROJECT GROUP

TYPICAL STARTER DYKE WITH MUSKEG FOUNDATION

FIGURE VII-1



TYPICAL SECTION THROUGH STARTER DYKE

ALSANDS PROJECT GROUP

TYPICAL STARTER DYKE
WITHOUT MUSKEG FOUNDATION

FIGURE VII-2

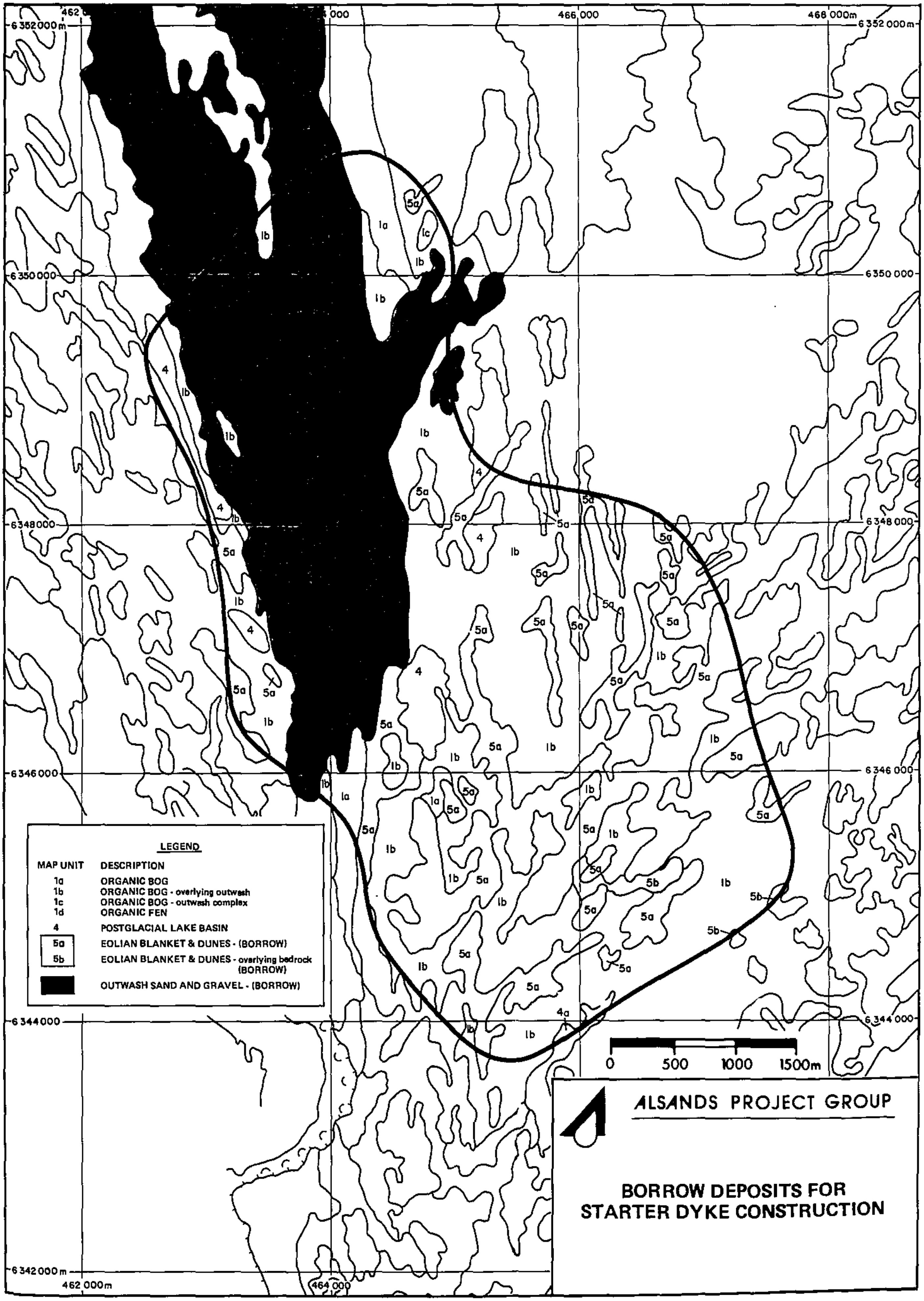
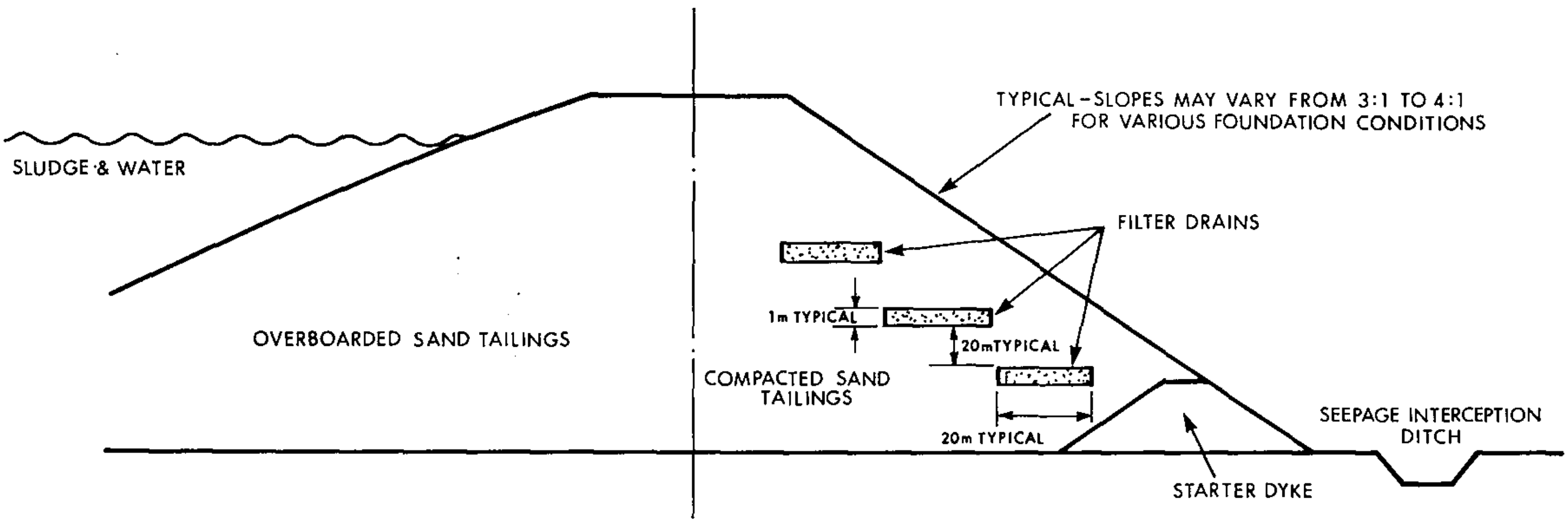

LEGEND
MAP UNIT DESCRIPTION
1a ORGANIC BOG
1b ORGANIC BOG - overlying outwash
1c ORGANIC BOG - outwash complex
1d ORGANIC FEN
4 POSTGLACIAL LAKE BASIN
5a EOLIAN BLANKET & DUNES - (BORROW)
5b EOLIAN BLANKET & DUNES - overlying bedrock (BORROW)
OUTWASH SAND AND GRAVEL - (BORROW)
0 500 1000 1500m
ALSANDS PROJECT GROUP
BORROW DEPOSITS FOR STARTER DYKE CONSTRUCTION
6 352 000m
6 350 000
6 348 000
6 346 000
6 344 000
6 342 000m
462 000m
464 000
466 000
468 000m

FIGURE VII-3



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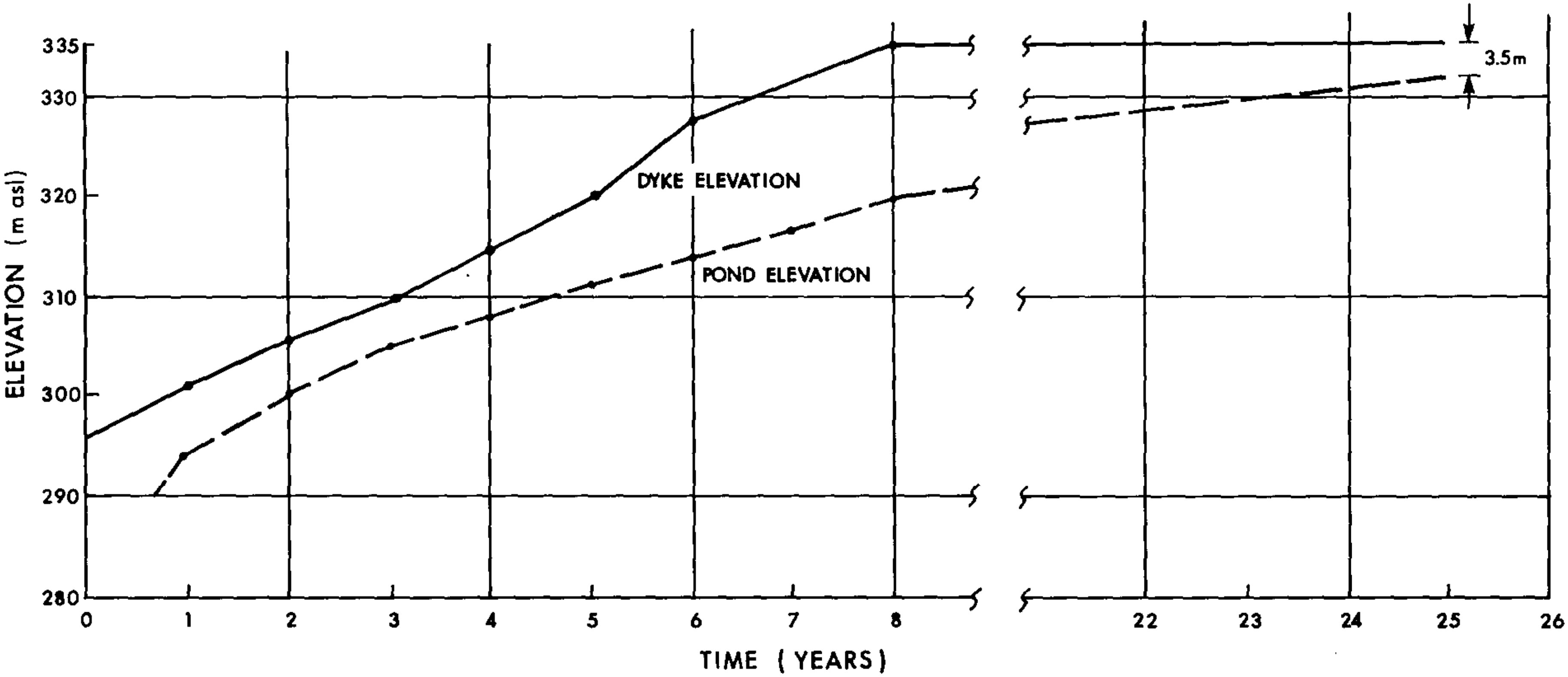
**TYPICAL DYKE SECTION
WITH SEEPAGE CONTROL**

FIGURE VII-4



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EXTERNAL TAILINGS POND
RISE IN DYKE AND
POND LEVEL ELEVATIONS

FIGURE VII-5

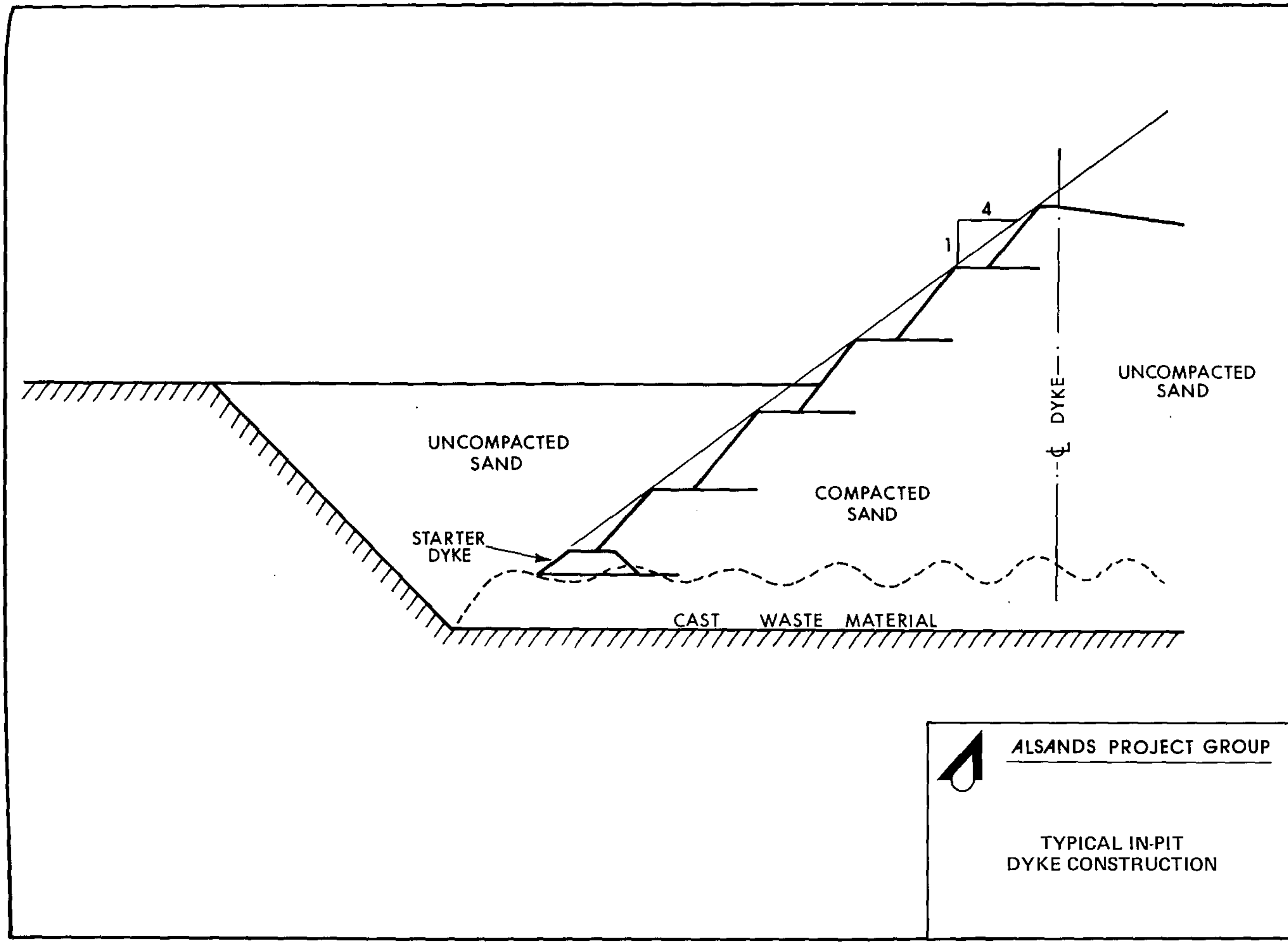
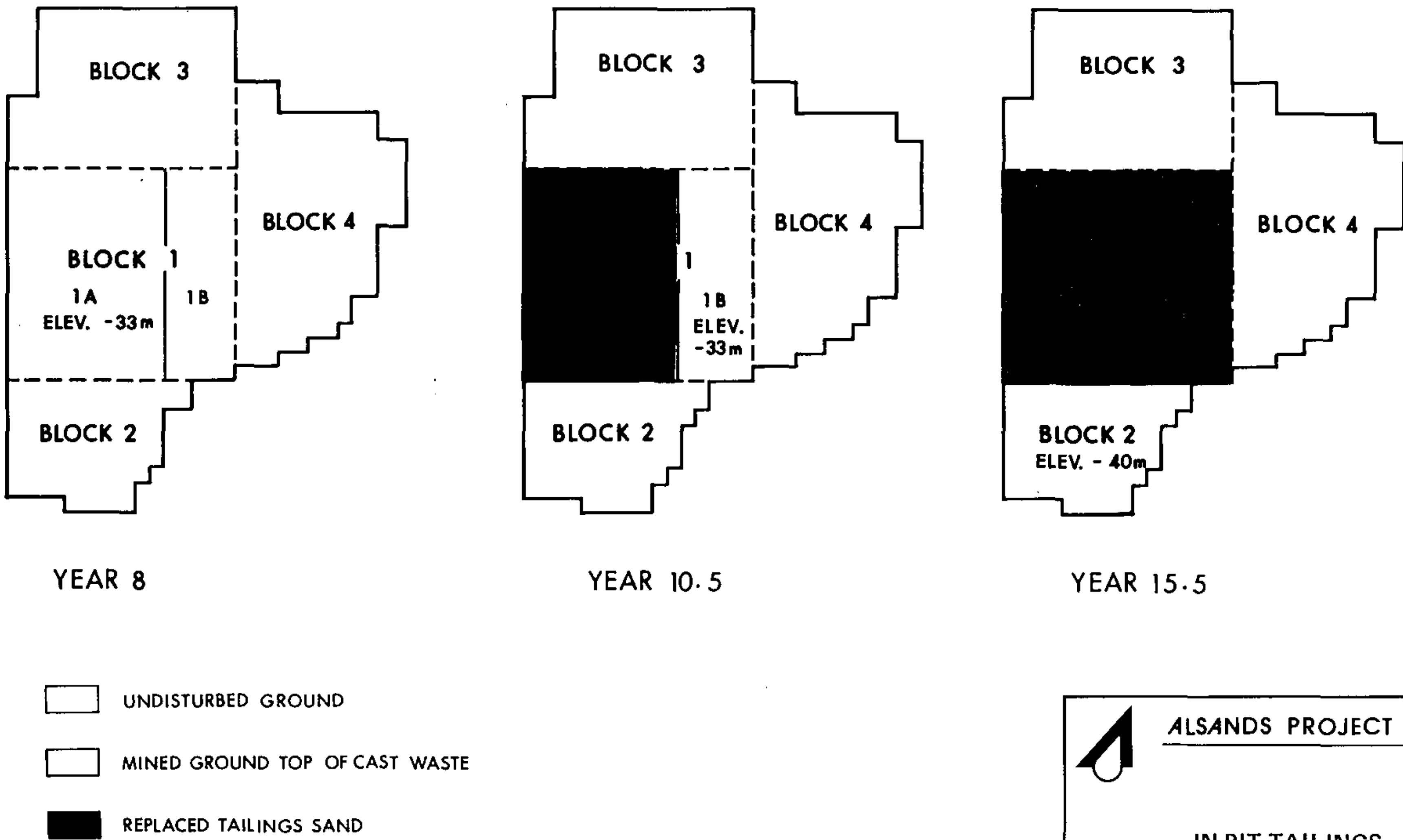

4
1
UNCOMPACTED
SAND
DYKE
℄
UNCOMPACTED
SAND
COMPACTED
SAND
STARTER
DYKE
CAST WASTE MATERIAL
ALSANDS PROJECT GROUP
TYPICAL IN-PIT
DYKE CONSTRUCTION

FIGURE VII-6



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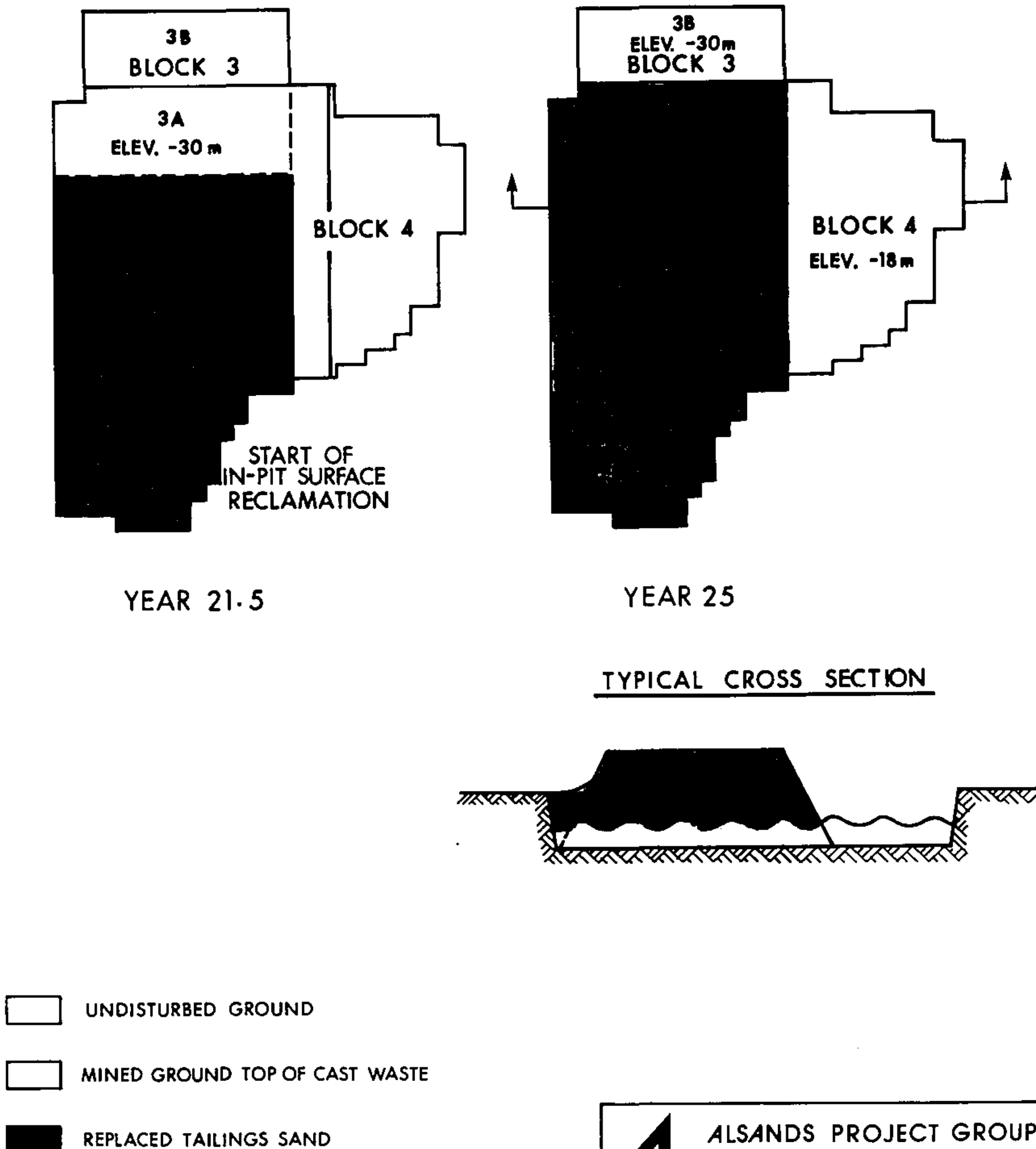
IN-PIT TAILINGS
DISPOSAL PLAN

FIGURE VII-7



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IN-PIT TAILINGS
DISPOSAL PLAN

FIGURE VII-8

VIII Upgrading and Utilities Process Selection

Overview

In selecting the Upgrading and Utilities process scheme the Applicant has determined the need to upgrade Athabasca bitumen, and has evaluated Upgrading Process configurations which were considered suitable in the context of the overall Project. This involved not only the requirements of Upgrading, but also of Mining, Extraction, and Utilities. The candidate Upgrading Process schemes were evaluated in detail with the assistance of involved process licensors. A detailed economic analysis was made of the alternative schemes on the basis of a bitumen feed rate of 25 000 m^3/d (157 500 B/D). Technical factors were also major considerations in the process selection.

The selected Upgrading scheme is based on Fluid Coking with hydrogen manufacture initially by Partial Oxidation (Gasification) of Coker Gas Oil, and ultimately by Gasification of Fluid Coke, depending upon satisfactory development of this technology as further discussed below. Hydrogen manufacture by Partial Oxidation of natural gas is an alternative for the initial period. The state of development of Gasification technology is reviewed, and a schedule is projected for incorporating Coke Gasification into the Upgrading scheme.

Five tail gas treating processes for Claus Sulphur Plants were evaluated. All had a minimum design recovery of 99 percent. A SCOT Cascade process was selected because of its high overall recovery efficiency of 99.9 percent, even though it was not the most cost effective choice.

Upgrading Requirement

Athabasca bitumen produced by the Hot Water Extraction Process is a heavy, viscous, high residue material containing substantial quantities of sulphur, nitrogen, metals and clay. Its properties are shown on Table VIII-1. This bitumen does not meet gravity and viscosity requirements for transportation by pipeline, and its high specific gravity, sulphur, nitrogen and ash contents preclude it from direct use in most conventional refineries. There is thus a need for Upgrading facilities at the plant site to produce a crude oil compatible with conventional pipelining and refining operations, and having a composition and quality consistent with projected future oil product requirements.

Upgrading Alternatives

In selecting candidates for the Primary Upgrading process, reliability is a fundamental consideration. The selected process must be capable of sustained operation at a high stream factor in order not to pose an unacceptable risk to overall Project economics. Accordingly, candidates for the primary Upgrading process are confined to those which have been proven commercially viable and which offer demonstrated potential for operability on Athabasca bitumen. Atmospheric and other emissions must be held to acceptable levels by means of proven technology. Additionally, candidate processes are confined to those for which the relationship of synthetic crude yield to capital and operating costs renders them economically competitive.

The process schemes which were evaluated in detail are:

Fluid Coking with coke stockpiling
Fluid Coking with Coke Combustion
Fluid Coking with Partial Oxidation of Coke
Flexicoking
Expanded Bed Hydroconversion — Hydrovisbreaking

These schemes are outlined below with brief descriptions of the key processes.

FLUID COKING AND COKE STOCKPILING

The overall flow scheme for Fluid Coking with stockpiling of the excess coke is shown in Figure VIII-1. Hydrogen manufacture is by Partial Oxidation of Coker gas oil.

Licensed by Exxon Research & Engineering, Fluid Coking is designed to upgrade heavy residues to gas oil, distillate, naphtha, gas, and coke. Its configuration is shown on Figure VIII-2. Bitumen is fed directly to a Fluidized Bed Reactor where Coking (cracking) takes place. The coke bed is fluidized by the addition of steam at the reactor bottom and by the product vapours. The vapour products pass overhead through cyclone separators which remove most of the entrained coke for return to the reaction zone. The vapours are further scrubbed and cooled with oil, which is recycled to the reactor, and then fractionated into the desired product cuts for further processing. Coke, which has given up considerable heat to feed preheat and cracking, is circulated back to the burner where partial combustion occurs with air. Hot coke is returned to the reactor from the burner to heat balance the process. Yields are given in Table VIII-2.

Product coke is removed from the burner continuously to maintain constant fluid bed inventory, and after quench cooling and some internal particle classification, is transported to storage.

The flue gas from the burner containing carbon monoxide and hydrogen sulphide is burned in a CO boiler to generate steam, and to provide Diluent Recovery Unit heat. It then proceeds to the stack through electrostatic precipitators. The licensor of the Fluid Coking process reports that the sulphur level of the coke combusted in the burner is lower than in either the liquid feed or in the net coke. This is attributed to the preferential burning of carbon over sulphur at the burner conditions, and results in the accumulation of sulphur on the coke rejected to storage.

In this scheme, hydrogen is produced by Partial Oxidation of coker gas oil. Due to this being a less familiar process, a brief description follows.

The first commercial Partial Oxidation or Gasification units came on stream in the early 1950's, first on natural gas, then on low quality, high sulphur liquid streams. There are in excess of 100 units operating in the world today.

The process sequence for the Gasification of a heavy liquid feedstock to produce hydrogen, as licensed by Shell, is outlined in Figure VIII-3. In this process the heavy gas oil, along with carbon recycle, is partially reacted in the combustor with oxygen in the presence of steam to produce hydrogen and carbon monoxide. The carbon monoxide is then reacted (shifted) catalytically with additional steam, to produce additional hydrogen and carbon dioxide. Sulphur in the feedstock is converted into hydrogen sulphide and recovered as sulphur by conventional gas treating processes. The carbon dioxide is also removed and vented to atmosphere, yielding relatively high purity hydrogen.

FLUID COKING WITH COKE COMBUSTION

The overall flow scheme for Fluid Coking with Coke Combustion is shown in Figure VIII-4. To utilize the energy from the coke, hydrogen manufacture is by Steam Methane Reforming of Coker gas which was used as plant fuel in the previous scheme.

The net coke from the Fluid Coker, which provides fuel for the Utility boilers, is high in sulphur and heavy metals. Combustion of this material thus requires the installation of Flue Gas Desulphurization (FGD) Units to reduce sulphur dioxide emissions to an acceptable level. Sulphur content of the coke, at over 9 percent, is much higher than that encountered in thermal grade coals.

The FGD process selected from several candidates in this case is a lime ry system. It requires development of a sizeable limestone quarry and quent disposal of large quantities of stabilized sludge.

ID COKING WITH PARTIAL OXIDATION OF COKE

verall flow scheme for Fluid Coking with Partial Oxidation of coke to e hydrogen is shown in Figure VIII-5.

In the Coke Gasification process carbon monoxide and hydrogen are ced in a gasifier by reaction of coke with steam and oxygen (Figure VIII-6); bon monoxide is further reacted with steam to yield hydrogen and carbon ide. The latter is removed by conventional gas treating processes to yield a ively pure hydrogen for the Hydrogen Processing Units.

The fluid coke must be ground to a uniformly small particle size for proper bustion, and very close control of the feed rate to the reactor is required for dy combustor conditions. As the Gasifier reactor operates above the fusion of the ash and clays in the feedstock, they form a liquid slag which upon ification is inert and readily disposable. The sulphur in the coke is converted ydrogen sulphide and removed in the gas treating facilities for recovery as ital sulphur.

XICOKING

erall flow scheme for Flexicoking is shown in Figure VIII-7. Hydrogen uracture is by Steam Methane Reforming of Coker gas.

Licensed by Exxon Research and Engineering, the Flexicoking process tes the Coke Gasification operation with normal Fluid Coking. Utilizing air partial oxidation agent, the coke product is converted to a low heat content 85-95 BTU/SCF – 3200-3600 KJ/m^3). Yields are identical to Fluid Coking ie exception of coke disposition, as given in Table VIII-2.

The Flexicoking process is shown in Figure VIII-8. Coke is circulated ng three major vessels: reactor, heater, and gasifier. The reactor, scrubber, and nation system are identical to that shown for the Fluid Coker. The heater a heat exchanger between hot coke from the gasifier and cold coke from reactor. There is no combustion in the heater. The coke produced from oil ck is withdrawn to the gasifier where it reacts with steam and air to produce gas containing carbon monoxide and hydrogen. Steam and air rates control gasifier reaction. The hot coke gas plus a control stream of hot coke are d from the gasifier to the heater to satisfy the reactor heat demands. In this uration, any oil entrained in the coke from the reactor is cracked in the er, yielding lighter hydrocarbons which increase the heating value of the coke ost of the sulphur present in the low heat content gas is in the form of gen sulphide.

The hot untreated coke gas from the top of the heater vessel passes through m generation exchanger, tertiary cyclones to remove coke fines, and a -water scrubber system for final carbon cleanup. The hydrogen sulphide is oved in the gas treating facilities, and the product gas is then burned as fuel Utility Plant.

ANDED BED HYDROCONVERSION – HYDROVISBREAKING

Applicant's assessment of the Hydrovisbreaking process, both Gasification ombustion of the Hydrovisbreaker bottoms were considered. The overall schemes for the two approaches are shown on Figures VIII-9 and VIII-10. ost economic approach was residue Gasification for hydrogen manufacture nly this alternative was explored in detail. Hydrogen manufacture is lemented by Steam Methane Reforming of the hydrogen rich vent gases.

Licensed by HRI Engineering and CE-LUMMUS as H-OIL and L-C Fining respectively, this process is outlined on Figure VIII-11. The bitumen and hydrogen are fed upflow into an expanded (ebullated) catalyst bed. The backmixing of microspheroidal catalyst and oil within the reactor maintains an isothermal temperature throughout the reactor without the need for intermediate beds and quenches. The ebullating bed feature, along with the ability to add and withdraw catalyst continuously to maintain activity, makes this design amenable to oil sands bitumen with its high ash, metals, and solids content. The reaction heat generated is controlled by the liquid feed inlet temperature, which is operated below normal reactor temperature. Temperature control is provided on the hydrogen inlet stream by furnace firing.

The reactor products are separated in a conventional manner, with special attention given to minimizing hot oil heat exchangers and the attendant possible fouling. A multi-separator system is used to maximize heat recovery.

The unconverted hydrovisbreaker residue is vacuum distilled, yielding a relatively high endpoint material to gas oil Hydrotreating and eventually to product crude oil. The vacuum residue produced has a very high specific gravity and viscosity. Yields are compared to those of Fluid Coking and Flexicoking in Table VIII-2.

OTHER UPGRADING ALTERNATIVES

The following Upgrading alternatives were evaluated in less detail than those above. Reasons for their rejection are discussed.

Solvent Deasphalting/Hydrocracking and Partial Oxidation

The ERCB submission filed by Shell Canada Limited in 1973 was based on this process scheme, which is shown in Figure VIII-12.

In this scheme, the bitumen is vacuum distilled to yield gas oil and vacuum pitch. The latter is solvent deasphalted to recover additional "clean oil", and asphalt which is about 20 percent volume of the bitumen feedstock. This very heavy stream is gasified in an air Partial Oxidation Unit to clean, low heat content gas for plant fuel.

The vacuum gas oil stream is treated in a conventional Hydrotreater and the deasphalted oil is upgraded in a Hydrocracker. Hydrogen is produced by Steam Methane Reforming of hydrogen-rich Hydrotreater off gases and propane and lighter gases, with natural gas supplement. The Hydrotreater/Hydrocracker liquid products are combined with butanes to produce the synthetic crude oil.

After considerable additional research subsequent to the 1973 filing, the scheme was eliminated for both technical and economic reasons. The minimum attainable fuel yield exceeds the plant fuel requirements thus causing a project energy imbalance.

Delayed Coking

This process, which is employed by GCOS, has a total installed capacity of 200 000 m^3/sd (1.26 $\times$ 10^6 B/SD). In this process bitumen is heated in fired heaters to a cracking temperature and is subsequently soaked in large coking drums where coke and cracked gases are produced. The cracked products are recovered in conventional fractionation and gas recovery facilities and are processed in downstream units to produce essentially sulphur free fuel gas and saleable liquid products.

The process was evaluated on the premise that the approximately 5000 t/sd (4900 LT/SD) of coke produced would be utilized on site. This involves combustion of coke in the Utility Plant and Coke Gasification for Hydrogen manufacture.

The scheme was rejected for both technical and economic reasons. The tility Plant required to generate steam and power by combustion of some)00 t/sd (2950 LT/SD) of coke would cost roughly twice as much as conven- al facilities using clean fuel. Coke combustion involves Flue Gas De- lphurization which also has high capital and operating costs. Although sulphur nissions are comparatively low, Flue Gas Desulphurization is unattractive due agent requirements and waste byproduct disposal problems.

With regard to the Gasification of coke for hydrogen production, although e process appears economic, it has not yet been commercially demonstrated.

d Bed Hydrodesulphurization/Hydrocracking

ie overall flow scheme for fixed bed Hydrodesulphurization/Hydrocracking d be similar to the expanded bed Hydrovisbreaking scheme, i.e. Fig- VIII-9 and VIII-10. A general flow scheme for high pressure residue sulphurization and heavy oil cracking is shown on Figure VIII-13. The heavy sidue feed is preheated and combined with hot hydrogen before entering a l bed reactor. Its function is to demetallize and remove ash components over atively inexpensive catalyst. In the downstream reactors, the catalytic de- urization, denitrification, and hydrocracking reactions occur.

The reactor effluent is separated into vapour and liquid product streams and ted to product fractionation. The vapours from the cold product separator are bed for hydrogen sulphide removal. Part of this stream is purged from the to control hydrogen purity and the remainder is mixed with makeup lrogen, compressed, and recycled to the reactors.

This process is not practical for Athabasca bitumen because the high ash at is expected to cause plugging of the fixed reactor beds and high catalyst sumption. The process is also uneconomic because the maximum conversion to ter material of 565 degrees C plus residue is 50 percent. A higher conversion s required to avoid economic penalties which would be incurred if it were ssary to use surplus high sulphur residue as plant fuel or to incorporate it in synthetic crude stream; the latter is unacceptable because of the high ash it of the residue.

ethod of Process Selection

ding and Utilities process selection must consider the high degree of energy gration among the major Project sectors as depicted in Figure VIII-14. Mine and mining equipment size considerations support the constant bitumen rate 000 m³/d (157 500 B/D) from the Extraction Plant used for all cases. le oil production, and to a degree composition, varies with the process scheme with the extent to which crude components are required for energy or gen Plant Feedstock.

Corresponding fractions of the crudes deriving from each Upgrading ne are Hydrotreated to equivalent quality levels in terms of sulphur, nitrogen omaticity. The quality target is a marketable crude approaching the ies of conventional light crudes in the naphtha, distillate and gas oil ions.

or evaluation purposes, cases were developed on the basis of Project ficiency for energy and feedstock. This course derives from studies which ate that Project economics are relatively insensitive to substitution of natural oil at current crude/gas price relationships. No import or export of al power is assumed. For evaluation purposes, inclusion of propanes in was considered acceptable up to the 1.0 percent volume level. Any al propanes are treated as a separate, saleable energy stream.

tmospheric sulphur dioxide emission levels and their relationship to table ground level concentrations are discussed in the Environmental Impact

Assessment relating to this Application. For evaluation purposes the premise was to restrict sulphur emissions to the 76 t/sd (75 LT/SD) level on normal operation (5.2 t sulphur dioxide per 1000 m^3 of bitumen or 0.83 LT sulphur dioxide per 1000 Bbl of bitumen). Consequently, in the scheme based on Fluid Coke Combustion with Flue Gas Desulphurization, the assumption of treatment of part of the CO boiler flue gas was made for cost comparison purposes. Tail gas cleanup to achieve 99.0 percent sulphur recovery on Sulphur Plant feed is assumed (except in the above case).

Estimates of process yields, product stream properties, utility requirements, and catalyst and chemical consumptions were received from the sponsoring process licensor for each of the Upgrading processes. Capital cost estimates were prepared on a consistent basis from equipment lists.

Using the above information, detailed overall material and energy balances were developed by the Applicant, and capital and operating costs were determined. Major synthetic crude components were evaluated on the basis of their deemed value to Canadian refiners. These component values were used to assess the revenue impact of case-to-case variations in both crude composition and production level. Economics were developed on the basis of a 25-year production life for the Project, and Present Value Profit (PVP) used to measure the relative attractiveness of alternative Upgrading and Utilities configurations.

Present Value Profit is the cumulative net after-tax profit, discounted to a selected year, accruing from a project after providing for a specified return on investment. The PVP's reported in this evaluation indicate the difference in profit between schemes rather than the profitability of any individual scheme. They are derived from differential cash flows deflated to a 1978 constant dollar basis, then discounted at 10 percent to a 1978 present value. To assist in relating PVP's to other project parameters, a set of equivalents is provided in the table which follows.

SIGNIFICANCE OF INCREMENTAL PRESENT VALUE PROFIT
(PVP @ 10 percent, 1978)

A delta PVP of **\$10 million** is equivalent to the following changes in Project parameters:

CAPITAL	\$29.5 million (1978)
ANNUAL OPERATING COST	\$4.3 million (1978)
CRUDE PRODUCTION	145 m^3/d (910 B/D)
CRUDE VALUE	\$0.64/m^3 (\$0.10/B) (1978)
PROJECT EARNING POWER	approximately 0.1 percent

In addition to the economic analysis described above, each of the schemes was assessed on the following points:

The overall environmental acceptability of sulphur emissions and by-product waste.

The yield of synthetic crude oil on bitumen.

The extent that processes are commercially proven and demonstrated on Athabasca feedstocks.

Economic Comparison of Upgrading Alternatives

CRUDE PROPERTIES AND VALUATION

Composition and key properties of the crudes deriving from the alternative Upgrading schemes are presented in Table VIII-3. These crudes fall within a 3 degrees API gravity range, have essentially identical sulphur and nitrogen contents, and generally similar compositions. Some contain propanes as a result material and energy balance requirements. The crudes with the low gas oil content reflect the fact that in some schemes, part of this component is consumed as Hydrogen Plant feed or plant fuel.

As indicated previously, compositional differences were assessed on the basis of refinery values calculated for the major fractions. The distillate fraction has the highest value as it requires least processing prior to blending into finished product; propane and butane have the lowest values consistent with their markets relative to light oils. Values calculated for the five alternative crudes fall in a range equivalent to 1.0 percent of crude value.

ECONOMIC FINDINGS

For reasons of high volumetric product yield attainable without disproportionate investment and operating costs, **Fluid Coking** with **Coke Gasification** for hydrogen generation has the potential to be the economically superior Upgrading alternative. The following discussion uses this alternative as a basis for comparison. This economic *base case* assumes that all hydrogen is derived by Coke Gasification over the entire Project life.

The major elements of the alternative cases which contribute to process economics are displayed in the overview comparison of Table VIII-4. The "delta PVP's" indicated in this Table are the net of revenue, investment and operating costs. Investment and operating cost offsets from the base case are indicated in relative terms in Table VIII-4, while Table VIII-5 illustrates synthetic crude plus LPG yields for each case.

Fluid Coking with **Coke Stockpiling** has the disadvantage of significantly lower crude yield and hence revenue than the base case, because the energy in coke is not recovered. Despite lower capital and operating costs resulting from the higher quality of Gasification feed, the yield impairment leads to a PVP debit of [illegible] million (1978).

Fluid Coking with **Coke Combustion** has comparable energy efficiency to the base case, as indicated by the weight percent crude yield. The high capital and operating costs associated with coke burning boilers and Flue Gas Desulphurization facilities necessary to meet the base case sulphur emission level make this the least economic of the alternatives examined.

The **Flexicoking** case is based on gasifying 90 percent of the gross coke production, which is equivalent to utilizing 83 percent of the net coke in Fluid Coking. Burning the resulting low heating value, low pressure coke gas in the utility plant boilers eliminates gas turbines and causes increased dependence on less efficient condensing turbines for power generation. The lower coke utilization and the less efficient Utilities system reduce the energy efficiency of this case compared to the base, resulting in a lower crude production. Investment and operating costs are higher than the base case owing to a more complex primary Upgrading Process, and to higher steam generating capacity and more costly boilers needed for burning low heating value coke gas. The consequence is a PVP debit of $70 million (1978) versus the base case.

The **Hydrovisbreaking** case was evaluated at 83.5 percent volume conversion, the level for which residue yield corresponds to Partial Oxidation Hydrogen Plant feed requirements. Because the residue is completely consumed and because use of a combined Utility cycle is consistent with the energy balance, the case has high energy efficiency and the highest crude yield of all the alternatives. Investment and operating costs are higher than the base case owing to the nature of the HVB process: more expensive facilities, much higher hydrogen consumption, and significant catalyst costs. The net result is a $35 million PVP debit versus the base case.

As discussed in the next section, confidence in the Hydrovisbreaking process would be greater at lower conversion levels of 70 to 75 percent by volume. The economics of lower conversion were found to be less attractive than the case evaluated. Because the additional residue yield is used as boiler fuel, the lower conversion case involves Flue Gas Desulphurization, a reduction in efficiency of power generation and an increase in the capital costs of Utilities.

Technical Comparison of Upgrading Alternatives

FLUID COKING WITH COKE STOCKPILING

This scheme involves the least technological stepout. All other alternatives involve in varying degrees major business risks which are of great concern on a project of this magnitude. This scheme also offers the option to use natural gas for hydrogen manufacture with a resulting increase in synthetic crude yield, or to be self-sufficient and use a heavy liquid for this purpose. Its economics also came closest to the selected case.

The Hydrogen Production Unit is decoupled from the Primary Upgrading Unit, which is important from the reliability standpoint.

The problems associated with the design, engineering, construction, and commissioning in a remote location of most of the facilities required will have been encountered before.

On the negative side the stockpiling of some 2500 t/d (2450 LT/D) of coke represents an incomplete utilization of the resource and an additional environmental consideration. As a result of stockpiling, there is a significantly lower crude oil yield per barrel of bitumen intake when excluding the possible use of natural gas. Also sulphur dioxide emissions are higher than in some of the alternatives (Table VIII-4).

FLUID COKING WITH COKE COMBUSTION

This scheme offers several of the advantages of the previous scheme, plus the attraction of coke utilization.

Fluid Coke Combustion in Utility Plant boilers is a commercially demonstrated technology. However Athabasca-derived fluid coke is very high in sulphur and metals and is low in volatility.

There would be a minimum of excess stockpiled coke in this scheme. Excess coke would be stockpiled during normal operation, however, and recovered from the pile during the 90 days per year when one of the Fluid Cokers is shut down.

On the negative side, Flue Gas Desulphurization (FGD) is required on the boiler house stacks, and although such units are in operation none have operated with such high sulphur fuel or in a comparable environment. The lime scrubbing FGD process, selected as most viable, generates large quantities of waste by-product and requires large chemical usage (limestone quarry required). These are serious environmental considerations in themselves.

The hydrogen production is from Coker cracked gas, and hence associated Hydrogen Processing Units would have to shut down when the Fluid Coker is down, unless natural gas in high volumes were available. This reduces the reliability and availability of the Upgrading Plant.

Sulphur dioxide emissions are comparable to the previous case (Table VIII-4).

FLUID COKING WITH PARTIAL OXIDATION OF COKE

This scheme offers the advantage of proven Fluid Coking while addressing the utilization of the excess fluid coke. The technical exposure associated with Partial Oxidation of fluid coke is limited to the periphery, and the Applicant could proceed through the necessary prototype stage and phase in the rest of this development without jeopardizing the main process and the project revenue.

This is probably the only way that a technological stepout of this magnitude ›ould be introduced into a grass roots major project such as this.

While comparable to the previous cases on sulphur dioxide emissions, Gasifi- ..ion is clearly superior to Coke Combustion from an overall environmental tandpoint. It utilizes coke with no new sources of sulphur emissions, no additional ı d surface disturbances and minimal stockpile requirements.

'LEXICOKING

' 's scheme minimizes the production of excess fluid coke by converting coke to) heat content fuel gas. The net coke handling and storage facilities are hence gnificantly reduced in size compared to the Fluid Coker. In addition, the sulphur i ‹ide emissions are comparatively low (Table VIII-4).

On the negative side, the Flexicoking process has several drawbacks in ›mparison to Fluid Coking. The process is more complex since a third major ; :el and associated coke circulation lines are present. The gasification of some ‹ 0 t/d (4300 LT/D) of high sulphur gross coke requires major sulphur removal ıcilities on the low heat content gas. Also inherent is the operation of the plant ı-' system and Utility Plant on low heat content gas.

In this scheme the technical exposure is on the primary process. Pertinent to ›eration of the Flexicoker on Athabasca feedstock are several technical consider- :-ns which could increase the Project risk. In the opinion of the Applicant, the ı clay content of the feedstock has a possible impact on the ability to maintain workable coke particle size distribution and the required degree of coke ı-ification. The turndown capability of a Flexicoker designed for Athabasca :men is also limited. In addition, there is also a lack of commercial experience r Flexicokers operating on long residue comparable to Athabasca bitumen. The ᵖnts in operation and in the design phase are all for short residue.

YDROVISBREAKING WITH RESIDUE GASIFICATION

ıis scheme has no by-product coke, the highest crude oil yield on bitumen (with :ntial for additional liquid yield if natural gas is used for energy balance), and ry low sulphur dioxide emission.

On the negative side the scheme involves technical exposure with the ıary process. The Hydrovisbreaking process has not demonstrated the ability meet and sustain in a commercial plant the 83.5 percent volume conversion /el required. Reducing the conversion to a level which appears more widely :pted, say 75 percent, increases the production of high sulphur residue. The sidue would have to be utilized in the plant fuel system.

The total dependence on a slagging type gasifier to consume the heavy high residue also increases the technical risk. In addition, the Hydrovisbreaker and gasifier are close coupled because intermediate residue storage is limited. This a result of the expected thermal instability of this high ash product at the high ›erature required to maintain pumpability.

If excess bottoms are produced due to low Hydrovisbreaking conversion or ver hydrogen requirements, no means of residue disposal are available. The ' ash level would create problems in the refineries' fuel and bunker products re ash specifications and filterability tests must be met to ensure a clean rning fuel at the customer level. In addition, insufficient data is available to :ate the high conversion residue can be back-blended into synthetic crude.

Hydrovisbreaking units have a relatively high operating complexity; specifi- ly they contain a high number of components operating at high pressure and ›erature in a potentially fouling medium.

Upgrading Process Selection

SELECTED SCHEME

Many factors were considered in selecting the Upgrading and Utilities Process configuration. A primary consideration was the efficiency of resource utilization and the desirability of avoiding the stockpiling of energy by-products. Another equally important factor was the environmental impact of the various alternatives, not only as to sulphur emissions, but also as to by-product wastes. The economic competitiveness of the various schemes and the risks associated with each were also major considerations.

On balance, the selected scheme based on **Fluid Coking** with **Coke Gasification** for hydrogen manufacture comes closest to meeting all of the above objectives. Although the Coke Gasification technology will not be available for the initial plant design and operation, it is anticipated that with successful development this feature can be incorporated into the plant five to eight years from startup. To facilitate the addition of Coke Gasification facilities when the technology is available, the initial plant design will be based on Oil (or Natural Gas) Gasification. The initial Gasification Plant facilities will be designed to minimize the costs of conversion to coke. The Coke Gasification development schedule is discussed in the following section.

Two processes can be applied to Hydrogen Generation based on natural gas feedstock – Steam Methane Reforming (SMR) and Partial Oxidation (POX). They are equally efficient in terms of combined feed and fuel requirements, but POX has the higher capital costs as it requires a supporting Oxygen Plant. The higher cost of the POX alternative, however, will be offset by the reduced cost of conversion to coke utilization provided that this is accomplished within the projected five to eight years from startup. Nevertheless, this approach entails additional financial commitment for the POX unit.

Notwithstanding the expected five to eight year lag in implementation of Coke Gasification, the selected Upgrading scheme has one of the highest yields of synthetic crude on bitumen – i.e. 86.8 percent volume on a propanes plus basis. Gasification is not only an efficient way to utilize the coke, but also is environmentally acceptable in terms of sulphur emissions and waste by-products.

COKE GASIFICATION DEVELOPMENT

Since 1973 there has been a high level of research and development activity on coal conversion. The United States Department of Energy and others have sponsored many research and development programs and demonstration projects which are expected to result in commercial units by the mid-1980's. Several low pressure Koppers-Totzek and medium pressure Lurgi units are in service on coal feedstocks, and pilot plant tests have been carried out on both delayed and fluid coke. Both Shell International Petroleum Company and the Texaco Development Corporation have active development programs on high pressure coal gasification underway. They are confident that Coal Gasification technology will be applicable to fluid coke.

Since early 1974, Shell International and Krupp-Koppers have been working together in the development of a high pressure Coal Gasification process. This combines the experience of Krupp-Koppers, who have built 16 plants working at atmospheric pressure, and Shell, who have obtained know-how from high pressure Oil Gasification processes employed in some 40 plants around the world. A 150 t/d demonstration unit has been built at Shell's Harburg Refinery (Germany) and is now in operation. This demonstration unit was preceded by two pilot plants at Shell's Amsterdam Laboratory. One of these, a 5 t/d facility, has been in operation approximately two years and is scheduled for a test run on Athabasca fluid coke late in 1978.

Texaco has extensive experience on oil gasification and experience on coal lating back to the late 1950's when a 100 t/d pilot was operated in West ginia. Their Montebello, California research facilities include a 15 t/d unit for il. They have tested all types of hydrocarbons, including coals and chars for ynthesis gas manufacture. Texaco also have a 150 t/d demonstration unit which been in operation since early 1978 at Ruhr-Chemie, Germany.

Logical development of either of the above technologies for commercial ipplication on Athabasca Fluid Coke involves the following steps:

cessful demonstration of plant operation by the process licensor on Fluid Coke
elopment of design basis specifications by the licensor for a commercial scale unit
onstruction of a prototype facility in the Upgrading Plant
cessful operation of the prototype unit
ipletion of the design, engineering and construction of the full size facility with etirement of parts of the Oil (or Natural Gas) Gasification facilities.

The selected Upgrading scheme can employ either the Shell or Texaco sification Process. The Applicant intends to co-operate with both licensors in heir efforts to commercialize a viable process for Coke Gasification. The selection ill be based on the longer term considerations of:

onvertibility of the Partial Oxidation Units from gas oil (or natural gas) to coke ocessing (redundancy) and impact on the Utilities facilities.
Timing of commercialization of Coal/Coke Gasification design.
nger term economics of coke utilization (efficiency).

OKE GASIFICATION DEVELOPMENT SCHEDULE

current development activities of the two licensors of Coal Gasification nology, Shell-Koppers and Texaco, are such that design specifications based n coal experience could be available to allow construction of the prototype unit ch would be of commercial size and ultimately become one of the three to four e Gasification reactors required. The construction would coincide at least artly with the main plant facilities. Such a schedule could allow completion of the otype some one to three years after the mechanical completion of the first grading train. Operation of the prototype for a one to two-year period would expected to establish technical feasibility — in particular reliability — and vide improved parameters for design of the remaining Gasification facilities. to three years for design and construction of the remaining facilities would ien be required.

From the above premise, it is expected that an overall time frame of some to eight years after completion of the first Upgrading train will be required to monstrate fully and construct the Coke Gasification plants. The projected hedule for the above steps is shown in Figure VIII-15.

Owing to the present immaturity of the technology to produce hydrogen m fluid coke, the Applicant is unable to make a firm commitment to an iplementation schedule. Significant revisions to development programs, sched- and plant costs would necessitate reviews to assure the integrity of the nology and its economic viability. The Applicant believes, however, that iasing in technology for Coke Gasification for the production of hydrogen esents the soundest approach for the achievement of reliable economic ations while maximizing utilization of by-product coke. The Applicant will date the ERCB as to the progress of Coke Gasification developments.

Claus Tail Gas Process Alternatives

A three-stage Claus Sulphur Plant recovers approximately 96 percent of the sulphur in the feedstream. A minimum target overall Sulphur Plant recovery efficiency was set at 99.0 percent, and a study of alternative methods of achieving this goal was carried out. The following processes were evaluated:

BSRP (Beavon Sulphur Recovery Process, including the Stretford Process)
SCOT (Shell Claus Offgas Treatment Unit)
SCOT with Amine Cascade
BSR Selectox 32 (Beavon Sulphur Recovery)
Sulfreen

The results are summarized in Table VIII-6.

The selected Sulphur Recovery configuration includes the SCOT with Amine Cascade Unit. It was selected over the less expensive Sulfreen and BSR Selectox 32 processes owing to its very high recovery efficiency. While the efficiencies of the SCOT, SCOT "Cascade" and BSRP Units are similar, the SCOT "Cascade" system is the most cost effective in this Application.

The Cascade system involves using the treating amine first in the SCOT system at the Sulphur Plant and then in the balance of the Upgrading Plant before regeneration. In this way capital and energy requirements for regeneration are considerably reduced.

The overall cost for the sulphur removal is affected significantly by the mode of incineration and the cost of the fuel used. The selected design will use the CO boiler as the incinerator, recovering most of the incineration heat.

TABLE VIII-1

PROPERTIES OF ATHABASCA BITUMEN

	TOTAL	IBP-345 DEG. C	345-525 DEG. C	525+ DEG. C
TBP Cut Range				
Wt. Percent (Incl. Solids)	100	13.15	32.55	54.30
Vol. Percent (Incl. Solids)	100	14.70	33.90	51.40
Gravity, Degrees API				
Incl. Solids	8.3	25.4	14.1	0.8
Solids Free	8.8	25.4	14.1	1.8
Sulphur, Wt. Percent	4.9	1.88	3.65	6.4
Nitrogen, Wt. Percent	.4	.012	.16	.73
Oxygen, Wt. Percent	.8			
Vanadium, ppmw	250			
Nickel, ppmw	75			
Ash, Wt. Percent	.70			
CCR, Wt. Percent	13.3			
Pour Point, Degrees C	10			
Flash Point, Degrees C	205			
C_5 Insoluble, Wt. Percent	18			
Viscosity				
CS at 100 Degrees C	185			
CS at 135 Degrees C	40			

TABLE VIII-2

YIELDS – PRIMARY UPGRADING UNITS

	FLUID COKER	FLEXICOKER	HYDROVISBREAKER
C_3 Minus, Percent Wt.	7.24	7.24	6.14
Total C_4, Percent Vol.	3.01	3.01	1.71
C_5 – 220 C	17.94	17.94	22.1
220 – 345 C	23.34	23.34	23.2
345 – 525 C	42.09	42.09	46.6
525 Plus			8.52
Gross Coke, Percent Wt.	15.4	15.4	
Net Coke, Percent Wt.	9.2	1.5	
Burned/Gasified Coke, Percent Wt.	6.2	13.9	

TABLE VIII-3

**CRUDE COMPOSITION AND QUALITY
ALTERNATIVE UPGRADING SCHEMES**

	FLUID COKING			FLEXICOKING	HYDROVISBREAKING
COKE/RESIDUE DISPOSITION	**GASIFY FOR HYDROGEN**	**STOCKPILE**	**BURN +FGD**	**FUEL GAS**	**GASIFY FOR HYDROGEN**
CRUDE QUALITY					
API, C_4^+	33.0	33.9	32.9	33.0	31.3
Sulphur, Percent Wt.	0.24	0.24	0.24	0.24	0.23
Nitrogen, Percent Wt.	0.07	0.07	0.07	0.07	0.08
COMPOSITION, PERCENT VOL.					
C_3	1.0	1.0	—	—	—
C_4	3.8	4.0	3.8	3.9	1.8
C_5 – 150C	17.5	18.3	17.5	17.8	17.7
150 – 335C	37.5	39.6	37.4	38.1	41.7
335C+	40.2	37.1	41.3	40.2	38.8
TOTAL	100.0	100.0	100.0	100.0	100.0

TABLE VIII-4

OVERVIEW COMPARISON OF ALTERNATIVE UPGRADING SCHEMES

	FLUID COKING			FLEXICOKING	HYDROVISBREAKING
COKE/RESIDUE DISPOSITION	GASIFY FOR HYDROGEN[5]	STOCKPILE[5]	BURN +FGD	FUEL GAS	GASIFY FOR HYDROGEN
Bitumen Rate, m^3/d[1]	25 040	25 040	25 040	25 040	25 040
Total Liquid Product, m^3/d[2]	21 730	20 360	21 520	21 140	21 830
Total Liquid Product Yield[3],					
Percent Vol.	86.8	81.3	85.9	84.4	87.2
Percent Wt.	73.4	68.5	73.3	71.9	75.0
SO_2 Emissions, t SO_2/1000 m^3 Bitumen	5.2	5.0	5.0	2.9	1.2
Delta PVP, $MM 1978	Base	− 30	−120	− 70	− 35
Relative Investment, Percent[4]	100	88	115	110	109
Relative Operating Cost, Percent[4]	100	89	139	104	122

Notes:
1. Feed to Primary Upgrading Process
2. Includes LPG Sales on a Volumetric Basis
3. Product Yield is Basis Bitumen Feed to Upgrading
4. Considers Upgrading and Utilities only
5. Liquid Product Yields for the Selected Scheme Presented in Chapter IX Marginally Exceed the Levels Included Above due to Increased Hydrotreating and Coke Utilization

TABLE VIII-5

BITUMEN INPUT/SYNTHETIC CRUDE OUTPUT

		FLUID COKING			FLEXICOKING	HYDROVISBREAKING
COKE/RESIDUE DISPOSITION		GASIFY FOR HYDROGEN	STOCKPILE	BURN +FGD	FUEL GAS	GASIFY FOR HYDROGEN
Bitumen Feed	(m^3/d)	25 040	25 040	25 040	25 040	25 040
Gross C_4^+ Make	(m^3/d)	21 560	20 250	21 560	21 560	23 400
Gas Oil to Fuel	(m^3/d)	260	270	40	420	1 570
Synthetic Crude	(m^3/d)	21 300	19 980	21 520	21 140	21 830
LPG To Crude	(m^3/d)	220	200	—	—	—
Synthetic Crude with LPG	(m^3/d)	21 520	20 180	21 520	21 140	21 830
LPG To Sales	(m^3/d)	210	180	—	—	—
Total Sales	(m^3/d)	21 730	20 360	21 520	21 140	21 830
Volume Ratio[1]	(%)	86.8	81.3	85.9	84.4	87.2
Stored Energy	(t/d)	236	2 146	25	318	—
(Equiv. m^3/d)		191	1 765	16	445	

Notes:

1. $\text{Volume Ratio} = \dfrac{\text{Total Sales}}{\text{Bitumen Feed}} \times 100\%$
2. The above Yield Basis was used for Process Selection only

/ LE VIII-6

PHUR PLANT – TAIL GAS PROCESSES
3OILER INCINERATION

	BSRP	SCOT	SCOT CASCADE	BSR SELECTOX-32	SULFREEN
a_ital Cost	1.5	1.4	Base	0.9	1.0
otal Equiv. Operating Cost	1.3	1.4	Base	0.7	0.6
v rall Sulphur Plant Recovery ficiency	99.9	99.9	99.9	99+	99
il Gas Unit Sulphur Recovery (·/d)	40	40	40	30+	30
hur Emission From Sulphur Plant (t/d)	1	1	1	10	10+

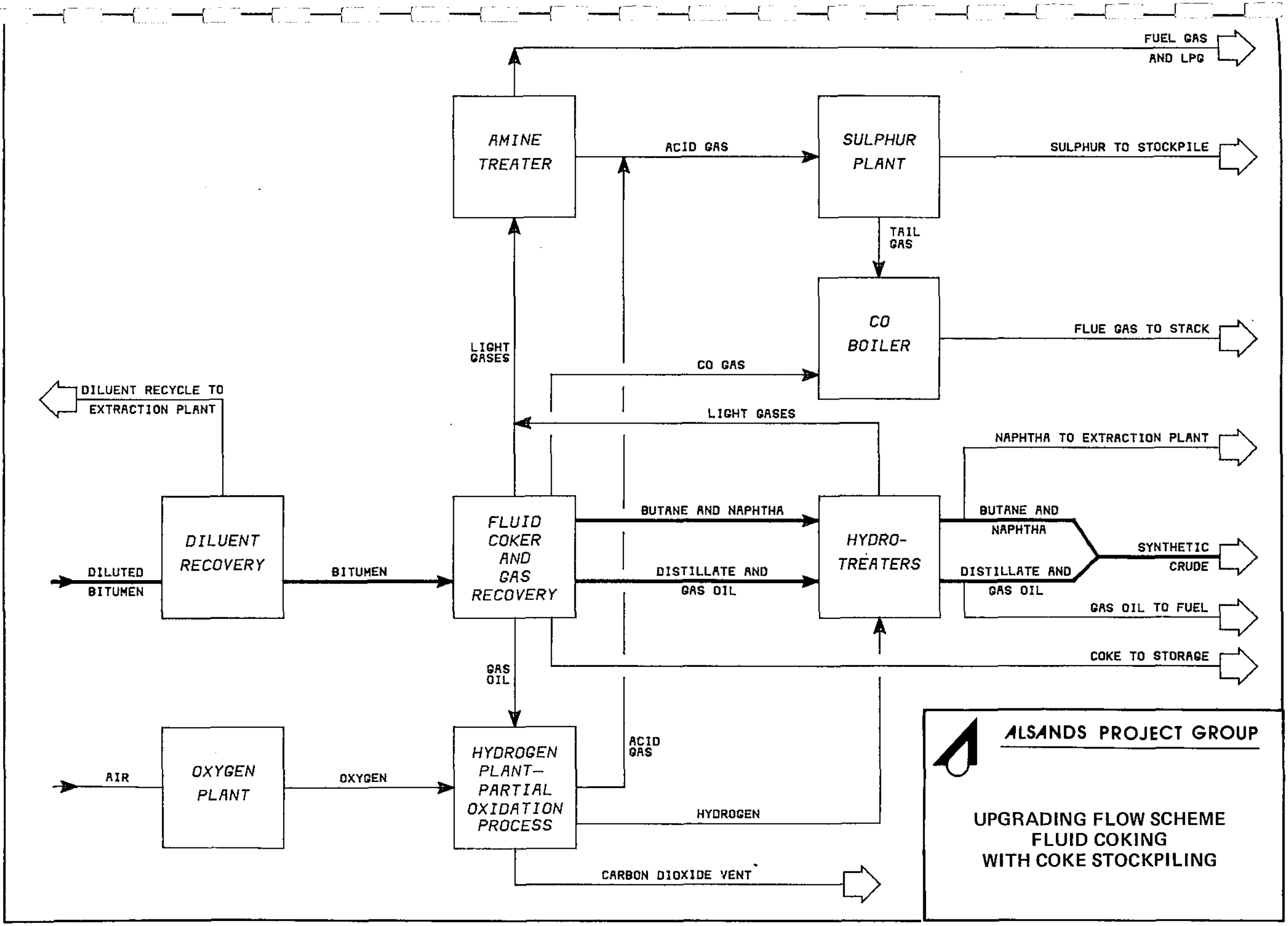
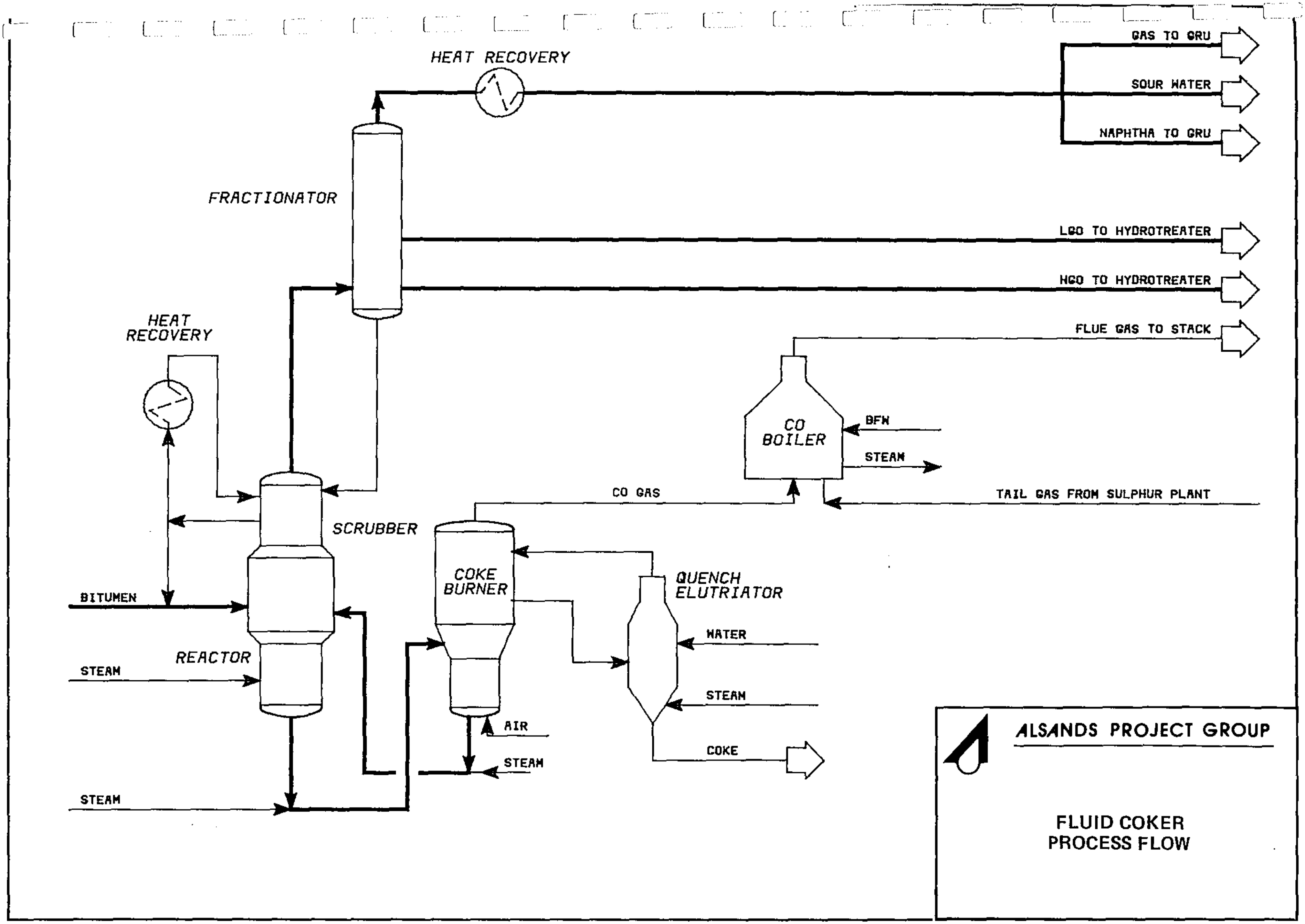


FIGURE VIII-1


HEAT RECOVERY
GAS TO GRU
SOUR WATER
NAPHTHA TO GRU
FRACTIONATOR
LGO TO HYDROTREATER
HGO TO HYDROTREATER
FLUE GAS TO STACK
HEAT RECOVERY
CO BOILER
BFW
STEAM
CO GAS
TAIL GAS FROM SULPHUR PLANT
SCRUBBER
COKE BURNER
QUENCH ELUTRIATOR
BITUMEN
WATER
REACTOR
STEAM
STEAM
AIR
STEAM
COKE
STEAM
ALSANDS PROJECT GROUP
FLUID COKER PROCESS FLOW

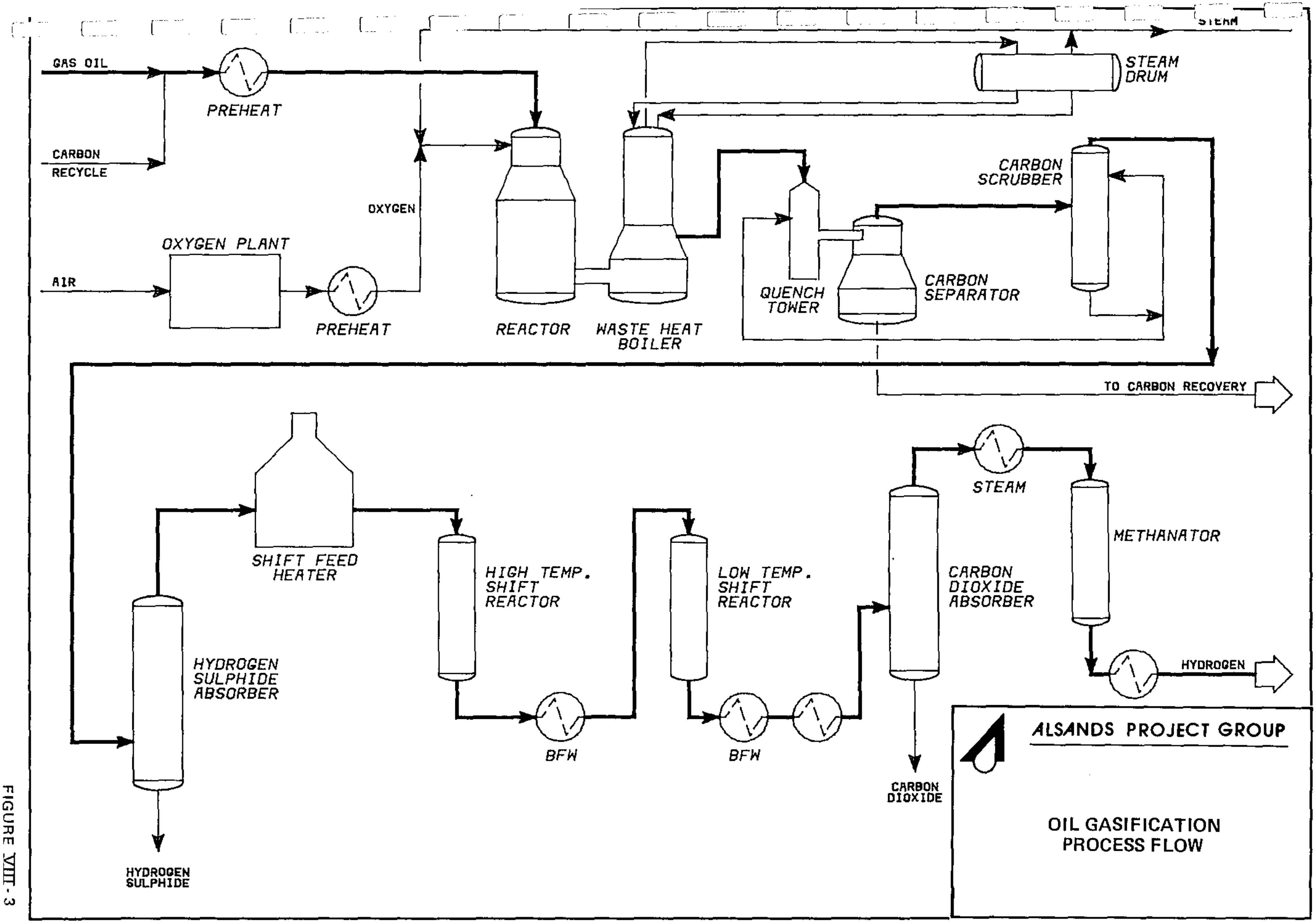
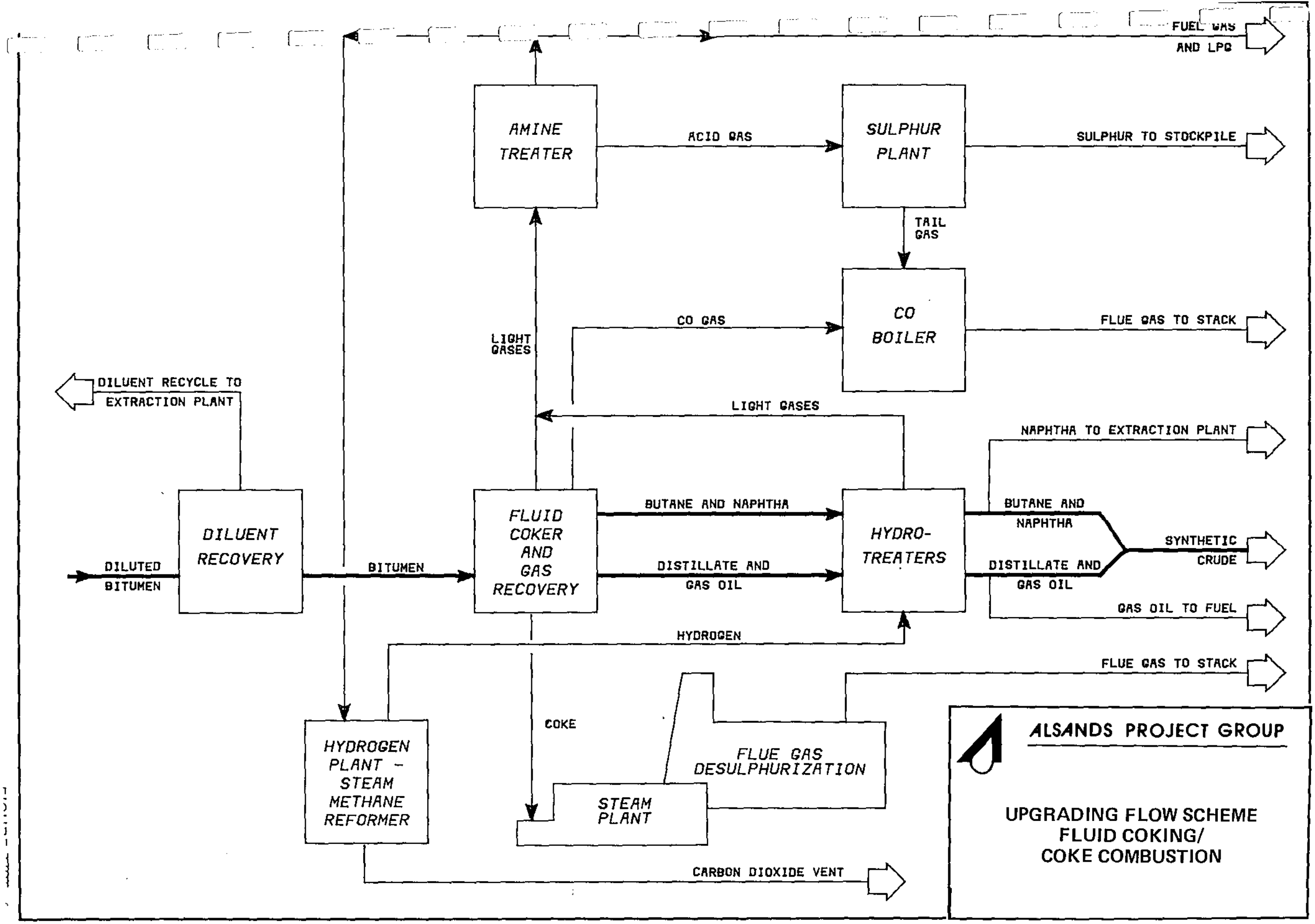


FIGURE VIII-3


FUEL GAS
AND LPG
AMINE TREATER
ACID GAS
SULPHUR PLANT
SULPHUR TO STOCKPILE
TAIL GAS
CO GAS
CO BOILER
FLUE GAS TO STACK
LIGHT GASES
DILUENT RECYCLE TO
EXTRACTION PLANT
LIGHT GASES
NAPHTHA TO EXTRACTION PLANT
DILUTED BITUMEN
DILUENT RECOVERY
BITUMEN
FLUID COKER AND GAS RECOVERY
BUTANE AND NAPHTHA
DISTILLATE AND GAS OIL
HYDRO- TREATERS
BUTANE AND NAPHTHA
DISTILLATE AND GAS OIL
SYNTHETIC CRUDE
GAS OIL TO FUEL
HYDROGEN
FLUE GAS TO STACK
COKE
HYDROGEN PLANT - STEAM METHANE REFORMER
FLUE GAS DESULPHURIZATION
STEAM PLANT
CARBON DIOXIDE VENT
ALSANDS PROJECT GROUP
UPGRADING FLOW SCHEME
FLUID COKING/
COKE COMBUSTION

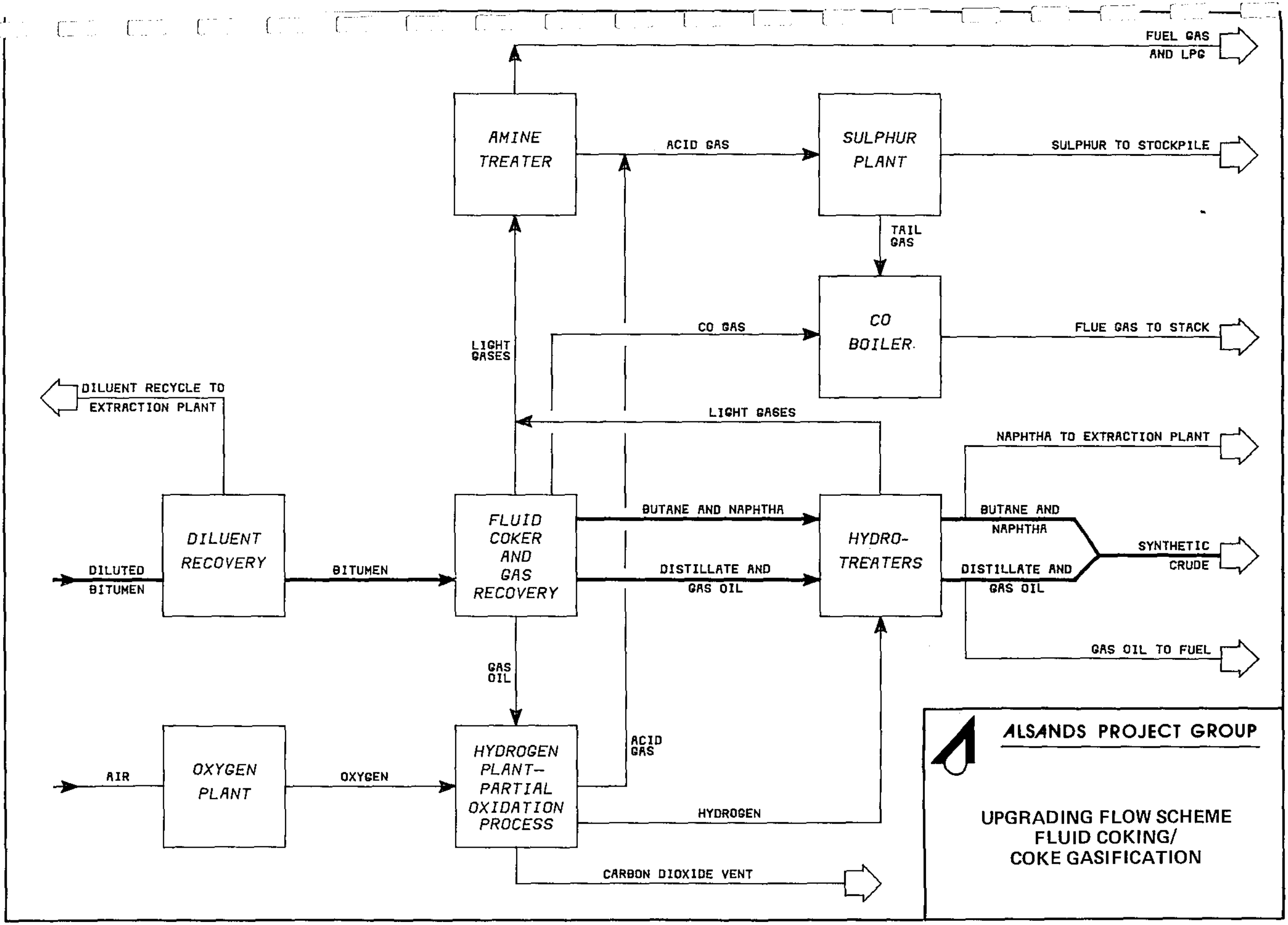


FIGURE VIII-5

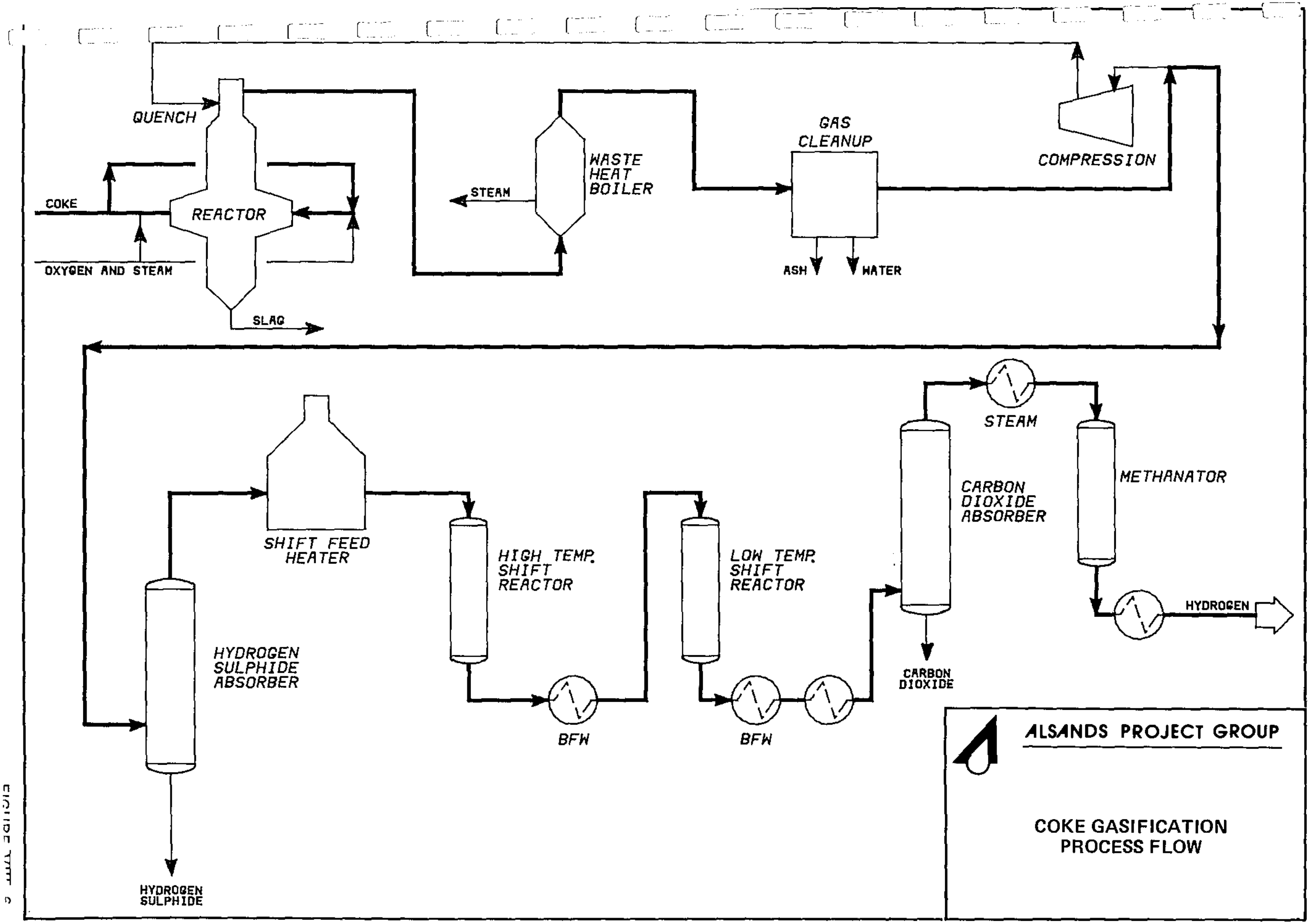
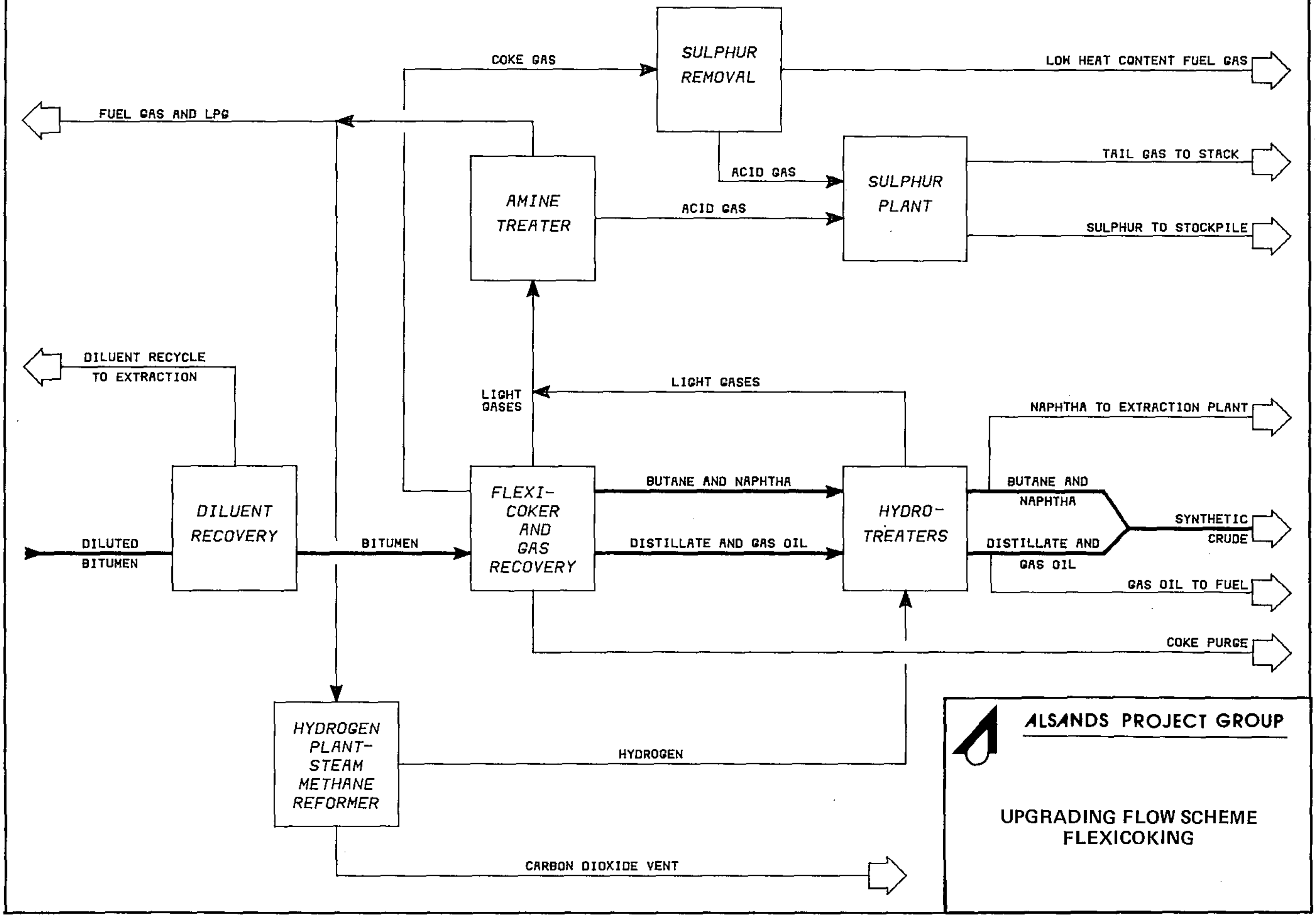


FIGURE VIII-6



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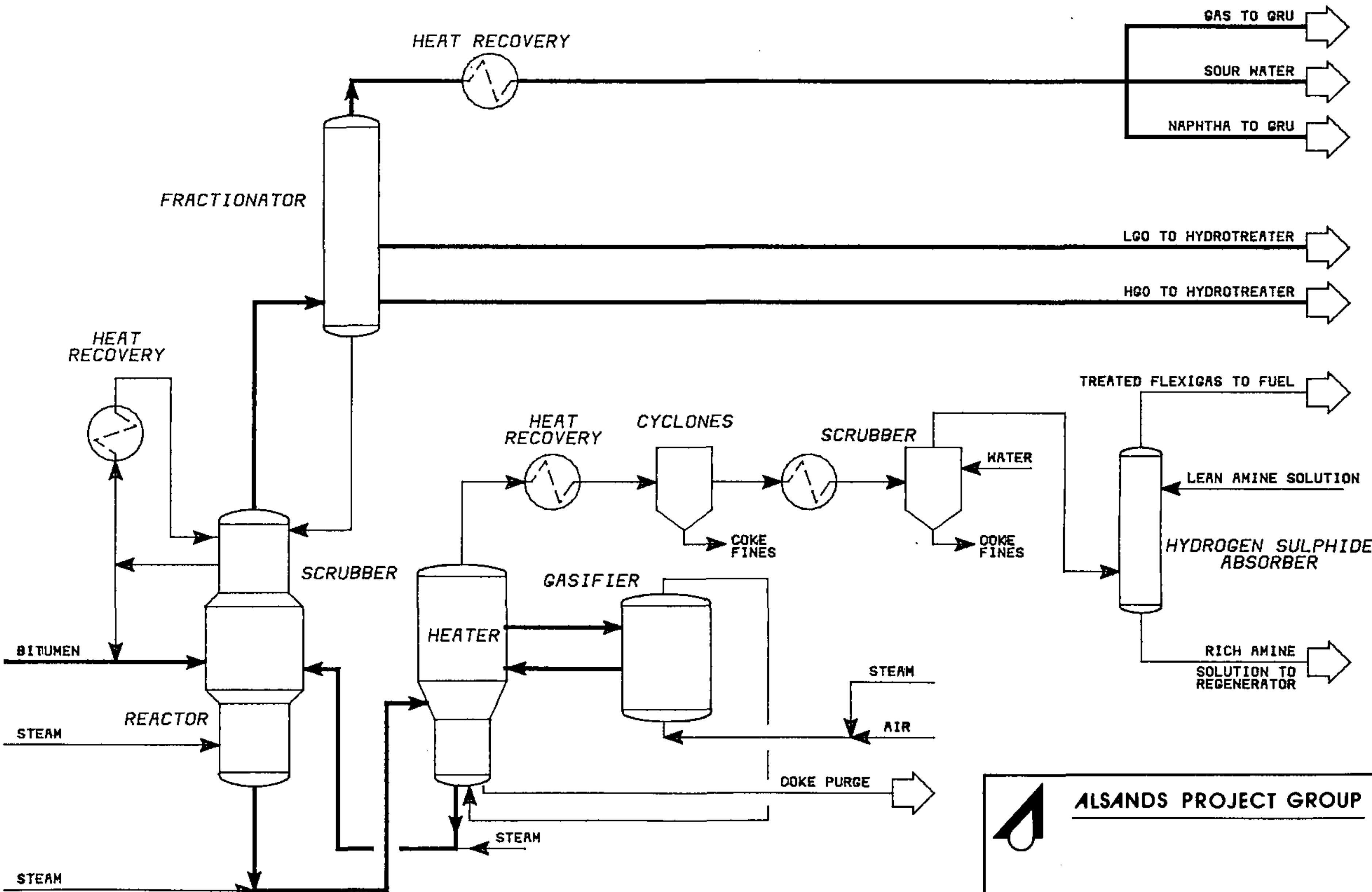
UPGRADING FLOW SCHEME
FLEXICOKING

FIGURE VIII-7



ALSANDS PROJECT GROUP

FLEXICOKER
PROCESS FLOW

FIGURE VIII-8

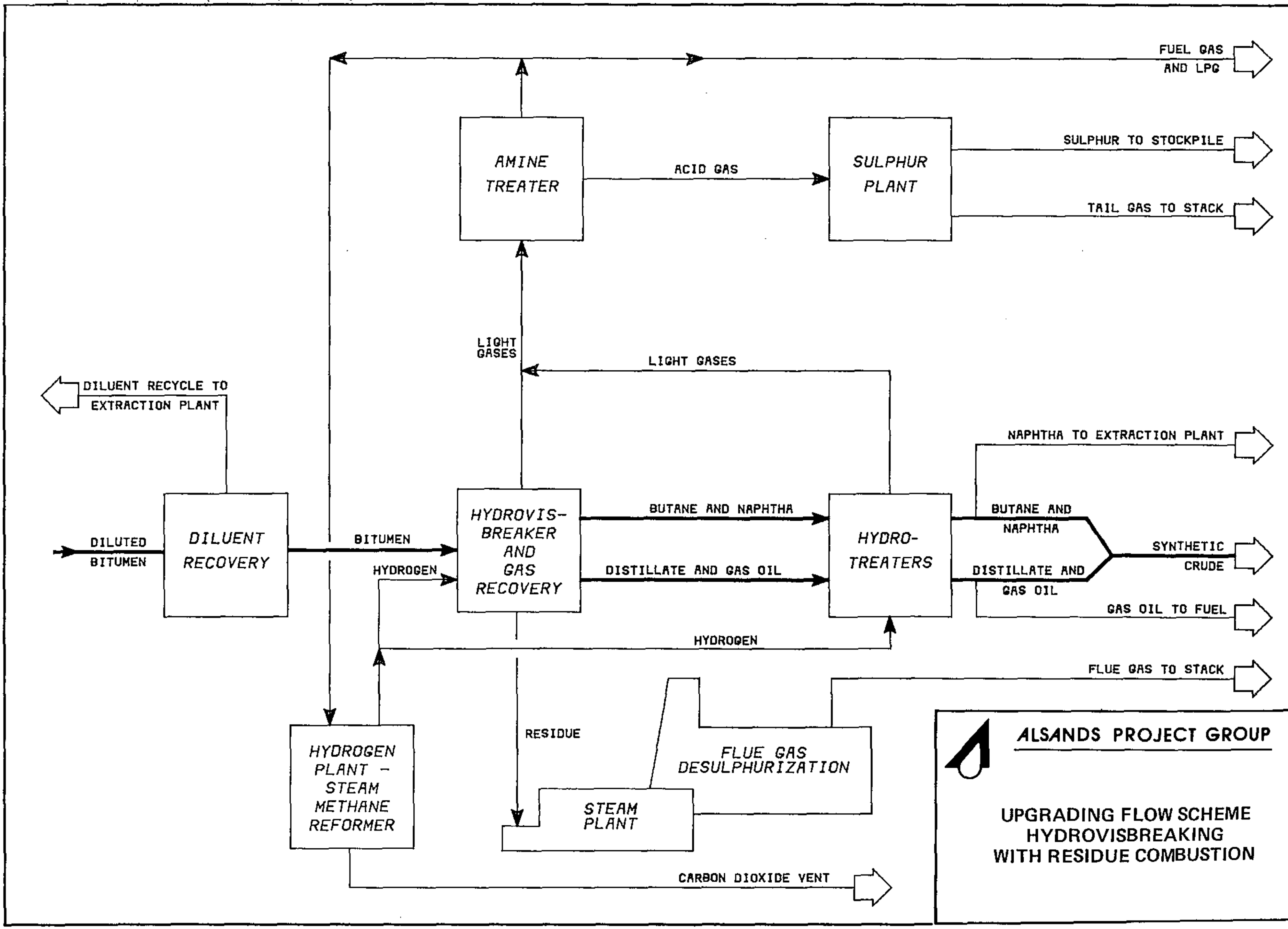
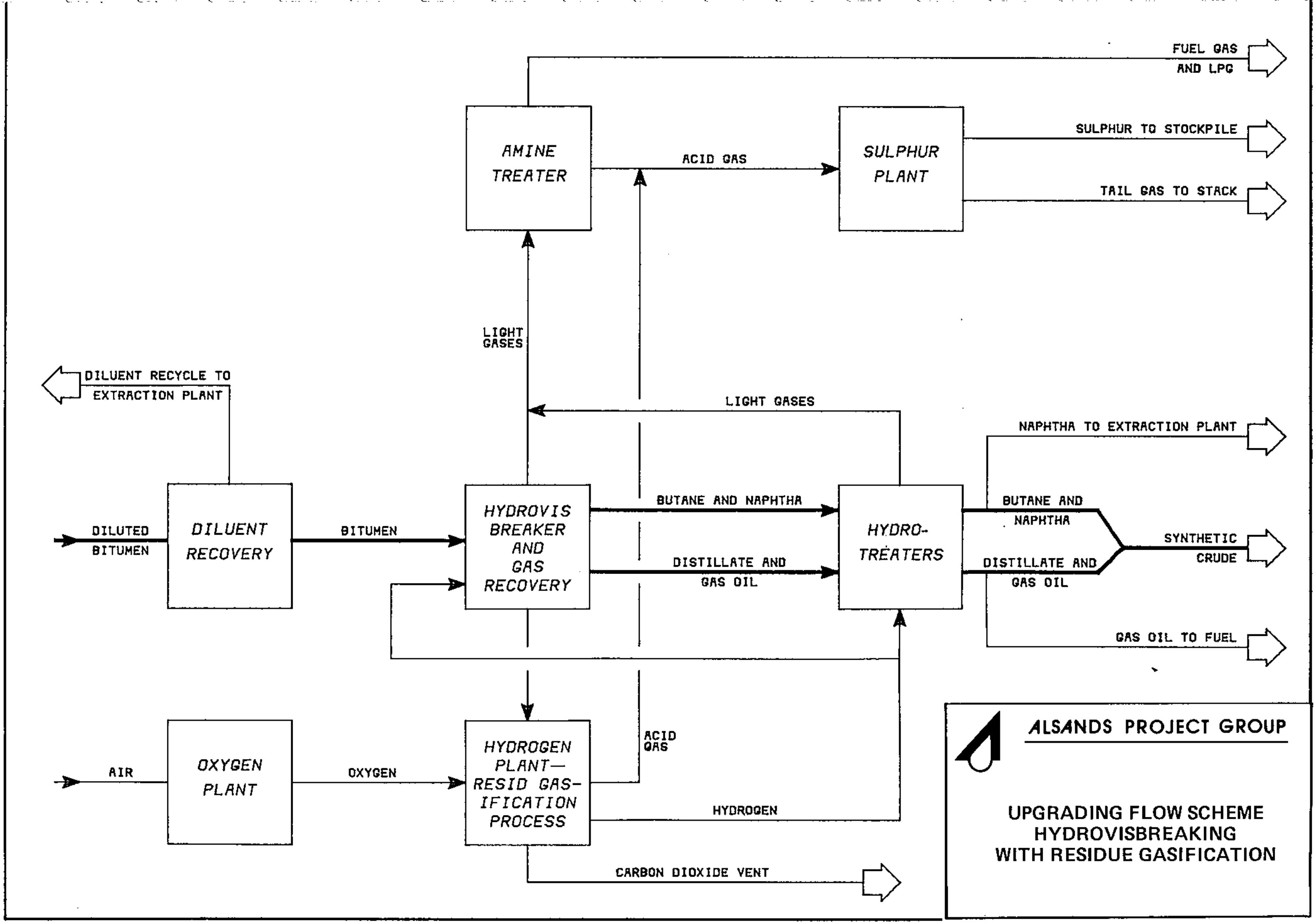


FIGURE VIII.9



UPGRADING FLOW SCHEME
HYDROVISBREAKING
WITH RESIDUE GASIFICATION

FIGURE VIII-10

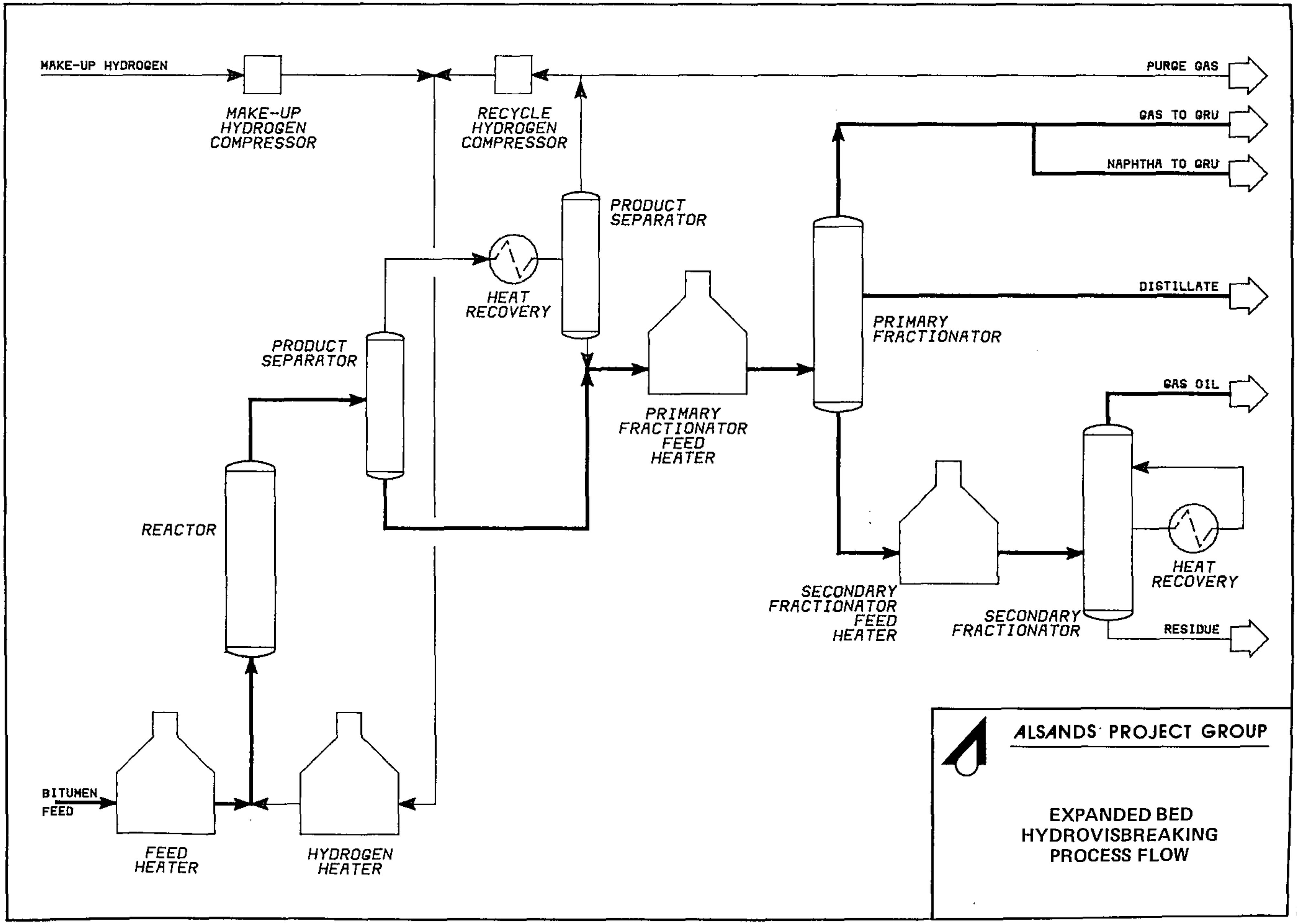
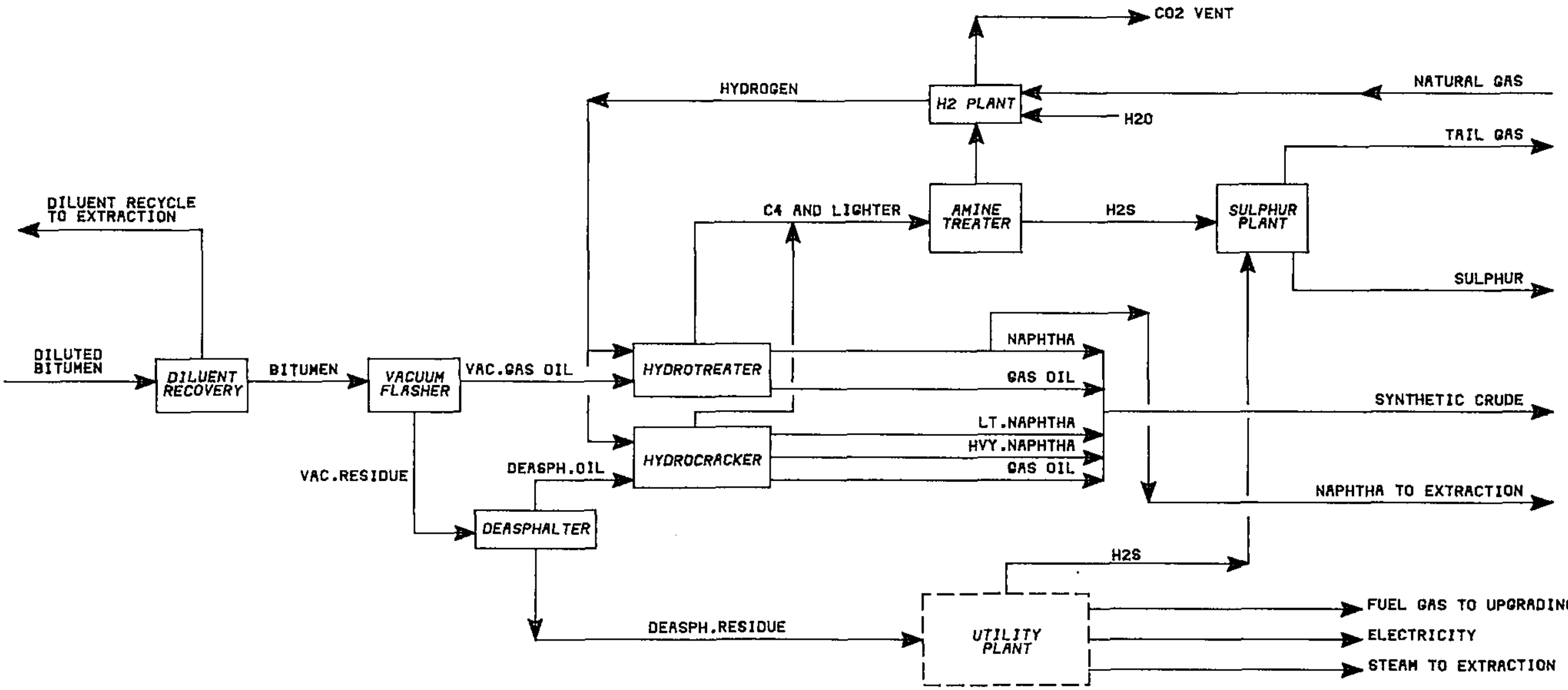


FIGURE VIII-11



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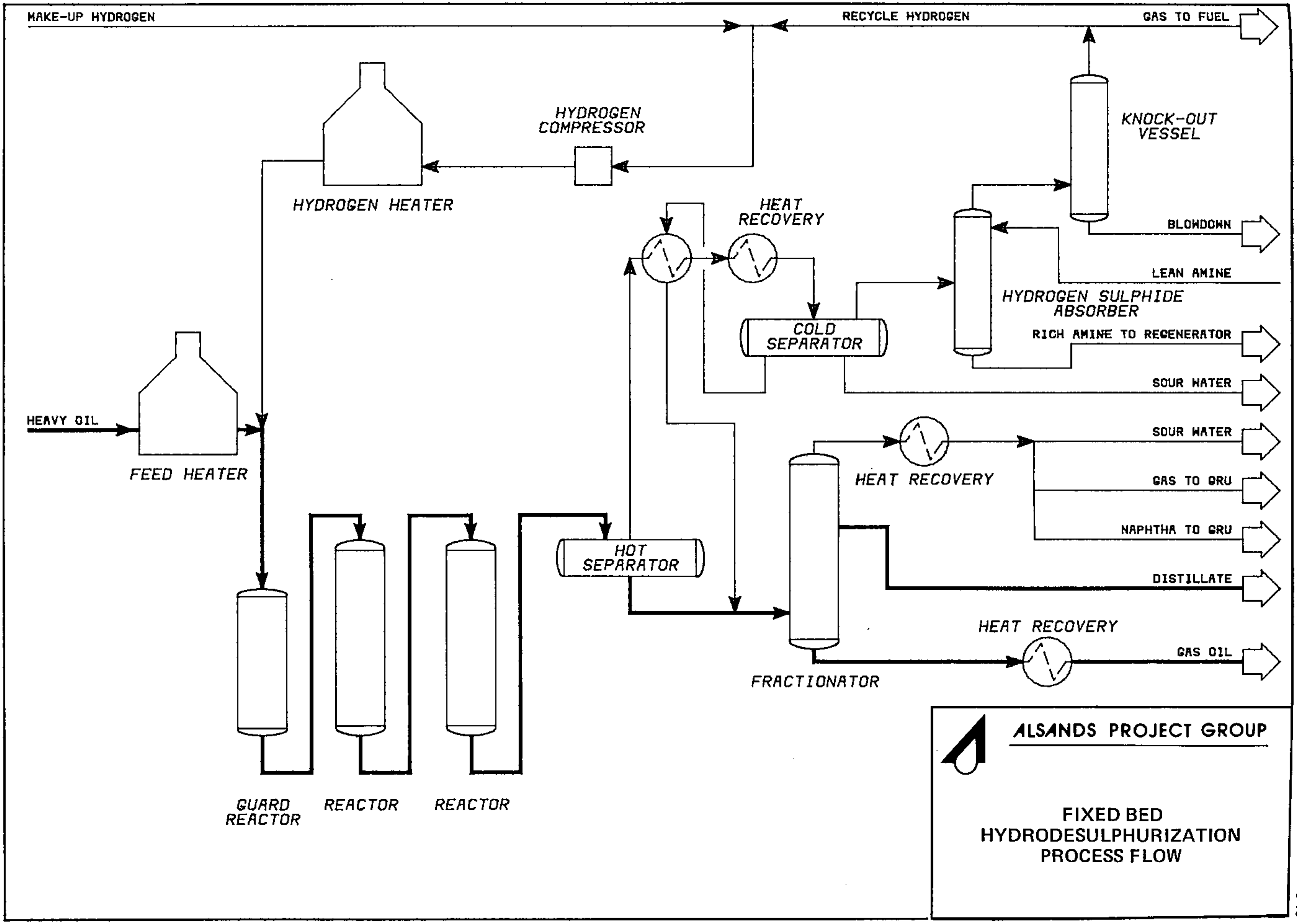
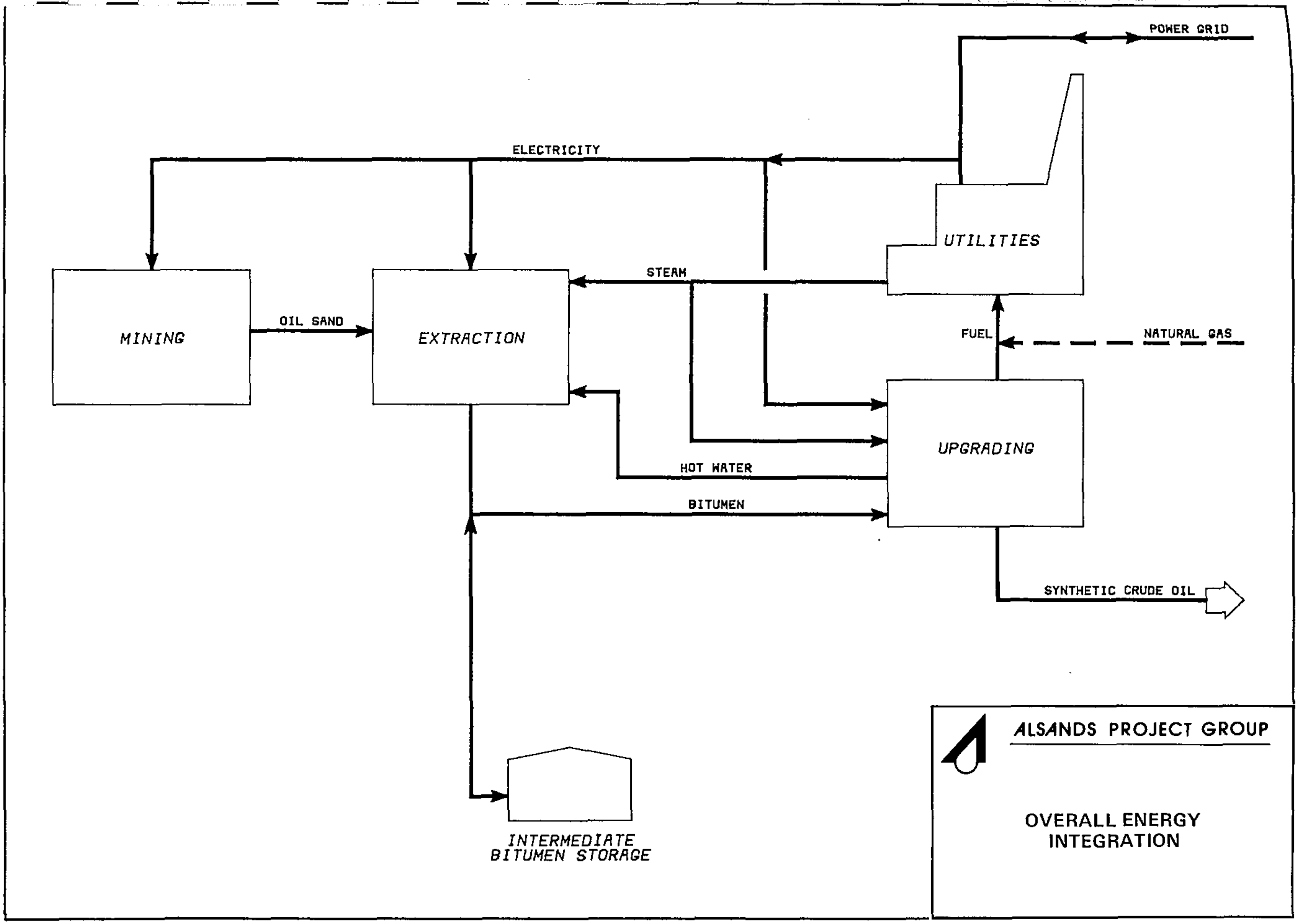
VACUUM FLASHING
DEASPHALTING/HYDROCRACKING
AND PARTIAL OXIDATION
PROCESS FLOW

FIGURE VIII-12



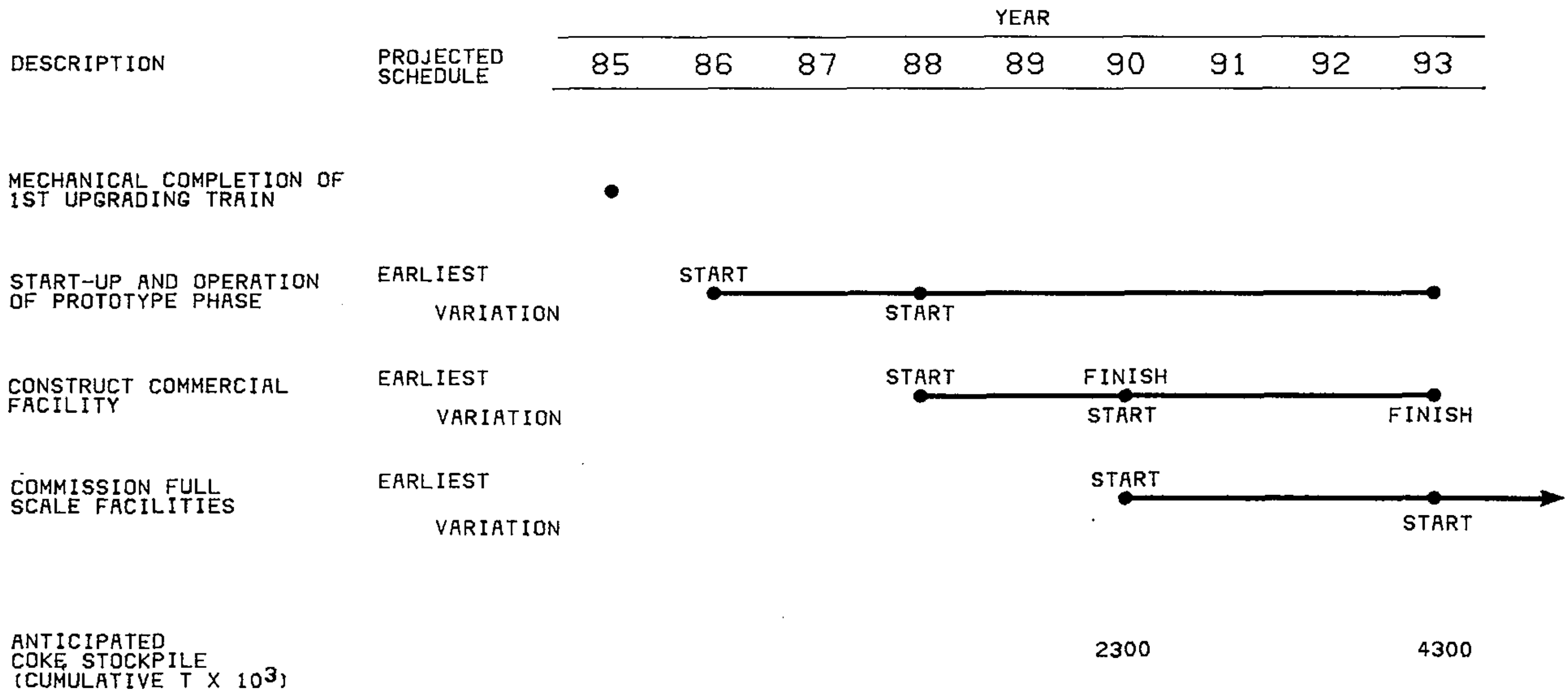
FIXED BED
HYDRODESULPHURIZATION
PROCESS FLOW

FIGURE VIII-13



OVERALL ENERGY INTEGRATION

FIGURE VIII.14



ALSANDS PROJECT GROUP

PROJECTED SCHEDULE
FOR COKE UTILIZATION

FIGURE VIII-15

IX Upgrading and Utilities Plants

Overview

The central features of the Upgrading Facilities are Fluid Coking of bitumen and hydrogen production by Partial Oxidation (POX). Feedstock to the POX units will be Coker heavy gas oil during the initial five to eight years, after which it is planned to phase in Gasification of coke pending satisfactory development of this technology as discussed in Chapter VIII. The practicality of using natural gas in place of Coker gas oil in the initial years is also being examined. The Fluid Coker products are hydrotreated to the extent required to produce a synthetic crude quality and composition in line with the requirements of the receiving refineries.

The Utilities are designed essentially to satisfy the power and steam requirements of the Project. The system is designed to be efficient by including combined cycle, power and steam production, while being sufficiently flexible to accommodate the variations in power and steam requirements.

The Sulphur Recovery facilities include two Claus Plants and two SCOT tail gas cleanup processes with Amine Cascade designed for 99.9 percent recovery. The Sulphur Recovery Plants will be designed for 150 percent of sulphur production during the initial period, and for 120 percent during the ultimate phase when coke is being gasified.

Upgrading Facilities

INTRODUCTION

The Upgrading Facilities incorporate the following principal process units: Diluent Recovery, Fluid Coking with CO Boilers, Naphtha and Distillate/Gas Oil Hydrotreaters, Gas Recovery Units and Treating Facilities, Partial Oxidation Units for hydrogen manufacture and Claus Sulphur Plants with tail gas recovery units. The units are arranged as shown on the Material & Energy Balance flowsheets at the end of this section. In general, there are two complete process trains each designed for a 14 310 m^3/sd (90 000 B/SD) bitumen rate to the Fluid Cokers. There are some exceptions, for example in the Partial Oxidation Unit, where specific equipment can serve either train.

Two modes of operation are detailed for this plant: initial operation with hydrogen produced from coker heavy gas oil and ultimate operation with hydrogen produced from fluid coke. An alternative case for the initial period is based on hydrogen production from natural gas. The respective material and energy balances are tabulated and discussed at the end of this section.

A general description of the process facilities follows.

PROCESS UNIT DESCRIPTIONS

Diluent Recovery Units (DRU)

The purpose of these facilities is to produce a dry bitumen from the diluent/bitumen/water mixture that is fed to them from the Extraction Plant, and to recycle the recovered diluent back to the Extraction Unit. The bitumen enters the unit diluted with an equal volume of naphtha and carries residual clay and water. The diluent is produced on the Naphtha Hydrotreater; its make-up rate to offset Extraction Plant losses is about 475 m^3/d (3000 B/D).

The feed rate to each Diluent Recovery Unit is approximately 28 620 m^3/sd (180 000 B/SD) and the separation of water, naphtha, and bitumen in a distillation process is done in a carefully staged heating and flashing operation. Recovered water is collected and routed to the sour water treating facilities, and the dry bitumen product flows directly to the Fluid Cokers, which balance on intermediate bitumen storage.

Fluid Coking

First commercialized in 1954, this process now has a total capacity exceeding 47 700 m^3/sd (300 000 B/SD) in at least 11 units. This includes the two 11 600 m^3/sd (73 000 B/SD) units at Syncrude. Conceptually the process is similar to the universally-employed Fluid Catalytic Cracking Process; the difference is that a fluidized bed of coke granules formed in the coking process is used, rather than catalyst.

Bitumen feedstock from the Diluent Recovery Unit is fed directly into the reactor. The subsequent coking or cracking reaction produces a wide range of hydrocarbon products and causes additional coke to form in the fluidized bed. This process was described in more detail in Chapter VIII.

The Fluid Coker is limited to a maximum product endpoint dictated by the maximum operating temperature on the overhead scrubber. Higher temperatures would result in unacceptable coke build-up. Coker gas and naphtha are routed to the Gas Recovery Unit while light and heavy gas oil streams are sent to downstream Hydrotreaters. Because of the unstable nature of the Coker product streams, there is a minimum of intermediate storage.

The CO Boiler acts as the incinerator for both Fluid Coker burner gas and the tail gas from the Sulphur Plant and generates some 3800 t/sd (350 000 lb/hr) of steam on each unit. Fines entrained through the burner cyclones to the CO Boiler are removed by electrostatic precipitators on the CO Boiler flue gas. The fines from the electrostatic precipitators are collected and transferred to the coke storage hoppers.

The net product coke from the burner is cooled in the quench elutriator by a stream of water and steam. The vapour produced tends to sweep the small coke particles back into the burner, resulting in a larger particle size net coke. This is transported pneumatically to storage hoppers from where it can be transferred to storage, returned to the unit, or sent to Coke Gasification in the ultimate phase of this plant.

Hydrogen Manufacture

The 4.29×10^6 m^3/d (152×10^6 SCF/D) of hydrogen demand for the Hydrotreating units will be met initially by Partial Oxidation (POX) of Coker heavy gas oil and, in the ultimate configuration when 4.81×10^6 m^3/d (170×10^6 SCF/D) is required, by the Partial Oxidation of fluid coke. Also under consideration for the initial phase, while the Coke Gasification technology is being proven, is the use of natural gas. This option is discussed later in this chapter.

Initial plant design will be predicated on ultimate operation using coke although equipment required solely for coke would be installed as needed. The gasifiers designed for coke will have oil firing capability. This will permit an orderly commissioning of these units as well as minimizing interruptions to hydrogen production in the case of Fluid Coker upsets.

The process flowsheets for Oil and Coke Gasification feedstock were presented in the previous section as Figures VIII-3 and VIII-6. In both cases hydrocarbon feedstock is partially oxidized (combusted) in relatively small, high capacity reactors. As high purity hydrogen is required, oxygen must be used instead of air. Oxygen, steam and hydrocarbon react at high temperatures in a refractory-lined combustor to produce carbon monoxide and hydrogen. After cooling and carbon clean-up, the raw gas enters a conventional work-up system, first to remove the hydrogen sulphide, then to convert or shift the carbon monoxide to carbon dioxide with the release of additional hydrogen – *carbon* *monoxide + water = carbon dioxide + hydrogen* – and finally to remove the large quantities of carbon dioxide.

The methanation step combines hydrogen with trace carbon oxides which have passed through the system, the latter being a poison to the downstream hydrotreating catalysts.

A small amount of carbon is produced in the POX reactor on oil feedstock. The reaction section of the unit includes carbon recovery and recycle facilities for the oil operation.

For the proposed coke operation, new or add-on facilities required include a coke grinding and feeding system. In addition, the reactors and waste heat exchangers will be replaced or modified on conversion to coke, and slag/ash removal and handling facilities added.

The plants have a high environmental acceptability, with no new sulphur emission source associated with the Coke Gasification. The hydrogen sulphide is routed to the Sulphur Plant and net water from the carbon scrubber section is small in volume and amenable to treatment. In the Coke Gasification design, there are no tars or phenols produced and the ash in the feedstock is removed as an inert slag.

Oxygen Plant

The oxygen required by the Partial Oxidation Unit is produced by the low temperature separation of oxygen from air. The principal operations in this process are air compression, removal of water and carbon dioxide, expansion refrigeration, separation and rectification via distillation, removal of trace carbon dioxide and hydrocarbon, and product oxygen compression. The design and size of the plant is similar to packaged oxygen units in operation at major steel mills.

Total oxygen demand of 1780 t/sd (1750 LT/SD) in the initial gas oil phase of operation, and 2240 t/sd (2205 LT/SD) in the ultimate coke case, is split between two parallel trains.

Hydrotreaters

Hydrotreatment of various crude oil components is required to reduce sulphur, nitrogen, olefin and aromatic concentrations to acceptable levels, to produce a product suitable for downstream refining operations.

The Naphtha Hydrotreating Process combines hydrogen and naphtha in vapour phase over fixed bed catalysts with staging to obtain the optimum conditions for the specific chemical reactions in each reactor. Butanes/butylenes, coker naphtha and cascade naphtha from the Gas Oil Distillate Hydrotreaters make up the feed to two parallel Naphtha Hydrotreaters, each producing 3340 m^3/sd (21 000 B/SD) of hydrotreated butane and heavier liquid in the ultimate configuration. A Diluent Preparation Unit, common to both Naphtha Hydrotreaters, separates a narrow boiling range naphtha which is recycled to the Extraction Plant as diluent make-up. The remaining hydrotreated butane plus product is blended to synthetic crude. The naphtha is suitable for feed to conventional refinery Catalytic Reforming Units.

The Distillate/Gas Oil Hydrotreating processes combine hydrogen with distillates or heavy oils predominantly in the liquid phase over fixed bed catalysts, normally at higher pressures and residence times than for lighter feed.

While the economics of alternative Upgrading configurations have been evaluated on the basis of Naphtha Hydrotreating and combined Distillate/Gas Oil Hydrotreating, the Applicant wishes to point out that a separate Hydrotreater facility treating a light distillate cut could be a subsequent optimization of this Application, in the interests of better synthetic crude quality, more efficient hydrogen management, and internal optimization of the Hydrotreating design package.

Total volume of distillate and gas oil hydrotreated product ranges from 17 500 to 19 100 m^3/sd (110 000 to 120 000 B/SD). Characteristic of Hydrotreating heavy oil fractions is the generation of a cascade naphtha which is high in aromatics and low in other qualities. These streams are sent to the Gas Recovery Unit and subsequently to the Naphtha Hydrotreaters for retreatment. This ensures that the final naphtha product meets product quality sulphur and nitrogen criteria. There is also a small propane and lighter gas production which is routed to the Gas Recovery Unit.

Recycle gas is scrubbed with amine solution to remove hydrogen sulphide and the rich amine is returned to a common regeneration system for sulphur recovery.

Gas Recovery/Treaters

Feeds to the Gas Recovery/Treaters sections include the following streams:
*gas and naphtha from the Fluid Coker
*gas and cascade naphtha, from the Distillate/Gas Oil Hydrotreaters
*gas from the Naphtha Hydrotreaters
*Amine treating solution cascaded from the Tail Gas SCOT Absorber.

The Gas Recovery fractionation system is designed to produce the following products:
*Ethane and lighter gas which pass to the Fuel Gas Treater
*liquid propane/propylene (LPG) which is routed to storage after amine treating, caustic treating and extractive Merox treating
*liquid butanes, butylenes and naphtha which pass to the Naphtha Hydrotreater

The Gas Recovery fractionation heat requirements are met in large part by a circulating stream of Fluid Coker fractionator gas oil.

Sulphur Recovery

Acid gases from the Gas Recovery/Treaters and the Hydrogen Plant work-up section are routed to the Sulphur Plant. The Sulphur Recovery system consists of two parallel trains comprising three-stage Claus units followed by SCOT (Shell Claus Offgas Treating) units. Each unit will normally operate on 50 percent of the plant throughput. The design Sulphur Recovery for the Claus unit is 96 percent and, when combined with the SCOT unit, the overall Sulphur Recovery efficiency will be increased to 99.9 percent.

Each Sulphur Plant will be designed for 60 percent of total production for the ultimate case when coke is being gasified. As a result, during the initial phase, each plant will have a capacity of 75 percent of total production; therefore, the greatest capacity margin will be available during the commissioning period.

The conventional Claus process is widely used and is not described at this point. The SCOT process is a more recent (1972) development, designed to recover sulphur compounds which have passed through the Claus plant. These compounds are reduced over a cobalt/molybdenum catalyst to hydrogen sulphide which is then recovered in an amine absorber. Hydrogen sulphide stripped from the amine is then recycled to Claus Plant feed. The tail gas which remains after hydrogen sulphide absorption contains 200 to 300 ppmv hydrogen sulphide, and is routed to the CO boiler for incineration of the hydrogen sulphide to sulphur dioxide.

Sour Water Handling

Process sour water containing ammonia and hydrogen sulphide is collected from the Diluent Recovery, Fluid Coker, Naphtha Hydrotreater, Gas Oil Hydrotreater and Gas Recovery Units and sent to the main sour water stripper. In addition, the Partial Oxidation Unit (POX) has its own dedicated sour water stripper.

The stripped gas is sent to the Sulphur Plant and the stripped water is routed to the recycle water storage basin at the rate of 7360 m^3/d (1350 USGPM) from the main stripper and 680 m^3/d (125 USGPM) from the POX stripper.

Utilities Facilities

INTRODUCTION

The Utility Plant has been designed to satisfy the total energy requirements of the Project. Connected by a tie line with a provincial grid network, the power producing facilities will be internally controlled in order to achieve an acceptable import-export power balance while minimizing demands on the grid.

A brief description of the major equipment components is given below and a simplified flow sheet is shown on Figure IX-1.

The majority of the steam produced on the site is at a higher pressure and temperature level than that required by most of the consumers. Steam for these consumers is supplied through suitable back pressure turbo generators which reduce the steam in pressure and temperature to the required level while generating by-product power.

Steam letdown stations are provided to balance the steam-electrical demand. The stations operate in parallel with the back pressure turbo generators and will automatically supply steam to the consumers, either when a back pressure turbine is out of service or when the demand of the steam consumers exceeds the normal steam supplied from the machines.

Only part of the total site power requirement is satisfied by these back pressure turbo generators. The balance is normally supplied by gas turbines coupled to electric generators. When the power demands exceed the combined power being supplied from the gas turbines and back pressure turbo generators operating on a balanced steam system, additional power is obtained from a steam condensing turbo generator. The gas turbines are fired using fuel produced in the Upgrading units with the exhaust fed to boilers. Exhaust heat for steam production is recovered in the boilers with the steam being subsequently supplied, as noted above, via the back-pressure turbines to the various site consumers. Supplemental fuel firing of the boilers is required to control the degree of steam superheat and to provide flexibility in boiler operation by means of altering steam output to balance variations in site steam and power demands.

With the above system, variations in steam and power demands across the site can be balanced by the facilities available in the Utility Plant. The integrated operation of gas turbines and back pressure turbo generators is optimized to obtain a high operating efficiency from the steam and power systems.

High quality boiler feed water for the various boilers and steam generators is produced in a water treatment plant located by the Utility Plant. Condensate returned from the process units and the steam condensing turbo generators combines with the treated water for deaeration and final conditioning before being supplied to the boilers.

The total site is largely self sufficient in energy, with the Upgrading Plant supplying all normal fuel requirements. Light ends from the Upgrading Plant supply the unit heaters, the Utility Plant boilers and the gas turbines. Propane, in excess of the normal fuel requirements, is liquefied and stored for sales or periods of high fuel demand.

During site startup and associated commissioning of individual units, imported supplies of propane, hydrotreated gas oil and/or natural gas will be required. These imported fuels will be replaced by the normal site-produced forms of fuel as the commissioning process proceeds.

The Utility Plant will be designed to accommodate the proposed ultimate process configuration which includes Coke Gasification for hydrogen production.

STEAM GENERATION

Superheated steam in both the Upgrading area and the Utility Plant is generated at approximately 6.2 MPa (900 psia) and 480 degrees C (900 degrees F). The CO boiler associated with the Fluid Coker produces the majority of the high pressure steam in the Upgrading area. This steam level was selected to accommodate the variable site energy demands which are external to the Utility Plant. These demands are largely in the form of electrical power for the Mine, Extraction, Upgrading and Offsites and low pressure steam for Extraction and Upgrading.

The majority of the steam consumed by Extraction and Upgrading, as well as that required by utilities for boiler feed water heating and deaeration purposes, is required at 0.45 MPa (65 psia) and 150 degrees C (300 degrees F). Consumers of this steam, and the remaining consumers of steam at intermediate pressure and temperature levels, are supplied via back-pressure turbo generators which reduce the high pressure superheated steam to the condition required by the consumer. By-product power is produced efficiently by the back-pressure turbo generators during this process. The outlet steam from the back-pressure turbo generators has sufficient superheat to allow for temperature loss in the distribution system.

Efficient utilization of energy and equipment reliability were both important factors in selecting the steam conditions for the major steam producers and consumers. The 6.2 MPa (900 psia) steam cycle has proven reliability combined with stringent, but reasonable, water treatment requirements. Higher pressure and temperature steam cycles require the use of alloy steels in the steam generators, the distribution systems and consuming sections, combined with ultra high purity treated water.

The demands for power and steam normally fall within the operational range of the power generating system. Increase in steam demand without a concomitant increase in power demand is satisfied by the use of pressure temperature let-down stations called desuperheating stations. These desuperheating stations augment the steam supply to the low pressure consumers in excess of that supplied by the back-pressure turbo generators, keeping steam and power within balance.

Should the power requirements increase, with the demand for steam remaining constant, high pressure steam can be diverted to the steam condensing turbo generator. In this manner increasing power demand can be met without exceeding the steam demand of the systems outside the Utility Plant.

ELECTRICAL

The electrical power is to be generated largely within the complex. Power will be purchased from the grid for emergencies, startup, and for the peaks associated with the dragline operation.

The Utility Plant design produces by-product power in a combined cycle. Gas turbines produce electrical power and exhaust hot gases to a heat recovery boiler. The heat recovery boiler generates steam with the aid of support fuel. The steam is put through back-pressure turbines to produce additional electrical power. This configuration is termed a *combined cycle,* with the power produced through the back-pressure turbines termed *by-product power.*

Electrical power in excess of that which balances with the demand for low level steam is produced via a condensing steam turbine.

HEAT INTEGRATION

In previous sections the integrated production of power and process steam from gas-turbine and steam-turbine driven electric generators has been described. Through the selection of appropriate equipment and facility configuration the normal site power and steam requirements will be satisfied.

An additional major energy demand is the hot water required for the Hot Water Extraction Process. Low level heat (below 150 degrees C — 300 degress F) from the Upgrading Process is used to heat Extraction Plant water. This heat would normally be rejected to the atmosphere via air coolers or circulating cooling water systems in a conventional refinery installation. The Extraction Plant water is heated in specially designed Upgrading Exchangers and is stored in a hot water tank for use as required by Extraction. This system is shown in schematic form in Figure IX-2.

Heat rejection requirements at low level in the Upgrading area essentially coincide with the heat requirements for hot water in Extraction. Steam trim exchangers are provided to enhance temperature control; however, they are not expected to be required in normal operation. Steam trim exchangers will be utilized fully during an Upgrading turnaround when half of the heat normally available to Extraction water is removed. Owing to the extent of the integrated design of the Upgrading cooling water/Extraction hot water systems, there are expected to be a minimum of load swings caused by summer/winter operation. During Upgrading turnarounds, when the Extraction Plant continues normal operation and half the normal fuel supply is removed, significant quantities of supplemental fuel are required in the Utility Plant to supply the much increased steam demand.

The energy requirements of the total complex are influenced by the relationship between Process Units. For example, stockpiles provided in the Mine have effectively delinked the Mine and Extraction Plants, which will provide steadier Extraction Plant operation. Selectivity in Mining provided by the draglines plus material blending are expected to assist in lowering and smoothing the Extraction Plant energy demand. The hot water tank combined with Upgrading heat to Extraction water will reduce the impact of remaining swings on the fuel demand. Changes in any of these basic design features will have a significant impact on the fuel demand. Optimization and heat integration studies will continue as detailed Project design proceeds.

UTILITY PLANT EQUIPMENT

There are as noted above five major categories of equipment involved in the Utility Plant:

Gas Turbine-Driven Electric Generators
Heat Recovery Steam Boilers
Back-Pressure Steam Turbine-Driven Electric Generators
Condensing Steam Turbine-Driven Electric Generators
Ancillary Equipment

Gas Turbine Electric Generator

The gas turbine electric generator consists of an air compressor, a combustor, a hot gas expander turbine, and an electric generator. The air compressor provides compressed air to the combustor section where, combined with fuel, the mixture is burned. Hot (1000 degrees C — 1800 degrees F), high pressure (1.4 MPa — 200 psia) gas is exhausted through the expander turbine, driving both the electric generator and the air compressor. High temperature (500 degrees C — 900 degrees F or hotter) exhaust gas from the turbine outlet, which is rich in oxygen, effectively provides preheated air to the downstream heat recovery boiler.

Three gas turbine electric generators of approximately 70 MW output capacity each are to be provided. One of these is a spare unit during normal operation.

Heat Recovery Boiler

The heat recovery steam boiler is simply a substitute for a normal power boiler. The main difference is that it recovers heat from the gas turbine exhaust and, because there is a large amount of preheated excess air in the gas turbine exhaust, supplemental fuel can be fired to control both superheat in the produced steam and the rate of steam production. The exit temperature of the flue gas from the heat recovery boiler will be approximately 200 degrees C (400 degrees F).

Three 8700 t/d (800 000 lb./hr.) boilers are to be provided, one of which is a spare during normal operation. For one half Upgrading shutdown with Mine and Extraction operating at design conditions, all boilers will be required.

As noted above, the high pressure superheated steam generated in the heat recovery boiler is supplied to the steam turbines for electrical power generation and low pressure steam production.

Back-Pressure Steam Turbine

Back-pressure steam turbines provide both electric power generation and low pressure, somewhat superheated, steam for process use. The electrical power generated from the back-pressure turbines is termed *by-product power.* As long as there is use for the process steam, the electricity generated in this manner is generated at high efficiency. Electrical power requirements in excess of low pressure process steam requirements is more efficiently generated through condensing turbines.

Three back-pressure units are to be installed, one of which is a spare for normal operation. During one half Upgrading shutdown, with the Mine and Extraction Plant at normal operation, all units will be required.

Condensing Steam Turbines

Condensing steam turbine drives are designed for vacuum conditions at the turbine steam exhaust. Because of the resulting greater pressure drop through it, the efficiency of the condensing turbine is higher than that of the back-pressure unit. The thermal efficiency, however, when compared to the by-product system where the steam exhaust is used for process purposes, is poorer for the condensing unit. The lower thermal efficiency is due to the large quantity of heat in the exhaust steam being lost to the cooling water system via the turbine condenser.

One 50 MW unit is to be provided in condensing service.

Water Treatment Facilities

The water treatment facilities are designed to process settled Athabasca River water in two major sections. In the first section, the clarifier/filter processes approximately 82 000 m^3/d (15 000 USGPM) of water. This stream is divided with some 49 000 m^3/d (9000 USGPM) available to the Upgrading and Extraction plants as process water, and the balance being demineralizer plant feed.

In the second section, the demineralizer plant, the filtered water passes through several stages of treatment including ion exchange. The resulting treated water is suitable for use as makeup for the high pressure boiler feed water system.

Blowdown from the water treatment plant is neutralized to a pH range of 6 to 9 before being discharged to the tailings pond.

Ancillary Facilities

The Utility Plant requires the following supporting pieces of major equipment:

PROCESS AND UTILITY COOLING TOWERS

These units remove heat from both the Process and the Utility sections. The utility cooling water tower is primarily for use with the condensing turbine.

PLANT GAS COMPRESSORS

These supply fuel gas to the gas turbines at the required pressure. Only gas turbine fuel is handled in these compressors.

DEAERATOR

These facilities are provided as part of the water treatment facilities for boiler feed water preparation.

STEAM TRIM EXCHANGERS

These are provided to permit steam heating of Extraction Plant water when heat from the process units is insufficient.

BOILER FEED WATER PUMPS

These are designed to provide the boiler feed water required for all steam generators in both Upgrading and Utilities.

DESUPERHEATING STATIONS

These are provided to enable balancing of electrical production with process steam demands. The units will produce steam at a suitable pressure and temperature, independent of the electrical production. Higher pressure/temperature steam is blended with treated water or condensate to produce the desired steam level.

Upgrading and Utilities Offsite Facilities

TANKAGE

Approximately seven million barrels (1.1×10^6 m^3) of tankage will be provided for water, dilute and finished bitumen, intermediate feedstocks, upgraded crude components, propane and miscellaneous chemicals. Storage of bitumen and intermediate feedstocks is provided to ensure a constant feed supply to the various Processing Units and to accommodate major plant shutdowns.

The tank farm will be dyked to deal with potential product spills, and will be protected by fire-fighting facilities. Any spills will be contained and handled within the confines of the tank farm.

SULPHUR STORAGE AND HANDLING

The liquid sulphur from the Sulphur Recovery Units will be pumped from a local storage pit to the sulphur storage area. It will then be formed into solid blocks using technology proven in sour natural gas plants.

An area of 10 to 15 ha (25 to 40 acres) will be allocated for the initial ten years of operation, with provision for future expansion as necessary.

COKE STORAGE AND HANDLING

Solid coke from the Fluid Coker is slurried together with fly ash from the electrostatic precipitators located on the outlet of the CO boilers, and is pumped to the coke storage area. Excess water is decanted and returned for re-use in the slurrying process. Makeup water will be required to compensate for water entrained in the coke storage area. The storage area will be lined to prevent seepage to ground water.

An additional area of 1 to 2 ha (2 to 5 acres) may be required for dry coke storage to accommodate feed requirements of the Coke Gasifier.

FLARE AND BLOWDOWNS

All units will be provided with appropriately sized pressure relieving devices and blowdown headers which will connect to the flare systems. A minimum of two flares will be provided with associated knockout drums and automatic ignition systems.

PONDS AND BASINS

The coke storage area discussed above under Coke Storage and Handling will be of clay-lined earthen construction. Coke will be piled to between 5 and 10 m (15 and 30 feet) high. The ultimate size of the pond will be 50 to 100 ha (150 to 300 acres), built in annual increments of 10 to 15 ha (25 to 40 acres).

The recycle water storage basin, which is provided to blend various water streams and increase the reliability of the once-through cooling water system, will be of impermeable construction some 5 m (15 feet) deep, and will cover an area of 4 to 6 ha (10 to 15 acres).

SEWERS AND DRAINAGE

An oily water sewer system will be provided within the Upgrading area. These waters will be treated in an oil interceptor separator before being routed to the recycle water storage basin. A similar approach is planned for potentially contaminated surface water runoff.

Process water blowdown is non-oily and therefore is routed directly to the recycle water storage basin. Further opportunities for recycle will be examined as detailed plant design proceeds, and could include steam system blowdown to recycle water storage, depending on overall water balance requirements.

POTABLE WATER AND SANITARY SEWAGE

An in-plant system will be installed sized to provide potable water of .453 m^3/d per person (120 USGPD) for a 6500-man camp, and sewage facilities for 80 percent of the potable water flow. The approximately 3000 m^3/d (550 USGPM) of potable water would be treated to Alberta Environment standards for municipal water supplies. Appropriate emergency storage would be included. The approximately 2400 m^3/d (440 USGPM) of sanitary sewage would be treated in a Rotary Biological Contactor secondary sewage treatment plant at 95 percent efficiency to reduce the inlet BOD of 250 mg/L and suspended solids of 275 mg/L to less than 20 mg/L in the discharge. These facilities will be used for the plant throughout the Project life.

The minimum winter flow in the Athabasca River is approximately 9.0×10^6 m^3/d (1.65×10^6 USGPM), providing a dilution of greater than 3000:1 for the discharge.

In the event that a new town is developed in conjunction with this project, a joint sewage treatment facility will be considered.

Crude Quality

The basic criteria for crude quality are discussed under the heading of Upgrading Requirement in Chapter VIII. While these considerations themselves determine, to a considerable degree, the required crude quality, the Applicant is continuing to assess both future quality needs and Hydrotreating process designs which can best meet them. For this reason there is some latitude in the definition of Alsands crude target composition and properties. These are compared in Table IX-1 to light, conventional Alberta crude.

The Hydrotreating requirements of Fluid Coker products will be determined by several factors. As a minimum, the reactive olefins must be saturated to achieve satisfactory storage stability. The severity of the naphtha Hydrotreating will be determined by the maximum nitrogen and sulphur contents which will be acceptable to catalytic reformers in the receiving refineries.

The minimum Hydrotreating requirement for Fluid Coker distillate and gas oil products will be to reduce sulphur and nitrogen content. The severity of Hydrotreating required for these products, however, will likely be set by the aromatic content of the various fractions. Distillate aromaticity is of particular significance because refineries are not generally equipped to modify this property of synthetic distillate. Thus it will likely find its way into finished oil products at essentially the same aromatics level as in the synthetic crude. The combustion requirements of kerosene type jet fuel, diesel fuel and furnace oil will determine the extent to which aromatics should be reduced in the various distillate fractions. The gas oil Hydrotreating requirement will be based on attainment of nitrogen and aromatics contents compatible with the cracking capability of the receiving refineries.

Natural Gas Alternative

During the initial period of operation, estimated at five to eight years, hydrogen could be manufactured by Partial Oxidation (or Steam Methane Reforming) of natural gas instead of Coker gas oil. (Steam Methane Reforming of the natural gas would also be reviewed.) The displaced gas oil would be hydrotreated and included in the synthetic crude oil, increasing propane plus production by 1280 m^3/d (8050 B/D). The natural gas required for Hydrogen Plant feed would be 55.7 TJ/d (52.8×10^9 BTU/D) (LHV). These volumes are based on no Coke Gasification, whereas the Applicant anticipates that operation of prototype Coke Gasification facilities for much of the initial period would reduce the natural gas requirement with the synthetic crude output remaining unchanged.

The economics of natural gas usage in place of gas oil during the initial period are under review. Key factors which affect these economics include:

the price relationship between synthetic crude and natural gas projected for the period under consideration

the cost of pipelining the necessary gas volume from field to plant gate

incremental costs of converting from natural gas to coke

In addition to project economics, the benefits/costs to Alberta and to Canada of increasing synthetic crude production by utilizing natural gas during the initial period will be considered. Reference to the energy balances of the following section indicates that the use of gas would result in a higher overall Upgrading energy efficiency. The selection of natural gas versus Coker gas oil for Partial Oxidation Plant feedstock does not impact on sulphur emissions.

Material and Energy Balances

PROCESS PHASING

During the initial phase of operation, hydrogen will be generated from either Coker gas oil or natural gas. The Applicant is planning that by-product fluid coke ultimately be utilized for hydrogen manufacture, assuming satisfactory development of this technology as discussed above. In view of these process options, three material and energy balances are presented in this section:

Initial operation – hydrogen from Coker gas oil

Initial operation – hydrogen from natural gas

Ultimate operation – hydrogen from fluid coke

MATERIAL BALANCE

The flow schemes showing the main plant flows are given in Figures IX-3, 4, and 5. The corresponding material balances for the Upgrading and Utilities sections are shown in Tables IX-2, 3, and 4. These material balances do not reflect any intermediate type of operation between the initial and ultimate phases. Absence of definition of the capacity of the prototype coke POX plant at this time precludes presenting a material balance for any intermediate case.

In all three cases 25 040 m^3/d (157 500 B/D) of recovered bitumen are processed in the Diluent Recovery Units as feed for the Fluid Cokers. There are differences in the amounts of fuel consumed and synthetic crude produced in the three cases, due to the varying methods of producing hydrogen and the degree of Hydrotreating of the Coker liquid products. A comparison of the fuel requirements and plant yields is shown in Table IX-5. The energy balances are given in Table IX-6.

Hydrogen Produced from Coker Gas Oil

In this option for initial operation, 19 990 m^3/d (125 700 B/D) of synthetic crude (including butanes) are produced from the 25 040 m^3/d (157 500 B/D) of bitumen. The feed to the Partial Oxidation Unit to produce the 4.29×10^6 m^3/d (152×10^6 SCF/D) of hydrogen required for hydroprocessing is 1550 m^3/d (9750 B/D) of unhydrotreated Coker gas oil. The gas recovery section processes 83.2 TJ/d (78.9×10^9 BTU/D) of propanes and lighter gases produced by the Coker and Hydrotreaters. Twenty-five percent of the above is recovered in the form of LPG to be used as a swing fuel in the Utility Plant. When LPG is surplus, it is blended into synthetic crude to an amount of one percent volume, or sold as LPG product. Hydrotreated gas oil is also used as a supplemental fuel during shutdown periods, since LPG storage capacity is not sufficient to cover the entire 30-day shutdown period.

A total of 129.2 TJ/d (122.5×10^9 BTU/D) of fuel, on an annual average basis, is consumed in the plant. Of this amount, 80.7 TJ/d (76.5×10^9 BTU/D) is supplied by plant gas, LPG and treated gas oil, with the remainder coming from the coke burned in the Fluid Coker. The 129.2 TJ/d (122.5×10^9 BTU/D) of fuel consumed is equivalent to approximately 13.4 percent of recovered bitumen feed. The energy equivalent of the saleable products, synthetic crude and LPG, is 731 TJ/D (693×10^9 BTU/D). This provides an energy recovery from bitumen to product of 75.6 percent.

Net by-product coke is produced at a rate of 2495 t/d (2456 LT/D) and is stockpiled during the initial phase. Sulphur is produced at a rate of 949 t/d (934 LT/D) and is stockpiled for potential future sales.

Hydrogen Produced from Natural Gas

There is a purchase of 55.7 TJ/d (52.8×10^9 BTU/D) of natural gas for the POX Hydrogen Plant. In this case, the plant gases produced are excess to the fuel requirements, hence an amount of 9.9 TJ/d (9.4×10^9 BTU/D) is used to supplement the Hydrogen Plant feed and to reduce the amount of natural gas purchased. Because natural gas is used during the initial phase of operation, all Coker liquid products are Hydrotreated for blending to the synthetic crude. The gas oil Hydrotreating capacity is now higher to accommodate the extra gas oil feed. Total hydrogen consumption is 4.65×10^6 m^3/d (165×10^6 SCF/D) in this case.

The propanes and lighter gases recovered in the Gas Recovery section for fuel are 84.8 TJ/d (80.4×10^9 BTU/D). Twenty-five percent of this fuel is recovered in the form of LPG to be used as a swing fuel in the Utility Plant. Surplus LPG is blended into the synthetic crude to an amount of one percent volume, with the remaining LPG fed to the POX Hydrogen Plant. Hydrotreated gas oil is also used as a supplement to fuel during shutdown periods. A total of 128.4 TJ/d (121.7 × 10^9 BTU/D) of fuel is consumed in the plant on an annual average basis. This is equivalent to approximately 13.3 percent of recovered bitumen. Of this amount, 79.7 TJ/d (75.7 × 10^9 BTU/D) is supplied by plant gas, LPG, and treated gas oil with the remaining heat requirements supplied by the coke burned in the Fluid Coker.

Synthetic crude production is 21 620 m^3/d (136 000 B/D), including butanes. In comparison with initial operation on Coker gas oil as Hydrogen Plant feed, an additional 1280 m^3/d (8050 B/D) or 53.1 TJ/d (50.3 × 10^9 BTU/D) is available as product. This raises the energy equivalent of saleable products to 785 TJ/d (744 × 10^9 BTU/D), giving an energy recovery to product from bitumen plus natural gas of 76.7 percent.

Net by-product coke is 2495 t/d (2456 LT/D) and is stockpiled during the initial phase. Sulphur is produced at a rate of 948 t/d (933 LT/D) and is stockpiled for potential future sales.

Hydrogen Produced from Fluid Coke

Fluid coke is fed to the Hydrogen Plant POX section to produce the 4.81 × 10^6 m^3/d (170 × 10^6 SCF/D) of hydrogen required in this case. All of the fluid coke produced is expected to be required for POX feed. Depending on the requirements of the coke POX technology selected, supplemental feedstock may be needed on a continuous basis. Some of the stockpiled fluid coke could be reclaimed if this proves technically and economically feasible.

A total of 86.5 TJ/D (82.0 × 10^9 BTU/D) of propane and lighter fuel is produced. Approximately 25 percent of this is recovered and stored as LPG for use as swing fuel. LPG surplus is blended into synthetic crude or sold as LPG. A total of 131.7 TJ/d (124.8 × 10^9 BTU/D) of fuel is consumed in the plant on an annual average basis. This is equivalent to approximately 13.6 percent of recovered bitumen. Of this amount, 83.1 TJ/d (78.8 × 10^9 BTU/D) are supplied by plant gas, LPG and treated gas oil, with the remaining heat requirements being supplied by the coke burned in the Fluid Coker.

Production of synthetic crude, including butanes, is 21 700 m^3/d (136 500 B/CD). The energy equivalent of the saleable products, synthetic crude plus LPG, is 793 TJ/d (752 × 10^9 BTU/D), equal to an energy recovery from bitumen of 82.0 percent. Thus, utilization of the fluid coke provides a net product gain of 62 TJ/d (59 × 10^9 BTU/D) or 6.4 percent energy equivalent on bitumen, from the initial case on gas oil.

Sulphur is produced at a rate of 1163 t/d (1145 LT/D) and is stockpiled for potential future sales.

ENERGY BALANCE

The fuel balances for the three process options: hydrogen production from gas oil, natural gas, and coke, are shown in Table IX-7. The data indicates that the propane minus production from Upgrading, during normal operation, exceeds the demands for fuel in Upgrading and Utilities. The excess propane can be blended to crude, sold as LPG or, in the case of the natural gas POX Unit, be part of the feed to the POX Unit. Hydrotreated gas oil supplies the balance fuel demands largely required during Upgrading turnarounds when half the source of propane minus fuel supply is removed. Excluded from the energy/fuel balance shown on this Table is the energy content of the coke which is consumed in the Fluid Coker burner.

Tables IX-8, 9, and 10 show the power, total steam and energy to and from water on the basis of production and consumption for the three modes of operation. The power figures indicate that, while the production is totally from the

Utility Plant, the consumption is distributed over the Mine, Extraction, Upgrading and Utilities/Offsites Plants. In all three process options the power consumption of the Upgrading Plant is heavily influenced by the power requirements of the POX Unit.

Steam is generated in the various units of the Upgrading Plant, largely in the Fluid Coker, with the balance being supplied by the Utility Plant. Consumption of steam is in three main areas: Extraction, Upgrading and Utilities; with the major consumers being the conditioning drums in Extraction, the Diluent Recovery Unit in Upgrading, and the Deaerator in the Utility Plant.

Energy to water is supplied totally from the Upgrading Plant heat integration system under normal operation. The total consumer of hot water is the Extraction Plant. When half the Upgrading Plant is shut down for turnaround, half the heat integration between Upgrading and Extraction is lost. During these periods steam is used to replace the energy that was formerly supplied by the Upgrading Plant to the water.

The design of the Utility Plant will be the same for the initial and ultimate operation. Flexibility in the system will accommodate the somewhat different energy balances.

SULPHUR RECOVERY AND EMISSIONS

The sulphur balances for the three cases are shown in Tables IX-11, 12, and 13. It is significant to note from these tables that when the net coke is fully utilized for hydrogen production, the recovered sulphur increases significantly, but the level of emissions stays virtually constant.

The emissions from the Project are from three sources as shown on Table IX-14. The Sulphur Plant, having an overall recovery efficiency of 99.9 percent, contributes only slightly to the sulphur emissions. Fuel for the plant also contributes a minor quantity to the emissions. The majority of emissions results from the operation of the burner in the Fluid Coker where a portion of the gross coke is internally combusted for energy balance. Design data supplied by the process licensor shows that the burned coke has a favourable sulphur distribution when compared to the sulphur content of the average coke.

The flue gas from the Coker burner is incinerated in the CO boiler which also acts as an incinerator for the Sulphur Plant tail gas. The CO boiler flue gas combines with the flue gases from the Utility Plant in a single high stack.

The potential variation in sulphur emissions is shown in Table IX-14. These variations are largely due to the possible increase in the sulphur content of the burned coke above that shown in the licensor's design data. The design basis and variations are subject to confirmation through actual plant operation on Athabasca bitumen. The figures quoted in this Table are exclusive of the impact of operational upsets.

TABLE IX-1

COMPARISON OF CRUDE COMPOSITIONS AND PROPERTIES

		ALSANDS TARGET CRUDE	LIGHT CONVENTIONAL ALBERTA CRUDE
Gravity, API		34-36	37-40
Sulphur, Percent Wt.		0.1-0.15	0.3-0.6
Nitrogen, Percent Wt.			
$345C^+$ Gas Oil		0.05	0.1
COMPOSITION, Percent Vol.			
	C_3 – C_4	3-5	3-4
Naphtha	C_5 – 150C	15-20	22-24
Distillate	150 – 345C	35-45	35-37
Gas Oil	345 – 560C	33-38	27-30
Residue	560C +	NIL	8-10

TABLE IX-2

MATERIAL BALANCE
INITIAL OPERATION – HYDROGEN FROM COKER GAS OIL

	REFERENCE UNITS	t/d
IN		
Recovered Bitumen (ash free)	25 040 m^3/d	25 205
Ash Plus Clay		177
Oxygen		1 556
Net Chemical Water Consumption		1 844
TOTAL		28 782
OUT		
Upgraded Crude C_4^+	19 990 m^3/d	16 875
LPG to Crude	170 m^3/d	91
LPG to Sales	370 m^3/d	191
Fuel Gas	64.3 TJ/d	1 345
LPG to Fuel	250 m^3/d	132
Gas Oil to Fuel	270 m^3/d	250
Burned Coke		1 563
Net Coke (Incl. ash plus Clay)		2 495
Product Sulphur		949
CO_2 Vent		4 433
Net Loss		102
Diluent to Extraction	470 m^3/d	356
TOTAL		28 782

TABLE IX-3

MATERIAL BALANCE
INITIAL OPERATION – HYDROGEN FROM NATURAL GAS

	REFERENCE UNITS	t/d
IN		
Recovered Bitumen (ash free)	25 040 m³/d	25 205
Ash Plus Clay		177
Oxygen		1 823
Net Chemical Water Consumption		785
Natural Gas	55.7 TJ/d	1 141
TOTAL		29 131
OUT		
Upgraded Crude C_4^+	21 620 m³/d	18 343
LPG to Crude	190 m³/d	98
Fuel Gas	65.5 TJ/d	1 366
LPG to Fuel	200 m³/d	106
Gas Oil to Fuel	250 m³/d	227
Burned Coke		1 563
Net Coke (Incl. ash plus Clay)		2 495
Product Sulphur		948
CO_2 Vent		3 528
Net Loss		100
Diluent to Extraction	470 m³/d	355
TOTAL		29 131

TABLE IX-4

MATERIAL BALANCE
ULTIMATE OPERATION – HYDROGEN FROM FLUID COKE

	REFERENCE UNITS	t/d
IN		
Recovered Bitumen (ash free)	25 040 m³/d	25 205
Ash Plus Clay		177
Oxygen		1 963
Net Chemical Water Consumption		3 436
TOTAL		30 781
OUT		
Upgraded Crude C_4^+	21 700 m³/d	18 314
LPG to Crude	190 m³/d	98
LPG to Sales	360 m³/d	189
Fuel Gas	66.9 TJ/d	1 392
LPG to Fuel	270 m³/d	141
Gas Oil to Fuel	260 m³/d	234
Burned Coke		1 563
Coke Gasifier solids		223
Product Sulphur		1 163
CO_2 Vent		6 970
Net Loss		138
Diluent to Extraction	470 m³/d	356
TOTAL		30 781

TABLE IX-5

SUMMARY OF MAIN PLANT STREAMS FOR UPGRADING PROCESS OPTIONS

	INITIAL OPERATION HYDROGEN FROM COKER GAS OIL	INITIAL OPERATION HYDROGEN FROM NATURAL GAS	ULTIMATE OPERATION HYDROGEN FROM FLUID COKE
Recovered Bitumen Feed, m^3/d	25 040	25 040	25 040
97% H_2 production, 10^6 m^3/d	4.29	4.65	4.81
H_2 Plant Feed			
Coker Gas Oil, m^3/d	1 550		
Natural Gas, TJ/d		55.7	
LPG, m^3/d		410	
Fluid Coke, t/d			2495
Plant Gas to Fuel, TJ/d	64.2	65.6	66.9
LPG to Fuel, m^3/d	250	200	270
HTGO to Fuel, m^3/d	270	250	260
C_4^+ Synthetic Crude, m^3/d	19 990	21 620	21 700
LPG to Synthetic Crude, m^3/d	170	190	190
LPG to Sales, m^3/d	370	—	360
Liquid Product Yields on Bitumen			
C_4^+ % vol.	79.8	86.4	86.7
% wt.	67.0	72.8	72.7
C_3^+ % vol.	82.0	87.1	88.9
% wt.	68.1	73.2	73.8

TABLE IX-6

PROJECT ENERGY BALANCES (RECOVERED BITUMEN BASIS)

	INITIAL OPERATION HYDROGEN FROM COKER GAS OIL TJ/d	INITIAL OPERATION HYDROGEN FROM NATURAL GAS TJ/d	ULTIMATE OPERATION HYDROGEN FROM FLUID COKE TJ/d
IN			
Recovered Bitumen	967.2	967.2	967.2
Natural Gas		55.7	
	967.2	1022.9	967.2
OUT			
Naphtha loss in Extraction	15.4	15.4	15.4
Total Plant Fuel	80.7	79.9	83.1
Burned Coke	48.5	48.5	48.5
Net Coke	72.0	72.0	
Unconverted Coke (in solids)			1.5
Synthetic Crude and LPG	731.6	784.6	793.0
Losses (to balance)	19.0	22.5	25.6
	967.2	1022.9	967.2

TABLE IX-7

PROJECT ENERGY BALANCES —— FUEL BASIS

	INITITAL OPERATION HYDROGEN FROM COKER GAS OIL TJ/d	INITIAL OPERATION HYDROGEN FROM NATURAL GAS TJ/d	ULTIMATE OPERATION HYDROGEN FROM FLUID COKE TJ/d
IN			
Propane and lighter (From Upgrading)	83.2	84.8	86.6
HTGO (Balancing Fuel)	10.5	9.5	9.8
TOTAL	93.7	94.3	96.4
OUT			
Upgrading (Fuel)	11.3	14.7	10.9
Utilities (Fuel)	69.4	65.2	72.3
Propane to Product	13.0	4.5	13.2
Propane to POX	–	9.9	–
TOTAL	93.7	94.3	96.4

TABLE IX-8

UTILITIES PRODUCTION AND CONSUMPTION
INITIAL OPERATION – HYDROGEN FROM COKER GAS OIL

	MINE	EXTRACTION	UPGRADING	UTILITIES AND OFFSITES	TOTAL
NORMAL POWER (MW)					
Production				258	258
Consumption	57	56	117	28	258
AVERAGE TOTAL STEAM (t/d)					
Production			25 376	14 359	39 735
Consumption		14 207[1]	17 004	8 524	39 735
ENERGY TO/FROM WATER (GJ/h)					
Production			3 107		3 107
Consumption		2 804			2 804

Note:
1. Includes Steam to Extraction Exchangers

TABLE IX-9

UTILITIES PRODUCTION AND CONSUMPTION
INITIAL OPERATION — HYDROGEN FROM NATURAL GAS

	MINE	EXTRACTION	UPGRADING	UTILITIES AND OFFSITES	TOTAL
NORMAL POWER (MW)					
Production				266	266
Consumption	57	56	125	28	266
AVERAGE TOTAL STEAM (t/d)					
Production			27 793	13 009	40 802
Consumption		14 207[1]	16 895	9 700	40 802
ENERGY TO/FROM WATER (GJ/h)					
Production			3 179		3 179
Consumption		2 804			2 804

Note:
1. Includes Steam to Extraction Exchangers

TABLE IX-10

UTILITIES PRODUCTION AND CONSUMPTION
ULTIMATE OPERATION – HYDROGEN FROM FLUID COKE

	MINE	EXTRACTION	UPGRADING	UTILITIES AND OFFSITES	TOTAL
NORMAL POWER (MW)					
Production				277	277
Consumption	57	56	136	28	277
AVERAGE TOTAL STEAM (t/d)					
Production			26 181	15 154	41 335
Consumption		14 207[1]	16 721	10 407	41 335
ENERGY TO/FROM WATER (GJ/h)					
Production			3 120		3 120
Consumption		2 804			2 804

Note:
1. Includes Steam to Extraction Exchangers

TABLE IX-11

SULPHUR BALANCE
INITIAL OPERATION – HYDROGEN FROM COKER GAS OIL

	t/d	% OF TOTAL
IN		
Bitumen	1234	100
OUT		
Recovered[1]	949	76.9
Synthetic Crude	16	1.3
Contained in Coke	215	17.4
Emissions[2]	54	4.4
TOTAL	1234	100.0

Notes:
1. Based on 99.9% recovery efficiency.
2. Based on licensor design data.

TABLE IX-12

SULPHUR BALANCE
INITIAL OPERATION – HYDROGEN FROM NATURAL GAS

	t/d	% OF TOTAL
IN		
Bitumen	1234	100
OUT		
Recovered[1]	948	76.8
Synthetic Crude	17	1.4
Contained in Coke	215	17.4
Emissions[2]	54	4.4
TOTAL	1234	100.0

Notes:
1. Based on 99.9% recovery efficiency.
2. Based on licensor design data.

TABLE IX-13

SULPHUR BALANCE
ULTIMATE OPERATION – HYDROGEN FROM FLUID COKE

	t/d	% OF TOTAL
IN		
Bitumen	1234	100
OUT		
Recovered[1]	1163	94.2
Synthetic Crude	17	1.4
Contained in Coke	—	—
Emissions[2]	54	4.4
TOTAL	1234	100.0

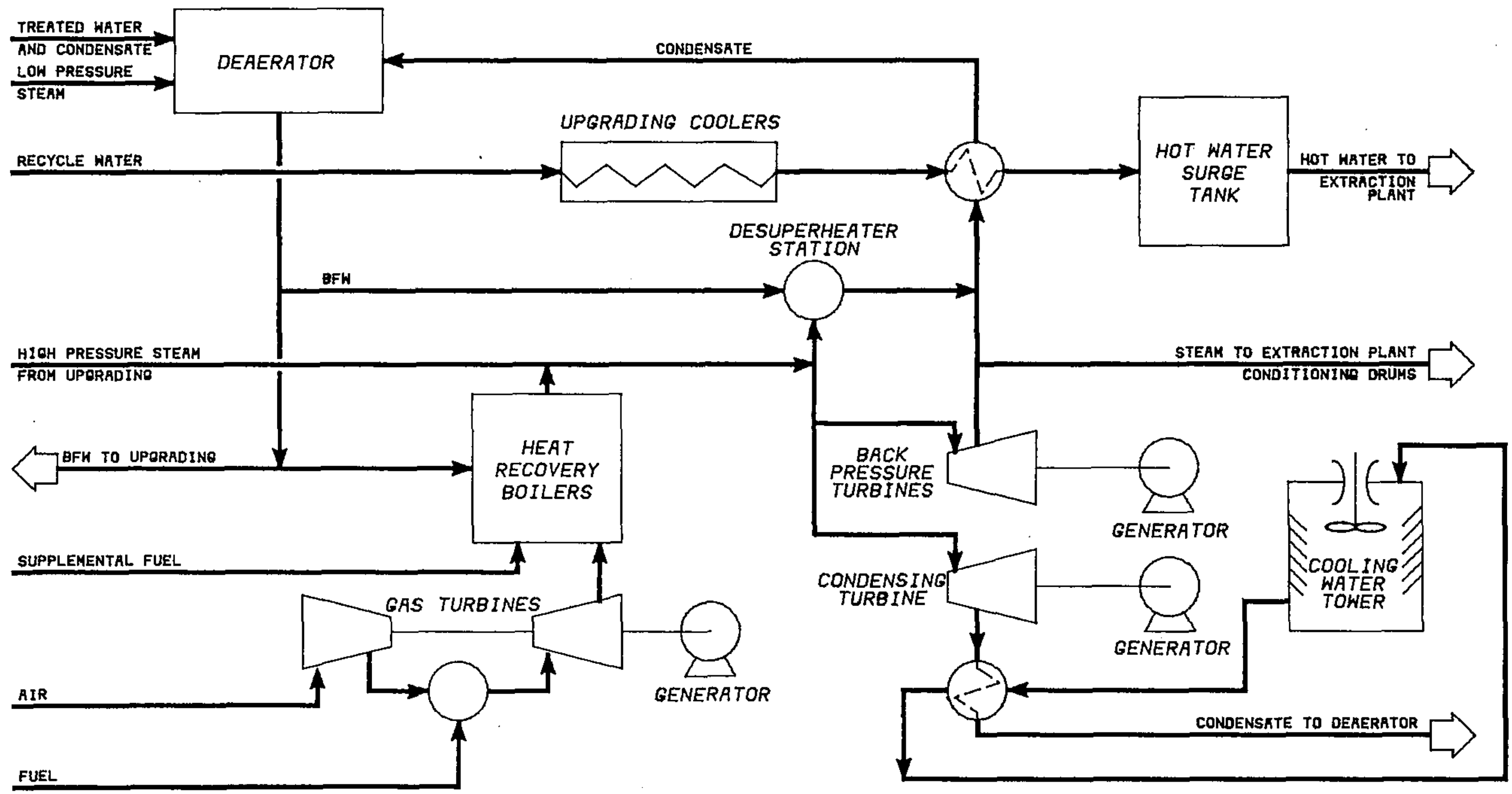
Notes:
1. Based on 99.9% recovery efficiency.
2. Based on licensor design data.

TABLE IX-14

SULPHUR EMISSIONS – SOURCES

SOURCE OF EMISSION	DESIGN BASIS	POTENTIAL VARIATION
Burner (t/sd)	58	85
Sulphur Plant (t/sd)	1	3
Fuel (t/sd)	3	3
Total Sulphur (t/sd)	62	91
Ratio (t SO_2/1000 m^3 Bitumen)	4.3	6.4

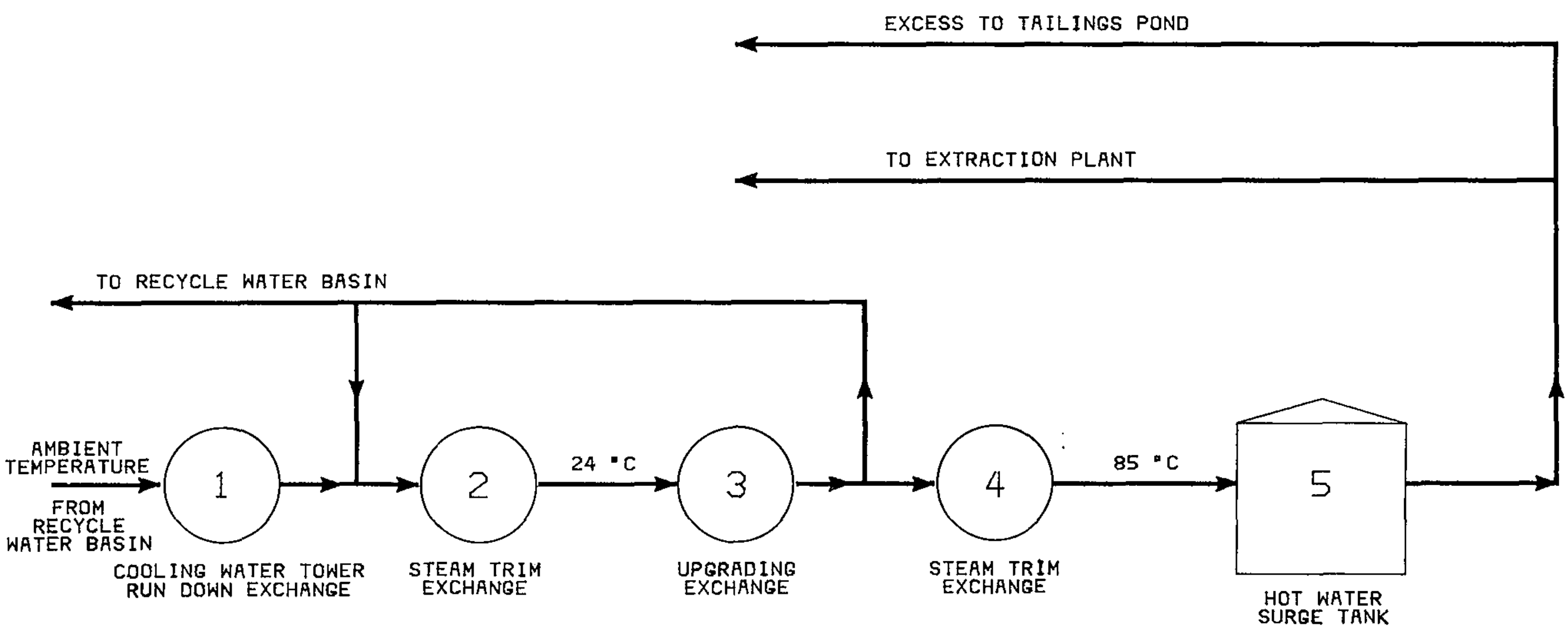
Note: Stream Day Basis.



ALSANDS PROJECT GROUP

SIMPLIFIED UTILITY
FLOW SCHEME

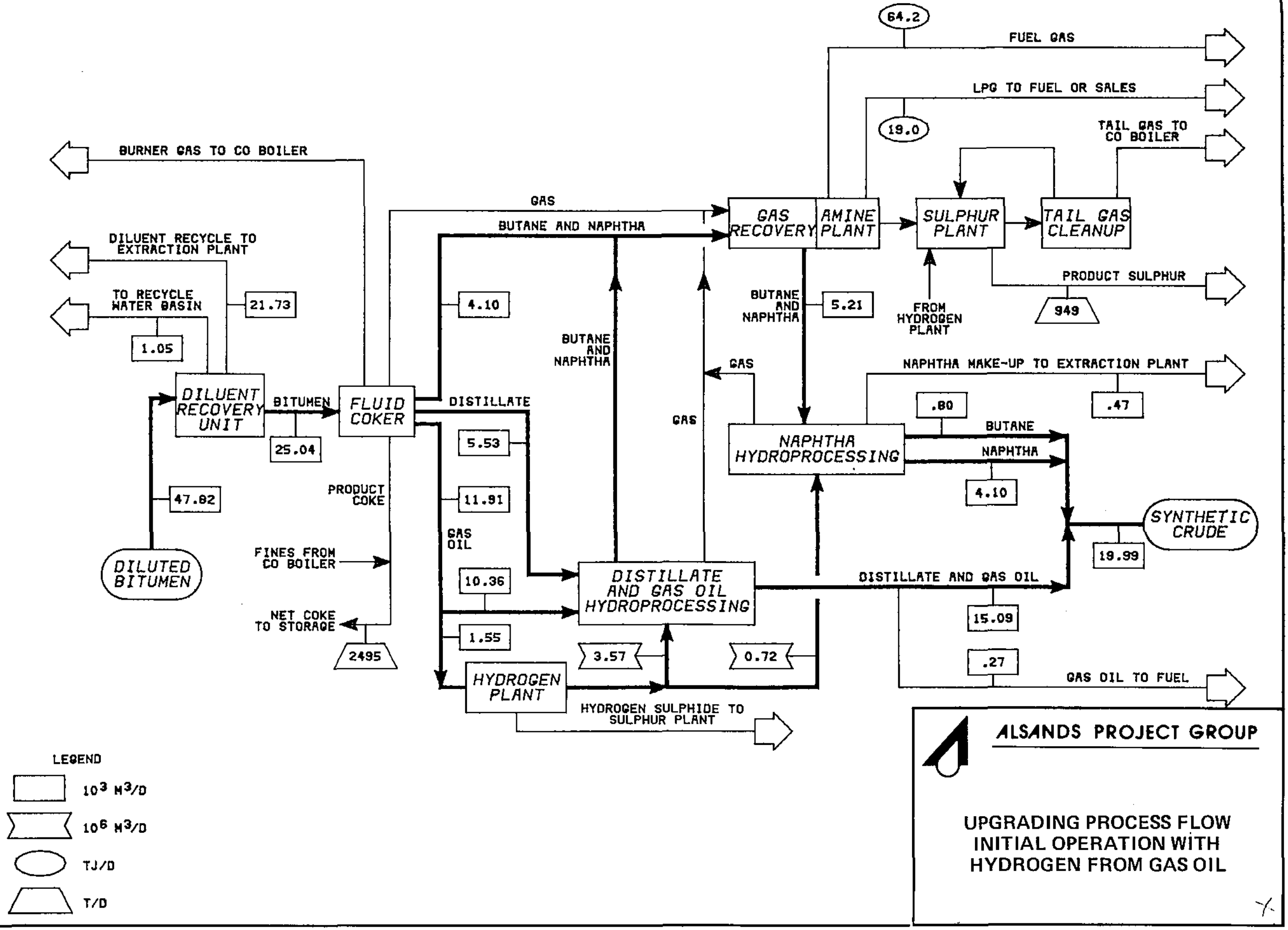
FIGURE IX-1



ALSANDS PROJECT GROUP

SIMPLIFIED INTEGRATED WATER SYSTEM— UPGRADING COOLING/ EXTRACTION HOT WATER

FIGURE IX-2



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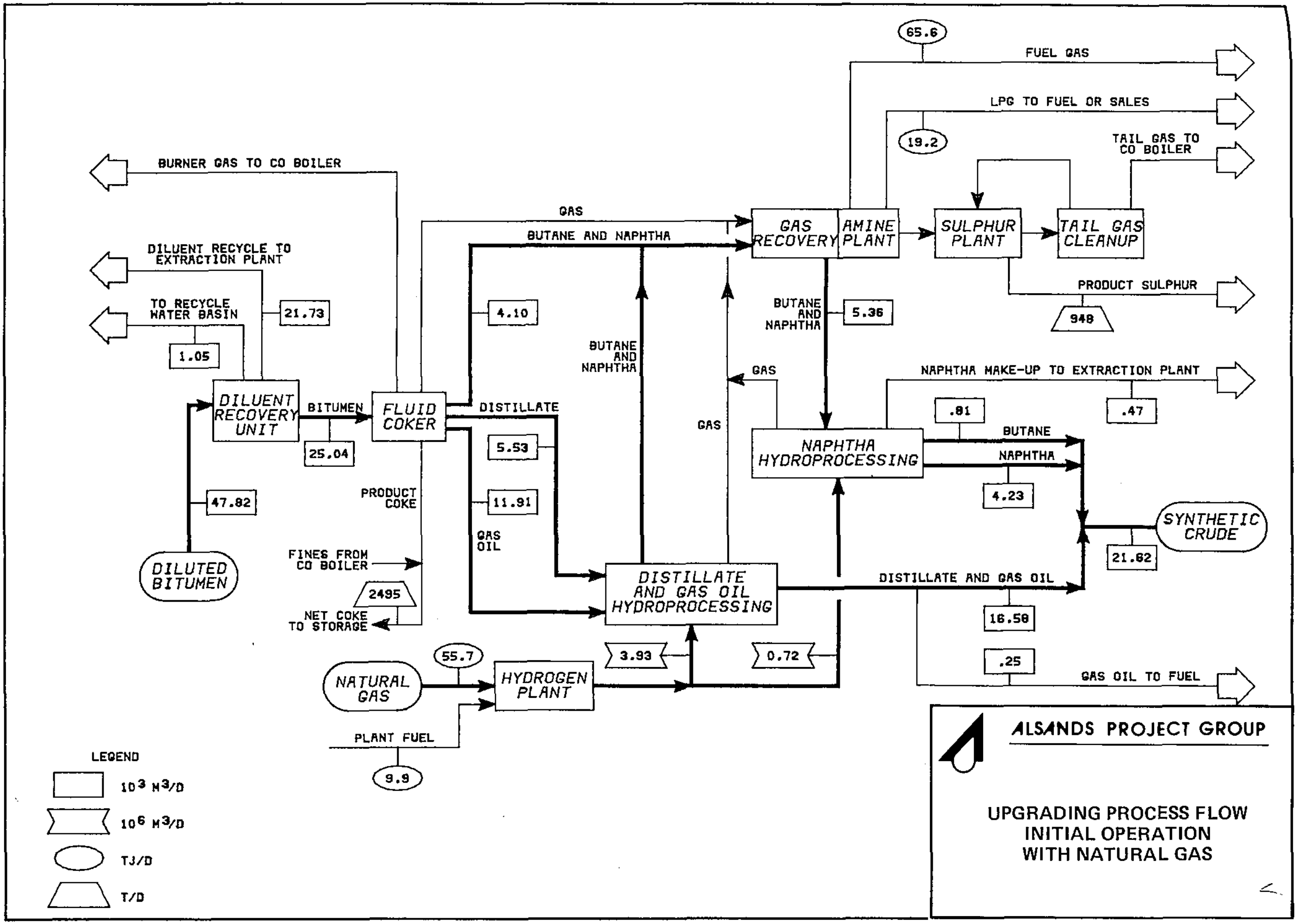
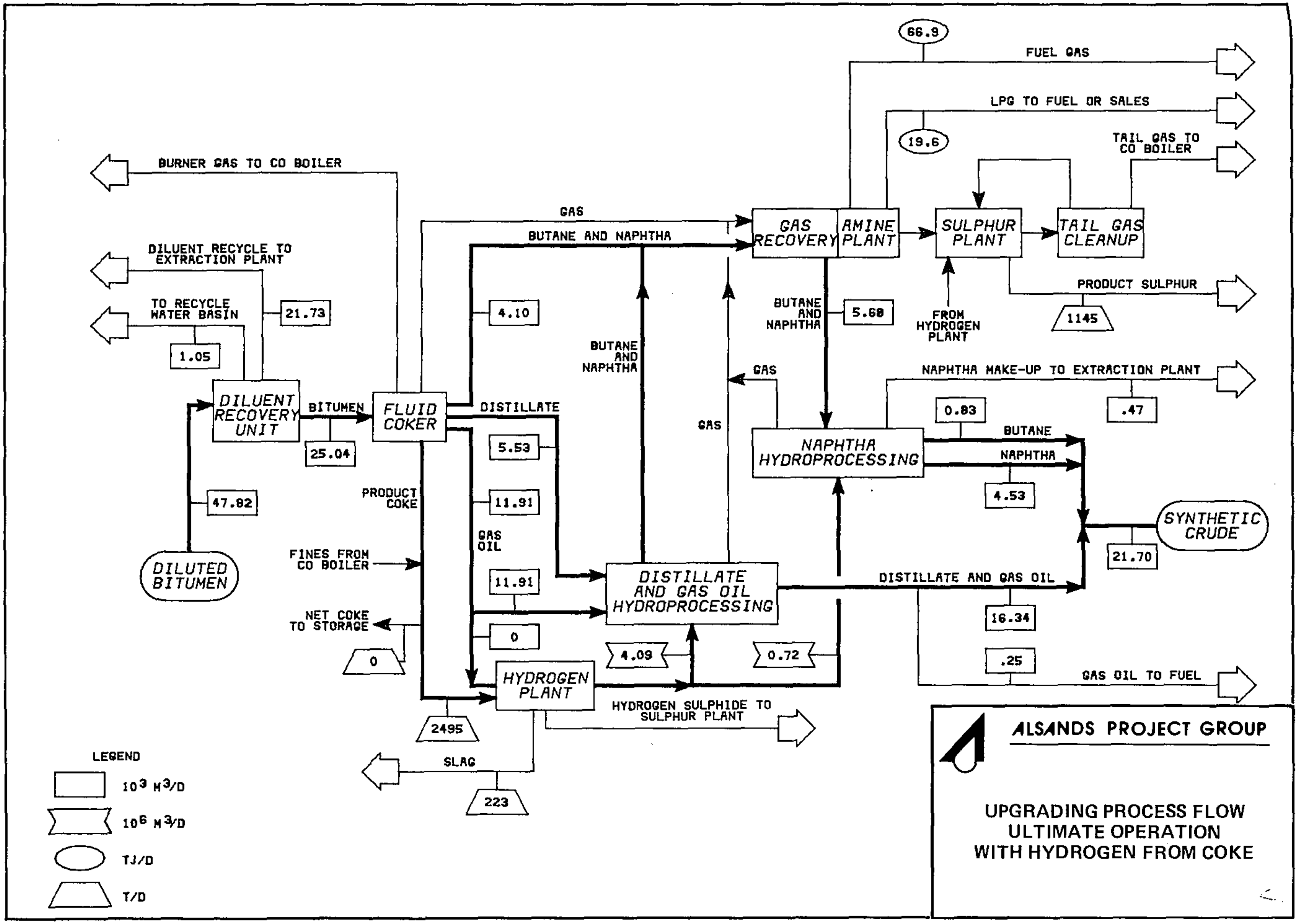
UPGRADING PROCESS FLOW
INITIAL OPERATION WITH
HYDROGEN FROM GAS OIL

FIGURE IX-3



FUEL GAS
65.6
LPG TO FUEL OR SALES
19.2
TAIL GAS TO CO BOILER
BURNER GAS TO CO BOILER
GAS
BUTANE AND NAPHTHA
GAS RECOVERY
AMINE PLANT
SULPHUR PLANT
TAIL GAS CLEANUP
DILUENT RECYCLE TO EXTRACTION PLANT
21.73
TO RECYCLE WATER BASIN
1.05
4.10
BUTANE AND NAPHTHA
5.36
PRODUCT SULPHUR
948
BUTANE AND NAPHTHA
GAS
NAPHTHA MAKE-UP TO EXTRACTION PLANT
.81
.47
DILUENT RECOVERY UNIT
BITUMEN
FLUID COKER
DISTILLATE
GAS
NAPHTHA HYDROPROCESSING
BUTANE
NAPHTHA
25.04
5.53
4.23
47.82
PRODUCT COKE
11.91
GAS OIL
SYNTHETIC CRUDE
21.62
DILUTED BITUMEN
FINES FROM CO BOILER
2495
NET COKE TO STORAGE
DISTILLATE AND GAS OIL HYDROPROCESSING
DISTILLATE AND GAS OIL
16.58
.25
GAS OIL TO FUEL
55.7
3.93
0.72
NATURAL GAS
HYDROGEN PLANT
PLANT FUEL
9.9
LEGEND
10^3 M^3/D
10^6 M^3/D
TJ/D
T/D
ALSANDS PROJECT GROUP
UPGRADING PROCESS FLOW
INITIAL OPERATION
WITH NATURAL GAS

FIGURE IX-4


66.9
FUEL GAS
LPG TO FUEL OR SALES
19.6
TAIL GAS TO CO BOILER
BURNER GAS TO CO BOILER
GAS
BUTANE AND NAPHTHA
GAS RECOVERY
AMINE PLANT
SULPHUR PLANT
TAIL GAS CLEANUP
DILUENT RECYCLE TO EXTRACTION PLANT
21.73
TO RECYCLE WATER BASIN
1.05
4.10
BUTANE AND NAPHTHA
5.68
FROM HYDROGEN PLANT
PRODUCT SULPHUR
1145
BUTANE AND NAPHTHA
GAS
NAPHTHA MAKE-UP TO EXTRACTION PLANT
.47
0.83
DILUENT RECOVERY UNIT
BITUMEN
FLUID COKER
DISTILLATE
GAS
NAPHTHA HYDROPROCESSING
BUTANE
NAPHTHA
25.04
5.53
4.53
PRODUCT COKE
11.91
47.82
GAS OIL
SYNTHETIC CRUDE
21.70
FINES FROM CO BOILER
DILUTED BITUMEN
DISTILLATE AND GAS OIL HYDROPROCESSING
DISTILLATE AND GAS OIL
11.91
NET COKE TO STORAGE
16.34
0
0
4.09
0.72
.25
HYDROGEN PLANT
GAS OIL TO FUEL
2495
HYDROGEN SULPHIDE TO SULPHUR PLANT
LEGEND
10^3 M3/D
10^6 M3/D
TJ/D
T/D
SLAG
223
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UPGRADING PROCESS FLOW
ULTIMATE OPERATION
WITH HYDROGEN FROM COKE

FIGURE IX-5

X Offsite Facilities

Introduction

Certain offsite facilities will be required to support and service the Project. These include housing accommodation and community facilities for the permanent plant staff, roads and bridges for access, synthetic crude pipeline, natural gas pipeline, power line, water supply line, and a telephone communications system. In addition, the need for marshalling yards, and rail and air access must be considered. Table X-1 shows the estimated capital cost and manhours of work generated by each activity.

Living Accommodation

The completed plant will require an estimated 2500 employees for operation and maintenance. With allowances for service sector employment and families, this will result in an estimated population increase of 13 500 in the area.

Community alternatives being considered are:

expansion of Fort McMurray
developing a new town site closer to the proposed new plant

EXPANSION OF FORT MCMURRAY

The current population of Fort McMurray is approximately 24 500. There is an adequate service sector base which should improve over the next few years as Syncrude development activity levels off. Although the addition of another 15 000 people to the town would again cause a large impact, the town has developed plans for such an event. Designated new development areas surrounding the town have been set aside, any one of which would be large enough to accommodate the Project housing requirements.

The principal problem with housing the people in Fort McMurray is the extended time required for the operating staff to travel to and from work. The plant will be approximately 75 km (50 miles) from Fort McMurray which would involve approximately 2 1/2 hours travel time per day for a round trip.

NEW TOWN

Studies conducted for industry, the Alberta Government and the North-East Alberta Regional Commissioner have indicated preference for the establishment of a new town in the vicinity of the plant site (Underwood McLellan and Associates – 1973, Ekistic Design Consultants – 1975).

These studies concluded:

* *Development of a new town north of Fort McMurray would be in the long term interests of developing North-East Alberta*
* *The town site should be located on the east side of the Athabasca River and West North-West of McClelland Lake as shown on Figure X-1. This location would reduce the travel time by approximately 1 1/2 hours per day for a round trip, in comparison to commuting from Fort McMurray*
* *The town plan should allow for an initial population of about 12 000 people with a capability of phased development to 45 000*
* *The new town development could be timed coincident with the development of the Applicant's Project*

As a result of these studies, the Applicant has concluded that housing permanent operating staff in such a new town would be preferable to Fort McMurray if appropriate developmental and financial support arrangements can be developed with the Provincial Government.

If a new town is to provide the community facilities and housing for the Applicant's work force and to ensure timely and efficient development, a development authority will likely be established with the power to effect the necessary work. The Applicant is prepared to work closely with such a Development Authority and with appropriate government departments to ensure the necessary planning and agreements are put in place in a timely fashion.

The total cost of the town is estimated at approximately $500 million (1978), distributed approximately as follows:

Housing (excluding services)	$225 million
Services and Infrastructure	100
Industrial and Business	140
Offsite Utilities	50
Urban design	25

These costs are not included in the Applicant's capital cost estimates.

Utility Corridor

RATIONALE AND LOCATION

The Applicant proposes that all of the utilities required for both the plant and town be located in a narrow corridor located near the top of the bank of the Athabasca River. The facilities in the corridor will include a highway, synthetic crude pipeline, gas pipeline, power line, and water line. The corridor will follow the general routing shown in Figure X-1. A typical cross section of the utilities in the corridor is shown in Figure X-2. The corridor is shown at 180 m (540 ft) wide with room for expansion to 240 m (720 ft). The corridor concept is examined in a multi volume study (Alberta Oil Sands Corridor Study Group, June 1974). The report strongly recommends the corridor concept for developments of this nature in order to minimize environmental damage by careful selection of a single route for all facilities needed to service a newly developed region.

HIGHWAY AND BRIDGE

In order to gain access to the plant and new town site, it will be necessary to extend Highway 963 north from the Syncrude Plant to a location 5 km (3 miles) south of Fort MacKay. The road will then cross the Athabasca River via a bridge and proceed north along the east side of the river to the new town site. The total length of the new highway will be approximately 58 km (36 miles). The highway and bridge will be constructed and maintained by Alberta Transportation. A 5 km (3 mile) access road will be built by the Applicant to connect the new highway to the plant site.

The highway is planned to be a high quality two lane road with a 14 m (44 ft) wide finished pavement surface, two 4 m (12 ft) wide running lanes and 3 m (10 ft) wide shoulders. The total cost of the new road is estimated to be $43 million (1978).

The Athabasca River bridge will be approximately 430 m (1300 ft) long, with a curb width of 10 m (33 ft) carried on girders so there will be no vertical clearance problem. A pier to pier distance of 100 m (330 ft) and a vertical clearance of 18 m (60 ft) will be provided over the navigable channel to permit barge traffic to operate. The bridge, which is currently under construction, is designed to HS25 standards, which will accommodate a gross overload of 410 t (450 ST) with a special vehicle. The total cost of the bridge is estimated at $15 million (1978).

SYNTHETIC CRUDE PIPELINE

A pipeline will be required with capacity to ship approximately 27 000 m^3/sd (170 000 B/SD) of synthetic crude from the plant site to the market. Two oil pipelines from Edmonton to the Fort McMurray area presently serve the GCOS and Syncrude plants. The GCOS owned line is 407 mm (16 inches) in diameter, and the Syncrude line, owned and operated by Alberta Oil Sands Pipelines Ltd., is 560 mm (22 inches) in diameter.

Neither system as currently equipped has sufficient capacity to handle the anticipated production from the proposed plant. However, the AOSPL system capacity could be upgraded by adding additional equipment to handle the anticipated new production. This upgrading would cost approximately $50 million (1978). The Applicant is also studying the advantages and economics of other options including a separate pipeline.

If the AOSPL system is expanded to handle the Applicant's needs, a trunk line would be constructed from the new plant site to AOSPL's pump station south of the Syncrude plant. The line would likely consist of 50 km (32 miles) of 508 mm (20 inch) pipe and a booster pump station. These facilities would cost approximately $10 million (1978). This figure has not been included in the Applicant's Project cost estimate. The entire system would be constructed in a one year period, probably in 1984.

Although ownership of the pipeline has not been determined, on a tariff basis the shipping cost is estimated at $0.06/$m^3$ ($.40/Bbl) (1978) from the plant to Edmonton.

GAS PIPELINE

Natural gas will be required for heating the construction camps and the proposed new town, and during the construction and operation of the plant and mine. Full-time use of natural gas in plant operation is also under consideration as discussed in Chapter IX.

Natural gas is presently supplied to the Fort McMurray area by two pipelines. The first is owned and operated by Albersun Pipeline Ltd., a wholly owned subsidiary of Sun Oil Company Limited. It supplies gas to the GCOS plant, the town of Fort McMurray and the Amoco in-situ test site at Gregoire Lake. The line is 254 mm (10 inches) nominal diameter with a working pressure of 6200 kPa (900 psi). It runs approximately 270 km (170 miles) from Atmore to the GCOS plant via Fort McMurray. Gas is supplied by six fields in the Atmore area. The line is also tied into the AGTL system.

The current peak demand by users of this line is as follows:

GCOS		510×10^3 m^3/d (18 MMSCF/D)
Fort McMurray	summer	282×10^3 m^3/d (10 MMSCF/D)
	winter	564×10^3 m^3/d (20 MMSCF/D)
Amoco		56×10^3 m^3/d (2.0 MMSCF/D)

The capacity of the line is approximately 1130×10^3 m^3/d (40 MMSCF/D) but could be increased to approximately 2100×10^3 m^3/d (75 MMSCF/D) by starting up an existing compressor station in the line.

The second line is owned by Pelican Pipelines Ltd. and operated by Simmons Pipeline Ltd. to supply gas to the Syncrude Plant. The line is a 407 mm (16 inches) nominal diameter with a working pressure of 8300 kPa (1200 psi). It runs approximately 270 km (170 miles) north from Atmore to the Syncrude

Plant. Gas is supplied by four fields north of Atmore. The line is also tied in to the AGTL system.

Syncrude's estimated consumption will average 1830×10^3 m^3/d (65 MMSCF/D). With additional compressor stations the line could handle in excess of 5000×10^3 m^3/d (180 MMSCF/D).

New gas requirements in the area as a result of the construction and operation of the Project, assuming that the use of gas for the manufacture of hydrogen in the Plant is selected, are estimated as follows:

1982–1985	Construction Camps 8000 people maximum	200×10^3 m^3/d (7 MMSCF/D) (winter peak)
1986–Onwards	New Town 12 000 people	282×10^3 m^3/d (10 MMSCF/D) (initial winter peak but increasing as town grows)
	Plant	1830×10^3 m^3/d (65 MMSCF/D) (initial period)

Based on the current surplus capacity in the Albersun and Simmons gas lines, the above increase in demand could be met by constructing a 58 km (36 mile) line from the GCOS/Syncrude area to the new town, a 5 km (3 mile) spur into the plant, and probably at least one compressor station.

The cost in 1978 dollars of providing the above facilities is estimated as follows:

407 mm (16 inch)	–GCOS/Syncrude Area to Plant Site	\$5.3 million
254 mm (10 inch)	–Plant Junction to New Town	2.9
Compressor Station		2.5
TOTAL		\$10.7

Approximately one year would be required for design and materials procurement, and approximately three months for construction. The Applicant has assumed this pipeline will be owned by others.

POWER LINE

A power line will be required for the construction camps and new town, for standby power for the plant, and to accommodate dragline power demand peaking.

Alberta Power presently supplies power to the Fort McMurray area through a 240 kV transmission line from the Mitsue substation via Wabasca to the Syncrude Plant. A 144 kV line connects Fort McMurray to the grid from the Syncrude substation.

The Applicant proposes to use the power line to absorb dragline peaking at the plant, with only intermittent purchases. New power requirements in the area as a result of the construction and operation of a new oil sands plant will be basically limited to those of the construction camps and the new town, estimated peak at 20 Mw in winter. This can be handled by an extension of the existing system, which would consist of:

* a 240 kV line from the Syncrude substation to the plant site
* a 72 kV line from the plant site to the new town site

* modifications to the Syncrude substation
* two 240 kV to 72 kV transformers at the plant site
* two 72 kV to 25 kV transformers at the town site
* telecommunications equipment for load control, line and substation monitoring.

WATER SUPPLY LINE

A water supply line will be required to provide water for the total plant complex. The water would be obtained from the Athabasca River at a point east of Ings Island as shown in Figure IV-1. A settling pond will be created by a dam in an abandoned channel in the river valley. The water would be delivered to the plant through a 1400 mm (56 inch) pipeline approximately 12.5 km (8 miles) long. High head pumps would be located at the river bank. The line would be located in the proposed utility corridor as shown in Figures X-1 and X-2. The system, including the dam, pumps and pipeline and water requirements, is more fully described in Chapter VI. The $7.5 million construction cost is included in the cost of the plant.

Telecommunications

Temporary communications facilities will be required to serve the various construction sites, and eventually, the plant and the new town of 12 000 people. All temporary and permanent facilities would be connected by microwave radio and would include television to the town site. There would be no significant impact on the Fort McMurray phone system if a new town is built. The facilities would be owned and operated by Alberta Government Telephones.

The total cost of the temporary facilities would be approximately $530 000 (1978). About one year would be required to design and construct the temporary facilities which would be used for the first two years of construction.

The total cost of the permanent facilities would be approximately $10.4 million (1978). About two years would be required for design and construction.

Rail Access

Rail access to the region is available only as far as Fort McMurray. The Applicant does not expect to propose an extension of rail to the plant or town site. An extension could not be completed in time to assist in plant construction.

Air Access

During the initial construction phase, an existing 1200 m (4000 ft) long airstrip will be utilized to service the site. The airstrip is approximately 4 km (2.5 miles) south of the plant site, and a temporary road would be constructed to connect the two. There is another airstrip approximately 1030 m (3500 ft) long at Bitumont, and a winter trail which passes within 2 km of the proposed town site could be used during the inital phases of the town construction.

However, as the construction work force increases and to service the long-term needs of a new town, a new 1800 m (6000 ft) airstrip equipped with temporary facilities capable of handling large aircraft such as the Boeing 737 or Hercules, will be required. A possible site has been selected by the Applicant approximately 8 km (5 miles) south of the town site and 4 km (2.5 miles) east of the proposed new highway as shown on Figure X-1. It would be desirable to have the airstrip operational, together with the construction of that portion of the new highway connecting town site, air strip and plant site, by the third quarter of 1980. The total cost of the system would be approximately $2.0 million (1978). Initially, the airstrip would be owned and operated by the Applicant, but as the new town develops and the plant becomes operational, satisfacto arrangements are anticipated with Alberta Transportation or MOT to take ov the airstrip and provide permanent facilities.

Marshalling Yard

A marshalling yard of approximately 40 ha (100 acres) will be required. Tl Edmonton area has been selected due to labour availability, lower overall labo cost, and minimum impact on the community. The yard will contain an offi building, warehouse, prefabrication shops, laydown and storage area and fabric tion erection area. The labour force at the yard will peak at approximate 1100 people in mid-1983.

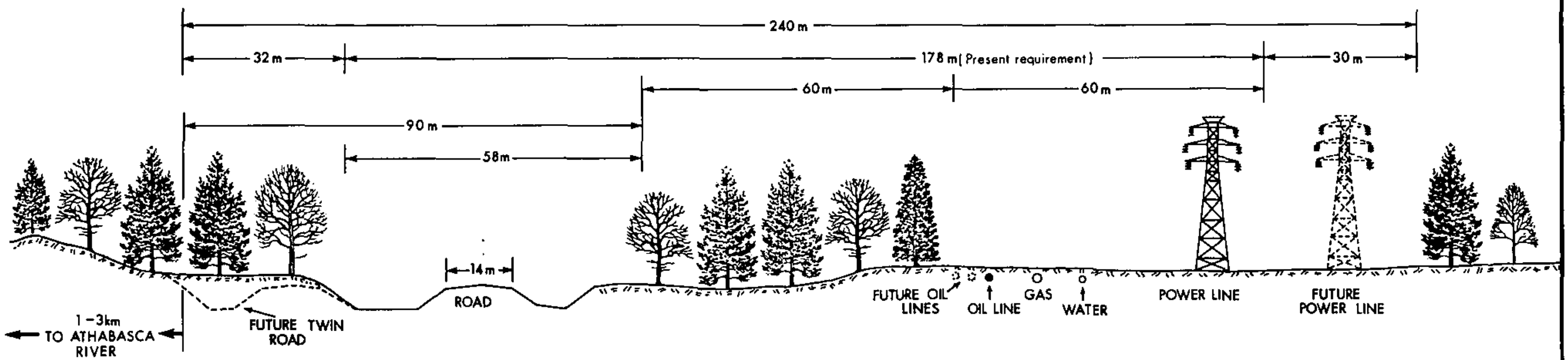
The yard and the type of work to be performed are discussed in more det in Chapter XI on Project Engineering and Construction.

TABLE X-1

ESTIMATED LABOUR GENERATED BY OFFSITE FACILITIES

FACILITY	CAPITAL COST ($ × 10^6 1978)	CONSTRUCTION LABOUR (1000 MANHOURS)
Town		
Housing	225	5000
Services and Infrastructure	100	2000
Industrial and Business	140	2000
Other	75	1200
Road and Bridge	58	810
Synthetic Crude Line	60	1200
Natural Gas Line	11	150
Power Line	10	100
Telecommunications	11	85
Air Access	2[1]	75

Note:
1. Included in Applicant's cost estimate



ALSANDS PROJECT GROUP

TYPICAL UTILITY CORRIDOR
CROSS SECTION

FIGURE X-2

XI Project Engineering and Construction

Project Management and Engineering Services

The Applicant intends to execute the Project utilizing contracting firms who have expertise in managing large projects as well as relevant technical experience. Alberta/Canadian content will be maximized in all phases of the Project, including management, engineering, procurement and construction. The type of management structure needed to carry out the Project is currently being reviewed. A joint venture formed to manage the Project and clearly aimed at developing long term Canadian project management expertise will be considered. To meet the schedule as shown in Figure XI-1 a decision on the Project Management structure and selection of the contracting firm(s) is required during the last quarter of 1979.

Alberta/Canadian engineering contractors, consulting engineers, and construction service companies will be utilized on the Project to the extent that they are qualified and available. Contracts will be awarded to those firms which provide the greatest Alberta/Canadian content in their bids and engineering proposals, provided that these firms are competitive in quality, price, delivery and technical services.

The total home office manhours required for the Project including engineering, procurement and project management are estimated to be six million.

Project Schedule

The Applicant plans to commence detailed engineering early in 1980 and to follow this closely with equipment selection. Engineering is expected to be 90 percent complete during the first half of 1983.

The Applicant plans to begin plant site clearing and drainage in late 1979. The installation of temporary construction facilities and site grading will commence during the second half of 1980; foundations will begin mid-1981. The plant will be mechanically complete between mid and end of 1985.

Figure XI-1 is a Project schedule showing major engineering and construction milestones. Completion by the end of 1985 is based upon receiving appropriate approvals from Government regulatory agencies, and upon receiving satisfactory agreements on royalties and taxes and other commercial terms by the third quarter of 1979.

Construction Labour Force

The site construction labour force is estimated to peak at 6700 people in 1984, plus an additional peak of 1100 people (in 1983) at a marshalling yard in Edmonton. An estimated 35 million construction manhours will be required for initial plant construction, including modularization and preassembly work at the Edmonton marshalling yard. The Applicant expects the majority of the work force to come from Alberta, and will work with native and appropriate Government agencies to ensure native participation.

Existing apprenticeship and vocational training programs will be supported to ensure the necessary skilled labour will be available for initial plant construction. Onsite training activities which the Applicant is prepared to initiate and support if necessary include industrial workers courses, surveying, rigging and hoisting, electrical, welding, pipe-fitting and insulating.

Modularization Concepts

A marshalling yard for prefabrication, preassembly (module construction) and marshalling of equipment and services will be located in Edmonton. The yard will contain laydown, storage and fabrication/assembly areas, office and warehouse buildings and prefabrication/assembly shops. These facilities will require an area of approximately 40 ha (100 acres).

The marshalling yard construction work force is expected to peak at 1100 at the beginning of 1983. Approximately four million manhours of work will be generated as a result of modularization and marshalling work during the Project construction period. This represents 12 percent of the total estimated field manhours.

Typical marshalling yard activities include:

* General carpentry including forms for foundations, timekeeper and craft labour buildings, temporary office buildings, and tool lock-ups
* Concrete – precast foundations for pumps and pipe supports, precast arches and beams, precast manholes and catch basins
* Fireproofing of pipe supports and vessels
* Electrical – duct bank assemblies, heat tracing of vessels, pumps, etc., skid mounted substations and switchgear
* Insulation of vessels and prefabricated pipe
* Skid mounting small process units and/or parts of larger units (will include pipe, vessels, instrumentation, insulation, electrical, etc.)
* Welder training and testing
* Warehousing and material control
* Purchasing including traffic and expediting.

Transportation

The Applicant has made preliminary investigations into the preferred modes of transportation for equipment, materials and people. Freight will be carried to the job site primarily via truck. Rail facilities will be used as far as Fort McMurray as required.

The transportation network from Fort McMurray to the plant site prior to completion of the bridge across the Athabasca River (expected at end 1981) is expected to include a combination of road, river ferry barge, ice bridge and air, depending on the season. Transport of people to the job site will be primarily by aircraft until the bridge is completed.

The Applicant expects to transport approximately 800 000 t of freight during the construction period, as detailed on Figure XI-6.

Construction Camp

Accommodation at the site will be provided for both male and female manual workers on a single status basis in accordance with the Alberta Building Trades Council requirements. The Applicant plans to investigate the feasibility of providing accommodation for married couples, either through establishing a trailer park on site or by designing the single status camp to accommodate them.

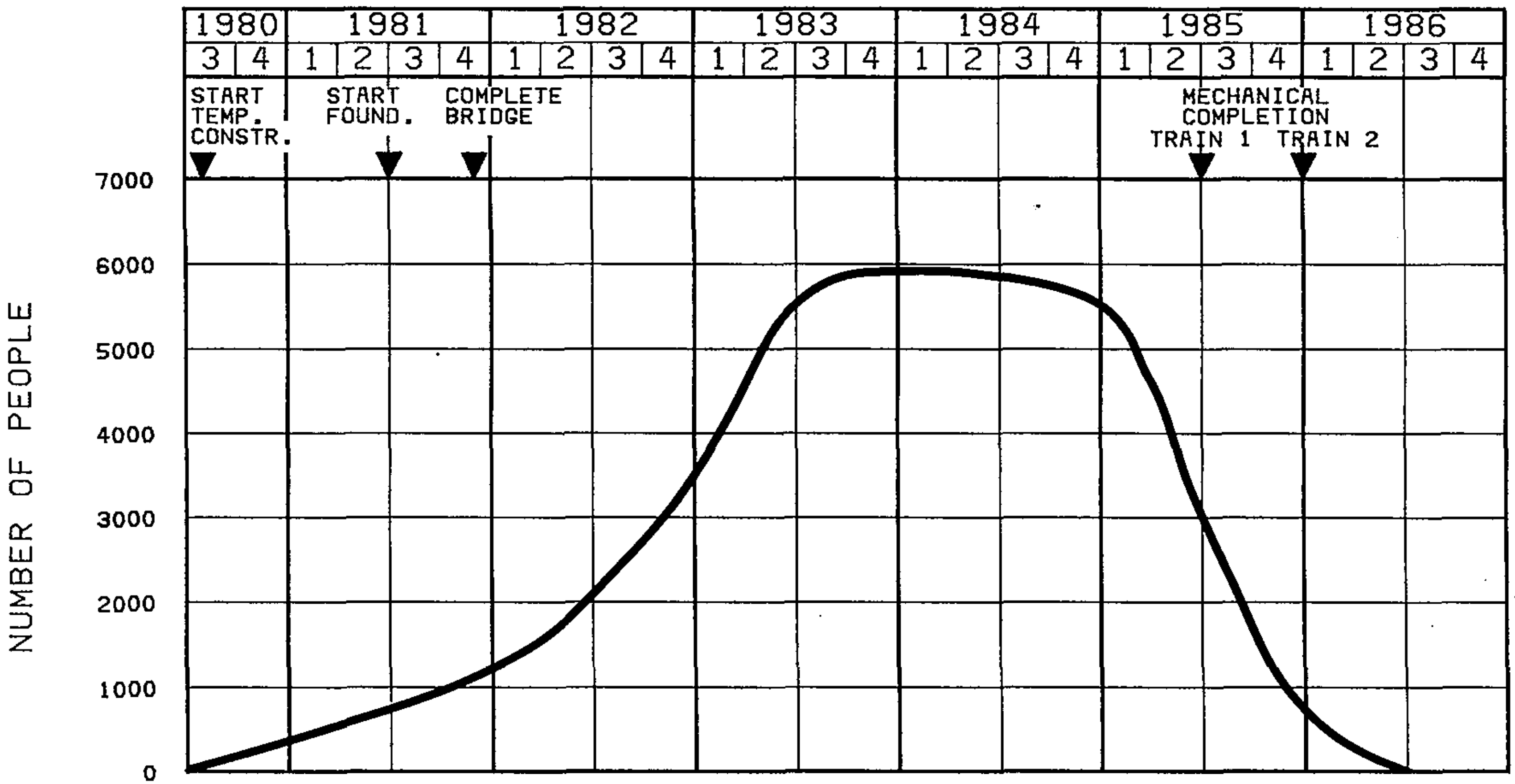
Non-manual workers will either be accommodated in the single status camp, in separate trailers at the site, or will commute from their permanent residence.

Provision will be made for a peak camp requirement of 6500 people. The estimated phasing of the camp requirement is shown in Figure XI-7. Suitable dining and kitchen complexes as well as recreation facilities will be provided.

The job site will be as complete and self-sufficient in leisure and recreation facilities as possible, to maintain good morale on the Project. Amenities such as medical facilities, security, church services, library, post office, bank, dry cleaners, commissary, and a restaurant will be provided as required by the Alberta Building Trades Council.

Labour Relations

The Applicant will be working with contractors and labour organizations to ensure a cooperative effort on labour agreements and other matters necessary for provision of the labour force for construction of the Project.



NOTE: INCLUDES - ABSENTEEISM
- CONTINGENCY AND CHANGE ORDERS
- TURN-OVER AND OTHER

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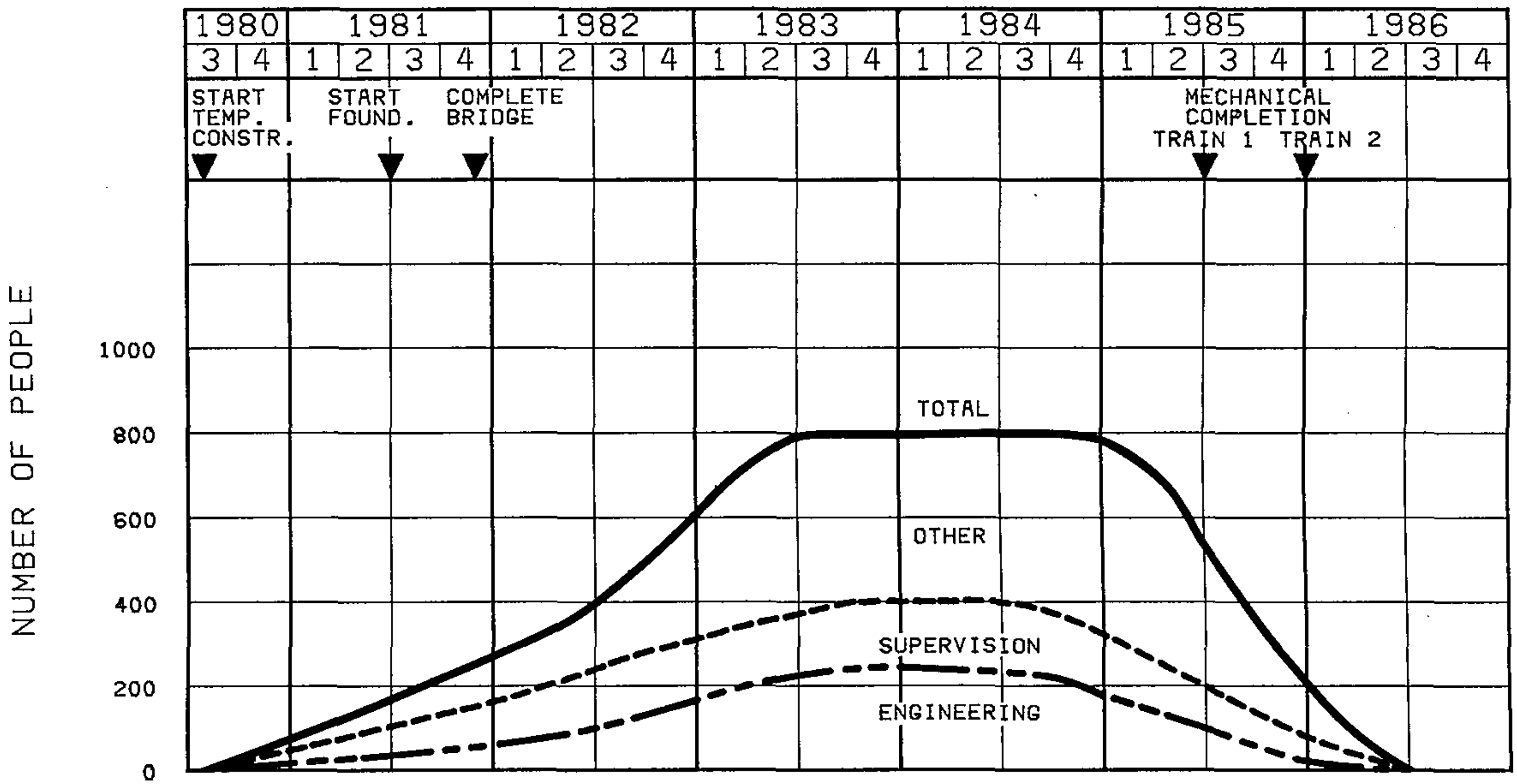
TOTAL MANUAL FORCE JOBSITE

FIGURE XI-2



NOTE: INCLUDES - ABSENTEEISM
- CONTINGENCY AND CHANGE ORDERS
- TURN-OVER AND OTHER

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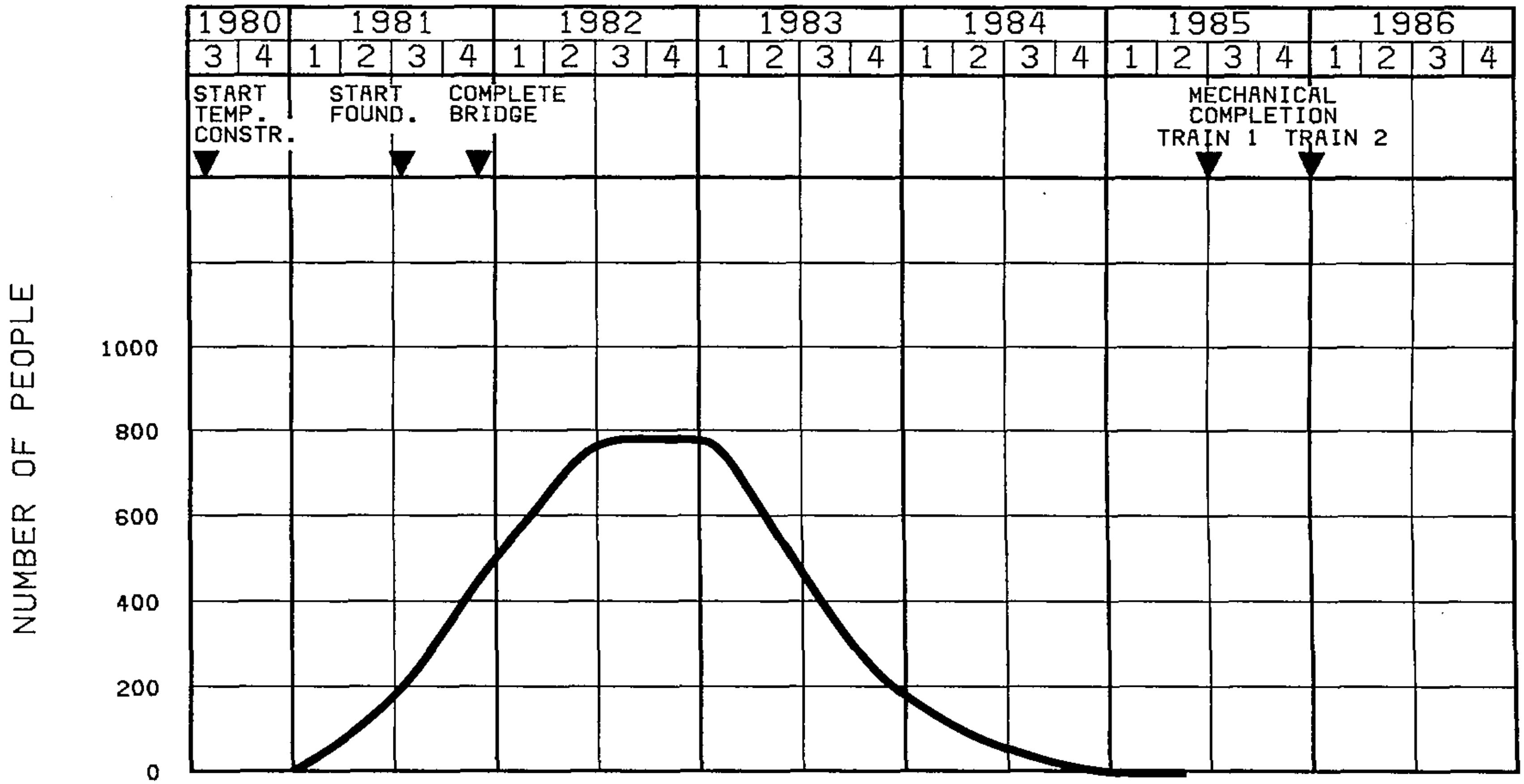
TOTAL NON-MANUAL FORCE
JOBSITE

FIGURE XI-3



NOTE: INCLUDES - ABSENTEEISM
- CONTINGENCY AND CHANGE ORDERS
- TURN-OVER AND OTHER

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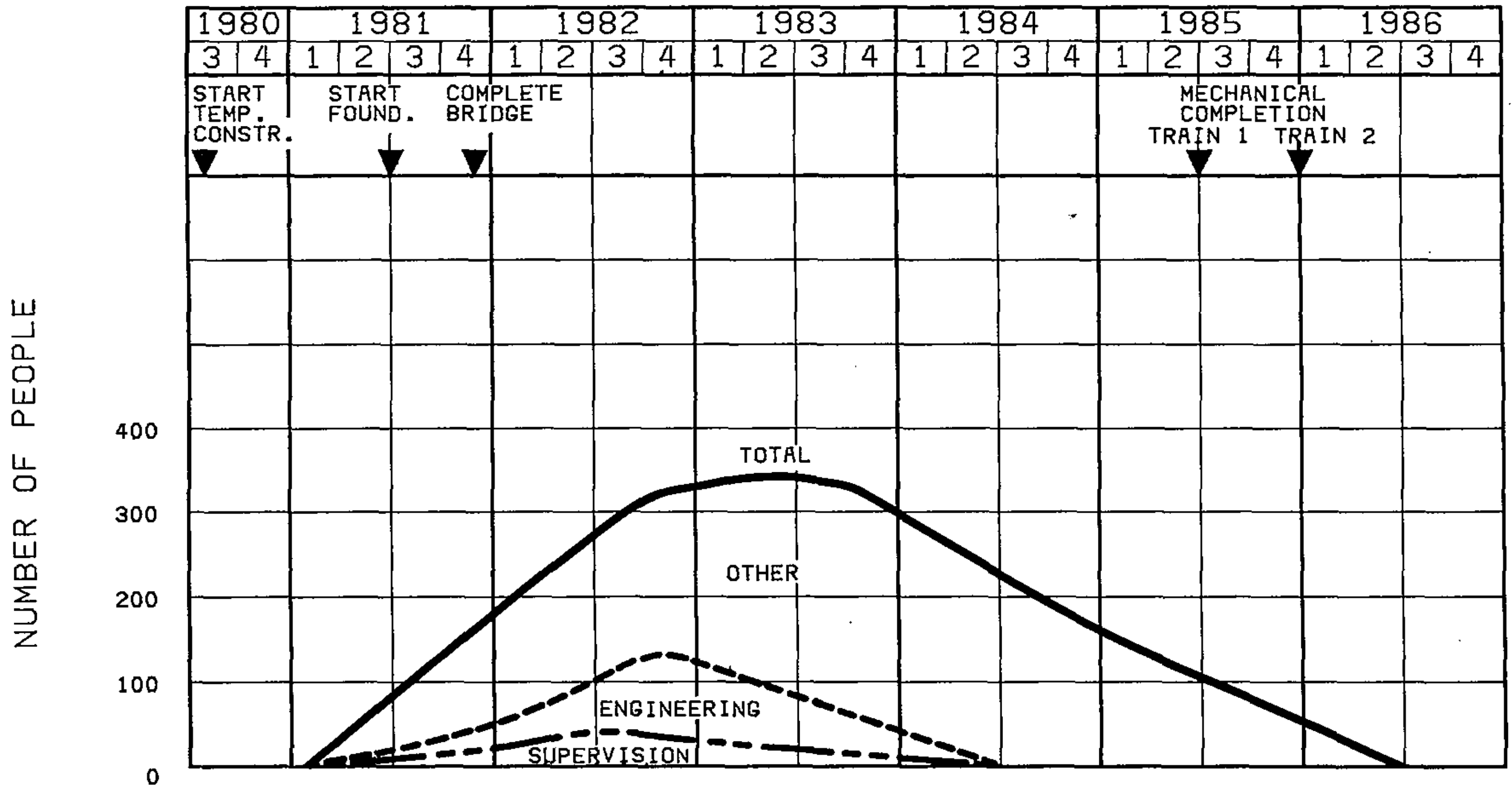
TOTAL MARSHALLING YARD MANUAL

FIGURE XI-4



NOTE: INCLUDES – ABSENTEEISM
– CONTINGENCY AND CHANGE ORDERS
– TURN-OVER AND OTHER

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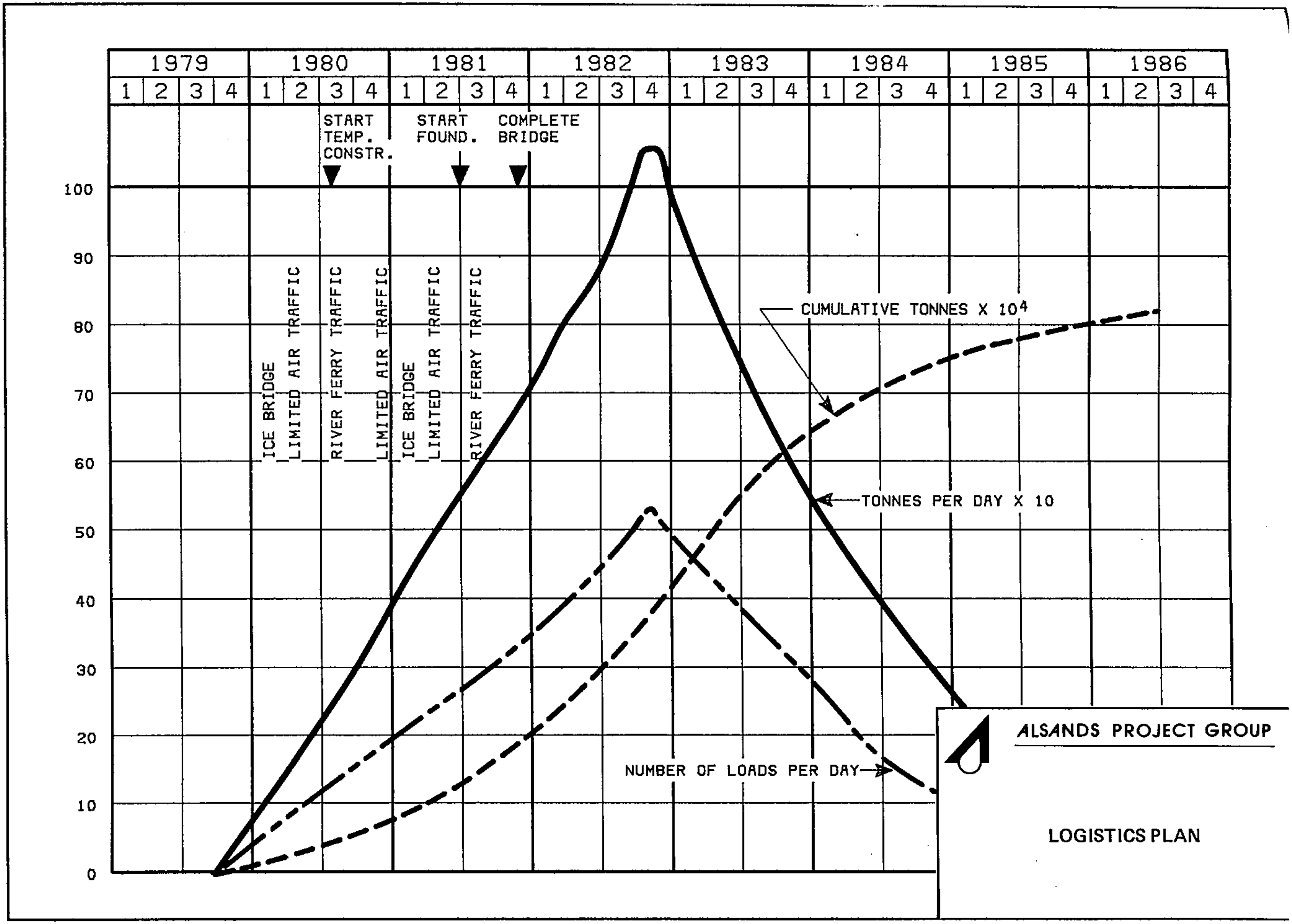
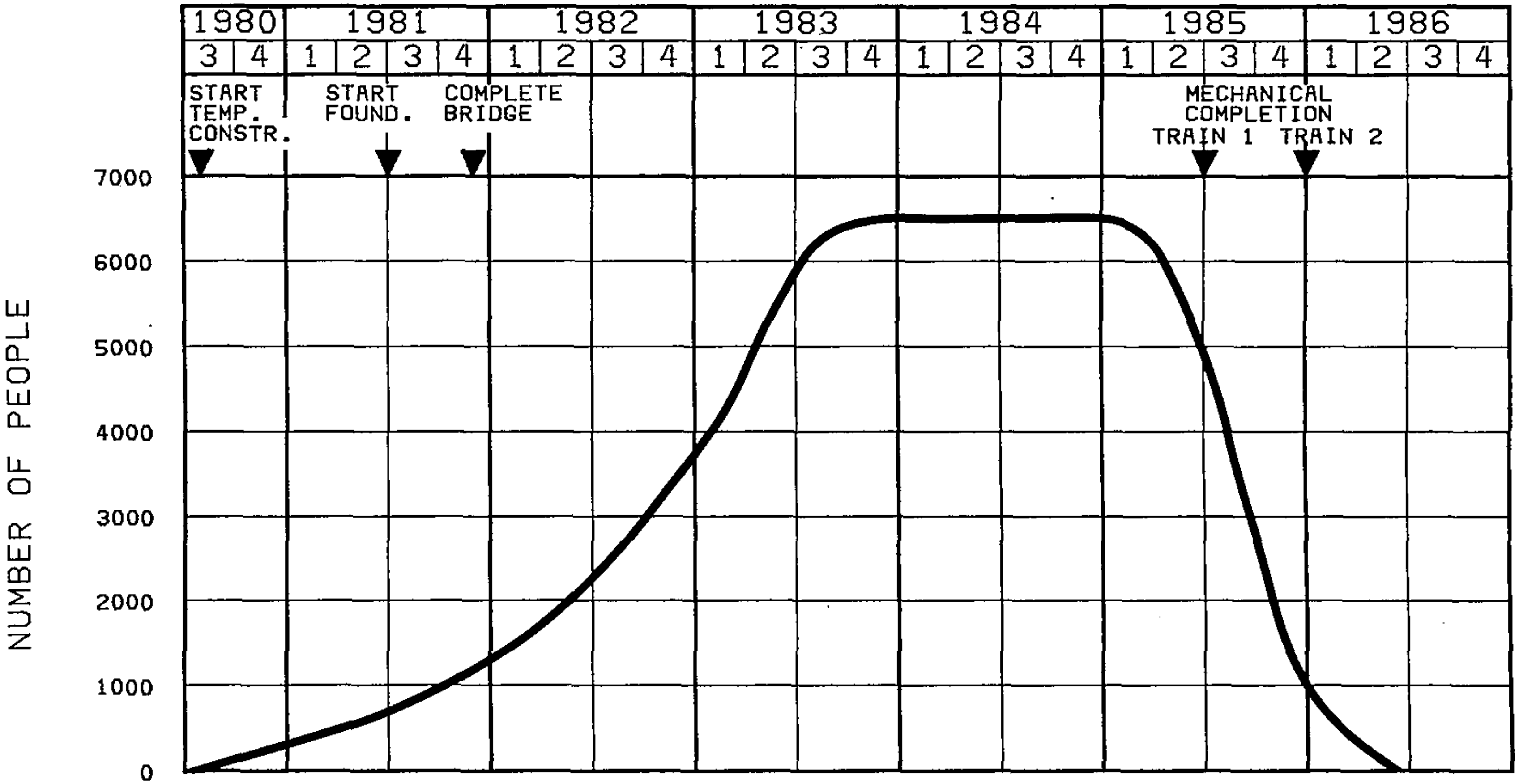
TOTAL MARSHALLING YARD NON-MANUAL

FIGURE XI-5



1979 1980 1981 1982 1983 1984 1985 1986
1 2 3 4
START TEMP. CONSTR.
START FOUND.
COMPLETE BRIDGE
100
90
80
70
60
50
40
30
20
10
0
ICE BRIDGE
LIMITED AIR TRAFFIC
RIVER FERRY TRAFFIC
LIMITED AIR TRAFFIC
ICE BRIDGE
LIMITED AIR TRAFFIC
RIVER FERRY TRAFFIC
CUMULATIVE TONNES X 10⁴
TONNES PER DAY X 10
NUMBER OF LOADS PER DAY
ALSANDS PROJECT GROUP
LOGISTICS PLAN

FIGURE XI-6



NOTE: INCLUDES - ABSENTEEISM
- CONTINGENCY AND CHANGE ORDERS
- TURN-OVER AND OTHER

ALSANDS PROJECT GROUP

TOTAL CAMP REQUIREMENTS AT JOBSITE

FIGURE XI-7

XII Summary of Biophysical Impact Assessment

As noted in previous chapters, The Applicant is applying to the Energy Resources Conservation Board for approval to undertake a major oil sands mining development. The Project will produce up to 22 250 m^3/d (140 000 B/D) of synthetic crude oil and LPG and will involve open pit mining, Bitumen Extraction, Bitumen Upgrading and a utility plant.

The Project will be located 64 km (40 miles) north of Fort McMurray on the east side of the Athabasca River. The community of Fort MacKay is approximately 13 km (8 miles) to the southwest of the plant site, and Edmonton is a further 500 km (300 miles) away. Associated offsite facilities will be developed within the bituminous sands region and a marshalling yard will be developed in east Edmonton.

Introduction

Early in 1978, Alberta Environment formally requested an Environmental Impact Assessment and forwarded assessment guidelines to the Applicant. An approved table of contents was then developed with the Interdepartmental Relations Division of Alberta Environment. Implicit in these discussions was the Applicant's intention to identify, describe and find solutions for environmental concerns at the conceptual Project design level. For this purpose, site-specific environmental information was to be employed in the impact analysis. Baseline terrain, vegetation, faunal, meteorological and archaeological data previously collected by members of the Project group were used, along with results of on-site studies by the Alberta Oil Sands Environmental Research Program.

The Applicant intends to provide environmental protection planning information at a more detailed level when applying for permits required under the Clean Air Act, Clean Water Act and other provincial legislation. The Development and Reclamation Plan will be a prominent vehicle for the transmission of additional information, particularly with respect to runoff control and surface reclamation.

As a result of the assessment, the Applicant believes the level of environmental baseline information available regionally and for the Project Area is adequate in most cases to identify potential effects and determine in a broad sense their scope and significance. Where information appears deficient, additional programs of study are proposed. Similarly, Project information presently available at the conceptual design level is considered sufficient for the initial identification and scoping of environmental concerns. Environmental protection and mitigation procedures are considered feasible on the basis of information at hand, but in many instances will require refinement as the Project proceeds. Environmental input to Project planning through monitoring and other programs will continue on a regular basis for the life of the Project.

The Applicant believes that the environmental consequences of this Project can be controlled or mitigated in a manner generally acceptable to the affected public and to the Alberta government and will work on a continuing basis to ensure a satisfactory level of impact.

Details of the Project are provided in previous sections of this Application. Aspects of greatest importance to the environment are discussed below along with predicted consequences.

Environmental Setting

Main features of local and regional environmental settings are summarized in the following subsections.

LANDFORMS AND SOILS

The Alsands Project Area is a region of low relief bordered on the west by the incised valley of the Athabasca River. The elevation of the valley floor is 235 m (770 ft) ASL whereas the uplands area rises to 315 m (1030 ft) ASL. The underlying Precambrian basement and Palaeozoic formations dip gradually to the west. They are overlain by bitumen-rich sands of the Lower Cretaceous McMurray formation and by more recent glacial-fluvial deposits.

Major topographic features of the region include the Fort Hills to the north and the Birch Mountain and Muskeg Mountain Uplands to the northwest and southeast, respectively. Regional landforms include dunes and eolian blankets, glaciofluvial plains and organic bogs and fens.

The impeded surface drainage pattern of the region has encouraged the development of organic soils, especially Mesisols, which fill depressions over a major part of the study area. Better drained expanses exhibit a variety of mineral soils which reflect the wide geological and topographical diversity of the oil sands region. Soil types such as Eluviated Eutric Brunisols and Orthic Gray Luvisols correspond to glaciofluvial sands which are a dominant parent material.

WATER

Surface Water

The Project Area is within the watersheds of the Muskeg River, its major tributary Hartley Creek and the main stem of the Athabasca River. The area eventually drains into Lake Athabasca through an intricate delta complex — the Peace-Athabasca Delta.

Water quality of the Athabasca and Muskeg Rivers varies seasonally with discharge rates. The average minimum flow of the Muskeg River is $0.6 m^3/s$ (21 cfs), and dissolved solids concentrations are highest during this period. Lowest concentrations are recorded during spring freshet when dilution of groundwater is at a maximum. Chloride ion concentrations of Muskeg River water range between approximately 2 and 30 ppm on an annual basis.

In contrast, greater dilution creates an opposite condition in the waters of the Athabasca River. Chloride ion content averages 10 ppm with a minimum of 2 ppm in the winter. Groundwater discharge is less important as a water supply to the Athabasca River.

Thirty small ponds dot the landscape of the Project Area. Most are features of the poorly drained wetland muskeg which covers 60 percent of the area. Oxbow lakes line the floodplains of both the Muskeg and Athabasca Rivers.

Groundwater

Five aquifers have been identified in the formations which underlie the bituminous sands region. The two deepest are within the La Loche and Methy formations of the Middle Devonian section. Groundwater in deepest units is saline. The Methy aquifer in the Project Area has a total dissolved solids content of 22 500 mg/L, mostly consisting of NaCl (17 700 mg/L). Over 100 m (330 ft) of argillaceous limestone, shale and evaporites separate these waters from those of the McMurray formation, where three water-bearing zones are recognized. The basal aquifer is the deepest and has a total dissolved solids content of around 4100 mg/L, with NaCl (1800 mg/L) and NaHCO3 (1500 mg/L) as primary constituents. The intra-orebody aquifers consist of discontinuous water-bearing zones within the bituminous sands deposits. A shallow aquifer is contained in the sands and gravels of the near-surface strata. This water is regarded as fresh, with a maximum chloride level of 145 mg/L.

THE ATMOSPHERE

The continental climate of northern Alberta is expressed by a large annual temperature range and a summer precipitation maximum. The winter season has severely low temperatures, light winds and consequently strong nocturnal inversions. Snow cover and low solar angle keep surface heating at a minimum and mixing is restricted to a shallow layer above the ground surface. Summer weather conditions may be dry and stable but moist and unstable air masses predominate. These conditions may lead to the formation of weaker nocturnal inversions with daytime mixing layers.

Winds in the area are generally light and westerly. Topographically induced local circulations may develop due to differential heating on sunny days. Mesoscale circulation patterns are also influenced by valley drainage winds which may encourage local valley inversions at night.

Air quality in the region is influenced by emissions from existing sources. A sulphur dioxide monitor in the vicinity of the plant site recorded half hour sulphur dioxide ground level concentrations in excess of 0.2 ppm on 22 occasions over a recent thirteen month period. Other remote stations in the region have occasionally recorded concentrations of carbon monoxide and ozone which exceed Alberta standards over a short-term averaging period. Levels of nitrogen dioxide and total suspended particulates have not been found to exceed ambient air standards.

Biological Resources

VEGETATION

The Project Area lies within the mixedwood subsection of the Boreal Forest Biome of Canada. Vegetation patterns reflect the moisture regime, with aspen, poplar and jack pine characterizing the well drained sites of eolian and alluvial landforms. Black spruce and tamarack stands predominate in poorly drained zones, but give way to sphagnum bogs and fens, where standing water is common. Successional trends in the upland forest zones lead to white spruce dominance. These patterns have become complex in some areas due to frequent fires. The resultant vegetation mosaic includes three categories (peatland, upland forest, and aquatic) and contains nine physiognomic types.

Forestry and agriculture capabilities within the area are limited due to severe climate and wet soils with low nutrient levels. Productive forest zones within the Project Area are of medium site index. The majority are not currently supporting commercial stands. Low commercial ratings have been applied due to the immaturity of the forests and the predominance of low-value aspen. Undisturbed areas may be expected to mature towards higher value stands of aspen-spruce, spruce-balsam-fir and jack pine.

TERRESTRIAL FAUNA

Forty species of mammals, including moose, bison, caribou and black bear are found in the region, but of the larger species only moose and bear occur regularly within the Project Area. The beaver is the most valuable furbearing mammal although the otter, mink, fisher and others are also taken. Seven habitat types have been identified on the Project Area, all with production capabilities reduced by adverse site conditions. Further north the Peace-Athabasca delta provides diverse habitats which attract nesting and breeding waterfowl in great numbers, many of which pass over the Project Area on migration.

AQUATIC FAUNA

Over 25 fish species have been identified in the waters of the Athabasca River drainage. They include wide-ranging species such as goldeye, walleye and lake whitefish which use lakes and streams of the watershed for spawning. Species such as suckers, Arctic grayling and trout-perch feed or spawn in the Muskeg River. Early spring is the main upstream migration period for adults, with fry appearing in the Athabasca during June and July. Larger lakes within the region have been identified as trophy lakes for walleye and pike, but there are no lakes of that type near the proposed Project. There are suckers in some of the Project Area's deeper lakes in summer, but the presence of permanent fish populations is undetermined.

Historical Resources

Archaeological resources in the mixedwood section of northeastern Alberta have been shown to span a 7000 to 8000 year period. During a recent archaeological survey of the Project Area, 329 artifacts were collected at 36 sites clustered along waterways. A site near the temporary airstrip has been tentatively identified as one of potential importance. Paleontological specimens are expected in bituminous sands deposits (plant material) and glacio-fluvial strata (vertebrates).

Basis for Impact Assessment

To identify environmental concerns, elements of the Project were superimposed on existing environmental conditions. Potential environmental effects were rated as negligible, minor or major and scaled in relation to expected magnitude and duration of consequences.

The potential concerns identified and discussed are primarily those anticipted from normal operation of a project designed and constructed with due care for environmental matters, using current and feasible engineering practices.

Offsite developments such as the townsite and utility corridor will not be the sole responsibility of the Applicant and may be subject to other assessments.

Major Environmental Consequences

For purposes of this summary, environmental effects will be reviewed according to the type and source of environmental risk. Several prominent categories have been identified, each of which contains a number of major, minor and negligible concerns. There are:

surface disturbance
surface and groundwater management
atmospheric emissions
new town and utility corridor

SURFACE DISTURBANCE

A major consequence of the Project will be disturbance to approximately 13 500 ha (33 500 acres) of forest and muskeg, 8000 ha (20 000 acres) of which will be the result of development of facilities on the Project Area over a 25 year period (Table XII-1). All terrestrial and aquatic habitats are capable of producing some wildlife and most upland terrain can sustain limited production of commercial timber. The primary facilities will usurp approximately 3000 ha (7500 acres) of uplands and 5000 ha (12 300 acres) of lowlands, the latter mostly bog or fen. Wildlife in those areas will be displaced with little chance for successful colonization of surrounding habitats. The sustained production of an average of five moose per year could be lost through habitat disturbance on the Project Area, as well as the opportunity to trap most species of furbearers. Losses of production will involve a number of terrestrial bird species, some waterfowl, several pairs of common loons and one or more sandhill cranes. Wildlife species classified as rare and endangered are not known to be involved. Similarly, unique land forms are not involved and no rare or endangered plants have been identified on the Project Area.

Timber losses will be evaluated through a timber inventory. A salvage operation will be undertaken in which local permit holders and operators will become involved through appropriate government contracts. There is possibility of minor tree "blowdown" on the edges of cleared areas. The region is subject to periodic fires and forest fire hazard could initially increase through the presence of construction crews. Once the area is cleared, however, and contingency mechanisms are in place the fire hazard should be no greater than before, while the opportunity to control natural fires would be enhanced through the presence of equipment and manpower.

A surface reclamation program with forestry and wildlife land uses as prime objectives will endeavour to restore previous levels of productivity. The reclamation approach will be described in detail in a final Development and Reclamation Plan. The Plan encompasses the following concepts:

*The Applicant proposes to stockpile organic material (muskeg) and provide mineral soils from the overburden layer for use in a soil mix over lean bitumen sands. There is sufficient organic material throughout the Project Area, and recent drilling studies have identified mineral overburden for that purpose. A detailed soil survey will be conducted over the mine area to further evaluate soil suitability for reclamation. Sorting, handling and storage procedures to ensure availability will be developed. Toxicity of overburden will not pose a problem as objectionable materials will be selectively placed into pit bottoms.

*Generally, dyke slopes will be reclaimed with erosion-preventing vegetative cover soon after construction. Revegetation will follow upward along the outer slopes of the dykes as they increase in height. In-pit dyke slopes will be temporarily revegetated if required to reduce erosion, even though the spaces between them and pit walls will eventually be filled with tailings sand.

*The tailings management plan provides a basis for reclamation scheduling. Tailings will be pumped to in-pit storage areas after year eight, with sludge and water brought back to the external tailings pond. When the pits are filled with sand, surfaces will be revegetated. Post-Project monitoring will take place to ensure successful reclamation. The final configuration will consist of an open tailings pond, low, sloping hills over reclaimed pits, and two open pits approximately 716 and 304 ha (1770 and 750 acres) in size. The two final pits would be reclaimed if the Project is extended. Otherwise, they would be filled with water in order to control surface oil build-up, and left as deep lakes. Banks would be sloped and revegetated. Water quality would be monitored and improved, if required.

*Ditches, the gravel area and other disturbed regions will be revegetated as soon as possible after cessation of their use. If the Project is abandoned after 25 years, buildings and equipment would be dismantled and removed and surfaces graded and restored.

*Studies will be undertaken to determine the expected condition of the tailings pond after abandonment, and to evaluate preferred methods of reclamation.

*Experimental vegetation plots will be developed to determine the most appropriate mixes of soil materials, soil amendments and plant species for use on each type of disturbed area.

During site preparation and construction, 26 ponds each over 1 ha (2.5 acres) in size will be lost. Most are shallow muskeg ponds with a role in watershed storage capacity but probably not supportive of permanent fish populations. However not all have been surveyed in winter. Two or three deeper lakes in the area identified as a source of granular resources contain coarse fish species in summer which have been utilized by residents of Fort MacKay. Depending on the final design for gravel resource use, these lakes and their fish populations may be impaired. A scheme for pit development in the granular resource area will be addressed in the Development and Reclamation Plan.

A total of 1 km (0.6 miles) of minor streams could be involved in gravel pit operations south of the Muskeg River. One "reach" may contain fish populations in transit to the above lakes. The Muskeg River and Hartley Creek have been recognized as important fish spawning and rearing areas, and as a result the mine plan has been altered to provide for their protection. Diversion of the Muskeg River is not contemplated during the 25 year mine plan.

The presence of a tailings pond approximately 2100 ha (8 square miles) in size along a major waterfowl flyway from the Peace-Athabasca Delta to the prairies may present an attraction to overflying geese and ducks during spring and fall periods. Hydrocarbons on the surface could harm waterbirds even if slicks were thin and amounts limited. A waterfowl protection program will be implemented during the Project and may be continued after abandonment. Investigative planning will be undertaken to establish the most feasible method of preventing waterfowl-tailings pond interaction.

During the 1974 archaeological reconnaissance, a number of significant sites were discovered. These will be resurveyed and new areas evaluated in 1979. The Applicant believes it unlikely that sites warranting delay in Project initiation will be discovered, but in that event, is committed to study or salvage. The Impact Assessment details a procedure for noting artifacts encountered during site preparation and construction. Similarly, paleontological items of interest that may be discovered during mining or gravel pit development will be noted.

SURFACE AND GROUND WATER MANAGEMENT

Surface Water

The movement of fine, silty materials from glacial drift strata immediately below the muskeg layer could occur if precautions are not taken, with subsequent harm to aquatic habitat of the Muskeg River (Griffiths and Walton, 1978). Management of surface water to prevent siltation of streams during early phases of the Project will be the subject of a detailed drainage management scheme based on experience gained through plant site drainage. Drainage of the plant site in 1979 will be used as a pilot project. Solutions will be found in standard engineering practices. Because of the general lack of relief, control of surface runoff will be accomplished through structures on the ditching system, if required.

There is also potential for the transport of fine sediments from materials exposed during road construction and bridge placement. While some sedimentation is unavoidable, care will be taken during construction to impede ditch flows with mechanical barriers. Revegetation will take place as soon after disturbance as possible. Muskeg River bridge site selection will take into account the potential for persistent erosion at bridge approaches. If necessary, mechanical means of erosion control will be part of the design.

Removal of muskeg will slightly reduce the storage capacity of the watershed. Approximately seven percent of the Muskeg River watershed will be affected over the 25 year period, with the consequence that flood peaks may be slightly intensified and more frequent. In Chapter V it is proposed that settling ponds be constructed if necessary for temporary holding of water pumped to depressurize the basal aquifer. These ponds may be also utilized as emergency storage areas during precipitation peaks. The proposed drainage plan based on hydrological study will provide a basis for determining placement of settling ponds.

Water will be obtained from the Athabasca River to augment recycled water in the processing scheme and to provide potable water to camps. A maximum of 2.8 m^3/s (97 cfs) will be drawn from the Athabasca River and piped along the utility corridor to the plant site. Requirements are less than 2.8 percent of the winter minimum for the Athabasca River and as a result no detrimental effect is expected.

There is potential for escape of contaminants to surface waters around storage areas and emergency ponds, and also for leaching of heavy metals, sulphur or other compounds from storage piles. All storage areas containing potentially toxic materials will be dyked, and surface runoff waters will be impounded on site.

During early years of development, minor seepage is anticipated from the tailings pond. Material will originate from stored sludge and water inside the dykes. Within three years the pond is expected to seal from the inside as fine materials settle from the tailings. As a control measure, the pond will be surrounded by a dyke, an outer ditch excavated to impervious layers and the collected water pumped back into the tailings pond. The quality of water outside the ditch will be monitored. If the ditching arrangement proves inadequate to prevent groundwater contamination, mechanisms such as relief wells or impervious curtains will be investigated. The tailings pond will be constructed in such a manner as to maintain its integrity. Details of dyke construction are shown in Chapter VII.

Sewage from the campsites and solid refuse from all sources will be disposed of in an environmentally acceptable manner. Solid refuse from camps will be incinerated as required with the residue placed in sanitary landfills to be specifically located at a later stage of Project design. The Applicant feels that adequate sites are available in upland terrain units within the Project Area and will monitor adjacent surface and groundwaters as a precautionary measure. Sewage will be treated to government standards of effluent disposal and the effluent transported to the Athabasca River.

Groundwater

The geology of the Project Area sustains three aquifer zones that will be affected by mining. In descending order they are the shallow, intra-orebody and basal aquifers. A fourth zone in the Devonian, the Methy aquifer, will not be directly affected by the Project.

The shallow aquifer flows through surface sands and gravels above the bituminous sands deposits, and is subject to sequential drainage over 25 years as one step in site preparation. In total, 8000 ha (20 000 acres) will be affected. This aquifer and the organic material above it provide most of the winter flow within the Muskeg River, but only a small percentage of the Muskeg watershed will be affected and winter flows should be only slightly reduced. Monitoring of the quantity and quality of water moving through the Muskeg River in all seasons will continue throughout the Project. Should monitoring indicate either a serious reduction in flows or a change in chemical properties, provision will be made for release of stored water in settling ponds. Again, this potential problem will be considered in detail within the drainage portion of the Development and Reclamation Plan.

Intra-orebody aquifers and the basal aquifer will be contacted during the mining process. In order to maintain slope stability, the basal aquifer near areas to be mined will be depressurized through adjacent deep well systems. During most of the mine life, depressurization water will be pumped to the tailings pond and recycled for use in the Extraction Plant. Prior to construction of the tailings pond, depressurization water will be directed through settling ponds into the Muskeg River. This phase will last approximately two years. Since basal aquifer water reaches nearly 4100 mg/L total dissolved solids and depressurization flows are estimated to be in the area of 190-250 L/S (3000-4000 USGPM), there is a potential for significant change in the quality of Muskeg River water during low flow periods. Chloride concentration could rise from 15 to 960 mg/L under average minimum flow conditions and it is expected that this order of change would be detrimental to aquatic fauna. To preclude this effect, storage ponds may be used to hold water for release until there is sufficient water in the Muskeg River for dilution. Sump water from the mine, containing some hydrocarbons from the sands, will also be directed to the ponds where sediments will settle prior to release. Bitumen will be removed via a straw filter system after the water leaves the ponds, an approach that has been used successfully in decanting the test pit water over the last several years.

Hydrological survey results indicate that connection with the Methy aquifer will not occur during the life of the mine. In the unlikely event that a connection develops, the saline Methy water would be transported to a disposal well for reinjection into approved geological formations.

ATMOSPHERIC EMISSIONS

The Upgrading and Utilities Plants could emit from 62 to 91 t/sd (61 to 90 LT/SD) of sulphur, depending mainly on the sulphur content of the coke burned in the Fluid Coker burner as discussed previously in Chapter IX. Emissions will be primarily from a high stack, assumed at this time to be in the range of 183 m (600 ft). Shutdown of one tail gas unit could temporarily produce an additional 20 t/sd (20 LT/SD). At the design level of 62 t/sd (61 LT/SD), neither Alberta government standards nor federal guidelines for ground level concentrations of sulphur dioxide will be exceeded, according to plume dispersion calculations using the model currently approved by Alberta Environment.

In order to chart the probable dispersion of sulphur dioxide ground level maxima, a hypothetical configuration based on an emission rate of 76 t/sd (75 LT/SD) and assuming stack design parameters similar to those of Syncrude, was subjected to plume dispersion calculations using limited mixing situations. Assuming zero background, the calculations predict total compliance with standards for annual average ground level concentrations and compliance 99.8 percent of the time with the half hour operating standard of 0.2 ppm taken over a one year period. Maps developed from these data can be used to locate monitors. The Applicant intends to establish an air quality monitoring program early in the construction period and continue it throughout the operating period.

Regional sulphur deposition rates (dry sulphur) were calculated using the same assumed configuration. Rates no greater than 5.5 kg/ha/y (5.0 lbs/acre/y) were predicted for any point within the Project Area, and lesser amounts can be expected elsewhere within the bituminous sands region. Plum dispersion analysis indicates that overlapping with plumes from Syncrude or GCOS will be infrequent. Total deposition of sulphur will however be cumulative over part of the region.

Additional studies of baseline sulphur conditions in soil and vegetation will be undertaken prior to processing plant startup. A comprehensive soils and vegetation monitoring system will be established to ensure that harmful trends are recognized if these studies indicate that the addition of sulphur from the Alsands Project may cause growth problems,

Long range transport of sulphur dioxide and chemical derivatives has not been the subject of study, but chemical transformation of sulphur dioxide within the Project airshed is not expected to produce precipitation problems such as those experienced in eastern Canada or Scandinavian countries (Western Research, 1976). The higher buffering capacity of waterbodies in the bituminous sands area would likely prevent significant change in pH levels even if the situation were to develop. Nevertheless, the onsite water quality measurement program will monitor trends in pH and a number of related parameters.

Emissions of oxides of nitrogen will occur primarily through the tall stack at rates predicted to be within Alberta Standards. Particulate emissions will be removed from the stack gases by electrostatic precipitators to within provincial standards.

The possibility of damage to vegetation as a result of stack emissions has been reviewed and it appears that arboreal lichens could be affected by ground level concentrations of sulphur dioxide within 10 km (6 miles) of the source. The presence or absence of arboreal lichens may serve as an indicator of air purity. Similarly, there is a long term possibility for some impact upon terrestrial lichens and mosses within a few kilometres of the plant site. The potential for impact is greatest on portions of the Project Area to be disturbed in the course of other activities.

Even the highest expected sulphur emission levels and ground level concentrations anticipated from the Alsands Project are unlikely to be of the type or extent that could cause acute damage to vascular plants (trees, shrubs and herbs).

Consideration will be given to the implementation of biomonitoring systems involving lichens and important tree species. If harmful trends associated with the Alsands operation are recorded on this basis, future technological developments may make it practical to lower emission levels.

NEW TOWN AND UTILITY CORRIDOR

A major environmental effect will occur from a proposed new town and airstrip north of the Project Area. The environmental suitablility of the townsite has been reviewed by the NE Regional Commission. The site is free of many environmental concerns and has the benefit of not covering economically retrievable bitumen deposits. A major effect of the town will be the introduction of approximately 12 000 people, many of whom will exert pressure upon local and regional resources during pursuit of recreational opportunities. For example, road access to the Gardiner and Namur Lakes may be developed, resulting in over-fishing of vulnerable fish stocks and disturbance of colonial nesting water birds. Impacts would not all be detrimental if fisheries, wildlife and other resource management effort is increased.

Disturbance to wildlife is not expected to be a concern except along the utility corridor. Improved access will provide opportunity for hunters to remove moose and other game within a few kilometres of the road edge.

The construction, operation and maintenance of the highway, communication systems, power lines and natural gas and crude oil pipelines within an extended corridor will present potentially significant linear disturbances. Implications would be more extensive if a new town is developed because more streams would be crossed and greater amounts of land involved. Primary concerns are the potential for erosion and stream siltation during construction, escape of hydrocarbons during operation of the crude line, and clearing and maintenance of rights-of-way throughout the life of the Project. These and other potential problems are commonly met in similar situations elsewhere and should be addressed adequately by developers of corridor facilities.

TABLE XII-1

APPROXIMATE SURFACE DISTURBANCE

	LOWLAND (ha)	UPLAND (ha)	TOTAL (ha)	LAKES (no.)	STREAMS (km)	PRODUCTIVE FOREST SITE (ha)
Mine Area						
Total	1825	875	2700	8	—	804
1st 5 yr. period	390	60	450	2	—	nd[3]
2 final pits	910	530	1450	2	—	nd[3]
Tailings Pond	1000	1100	2100	6	—	1040
Camp						
Construction	430	70	500	1	—	300
Permanent	10	40	50	—	—	40
Plants and Storage	330	70	400	—	—	20
Muskeg Storage	50	7	60	2	—	—
Granular Resources						
Total	350	300	650	8	1	270
Initial Pit	50	50	100	4	—	nd[3]
Area Between Facilities[1]	950	350	1300	—	—	nd[3]
Reservoir	20	20	40	1	—	—
TOTAL ONSITE			7950			
Utility Corridor						
Bridge to New Town			1200	—	4[2]	nd[3]
Spur to Plant Site (onsite)			150	—	—	nd[3]
New Town			3500	—	1	nd[3]
Airport			900	—	—	950
TOTAL OFFSITE			5650			
TOTAL PROJECT			13 550			

Notes:
1. May not be totally drained or cleared
2. Crossings
3. No data

XIII Summary of Regional Socio-Economic Impact Assessment

Introduction

The Applicant commissioned consultants to prepare a Regional Socio-Economic Impact Assessment for the Project. This Chapter summarizes that Assessment, filed in two volumes in support of this Project.

Significant regional social benefits have been identified by this Assessment. They include:

* additional income to the region of $660 million during construction and $185 million annually during operations (all dollar figures quoted in this Chapter are 1978 dollars),
* availability of many skilled and unskilled job opportunities and work training for future projects,
* the growth of commercial services,
* the expansion of social services.

Social costs identified are those normally associated with rapid growth. These problems will be èvident in the early years of the Project and should diminish with time. Most can be mitigated by ensuring early implementation of social services delivery systems, early construction of housing, and maximum efforts at building community social networks.

The Study Area

The Study Area is the Northeast Alberta Region as defined by the Government of Alberta, and is shown in Figure XIII-1. This region has a population of about 26 500 in 1978, with about 92 percent in the regional centre of Fort McMurray. The remainder live in Fort Chipewyan, Fort MacKay or Anzac, which are predominantly native communities. There is virtually no rural based population in the Area.

Regional Economy and Labour Force

The regional economy is based on the oil sands mining activities of GCOS and Syncrude Canada Ltd., and on trade and services activity in Fort McMurray. There is also some renewable resource harvesting and low intensity forestry, but virtually no agriculture and little manufacturing.

The employed labour force of the Study Area is approximately 11 200, apportioned between Fort McMurray (10 900 employed), Fort Chipewyan (210), Fort MacKay (40) and Anzac (50). An estimated 1000 persons are unemployed. Fort McMurray dominates the regional economy, with almost all of the regional trade and services sector.

The economy in the smaller communities of Fort Chipewyan, Fort MacKay, and Anzac is a mixture of seasonal and part-time wage employment, resource harvesting (trapping, fishing and hunting), and some limited full-time employment in the public sector. Government transfer payments provide an additional source of income for some of these communities. Resource harvesting is of relatively greater importance to the isolated community of Fort Chipewyan than to Fort MacKay and Anzac, which are accessible to wage employment opportunities and have a higher proportion of their labour force engaged therein.

Regional Impacts

POPULATION GROWTH

The regional population growth generated by the Project and the construction of the required additional community facilities will affect levels of employment and income and the demand for goods and services within the region. The economic impacts are closely tied to the growth cycle of the Project which is shown in Figure XIII-2. This graph illustrates the population that will be added to the region during the Project construction and operational phases from direct and indirect employment. The growth of Project-related population may be summarized as follows:

* After the Project start in 1980, the population level will build rapidly to the construction work force peak in the second quarter of 1984. At this time, approximately 17 600 persons will be added to the region.
* Nine months later at the peak of overall activity, the additional resident population will peak at 23 200.
* Once fully operational status is attained after 1988 and the construction camps are closed, the Project-related additions to the regional population will stablize at about 13 450.

EMPLOYMENT DURING CONSTRUCTION

During the construction phase, most of the labour demand will be met by in-migrants to the region, as the unemployed labour force will be too small to support the Project. Construction-related employment within the region will add approximately 13 000 jobs to the region (Table XIII-1).

All of the estimated 1000 persons unemployed in the Study Area could be readily employed, assuming barriers to participation such as inaccessibility to the jobsite, lack of appropriate skills, disinterest in wage employment and other impediments to participation can be overcome.

EMPLOYMENT DURING OPERATIONS

New long term employment opportunities number approximately 5000 (Table XIII-1).

The majority of the 2500 direct operating jobs require specialized skills. Since most persons in the region with the required job skills are presently employed at GCOS and Syncrude, most operating jobs will likely be held by in-migrants or by local persons who receive appropriate training. The capability of Keyano College and Alberta Vocational Centre to supply trained graduates and to upgrade persons employed within the region will determine the number of direct jobs filled by local population.

The 2500 indirect employment opportunities will include a wide variety of opportunities for skilled and unskilled labour. These indirect jobs will provide the most opportunities to the presently unemployed labour force.

ECONOMIC BENEFITS

Economic benefits to the Study Area will total about $660 million during the construction phase (1981-86). Of this total, $585 million will be payroll and goods and services income arising directly and indirectly from the Project. The balance of $75 million will come from the regional share of the new town development (Table XIII-2).

Economic benefit to the Area will total about $185 million *annually* during the operations phase (Table XIII-3). Of this amount $130 million is direct income, and $55 million is induced. From the perspective of the regional economic base, the Project will chiefly affect the oil and mining sector. It will also foster growth and qualitative expansion of the Fort McMurray trade and services sector, which currently exhibits deficiencies in certain areas. The expansion of this sector will arise from both expenditures of personal employment income and direct purchases of goods and services required on the Project.

Project and new town construction labour force regional payrolls will total \$490 million during construction, and \$105 million annually during operation. Based on patterns of expenditure experienced elsewhere, most of the income of the resident labour force will likely be spent on food, housing, and transportation. Lesser amounts will be spent on clothing, furnishings, recreation, and household operating expenses. Retail stores in both the proposed new town and in Fort McMurray will benefit. Large capital purchases for items such as automobiles may be made outside the region. Purchases of goods and services for the Project and new town construction will total \$173 million during the six years of the construction phase, and approximately \$79 million *annually* during the operations phase.

Little impact can be expected on the manufacturing sector because of its limited extent and the predominance of Edmonton. Some benefits will flow to the forest products sector during construction activity in response to the demand for dunnage, timbers, scaffolding and assorted lumber.

LAND USE IMPACTS

The Project will adversely affect five trapping areas adjacent to and on the mine, plant, and town site. The registered trappers will lose a source of seasonal income from these areas, and will be compensated. The total annual receipts from trapping on the five registered areas averaged approximately \$5800 for the years 1971-77. This is equivalent to \$1160 annually for each trapping area.

The increase in the Study Area population will substantially increase the demand for outdoor recreation and campground facilities. Mitigative measures could include the construction of an access road to and development of some of the excellent outdoor recreational resources in the district (eg. Namur Lakes). Other measures would be required in suitable areas southeast of Fort McMurray to provide additional outdoor recreation capacity.

Study Area Communities

Of the four existing communities in the Study Area, only Fort McMurray might feasibly be expanded to provide accommodation for the Project labour force. Although the Applicant has not yet finalized its own policies relative to housing it is considering various options including development of a new town. The Applicant intends to pursue alternatives with appropriate government departments during the next several months. The new town option appears to agree with the Alberta Government's proposed development plan for the Northeast region. It could also form a nucleus for future resource developments. Accordingly, the Applicant has assumed for purposes of this Regional Socio-Economic Impact Assessment that the majority of its construction supervisory and permanent operating staff will be housed in a new town.

The four existing communities in the Study Area differ widely in composition and setting. Fort Chipewyan and Anzac will experience little overall impact from the Project beyond employment effects because of their isolation from the Project site. On occasion, impacts on transportation, communication, and service delivery systems occurring throughout the Study Area may produce some local effects.

The proposed new town will experience most of the Project impacts, along with Fort McMurray (the regional centre), and Fort MacKay (the closest existing community to the proposed plant site).

THE NEW TOWN

The site of the proposed new town for the Project staff is currently uninhabited, but it could have a population of about 12 000 people during the operations phase. It would differ from Fort McMurray, 100 km (62 miles) to the south, because it would be completely new — an "instant town" with no previous roots. Like other new resource development communities, it would have a young population with some over-representation of males, and a higher population turnover than in older communities.

Basic facilities and services are assumed to be in the new town during the construction period prior to the build-up of population. The earliest residents may find only a minimum of commercial, health, education and other social services. These will grow rapidly, however, so that by advent of the operations phase the new community would have all facilities and services appropriate to a town of 12 000 people.

Population

The population build-up in the new town would begin in 1981, and reach an expected 8000 persons by mid-1984. Nine months later at the peak of overall development activity, the population could reach 14 100, some of whom would be housed in temporary accommodation. It could then decline to about 12 000 when the Project is fully operational after 1988.

Economic Benefits

During the construction phase the new town would receive approximately $290 million in direct and indirect income from Project payrolls and goods and services purchased. Direct expenditures by Alsands would total $200 million, and re-spending effects an additional $90 million. A further $20 million would be generated locally by the new town construction activity.

During the operations phase, benefits to the new town would stabilize at about $134 million annually. Project expenditures would account for $94 million, and re-spending effects $40 million. Payrolls represent 70 percent of the economic benefit during operations.

Socio-Cultural Impacts During Construction

Most of the socio-cultural impacts in the Study Area would be felt in the new town. The rapid regional growth will create challenge and increased opportunity as well as economic benefit for workers and residents in the new town and throughout the Study Area. Concurrent with these benefits will be problem areas such as:

* the newness of the environment to in-migrants,
* the disruption, confusion, and frustrations caused by continuing construction activity,
* the inadequacies of new service delivery systems which will be inaugurating their programs,
* the lack of voluntary associations,
* the stranger-status of most residents with the lack of friends or relatives in town.

Symptoms expected would be similar to those observed in other new resource towns, and would include above average consumption of liquor, family dissention and breakup, and school, crime and mental health problems. These problems would be more characteristic of the community business, service, and Project personnel than of the construction workers, who are more familiar with such conditions.

Mitigative measures to be implemented in the new town should include:
* scheduling of facilities construction to ensure completion before they are needed,
* early staffing of service delivery systems with experienced workers well in advance of population peak demand,
* advising new staff of the initial frustrations to be expected,
* substantial, aggressive organizing of volunteer community assistance programs, and recruitment of volunteers for them,
* ensuring an adequate number and variety of attractive, well-stocked commercial facilities.

The severity of these socio-cultural impacts on the new town will be influenced by its development schedule, financial resources, and the level of adequately staffed services. Acceptable housing, health services, schools, recreation facilities, and other public and private services will be required by 1984 for a population of about 8000. By 1985, these services will be required to sustain a population of 14 000, which includes a peak level of 2000 persons above the estimated long term population of the town.

During 1985 and 1986 in particular, demands for education, social, and certain health services will be high because many in the population will be young, transient, and problem prone, and will experience difficulty in adapting to the new environment. This will be a difficult period for the service delivery agencies because they will encounter a heavy workload early in their operational life.

Socio-Cultural Impacts During Operations

From a long term perspective, once the new town has become stabilized, the infrastructure and services themselves become a major Project benefit. These will contribute significantly to service delivery in Fort MacKay and perhaps in Fort Chipewyan, as well as to the Provincial Government objective of fostering development in the Northeast Alberta Region.

The early operations phase impacts on the new town will be generally similar to those experienced during construction, but less severe, because:
* construction period disruption will have ended, reducing the sources of frustration,
* service delivery agencies and information organizations will be better organized and able to respond,
* neighbourhood support systems will begin emerging,
* the new environment will lose its strangeness.

As time passes these mitigating influences will become stronger unless high turnover rates persist. The lower the turnover rate, the more rapid will be the disappearance of these adverse impacts.

FORT MCMURRAY

Fort McMurray is the largest community in the Study Area, with a population which increased ten-fold from about 2500 in 1966 to 24 500 in 1978. An oil sands boom town easily accessible from the rest of the province, it owes its growth to the GCOS and Syncrude developments. It has an almost completely white population, with many young adults and children, very few elderly people, and a relatively high population turnover rate. The employed labour force currently numbers about 10 900 and the unemployment rate is about 6 percent.

Current socio-cultural conditions in Fort McMurray reflect the recent construction boom, for which the town was ill prepared. Social and other problem rates have been relatively high, particularly among wives trying to establish themselves in new subdivisions in a strange environment.

Basic infrastructure and services are generally superior in Fort McMurray relative to other resource communities of a similar size. These services are clearly superior to the other communities in the Study Area. Fort McMurray is well served by airlines, roads, rail, and seasonal water transport. The quality of housing and indoor recreational facilities is above average. Educational, social and medical service delivery systems are all well developed, though most have recently experienced the problems of rapid growth. Services in the trade sector are limited but are expanding rapidly. Developed outdoor recreation facilities at the Provincial campground at Gregoire Lake are presently at capacity.

Project Impacts

Initial population impacts on Fort McMurray will be felt by mid 1984, when the town will have grown by about 1800 service related people. Nine months later at the peak of overall activity this will have increased to 2500. It will then decline to about 1900 when the Project is fully operational.

The Project will contribute significantly to the economy of Fort McMurray. The total for the entire construction period is expected to be $320 million. Of this amount $180 million will be direct expenditures by Alsands for payrolls and goods and services, and $80 million from indirect re-spending effects. The balance of $50 million will be created locally from new town construction.

During the Project operations phase, annual income to Fort McMurray will total about $45 million. Of this amount Alsands direct expenditures will total $32 million, and indirect re-spending effects $13 million. Forty million dollars of the annual income will be payments for goods and services. Figure XIII-3 summarizes the share of total regional income that will accrue to Fort McMurray, as well as to the other communities of the Study Area.

The socio-cultural impacts on Fort McMurray during the construction and operations phases will be similar to those on the new town, but at a much lower level. There will be fewer newcomers and the formal and informal social service and support systems available to help integrate them will be more effective.

In summary, Fort McMurray currently has adequate basic infrastructure and services, with capacity to meet new growth. It will be able to handle adequately the Project impacts expected during the peak years of activity, 1983-1986, when an expected maximum of 2500 Project related persons will be added to the town. In addition, the planning and administrative personnel of the community have had first-hand experience in dealing with the impacts of large energy projects.

FORT MACKAY

Fort MacKay is located about 13 km (8 miles) southwest of the Project site. It is a small settlement with a population in 1978 of 204, 92 percent of whom are native people. Most of the population are young adults and children. The employed labour force currently numbers about 40, and the unemployment rate is about 42 percent.

Fort MacKay people have already been influenced by the GCOS development, which pre-empted their traditional summer camp area, and also by the Syncrude construction work opportunities which attracted many from their bush and trapping lifestyle.

Fort MacKay is entirely lacking in basic water and sewage services and in local police protection. It is deficient in health and social services, which must be sought in Fort McMurray except on the few days a month that personnel from these agencies visit the community.

Project Impacts

The Project and the new town will offer a wide range of employment opportunities to the residents of Fort MacKay. The Applicant will work with the community to develop programs and transport systems to maximize these opportunities.

Fort MacKay may experience some population growth pressure from transient individuals attracted by its proximity to the Project site. Population expansion of Fort MacKay will be restrained, however, by the lack of freehold land.

The calculation of economic benefits to Fort MacKay is based on the assumption that about 30 persons, the number presently unemployed, will work on the Project each year. Their wages would add about $850 000 to the annual income of the community from commencement of construction in 1981 until termination of the operations phase. No indirect economic effects have been calculated because it is assumed that these would accrue primarily to the new town, and to a lesser extent to Fort McMurray. Figure XIII-3 shows the regional share of income accruing to Fort MacKay.

In Fort MacKay the most severe impacts during the construction phase are expected to be mental health and social integration problems. Mitigative efforts should be continued to improve community solidarity. The Applicant recommends stationing RCMP in the community to control incursions by construction workers as well as community behaviour problems, and employing a social worker experienced and effective in working with native people. The Applicant will make every effort to prevent unwanted incursions of workers into the community.

Project impacts on Fort MacKay during the operations phase will be more favourable because construction workers will have left, and operations work schedules are less disruptive and stressful than those of the construction period. Appropriate mitigative efforts should involve providing experienced and effective community workers able to help people understand, resolve, and eventually prevent the problems they encounter. Some problem conditions may persist for some time, because the transition from bush life to wage employment often takes years to achieve. Social conditions in this community may be expected to improve steadily with time.

The relocation of many social and health services from Fort McMurray to the new town with the onset of the operations phase is expected to improve service delivery in Fort MacKay.

FORT CHIPEWYAN

Fort Chipewyan, isolated without road access at the northern extremity of the province, is the oldest and largest predominantly native community in the province. It is located about 160 km (100 miles) north of the Project site. Its population is about 1640 inhabitants, 94 percent of native origin. As a result of high Indian birth rates in recent years it has many young adults and children, but it also has a good representation of elderly people. Once an important trapping and transportation centre, it has grown rapidly and changed in the last decade as people have moved in from surrounding bush areas. It now depends heavily on government employment and income support programs. It has experienced few impacts during the Syncrude construction phase. The employed labour force currently numbers about 210, and the unemployment rate is about 58 percent.

Most of the native population of Fort Chipewyan lack basic water and sewage service. There is a nursing station which provides out-patient care, and a local RCMP detachment. Most other health and social services must be sought in Fort McMurray except on those days when service delivery representatives visit the community.

Project Impacts

In view of their high rate of unemployment, hiring of Fort Chipewyan residents will yield important economic benefits to this community. The Applicant is prepared to discuss ways of optimizing participation with community leaders, and to work out the special transportation and scheduling arrangements that may be required. The Applicant has commissioned a survey of employment interests and experience of Fort Chipewyan residents, and the information obtained will help with the above objectives.

If some Fort Chipewyan residents become extensively involved in the Project, the town may in time experience a net population decrease. This would be temporary during the construction phase, but might be permanent if some residents decided to relocate to the new town during the operations phase.

As a basis for calculating Project economic benefits to Fort Chipewyan, about two-thirds of the 290 people currently unemployed in this community are assumed to obtain employment during both the construction and operations phases. Resulting wages would total $5.4 million per year at current wage levels. No estimate of re-spending effects in Fort Chipewyan has been made. Figure XIII-3 illustrates the share of regional income accruing to the community.

If Fort Chipewyan residents become heavily involved in construction employment, there may be increases in alcohol related violence and in dependency payments resulting from affluence and inflation. To minimize these problems it will be necessary to maintain social services at needed levels. These services will likely be supplied from Fort McMurray for Fort Chipewyan as well as for Fort MacKay and Anzac. It will thus be critically important to ensure that service delivery to these outlying settlements does not suffer as the demands on service agencies increase during the construction phase. This will be critical only during the early construction phase until agency offices are established in the new town, since increased demands in Fort McMurray will be minimal.

No significant new socio-cultural impacts are expected in Fort Chipewyan during the operations phase. Problems experienced during the construction phase are expected to decline, as construction work is replaced by less disruptive operations work, and as people adapt to wage employment conditions.

ANZAC

Anzac is a small predominantly native community 40 km (24 miles) southeast of Fort McMurray. The population in 1978 is 150. The Anzac people have gradually integrated into seasonal or year-round employment since the early 1960's. Buffered by their distance from Fort McMurray, they experienced few noteworthy impacts during the Syncrude construction phase. The employed labour force currently numbers about 40, and the number of persons unemployed is low.

Project Impacts on Anzac

The Alsands Project is not expected to have any significant population, economic or socio-cultural impacts on Anzac, during either the construction or the operations phase.

Framework For Managing Socio-Economic Impacts

Specifically identified impacts and mitigative approaches have been outlined above. In order to address realistically the tasks of mitigating adverse impacts and enhancing beneficial ones within the region and the local communities, a coordinated approach by government and industry that involves all relevant government agencies will be necessary. This is particularly applicable in establishing the new town because of the dominant position it holds in Project impacts affecting the region.

The Applicant recommends that a single body or development agency be established to oversee the socio-economic effects of the Project, as well as ensuring the successful and timely development of the new town. This agency should include representatives from the Provincial Government, Northeast Regional Commission, the communities of Fort Chipewyan, Fort MacKay, Fort McMurray and the

Applicant and its contractors, as well as those responsible for new town development.

The central purpose of this agency would be to:

* mobilize to manage growth at the regional and community level,
* monitor ongoing socio-economic impacts and evaluate the best means for handling them,
* develop and monitor the implementation of a rapid growth plan that anticipates regional and local needs, with particular reference to the new town.

TABLE XIII-1

ESTIMATED POPULATION AND EMPLOYMENT ADDED TO THE REGION AND SELECTED COMMUNITIES 1984, 1985, AND 1988

	PEAK CONSTRUCTION 2ND QUARTER, 1984	PEAK DEVELOPMENT ACTIVITY 1ST QUARTER, 1985	OPERATIONS PHASE AFTER 1988
POPULATION ADDED			
Project and New Town Camps	8 000	6 580	0
New Town	7 790	14 100	11 550
Fort McMurray	1 780	2 460	1 900
TOTAL	17 570	23 140	13 450
EMPLOYMENT ADDED			
Project and New Town Camps	7 850	6 450	0
New Town	2 530	5 290	4 250
Fort McMurray	640	1 330	755
TOTAL (Including induced employment)	11 020	13 070	5 005

Note:
1. Figures include both direct and indirectly induced employment.

TABLE XIII-2

REGIONAL ECONOMIC IMPACT FROM PROJECT AND NEW TOWN DEVELOPMENT CONSTRUCTION PHASE, 1981 TO 1986

	DIRECT	INDIRECT	TOTAL
PROJECT			
Payroll Income	319	128	447
Goods & Services	101	40	141
SUBTOTAL	420	168	588
NEW TOWN			
Municipal Infrastructure			
Payroll Income	3.6	1.4	5.0
Goods & Services	2.3	0.9	3.2
Residential, Commercial, and Industrial Properties			
Payroll Income	23.3	9.3	32.6
Goods & Services	15.5	6.2	21.7
Regional Utilities			
Payroll Income	2.3	0.9	3.2
Goods & Services	5.3	2.0	7.3
SUBTOTAL (figures rounded)	52	21	73
REGIONAL TOTAL (1981–1986)	472	189	661

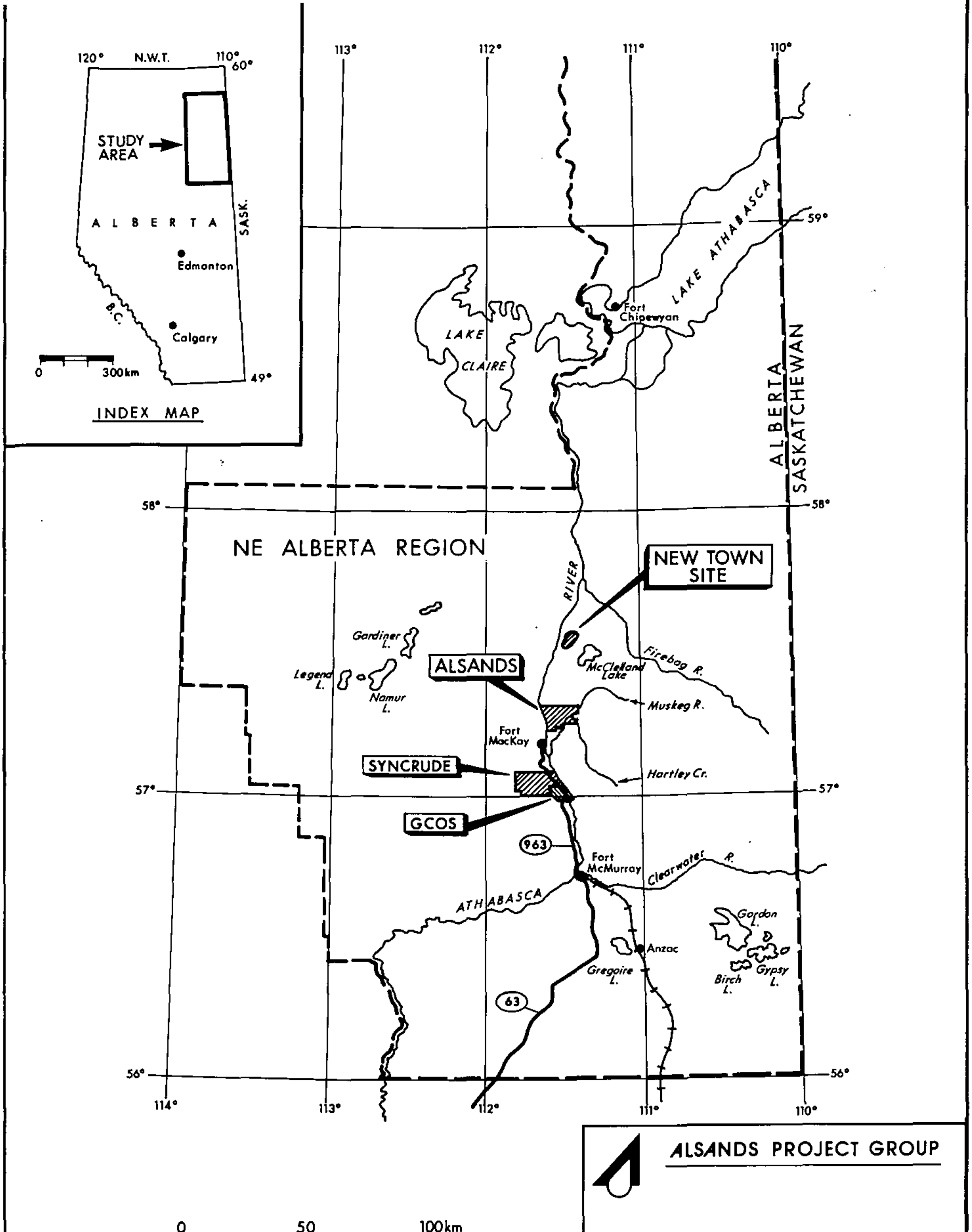
Note:
1. All figures are in $\$ \times 10^6$ (1978).

TABLE XIII-3

ESTIMATED ANNUAL REGIONAL INCOME FROM PAYROLLS AND GOODS AND SERVICES DURING OPERATIONS PHASE

	DIRECT INCOME	INDIRECT INCOME	TOTAL
Gross Payrolls	75.8	30.3	106.1
Purchased Goods and Services	56.6	22.6	79.2
TOTAL	132.4	52.9	185.3

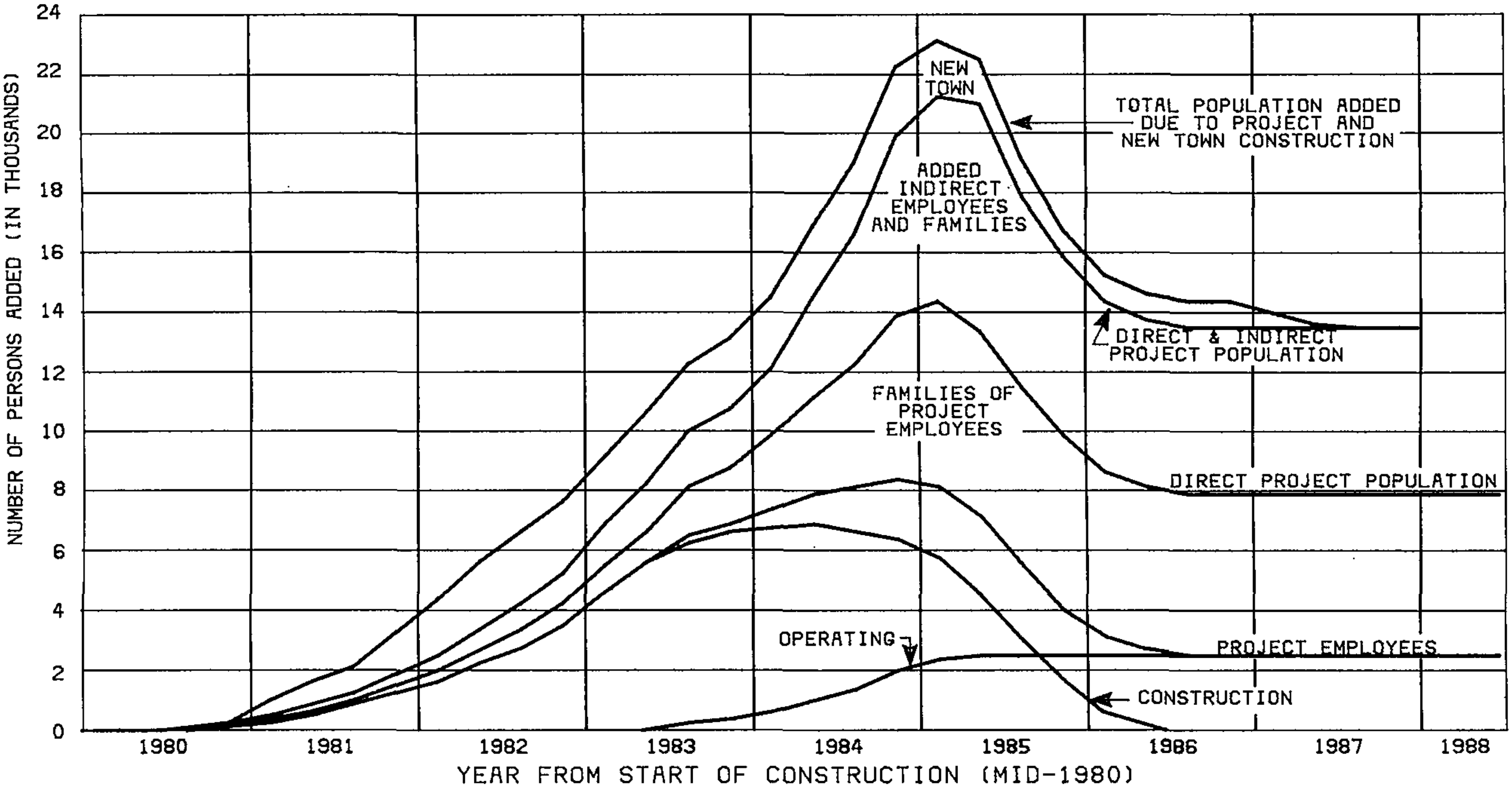
Note:
1. All figures are in $\$ \times 10^6$ (1978).



ALSANDS PROJECT GROUP

STUDY AREA

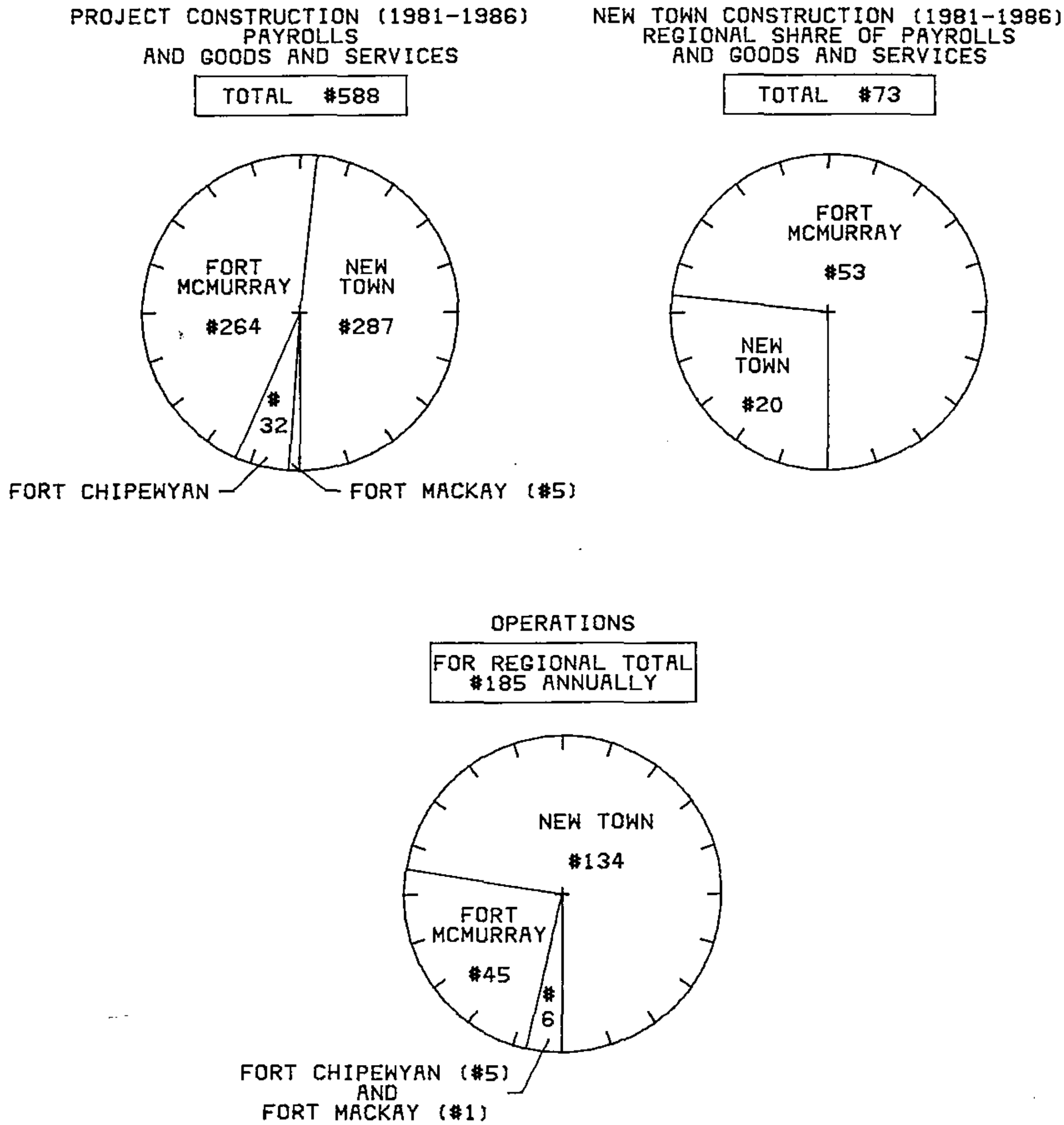
FIGURE XIII - 1



ALSANDS PROJECT GROUP

REGIONAL POPULATION GROWTH FROM PROJECT AND NEW TOWN CONSTRUCTION

FIGURE XIII-2



ALSANDS PROJECT GROUP

ECONOMIC IMPACT ON REGION AND COMMUNITIES FROM CONSTRUCTION AND OPERATIONS PHASES

$\$ \times 10^6$ (1978)

FIGURE XIII - 3

XIV Summary of Benefit-Cost Analysis

Introduction

The Applicant commissioned consultants to prepare a Social Impact-Benefit/Cost Analysis for the Project. This Chapter summarizes the Benefit-Cost aspects of this analysis.

A benefit-cost analysis views the effectiveness of a project from the standpoint of society in general and includes both private and public benefits and costs. In this report a clear distinction has been drawn between the economic impacts as such, and the benefit-cost analysis of those impacts. Every economic activity produces economic impacts, but in the measurement of benefits and costs only those economic impacts which are extra or incremental over what would happen in the absence of the Project are considered.

The Project will produce 200 million m^3 (1260 million Bbl) of synthetic crude oil and LPG which will increase the security of supply and have a positive impact on the national balance of payments of $17.2 billion (1978) over life. During construction an annual average of 11 500 direct plus indirect jobs will be created in Canada. At the peak of construction more than 21 800 people will be employed on activities directly and indirectly related to the Project. The operation of the plant itself will create a total of 6500 new jobs in Canada. The total monetary effect on Alberta is $30.2 billion (1978) over life, while the effect on Canada is $43.7 billion (1978). The Benefit-Cost Analysis demonstrates that the Project provides a large net social benefit to Alberta and to Canada. These positive results confirm the desirability of the Alsands Project.

In the sections that follow the commercial feasibility of the Project is first defined. The subsequent sections deal with the economic impacts of the Project upon Alberta and Canada. These impacts are then examined in the context of a benefit-cost analysis.

Commercial Feasibility

The Alsands Project will involve the spending of approximately $4.9 billion to achieve the first production of synthetic crude oil in 1986. The facilities will produce at an annual rate of 7.6 million m^3 (48 million barrels) from 1987, when the capital expenditure will have reached $5.1 billion. Additional capital injections will allow the annual output to increase to 8.1 million m^3 (51 million barrels). Over the life of the Project, the ultimate capital expenditure will reach $5.9 billion and 200 million m^3 (1260 million barrels) will be produced. In order to calculate the financial results of this massive Project in real terms, pertinent figures have been stated in "real" 1978 values by the use of inflation and deflation factors. This method best translates the effect of the variable factors such as taxes and royalties into real terms. Up to 1980 current costs have been increased by 10 percent per year. From 1981 onwards these costs were increased at an annual rate of 7 percent. A deflator of 7 percent was then applied to bring all values to a 1978 level. Unless otherwise noted all dollar values are stated in "real" 1978 values.

The commercial feasibility of the Project rests on several fundamental assumptions which are noted herein and are incorporated in the financial analysis. The assumptions will have varying effects on each company according to its individual economic situation.

The financial analysis is based on a synthetic crude plant gate value of $14.88/Bbl (mid 1978), which is based on the average price of imported crude at Montreal, adjusted for quality premium, transportation costs and US/Canadian dollar exchange rate.

Since there is presently no royalty system that applies to new oil sands projects in Alberta, the Applicant has assumed a profit-sharing royalty for purposes of Project analysis. The formula is structured to provide increasing royalty payments with accumulative profitability.

Federal income taxes have been calculated at the presently effective rate of 36 percent; Provincial taxes are 11 percent of taxable income. Existing and proposed income tax legislation and regulations (including the November 16, 1978 Budget) have been incorporated into the evaluations. In addition, the Applicant has assumed and included further tax incentives which it considers necessary as part of the commercial terms to make the Project commercially viable.

Actual commercial terms acceptable to the parties to the Application and the governments have not yet been formulated.

Sponsorship of the project is being considered by nine companies, each of which may have a different taxable income base. Hence a sponsoring company's ability to use tax incentives during construction will vary depending upon each company's tax status. In the Applicant's judgment the most realistic basis for illustrating the effect of this Project on the Provincial and Federal economies is to assume that 80 percent of the capital invested will be provided by companies able to fully utilize the tax incentives in the pre-production stage, and the remaining 20 percent of capital expenditures will result in deferred tax credits until production revenue is available. This case is documented in the cash flows on Table XIV-1 and is referred to as the 80/20 investment scenario.

The facilities are still considered by lenders to reflect first generation technology with inherent risks, despite the existence of other oil sands projects. Further, because of the long construction lead time, the facilities will not produce any income for a number of years and cannot provide the necessary debt service assurances lenders seek during this period. Accordingly, the sponsoring companies believe they will be expected to shoulder the whole risk and because of this, the project economics have been evaluated on the basis of 100 percent risk capital.

The Project cash flow data are shown on Table XIV-1, and are calculated in "as-spent" dollars. The Applicant has tested the Project economics in several ways. It can be observed from the results shown on Table XIV-2 that each company's internal rate of return is highly sensitive to a delay in the crude oil price rising at the same rate as cost inflation (the down-side price risk) and is also very dependent on the capital and operating cost expenditures.

To carry out the venture in the face of the real and significant risks, an opportunity to earn a compensating return must be available to each company. Aside from the general Project risks there is the additional exposure of a one-time decision with an extremely long lead time (from the engineering cost estimate to effective commercial production) for an investment of immense magnitude.

The Project analysis indicates that a company with sufficient other taxable income to utilize currently all of the tax incentives, would earn a real return of 10.5 percent, and a current basis return of 18.3 percent. Payout of the investment will occur about 13 years after the initial expenditures.

The Project can be commercially viable in light of the risk when provided with the assumed tax incentives and the proposed royalty and on the basis of the other assumptions incorporated herein.

The Economic Impact on Alberta

The Alsands Project will have a significant economic impact upon the Province. In this section the economic impact is first stated in terms of the total dollar effect *The Monetary Effect*. This is followed by a discussion of specific economic effects. Some of these effects are not measurable in dollar terms. Those which are measurable have already been accounted for in the Monetary Effect section, but are abstracted for emphasis.

THE MONETARY EFFECT

The total Project capital expenditure is estimated at $4.0 billion. In addition a capital expenditure of $0.5 billion is estimated for infrastructure. Not all of the total capital expenditure of $4.5 billion will be spent for goods and services that originate in Alberta, so to describe the Alberta economic impact an allowance must be made for these "leakages'. Accordingly, the direct monetary impact of the capital expenditures on Alberta is estimated at $2.6 billion.

In addition to capital expenditures the effect of the continuing flow of revenue into the economy from the sale of synthetic crude oil causes a monetary impact. The total revenue from crude oil sales over the life of the Project is estimated at $18.5 billion. Some of the revenue will go directly to the Federal Government as corporate income tax payments (of which a portion will be re-spent in Alberta); some will go for operating expenses which require goods and services not available in Alberta; and some will go to repay the investors who supplied the capital (of which some will be re-invested). After calculating the net amount of these leakages the direct monetary impact of the operations phase of the Project on Alberta amounts to $14.2 billion.

To calculate the total impact on the Alberta economy a multiplier analysis is used. The multiplier analysis reflects the fact that when money is spent it first appears as an income receipt and then reappears as an expenditure by that income recipient. These secondary or induced expenditures would not have occurred but for the initial expenditure. Further augmentation results when the incomes resulting from the original induced expenditures are themselves re-spent.

In the process, an ultimate increase in aggregate income is generated which is greater than the magnitude of the initial expenditures. The ratio of the ultimate increase to the initial expenditure is referred to as the multiplier.

The appropriate multiplier for Alberta has been determined to be 1.8. This multiplier is applied to the direct monetary impacts to determine the total monetary impact.

The undiscounted monetary effect on Alberta of the Project in 1978 dollars is as follows:

Direct — $16.8 billion
Total — $30.2 billion

SPECIFIC ECONOMIC EFFECTS

Much of the initial impact of the Project will be felt in the Northeast region but there are some significant economic effects that will be spread over the entire Province. These are discussed as follows:

Employment

The Project will create substantial employment impacts in Alberta during both construction and operation.

In the construction phase, the direct manpower requirements for the plant, marshalling yard, new town, and other infrastructure will become significant in 1980, build to a peak of approximately 9600 workers in 1983 and then decline towards 1986.

Using an industrial development scenario which assumes that this Project and others of similar size proceed concurrently, an analysis of the supply and demand for construction trade labour indicates that some 60 percent of the workers required for the Project will come from Alberta, 35 percent from the rest of Canada, and the remainder from elsewhere.

During the operations phase, the Project will require approximately 2800 permanent employees, with 2500 located on the plant site. This will result in 5600 permanent jobs in Alberta. The 25 year duration of the Project will enhance Alberta's employment stability.

In the operations phase, the initial labour demands of several major concurrent projects will also cause shortages of Alberta operating and maintenance personnel. Some 60 percent of the operating manpower will come from Alberta, with the remainder from the rest of Canada.

Manpower Skills

A wide range of manpower skills is required for both the construction and operation of this Project. This demand for skilled labour will create opportunities in Alberta for training and upgrading existing manpower skills. The Applicant is prepared to work with government agencies, educational institutions and labour associations to identify these opportunities.

The Project will also have the effect of increasing the trained provincial labour pool used for the construction and operation of large projects. This will be particularly significant for the plant operations where Alberta has not previously had a large indigenous industrial operations labour pool to draw upon.

There will also be opportunities for a wide range of other skills in the Project — engineering, accounting, management, technological, clerical and others. This will not only have the effect of stimulating training of these skills, but will also allow Alberta to offer employment opportunities for residents as they complete their training. The Applicant's policy on Project Management and Engineering for the Project is predicated on utilizing Alberta expertise to the maximum practical extent. This will result in the development of project management and engineering skills which will enable Albertans to better compete in these areas on major engineering projects.

Energy Policy

The development of the oil sands reserves in Alberta in an orderly manner has been a fundamental part of Alberta Government energy policy. As conventional crude oil production declines over the remainder of this century, the development and production of non-conventional crude oil reserves will become of increasing importance to Alberta's economy. The Alsands Project contributes significantly to this energy policy.

Research and Development

The Project provides opportunities for research and development. As an example, the Applicant plans to examine Coke Gasification technology which if successful would be carried through to prototype and commercial scale development.

Transportation, Communication and Supply

There are substantial economic impacts due to the transportation, communications and supply requirements associated with the Project during the construction and operations phases.

During construction there will be $151 million of expenditure for roads, bridge, an airstrip, gas and crude oil pipelines, telecommunications and power lines. These facilities form a major portion of the infrastructure required to service the plant and the new town, and allow access for future developments in the region.

During operations, the Alberta economic impact of synthetic crude transportation is estimated to be $18 million per year or a total of $440 million over the Project life.

Alberta Government Financial Impacts

The Project will generate revenues to the Provincial Government but at the same time the Government will incur certain expenditures. Capital expenditures by the Province for the road, bridge, airstrip and new town are estimated at $83 million. Once production commences there will be three main sources of provincial revenue: royalties, corporate income tax, and personal income tax. The total direct revenue from these sources is estimated to be $2.5 billion, or an average of $94 million annually. Provincial Government operating expenditures are estimated to be $10 million per year or $250 million over the life of the Project.

The Project will be required to pay municipal property and school taxes to Local Improvement District 18 once the plant is completed. Over the life of the Project these amount to an estimated $230 million.

Secondary Industry and Diversification of Alberta's Economy

Construction of the Alsands Project will require $1.7 billion of materials and equipment. Alberta manufacturers and producers will supply an estimated 34 percent or $0.6 billion of this.

The direct effect of the Project is particularly pronounced in the machinery and equipment, metal fabrication, and primary metal product categories. Expansion of existing manufacturing facilities could provide substantial gains in economies of scale. The Applicant is prepared to work with government agencies and manufacturing organizations to identify major opportunities for growth. In certain areas where Alberta has limited existing manufacturing facilities, these facilities may become viable if the Alsands Project is viewed as being the forerunner to a number of major projects.

During the operations phase an estimated $42 million would be spent annually on materials and equipment produced by Alberta manufacturers. Over the life of the Project this represents a $1 billion market for Alberta goods and services.

The industrial nature of this Project, combined with its remote location makes it consistent with the industrial development and diversification policy of the Alberta Government.

Net Social Benefits to Alberta

The net social benefits to Alberta can be described by a benefit-cost analysis which is a technique for evaluating the relative merits of alternative investments. It has been developed and refined to assist government decision-makers in the selection of public investments. The goal is efficient resource allocation.

Analytically benefit-cost analysis is similar to the techniques used by the private sector. Private firms typically evaluate a project by discounting the project's expected cash flows over time by the "cost of capital" to the firm in order to arrive at the net present value of the project. Projects are then ranked on the basis of their net present value plus "intangibles" that have not been included in the financial flows.

The principal difference between benefit-cost analysis in the public sector and present value calculation in the private sector derives from the fact that the public sector usually represents a more inclusive socio-economic unit than a private firm. Factors that are external to the firm's decision become internal to the social unit. As the unit becomes larger more inclusive factors must be included in the analysis.

Secondly, the objective of benefit-cost analysis is to compare benefits and costs in dollars and cents, a common measuring unit; this frequently is not possible in the public sector so non-measurables must be clearly accounted for in qualitative terms.

It is usual in benefit-cost analysis to assume a partial equilibrium situation with full employment of production factors. Acceptance of the full employment assumption implies that not all of the jobs created by the Project are a net benefit because other economic activity would take its place. From a very practical standpoint, this may be a questionable assumption.

For the quantitative measures the social discount rate is one of the most important factors in benefit-cost analysis. This is true because too low a rate will encourage projects to go ahead when the resources of land, labour and capital could better be utilized in other sectors of the economy. Similarly, too high a rate will result in projects being rejected that could have improved the performance of the economy, again resulting in an inefficient economy.

A range of social discount rates varying from 0 percent to 15 percent has been used in the analysis. The appropriate rate for Alberta most likely lies in the lower end of this range.

The expected net social monetary benefit to Alberta measured in real terms at various social discount rates is:

PERCENT	**0**	**5**	**10**	**15**
BENEFIT – \$ $\times 10^6$	4610	1340	330	-10

The additional net social benefits and costs of the Project to Alberta are summarized below. (The environmental and regional impacts are further discussed in Chapters XII and XIII respectively.)

* *Development of the new town will further the Northeast Regional Plan, expanding access and development northward,*

* *Even under the full employment assumption plant operations will directly create at least 1100 additional jobs,*

* *Commercial development opportunities will be increased, thereby making a greater selection of goods and services available to residents of the Northeast region,*

* *A net social cost would result from the abnormal social environment during the period of rapid growth in population and rapid development of the plant and town. As a consequence there would be a need for increased delivery of social services in the region to reduce these impacts,*

* *Development of a new community with its attendant financial and social expenditures will help relieve the pressure for growth in larger urban settings,*

* *The environmental costs of the Project include surface disturbance to land in the Project Area prior to reclamation, minor modifications to the regional eco-systems and pressure on regional resources during pursuit of recreational opportunities by the new inhabitants of the region,*

* *The skills of Alberta labour will be upgraded and the Project will contribute to regional and provincial employment stability,*

* *The Project will contribute to the fulfillment of Alberta's energy and industrial diversification policies,*

* *Both the productivity and the stability of the Alberta economy will be improved,*

* *Oil sands technology will be advanced,*

* *Project management capability in Alberta will be increased.*

The Economic Impact on Canada

The Alsands Project is one of the largest energy developments planned for Canada in the next decade. This section discusses the major impacts which are additional to the Alberta impacts already discussed.

THE MONETARY EFFECT

The total undiscounted monetary effect of the Project upon Canada includes Alberta and is therefore more substantial than the impact in Alberta alone. This is because a large portion of the capital expenditure and revenue leakages from Alberta are captured within the rest of Canada, and the income multiplier for all of Canada is therefore some 15 percent greater than the Alberta multiplier. The undiscounted monetary effects are:
Direct — $20.8 billion
Total — $43.7 billion

SPECIFIC ECONOMIC EFFECTS

The Balance of Payments

The Project will have a positive impact on the Canadian balance of payments of $17.2 billion. This is mainly due to the replacement of imported crude by the synthetic crude oil production.

Employment

The engineering and construction of the Project facilities and infrastructure will require some 55 million manhours of labour spread over the 1979-87 period. During construction an annual average of 11 500 direct plus indirect jobs will be created in Canada and at the peak of construction more than 21 800 people will be employed on activities directly and indirectly related to the Project.

There will be 2800 people directly employed during the operations phase of the Alsands Project and in total the Project will create 6500 permanent Canadian jobs.

Manpower Skills

There will be significant impacts upon Canadian manpower skills due to the Project. Workers will have the opportunity for upgrading and re-training to meet the requirements of the construction and operation of this advanced technology Project. The Applicant is prepared to work with government agencies and labour organizations to identify these training opportunities.

The Applicant's Policy on Project Management and Engineering is predicated on utilizing Canadian expertise to the maximum practical extent. This will result in the development of project management and engineering skills which will enable Canadians to better compete in these areas on major worldwide engineering projects.

Energy Policy

The energy policy of the Federal Government is to establish Canadian energy self-reliance. This requires that, while there may not be energy self-sufficiency, there will be enough energy to avoid the most serious consequences of a supply interruption from foreign sources. The Alsands Project is a major step in that direction with the production of some 22 250 m^3/d (140 000 B/D) of synthetic crude oil.

This production will add 11 percent to the estimated potential producibility of crude oil and equivalent in 1985 (basis September, 1978 NEB predictions) and will be a major contributor to the supply of oil from oil sands and heavy oils sources.

Federal Government Financial Impacts
The Federal Government will will receive direct income tax payments from the Project, its suppliers and its employees, estimated to total $1.8 billion over life or an average of $54 million per year. These will be partially offset by expenditures estimated at $16 million per year or a total of $390 million over life.

Transportation
The construction and operation of Alsands will have an important economic impact on transportation facilities throughout Canada. As an example, movement of the synthetic crude oil will result in a total economic impact of $1.0 billion over the Project life or an average of $42 million per year.

Impact on Canadian Secondary Industry
During the construction phase the Project will purchase an estimated $1.3 billion in equipment and materials from Canadian manufacturers. Many sectors of the Canadian economy that are currently operating below capacity will receive a major stimulus from the Project. There will be a pronounced increase in demand for machinery and equipment, metal fabrication products and construction equipment. The Applicant is prepared to work with government agencies and manufacturing organizations to identify areas where Canadian production capacity and capability may be increased to lessen dependence on foreign suppliers.

The operations phase of the Project will create a market of $68 million annually or $1.7 billion for Canadian manufacturers over the Project life.

Net Social Benefits to Canada

The expected net social monetary benefit to Canada from the Project measured in real terms at various social discount rates is:

PERCENT	**0**	**5**	**10**	**15**
BENEFIT – $\$ \times 10^6$	7420	1900	260	-250

In addition to the net social benefits and costs of the Project to Alberta there are some further benefits and costs of particular relevance to Canada:

* *The development is consistent with the National Energy Policy,*
* *The Project creates a strong beneficial effect on the Canadian balance of payments,*
* *The project creates highly skilled job opportunities of benefit to all regions of Canada,*
* *The security of energy supply to Canadian consumers is enhanced,*
* *Idle manufacturing capacity will be utilized.*

TABLE XIV-1

PROJECT FINANCIAL ANALYSIS

A. PROJECT CASH FLOW FOR THE "80/20" INVESTMENT SCENARIO, EXPRESSED IN "AS SPENT" $ × 10^6

	REVENUE	OPERATING COSTS	CUMULATIVE CASH SHORTFALL	CAPITAL COSTS	ROYALTY	INCOME TAX ALBERTA	INCOME TAX FEDERAL	APPLICANT'S NET CASH FLOW
1978			3	3		–.4	–1	–2
1979			29	26		–3	–10	–13
1980			238	210		–17	–65	–128
1981			688	450		–44	–159	–247
1982			1 670	982		–96	–346	–540
1983			2 891	1 220		–137	–471	–612
1984			3 903	1 013		–132	–434	–447
1985			4 903	999		–118	–390	–491
1986	573	477	4 932	120	6	–26	–75	71
1987–2011 (Average Annual)	3 346	1 296		37	416	164	512	921
TOTAL	84 214	32 868		5 941	10 400	3 528	10 840	20 637

B. PROJECT CASH FLOW FOR THE "80/20" INVESTMENT SCENARIO EXPRESSED IN INFLATED/DEFLATED MID-1978 $ × 10^6

	REVENUE	OPERATING COSTS	CUMULATIVE CASH SHORTFALL	CAPITAL COSTS	ROYALTY	INCOME TAX ALBERTA	INCOME TAX FEDERAL	APPLICANT'S NET CASH FLOW
TOTAL	18 500	7 377		4 038	1 783	478	1 223	3 601

TABLE XIV-2

SENSITIVITY ANALYSIS – INCREMENTAL/DECREMENTAL EARNING POWER PERCENTAGE RELATED TO A JOINT VENTURE INVESTMENT SCENARIO

	AS-SPENT DOLLARS PERCENT	INCREMENT/ DECREMENT PERCENT	INFLATED/ DEFLATED MID-1978 DOLLARS PERCENT	INCREMENT/ DECREMENT PERCENT
Joint Venture Earning Power[1]	18.3		10.5	
Investment +$400 × 10^6 (1978)		−1.0		−0.8
−$400 × 10^6 (1978)		+1.1		+1.1
Operating Costs +10%		−0.8		−0.7
−10%		+0.7		+0.7
Differential Inflation				
Crude Price versus Costs +2%		+4.4		+4.2
−2%		−5.9		−5.5

Note:
1. The calculated internal rate of return applies only to those companies who are able to utilize all tax incentives earned against their other taxable income on a current basis.

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