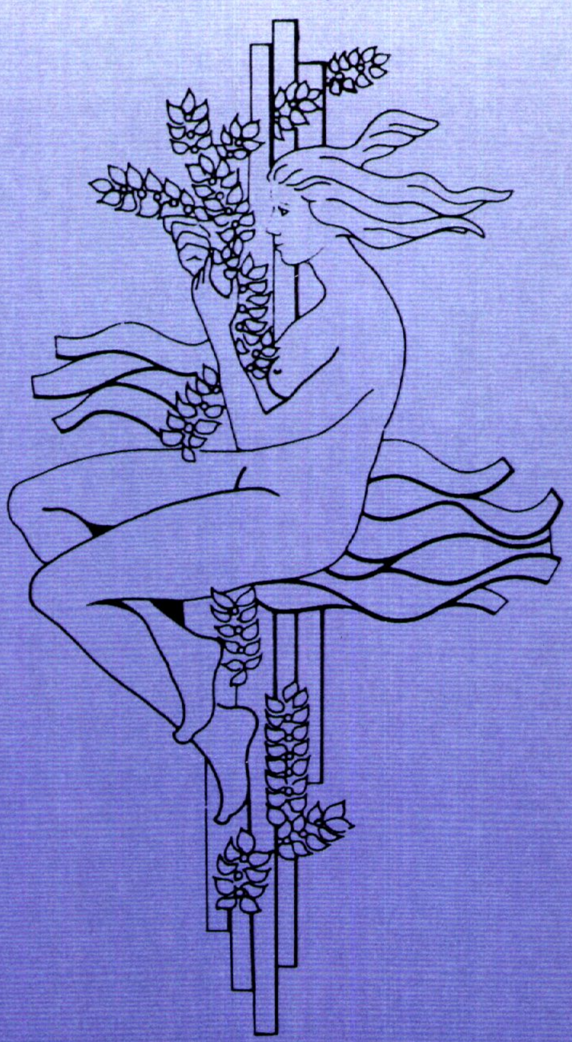
" FORGET ME NOT REPORT "



APRIL 1989

"FORGET ME NOT" REPORT

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CHAPTER I

INTRODUCTION

CHAPTER I

Introduction

The management of Elf Aquitaine Norge A/S decided on the 20th of January 1989 to launch a study in order to plan the necessary actions which have to be taken to adapt the Frigg Facilities Operations of the company to the decline of the Frigg Main Reservoir. A task force named "Forget me not" was established.

The task force has consisted of the following members:

Mr. Kåre A. Tjønneland (head of group)	Licence Cooperation Division
Mr. Alexandre Allard	Finance Division
Mr. Jean-Marc Benes	Management
Mr. Claude Cochard	Corporate Technical Evaluation Department
Mr. Tor Erik Hansen	Production Method Department
Mr. Emile Leporcher	Reservoir and Services Division

The Scope of Work of the task force was to evaluate all possible future use and organisation of the Frigg Field Facilities. Following area was to be considered:

- Possible future status of the Frigg Field Facilities
- Evaluation of future operating costs of the Frigg Field Facilities
- Potential customers for making use of the Frigg Field Facilities
- Financial consideration
- UK gas market
- Legal and contractual aspects

The purpose of the work was to establish a basis for a Frigg future strategy.

As seen from the report the task force has also included other areas of interest. This is done in order to make the report as adequate as possible.

The report is devided into 8 chapters. The first chapters contain the descriptional parts and relates to the existing facilities and market considerations. The middle parts contain the evaluations of pipeline infrastructure, future possible customers and financial considerations. In the last part of the report you will find the legal and contractual review of existing agreements and the possible future organisation of the owners of the Frigg Facilities.

Chapter II, first part of the report contains an executive summary of the whole report. This has been worked out in order to ease the reading of the report but it has to be stressed that the report should be read in its enirety if a full understanding of the conclusions and recommendations shall be obtained. The last part of this chapter outlines the recommendations in brief from the task force.

CHAPTER II

SUMMARY AND RECOMMENDATIONS

CHAPTER II - PART 1

Summary of Report

CHAPTER III

This chapter presents the technical description of the Frigg facilities (initial design, present status and some possibilities of future use). It includes 6 parts which are:

- General Presentation of the Frigg Field
- Description of the Frigg Field Facilities
- Frigg Transportation System
- Lifetime Analysis of Frigg Central Complex
- Potential Modifications
- Cost estimates

Part 1 General Presentation of the Frigg Field

Discovered in 1971, Frigg field started gas deliveries to BG PLC in 1977. The field is located on the Norwegian UK border, 190 km from the NW coast and 340 km from the Scottish coast. The initial gas in place was estimated to 235 BSCM.

The field development included two drilling platforms of 24 wells (CDP1 and DP2), two treatment platforms (TP1 and TCP2), one accommodation platform (QP) and one flare platform. The transportation system consists of two parallel 32" sealines (363 km) with a compression platform MCP01 located midway between Frigg and St. Fergus. The processing to commercial specifications takes place onshore at St. Fergus terminal (Scotland).

Part 2 Description of the Frigg Field Facilities

. Structures

Three types of structure exist on Frigg. TP1, TCP2 and CDP1 are concrete gravity structures. DP2 and QP are steel legged jackets of tubular construction. FP (Flare Platform) is an articulated steel tower mounted on a steel base.

. Description of facilities

Drilling platforms (CDP1 and DP2) include functions related to the wells only (wellhead, manifold, drilling/work-over rig) and some accommodation capacity.

Main processing facilities are located on TP1 and TCP2.

Processing facilities were initially designed to process Frigg gas of which compositional spectrum shows a high percentage of methane associated to a significantly quantity of heavy ends for this kind of gas. On Frigg, gas processing consists of:
- water/condensate/gas separation
- water/condensate separation
- gas dehydration
- gas export to St. Fergus Terminal
- condensate export through gas pipelines

In order to cope with the decrease of pressure of the reservoir, compressors were installed in 1982 on TCP2 in order to secure gas export to St. Fergus.

Main capacities of processing, compression, utilities are summarized hereunder:

	TP1	TCP2	TOTAL
Gas/cond./water separation (MSm^3/d)	60(3x20)	60(3x20)	120
Gas dehydration (MSm^3/d)	45(3x15)	60(3x20)	105
Gas metering (MSm^3/d)			
main export system	45(3x15)	60(3x20)	105
satellite		(10+7+6)x2	20
Condensate separation (m^3/d)	15000	15000	30000
Condensate injection (m^3/d)	900(2u)	900(2u)	1800
Water disposal (m^3/d) (coalescer, oil skimmer)	2500(1u)	2500(1u)	5000
Utilities:			
. power generation (MW)	7.5(3x2.5)	4.2(3x1.4)	11.7
. glycol regeneration (m^3/h)	45 (3x15)	45(3x15)	90
Compression:			
. Main compression			
power MW		3x32	96
flow rate MSm^3/d		3x40	80
utility power gen. MW		2x12	24
. Low pressure gas comp.			
power MW		2x12	24
flowrate Msm^3/d		2x4.5	9

Accommodation facilities totalize 276 beds split as follows:

- QP: 129
- CDP1: 81
- DP2: 66

. Connections to other fields.

Presently four fields are connected to the Frigg node. NEF and EF are two satellite gas fields which are operated from Frigg (satellite subsea developments). Odin operated by Esso is connected to Frigg for processing and export, Odin platform is a wellhead platform. North Alwyn is connected to TP1 which insures the riser platform function in order to allow the connection of the 24" Alwyn pipeline to the 32" sealines of the Frigg Transportation System.

- Possibilities for future connections

TP1 and TCP2 platforms include several risers and J tubes available for future use. Available diameters are:

Risers	J-tubes
32"x 149 bar	10"3/4
26"x 172 bar	12"
24"x 49 bar	

Part III Frigg Transportation System

The Frigg transportation system consists of
- two 32in pipelines (363 km long) in parallel between TP1/TCP2 and St. Fergus terminal
- one intermediate compression platform (MCP01) located midway
- the St. Fergus terminal

Assuming that inlet pressures at Frigg and arrival pressures at St. Fergus are respectively 148 bar and 47 bar, the transportation capacity of each 32" sealine is

- bare line (without MCP01 compressors): 33.3 MSm^3/d
- with one MCP01 compressor: 40.8 MSm^3/d
- with two MCP01 compressors (serial conf.): 43.8 MSm^3/d

Two 38000 HP turbo-compressors are installed on MCP01. Their use in parallel allows to reach maximum transportation capacity 87 MSm^3/d on a short term basis.

The St. Fergus terminal has been designed to process Frigg gas type. Processing consists of liquid (condensate and distillate) hydrocarbon removal, dehydration being previously performed at Frigg. The cooling to -18/-22°C using a freon system allows to get the commercial specifications ($38 < GCV < 40.5\ MJ/m^3$, $47.3 \leq WI < 52.2\ MJ/m^3$). The total gas treatment capacity is 108 MSm^3/d (6 trains of 18 MSm^3/d).

The liquids extracted from the chilling are stabilized to deliver condensate (stabilization capacity: 600 m^3/d).

Part IV Lifetime Analysis of Frigg Central Complex

In order to foresee the future use of Frigg, lifetime analysis have been performed for some platform structures and for some topside equipment. From this analysis it results that QP, TP1 and TCP2 structural lifetime has been extended up to 2025. This analysis has not been performed for the other structures.

The evaluations performed on TCP2 facilities allows reasonably to extend the lifetime of main rotating and process equipment of the Frigg Central Complex up to 2025.

Part V Potential Modifications

The load capacities of the Main Support Frame (MSF) of TP1 and TCP2 are respectively 10800 tonnes and 21300 tonnes (total capacity: 32100 tonnes). The present load occupancy is 25350 tonnes which leaves an availability of 6750 tonnes additional capacity (2800 tonnes on TP1, 3950 tonnes on TCP2). With some modifications and removal of some modules on TP1, this load availability could be raised to 11200 tonnes.

This load availability and the studies performed in the past allow to list the following potential services which could be supplied by Frigg to other fields:

- With minor modifications:
  . tie-in and transit operations
  . processing of "lean" gas similar to Frigg gas type
    - water/condensate/gas separation
    - gas dehydration
  . gas compression
- With medium size modifications:
  . gas/condensate separation with condensate return, gas dehydration
- With major modifications:
  . processing to commercial specifications (turbo-expander, liquid export)
  . CO_2 removal
  . crude oil separation and stabilization
  . treatment for water injection

Several risers of different diameters are available, other will be available with the shut-in of the drilling platforms, larger diameter risers (36, 40, 42") can be installed using some support structure, those ones allow to envisage a wide range of connection to Frigg.

Part VI Cost Estimates

This part presents cost information about future operating expenses in different operational configurations and possible additional investments.

Operating costs have been estimated with the presently known production forecasts. In this reference case, the routine opex will decrease progressively from 600 MNOK (in 1988) down to 120 MNOK (in 1998) when the only operational function on Frigg could be the Alwyn transit.

For future operation without gas production from the Frigg reservoir, so far as operation is concentrated on one platform (TCP2 for instance) it can reasonably be stated that opex will be minor than 300 MNOK, the start-up of the operation of the second platform introduces a critical step and opex become higher than 300 MNOK/year.

The allocation rules have been applied according to the principles of the Accommodation Agreement, on a first approach it can look like that proposed allocation rules trigger some abnormal increase of opex allocated to the association in charge of a third party operation, in reality this allocation is well enough representative of the actual operating costs of the involved operation.

Several investment estimates have been performed for different additional services which could take place on Frigg. The main comment is that all those additional projects could take a major advantage in terms of investment from the existing infrastructure (structure and utilities).

CHAPTER IV

Part 1 UK Gas Market

Treatment and transport capacity will be available at the Frigg Field and in the Frigg Transportation System in the near future.

While UK gas demand previously has been met by large fields we have recently seen a tendency to contract smaller and more numerous fields.

Committed gas supply will decrease as of 1991. British Gas is currently negotiating with several field owners to meet the decrease in volumes. British Gas may also well be able to cope with the situation by first using the historical cushion of gas paid for but not taken, lifting over the ACQ under the existing contracts, contract or integrate into existing contracts some minor Southern Basin developments where infrastructure is at hand or take some gas from satellites of existing fields.

Sufficient gas supply exists on the UK Continental Shelf to cover all demands up to year 2000. Gas contracts will be entered into for gas delivered from UK Central and Northern North Sea.

No major gas imports will be made from Norwegian suppliers in the 1990's, but if new Norwegian imports will be made around 2000, volumes have to be contracted in the 1990's.

No major gas contacts will be signed for deliveries of gas to UK for electricity generation before year 2000, but it is likely to belive that we will see a gradual increase up to 2000.

The gas price will stay at a low level in the years to come.

The strategy of future use of the Frigg Facilities cannot yet be based on exports of Norwegian Gas to UK before 2000. Due to the existing put option with British Gas in the Frigg Norwegian Gas Sales Agreement it might be possible to sell smaller satellites within blocks 25/1 and 25/2.

Part 2 The Continental Gas Market

The oil price slide which started in 1986 has restored gas competitive advantage against coal and electricity. The new deal of 1992, with a process of fiscal harmonisation and an open access to pipelines, the end of monopolies are favouarable to an increase of gas penetration.

However, until the mid -90's, continental Western Europe will likely remain in an over-supply situation.

At the end of 1990's, the market should become favourable to the sellers.

In a long-term outlook, it may be possible that gas market expansion be slackened because of non sufficient supplies.

The Frigg Facilities ought to have a link to the Continental gas grid in order to be able to offer services also to customers supplying the Continantal gas market.

CHAPTER V Pipeline Infrastructure Analysis

The future transportation specification of the Frigg Norwegian Pipeline will need to be redifined. A dry (commercial) gas specification has advantages, but will require an additional hydrocarbon dewpoint unit and a liquid export line. A rich gas specification for flowrates up to 30 MSCM/D can be applied, but will require additional facilities in St.Fergus. Further it will not make any export to the continent possible.

It is important to stress that none of the alternatives can reutilize the existing St.Fergus terminal.

The Frigg area will need a future liquid export solution in order to be more attractive for future customers. The following alternatives are selected:

- a pipeline to Bruce (if developed with pipeline)

- a pipeline to Sleipner - Kårstø (if selected) or alternatively:

- a pipeline to Ninian

- a pipeline to Kårstø directly.

For gas exports to UK, the FLAGS system will be a serious competitor. This because:

- the system has significant spare capacity by 1995,

- they are close to potential Norwegian fields,

- the pipeline can accept rich gas and NGL's which will reduce investments for eventual Norwegian fields

The pipeline from Alwyn to Frigg has spare capacity of 23 - 35 MSCM/D without or with recompression on Frigg. The pipeline should be regarded as part of the total system, because:

- the pipeline has capacity which could give tariff income,

- the pipeline can transport rich gas,

- the pipeline is located close to potential Norwegian fields, and will be a real competitor to FLAGS,

- the pipeline can be a link between the upper part of the North Sea and the continent.

The Frigg compressors are very well fitted for compression of Troll gas and if installed as part of Zeepipe they could increase the capacity and actually optimize the system. Further, by using the Frigg compressors the required power needed on Troll can be drastically reduced.

Installing a pipe between Frigg and Heimdal will increase the possibilities for Frigg and will open up new markets for both UK and Norwegian gases south of Frigg. Norwegian fields could pass through Heimdal - Frigg to UK or Norwegian plus UK gases to the continent.

CHAPTER VI

Part 1 Ordinary Field Service

In order to identify potential customers of Frigg facilities, an inventory of fields, discoveries and prospects within a large area around Frigg in Norwegian waters has been made. In UK waters, apart from Alwyn, Bruce and Beryl reserves in presently identified discoveries and prospects seem to be very small.

Three different categories have been identified:

- gas fields far from Frigg for which gas export via Frigg is one of several possible alternatives, especially in case of sale to UK. Services to be provided by Frigg could be: gas transit, gas export, gas recompression and, for some of them, if conditions are attractive enough, hydrocarbon dew point control.

  These fields are: Troll, Oseberg, Gullfaks South, 34/8, Huldra.
  Large gas quantities could be involved, with beginning not possible before 1995.

Outcome of decisions concerning use of Frigg facilities by these fields is quite uncertain and depend to a large extent on factors unrelated to Frigg. Existence of a pipe linking Frigg to the Statpipe-Zeepipe network would increase the probability of using Frigg facilities.

- small gas fields for which an economic development without use of Frigg facilities would be very difficult. At the present time, these are only discoveries or prospects; they represent about 60 Gsm3 gas of total gross (non probabilised) potential reserves in 6 accumulations. Of these, only one prospect is supposed to contain gas similar to Frigg gas. In the other ones, high pressure, high condensate content gas has been found or is the most likely fluid; processing such gas will most probably require a liquid hydrocarbon outlet from Frigg.

  These potential fields are: 25/2-12, Hild, 24/6, 30/10 Jurassic, 30/10 Paleocene, 24/4 FF'. Production from these fields could start in 1995 at the earliest.

- small oil fields close to Frigg: associated gas from such fields has a high NGL content; it can be sent to Frigg for process and export. Apart from this, it appears difficult but not impossible, depending on the circumstances, for Frigg to provide other services on an economically attractive basis.

  These potential fields are: Frøy, 25/2-5, 25/3.
  Earliest production start-up from these fields is end 1995.

Part 2 Frigg as a Gas Storage

Use of Frigg field as a gas storage appears technically feasible but could require important modifications of existing facilities like new compression facilities. Good reservoir sealing and the existing residual gas saturation will keep losses to a minimum. But, the high reservoir pressure is a major drawback, another being the fact that wells are on platforms not connected by bridge to the central complex.

But the potential needs for Frigg as a gas storage seem limited and would be attractive only as a marginal activity.

CHAPTER VII

Financial Considerations

Around 1995 both FUKA and FNA will run into an operating deficit on Frigg (tariff income minus opex). On the other hand the replacement value of Frigg topsides will be more than 10 BNOK in 1989 value. The financial challenge is to use this potential in order to transform a producing field into a service "profit-center".

The Ekofisk example

Such profit centers providing services to other fields exist in the North Sea. It appears more frequent in the Norwegian sector due to fiscal considerations (UK tax favours own investments i.e autonomy). The analysis of variuous systems in the Nortgh Sea provides also a clue to the transportation specifications, distances and capacities for successful service operations.

As a case example the Ekofisk system (especially gas services) has been analysed:
Most of the treatment income comes from gas. It represents about 800 MNOK a year. This level of revenue comes from the successful combination of dry gas/large spec oil outlets with existing spare capacities.

Frigg as a system must then choose the proper design and specification to enhance its own future:

- commercial gas from Frigg (pipe)
- connections to gas and liquid grids
- increase of the range of services (high and low pressure compression, water and hydrocarbon dewpoints units)

Frigg financial scenarios

How could Frigg last as a financially successful system (platforms, pipelines and terminal) ? First the unbalance between FUKA and FNA deficits has to be corrected to reflect the fact that between 1993 and 1997 most operations will be done on the Norwegian side. A shift from 60/40 operating cost division to an accomodation agreement will be necessary in order to cut the FUKA share of costs.

Two typical scenarios for Frigg future are then analysed:

1. Integrating Frigg in the Norwegian grid (Zeepipe) of gas transportation (Troll - Frigg - Sleipner).
2. Treating up to 20 MSCM/D of rich gas on Frigg.

The GRID scenario is based on a configuration of Zeepipe where Troll commercial gas goes through Frigg on its way to Sleipner. Necessary lobbying of Troll/Zeepipe partners and authorities will have to be based on technical as well as financial and commercial considerations such as:

- Existing compression not only can be used but improves the capacities of Zeepipe
- The quantities are huge, thus lowering the unitary cost
- Fuel gas for Frigg system and compression will be available at low cost (associated gases from the Frøy area)
- Some quantities could be sent to UK at low marginal cost.

In this minimal scenario Frigg would at least survive decently and at the same time be available for smaller satellite treatment at a marginal cost (25/2-12 or Northern Frigg UK/N prospects).

The TREATMENT scenario is based on investing 1.3 BNOK to treat rich gases during 3 periods of time:

- UK overspill (Beryl or others) from 1.10.1993 to 2002,
- Frigg satellites (25/2-12 or others) from 1996 to 2004,
- Oseberg or Gullfaks South from 2002 onwards.

These potential customers never exceed 20 MSCM/D. Frigg provides then a full range of services and receives tariffs in the range of 0.10 NOK/SCM (lower for UK customers due to lower taxation). In such a case Frigg does more than survive, it will be maintained as a profit center for the next 25 years.

The constraints on such a scenario are more severe as a liquid outlet is needed. Bruce - Forties or Sleipner - Kårstø are the most likely candidates in the time frame considered. Investment is unlikely for one customer alone. But two customers will be sufficient or even one if Frigg opex is covered by the GRID scenario.

As a whole financial survival seems feasable provided that all opportunities to use Frigg are seized, studied and lobbyed for. In short term, the most attractive soulutions are related to Troll. If Troll chooses a commercial gas option, then the GRID scenario should be studied in detail. If Troll chooses a raw gas option then every effort should be made to attract it to Frigg even if this means diluting our percentage in FNA.

In a more general sense Frigg need to disenclose itself by increasing its connections to existing and probable infrastructures. This being achieved, it will be easier to attrack treatment customers.

CHAPTER VIII

Part 1 Status of Existing Titles and Agreement

This part 1 contains a review of the duration of the Frigg production and transportation titles and of the agreement governing the relationships between FNA and FUKA.

All titles will continue in principles for the next twenty years or more, the Frigg Norwegian pipeline permit however may expire in 2003.

The depletion of the Frigg Field Reservoir will trigger the automatic termination of all agreements between FNA and FUKA. It appears that several agreements with third parties (Odin transportation contract, for instance) which would normally continue for several years, would be in jeopardy if that automatic termination should take place without the Frigg co-venturers having taken all precautionary steps to preserve their ability to perform under third party contracts.

It is concluded that the Frigg co-venturers ought to proceed with the discussion of future arrangements as soon as possible to avoid a contractual gap after the depletion of the Frigg Field Reservoir. It is also concluded that if the Frigg co-venturers should prove unable to arrive at satisfactory arrangements between them, the UK and Norwegian governments may impose arrangements, if only to protect third parties' rights.

Part 2 Schemes of Cooperation Between FNA and FUKA

Various schemes of ownership of the field installations and the pipelines are reviewed in this part 2.

We have identified and briefly described two extreme schemes:

(a) joint ownership of all facilities, and

(b) separate ownership and complete autonomy of all facilities

These extreme schemes are not regarded as capable of being accepted by the Frigg co-venturers at this stage. Between these two extreme schemes we have identified and briefly described three intermediate schemes:

(a) a scheme continuing in the future the current ownership arrangements of the platforms and the pipelines (i.e. joint ownership limited to the Frigg Central Complex, MCP01 and the initial Terminal facilities combined with separate ownership of risers, surfaces and pipelines),

(b) a scheme limiting joint ownership of the field installations to all or some of the facilities of mutual interest (QP in particular) combined with a distribution of the platforms on either side of the borderline to FNA and FUKA, and

(c) a scheme eliminating all joint ownership by the distribution of all assets currently jointly-owned, combined with a system of rent for the facilities of mutual interest (QP etc.).

The first two intermediate schemes seem capable of being accepted by the Frigg co-venturers and should be sufficiently flexible to keep all the options opened for the future activities of Frigg.

Part 3 Alternative Structure for Future Cooperation

This part 3 reviews the two models of legal structure for Frigg future activities:

- incorporated vehicle (treatment and/or transportation company)
- unincorporated vehicle (joint venture)

and concludes that the joint venture structure remains at this stage the more flexible structure for future Frigg activities.

Part 4 Imbalance in Field Ownership and Pipeline Ownership

This part 4 reviews the problems arising as a result of Statoil's acquisition of an additional interest in 1988 in the Frigg Norwegian pipeline whilst Statoil's interest at the Frigg licences remained at the same level (5%).

The procedure to rectify this imbalance is briefly described as well as the potential consequences of an increased participating interest of Statoil in the Frigg licences.

Noting that an increased participation of Statoil in the field facilities may assist in attracting customer fields to Frigg in the future, there is no immediate incentive to proceed with an offer to Statoil.

CHAPTER II - PART 2

Recommendations

The Frigg Facilities have today spare capacity to treat and transport new gases for the UK market. This capacity will increase in the coming years as the deliveries from the fields making use of the Frigg Facilities will decrease. Any new gases which could be sold to UK could be accomodated at Frigg without any new investments if the gases were of the same quality as the Frigg type gas.

This study has also shown that the Frigg Central Complex will be able to accomodate any type of conventional offshore hydrocarbon process equipment if the nesessary investments are made. There are no major obstacles as seen from the installations themselves. The Frigg Central Complex (QP, TP1, TCP2) has a fatigue liftetime to at least year 2025. It should be noted that no study has been performed in order to see how far beyond 2025 the installations can be kept active.

Further more TP1 and TCP2 have an additional load availability of 6800 tonnes on existing free spaces. Pipes up to 32" can enter the Frigg Central Complex by utilizing existing risers and J-tubes. For pipe sizes above 36" an additional structure will be needed.

The income from the Frigg Facilities has been significant in the past. We know that if no new customers are attracted to Frigg both FUKA and FNA will be faced with an operating deficit at the field around 1995. It is however a fact that the existing Frigg topsides have a value and we estimate such value to be in the range of about 10 to 15 BNOK (1989 value) and as such it should be a substantial point of departure for securing a future income.

The study has shown that the possibilities of selling larger quantities of new Norwegian gases to UK before year 2000 are rather small. We will however need new customers from around 1995 in order to keep up with the income while waiting for larger activities. We know that accumulations in the neighbourhood exist and that these accumulations might make use of Frigg Facilities as of 1995/96. They contain however, high pressure or high condensate content gas and if Frigg is serving those fields, a liquid hydrocarbon outlet from Frigg will most probably be required. A liquid export line in the neighbourhood of Frigg would therefore definitely increase the attractiveness of the Frigg Central Complex. EAN should together with the other Frigg partners work actively in different partnerships for such a liquid export line which Frigg could make use of when processing rich gases. The option proposed by Statoil to construct a condensate pipeline from Sleipner to Kårstø will be very interesting seen from Frigg's point of view.

As mentioned above the possibilities of selling new Norwegian gases to UK before year 2000 are rather limited. The Continental gas market is more attractive for the time being seen from a sellers point of view. New gas deliveries to this market should be achievable from mid. 1990's. A connection from Frigg to the continental gas grid would therefore also increase the attractiveness of Frigg. It goes without saying that in order to be able to connect Frigg to that market a customer is needed which will make the necessary investments possible.

The Troll field will start its deliveries to the Continent in 1996. At present, plans are to process the gas to commercial specification at the field and send it to Emden and Zeebrugge through a direct Troll - Sleipner pipeline. Troll gas may also be sent to Frigg if a pipeline via Frigg is more attractive to the Troll partners than a direct link. Frigg has and will have available compression capacity and could be able to boost the pressure through Sleipner up to the maximum of the pipeline. Such a scheme would also reduce the installed power needs on Troll and thereby make such a scheme more attractive to Troll. This solution should be looked into more in detail as soon as possible in order to start any necessary promotion before any firm decision is taken within the Troll group to install such compression power at the Troll field. It should also be mentioned that such an connection to Frigg might also open up possibilities for the Troll partners to make use of the Norwegian pipeline to the UK market. It will be much more simpel for BG to call for smaller quantities from Troll if needed if such a link already exists. Troll might also be able to deliver gas to take the swing factor from another gas field sold to BG or even sell gas to BG as spot quantities. All this should add up to an important value for the Troll partners with such a direct link to Frigg.

If the Frigg partners are able to "sell" such scheme they will receive income in a period which otherwise would have given deficit. It will further secure a link to the continental gas grid.

A possible compression on Frigg will require a lot of fuel and it might be possible to make partly use of the Frøy gas for such purpose if the Frøy field is decided to be developed.

In the neighbourhood of Frigg there are other fields which might be interested in treatment services from Frigg. If we are able to secure one customer for such service and thereby allow for the necessary investments on the field and the necessary connection to any liquid export system, this will easily attract other customers in need of the same services later. As seen from the report some smaller fields/prospects in this area will probably not be developed if the possibility of going to Frigg for processing and transport is not available. These smaller fields/prospects might also benefit to a large extent from a pipeline from Frigg to the Continental gas grid as it will probably be easier to sell smaller Norwegian fields to the Continent than to UK.

The Task Force will specially draw the Managements attention to the discussions within the Troll group on how to develop the Troll field. An interesting scheme which ought to be evaluated within EAN in more detail, and which could be an alternative to treatment at Troll or onshore, is to treat the whole of the Troll gas at Frigg to commercial specifications. If further evaluations conclude that this is an technical and economical attractive scheme, necessary promotions should be initiated. FNA might also in such a case consider to let the Troll partners become owners of the Frigg Central Complex. Any Troll processing on Frigg will secure the future of Frigg far into the next century.

The Task Force will also focus on the possibilities which might be opened by connecting Heimdal to Frigg. It will make arrangements possible for entering into agreements whereby gas already sold from Heimdal to the Continent can be physically sent to the UK market if fields further south is sold to the UK market but physically delivered to the Continent in replacement of the Heimdal gas.

Facing the coming situation on Frigg, the Task Force also finds it imperative to recommend to the Management a continued agressive exploration strategy within the Frigg area. New deposits in this area may be of great importance to Frigg if these are found and developed rapidly. The Task Force will further advise the Management to consider an accelerated drilling activity in the area

The Task Force is of the opinion that Frigg should have fair possibilities of becoming an important junction for the central part of the North Sea and to be established as a profitcenter as we see Ekofisk today. Frigg could also be able to serve as an important junction for UK fields as the connection Alwyn - Frigg might be utilized for northern fields and make it possible for UK field owners to play on two markets (UK and Continent) when negotiating with potential buyers. We will also point out the possibility that will exist for Elf UK being able to connect interests in UK fields to Alwyn and thereby be able to transport gas all the way to France.

It should be of the interest of FUKA to make future use of Frigg. The chances of getting new customers to Frigg are fairly good and any income will also affect FUKA as unitized facilities will have to be used. A new set of cost split arrangements for operating the Frigg Central Complex have to be agreed between FUKA and FNA based more on a cost for actual use principle. It would be natural to include such new split in an accomodation agreement for the future use of the facilities.

An extended processing service on Frigg will also be to the benefit of FUKA as any overspill gas can be taken into the Norwegian pipeline if the UK line is fully booked.

A formalized cooperation between FUKA and FNA should continue beyond the depletion of the Frigg main reservoir. The task force will recommend that the discussions initiated by EAN in connection with the accomodation agreement are reactivated. At the same time discussions related to the future accomodation agreement for the transportation system should start.

Conclusions:

The task force will recommend the following actions:

* Establish a task force in order to evaluate the technical and economical possibilities of treating Troll raw gas at Frigg.
* Establish a task force in order to evaluate the technical and economical possibilities of integrating Frigg into the Zeepipe system, using existing compressors.
* Assess the best liquid export soulutions for Frigg.
* Make a full study on the possibilities of utilizing the Frigg reservoir as a gas storage.
* Confirm an agressive exploration strategy in the Frigg area (on both sides of the border) and consider to accelerate the drilling activity.
* Reactivate the contractual negotiations with the Frigg Unit partners to secure signed accomodation agreements (field and transportation) within the depletion of the Frigg the main reservoir.
* Marketing the Frigg Facilities towards British and Norwegian Governments and towards potential future customers.

CHAPTER III

TECHNICAL DESCRIPTION

CHAPTER III - PART 1

General Presentation of the Frigg Field

1.0 Glossary of Terms

TP1	-	Treatment Platform no. 1
TCP2	-	Treatment and Compression Platform no. 2
QP	-	Quarters Platform
CDP1	-	Concrete Drilling Platform no. 1
DP2	-	Drilling Platform no. 2
FP	-	Flare Platform
NEF	-	North East Frigg
EF	-	East Frigg
MCPO1	-	Manifold Compression Platform no. 1
FNA	-	Frigg Norwegian Association
FUKA	-	Frigg UK Association
CCR	-	Central Control Room
FCDA	-	Field Control and Data Aquisition

Associated Gas	Natural gas associated with oil accumulations, which may be dissolved in the oil at reservoir conditions (dissolved gas) or may form a cap of free gas above the oil (gas cap)
Dry Gas	Natural gas composed mainly of methane with only minor amounts of ethane, propane and butane and little or no heavier hydrocarbons in the gasoline range.
Wet Gas	Natural gas having significant amounts of heavier hydrocarbons in the gasoline range
LPG	Liquefied Petroleum Gas. Essentially propane and/or butane meeting fuel use specifications, gaseous at normal temperature and pressure but held in the liquid state by pressure to facilitate storage and transport.
NGLs	Natural Gas Liquids. A mixture of liquids derived from natural gas, including propane, butane, ethane and gasoline components (pentane plus).
LNG	Liquefied Natural Gas. Natural gas, gaseous at normal temperature and pressure, but held in the liquid state at very low temperatures to facilitate storage and transport.
Condensate	A mixture of pentane and higher hydrocarbons
Commercial Gas	Dry natural gas (see above) which are complying with all of the buyer's gas quality specifications.
Live crude	Crude oil composed of heavy hydrocarbon liquids and significant amounts of lighter hydrocarbon liquids (NGL's). A live crude (or high true vapor pressure (TVP) crude) are normally complying with specification for TVP of about 125 psi at 60 ^{O}F.
Stabilized crude (or dead crude)	Crude oil composed of heavy hydrocarbon liquids with minor amount of NGL's. A stabilized crude (or low TVP crude) are normally complying with TVP or RVP specification of 10-14 psi at 60 ^{O}F. A stabilized crude will be transportable by tankers.

1.1 Initial Purpose

The Frigg field is a natural gas field which was discovered in 1971. It straddles the Norwegian - UK border of the North Sea continental shelf in blocks 25/1 and 10/1, between 59 Degrees 48' and 60 Degrees 00' North and between 01 Degree 97' and 02 Degree 15' East (European Datum 1960). It lies some 190 km from the Norwegian coast and 340 km from the Scottish coast. The location and the field layout are shown on Attachment III - 1.1

The reservoir consists of high porosity/permeability sand of lower Eocene and Paleocene age,probably deposited as a channelized marine fan. The maximum gas column was about 160 meters, underlain by a 9 meter thick oil leg and covering an area of 115 km^2.

The initial gas in place of the field was estimated to 235 BSm^3.
The gas contains 91 % methane and has a density of 0.71 kg/m^3.

The facilities of the Frigg Field and of the transportation system were designed to process and export up to 80 MSm^3/d of gas and have been delivering gas since 1977. They are located in 100 m of waterdepth.

1.2 General Description of the Frigg Facilities

1.2.1 General Arrangement

The Frigg field facitilies include six platforms:

- Two drilling platforms (CDP1 and DP2)
- Two process platforms (TP1 and TCP2)
- One living quarter platform (QP)
- One flare platform (FP)

The gas is exported to St. Fergus terminal in Scotland through two 32" pipelines (363 km long) in parallel.

In addition, the Frigg central complex is connected to:

- Two satellite fields (East Frigg and North East Frigg) operated by EAN
- Odin field operated by ESSO Norge (NW block 30/10)
- North Alwyn Field operated by TOM (UK sector)

The main functions of the Frigg central complex are:

- gas processing:	water/condensate/gas separation gas dehydration (water dew point)
- compression	

A sketch showing the Frigg Facilities is enclosed as Attachment III - 1.2.

1.2.2 Drilling Platforms

(a) CDP1
is a concrete structure standing in 97 m of water, and serves as a support for 24 gas wells and living quarters. It is located in the UK block 10/1.

Gas produced from these (23 wells are gas producers) wells is routed to TP1 via two 26" flow lines (500 m long). A maximum wellhead pressure of 172 barg and a gas flow rate of 2.0 to 2.5 MSm^3/D per well were used for the design of the topsides facilities (scrubbers and piping). Two wells (well 25/26) on CDP1 are used as observation wells.

(b) DP2
is a eight-legged steel lattice structure anchored by piles, it stands in 98 m of water, and serves as a support for 24 gas producing wells and living quarter. It is located in the Norwegian sector (block 25/1).

Gas produced from 23 of these wells passes through two 26" flow lines to TCP2 (700 m long). Design parameters are similar to the CDP1 ones. Two wells on DP2 (well 22/24) have been used for observation purposes and one well (well 3) is for liquid injection (including methanolated water from ODIN, NEF and EAST FRIGG) from TCP2.

1.2.3 Central Complex

The Frigg central complex comprises 4 platforms QP, TP1, TCP2 and FP. The main function of the overhaul complex is to treat and compress gas for further export to St. Fergus, separated hydrocarbon liquids are exported in commingted flow with the gas. A simplified process flow diagram is presented on Attachment III - 1.3.

(a) QP
is a steel jacket-type structure of four tubular legs, and stands in 104 m of water. It is equipped with a control room and living quarters capable of accommodating 120 persons. It straddles the Norwegian/UK border.

(b) TP1
is a concrete structure with a parallel caisson base surmounted by two colums supporting a steel deck, and stands in 103 m of water. Gas produced by CDP1 is treated on this platform before being exported to the St. Fergus terminal. Gas produced and treated on Alwyn transits via this platform to the St. Fergus terminal.

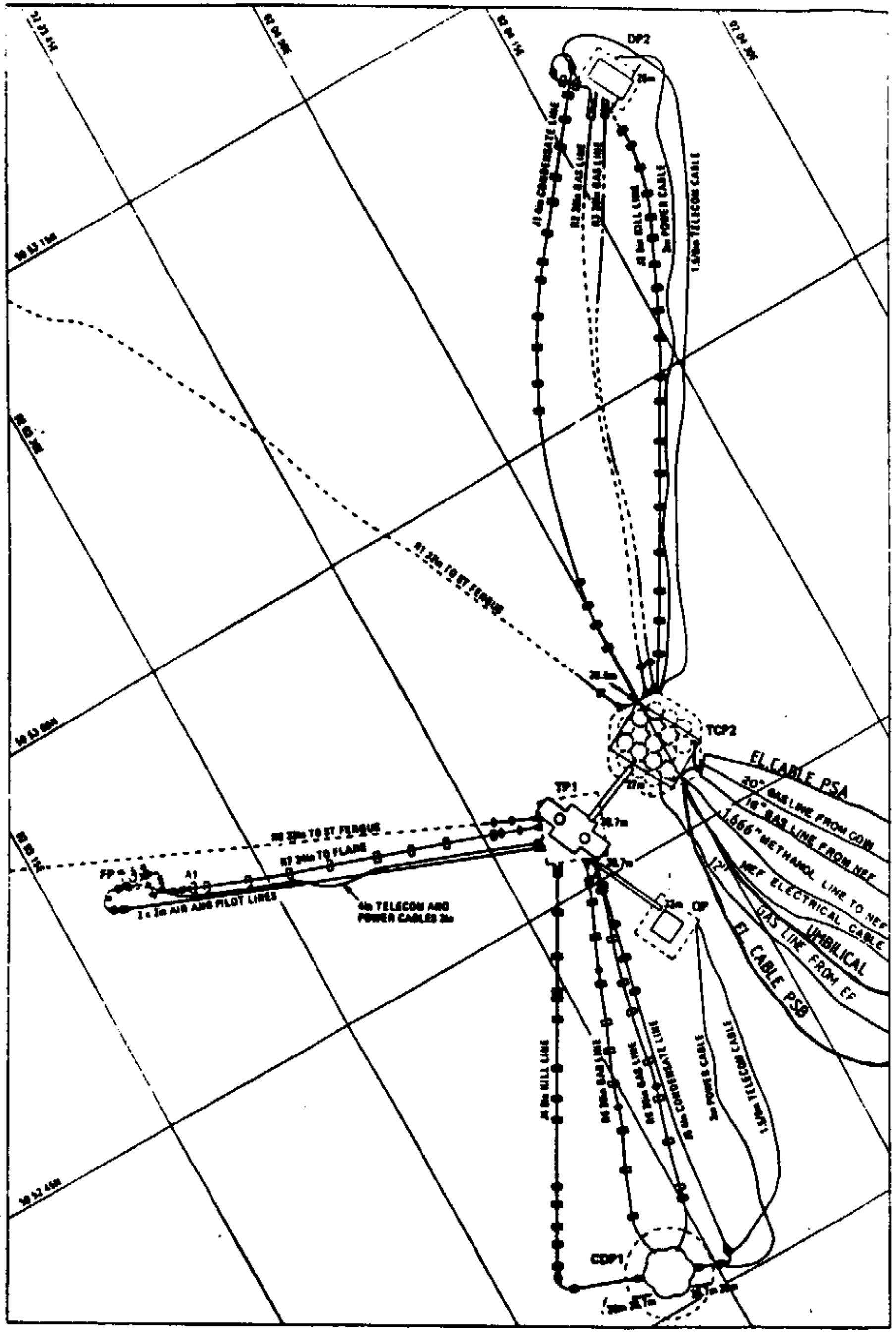
On TP1 the gas is treated to prevent water condensation and hydrate formation during its transportatoin to St. Fergus. Three parallel treatment streams are installed; each stream has a maximum flow capacity of 15 MSm^3/D, and contains a separator, glycol contactor and glycol regeneration unit. Equipment is also installed for condensate and fuel gas treatment with interconnection between TP1 and TCP2.

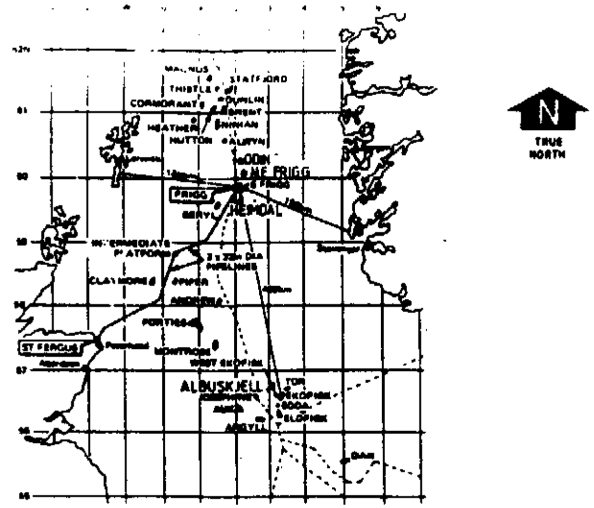
The gas produced and treated on the Alwyn field is transported to TP1 through a 24" line then transferred to the UK 32" sea line to St. Fergus terminal.

A 20" diameter cold vent stack is provided on TP1 as a back-up to the main flare platform, but depressurization must be limited to 6 MSm^3/D when this is in use.

This back-up system has been modified to handle low temperature gas as a result of Alwyn gas arriving on TP1 at low temperature. Consequently the cold vent system acts as a permanent relief system for equipment and piping handling cold gas as well as being a back-up system for the flare platform.
This platform is located in the UK sector.

(c) TCP2
is a concrete structure with a hexagon caisson base surmounted by three columns supporting a steel deck, and stands in 103 m of water. Gas produced by DP2, North East Frigg, East Frigg and Odin is treated, compressed on this platform before being transported to the St. Fergus terminal.





PLATFORM CO-ORDINATES			
STRUCTURE	GEOGRAPHICAL CO-ORDINATES	UTM CO-ORDINATES	TRUE ORIENTATION
DP1 MAST	59° 52' [illegible] N 02° 04' [illegible] E	6 [illegible] N [illegible] E	—
DP2	59° 52' [illegible] N 02° 04' [illegible] E	6 [illegible] N [illegible] E	[illegible]
TP1	59° 52' 47" [illegible] N 02° [illegible] E	6 [illegible] N 447 [illegible] E	[illegible]
TCP2	59° 52' [illegible] N 02° [illegible] E	6 [illegible] N 447 [illegible] E	331° [illegible]
QP	59° 52' [illegible] N 02° [illegible] E	6 [illegible] N 447 [illegible] E	[illegible] 17' [illegible]
CDP1	59° 52' 31" [illegible] N 02° 05' 41" 746 E	6 [illegible] N 447 [illegible] E	[illegible] 41"
FP	59° 52' 53" 519 N 02° 03' 21" [illegible] E	6 [illegible] N 447 [illegible] E	—

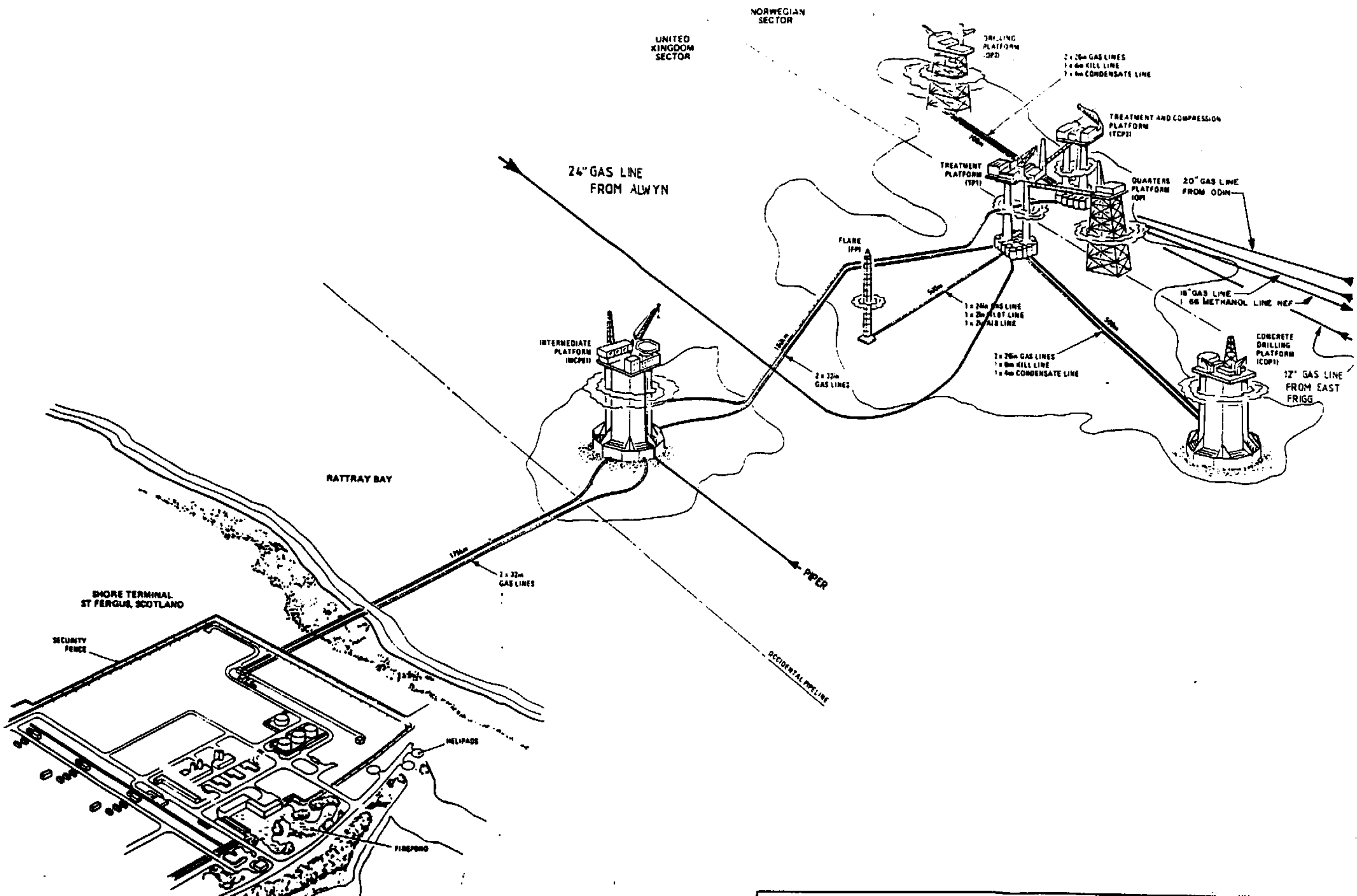
KEY

- UNBURIED LINE
- BURIED LINE OR LINE IN A TRENCH
- CONCRETE BLOCK (25t)
- CONCRETE BLOCK (10t)
- CONCRETE SADDLES
- GROUT BAG
- GROUT BAG NOT IN USE
- MATTRESS
- GREASE BOX
- SEAL PROTECTION
- SEAL PROTECTION WITH FLOW LIMITER
- SEAL PROTECTION WITH PERMANENT SEAL
- HYPERBARIC WELDING POSITION
- 20m CLEARANCE UNDER BRIDGE

NOTE
RIP RAP EXTENDS FROM TP1 TO CONCRETE BLOCK A1 ON 87 24in FLARE LINE

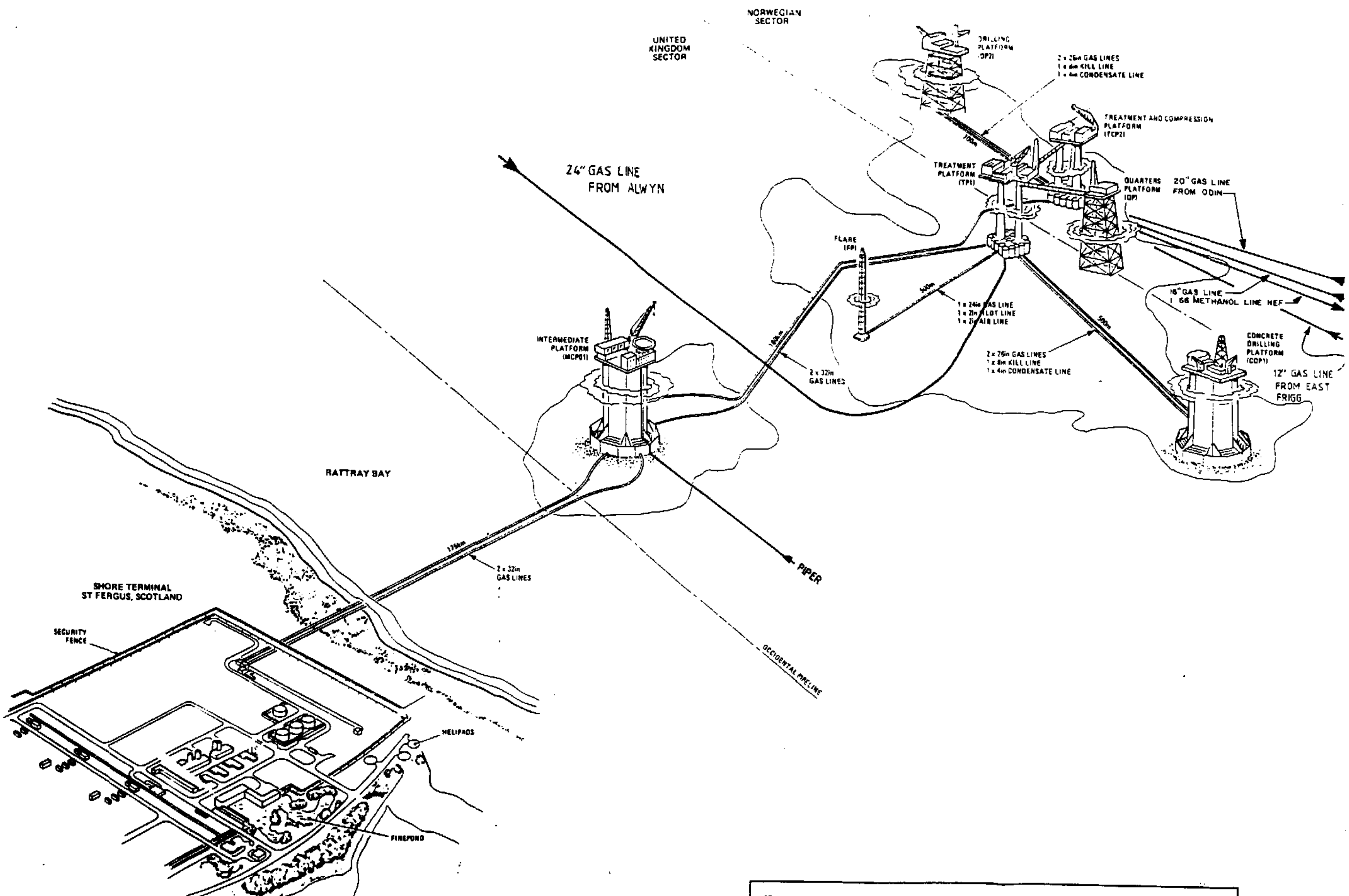
FRIGG FIELD - LOCATION

Attachment
III.1.2



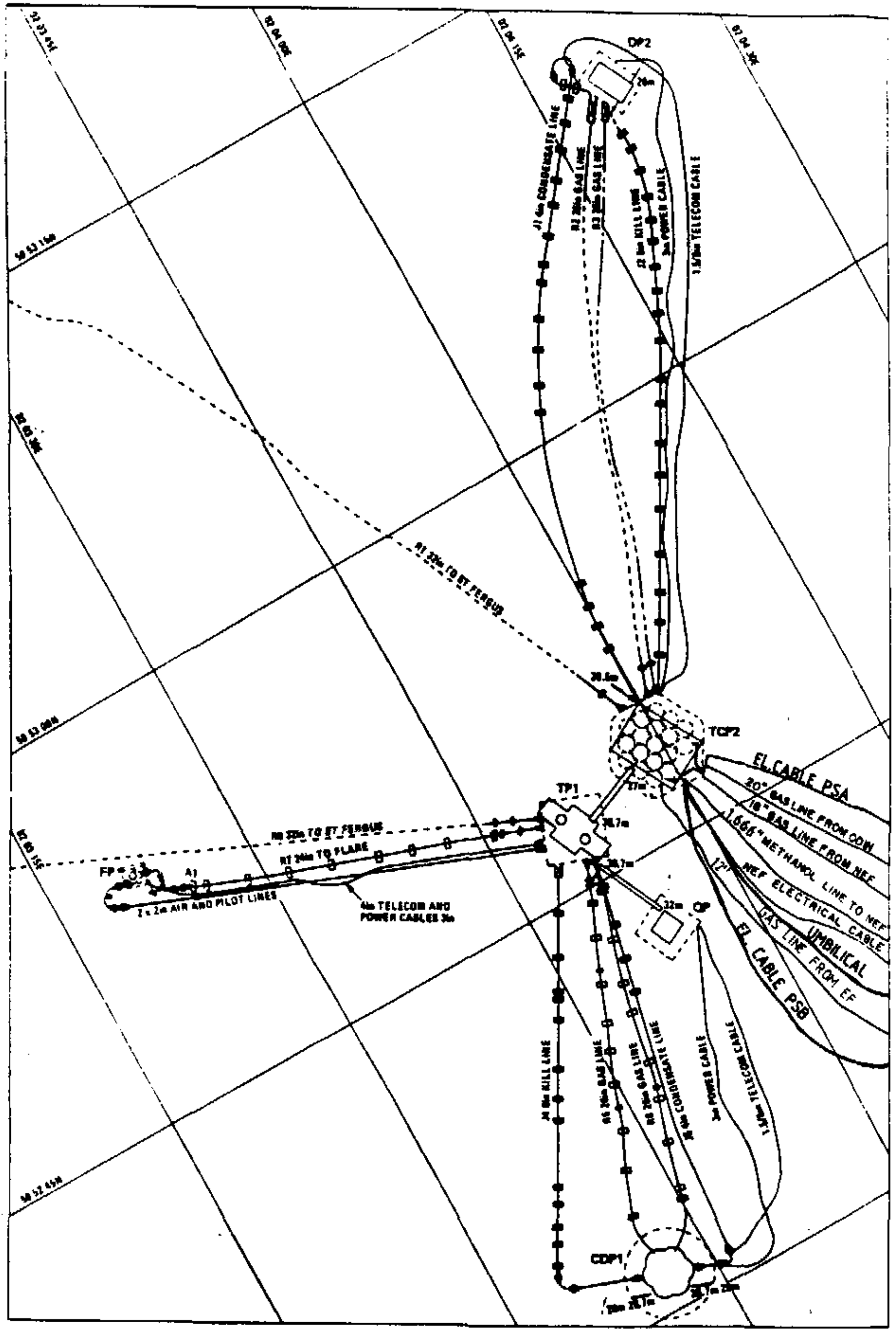
FRIGG FIELD - SUMMARY OF INSTALLATION

Attachment III.1.2

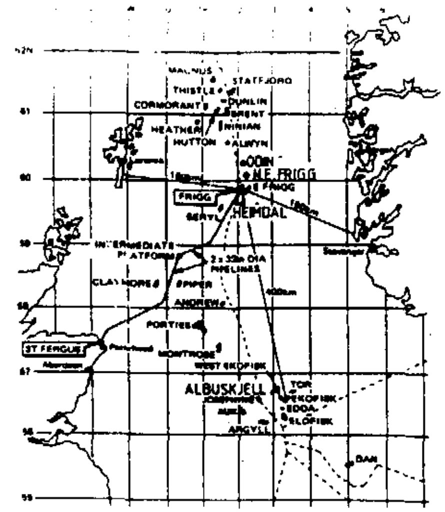


FRIGG FIELD - SUMMARY OF INSTALLATION

Attachment III.1.1



NOTE
RIP RAP EXTENDS FROM TP1 TO CONCRETE BLOCK A1 ON R7 24in FLARE LINE



TRUE NORTH

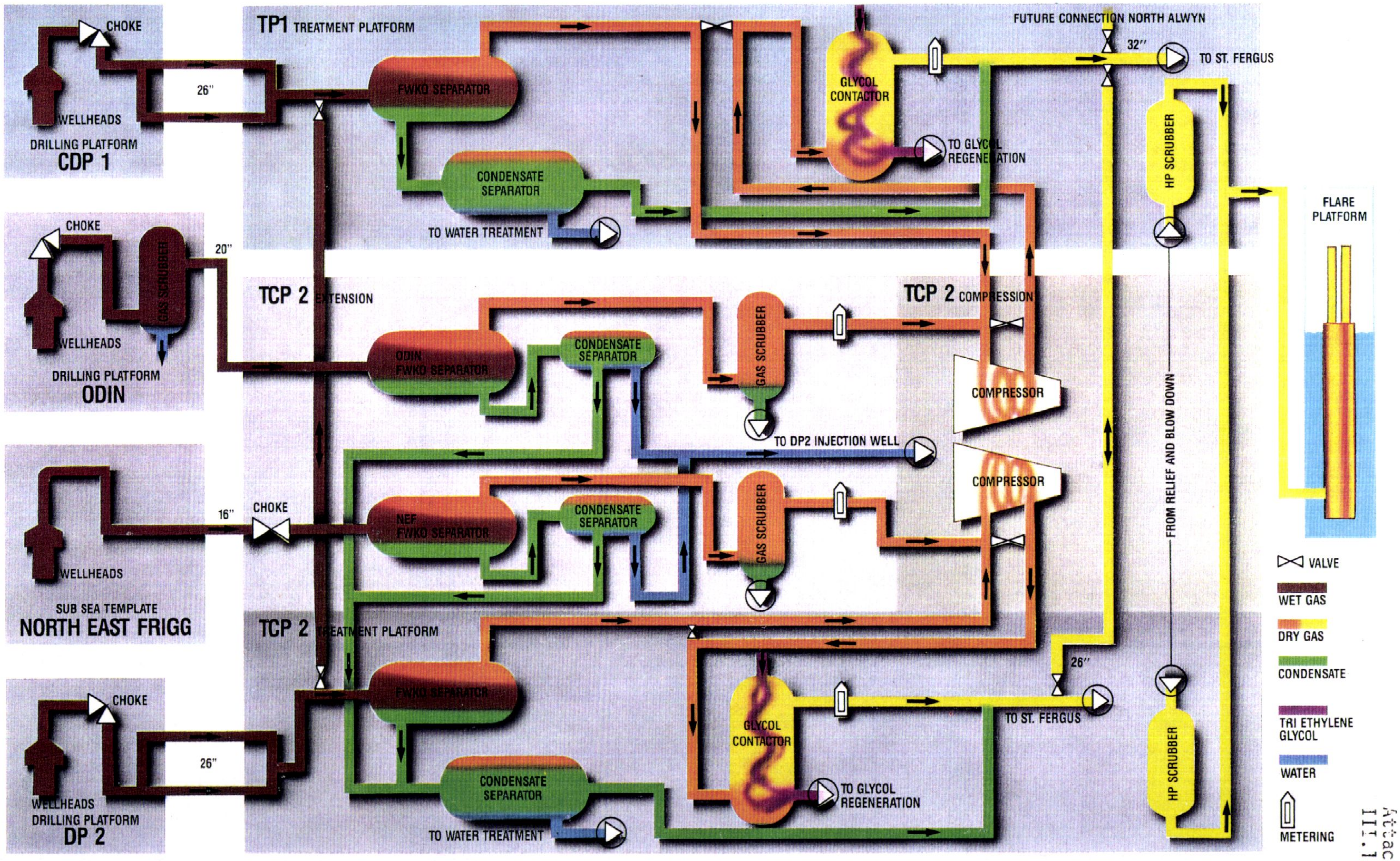
PLATFORM CO-ORDINATES			
STRUCTURE	GEOGRAPHICAL CO-ORDINATES	UTM CO-ORDINATES	TRUE ORIENTATION
DP1 MAST	59° 52' 40" 710 N 02° 04' 40" [illegible] E	6 638 334.30 N 446 506.06 E	—
DP2	59° 53' 10" 875 N 02° 04' 29" [illegible] E	6 638 [illegible] N 446 [illegible] E	332° 52' 17"
TP1	59° 52' 47" 270 N 02° 03' 51" 300 E	6 638 [illegible] N 447 610 30 E	336° 20' 28"
TCP2	59° 52' 46" 440 N 02° 03' 50" 530 E	6 638 [illegible] 14 N 447 743 02 E	331° 03' 06"
QP	59° 52' 42" 421 N 02° 03' 53" 825 E	6 638 300 00 N 447 862 90 E	336° 17' 43"
CDP1	59° 52' 31" 300 N 02° 03' 41" 745 E	6 638 000 30 N 447 [illegible] 81 E	010° 37' 41"
FP	58° 52' 53" 519 N 02° 03' 21" 293 E	6 638 740 50 N 447 150 50 E	—

KEY

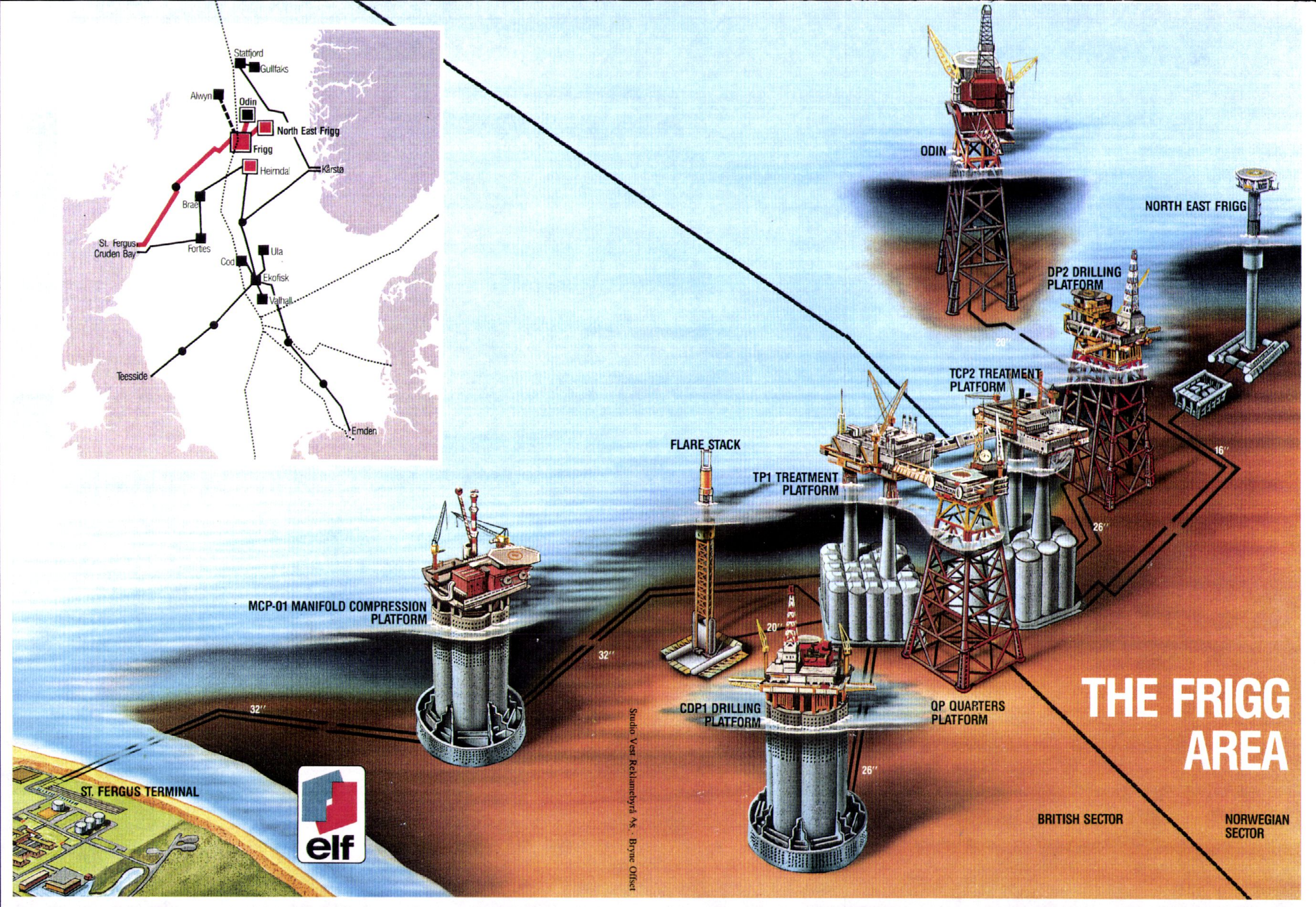
- UNBURIED LINE
- BURIED LINE OR LINE IN A TRENCH
- CONCRETE BLOCK (25t)
- CONCRETE BLOCK (10t)
- CONCRETE SADDLES
- GROUT BAG
- GROUT BAG NOT IN USE
- MATTRESS
- GREASE BOX
- SEAL PROTECTION
- SEAL PROTECTION WITH FLOW LIMITER
- SEAL PROTECTION WITH PERMANENT SEAL
- HYPERBARIC WELDING POSITION
- 20m CLEARANCE UNDER BRIDGE

FRIGG FIELD – LOCATION

FRIGG FIELD PROCESS FLOW



Attachment III.1.3


Statfjord
Gullfaks
Alwyn
Odin
North East Frigg
Frigg
Heimdal
Kårstø
Brae
St. Fergus
Cruden Bay
Forties
Ula
Cod
Ekofisk
Valhall
Teesside
Emden
ODIN
NORTH EAST FRIGG
DP2 DRILLING PLATFORM
20″
TCP2 TREATMENT PLATFORM
16″
FLARE STACK
TP1 TREATMENT PLATFORM
26″
MCP-01 MANIFOLD COMPRESSION PLATFORM
32″
20″
32″
CDP1 DRILLING PLATFORM
QP QUARTERS PLATFORM
26″
THE FRIGG AREA
ST. FERGUS TERMINAL
elf
Studio Vest Reklamebyrå As. · Bryne Offset
BRITISH SECTOR
NORWEGIAN SECTOR

The process equipment installed on TCP2 is similar to that on TP1, except for one FWKO vessel which is implemented in the Odin stream process equipment, and the addition of gas compression equipment to boost gas pressure prior to dehydration and pipeline export to St. Fergus. A 26" line from TP1 to TCP2 feeds TP1 gas to the compressor suction. A 24" line returns compressed gas from TCP2 to the TP1 dehydration system. TCP2 has a total treatment capacity of 3 x 20 MSm^3/D. 32" dry gas interconnection is provided between TP1 and TCP2. Thus after the gas has been metered it can be exported through the sub-sea line of either platform to St. Fergus. The TCP2 compressors have a total maximum capacity of 3 x 40 MSm^3/D.
This platform is located in the Norwegian sector.

(d) FP
It is a steel articulated column with a concrete ballasted steel base, and stands in 106 m of water. It is provided to depressurize TP1 and TCP2 process equipment which in case of an emergency, can be flared at a very high flow rate. TP1 is connected to FP by a 24 inch subsea line; TCP2 is connected into the start of the sea line on TP1 via the inter-platform brigde. FP is certified for a continous flow rate of 10 MSm^3/D with a maximum allowable short period flow rate of 34 MSm^3/D.

This facility is located in the UK area 500 m away from TP1. The structure is certified as a separate platform.

CHAPTER III - PART 2

Description of the Frigg Field Facilities

2.1 Treatment Platform No. 1 (TP1)

2.1.1 Structure

The platform TP1, standing in 104 m of water, is a concrete gravity structure comprising a skirt, base, caisson and two deck support columns.
Risers, and J-tubes are led up the inside of the columns to the deck.
The secondary structure is connected to the tops of the support columns.

The caisson and support columns are filled with sea water up to sea level. This water acts as ballast and ensures that no pressure differential exists between the inside of the structure and the surrounding sea.

The main deck structure (steel support frame) contains the pancakes and modules which have the production facilities.

A bridge connecting TP1 and TCP2 has its landing built into the deck structure.

Sketches of the structure are enclosed as Attachments III - 2.1, III - 2.2 and III - 2.3 hereto.

2.1.2 Topsides Facilities

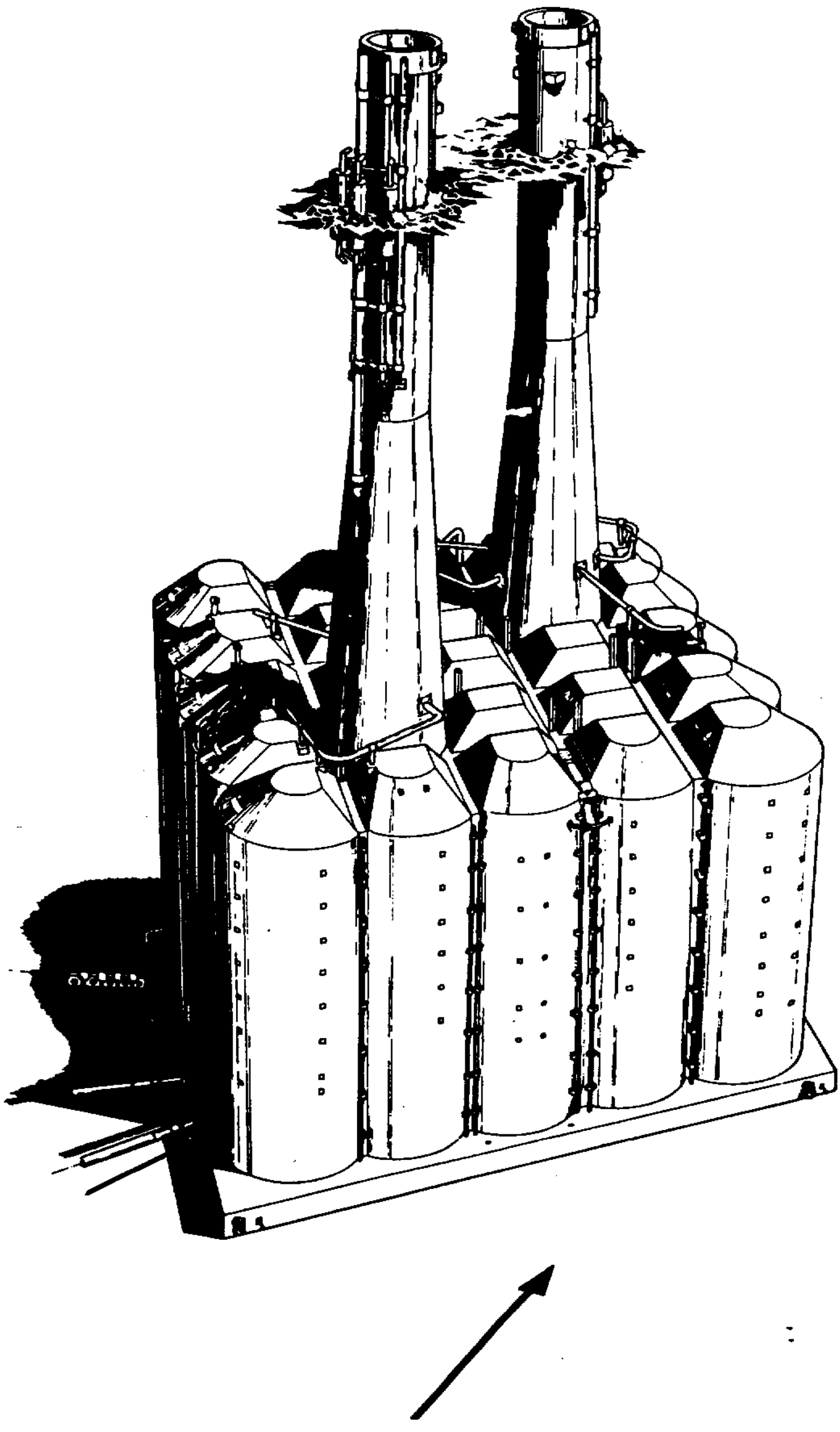
2.1.2.1 Process Treatment Facilities

TP1 includes 3 parallell gas treatment streams each containing 1 free water knockout separator (FWKO), a glycol contactor, a metering facility and four flow control valves. Liquid extracted is treated in one common treatment stream containing one condensate separator, one coalescer, one condensate storage/recycling tank and one oil skimmer.

The process facilities have the following proven capacities:

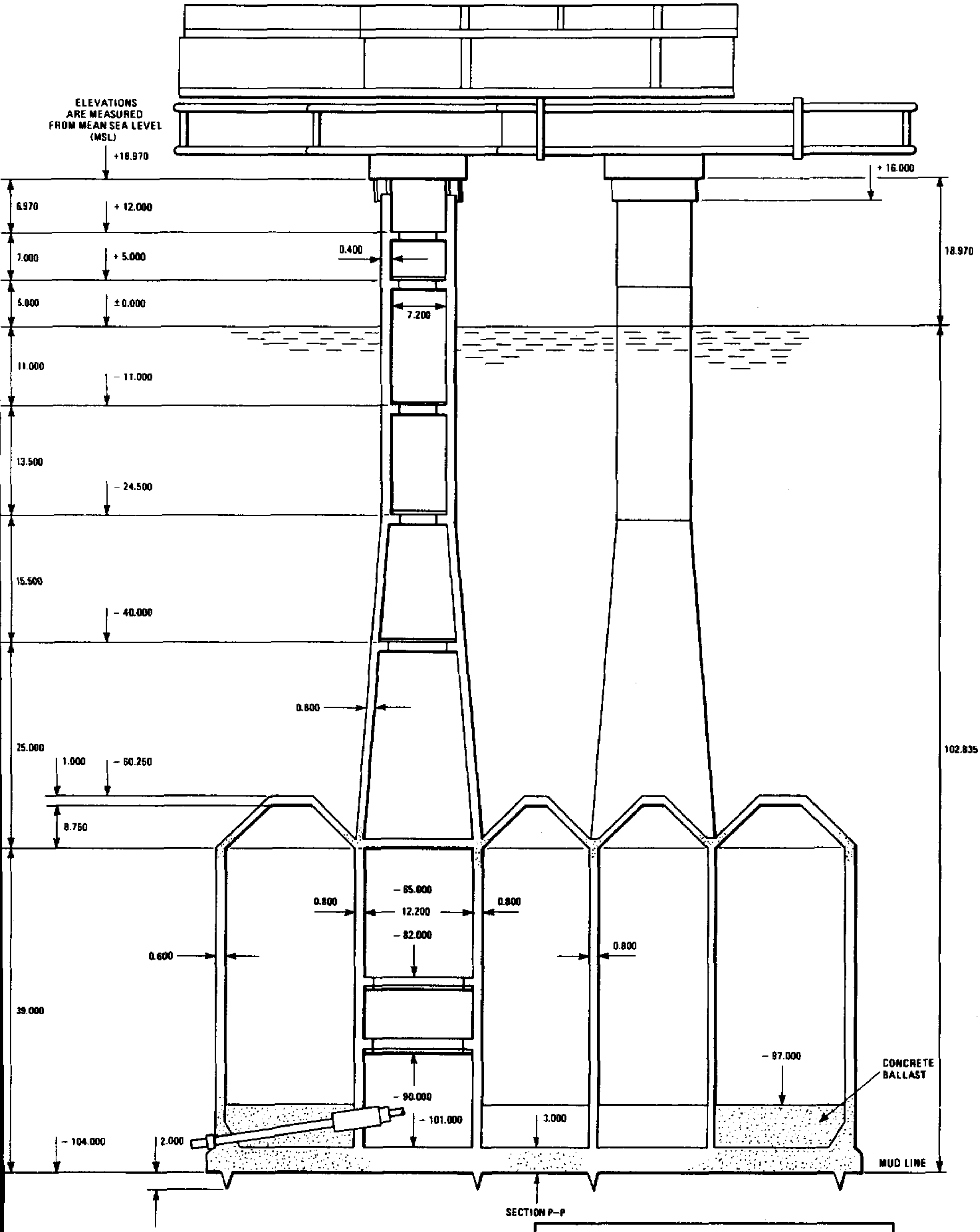
Service	No. of units	capacity	Unit Total cap.	Remarks
- Gas/cond./water separator	3	>20MSm^3/D	>60MSm^3/D	
- Gas dehydration	3	>15MSm^3/D	>45MSm^3/D	
- Fiscal gas metering	3	15MSm^3/D	45MSm^3/D	Defining present max.capacity
- Condensate separator	1	15000m^3/D	15000m^3/D	5 min retention time
- Condensate injection	2	480 m^3/D	900 m^3/D	
- Water treatment	1	2500 m^3/D	2500m^3/D	5 min retention time

Attachment
III.2.1



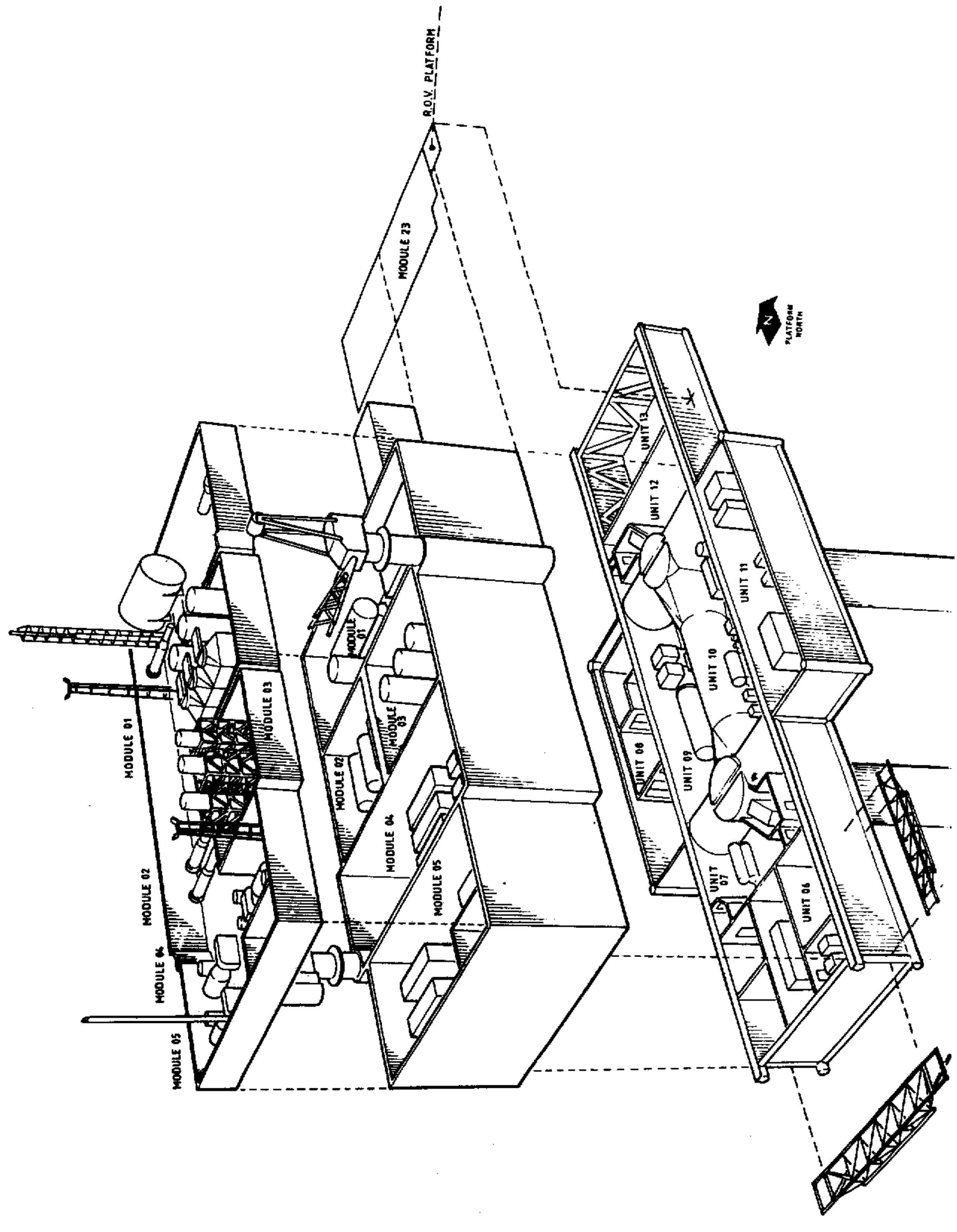
TP1 - General view.

Attachment
III.2.2



PRIMARY STRUCTURE

Attachment
III.2.3



SECONDARY STRUCTURE

2.1.2.2 Process Utilities

TP1 treatment facilities comprises the following main process and general utility systems: Power generation, glycol regeneration, fuel-gas treatment, high and low pressure relief, nitrogen generation, methanol, glycol and diesel storage, compressed air.

The facilities have the following capacities:

Power generation (3 Ruston generators)	: 3 x 2.5 MW
Glycol regeneration	: 3 x 15 m^3/hr
Fuel gas treatment	: 5000 m^3/hr
Low pressure relief	: 60 000 Sm^3/D
Methanol storage	: 140 m^3
Compressed air	: 2 x 510 Sm^3/hr

2.1.3 TP1 Future Utilization

In the present status, TP1 has an available load capacity of 2800 tonnes. In terms of area, without modifications or removal, 1100 m^2 and 290 m^2 are respectively available on the main deck and the cellar deck.
A general view of TP1 is showed on Attachment III - 2.4.

2.1.4 Flowlines and Risers

TP1 comprises the following risers and J-tubes.

Riser. no.	Col.no.	Dimensions	Status today	Free in	Remarks	MAWP bar
R8	2	32"x1.094"	in use St. Fergus	---		149
R1X	2	32"x1.094"	future riser	now	complete to deck	149
R1BU	2	32"x1.094"	back up for R8	now	not complete	149
R2X	2	24"x1.094"	in use Alwyn	---		185
R5	1	26"x1.0"	in use from CDP1	1990/91		172
R3BU	1	26"x1.0"	back-up for R5	now	not complete	172
R6	1	26"x1.0"	in use from CDP1	1990/91		172
R4BU	1	26"x1.0"	back-up for R6	now	not complete	172
R7	2	24"x0.625"	in use Flare	1994	cold temp.st.	49
R2BU	2	24"x0.625"	back-up for R7		cold temp.st. not complete	49

Attachment III.2.4

J-tubes

Tub no.	Col.no	J-tube dia(in)	Flowline dia	Content	Remarks
J1	1	18		-	Two power cables
J2		10.75		-	Empty
J3		10.75		2"	Fuel gas TP1 to FP
			2	Air	
J4		18"		8"(345 bar)	N_2 storage TP1 to CDP1
J5		10.75		4"(172 bar)	Condensate TP1 to CDP1

2.2 Treatment Compression Platform no. 2 (TCP2)

2.2.1 Structure

The platform TCP2, standing in 104 m of water, is a concrete gravity structure comprising a skirt, base, caisson and three deck support columns.
Risers and J-tubes are led up the inside of two of the columns to the deck.
The secondary structure is connected to the tops of the support columns.

The caisson and support columns no. 3 and 5 are filled with sea water up to sea level. This water acts as ballast and ensures that no pressure differential exists between the inside of the structure and the surrounding sea.

The main deck structure (steel support frame) contains the pancakes and modules which have the production facilities.

A bridge connecting TP1 and TCP2 has its landing built into the deck structure.

A sketch of the general view of the structure is enclosed as Attachment III - 2.5 hereto.

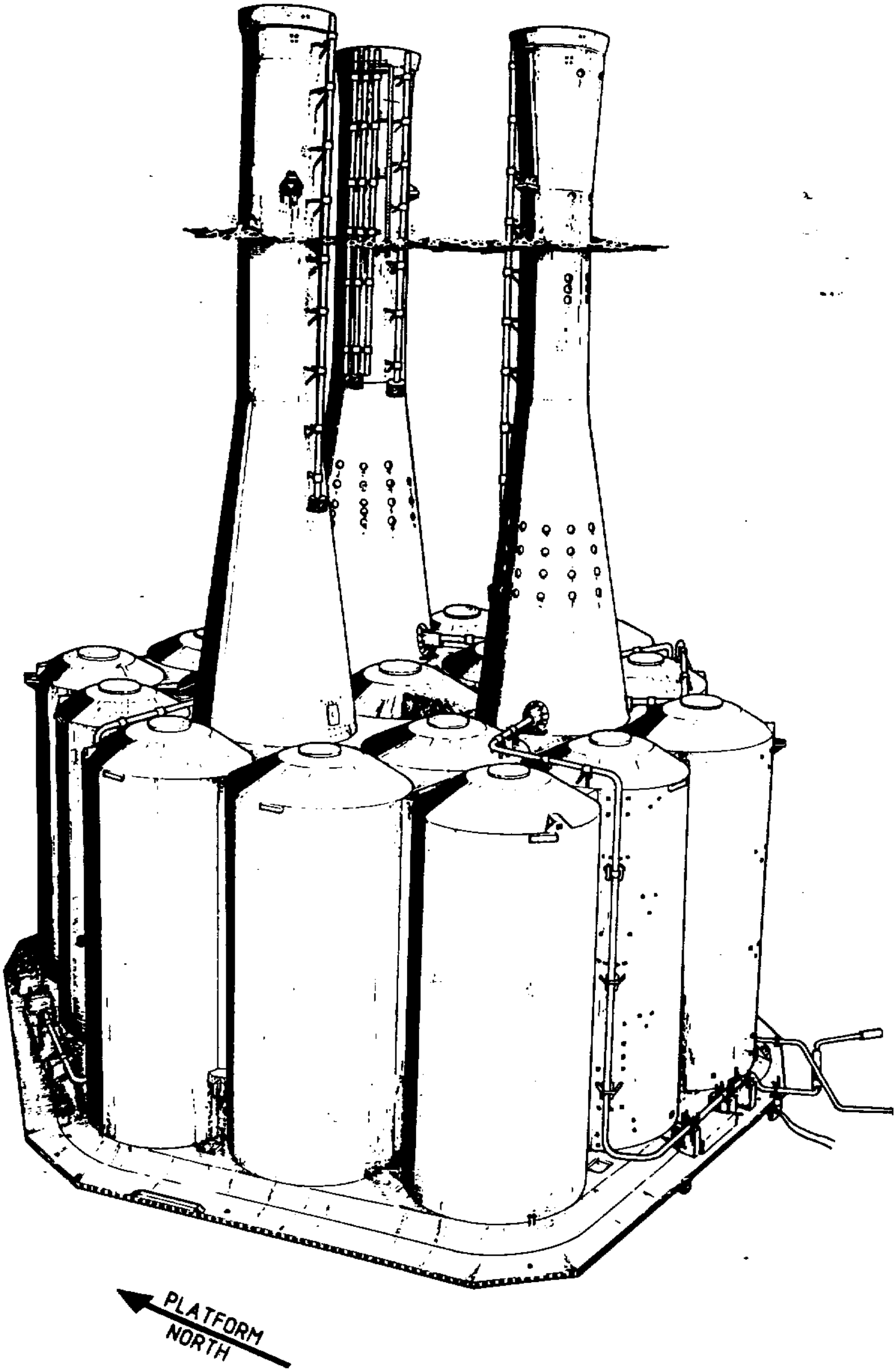
2.2.2 Topsides Facilities

The topside facilities are shown as sketches on Attachments II - 2.6 and II - 2.7 enclosed hereto.

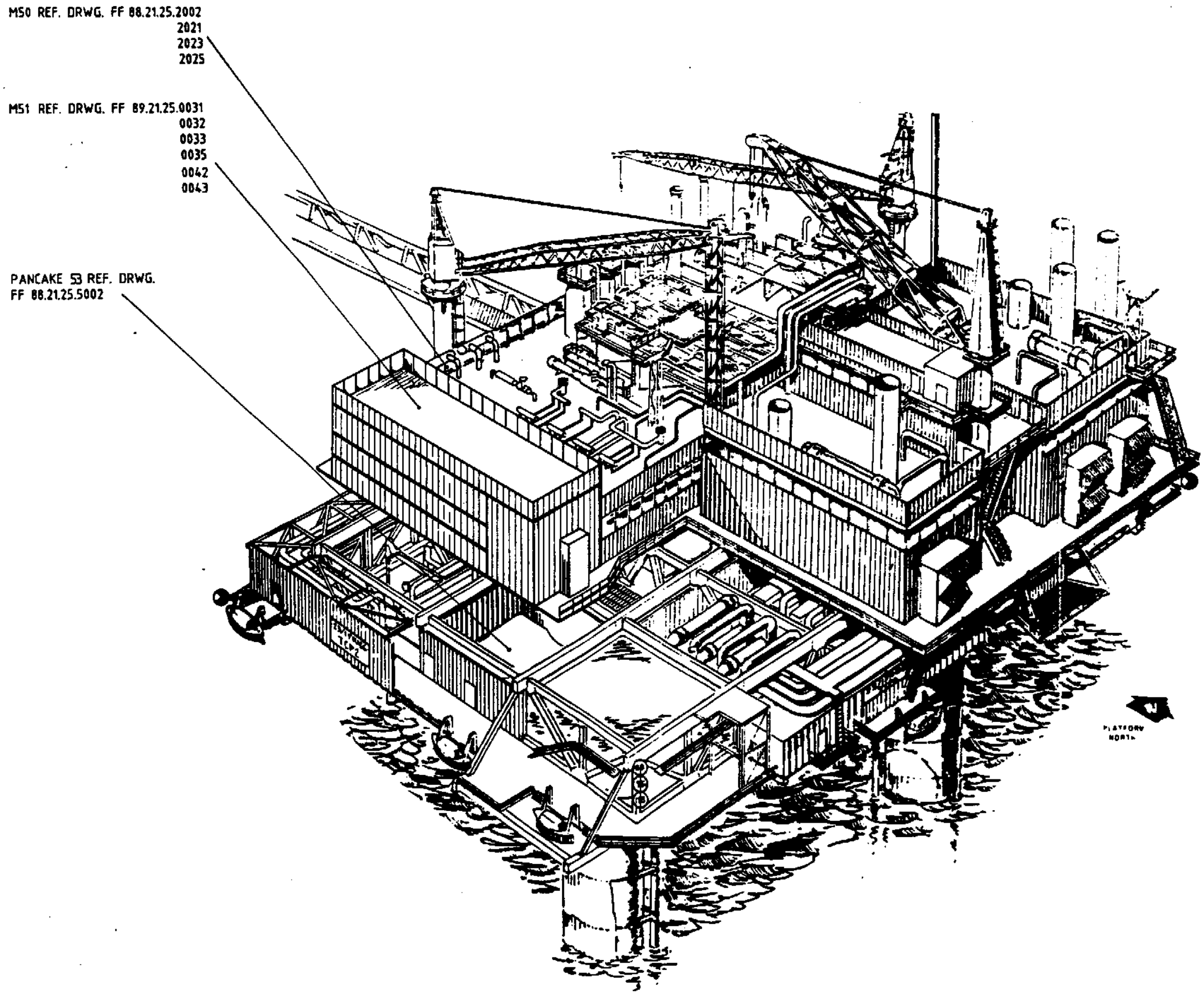
2.2.2.1 Process Treatment Facilities

TCP2 treatment includes 3 parallell gas treatment streams each containing 1 free water knockout separator (FWKO), a glycol contactor, a metering facility and four flow control valves. Liquid extracted is treated in one common treatment stream containing one condensate separator, one coalescer, one condensate storage/recycle tank and one oil skimmer.

The process facilities have the following proven capacities:



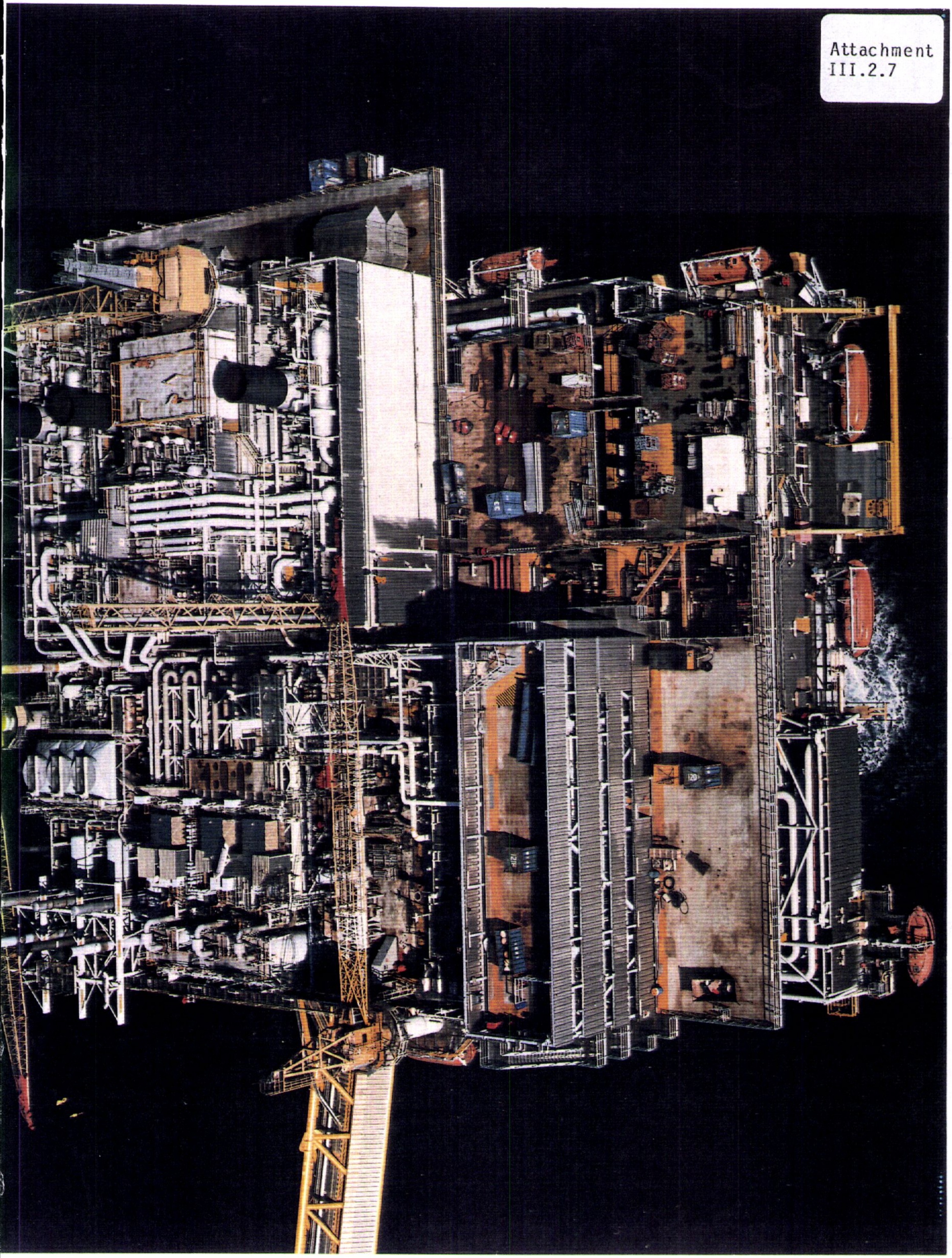
TCP2 - General view.



FRONTISPIECE

Attachment
III.2.6

Attachment
III.2.7



Service	No.of units	Unit capacity	Total cap.	Remarks
- Gas/cond./water separator	3	>20MSm^3/D	>60MSm^3/D	
- Gas dehydration	3	>20MSm^3/D	>60MSm^3/D	
- Fiscal gas metering	3	20MSm^3/D	60MSm^3/D	Defining present max. capacity
- Condensate separator	1	15000m^3/D	15000m^3/D	5 min retention time
- Condensate injection	2	480 m^3/D	900 m^3/D	
- Water treatment	1	2500 m^3/D	2500m^3/D	5 min retention time

2.2.2.2 Process Utilities

TCP2 treatment facilities comprises the following main process and general utility systems: Power generation, glycol regeneration, fuel-gas treatment, high and low pressure relief, nitrogen generation, methanol, glycol and diesel storage, compressed air.

The facilities have the following capacities:

Power generation (Kongsberg Generators)	:	3 x 1.4 MW
Glycol regeneration	:	3 x 15 m^3/hr
Fuel gas treatment	:	5000 m^3/hr
Low pressure relief	:	60 000 Sm^3/D
Methanol storage	:	140 m^3
Compressed air	:	2 x 510 Sm^3/hr

2.2.2.3 Compression Facilities

TCP2 compression facilities include 3 compression trains consisting of a gas tubine and a compressor.

From 1993 additional compression facilities will be installed for boosting of Odin low pressure gas. This equipment will be able to compress gas from suction pressure ranging from 10 to 41 bar up to a maximum discharge pressure of 153 bar (max. compression ratio: 9.5).

The following capacities are and will be available:

Service	No. of units	Rating	Unit cap.	Tot. cap.	Remarks	Max disc pressure bar
Frigg compress.	3	32MW	40MSm^3/d	80MSm^3/d	1 St. By	150
Odin compress.	2	12MW	4.5MSm^3/d	9MSm^3/d		153

2.2.2.4 Compressor Utilities

The TCP2 comprises the following utility system:

- Power generation (2 Stahl-Laval generators)	:2 x 12 MW
- Fuel gas treatment	: 2 x 1 MSm^3/d
- High press / Low temp. relief	: 3.8 MSm^3/d
- Gas cooling	: 3 x 32 MSm^3/d
- Cooling water pumps	: 2 x 2000 m^3/hr
- Sea water pumps	: 4 x 2000 m^3/hr
- Fresh water / sea water coolers	: 3 x 27.10^6 kcal/m
- Fresh water makers	: 2.27 m^3/hr

2.2.3 TCP2 Future Utilization

After installation of the Odin compression module, TCP2 has an available load capacity of 4000 tonnes.

The following surfaces are presently available:

Main deck	: 850 m^2
Cellar deck	: 270 m^2

2.2.4 Flowlines and Risers

Riser no.	Col.no.	Dimensions	Status today	Free in	Remarks	MAWP bar
R1	3	32"x1.094"	in use St.Fergus	---	not complete	149
R1E	3	32"x1.094"	back-up for R1	now		149
R2	3	26"x1.0"	in use from DP2	1993		172
R2E	3	26"x1.0"	back-up for R2	now	not complete	172
R3	3	26"x1.0"	in use from DP2	1993		172
R3E	3	26"x1.0"	back-up for R3	now	not complete	172
R4E	5	18"x1.0"	future riser	now		172
R5E	5	16"x1.0"	in use NEF	1993		200
R6E	5	20"x1.0"	in use Odin	1998		176
R7E	3	24"x0.94"	future riser	now	cold temp.steel	172

J-tubes

Tub no.	col.no.	J-tube diameter (in)	Flowline diameter (in)	Content	Remarks
J1	3	10.75"	4.5"(172 bar)	Meth.water	TCP2 to DP2
J2	3	18"	8.625"(345 bar)	N_2 storage	TCP2 to DP2
J3	3	12.75"	-	Cables	
J4	5	18"	1"	Service line + cables	TCP2 to EF
J5	5	18"	-	Cables	TCP2 to NEF
J6	5	12"	-	Free	
J7	5	18"	12"(172 bar)	Gas from EF	EF to TCP2

2.3 Quarters Platform (QP)

2.3.1 General Description

The Quarters Platform (QP) is a four-legged structure supporting facilities for field personnel accommodation, helicopter transport, communications and process platform control.

The secondary structure comprises two main sections - Modules A and B. The module roof is surmounted by a helideck, a helicopter hangar, a microwave antenna tower and a crane.

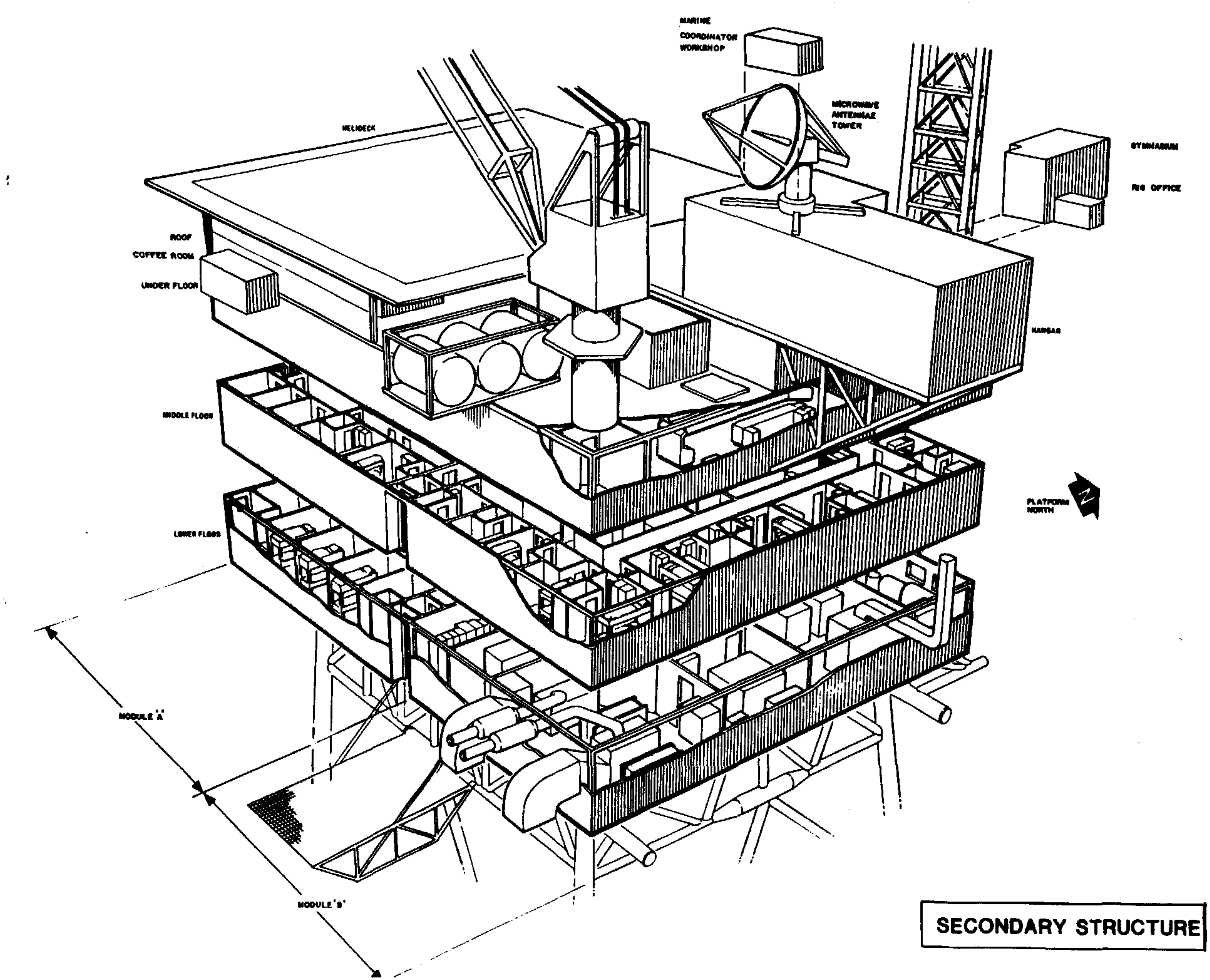
Module A is 16.4 m x 28 m in plan and weights approximately 1240 metric tonnes. Module B is 16.4 m x 25.7 m in plan and weights approximately 1360 metric tonnes. The module provides accommodation facilities for the 129 people working in the Frigg Field central complex, as well as control and communication facilities.
Attachments III - 2.8 and III - 2.9 show the general arrangement of QP.

2.3.2 Production Control Facilities

Facilities are provided on the platform to monitor and control each of the Frigg Field platform process systems from a central control room. A main console contains individual sections for the monitoring and control of process systems on CDP1, DP2, TP1 and TCP2 together with field utility systems and fire and gas detection systems. Monitoring facilities are provided for the Frigg Field electrical power network. Each section of the console comprises a mimic panel, a control panel and an instrument and alarm panel.

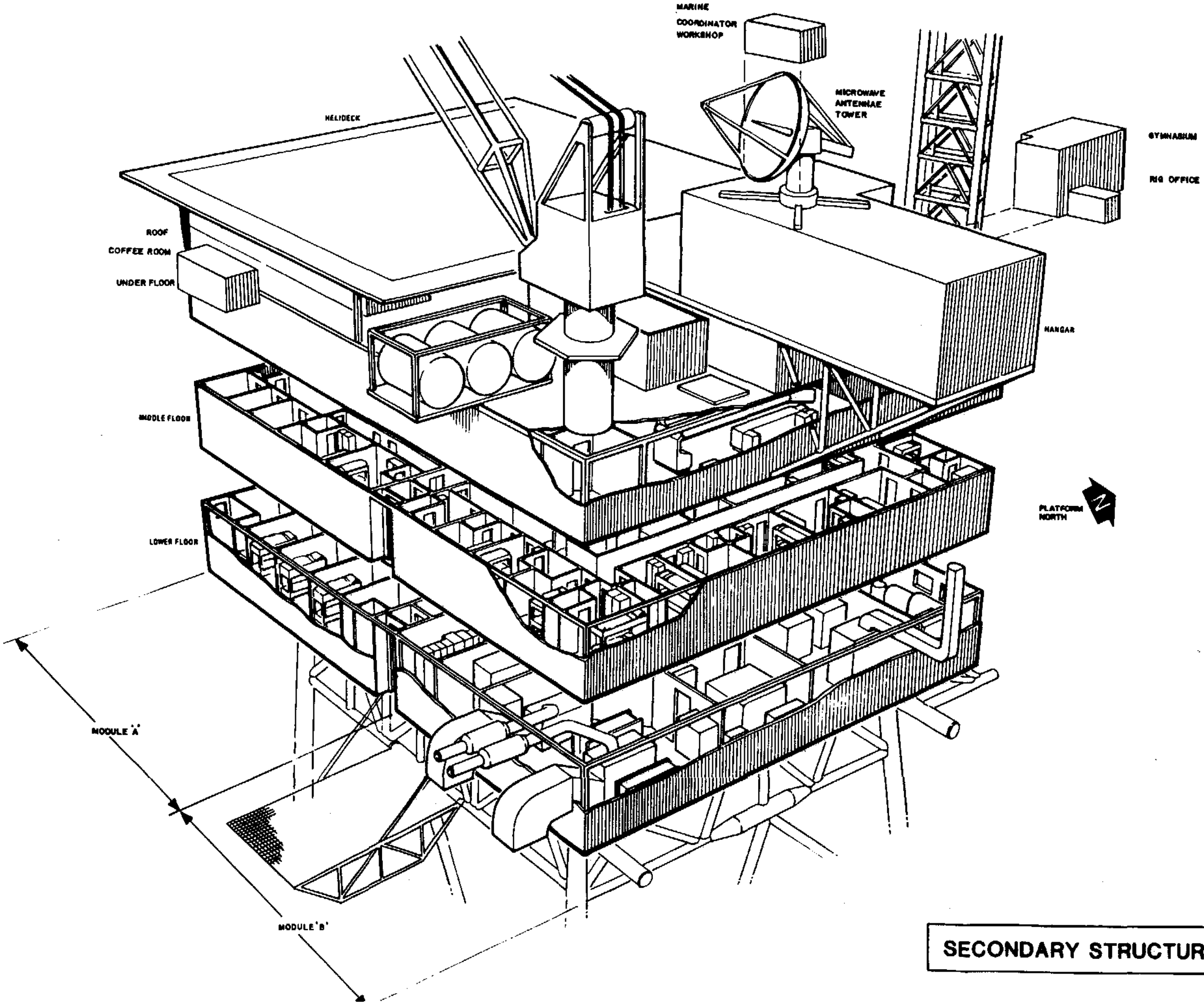
Separate consoles, also located in QP Control Room, provide monitoring and control facilities for FP, NEF and NEF-Odin treatment facilities on TCP2.
Status on certain items of Alwyn is also displayed in QP control room.
A new Field Control and Data Aquisition (FCDA) system was recently installed for remote operation and monitoring of the EF subsea stations as well as topside facilities.

In addition to control process facilities the main gas and condensate metering computer is located on QP for fiscal metering of TP1 and TCP2 gas and condensate export as well as NEF, ODIN and EF gas and condensate arriving at the field.
The Alwyn leak detection system is also connected to the same computer.



SECONDARY STRUCTURE

Attachmen
III.2.8



SECONDARY STRUCTURE

Attachment III.2.8

Attachment
III.2.9

2.3.3 Utilities

QP comprises the following utility systems:

- Potable Water System
- Utility Water Storage and Distribution
- Compressed Air
- Diesel Fuel System
- Jet Fuel System
- Washdown System
- Drainage System
- Ventilation Systems
- Power Generation and Inter-platform Electrical Connections
- Electrical Power Distribution
- Emergency Power Supplies
- Battery-supported Supplies
- Normal Lighting

2.3.4 Future Extension

No free space exists on QP for additional facilities as pancakes, modules etc.
For production control and monitoring the new FCDA system has spare capacity as well as it is easy expandable. Data are transferred from TCP2 and TP1 by the new data highway.

2.4 Flare Platform (FP)

2.4.1 General

The Flare Platform (FP) consists of an articulated steel tower mounted on a steel base. The foot of the tower and the base are both ballasted with concrete to stabilise the platform on the seabed. The buoyancy provided by a submerged float located approximately 15 m below the waterline keeps the tower in the normally upright position, while allowing the tower to tilt to a limited extent in any direction under the influency of wind and current.

Principal parameters of the platform are as follows:

Overall height including flare nozzles	150 m
Water depth	106.3 m
Above water height	43.7 m
Total weight (including ballast)	2806 tons
Capacity	34 MSm^3/D

A general view of the flare is showed on Attachment III - 2.10.

2.4.2 Main Gas System

Gas enters the platform from TP1 and/or TCP2 through a 24in subsea line, which bifurcates at the platform base into independent gas circuits.

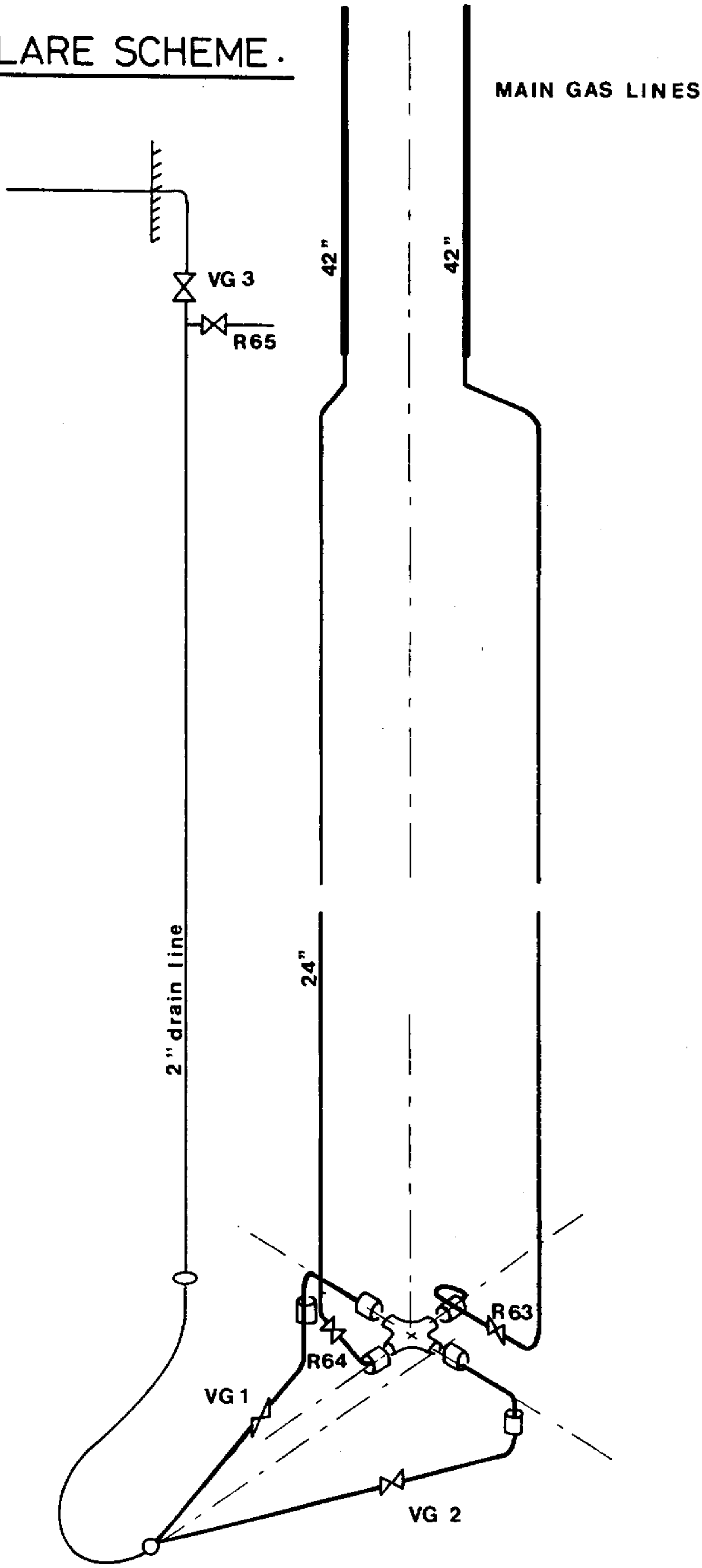
The flare gas circuit consists of 2 tubes with a diameter of 24" extended by 42" pipes.
The two gas circuits are made independent of each other by a 24" valve arrangement on the base pipework which can be hydraulically controlled from a distanse.
At articulation level, the gas flows through the universal joint.

Attachment III - 2.11 shows the general piping arrangement of the flare.

Attachment
III.2.10

Attachment
III.2.11

FLARE SCHEME.



The Main Gas System, incorporated in the Flare Platform, fulfills the following functions:

(a) System purging.
(b) High pressure relief.
(c) Protection of the 32in sales gas pipeline.
(d) Blowdown of TP1 and TCP2.
(e) Manual flushing.

A 2in parallel circuits is connected to the lowest point of the 24in gas line to facilitate gas bleeding and condensate removal. The drain line is fitted with a hydraulically operated isolating valve.

To prevent ingress of air and the formation of a potentially explosive gas/air mixture since the flare is cold operated the system is swept continuously with nitrogen at a nominal rate of 2400 m^3/d.

2.4.3 Future Use

The future use of the flare platform is believed to be limited, due to two main reasons:

1) Uncertainties of future lifetime and availability.
2) Non compatibility to receive cold gases from new satellite fields.

2.5 Extensions

2.5.1 General

To receive and treat gas from other fields than Frigg extensions of the original Frigg facilities are installed as follows.

Year	Platform	Name	Fields
1983	TCP2	TCP2 Extension	NEF + ODIN
1986	TP1	Alwyn Tie-In	Alwyn
1988	TCP2	EF Tie-In	EF

2.5.2 TCP2 Extension

The purpose of the installation is to treat the gas comming from NEF Field and the Odin Field. The gas/liquid goes through a FWKO vessel (Free Water Knock Out) where most of the water and condensate is separated from the gas. From the FWKO vessel the gas enters a scrubber where more liquid is removed. From the scrubber the gas is sent via a metering station to final treatment and compression on TCP2 before being exported to St. Fergus.

The liquid from the FWKO vessel and scrubber consists of condensate and methanolated water and are separated in two stages.

The condensate is sent to TCP2 or TP1. The methanolated water is sent to the methanolated water storage tank for further separation and filtration before it is continously pumped to DP2 for injection into well 3.

Capacities:

	Odin	NEF
- Gas/condensate separations:	>20MSm^3/d	>10MSM^3/d
- Gas metering	2 x 10MSm^3/d	2 x 7MSm^3/d
- Cond. treatment	See TCP2 treatment	

2.5.3 EF Tie-In

The EF Tie-in facilities on TCP2 performs the same functions for EF as TCP2-extension for NEF and Odin. In addition control and monitoring of the EF subsea stations are located in the module.

<u>Capacities</u>

- Gas condensate separation	: 7 MSm^3/d
- Gas metering	: 2 x 6 MSm^3/d
- Condensate treatment	: See TCP2 treatment

2.5.4 Alwyn Tie-In

Alwyn tie.in located on TP1 comprises facilities for receival and transfer of gas from the 24" line to one of the pipelines to Scotland. No treatment is performed.
The facilities consists of valves, piping, scraper trap and a low temperature relief system (see TP1) as well as a leak detection system.

<u>Capacity:</u>

Normal flow	> 10MSm^3/d
Max. depacking	23MSm^3/d

2.6 Concrete Drilling Platform No. 1 (CDP1)

2.6.1 General

The platform is a concrete gravity drilling and production platform constructed in two parts - namely a steel/concrete main deck structure mounted on a concrete substructure.

The deck structure comprises six prefabricated modules mounted on top of the support frame.

Each module houses equipment necessary to production phase or support function, as follows:
a) Modules WH1A and B, Well Production Facilities
b) Modules PM2 and 3, Process Facilities
c) Modules BR1 and 2, Electrical Power Generation and Control, Batteries and Utilities.

A drilling package is installed which consists of eight modules and a derrick. The modules are on the upper level of the structure; the derrick is above the wellhead modules at the platform southern edge. Accomodation is available for 81 people.

Attachment III - 2.12 exhibits the structure of CDP1.

2.6.2 Topside Facilities

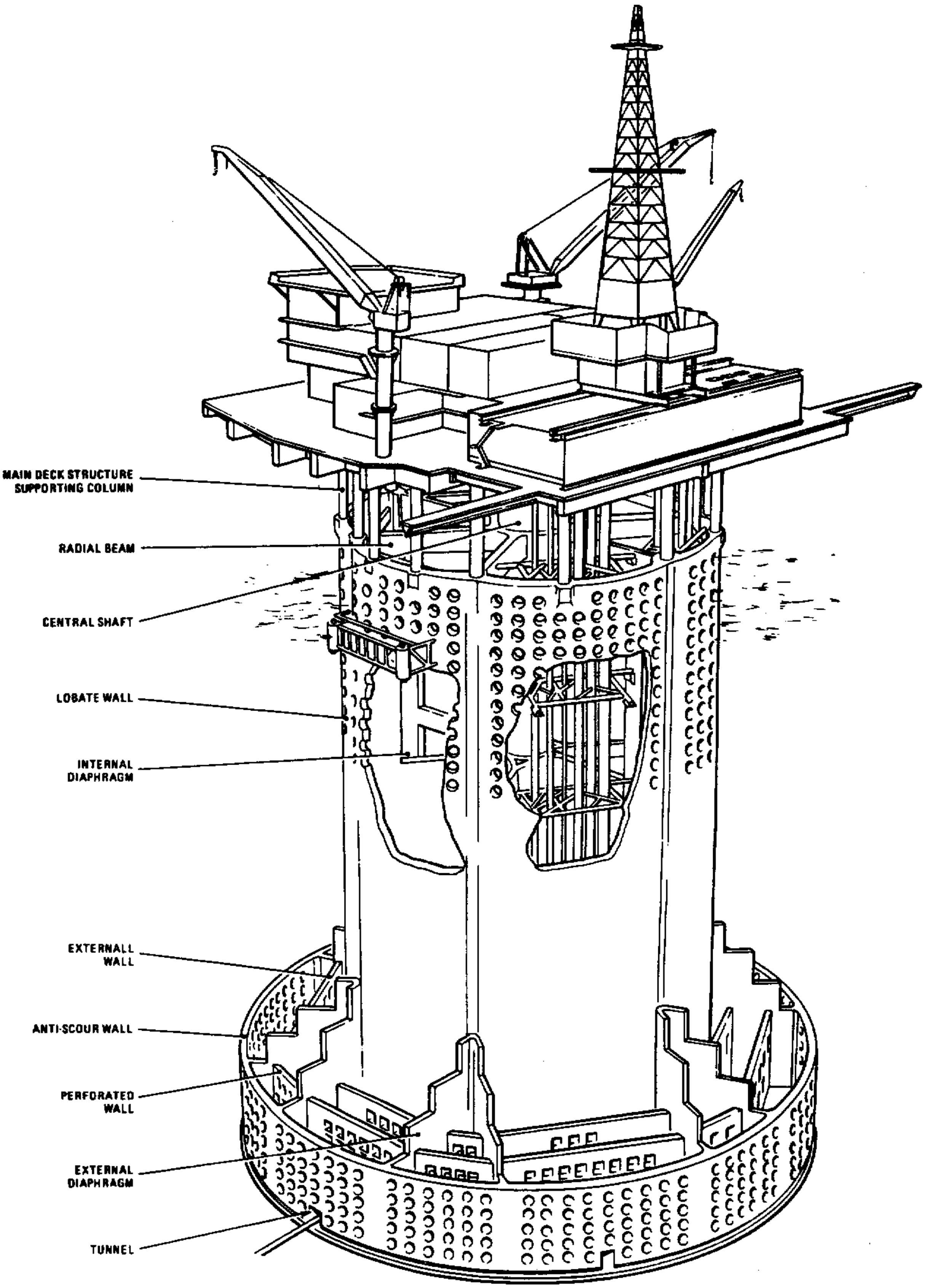
2.6.2.1 Production Systems

The twenty-four wells drilled from CDP1 are grouped in two clusters of twelve. The produced gas flows via two 26in subsea lines to TCP2 for treatment.

The flow from each well is individually controlled by choke valves at the wellhead and metering system.

Scraper pig traps are located at the entry of each 26 in line. Provision is made to inject corrosion inhibitor and/or methanol into each sea line.

Attachment
III.2.12



PRIMARY STRUCTURE

To horizontal burner booms are provided for decompression of the topside pipework.
The originally installed scrubbers/desanders for each well, test and start-up separators and condensate separators are bypassed.

The production modules also include a local control room for control of wells.

2.6.2.2 Drilling Package

The drilling facilities contain a complete package to perform drilling and work-over operations.

2.6.3 Flowlines and Risers

A number of risers are used to connect platform systems to sea lines laid on the seabed. These risers are:

(a) Gas production riser R5 - 26in diameter.
(b) Condensate riser - 4 1/2in diameter.
(c) Gas production riser R6 - 26in diameter.
(d) Nitrogen storage riser - 8 5/8in diameter.
(e) Two electrical risers - each 8 5/8in diameter.

2.6.4 Future Use

No lifetime extension studies or fatigue evaluations have been performed for CDP1 with the objective of using it beyond its original design lifetime.

CDP1 has suffered significant damages to the primary concrete structure. They have been repaired but they are under continuous surveillance both by instrumentation and annual visual inspection.
Attachment III - 2.13 shows a general view of CDP1.

2.7 Drilling Platform No. 2 (DP2)

2.7.1 General

DP2 is an eight-legged jacket structure of tubular construction. It is 106 m in height and rectangular in plan. The sides are 48.0 m x 25.0 m at elevation + 8.2 m and 61.7 m x 43.7 m at elevation - 100 m.

The deck structure comprises four prefabricated modules mounted on top of the support frame. Production equipment is located on Modules 1 to 3, with utility equipment and Living Quarters located in Module 4.

The drilling package is located on top of the production modules and comprises 13 modules, a helideck and a drilling rig. Accomodation is available for 66 people.

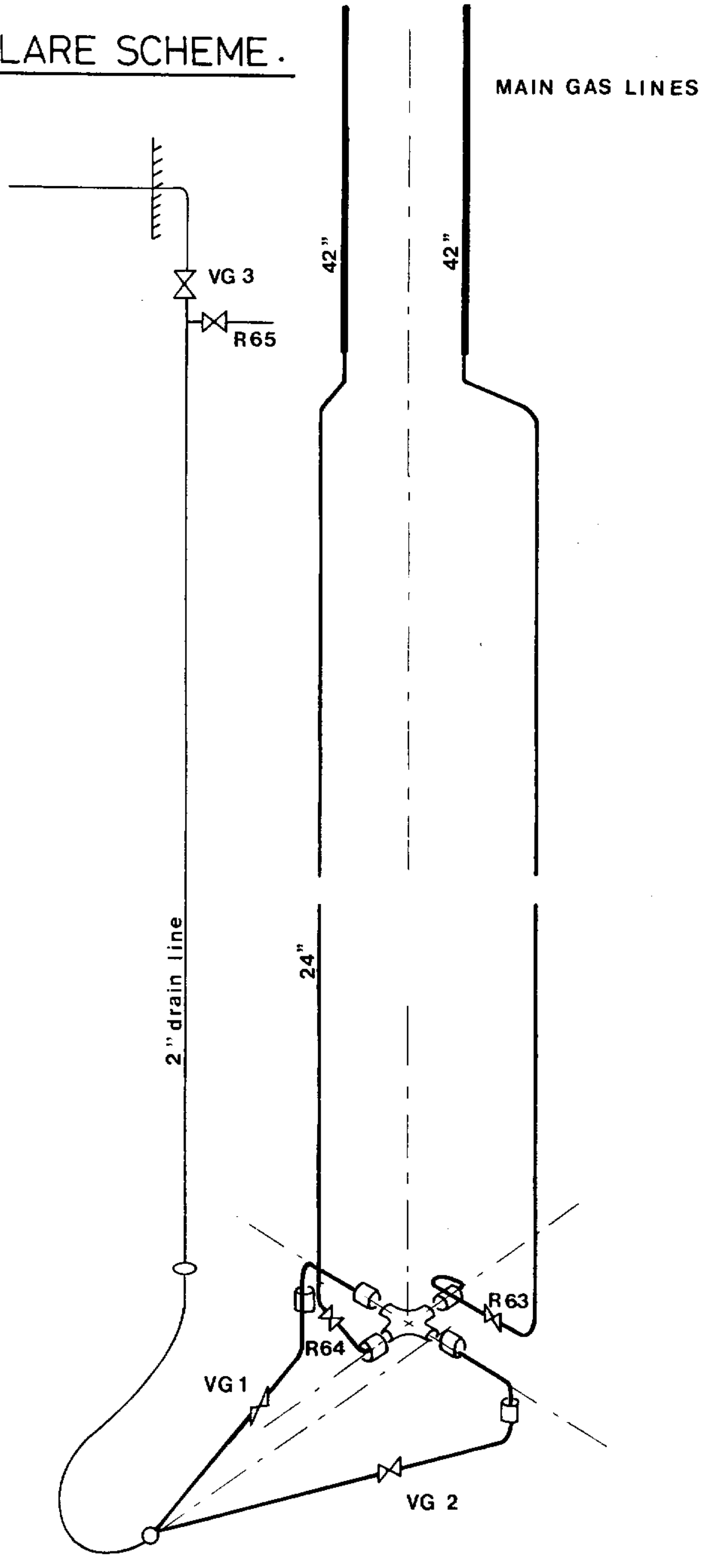
The load occupancy is presently split as follows:

Production modules:	2850 tonnes
Drilling modules:	3960 tonnes

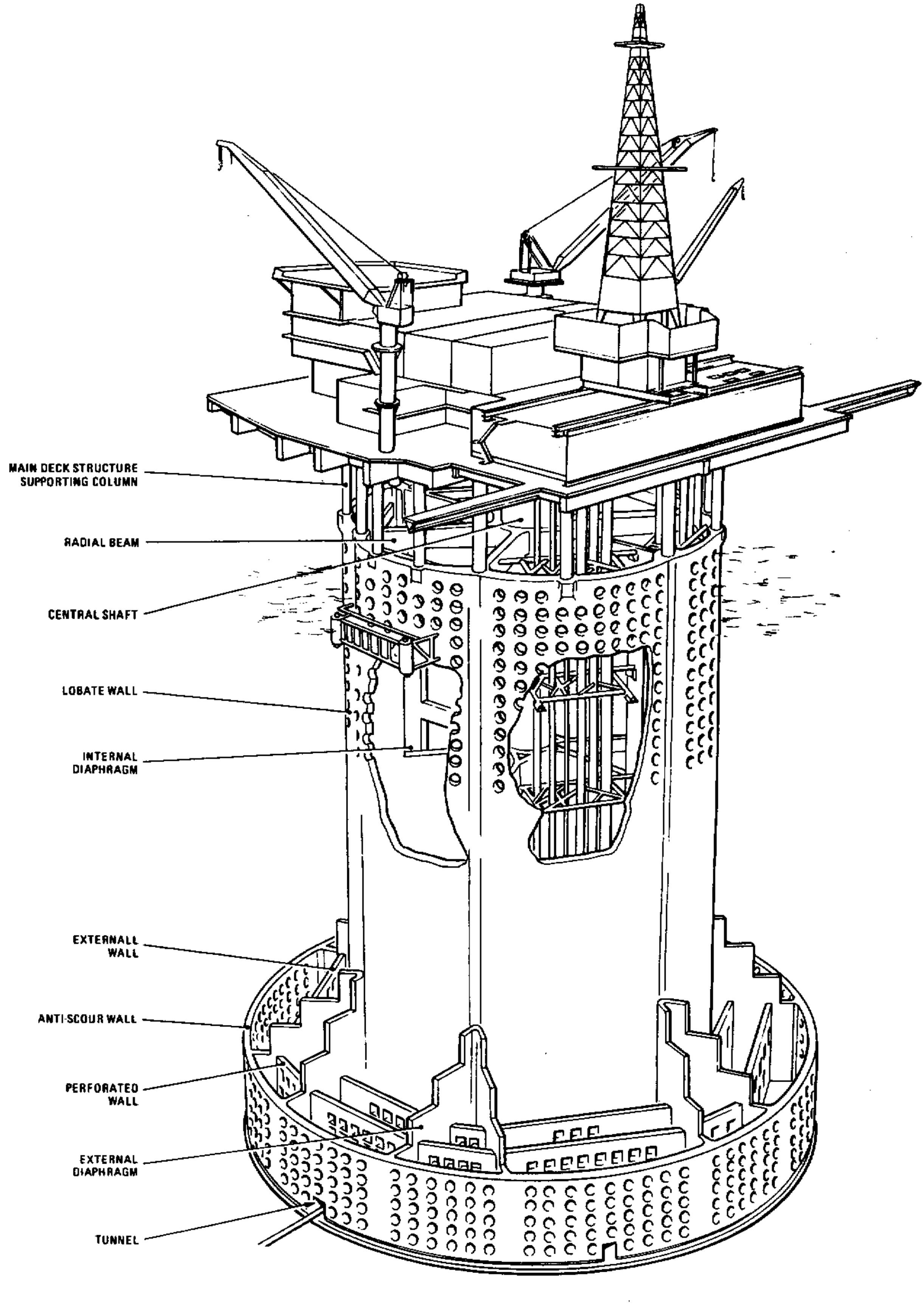
A general view of DP2 is showed on Attachment III - 2.14.

Attachment III.2.11

FLARE SCHEME.



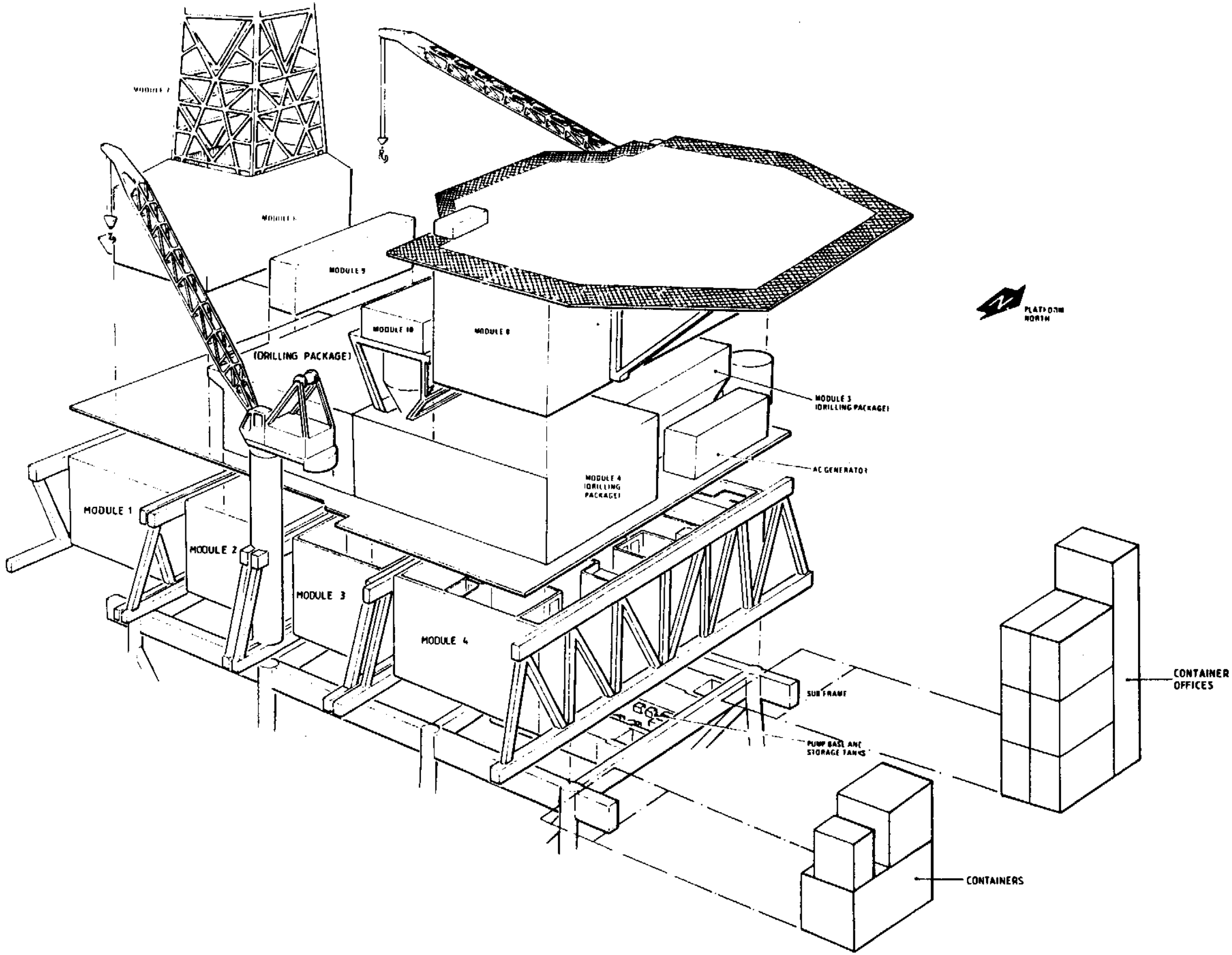
Attachment
III.2.12



PRIMARY STRUCTURE

Attachment III.2.13

Attachment
III.2.14



SECONDARY STRUCTURE

Attachmen
III.2.15

2.7.2 Top Side Facilities

2.7.2.1 Production Systems

The twenty-four wells drilled from DP2 are gropued in two clusters of twelve. The wellheads are located in Module 1, each cluster being separated by a fire-resistant parition wall. The produced gas flows via two 26 in subsea lines to TCP2 for treatment.
The flow of each well is monitored with individual chokes and metering devices.

Scraper pig traps are located at the entry to each 26 in line. Provision is made to inject corrosion inhibitor and/or methanol into each sea line.
Two horizontal burner booms are provided for decompression of the topside pipework.
The originally installed scrubbers/desanders for each well, test and start-up separators and condesate separators are bypassed.

The production modules also comprises a local control room for control of wells.

2.7.2.2 Drilling Package

The drilling facilities contains a complete package to perform drilling and work-over operations. The modules are numbered and designated as follows:

No 1	Mud Pump Room
No 2	Mud Preparation and Cementing Rooms
No 3	Auxiliaries Room
No 4	Engine Room
No 5	Sub Base
No 6	Substructure and Drilling Floor
No 7	Derrick
No 8	Living Quarters
No 9	Mud tank
No 10	Silos
No 11	Bulk cement
No 12	Generator fuel and water tanks
No 13	Sea water tank

The general arrangement of the topside equipment is showed on Attachment III - 2.15.

2.7.3 Flowlines and Risers

A number of risers are used to connect platform systems to sea lines laid on the seabed. The risers are:

(a) Gas production riser R2 - 26in diameter
(b) Condensate riser J1 - 4.1/2in diameter
(c) Gas production riser R3 - 26in diameter
(d) Mud killer riser J2 - 8.5/8in diameter
(e) Two electrical risers - each 8.5/8in diameter

2.7.4 Future Extension

If needed, any of the present drilling or production modules can be removed and be replaced by new facilities, giving a total available load equal to the existing modules loads, but lifetime extension study of this platform has to be performed prior to future modification.
New risers clamped to the jacket can be installed, and gas transferred to the central complex by the existing 26 in lines.

2.8 Summary of Capacity

The capacities of the main Frigg treatment systems can be summarized as follows :

- Gas/condensate separation	:	> 100 MSm^3/d
- Gas dehydration	:	105 MSm^3/d
- Condensate separation	:	> 2 x 15000 m^3/d
- Gas metering	:	150 MSm^3/d
- Gas export compression	:	80 MSm^3/d
- Power generation	:	> 30 MW

2.9 NEF Field Control Station (FCS)

2.9.1. General

The FCS is designed to remotely control the subsea equipment during normal unmanned operation and to accomodate personnel during times when the FCS is manned for routine inspection, maintenance or well control purposes. The FCS is made up of three components, the head containing the accommodation plant and equipment, the column supporting the head, providing stability and buoyancy, and the base to which the column is attached by an articulated joint.

A general view of the FCS and general sketch of the NEF facilities are exhibited in Attachments III - 2.16 and III - 2.17.

2.9.1.1 FCS Head

The FCS head is designed specifically for unmanned operation but is does contain all the necessary utilities for personnel visiting the platform for short periods. The most important function of the FCS is to be the central control unit for the gas production and supporting sub-systems including the following:

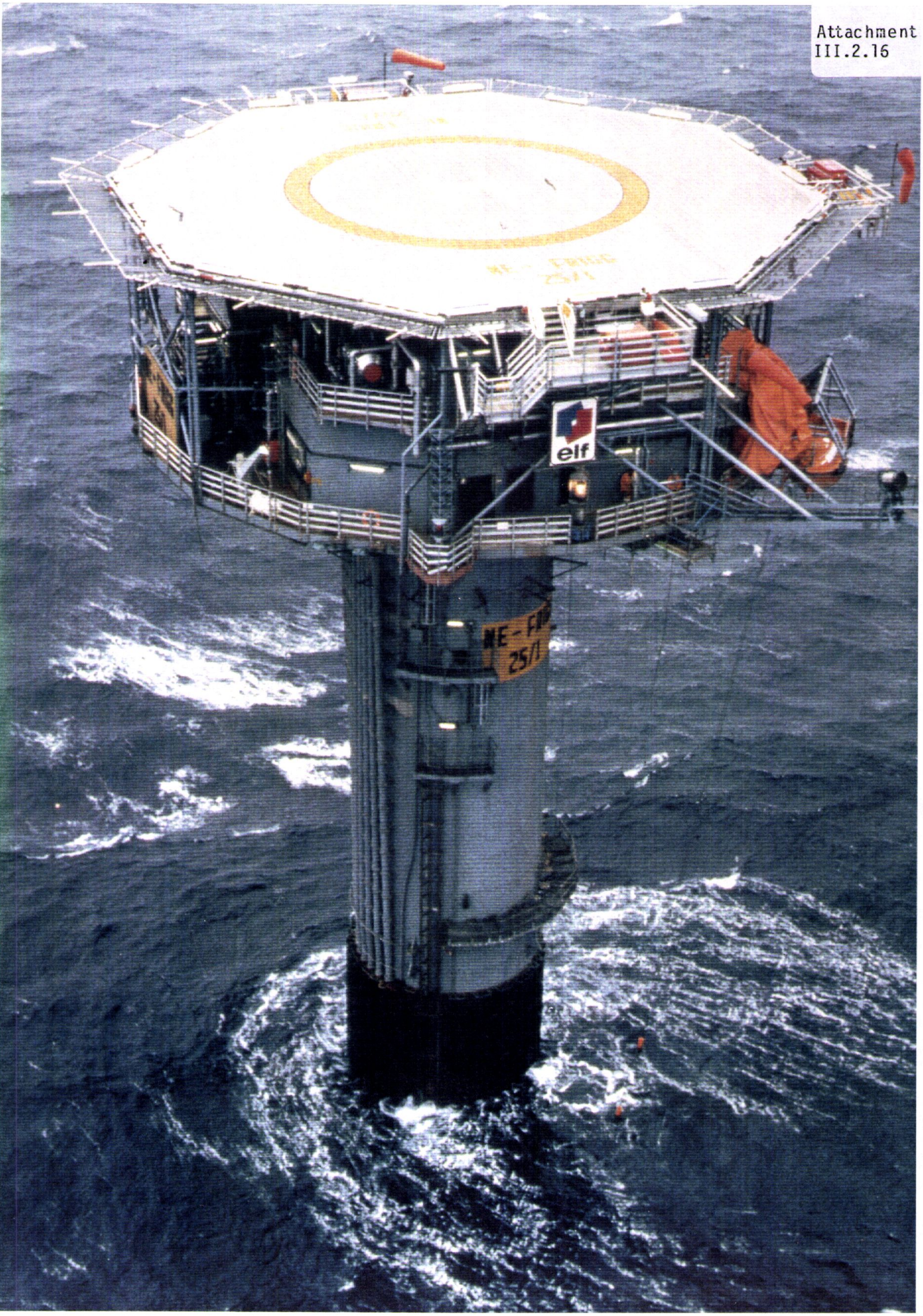
1. Remote control and monitoring of wells.
2. Transmission of data to the central control unit on the Frigg Field Quarters Platform (QP).
3. Injection of hydrate inhibitors at the wellheads.
4. Well killing. (Exceptional situation).

The head is arranged on four levels. The top level is a helideck, below which are living quarters, and then below the main deck containing the plant and equipment. The fourth and lowest deck supports the fuel and methanol storage tanks, together with their transfer and injection pumps.

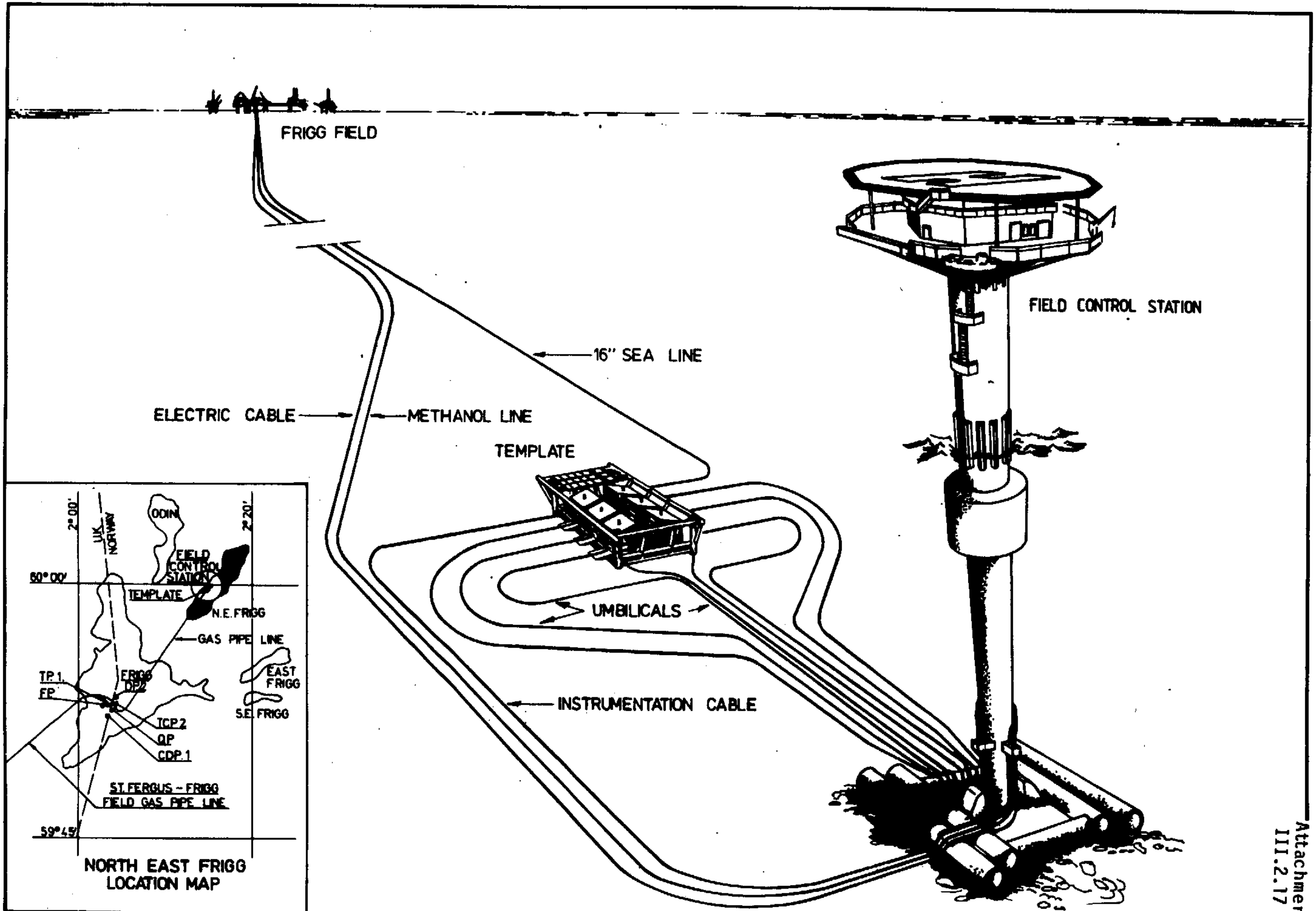
2.9.1.2 Column

The 8m diameter cylindrical flush sided steel column, supports the FCS head at the top end, whilst being anchored to the based through a Cardan Coupling. The column has a total height, from the coupling to section joint with the head, of 126.20 meters, and weights about 4500 tonnes.

Attachment
III.2.16



Attachment III.2.17



2.9.2 Production Facilities

2.9.2.1. Introduction

The production facilities on the FCS include those systems used to control, operate or service the subsea equipment. There are five systems comprising:

1. Inhibitor Injection System
2. Killing System
3. Flaring System
4. Service Manifold
5. Remote Control

2.9.2.2. Facility Description

2.9.2.2.1 Inhibitor Injection System

Methanol is injected into the wellheads and in certain circumstances the wells themselves to prevent the formation of hydrates. Methanol is supplied from TCP2 plaform to the FCS via a 2 inch subsea line, and stored in three 10 m^3 tanks. The tanks supply methanol to six sets of two injection pumps one set per well, with one pump for normal operation the second as standby. These pumps have a delivery flow which is adjustable between 20 - 150 litres/hour at 206 barg pressure. Connection to the well heads is by 1/2 inch injection line forming part of the umbilical

An additional pump which is manually opeated, is used to inject a large amount of methanol into the wellheads themselves during initial start-up. In this case the methanol is pumped through the 2 inch service line to the wellheads. The pump has a capacity of 6 m^3/hours at 206 barg.

2.9.2.2.2 Well Killing System

The well kill system will be used to kill the well if an emergency arises. The system comprises a mud storage and mud mixing tank of 20 m^3 capacity each, supplying a diesel driven twin injection pump of capacity 10.366 l/min, (each pump) is delivered to the wellhead through the 2 inch service line.

2.9.2.2.3 Flaring System

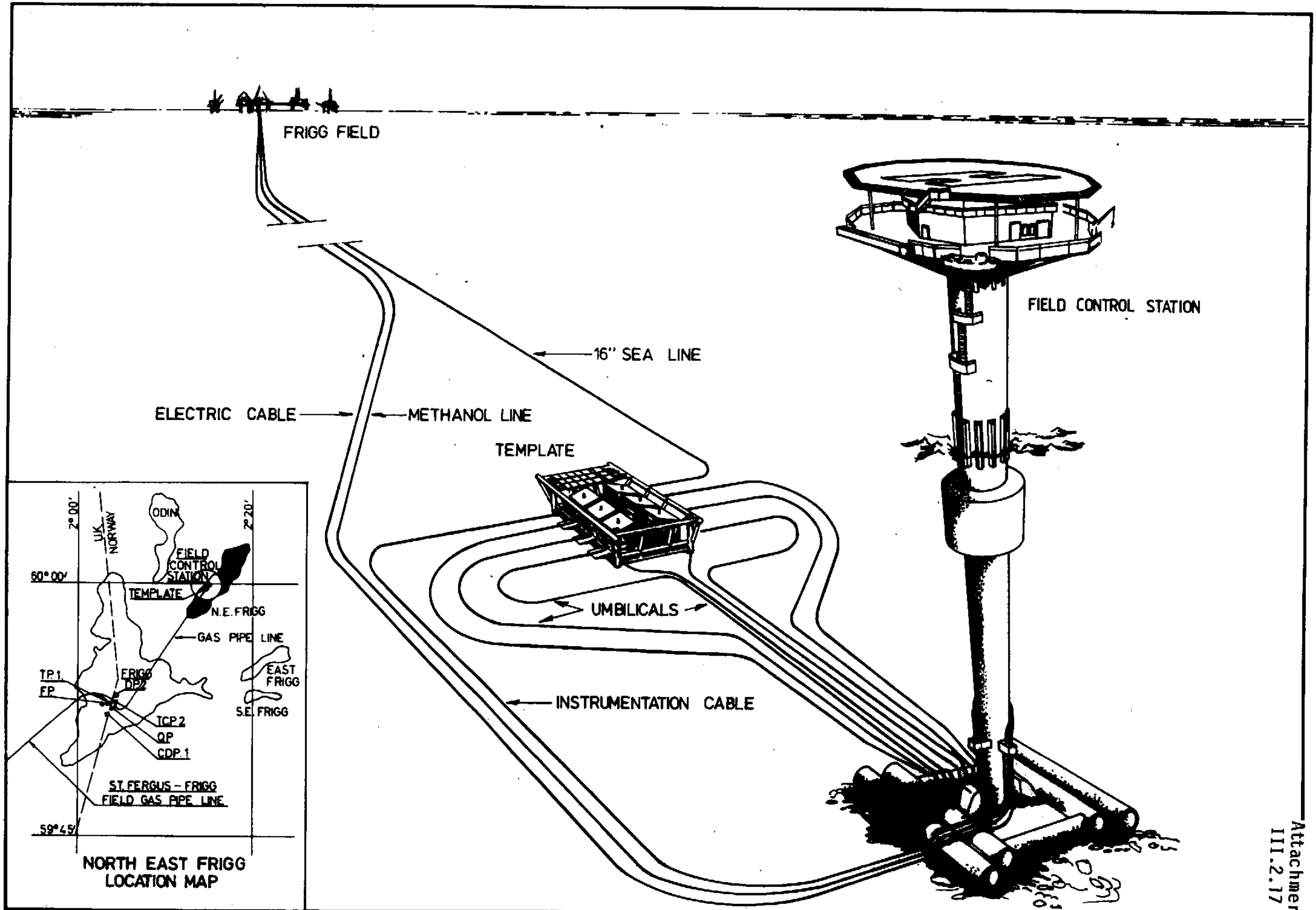
The flaring system is mainly used to bleed off the process gas and associated liquids from the subsea installation during the following operations:

Subsea Safety Valve Test
Pressure Transducer Test
Check or Repair of the Well Head
Destruction of Hydrate Plugs

2.9.2.2.4 Service Manifold

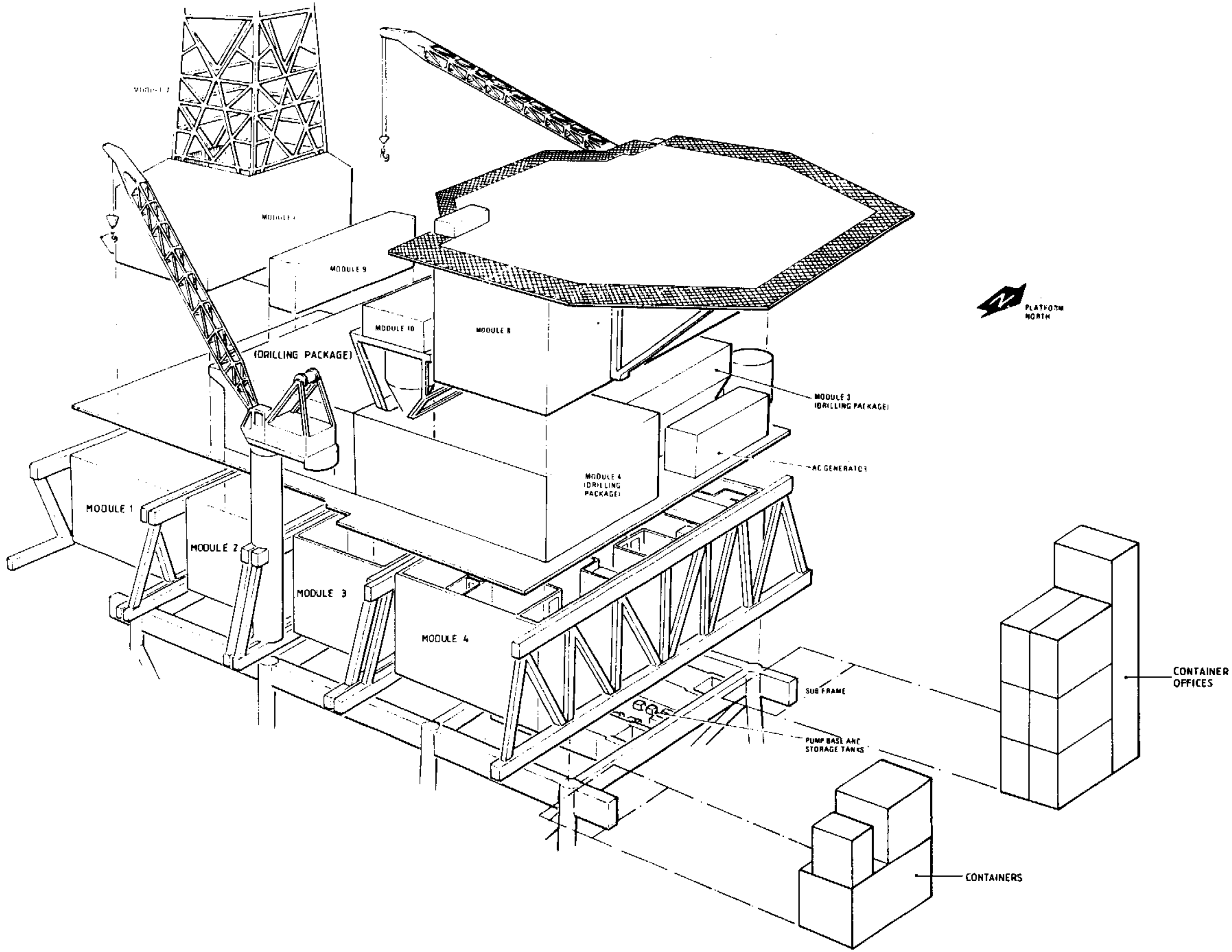
The service manifold on the main deck level groups together the various connections, valves, and instruments for the following systems:

. Well Killing System
. Methanol Injection System
. Flaring System



Attachment III.2.17

Attachment III.2.15



SECONDARY STRUCTURE

CHAPTER III - PART 3

Frigg Transportation System

3.1 General Description

The Frigg Field production consisting of natural gas and a small amount of condensate, is transported to shore by means of two pipelines, each of 32in outside diameter. Both pipelines follow parallel routes, approximately 70 meters apart, between the Frigg Field and the shore terminal at St. Fergus on the North East Scottish coast. The length of the first pipeline (No. 1) is 361 km while the second pipeline ($N^{o}2$) is 363 km. Located halfway along the two pipelines is an intermediate platform MCP-01. Water depths exceed 100 meters, and at some places reach 155 meters, for more than 80% of the route. A schematic of the transportation system is shown in the figure hereafter.

The pipelines begin at treatment platforms TP1 and TCP2 and then proceed South West to the manifold platform MCP-01. From here the pipelines again proceed South West to the St. Fergus shore terminal.

A sketch of the Pipeline System is enclosed as Attachment III-3.1 hereto.

3.2 Pipelines

The submarine pipelines connect the Frigg Field Production Platform (TP1 and TCP2) with the Intermediate Platform MCP-01 and the St. Fergus Shore Terminal.

The pipeline is a conventionally laid submarine pipeline consisting of 12 metre concrete coated pipe joints cathodically protected by zinc anodes.

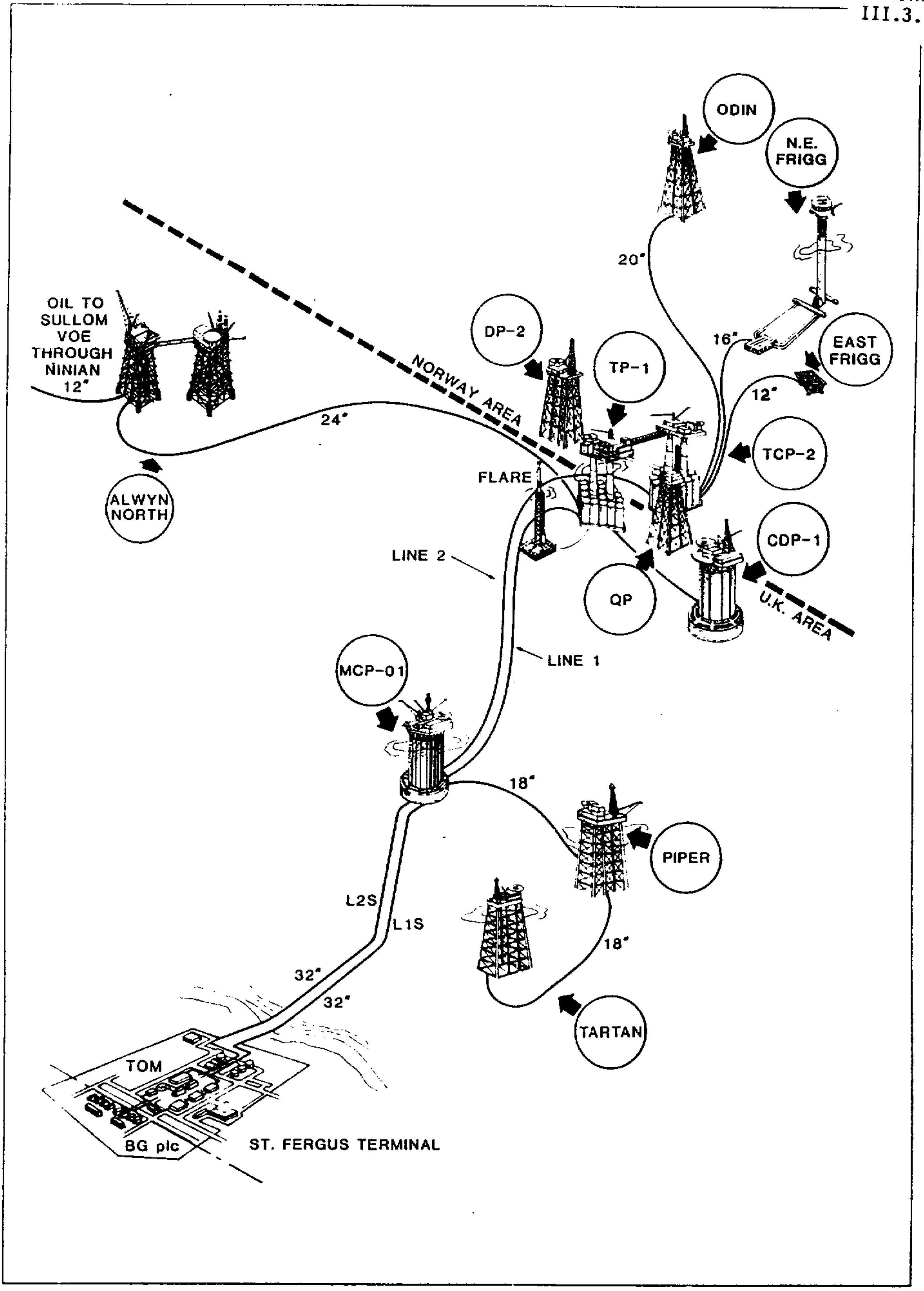
The pipe construction is 32in outside diameter, 3/4in wall thickness high yield steel piping manufactured in accordance with API 5LX65 specification. The concrete weight coating is applied to the pipe in various thickness from 45/8in to 17/8in to provide pipeline stability.

3.3 MCP-01 Platform

The intermediate compression platform (MCP-01) is located midway along the transportation system and supplies the following services:

- Receives gas from Piper/Tartan
- Can perform re-compression duties when required
- Is a pigging station
- Can interconnect the two 32in gas transmission lines to enable different modes of operation to take place

The platform is provided with two 38.000 HP turbo compressors, each capable of boosting a single line flowrate by approximately 7.5Mm^3/d. The compressors may be run as single unit per line or two compressors in series; series operation boosts the flowrate to a single line by approximately 10.5Mm^3/d.



THE 32in FRIGG PIPELINE SYSTEM

3.4 Pipeline Design and Operating Conditions

3.4.1 Flowrate

Maximum flowrate for each line without MCP-01 compression	:	33.3Mm^3/d
Maximum flowrate for each line with single MCP-01 compression	:	40.8Mm^3/d
Maximum flowrate for one line with two MCP-01 compressors in series	:	43.8Mm^3/d

3.4.2 Pressure

Maximum allowable working pressure (MAWP)	:	151.7 barg
Maximum Frigg discharge pressure	:	148 barg
Maximum pipeline operating pressure	:	148 barg
MCP-01 minimum arrival pressure	:	49 barg
MCP-01 maximum export pressure	:	148 barg
St. Fergus minimum arrival pressure	:	47 barg
St. Fergus nominal arrival pressure	:	49-59 barg
St. Fergus maximum arrival pressure	:	87 barg

3.4.3 Temperature

Minimum pipeline temperature	:	- 10^oC
Maximum discharge temperature from MCP-01	:	36^oC

3.5 St. Fergus terminal

On arrival at St. Fergus the gas from each line passes through a 600 m^3 slug catcher for collection of condensate. The gas is then routed to the two halfs of the terminal the UK-side and NW-side, each comprising 3 identical treatment trains (ph. I and II) capable of treating 18 MSm^3/d of Frigg type gases each, totally 108 MSm^3/d.

The processing consists of an inlet filter (only for 4 trains) a chiller, a gas-gas heat exchanger and a cold separation normally operated at -18^oC and 45 barg, and at last an outlet filter and metering.

The liquid handling capability of the equipment can be summarized as follows:

	sm^3/d
Inlet filter separator	155
(Note in UK phase 3 filter separators)	(465)
One cold separator	97
Two cold separator	194
Three cold separator	291
One gas/gas heat exchanger	13 m^3/d
One gas chiller	13 m^3/d
Condensate stabilizer	600 m^3/d (500 t/d)

Due to the reduction of the Frigg production and the entry of Alwyn gas the present capacity and operating of the St. Fergus terminal will not be sufficient to handle Alwyn gas alone and consequently a completely new terminal (owned by FUKA) is under construction and is scheduled to start-up in May 1990.

The new facilities (ph. III) consist of 2 gas trains each with a capacity of 10MSm^3/d.Each train consist of gas dehydration, gas-gas exchanger, scrubber and turbo-expander.

A common liquid train with a capacity of 1000 t/d collects liquid from the slug catcher and the cold separator. With the entry of new rich gas fields in the future additional gas and liquid trains will be installed.

3.6 St. Fergus Gas and Liquid Evacuation

3.6.1 General

St. Fergus is Scotland main hydrocarbon node point, and will in the future have several evacuation possibilities.

3.6.2 Gas

1) British Gas plc. (BG)
Two pipelines connect the St. Fergus/Frigg terminal to BG pipe network. The BG terminal collects, in addition to gas from Frigg, gas from the Flags and Fulmar pipelines via the Shell terminal. The BG terminal is mainly a manifold and compression station, comprising 8 turbo compressors with following capacities.

4	Avon 1533 turbines	=	4 x 13 MS m^3/d
2	Avon 1534 turbines	=	2 x 17 MS m^3/d
2	RB 211 turbines	=	2 x 30 MS m^3/d
		=	146 MS m^3/d

The network downstream the terminal consists of :
3 x 36" pipelines
1 x 42" pipelines
The system do however have bottlenecks further south limiting the present total capacity to approximately:
105 MS m^3/d
Plans exist to extent this capacity.

2) North Scotland Hydroelectric Board (NOSHEB)
Gas from the BP operated Miller field will in 1993 enter St. Fergus, by a 30" pipeline into a new terminal operated by Total. The gas from the field which is an acid gas, will not be treated before it is transferred further to the power station outside Peterhead by a 26" pipeline.
The capacity of the pipe is 28 MSm^3/d, giving a spare capacity more than 20 MS m^2/d.
A connection between the other terminals and the new pipe, could be done.

3.6.3 Liquid

1) Peterhead (Aberdeen Service Company)
Stabilized condensate from Frigg is presently transported from the St. Fergus terminal to a tanker loading station in Peterhead harbour by trucks.
A more attractive alternative is under evaluation, this export solution could not be maintained.

2) BP - Forties
A new 12" pipeline is presently under construction between St. Fergus and Cruden Bay, giving a connection to the Forties system and the terminal at Kerse of Kinneil and Grangemouth refinery. The line which should be operational by mid. 1989 has a capacity of 80000 bbl/d.
The extended NGL processing capacity of Kerse of Kinneil terminal is estimated to 6000 t/d, crude stabilization capacity is 500000 bbl/d.

3) <u>Shell - St. Fergus</u>

The Shell terminal is a terminal, which separates NGL natural gas where the gas is sent to BG, while the NGL is sent via a 20" pipeline to NGL terminal at Mosmorran. At Mosmorran terminal the NGL is frationated into :

- ethane
- commercial grade propane
- commercial grade butane
- natural gasoline.

The capacity is 2 x 4100 T/D feed.

CHAPTER III - PART 4

Lifetime Analysis of Frigg Central Complex

4.1 Platform/Structure Lifetime Analysis

Lifetime extension studies have been performed for some of the Frigg platforms. The results are summarized as follows:

- QP, TP1 and TCP2 lifetime have been extended up to 2025.
- The DP2 and CDP1 lifetime extension studies have not been performed.
- The lifetime extension of the Flare Platform has not been studied, it is not planned to do so, this equipment is not suitable for cold gases.
- The extension of the NEF - FCS has to be studied.

Attachment III - 4.1 presents the conclusions of the lifetime extension studies.

4.2 Equipment Lifetime Analysis

Lifetime extension studies have been performed for equipment located on TCP2 only, but assuming that operational conditions are similar on all platforms, conclusions are assumed to be similar for each family of equipment.

The following equipment have been evaluated:

- Main rotating equipment
  . UTI-turbines
  . Nuovo Pignione compressors
  . Stahl - Laval turbo-generators

- Process equipment

. FWKO separators	CV1A/B/C,CV210
. Condensate separators	CV3
. Condensate/methanol separator	CV203,CV213
. Condensate heaters	CE203,CE211
. Meth.water drum	CV220
. Compr.suct.scrubbers	11B01 A/B/C
. Compr.disc.scrubbers	11B02 A/B
. Gas coolers	11E01 A/B/C

It results from this evaluation that their lifetime can reasonably be extended up to the year 2025.

Attachments III - 4.2.1 and III - 4.2.2 give the results of lifetime extension evaluation of the rotating equipment and pressure vessels hereabove listed.

ATTACHMENT III - 4.1

PLATFORM :	QP, QUARTER PLATFORM
TYPE	STEEL JACKET, 4 LEGS

ITEM	COMMENTS
LIFETIME EXTENSION	Possible up to year 2025, provided present loading condition. General condition good, would require retrofitting of cathodic protection.
EXISTING RISERS	None
NEW RISERS	- Feasibility not studied. - Lifetime extension with additional loading could be a problem. - Riser protection not studied.
MODIFICATIONS	Complete cleaning above MSF. Relocation of living quarter and control room.
SCHEDULE CONSTRAINTS	Still in service when tie-in is required.
UNCERTAINTIES	- Lifetime extension with new risers. - Available space for pigging facilities. - Safety considerations, riser protection
IMR COST	Average 13.2 MNOK/year.
FUTURE WORK	- Influence of fabrication defects and pitting on fatigue life - Reevaluate pile sleeve connection. - Reevaluate life time extension with additional risers once riser configuration is known.
GENERAL INTEREST	**Interesting as quarter platform for central complex, but less attractive as stand alone riser platform.**

PLATFORM : TP1, TREATMENT PLATFORM NO. 1

TYPE CONCRETE GRAVITY PLATFORM

ITEM	COMMENTS
LIFETIME EXTENSION	Possible up to year 2025, with present loading conditions.
EXISTING RISERS	2 x 32", 2 x 26" (also available on TCP2). Can be used if NPD '84 rules are used. Access to TCP2 and FNA line required.
NEW RISERS	Not recommended due to additional loading.
MODIFICATIONS	No significant modifications foreseen.
SCHEDULE CONSTRAINTS	None
UNCERTAINTIES	- Design codes required for risers. - Pigging requirements, 3D bends only.
IMR COST	Average 7.3 MNOK/year.
FUTURE WORK	- Confirm fatigue results for shafts with SRS model - Reevaluation of foundation based on SRS model results and instrumentation results.
GENERAL INTEREST	Interesting as bridge support for TCP2 to QP, but less attractive as riser platform.

PLATFORM : TCP2, TREATMENT COMPRESSION PLATFORM 2

TYPE CONCRETE GRAVITY PLATFORM

ITEM	COMMENTS
LIFETIME EXTENSION	Possible up to year 2025 with present loading conditions. General condition of structure is good.
EXISTING RISERS	Range of available risers: "18, 24", 2 x 26", 32" can be used provided NPD '84 rules are used. 16" and 20" risers available after 1998.
NEW RISERS	- Additional risers 2 x 36" accomodated in a riser support structure (RSS). Studied but not recommended due to significant load increase on GBS. - If additional risers are required a riser platform linked by bridge is recommended.
MODIFICATIONS	- No significant modifications foreseen.
SCHEDULE CONSTRAINTS	None
UNCERTAINTIES	- Boat impact design of RSS, - Additional loading due to RSS - Pigging requirements, 3D bends only - Design codes for risers.
IMR COST	Average 12.1 MNOK/year
FUTURE WORK	- Confirm fatigue results using SRS model - Soil investigation - Fatigue evaluation without under pressure system
GENERAL INTEREST	Very interesting either using existing risers or linked to a new riser platform.

PLATFORM :	CDP1, CONCRETE DRILLING PLATFORM NO. 1
TYPE	CONCRETE GRAVITY PLATFORM

ITEM	COMMENTS
LIFETIME EXTENSION	- Not studied - Concrete structure has suffered cracking in external diaphragm walls
EXISTING RISERS	None
NEW RISERS	Not studied.
MODIFICATIONS	Major modifications required.
SCHEDULE CONSTRAINTS	CDP1 reservoir will be depleted and wells abondoned well in time.
UNCERTAINTIES	Lifetime extensions. Additional risers.
IMR COST	Not estimated
FUTURE WORK	Not recommended
GENERAL INTEREST	Not to be considered for tie-in of Troll.

PLATFORM :	DP2, DRILLING PLATFORM NO. 2
TYPE	STEEL JACKET, 8 LEGS

ITEM	COMMENTS
LIFETIME EXTENSION	- No lifetime extension studies performed. - Fatigue capacity very uncertain for extended lifetime. - Has suffered severe fatigue damages.
EXISTING RISERS	2 x 26" will be available after DP2 reservoir depletion.
NEW RISERS	- Feasibility not studied. - Lifetime extension with new risers not studied. - Riser protection not studied.
MODIFICATIONS	Well abondonment, conductor pipe removal conductor frame removal at - 9 meter, complete cleaning above MSF, retrofitting of cathodic protection.
SCHEDULE CONSTRAINTS	None, DP2 reservoir depleted and wells abandoned in time. Could be a problem in case of 3 risers with topside and metering is required.
UNCERTAINTIES	- Lifetime extension - Additional riser - Safetly considerations, riser protection.
IMR COST	Average 22.1 MNOK/year
FUTURE WORK	- Fatigue calculations (deterministic/stochastic) to determine possible lifetime extension - Foundation evaluation - Reevaluate DP2 in extreme condition
GENERAL INTEREST	Due to the major uncertainties, DP2 is not recommended.

PLATFORM :	TTRP, NEW RISER PLATFORM
TYPE	TRIPOD TOWER RISER PLATFORM

ITEM	COMMENTS
LIFETIME EXTENSION	No problem, will be designed according to required design life.
EXISTING RISERS	Will be designed with required risers plus additional risers for future tie-in flexibility. Design according to required codes.
NEW RISERS	Not applicalbe.
MODIFICATIONS	Not applicable
SCHEDULE CONSTRAINTS	None
UNCERTAINTIES	None apparant
IMR COST	Average 1.3 MNOK/year (Estimate 50% of RP).
FUTURE WORK	- Further investigation of safety aspects operational requirements, sealing of riser etc. - Pre engineering
GENERAL INTEREST	Very interesting and cost effective. In addition it could be a safety benefit for tie-in TCP2.

PLATFORM :	RP, NEW RISER PLATFORM
TYPE	STEEL JACKET, 4 LEGS

ITEM	COMMENTS
LIFETIME EXTENSION	No problem, will be designed according to required design life.
EXISTING RISERS	Will be designed with required risers plus additional risers for future tie-in flexibility. According to required codes.
NEW RISERS	Not applicable.
MODIFICATIONS	Not applicalbe.
SCHEDULE CONSTRAINTS	None
UNCERTAINTIES	None
IMR COST	Average 2.7 MNOK/year.
FUTURE WORK	Further optimization of design when riser configurations etc. is established.
GENERAL INTEREST	Very interesting. In addition it could be a safety benefit for tie-in to TCP2.

PLATFORM : FCS, NORTH EAST FRIGG

TYPE ARTICULATED COLUMN

ITEM	COMMENTS
LIFETIME EXTENSION	Possible to extend life from 10 to 12 years has been found in preliminary studies. But with some uncertainties.
EXISTING RISERS	None.
NEW RISERS	Feasibility not studied.
MODIFICATIONS	Will require extensive rebuilding for other usage than control station, i.e. loading tower, flare platform, riser platform
SCHEDULE CONSTRAINTS	--
UNCERTAINTIES	Life time extension. Feasibility of rebuilding for other purposes. Repair of universal joint connection bolt.
IMR COST	Estimated to 6 MNOK/per year (No detailed study made).
FUTURE WORK	- Life time extension studies and studies of structural modifications to extend life. - Feasibility studies of alternative use. - More detailed study to estimate future IMR cost.
GENERAL INTEREST CONCLUSION	

ATTACHMENT III - 4.2.1

SUMMARY SHEET
TCP2 GAS-TURBINES

TAG.NO: FT 4C-3F A **TITLE:** GAS TURBINE

P.O. NUMBER : 172 151

VENDOR : UTI-TPMS (UNITED TECHN. INTERNATIONAL, USA)

TYPE	: FT 4C-3F 2 SHAFT G.G. 3 STAGES FREE TURBINE VARIABLE SPEED
NOMINAL RATED POWER (MW)	: 30.5
ESTIMATED RUNNING HOURS **IN 1992** (h)	: 33000

YEAR OF FABRICATION	: 1978
YEAR PUT INTO SERVICE	: 1981
LIFETIME	: 2025

NOTES:

DUE TO ACTIVE WATER DRIVE IN THE FRIGG RESERVOIR, THE COMPRESSION FACILITIES HAVE BEEN UTILIZED LESS THAN FORESEEN DURING THE ENGINEERING PHASE OF THE UNITS.
A MAIN OVERHAUL IS SCHEDULED AFTER 24000 HOURS RUNNING PERIOD, AND CONSEQUENTLY THE UNITS SHOULD BE IN AN EXCELLENT SHAPE FOR NEW SERVICE IN 1992 AFTER THE FRIGG RESERVOIR IS DEPLETED.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

SUMMARY SHEET
TCP2 GAS-TURBINES

TAG.NO: FT 4C-3F B **TITLE:** GAS TURBINE

P.O. NUMBER : 172 151

VENDOR : UTI-TPMS (UNITED TECHN. INTERNATIONAL, USA)

TYPE : FT 4C-3F
2 SHAFT G.G.
3 STAGES FREE TURBINE
VARIABLE SPEED

NOMINAL RATED POWER (MW) : 30.5

ESTIMATED RUNNING HOURS IN 1992 (h) : 33000

YEAR OF FABRICATION : 1978

YEAR PUT INTO SERVICE : 1981

LIFETIME : 2025

NOTES:

DUE TO ACTIVE WATER DRIVE IN THE FRIGG RESERVOIR, THE COMPRESSION FACILITIES HAVE BEEN UTILIZED LESS THAN FORESEEN DURING THE ENGINEERING PHASE OF THE UNITS. A MAIN OVERHAUL IS SCHEDULED AFTER 24000 HOURS RUNNING PERIOD, AND CONSEQUENTLY THE UNITS SHOULD BE IN AN EXCELLENT SHAPE FOR NEW SERVICE IN 1992 AFTER THE FRIGG RESERVOIR IS DEPLETED.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

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SUMMARY SHEET
TCP2 GAS-TURBINES

TAG.NO: FT 4C-3F C **TITLE:** GAS TURBINE

P.O. NUMBER : 172 151

VENDOR : UTI-TPMS (UNITED TECHN. INTERNATIONAL, USA)

TYPE	: FT 4C-3F 2 SHAFT G.G. 3 STAGES FREE TURBINE VARIABLE SPEED
NOMINAL RATED POWER (MW)	: 30.5
ESTIMATED RUNNING HOURS IN 1992 (h)	: 33000

YEAR OF FABRICATION	: 1978
YEAR PUT INTO SERVICE	: 1981
LIFETIME	: 2025

NOTES:

DUE TO ACTIVE WATER DRIVE IN THE FRIGG RESERVOIR, THE COMPRESSION FACILITIES HAVE BEEN UTILIZED LESS THAN FORESEEN DURING THE ENGINEERING PHASE OF THE UNITS.
A MAIN OVERHAUL IS SCHEDULED AFTER 24000 HOURS RUNNING PERIOD, AND CONSEQUENTLY THE UNITS SHOULD BE IN AN EXCELLENT SHAPE FOR NEW SERVICE IN 1992 AFTER THE FRIGG RESERVOIR IS DEPLETED.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

SUMMARY SHEET
TCP2 GAS-COMPRESSORS

TAG.NO: BCL 607 A **TITLE:** CENTRIFUGAL COMPRESSOR

P.O. NUMBER : 172 151

VENDOR : NUOVO PIGNONE/ALSTHOM

TYPE : BCL 607 CENTRIFUGAL COMPRESSOR

COUPLING POWER (MW) : 21.3

SPEED (RPM) : 3600

ESTIMATED RUNNING HOURS IN 1992 (h) : 33000

YEAR OF FABRICATION : 1978

YEAR PUT INTO SERVICE : 1981

LIFETIME : 2025

NOTES:

IF THE COUPLING IS CHANGED, THE CENTRIFUGAL COMPRESSOR CAN TAKE A FAR HIGHER LOAD.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

SUMMARY SHEET
TCP2 GAS-COMPRESSORS

TAG.NO: BCL 607 B TITLE: CENTRIFUGAL COMPRESSOR

P.O. NUMBER : 172 151

VENDOR : NUOVO PIGNONE/ALSTHOM

TYPE : BCL 607 CENTRIFUGAL COMPRESSOR

COUPLING POWER (MW) : 21.3

SPEED (RPM) : 3600

ESTIMATED RUNNING HOURS
IN 1992 (h) : 33000

YEAR OF FABRICATION : 1978

YEAR PUT INTO SERVICE : 1981

LIFETIME : 2025

NOTES:

IF THE COUPLING IS CHANGED, THE CENTRIFUGAL COMPRESSOR CAN TAKE A FAR HIGHER LOAD.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

SUMMARY SHEET
TCP2 GAS-COMPRESSORS

TAG.NO: BCL 607 C **TITLE:** CENTRIFUGAL COMPRESSOR

P.O. NUMBER : 172 151

VENDOR : NUOVO PIGNONE/ALSTHOM

TYPE : BCL 607 CENTRIFUGAL COMPRESSOR

COUPLING POWER (MW) : 21.3

SPEED (RPM) : 3600

ESTIMATED RUNNING HOURS IN 1992 (h) : 33000

YEAR OF FABRICATION : 1978

YEAR PUT INTO SERVICE : 1981

LIFETIME : 2025

NOTES:

IF THE COUPLING IS CHANGED, THE CENTRIFUGAL COMPRESSOR CAN TAKE A FAR HIGHER LOAD.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

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SUMMARY SHEET
TCP2 GAS-TURBINES

TAG.NO: GT 35 A   TITLE: POWER GENERATION

P.O. NUMBER : 172 151

VENDOR : STAL-LAVAL/NYLANDS VERKSTED

TYPE : GAS TURBINE GT 35

RATED POWER (MW) : 13.5

YEAR OF FABRICATION : 1978

YEAR PUT INTO SERVICE : 1981

LIFETIME : 2025

NOTES:

THE GT 35 UNIT IS ESTIMATED TO BE IN PRODUCTION UNTIL THE LATER PART OF THE 1990-TH.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

SUMMARY SHEET
TCP2 GAS-TURBINES

TAG.NO: GT 35 B **TITLE:** POWER GENERATION

P.O. NUMBER : 172 151

VENDOR : STAL-LAVAL/NYLANDS VERKSTED

TYPE : GAS TURBINE GT 35

RATED POWER (MW) : 13.5

YEAR OF FABRICATION : 1978

YEAR PUT INTO SERVICE : 1981

LIFETIME : 2025

NOTES:

THE GT 35 UNIT IS ESTIMATED TO BE IN PRODUCTION UNTIL THE LATER PART OF THE 1990-TH.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

ATTACHMENT III - 4.2.2

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV1 A **TITLE:** FWKO SEPARATOR (ODIN SLUG CATCHER)

P.O. NUMBER : 2169-41-R01 PO 001

VENDOR : C.M.P.

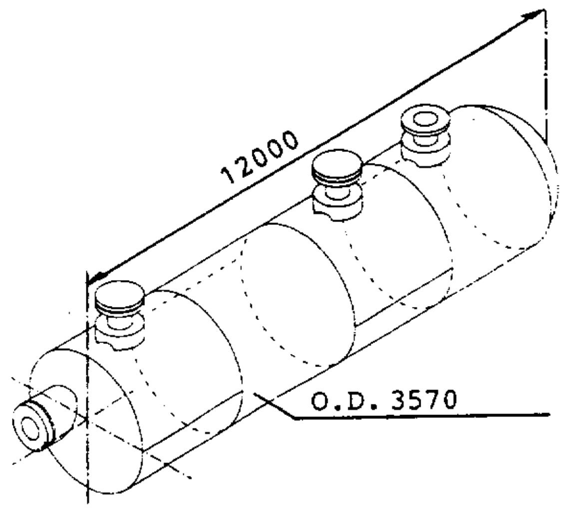
DESIGN CODE	: BS 1515 PART 1
HORIZONTAL/VERTICAL	: H
OD x L (mm)	: 3570 x 12000
VOLUME (m^3)	: 44.2
OPERATING PRESS (bar g)	: 170
DESIGN PRESS (bar g)	: 172.5
OPERATING TEMP (°C)	: 50
DESIGN TEMP (°C)	: 50
YEAR OF FABRICATION	: 1975
YEAR PUT INTO SERVICE	: 1977
LIFETIME	: 2025

NOTES:

DESIGN LATER CHECKED TO BS 5500 1976 AND FOUND SATISFACTORY.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CV1 A/B/C

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV1 B TITLE: FWKO SEPARATOR

P.O. NUMBER : 2169-41-R01 PO 001

VENDOR : C.M.P.

DESIGN CODE	:	BS 1515 PART 1
HORIZONTAL/VERTICAL	:	H
OD x L (mm)	:	2570 x 12000
VOLUME (m^3)	:	44.2
OPERATING PRESS (bar g)	:	139.9/70.9
DESIGN PRESS (bar g)	:	153
OPERATING TEMP (°C)	:	50
DESIGN TEMP (°C)	:	50
YEAR OF FABRICATION	:	1975
YEAR PUT INTO SERVICE	:	1977
LIFETIME	:	2025

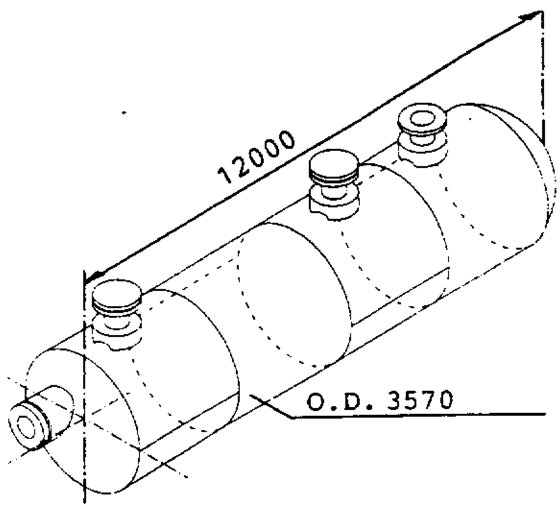
NOTES:

DESIGN LATER CHECKED TO BS 5500 1976 AND FOUND SATISFACTORY.

ORIGINALLY DESIGNED TO 172.5 BARS. LATER DERATED TO 153 BARS.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CV1 A/B/C

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SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV1 C   TITLE: FWKO SEPARATOR

P.O. NUMBER : 2169-41-R01 PO 001

VENDOR : C.M.P.

DESIGN CODE	: BS 1515 PART 1
HORIZONTAL/VERTICAL	: H
OD x L (mm)	: 2570 x 12000
VOLUME (m^3)	: 44.2
OPERATING PRESS (bar g)	: 139.9/70.9
DESIGN PRESS (bar g)	: 153
OPERATING TEMP (°C)	: 50
DESIGN TEMP (°C)	: 50
YEAR OF FABRICATION	: 1975
YEAR PUT INTO SERVICE	: 1977
LIFETIME	: 2025

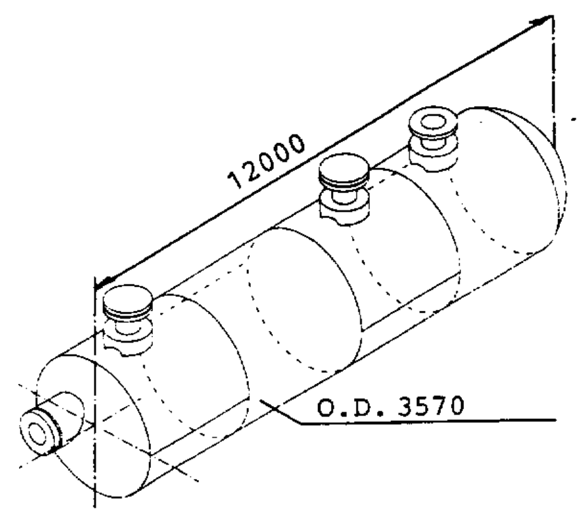
NOTES:

DESIGN LATER CHECKED TO BS 5500 1976 AND FOUND SATISFACTORY.

ORIGINALLY DESIGNED TO 172.5 BARS. LATER DERATED TO 153 BARS.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CV1 A/B/C

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SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV 3 **TITLE:** CONDENSATE SURGE TANK

P.O. NUMBER : 2169-41-R03 PO 010

VENDOR : KIRKDEAN

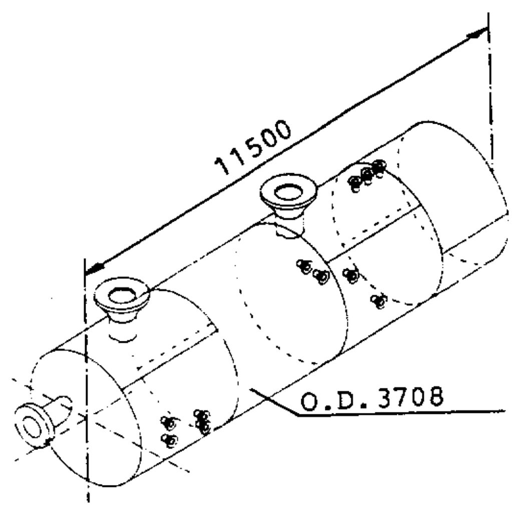
DESIGN CODE	: BS 1515
HORIZONTAL/VERTICAL	: H
OD x L (mm)	: 3708 x 11500
VOLUME (m^3)	: 106.35
OPERATING PRESS (bar g)	: 17.23
DESIGN PRESS (bar g)	: 18.96
OPERATING TEMP (°C)	: 30/50
DESIGN TEMP (°C)	: 50
YEAR OF FABRICATION	: 1975/76
YEAR PUT INTO SERVICE	: 1977
LIFETIME	: 2025

NOTES:

DESIGN CALCULATIONS, MATERIAL SERTIFICATES AND FABRICATION RECORDS MISSING.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CV 3

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CM 3 TITLE: PIG LAUNCHER,32" TO ST.FER.

P.O. NUMBER : 2169-49-R04

VENDOR : BROWN & ROOT

DESIGN CODE : BS 1515

HORIZONTAL/VERTICAL : H

OD x L (mm) : 945 x 5500

VOLUME (m^3) : -

OPERATING PRESS (bar g) : 152

DESIGN PRESS (bar g) : 153

OERATING TEMP (°C) : -

DESIGN TEMP (°C) : 50

YEAR OF FABRICATION : 1975

YEAR PUT INTO SERVICE : 1977

LIFETIME : 2025

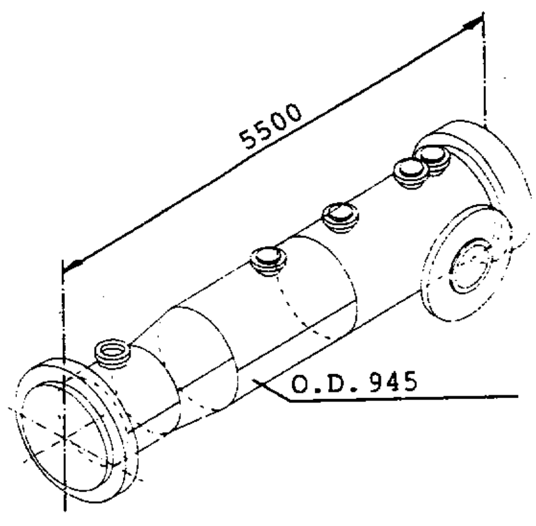
NOTES:

INFO. DESIGN PRESSURE NOT AVAILABLE. TEST PRESSURE WAS 229 bars. DESIGN PRESSURE; 229/1.5 = 153 bars.

DESIGN CALCULATIONS, MATERIAL CERTIFICATES AND FABRICATION RECORDS MISSING.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CM 3

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV 210 TITLE: SLUG CATCHER

P.O. NUMBER : 1 26 4005 00

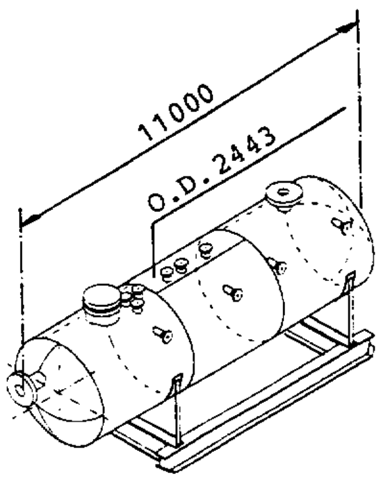
VENDOR : BABCOCK POWER LTD.

DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	:H
OD x L (mm)	: 2443 x 11000
VOLUME (m^3)	: -
OPERATING PRESS (bar g)	: 135
DESIGN PRESS (bar g)	: 176.5
OPERATING TEMP (°C)	: -
DESIGN TEMP (°C)	: -28/50
YEAR OF FABRICATION	: 1982
YEAR PUT INTO SERVICE	: 1983
LIFETIME	: 2025

NOTES:

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CV 210

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SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CE 211 **TITLE:** NEF CONDENSATE HEATER

P.O. NUMBER : 1 26 4004 00

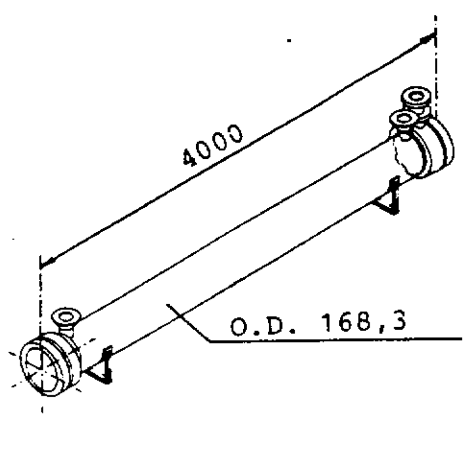
VENDOR : BRONSWERK HEAT TRANSFER BV

DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	: H
OD x L (mm)	: 168.3 x 4000
VOLUME (m^3)	: Shell: 0.052 Tubes: 0.019
OPERATING PRESS (bar g)	: Shell: 5 Tubes: 20
DESIGN PRESS (bar g)	: Shell: 24 Tubes: 176.5
OPERATING TEMP (°C)	: Shell: 52.5/58 Tubes: 2/20
DESIGN TEMP (°C)	: Shell: 0/107 Tubes: -12/107
YEAR OF FABRICATION	: 1982
YEAR PUT INTO SERVICE	:1983
LIFETIME	: 2025

NOTES:

LIFETIME EVALUATION BEYOND
YEAR 2025 NOT PERFORMED.

FIGURE:



CE 211

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV 204 TITLE: ODIN CONDENSATE/METH. SEP.

P.O. NUMBER : FO 1 26 4002 00

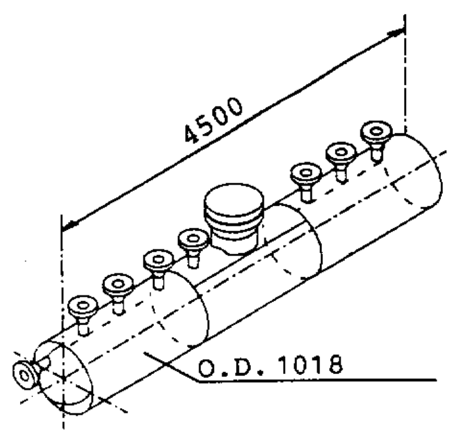
VENDOR : PEDER HALVORSEN A/S

DESIGN CODE	: BS 5500
HORIZONTAL/VERTICAL	: H
OD x L (mm)	: 1018 x 4500
VOLUME (m^3)	: 3.4
OPERATING PRESS (bar g)	: 19
DESIGN PRESS (bar g)	: 24
OPERATING TEMP (°C)	: 20
DESIGN TEMP (°C)	: 50/-12
YEAR OF FABRICATION	: 1982
YEAR PUT INTO SERVICE	: 1983
LIFETIME	: 2025

NOTES:

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CV 204

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV 213 TITLE: NEF CONDENSATE/METH. SEP.

P.O. NUMBER : FO 1 26 4002 00

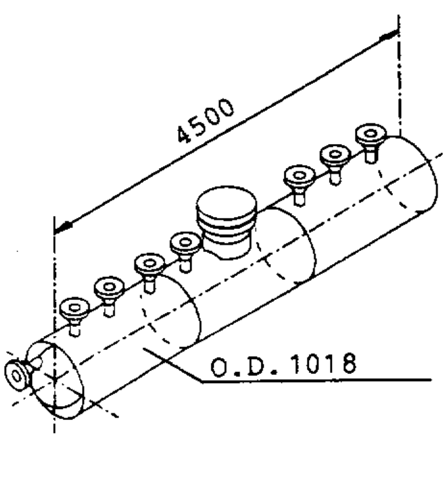
VENDOR : PEDER HALVORSEN A/S

DESIGN CODE	:	BS 5500
HORIZONTAL/VERTICAL	:	H
OD x L (mm)	:	1018 x 4500
VOLUME (m^3)	:	3.4
OPERATING PRESS (bar g)	:	19
DESIGN PRESS (bar g)	:	24
OPERATING TEMP (°C)	:	20
DESIGN TEMP (°C)	:	50/-12
YEAR OF FABRICATION	:	1982
YEAR PUT INTO SERVICE	:	1983
LIFETIME	:	2025

NOTES:

LIFETIME EVALUATION BEYOND
YEAR 2025 NOT PERFORMED.

FIGURE:



CV 213

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CE 203 TITLE: ODIN CONDENSATE HEATER

P.O. NUMBER : 1 26 4004 00

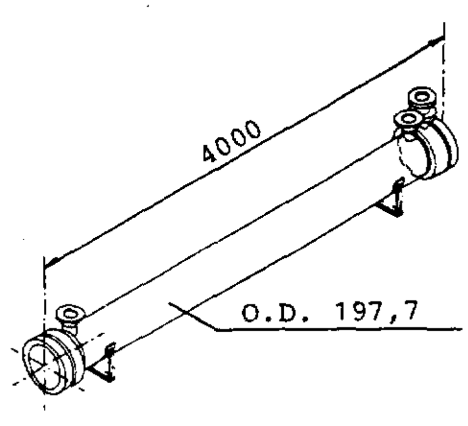
VENDOR : BRONSWERK HEAT TRANSFER BV

DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	: H
OD x L (mm)	: 197.7 x 4000
VOLUME (m^3)	: Shell: 0.052 Tubes: 0.019
OPERATING PRESS (bar g)	: Shell: 5 Tubes: 20
DESIGN PRESS (bar g)	: Shell: 24 Tubes: 176.5
OPERATING TEMP (°C)	: Shell: 52.2/58 Tubes: 2/20
DESIGN TEMP (°C)	: Shell: 0/107 Tubes: -12/107
YEAR OF FABRICATION	: 1982
YEAR PUT INTO SERVICE	: 1983
LIFETIME	: 2025

NOTES:

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CE203

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 B02 B TITLE: KNOCKOUT SEPARATOR

P.O. NUMBER : 172.153

VENDOR : AIROIL FRANCAISE

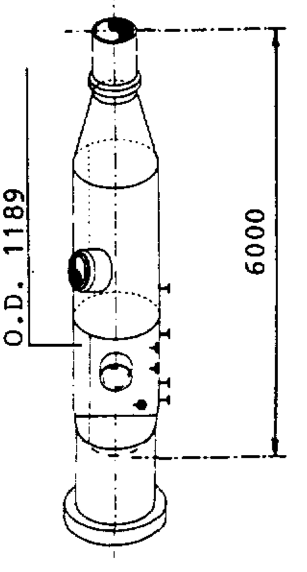
DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	: V
OD x L (mm)	: 1189 x 6000
VOLUME (m^3)	: 4.05
OPERATING PRESS (bar g)	: 152
DESIGN PRESS (bar g)	: 171
OPERATING TEMP (°C)	: 30
DESIGN TEMP (°C)	: 65
YEAR OF FABRICATION	: 1978
YEAR PUT INTO SERVICE	: 1981
LIFETIME	: 2025

NOTES:

THE VESSEL HAS A HISTORY OF DEFECTIVE INTERNAL COMPONENTS, WHICH MAY HAVE A SHORTER LIFETIME THAN THE VESSEL ITSELF.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 B02 A/B

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 B02 A **TITLE:** KNOCKOUT SEPARATOR

P.O. NUMBER : 172.153

VENDOR : AIROIL FRANCAISE

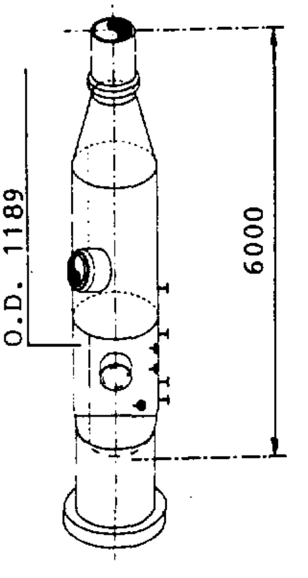
DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	: V
OD x L (mm)	: 1189 x 6000
VOLUME (m^3)	: 4.05
OPERATING PRESS (bar g)	: 152
DESIGN PRESS (bar g)	: 171
OPERATING TEMP (°C)	: 30
DESIGN TEMP (°C)	: 65
YEAR OF FABRICATION	: 1978
YEAR PUT INTO SERVICE	: 1981
LIFETIME	: 2025

NOTES:

THE VESSEL HAS A HISTORY OF DEFECTIVE INTERNAL COMPONENTS, WHICH MAY HAVE A SHORTER LIFETIME THAN THE VESSEL ITSELF.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 B02 A/B

elf aquitaine norge a s

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 B01 C   **TITLE:** SUCTION DRUM

P.O. NUMBER : 172.153

VENDOR : AIROIL FRANCAISE

DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	: V
OD x L (mm)	: 1189 x 7000
VOLUME (m^3)	: 4.86
OPERATING PRESS (bar g)	: 94.8
DESIGN PRESS (bar g)	: 171
OPERATING TEMP (°C)	: 50
DESIGN TEMP (°C)	: 65
YEAR OF FABRICATION	: 1978
YEAR PUT INTO SERVICE	: 1981
LIFETIME	: 2025

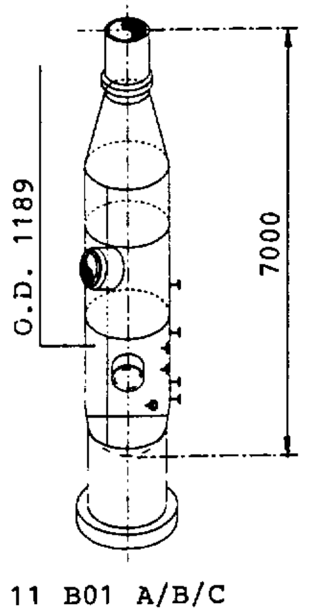
NOTES:

ONE MATERIAL TEST CERTIFICATE MISSING

THE VESSEL HAS A HISTORY OF DEFECTIVE INTERNAL COMPONENTS, WHICH MAY HAVE A SHORTER LIFETIME THAN THE VESSEL ITSELF.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 B01 A/B/C

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 B01 B **TITLE:** SUCTION DRUM

P.O. NUMBER : 172.153

VENDOR : AIROIL FRANCAISE

DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	: V
OD x L (mm)	: 1189 x 7000
VOLUME (m^3)	: 4.86
OPERATING PRESS (bar g)	: 94.8
DESIGN PRESS (bar g)	: 171
OPERATING TEMP (°C)	: 50
DESIGN TEMP (°C)	: 65
YEAR OF FABRICATION	: 1978
YEAR PUT INTO SERVICE	: 1981
LIFETIME	: 2025

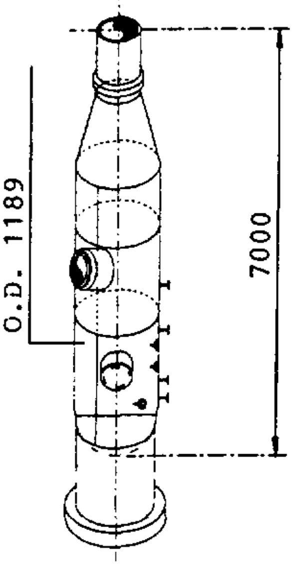
NOTES:

ONE MATERIAL TEST CERTIFICATE MISSING

THE VESSEL HAS A HISTORY OF DEFECTIVE INTERNAL COMPONENTS, WHICH MAY HAVE A SHORTER LIFETIME THAN THE VESSEL ITSELF.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 B01 A/B/C

elf aquitaine norge a s

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 B01 A TITLE: SUCTION DRUM

P.O. NUMBER : 172.153

VENDOR : AIROIL FRANCAISE

DESIGN CODE	: BS 5500 1976
HORIZONTAL/VERTICAL	: V
OD x L (mm)	: 1189 x 7000
VOLUME (m^3)	: 4.86
OPERATING PRESS (bar g)	: 94.8
DESIGN PRESS (bar g)	: 171
OPERATING TEMP (°C)	: 50
DESIGN TEMP (°C)	: 65
YEAR OF FABRICATION	: 1978
YEAR PUT INTO SERVICE	: 1981
LIFETIME	: 2025

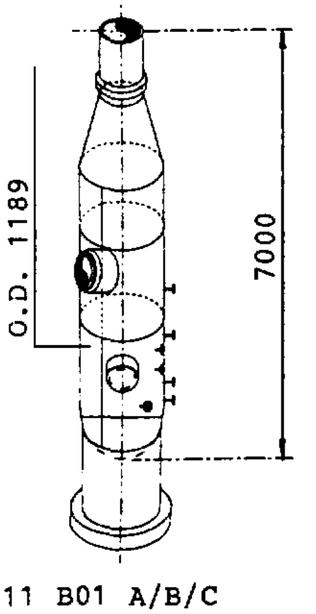
NOTES:

ONE MATERIAL TEST CERTIFICATE MISSING

THE VESSEL HAS A HISTORY OF DEFECTIVE INTERNAL COMPONENTS, WHICH MAY HAVE A SHORTER LIFETIME THAN THE VESSEL ITSELF.

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 B01 A/B/C

elf aquitaine norge a.s

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 E01 A   TITLE: GAS COOLER

P.O. NUMBER : 172.158

VENDOR : CREUSOT-LOIRE

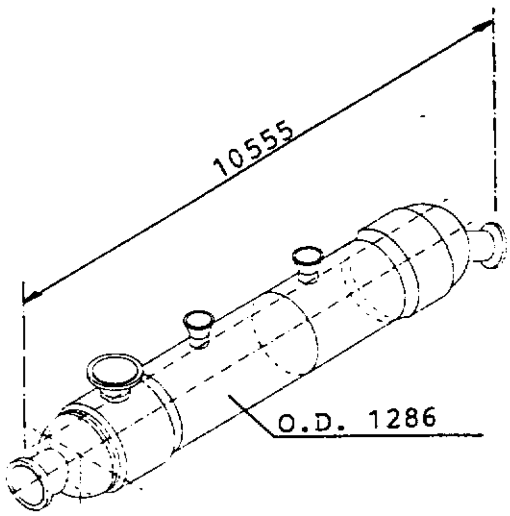
DESIGN CODE	: BS 1515		
HORIZONTAL/VERTICAL	: H		
OD x L (mm)	: 1286 x 10555		
VOLUME (m^3)	: Shell: 6.271	Tubes: 4.774
OPERATING PRESS (bar g)	: Shell: 4.2	Tubes: 153
DESIGN PRESS (bar g)	: Shell: 7	Tubes: 171
OPERATING TEMP (°C)	: Shell: 45	Tubes: 95
DESIGN TEMP (°C)	: Shell: 60	Tubes: 120
YEAR OF FABRICATION	: 1978		
YEAR PUT INTO SERVICE	: 1981		
LIFETIME	: 2025		

NOTES:

DESIGN CALCULATIONS, DRAWINGS, MATERIAL CERTIFICATES AND FABRICATION RECORDS MISSING

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 E01 A/B/C

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 E01 B **TITLE:** GAS COOLER

P.O. NUMBER : 172.158

VENDOR : CREUSOT-LOIRE

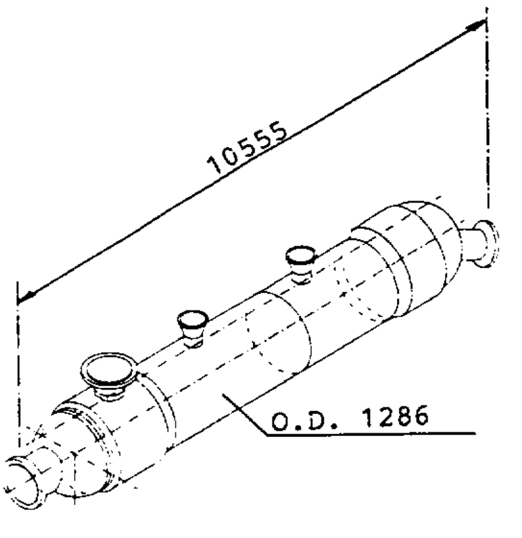
DESIGN CODE	: BS 1515		
HORIZONTAL/VERTICAL	: H		
OD x L (mm)	: 1286 x 10555		
VOLUME (m^3)	: Shell: 6.271	Tubes: 4.774	
OPERATING PRESS (bar g)	: Shell: 4.2	Tubes: 153	
DESIGN PRESS (bar g)	: Shell: 7	Tubes: 171	
OPERATING TEMP (°C)	: Shell: 45	Tubes: 95	
DESIGN TEMP (°C)	: Shell: 60	Tubes: 120	
YEAR OF FABRICATION	: 1978		
YEAR PUT INTO SERVICE	: 1981		
LIFETIME	: 2025		

NOTES:

DESIGN CALCULATIONS, DRAWINGS, MATERIAL CERTIFICATES AND FABRICATION RECORDS MISSING

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 E01 A/B/C

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: 11 E01 C **TITLE:** GAS COOLER

P.O. NUMBER : 172.158

VENDOR : CREUSOT-LOIRE

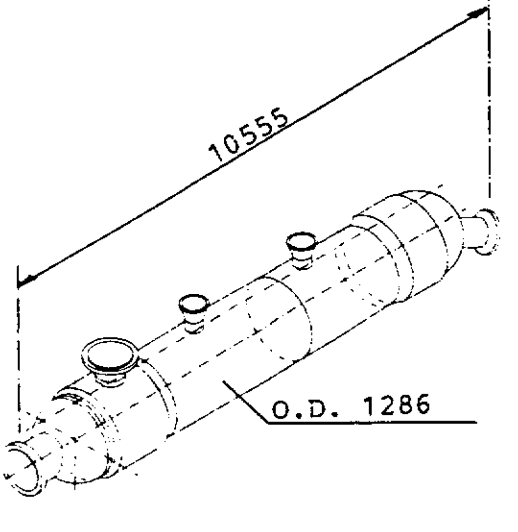
DESIGN CODE	: BS 1515		
HORIZONTAL/VERTICAL	: H		
OD x L (mm)	: 1286 x 10555		
VOLUME (m^3)	: Shell: 6.271	Tubes: 4.774	
OPERATING PRESS (bar g)	: Shell: 4.2	Tubes: 153	
DESIGN PRESS (bar g)	: Shell: 7	Tubes: 171	
OPERATING TEMP (°C)	: Shell: 45	Tubes: 95	
DESIGN TEMP (°C)	: Shell: 60	Tubes: 120	
YEAR OF FABRICATION	: 1978		
YEAR PUT INTO SERVICE	: 1981		
LIFETIME	: 2025		

NOTES:

DESIGN CALCULATIONS, DRAWINGS, MATERIAL CERTIFICATES AND FABRICATION RECORDS MISSING

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



11 E01 A/B/C

SUMMARY SHEET
TCP2 PRESSURE VESSELS

TAG.NO: CV 220 TITLE: METH.LATED WATER FLASH DRUM

P.O. NUMBER : FO 1 26 4002 00

VENDOR : PEDER HALVORSEN A/S

DESIGN CODE : BS 5500 1976

HORIZONTAL/VERTICAL : H

OD x L (mm) : 916 x 3400

VOLUME (m^3) : 2.04

OPERATING PRESS (bar g) : 9

DESIGN PRESS (bar g) : 15.2

OPERATING TEMP (°C) : 20

DESIGN TEMP (°C) : -20/50

YEAR OF FABRICATION : 1982

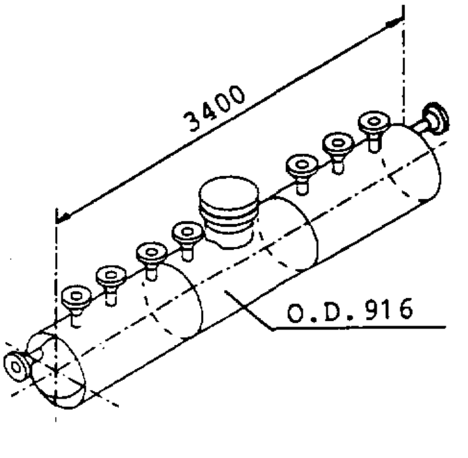
YEAR PUT INTO SERVICE : 1983

LIFETIME : 2025

NOTES:

LIFETIME EVALUATION BEYOND YEAR 2025 NOT PERFORMED.

FIGURE:



CV 220

CHAPTER III - PART 5

Potential Modifications

5.1 Introduction

This chapter reminds the initial or reevaluated load capacities and area of the platforms and the present available capacities of load and area. Then some cases of modification will be presented.

5.2 Characteristics of the Platforms.
Only TP1, TCP2 and DP2 are considered in what follows.

5.2.1 **TP1**

The Module Support Frame (MSF) was originally designed to carry:

. load on the main and upper deck	:	80500 KN (8200 tonnes)
. load on the cellar deck	:	13500 KN (1400 tonnes)
. total load capacity	:	94000 KN (9600 tonnes)

After revision, the total load capacity was risen to 106000 KN (10800 tonnes).

The present load occupancy is 78500 KN (8000 tonnes), which gives an available left load capacity of 2800 tonnes.

Reducing the live load and the hydro test load, this capacity could be increased by 500 tonnes.

The removal of modules 02, 03, 04 and 05 could free 3950 additional tonnes.

So the available load capacity could be:

. without any modifications	:	2800 tonnes
. with modification of live load and hydro.test	:	3300 tonnes
. with removal of modules 02, 03, 04, 05	:	7250 tonnes

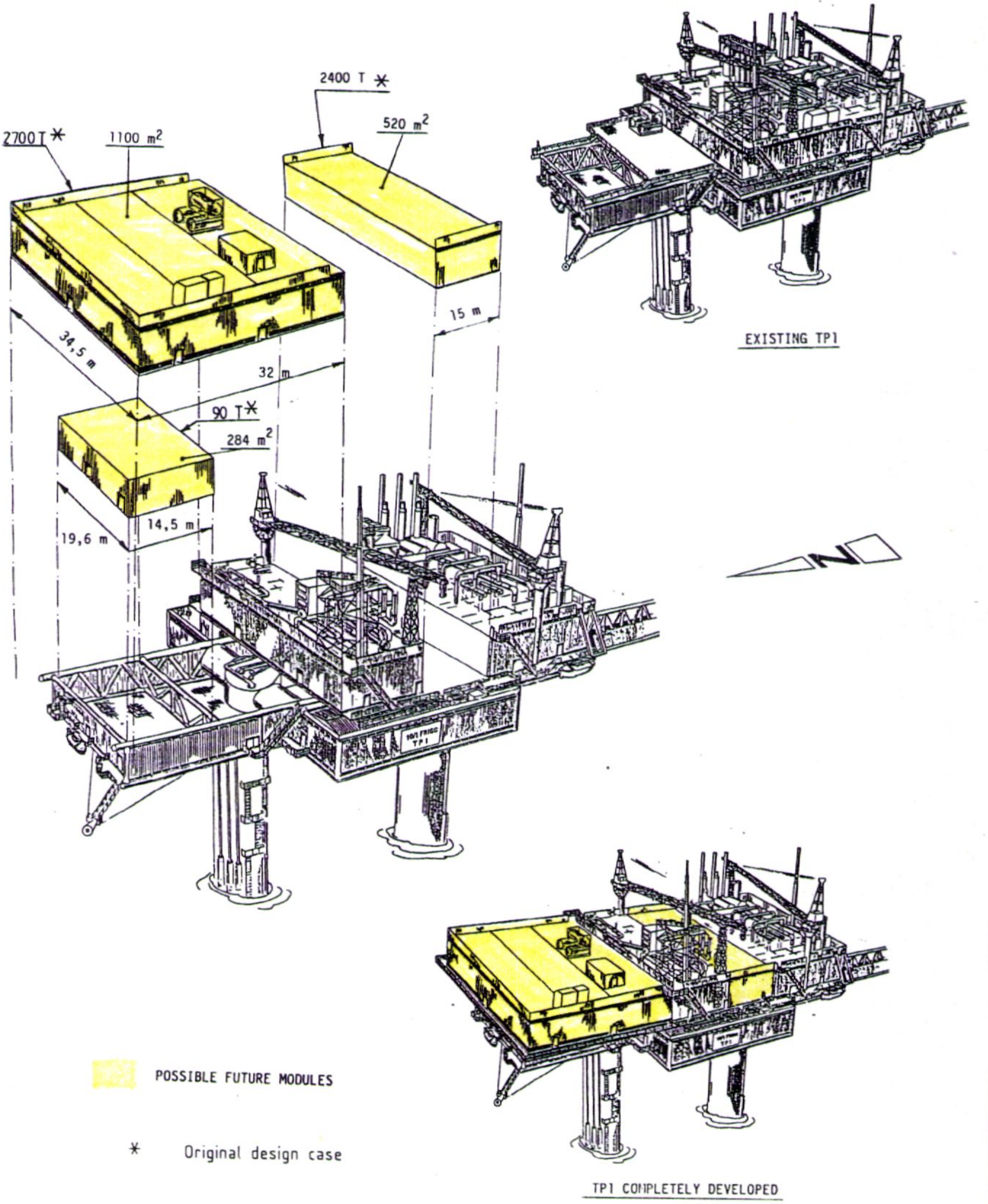
The general arrangement of TP1 and possibilities of modifications are exhibited in Attachment III - 5.1.

- The initial areas between the main trusses and in cantilever were:
  . cellar deck : 2474 m^2 (see Attachment III.5.2)
  . main deck : 1332 m^2 (see Attachment III.5.3)

Note: the available area of the main deck can be extended with the area of the modules themselves

- The present available areas are:
  . cellar deck : 290 m^2
  . main deck : 1100 m^2 approximately

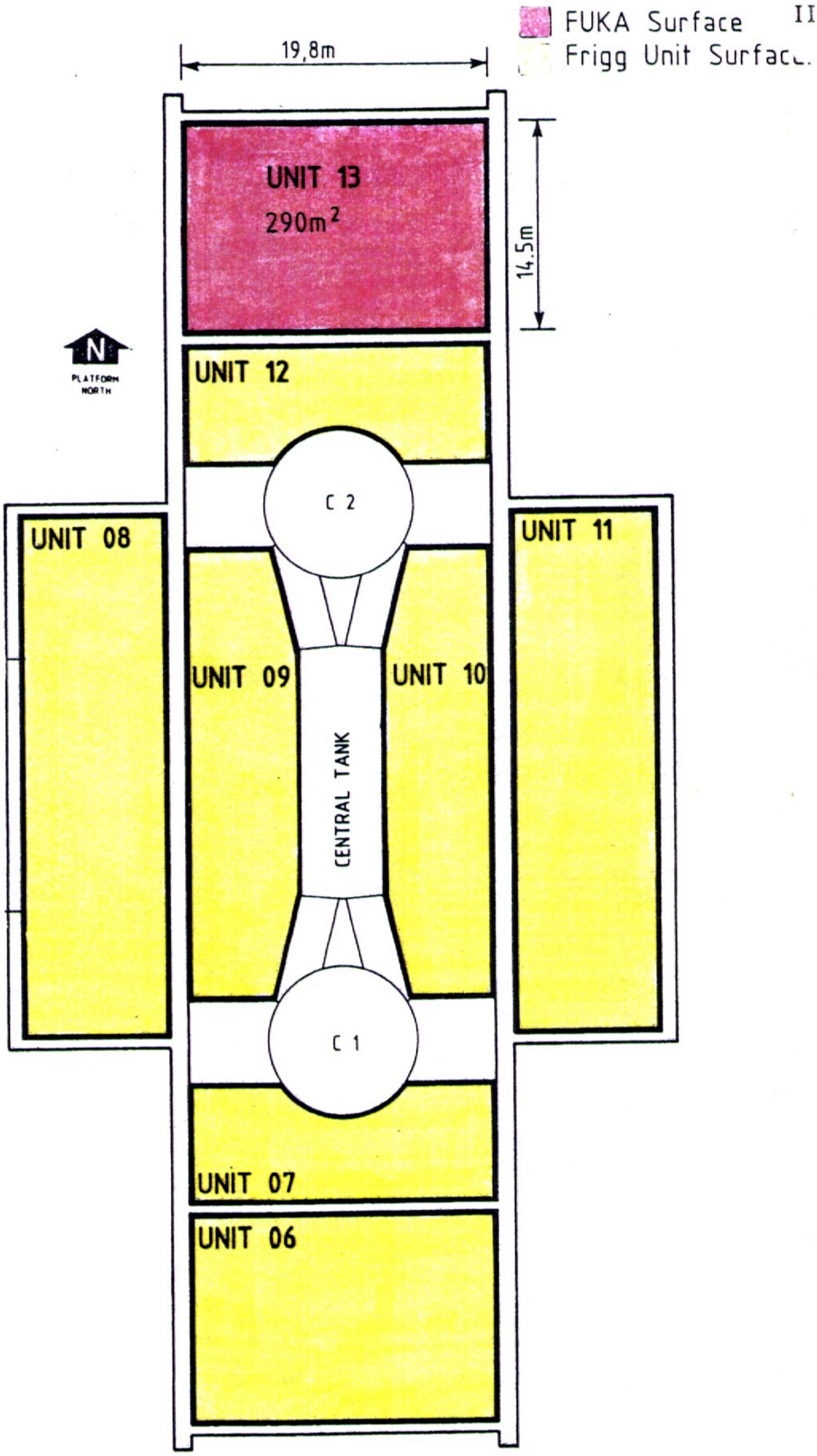
Attachment
III.5.1



Rev	Date	DESCRIPTION	by	app	Contractor
0	07.03.88	First issue	MO	Tør.	

elf aquitaine norge a/s P.O. Box 168 4001 Stavanger	FRIGG FIELD	Installation TP1	System ARC.
		Job no.	FUTURE MODULES TP1
		Scale ~	
		Drwg. no. FA	85 00 00 10 09 Rev. 0 Sheet 1/1

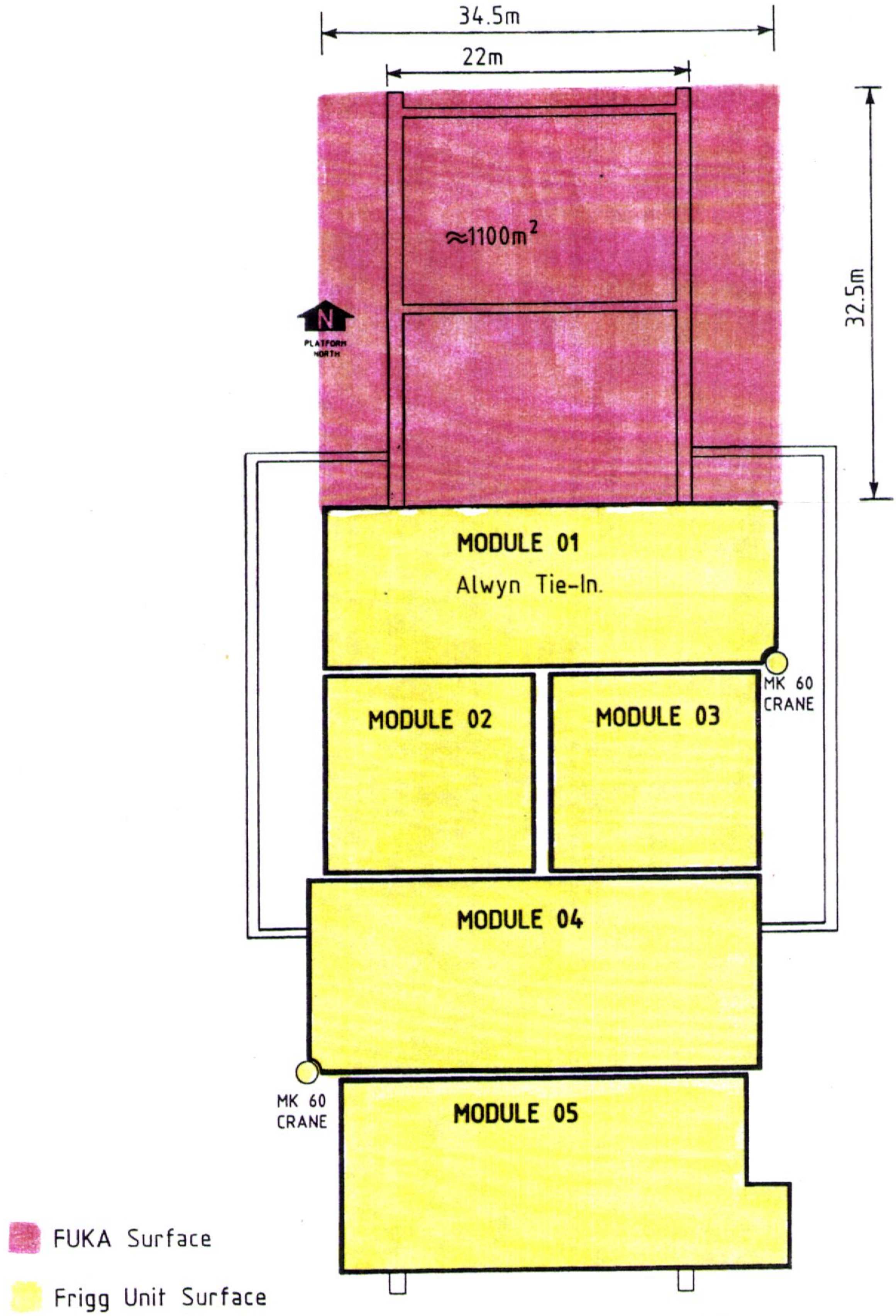
Attachment
III.5.2



UNITS 06, 07, 08, 09, 10, 11, 12. AND 13

TP1- CELLAR DECK

Attachment
III.5.3



MODULE 01, 02, 03, 04 AND 05

TP1-MAIN DECK

5.2.2 TCP2

The module support frame (MSF) was originally designed to carry:

. load on main deck	:	130500 KN	(13300 tonnes)
. load on cellar deck	:	78500 KN	(8000 tonnes)
. total load capacity	:	209000 KN	(21300 tonnes)

- The present load occupancy is 17350 tonnes (Odin compression module included) which leaves an available load capacity of 4000 tonnes.
  The general arrangement of TCP2 with possible extensions is exhibited on Attachment III - 5.4.

- Reducing the live load and the hydro test constraint, this remaining capacity can be increased by 1000 tonnes, therefore the available capacity would be 5000 tonnes.

- It is not presently considered to remove anyone of the modules of treatment and/or compression from TCP2.

- The present available areas are :
  - Cellar deck : 275 m^2 (see Attachment III - 5.5)
  - Main deck : 830 m^2 (see Attachment III - 5.6)

5.2.3 Drilling Platform DP2

Production and drilling modules totalize 6870 tonnes, this load capacity could be made available for future project.

5.3 Examples of Modification

With present system capacities and available deck space on the Frigg central complex, the installations can in principle be modified to do any kind of normal offshore hydrocarbon treatment services. The services are however dependent of different degrees of modifications, which have been proven feasible though numerous studies, as referred to below.

5.3.1 Minor Modifications

5.3.1.1 Tie-In and Transit to Pipelines

Description of function: Tie-in by use of existing risers, use of existing flow control valves and metering stations for flow control and leak-detection and connection to the pipelines by the existing discharge headers, requires only minor modifications.
Ref: Alwyn tie-in project, Bruce and Beryl tie-in (1985 + 1988), Troll tie-in (1986)

5.3.1.2 Gas/Condensate Separation, Dehydration and Compression

Description of function: Tie-in by existing risers, use of available FWKO separators, condensate separators, gas and condensate metering and compression, allows for a big flow range of gas to be accepted on the field by only minor modification.
Ref: NEF project, TCP2 - Extension project (i.e. NEF + Odin treatm.), EF + EF tie-in projects, Gamma project study (1986), block 3/30 (i.e Ranger) study (1987), FRØY sch. 6 (1988)

5.3.2 Medium Size Modifications

5.3.2.1 Gas/Condensate Separation, with Condensate Return, Residual Gas Compression, Gas Dehydration and Compression.

Description of function: Tie-in by existing risers, use of existing FWKO' sep., condensate separating, metering and compression, as well as installing new residual gas compressors and condensate return pumps.
Ref: Bruce Treatment Study (1988)

5.3.2.2 Oil Storage

By applying a specification for stabilized crude the columns of TCP2 can be converted to oil storage. The system will require modification of the columns (valves, pumps, venting etc.)
Ref. FRØY scheme 5.

5.3.3 Major modifications

5.3.3.1 Hydrocarbon Dewpoint Unit

Processing gas to a commercial specification complying with Gross Calorific Value, Wobbe Index or a Hydrocarbon Dew Point specification will require a new module containing heat exchangers, turbo-expander, deethanizer, heating system, residual gas compressors and condensate export pumps. In addition such a unit will require a liquid export system, which does not exist.
Ref: Troll treatment (1985), EF and Odin to continent (1985), Rich gas treatment on FRIGG (1988), Beryl treatment (1988).

5.3.3.2 CO_2 Removal

Reducing the CO_2 content offshore will require a complete new process, containing absorbtion, deabsorbtion towers, heat exchangers, heating system pumps etc., and will require a new module.
Ref: Beryl treatment (1988)

5.3.3.3 Oil Separation and Stabilization

Oil separation and stabilization can partly reuse existing equipment, but will require additional separators, heaters, compressor and coalescers.
An alternative can be to use a stabilisation tower.
The additional facilities can be either located in a module or on open packages.
Ref: FRØY scheme 5, (1988), Prestudy for a condensate stabilization module on Frigg (1986).

5.3.3.4 Injection Water Treatment

Injection water treatment will require a new module containing filters, deaerator tower, chemical injection package and injection pumps.

Ref: FRØY scheme 5,

5.3.4 Possibilities for External Structures

5.3.4.1 General

In order to tie-in pipelines with a greater size than 32" an external structure to existing platforms will be required.
Two different solutions have been studied:
1) Riser support structure, located on the outside of the existing column of TCP2
2) Riser platform by a bridge to TCP2

5.3.4.2 Riser Support Structure (RSS)

A detailed feasibility study has been carried covering various possibilities to install 2 x 36" gas transportation pipeline risers on Frigg TCP2 Platform Column 5.

The riser concept <u>selected</u> for the study considers two 36" risers supported by a tubular steel structure extending from base of the main structure slab to the module support frame (MSF). It is considered relatively simple and quick to install.

Transportation
The complete RSS incorporating 2 x 36" risers could be transported to the field on barge, heavy lift vessel or towed by attachment of floats.

Installation
The RSS would be attached to MSF support/pivot prior to being swung into its final position for attachment to the existing structure. During the installation phase, the RSS would be lifted using a heavy lift barge.

The conclusion of the study is that the concept is a feasible and cost effective method to install new risers. The following risers sizes were studied:
1) 36"+36"
2) 36"+34"
3) 36"+42" **
** A design with 42" may be difficult due to load limitations.

It is assumed that the RSS would be installed with 2 prefabricated risers even if only 1 was required for the selected scheme.

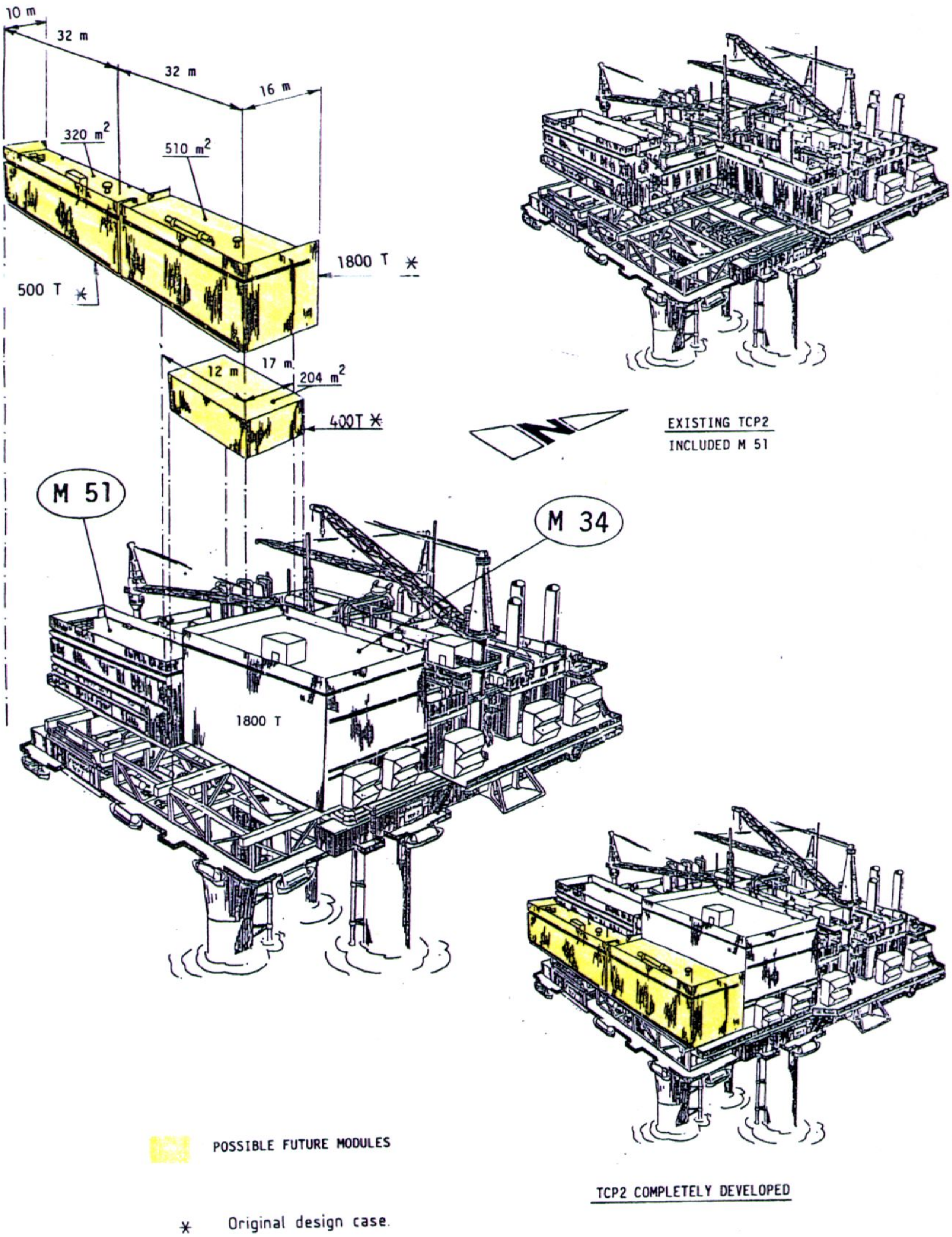
A sketch is enclosed as Attachment III-5.7 hereto.

5.3.4.3 Riser Platform (RP), Steel Jacket Structure

Several riser platform studies have been conducted having different objectives as described below:

<u>Troll Tie-in Study conducted in 1985</u>

For this study a Riser Platform was considered in order to accommodate:
3 x 36" gas lines (2 from Troll, 1 to Heimdal)
1 x 8" condensate to Heimdal
1 x 26" gas spare



POSSIBLE FUTURE MODULES

* Original design case.

Rev.	Date	DESCRIPTION	by	app
0	15.02.88	First issue	mo	TGt

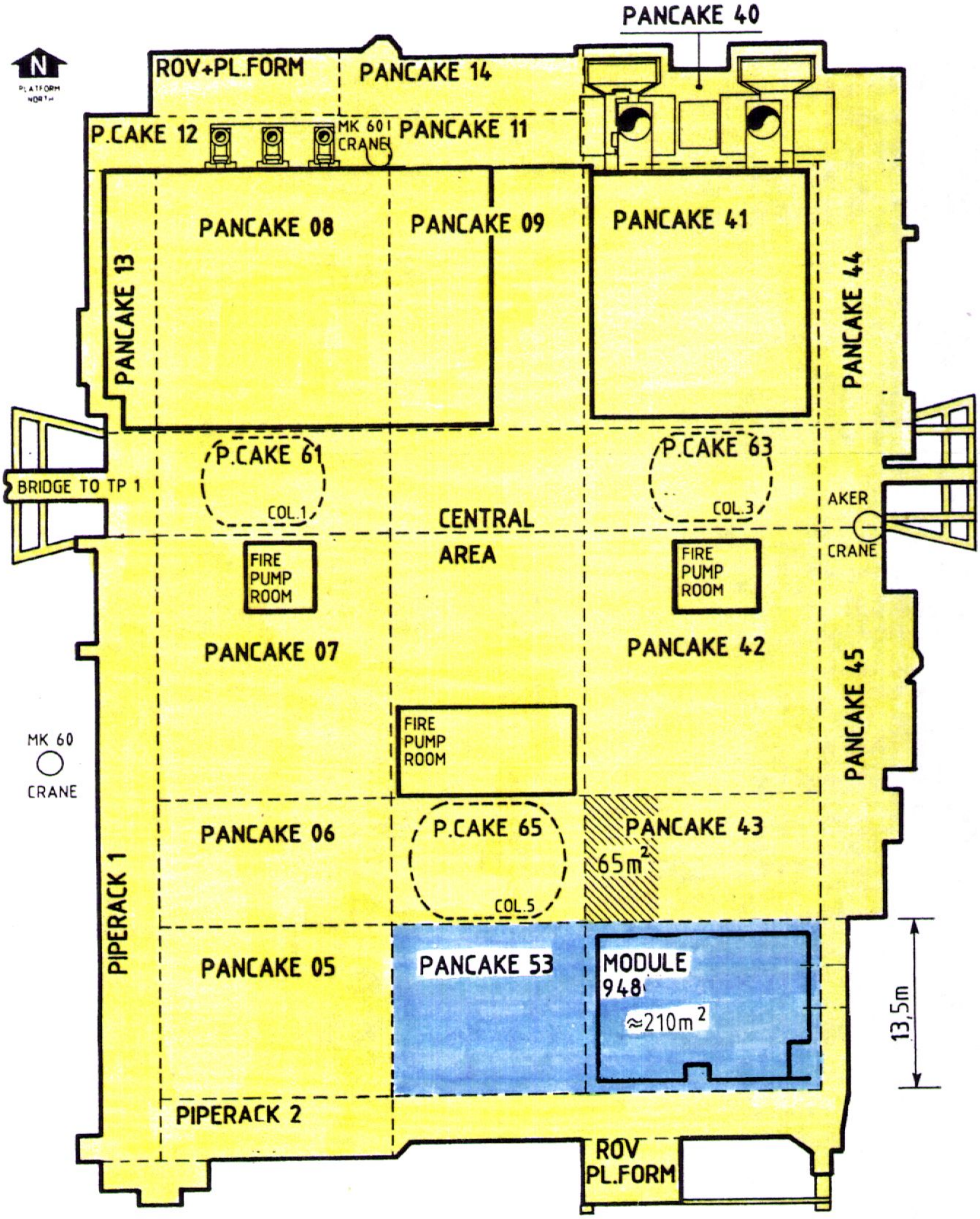
Contractor

elf aquitaine norge a/s
p.o box 168
4001 Stavanger

FRIGG FIELD

Installation TCP2 · System ARC.
Job no · FUTURE MODULES TCP2
Scale ~
Drwg. no FF 85 00 00 10 08 · Rev. 0 · Sheet 1 / 1

Attachment
III.5.5



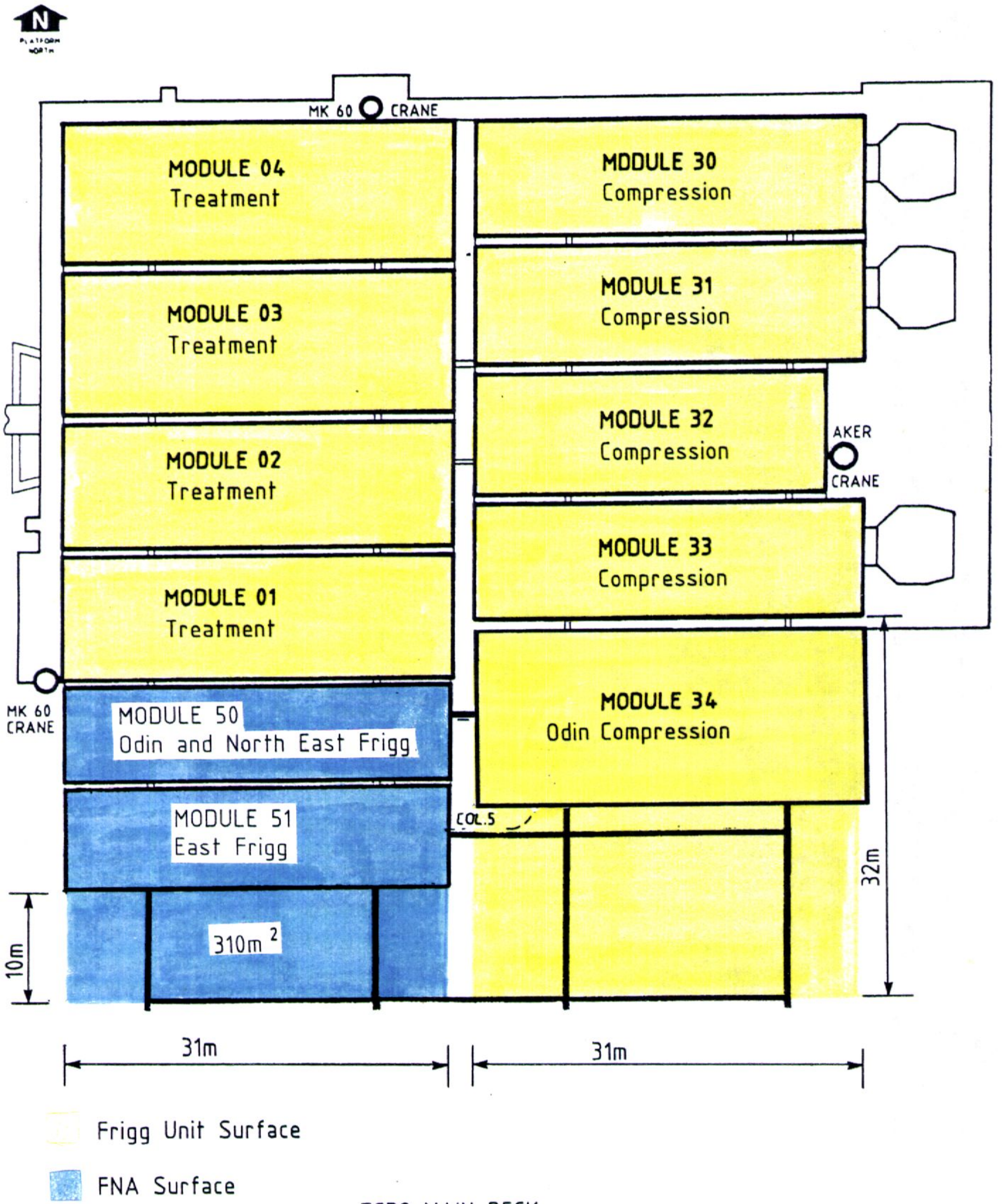
TCP2- **CELLAR DECK**

Frigg Unit Surface

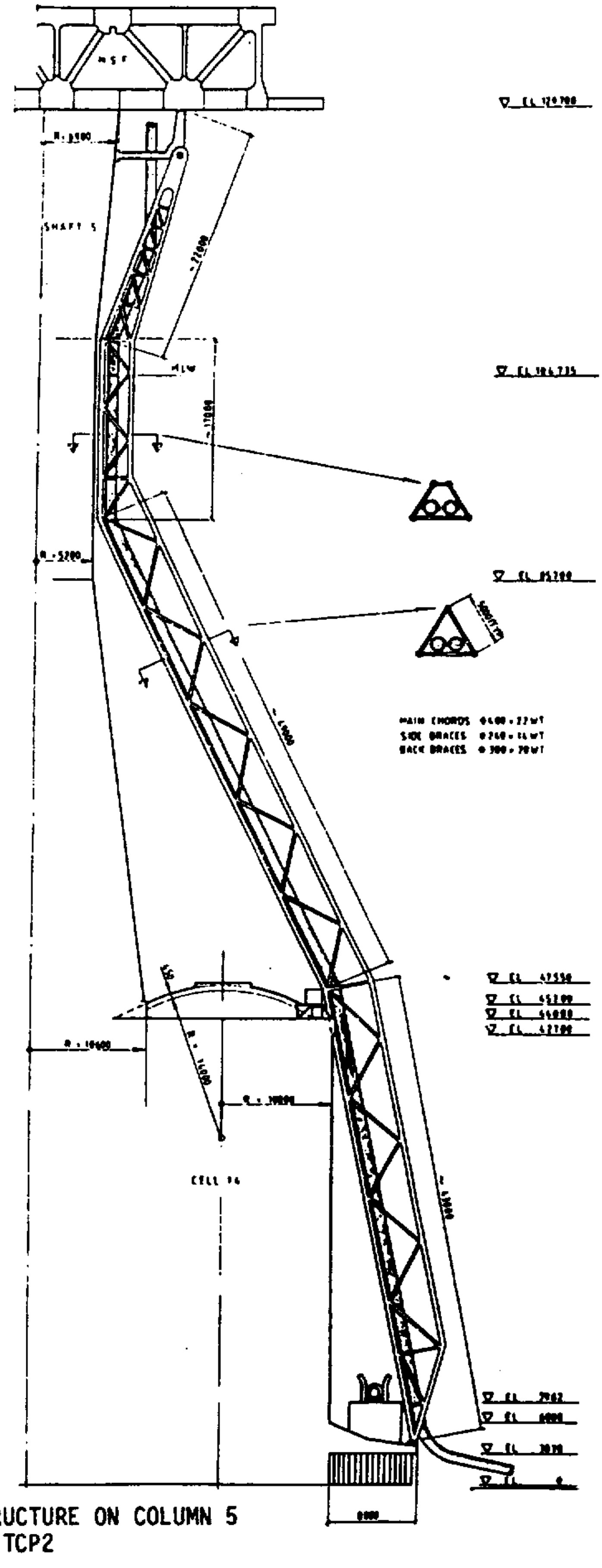
FNA Surface

Frigg Unit Surface free

Attachment
III.5.6



TCP2-MAIN DECK



RISER SUPPORT STRUCTURE ON COLUMN 5
OF TCP2

In addition, the bridge to TCP2 was checked to support the following lines:

3 x 36" gas
1 x 8" condensate
1 x 26" gas
2 x 6" fire fighting system
1 x 16" new flare
1 x 4" flare pilot
1 electric cable (beaconing)

Troll Study conducted in 1986

This study was somewhat limited compared with the study carried out in 1985. The results from the 1985 study were utilized as a basis.

For this study the following parameters have been studied:

2 x 42" gas risers
2 x 42" ESD valves
1 x 6" gas riser (spare)
Bridge to TCP2:
2 x 42" gas lines
1 electric cable (beaconing)

Sketches of the riser are enclosed as Attachment III-5.8 and and III-5.9 hereto.

Bridge design

In the 1985 study the bridge was extended past the riser platform as a cantilever in order to accommodate the flare. This was not required for the 1986 study.
The design of the bridge is based on a study performed by SNEA(P) "FRIGG FIELD - Future Tie-in Riser Platform".
This study accounted for a considerably higher pipeline load than required for this study.
Based on the above, the following estimates have been made for the bridge with length 120 m.

Structure	:	203 t
Piping + miscellaneous	:	266 t
Total	:	469 t

The bridge has a rectangular section.

Riser Platform Design

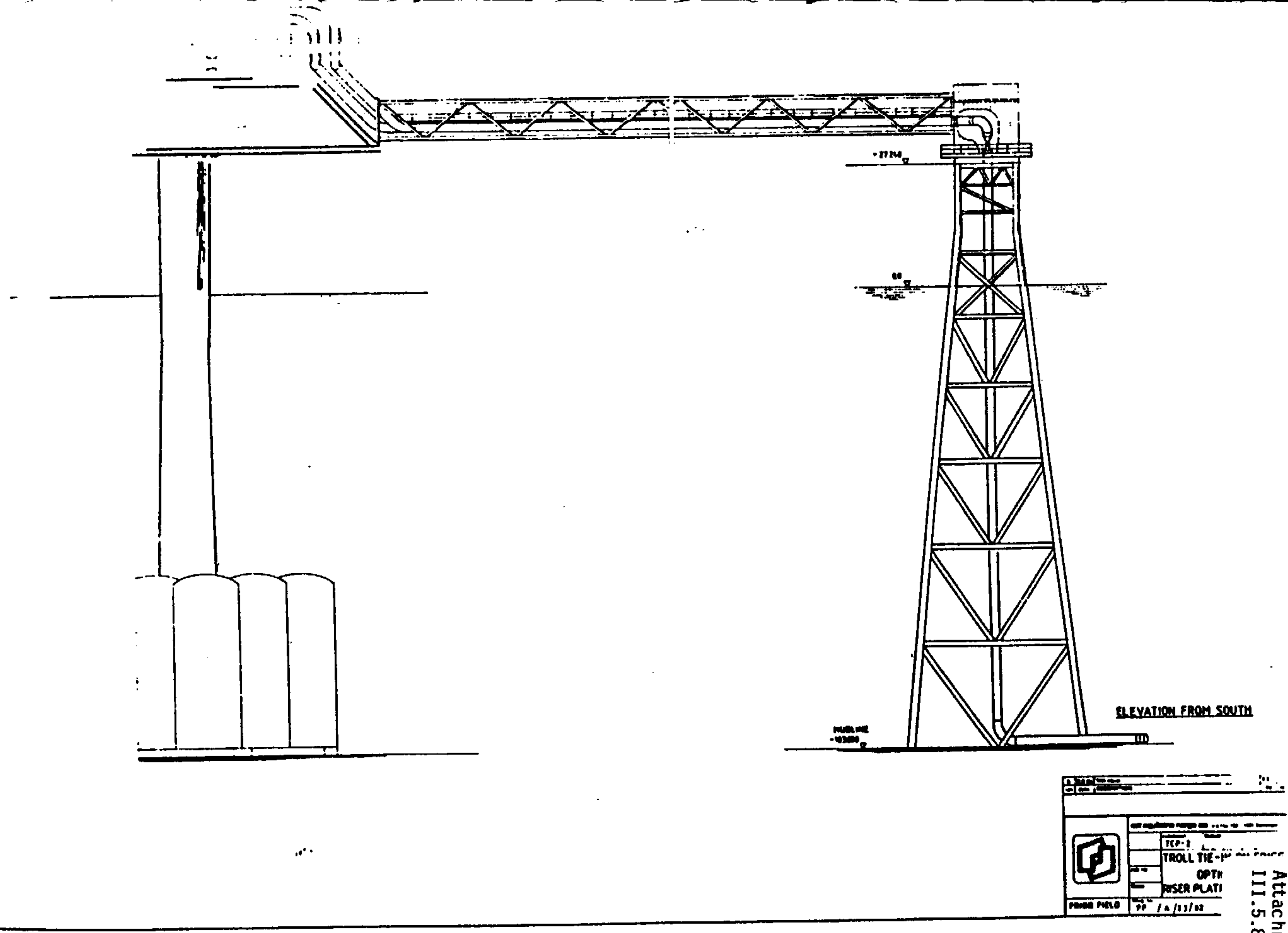
As 1 x 42" ESD valves will be located on the riser platform this imposes additional load onto the platform.

Loads from bridge	:	235 t
1 x 42" ESD valves + misc.	:	50 t
Total	:	285 t

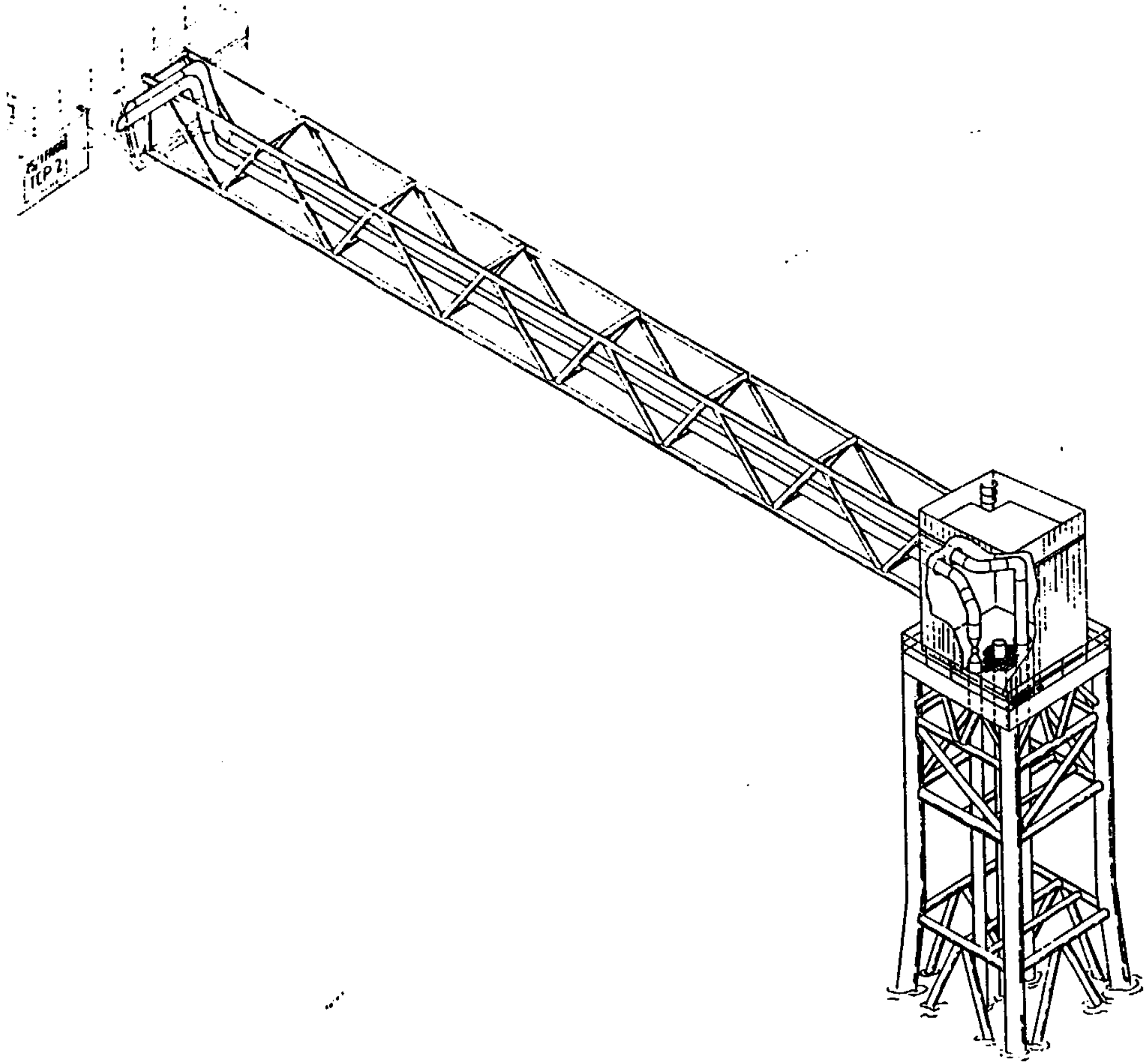
ESD valve for a future 36" import riser will add another 45 tons to the load.
In the SNEA(P) Study a riser platform was designed to carry a topside load of 350 tonnes.
Later a check for 750 t topsides load has been performed, and no modifications have been found necessary.

The jacket layout is as follow:

4 legs with 1 pile per leg
10 m x 10 m at the top
38.5 m x 38.5 m at the base



Attachmen
III.5.8



PERSPECTIVE VIEW FROM SOUTH

TROLL TIE-IN ON FRIGG
OPTION 'A'
RISER PLATFORM & BRIDGE

FRIGG FIELD | FP | A/ 23/ 02

Attachment III.5.9

Weight:

- Jacket structural steel	1460 t
- Piles	1190 t
- Deck	140 t
- Risers	389 t
- Anodes	130 t
Total	3309 t

Troll Study (1987)

The basis for this Troll study was comparable to the study performed in 1986.
It is assumed that a riser platform is installed having spare riser capacity (flexibility) for future tie-ins.
Spare risers: 1 x 30", 1 x 24", 2 x 20" J - Tubes
The following cases are considered:

i) spares + 42"
ii) spares + 42" + 36"
iii) spares + 36"
iv) spares + 34"

In terms of weight and cost the worst situation is case (ii).

The topside loading of option ii is split as follows:

- Topside weight of risers and J-tubes and miscellaneous piping	108 t
- Valves topside	222 t
- Bridge loading	326 t
- Deck and topside steel	200 t
- Miscellaneous equipment	30 t
Total topside weight	886 t

The jacket has been checked for a topside weight of 750 t with acceptable results and it is assumed that an increase load of 136 t will have insignificant effect on the jacket design.

Tripod tower riser platform (TTRP)

A conceptual study by Heerema was executed May 1987 in order to have a comparison with the jacket structure described earlier.

The basis for the study can be compared to option ii for the jacket structure (42", 36", 30" and 24" risers and 2 x 20" J - tubes). Environmental criteria are the same.

Two calculations have been performed (option 1 and 2) where the only difference is the dimension of the main column of the tripod sub structure determined by the required space between the internals.

Due to authority requirement for riser inspection it is recommended to use option 2 with 6.5 m crossection of main column.

Weight estimates

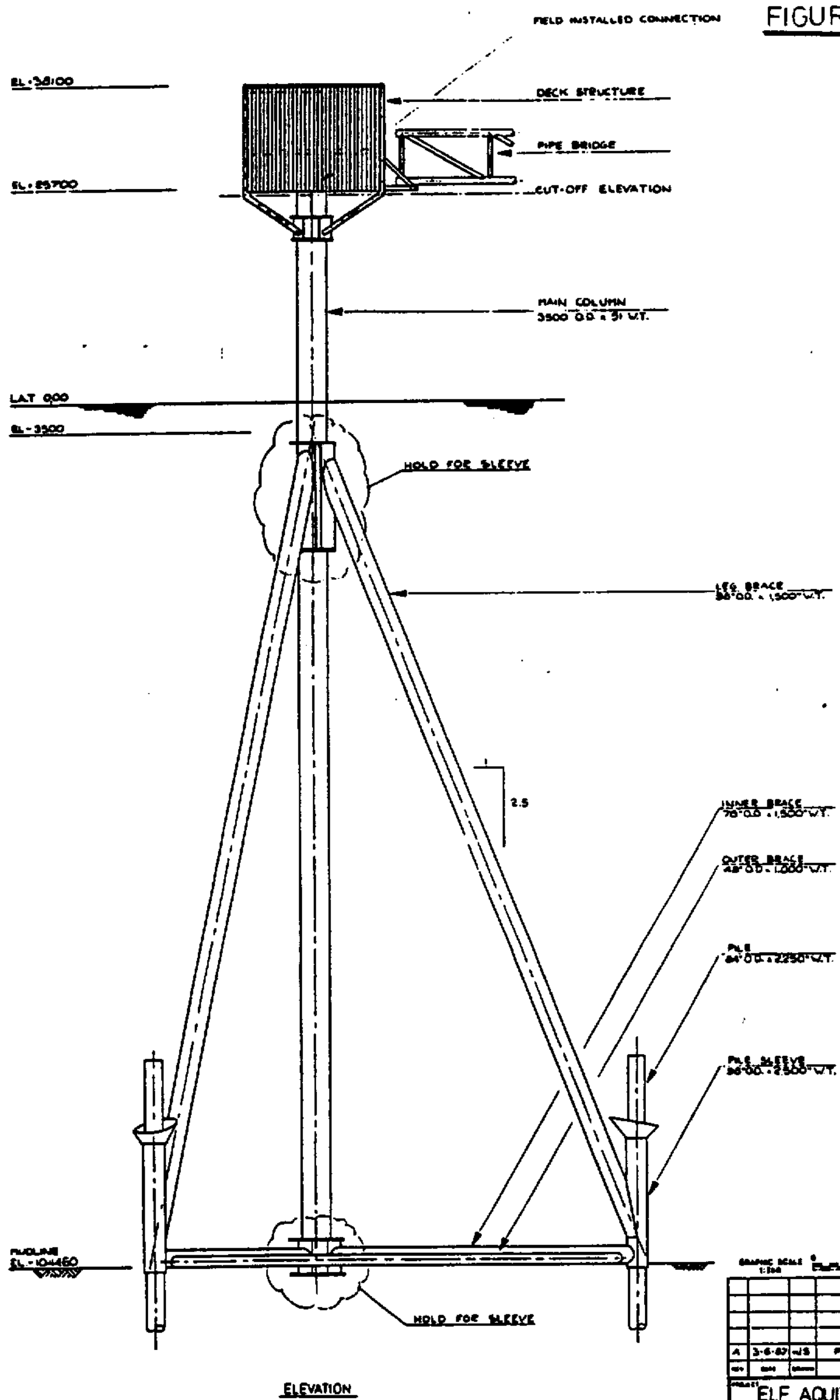
	Option 1	Option 2
Size main-column	3500 mm OD	6500 mm OD
Topside weight (incl. 50 % of bridge)	886 t	886 t
Weight substructure	2310 t	3460 t
Weight piles	420 t	570 t
Risers and J - tubes	400 t	400 t

Sketches are enclosed as Attachments III-5.10 and III-5.11 hereto.

Attachment III.5.10

HEEREMA

FIGURE 3



ELEVATION

GRAPHIC SCALE 1:250

REV	DATE	DRAWN	DESCRIPTION
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PROJECT: ELF AQUITAINE NORGE A/S RISER T.T.P.

SUBJECT: OPTION 1 GENERAL ARRANGEMENT

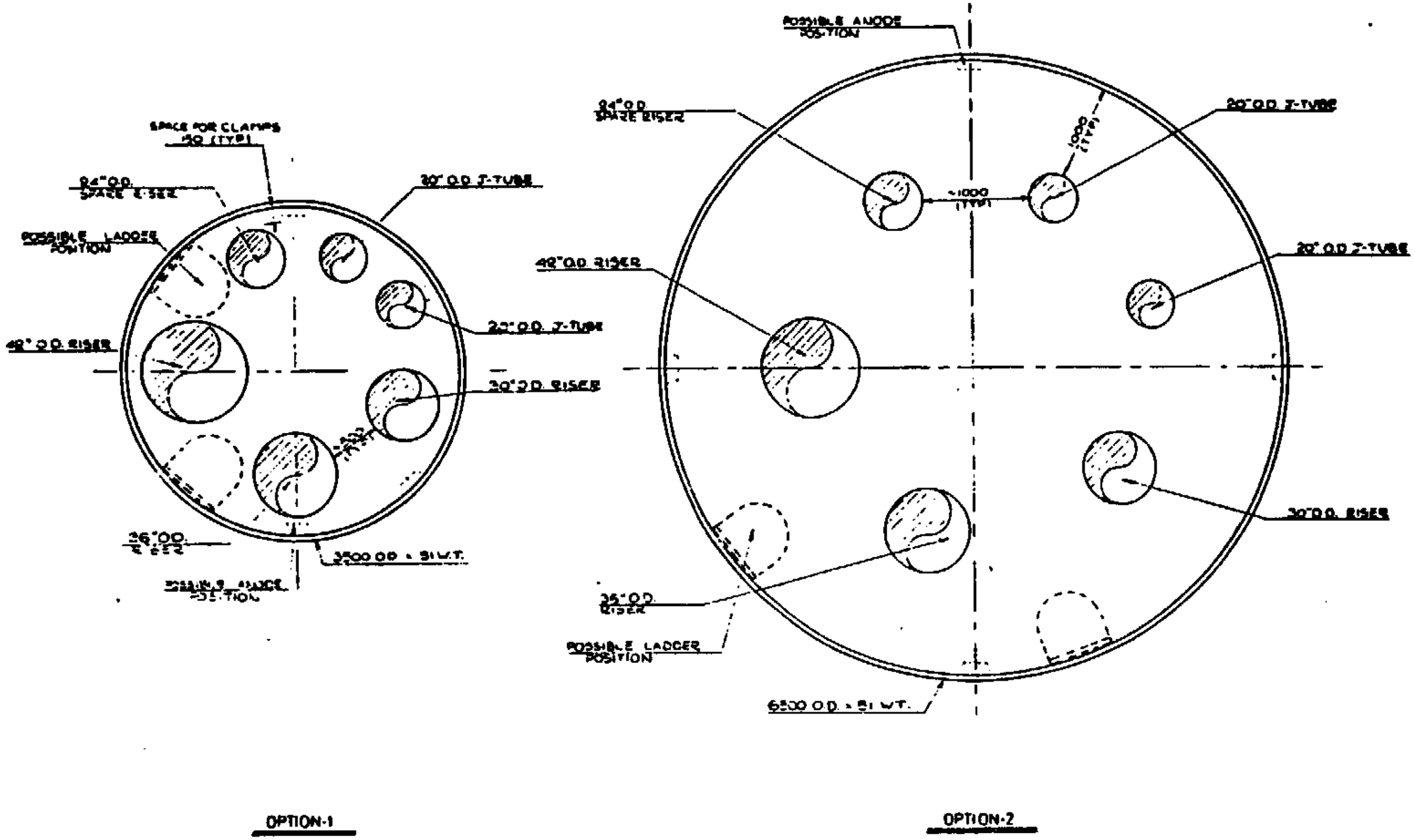
HEEREMA ENGINEERING SERVICE

SCALE		DRG. NO.	SHEET	REV
1:250		102.0917	01	A

GENERAL NOTES:
- ALL MATERIAL TO BE ST.52-D UNO

REFERENCE DRAWINGS:

GENERAL NOTES
STEEL QUALITY ST.52-3



A | 3-6-87 | HS | FOR BID

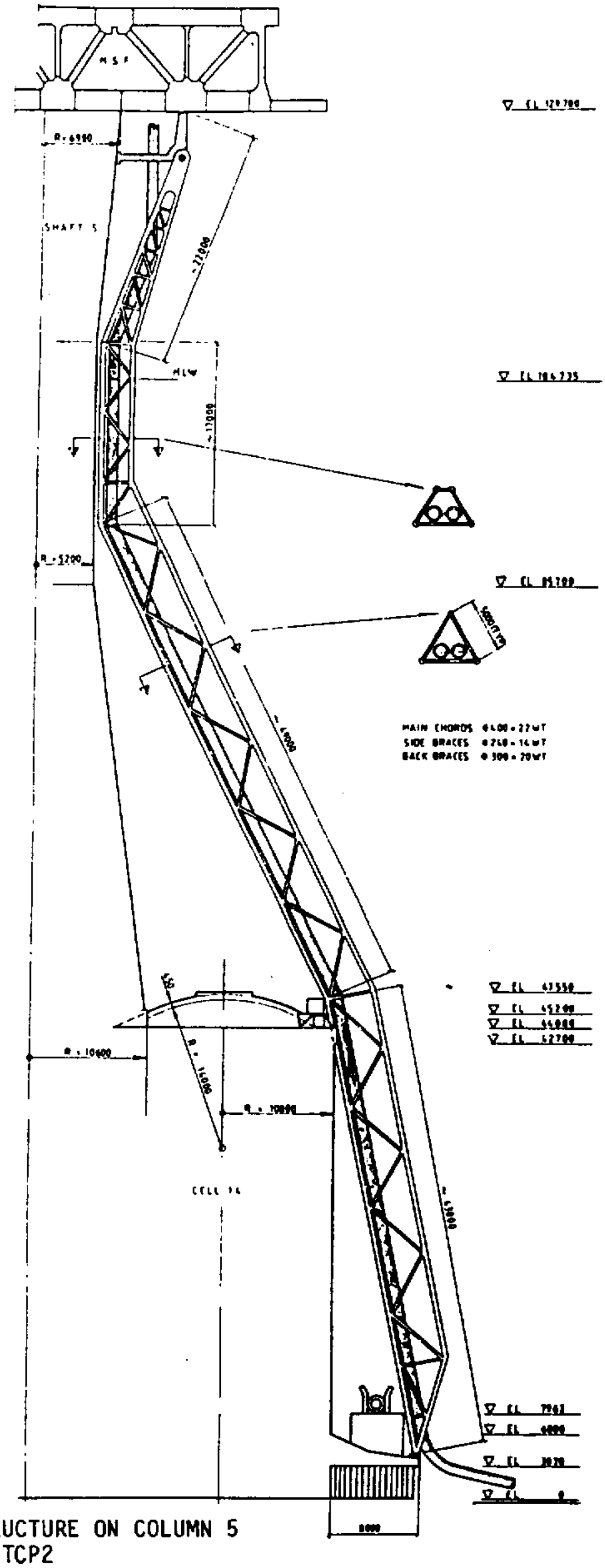
ELF AQUITAINE NORGE A/S RISER T.T.P.

INTERNAL COLUMN ARRANGEMENT

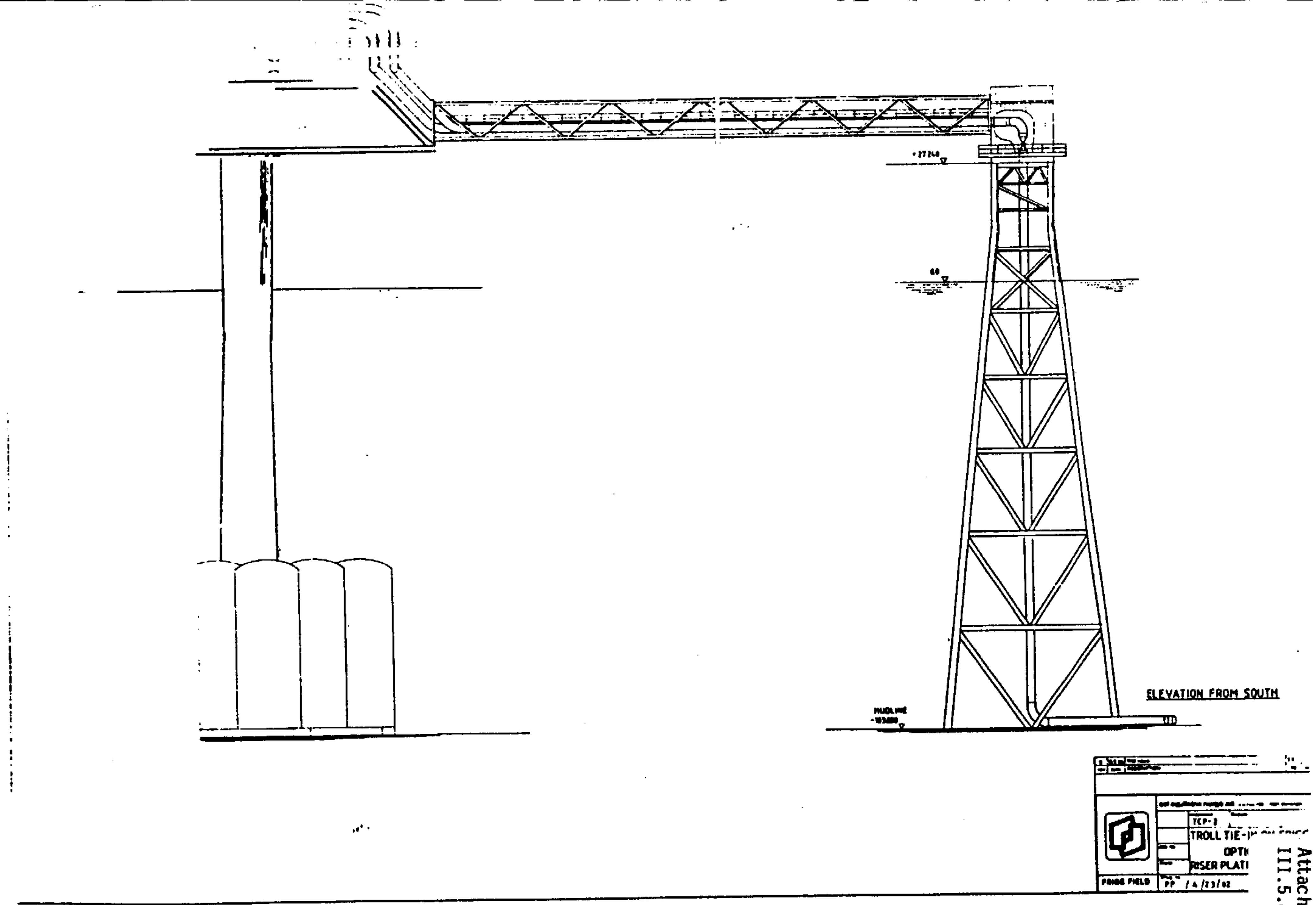
HEEREMA ENGINEERING

1:25 | 102.0917

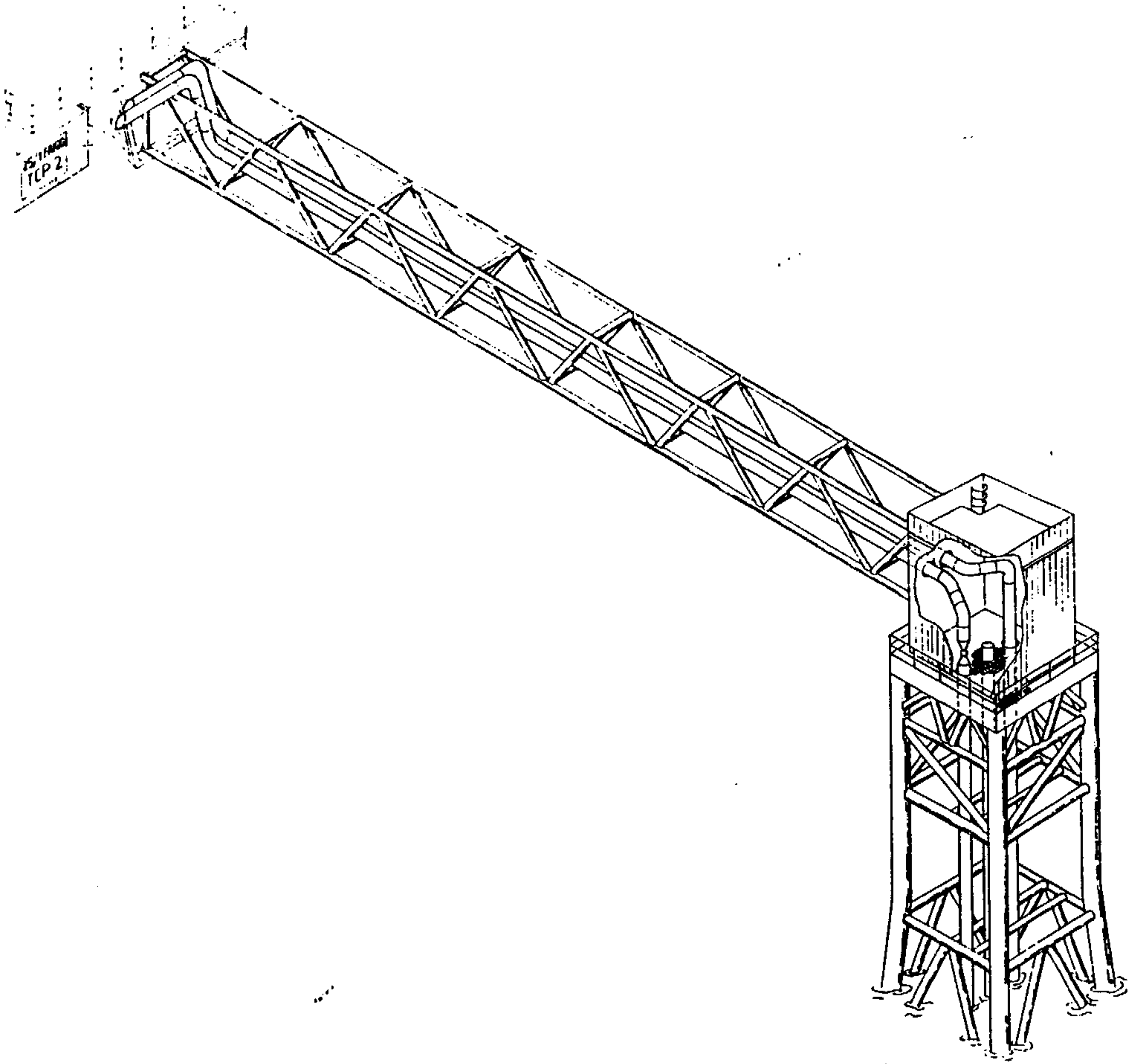
Attachment III.5.11



RISER SUPPORT STRUCTURE ON COLUMN 5
OF TCP2



Attachmen
III.5.8



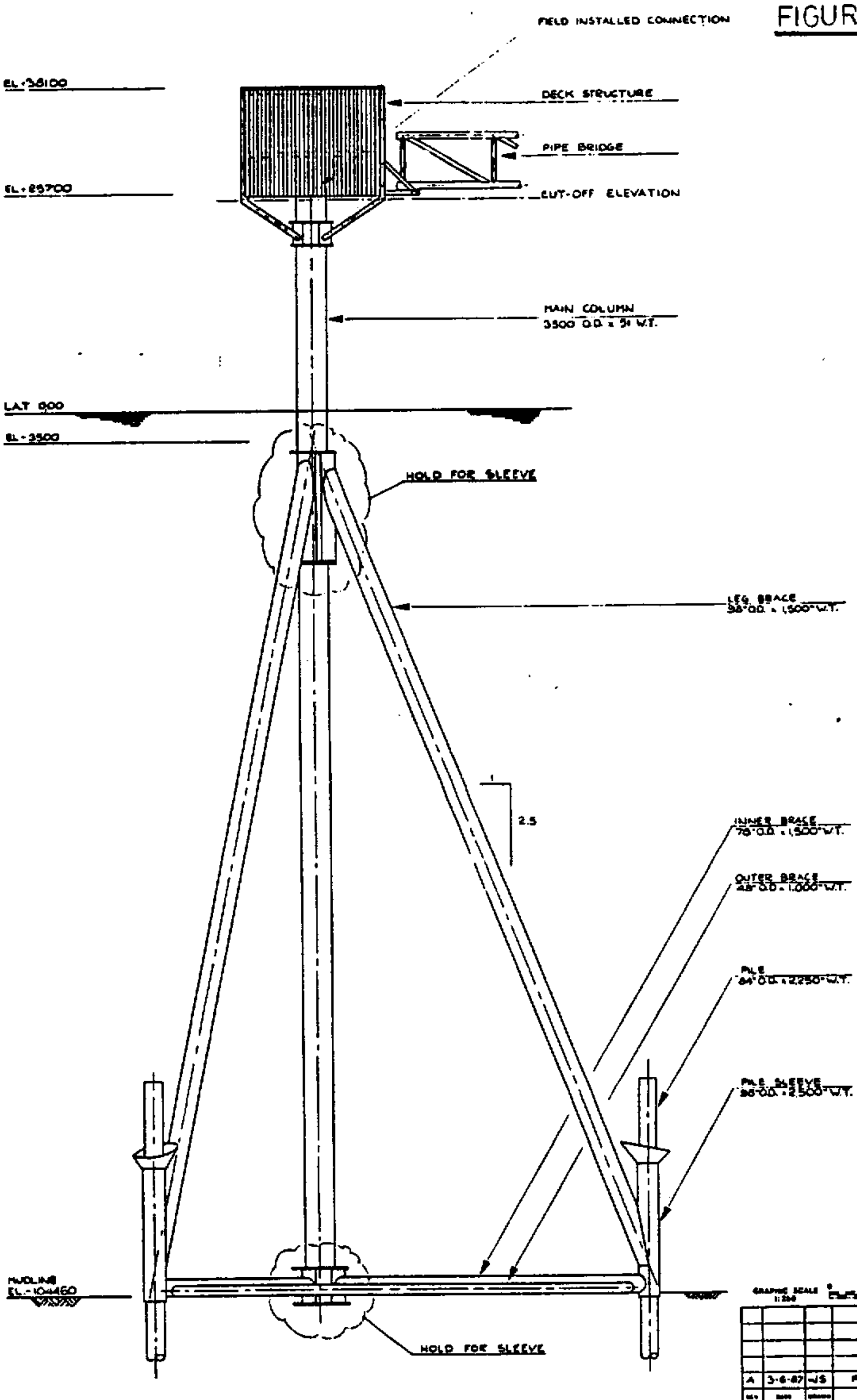
PERSPECTIVE VIEW FROM SOUTH

TROLL TIE-IN ON FRIGG
OPTION 'A'
RISER PLATFORM & BRIDGE

FRIGG FIELD | FF / A/ 2.3/ 02

Attachment III.5.9

FIGURE 3



ELEVATION

GENERAL NOTES:
- ALL MATERIAL TO BE ST.52-D UNO

REFERENCE DRAWINGS:

A	3-6-87	JS	FOR BID

ELF AQUITAINE NORGE A/S RISER T.T.P.

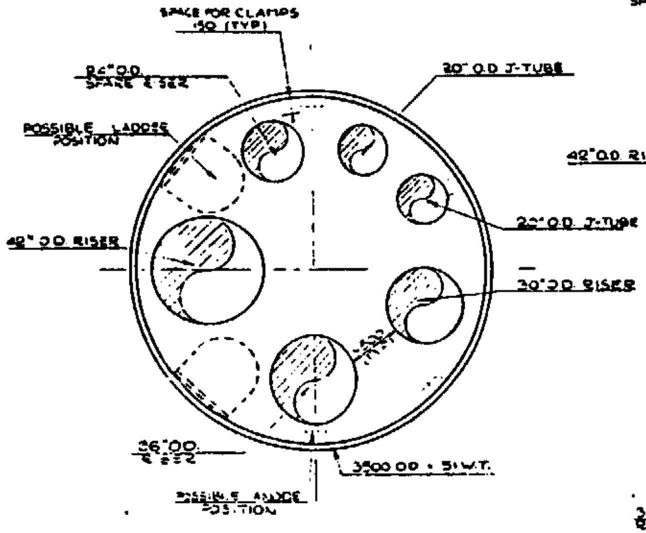
OPTION 1

GENERAL ARRANGEMENT

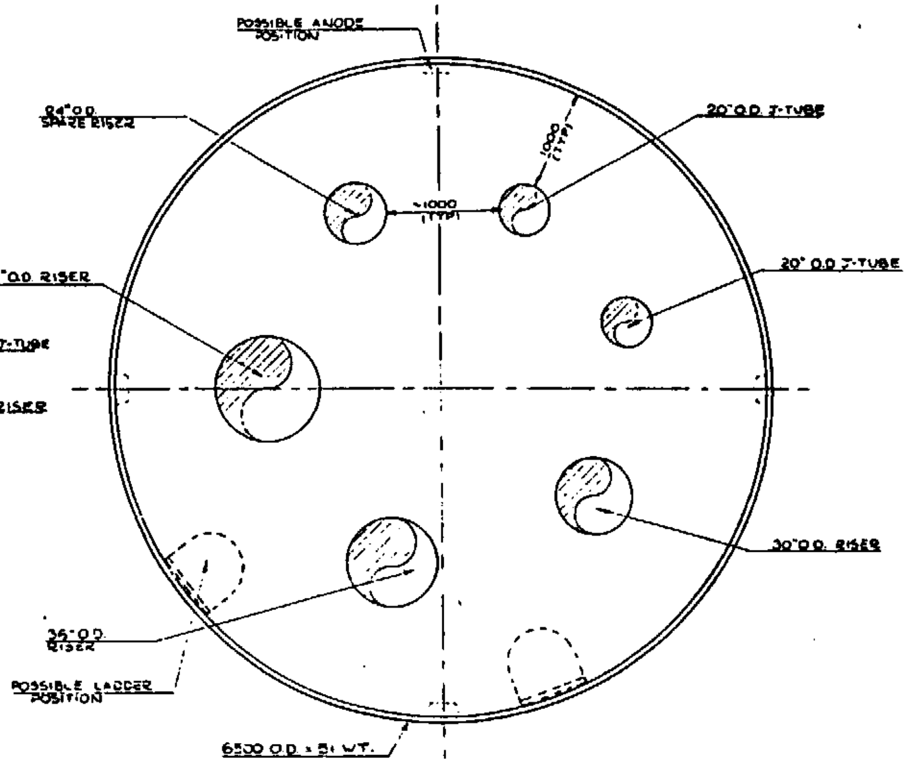
HEEREMA ENGINEERING SERVICE

Scale		Job No.	Drawing No.	Rev.
1:250		102.0917	01	A

GENERAL NOTES
STEEL QUALITY ST.52-3



OPTION-1



OPTION-2

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ELF AQUITAINE NORGE A/S RISER T.T.P.

INTERNAL COLUMN ARRANGEMENT

HEEREMA ENGINEERING

Scale: 1:25 | 102.0917

Attachment III.5.11

CHAPTER III - PART 6

Cost Estimates

6.1 Introduction

This chapter presents future operating costs of the Frigg Field in different configurations. It also presents some estimates of additional investments achievable within the presently existing arrangement of the processing facilities on TP1 and TCP2, those investments are mainly related to gas processing and do not consider a major reconversion of the existing equipment.

6.2 Operating Costs

Future operating costs have been evaluated for different scenarios which have been studied in some previous specific studies. Operating costs have been estimated for the Frigg Central Complex which consists of QP, TP1, TCP2 and for the whole field including CDP1, DP2, the flowlines and FP. Then those operating costs have been allocated to each association (FNA and FUKA). Figures are given in MNOK 89.

6.2.1 Methodology of Estimation

The basis for these estimates are the analysis of 1988 and 1989 operating costs for each platform (TP1, TCP2, CDP1, DP2, flowlines and FP). The detailed methodology is presented in the attachment III - 6.2.1 "OPERATING COST SCENARIOS - METHODOLOGY OF ESTIMATION".

6.2.2 Allocation Procedure

When costs are known for each function of each platform, they have to be allocated to each owner and/or user of the functions and platforms.

Two main periods have to be considered:

- The Frigg Unit period which will last up to the end of gas production on Frigg (present forecast: 1992).
- The post Frigg Unit period when the facilities will be used or partially used by partnerships different from Frigg Unit association.

(a) Frigg Unit period

During the Frigg Unit period, operating expenses are allocated according to the present existing rules. Specific allocations as FNA and FUKA are performed according to agreed percentages. Left unitized operating expenses are allocated according to gas liftings.

(b) Post Frigg Unit period

TP1 and TCP2 platforms include unitized equipment (structures, dehydration, TCP2 compression, QP platform, etc.) and specific owned facilities (FUKA Alwyn tie-in, FNA TCP2 extension facilities). CDP1 and DP2 are fully unitized.

In order to identify what has to be allocated to each owner or user, the following principles have been applied:

- Operating costs have been evaluated for a "Base" case. In that case, it is assumed that TCP2, TP1 and QP (reallocated to TP1 and TCP2) and CDP1 and DP2 are maintained in a shut-in status. Unitized costs are charged prorata share of ownership. Cocooned status costs of specific facilities are charged to the owner.

- Since, operating costs have been evaluated for TP1 and TCP2 according to the presently known firm gas bookings, (Alwyn, NEF, Odin and East Frigg). This case is the "Reference" case. Unitized "Base" case operating costs have been subtracted and allocated prorata ownership (FNA: 60.82%, FUKA: 39.12%).

  The difference for each function has been allocated to the user ("Base" case cost excluded).

- Future operating costs
  Finally some scenarios considering probable future operations have been estimated applying the hereabove allocation principles.

6.2.3 Operating Cost Estimates

6.2.3.1 Operating Costs 88/89

88 and 89 operating costs are presented on table 6.2.1 and 6.2.2.

These tables show the split of the different functions on each platform. The present breakdown consists of:

- structure
- process and transport
- unitized compression
- Odin compression
- process extensions (NEF, Odin, EF)
- Alwyn extensions
- Wells

They show that the opex of the Frigg field fully operated are about 600 MNOK/year. These figures exclude the specific services to satellites or third party fields, but include the percentage of operating cost allocated to FNA or FUKA specific operations.

6.2.3.2 "Base Case" Operating Costs

This "Base Case" is hypothetical but will be used for future allocation purposes. It is presented on table 6.2.3. It is assumed that the operating costs of the Frigg Field would only consist of maintenance of the structure. The platform would be demanned and would receive only temporary visits.

All the topsides facilities (processing/treatment equipment, power generator, compression) would be cocooned on a long-term basis and would not require continuous maintenance.

The amount of opex is 90 MNOK/year.

Note:

An alternate estimate has been performed assuming a cocooning of the facilities on a medium term basis and a minimum permanent manning on QP, the yearly opex would be 130 MNOK/year in that case.

6.2.3.3 "Reference Case" Operating Costs

The "Reference case" gives the future operating costs of the Frigg Field with the presently known conditions of operation. Main assumptions are the following:

- The gas Frigg Field will be producing up to 1992 (present forecast) and consequently existing rules of allocation will be applied.
- From 93 to 97, FNA will use some of the unitized facilities of TCP2 and specific equipment (Odin/NEF extensions, EF module, Odin low pressure compression module) to process and export NEF, EF and Odin gases.
- From 93 to the end of operation of North Alwyn, FUKA will use TP1 as riser/transit platform.

Operating costs of this "Reference Case" are summarized on table 6.2.4.

6.2.3.4 Estimate for Possible Future Scenarios.

Several scenarios were recently studied. The basic assumptions are the following:

- From 93 to 97 FNA will still use some of the TCP2 facilities to process and export gas from Odin, NEF and EF
- FUKA will use TP1 as riser/transit platform from 93 up to the end of operation of North Alwyn
- the future operational configurations come in addition to both thereabove operations.

Because of those facts, future operating expense estimates will consider two periods: 93-97 and post 97.

The four following possible scenarios are presented:

- TP1 riser platform
- Bruce treatment on Frigg
- Beryl treatment on Frigg
- Frøy gas or oil and gas processing on Frigg

- TP1 riser platform

  Transit operating costs are presented for one (Alwyn) and two (Alwyn + other field) tie-in operations on table 6.2.5.

It results from this estimate that the addition of a transit function is marginal in term of operating costs (+5 MNOK/year), in addition, the status of TCP2 in gas operation or without operation has a small effect on the cost allocation to the riser/transit platform.

- Bruce treatment on Frigg

Some preliminary studies showed that the processing of Bruce gas to the present existing FTS specifications (Frigg Transportation System operational constraint: -5°C at 140 bar water dew point) would be economically interesting on an investment point of view.

The following assumptions were considered:

- the totality of Bruce gas production would be processed on Frigg to the present transportation specification (-5°C at 140 bar)
- gas would be exported to St. Fergus
- condensate and regenerated hydrate inhibitor would be re-exported to Bruce via two dedicated pipelines
- this estimate excludes import and export transportation operating costs
- according operating costs would be allocated to FUKA (contractor of the operation)

Results are presented on table 6.2.6.
Compared to the "reference case" the processing of Bruce gas increases operating costs as follows:

	Frigg Field (MNOK)	FUKA allocation (MNOK)
93/97 period	+ 20	+130
post 97 period	+180	+180

- Beryl treatment on Frigg

This scenario considers the treatment of the Beryl gas profile with some additional rich UK gas if necessary in a turbo-expander module. Such a rich gas will be processed to the commercial specification, commercial gas will be exported to St. Fergus through the Norwegian pipeline, the liquids would be transported through the UK pipeline. FUKA would be the contractor of this operation.

All operations would take place on TCP2.

Table 6.2.7 shows the estimate of operating costs.

Compared to the reference case, this operation increases the operating costs at the Frigg Field of:

+ 25 MNOK/year during the 93/97 period
+160 MNOK/year during the post 97 period

For the same periods, the increases of the allocated costs to FUKA are:

+120 MNOK/year (93/97)
+160 MNOK/year (post 97)

- Frøy treatment on Frigg

  Operating costs have been estimated only for the post 97 period, but two cases have been evaluated:

  Case I:

  Gas treatment on Frigg to the transportation specifications, condensate is injected in the NW line.

  Case II:

  Oil and gas processing takes place on TCP2. Injection water facilities (treatment and pumping) are located on TP1.
  Figures are presented on table 6.2.8.

  Compared to the "reference case", case I the operating costs of the Frigg Field increase by 155 MNOK/year (FNA increase: 155 MNOK/year) and case II of 230 MNOK/year.

  For both cases, FNA is the contractor of the operations.

6.2.4 Transportation Cost Estimate

For information, present operating costs of the Frigg Transportation System are presented on table 6.2.9.

In a totally cocooned status (MCP01 demanned) the operating costs of the FNA transportation system would not be higher than 1.5M£/year.

6.2.5 Conclusions

The previous analysis shows that the routine operating costs of Frigg Field (including the drilling platforms) are about 600 MNOK/year at full capacity. For the 88 and 89 years, when TP1 and TCP2 are still in operation, the operating costs of the Frigg Central Complex (TP1, TCP2 and QP reallocated) are about 360 MNOK/year.

The conversion of TP1 to a riser status allows to decrease the operating expenses of the Central Complex to 280 MNOK.

The different scenarios which were previously studied show that so far as operations are concentrated on one platform, operating costs of the Central Complex will be maintained between 250 and 300 MNOK. The operation of a second platform introduces a critical step and opex become higher than 300 MNOK/year.

On a first approach, it could look like that allocation rules trigger some abnormal increase of allocated opex to the association in charge of a third party operation. Looking more in detail it appears that the increase of operating cost corresponds to the actual opex figure of the involved operation.

TABLE 6.2.1

1988 OPERATING COSTS
(MNOK/year)

PLATFORM MAIN FUNCTION	TP1	TCP2	CDP1	DP2	FLARE	LINES	TOTAL
STRUCTURE	13	12	27	21			73
UNITIZED TREATMENT	43	49	36	36	1	4	169
TRANSPORTATION	3	3					6
UNITIZED COMPRESSION		71					71
ODIN COMPRESSION		0					0
EXTENSIONS		20					20
COMMON	47	82	39	44			212
ALWYN EXTENSION	7						7
WELLS			17	28			45
TOTAL	113	237	119	129	1	4	603
ALLOCATION							
FNA	65.7	127	72	78	0.6	2.4	
FUKA	42.3	82	47	51	0.4	1.6	
Specific FUKA	5.0	0					
Specific FNA	0	28					
TOTAL							
FNA	65.7	155	72	78	0.6	2.4	373.7
FUKA	47.3	82	47	51	0.4	1.6	229.3

10% of total TCP2 costs allocated to FNA NEF/Odin extensions
7% of total TCP2 costs allocated to FNA EF extension (1 quarter in 1988)
4.4% of total TP1 cost allocated to FUKA Alwyn extension

TABLE 6.2.2

1989 OPERATING COSTS
(MNOK/year)

PLATFORM MAIN FUNCTION	TP1	TCP2	CDP1	DP2	FLARE	LINES	TOTAL
STRUCTURE	23.9	11.7	19.7	17.9	1	0	74.2
PROCESS/TRANS-PORT	29.9	90.4	17.6	39.3	0	4	181.2
UNITIZED COM-PRESSION		77.2					77.2
ODIN COMPRES-SION		0					
EXTENSIONS							
COMMON	63.9	61.2	27.1	47.5			199.7
ALWYN EXTENSION							
WELLS			8.5	20.9			29.4
TOTAL	117.7	240.5	72.9	125.6	1	4	561.7
ALLOCATION							
FNA	68.4	121.4	44.3	76.4	0.6	2.4	313.5
FUKA	44.1	78.2	28.6	49.2	0.4	1.6	202.1
Specific FUKA	0	40.9					40.9
Specific FNA	5.2	0					5.2
TOTAL							
FNA	68.4	162.3	44.3	76.4	0.6	2.4	354.4
FUKA	49.3	78.2	28.6	49.2	0.4	1.6	207.3

Note:

10% of total TCP2 costs allocated to FNA NEF/Odin extension
7% of total TCP2 costs allocated to FNA EF extension
4.4% of total TP1 costs allocated to FUKA Alwyn extension

TABLE 6.2.3

FRIGG FIELD OPERATING COST FORECASTS

BASE CASE
(MNOK/year)

PLATFORM	TP1	TCP2	CDP1/DP2	TOTAL
STRUCTURE	30	40	20	90
PROCESS/TRANSPORT	0	0	0	
UNITIZED COMPRESSION	0	0	0	
ODIN COMPRESSION	0	0	0	
FNA EXTENSIONS	0	0	0	
ALWYN EXTENSIONS	0	0	0	
TOTAL				90
ALLOCATION				
FNA				55
FUKA				35

TABLE 6.2.4

FRIGG FIELD OPERATING COST FORECASTS

REFERENCE CASE
(MNOK/year)

	88(1)	89	90	91-92	93-97	POST 97
CDP1	119	73	35	10	10	10
DP2 (inj.wells)	129	125	125	125	30 (20)	10
FLARE AND FLOWLINES	5	5	5	5	0	0
TP1 spec FUKA allocation	113 (5.0)	118 (5.0)	65 (3)	50 (20)	55 (25)	60 (30)
TCP2 spec FNA allocation spec FUKA allocation	237 (28)	240 (41)	270 (45)	230 (40)	235 (195)	40
Frigg Central Complex	350	358	335	280	290	100
Total Frigg Field	603	561	500	420	330	120
Allocation:						
- Unitized FNA	345	313	275	220	55	55
- Unitized FUKA	225	202	177	140	35	35
- Spec FNA	28	41	45	40	215	0
- Spec FUKA	5	5	3	20	25	30
TOTAL FNA	373	354	320	260	270	55
TOTAL FUKA	230	207	180	160	60	65

(1) actual costs

TABLE 6.2.5

FRIGG FIELD OPERATING COSTS

CASE: TP1 RISER PLATFORM
(MNOK/year)

	ALWYN ONLY		ALWYN+OTHER FIELD	
	93/97	POST 97	93/97	POST 97
CDP1/DP2	40	20	40	20
Spec FNA	(20)		(20)	
TP1	55	60	60	65
Spec FUKA	(25)	(30)	(30)	(35)
TCP2	235	40	235	40
Spec FNA	(195)		(195)	
Spec FUKA				
Frigg Central Complex	290	100	295	105
Total Frigg Field	330	120	335	125
Allocation				
- Unitized FNA	55	55	55	55
- Unitized FUKA	35	35	35	35
- Spec FNA	215		215	
- Spec FUKA	25	30	30	35
TOTAL				
- FNA	270	55	270	55
- FUKA	60	65	65	70

TABLE 6.2.6

FRIGG FIELD OPERATING COSTS

CASE: BRUCE TREATMENT ON FRIGG - FTS SPECIFICATIONS 20 MMSCMD
(MNOK/year)

		93/97	POST 97
CDP1/DP2		40	40
inj.well	FNA	(10)	
	FUKA	(10)	(20)
TP1		55	60
Spec FUKA		(25)	(30)
TCP2		255	200
Spec FNA		(95)	0
Spec FUKA		(120)	(160)
Frigg Central Complex		310	260
Total Frigg Field		350	300
Allocation			
- Unitized FNA		55	55
- Unitized FUKA		35	35
- Spec FNA		105	
- Spec FUKA		155	210
TOTAL			
	FNA	160	55
	FUKA	190	245

TABLE 6.2.7

FRIGG FIELD OPERATING COSTS

CASE: BERYL TREATMENT ON FRIGG

Commercial specifications 15.20 MMSCMD

FUKA contractor of Beryl gas processing
(MNOK/year)

		93/97	POST 97
CDP1/DP2		40	20
inj.well	FNA	(20)	
TP1		55	60
Spec FUKA		(25)	(30)
TCP2		260	200
Spec FNA		(100)	
Spec FUKA		(120)	(160)
Frigg Central Complex		315	260
Total Frigg Field		355	280
Allocation			
- Unitized FNA		55	55
- Unitized FUKA		35	35
- Spec FNA		120	0
- Spec FUKA		145	190
TOTAL			
	FNA	175	55
	FUKA	180	225

TABLE 6.2.8

FRIGG FIELD OPERATING COSTS

Case I : Frøy gas treatment (Post 97)
Case II: Oil and gas treatment + water injection (post 97)

(MNOK/year)

	CASE I	CASE II
CDP1/DP2	40	40
Spec FNA (inj.wells)	(20)	(20)
TP1	60	105
Spec FUKA allocation	(30)	(30)
Spec FNA/Frøy		(45)
TCP2	175	205
Spec FNA allocation (Frøy)	(135)	(165)
Spec FUKA allocation	0	
Frigg Central Complex	235	310
Total Frigg Field	275	350
Allocation		
- Unitized FNA	55	55
- Unitized FUKA	35	35
- Spec FNA	155	230
- Spec FUKA	30	30
TOTAL		
FNA	210	285
FUKA	65	65

TABLE 6.2.9

FRIGG TRANSPORTATION SYSTEM OPERATING COST

88/89 BUDGET
(K£/year)

	FNA System		FUKA System	
YEAR	88	89	88	89
PIPELINE	1282	1092	1296	1087
MCP01	4852	5392	4481	5611
TERMINAL	3403	3608	3539	3641
PETERHEAD	358	258	231	166
TOTAL	9895	10350	3547	10505
MCP01 Compression (MCP01 + Terminal)	2853	2762	0	
SF Alwyn Operations			1208	926
UK BP line			15	121
TOTAL	12748	13112	10770	11552

ATTACHMENT III - 6.2.1

OPERATING COST SCENARIOS

METHODOLOGY OF ESTIMATION

1. Basis

The basis for estimation is the analysis performed on the 1988 and 1989 actual or budgeted costs per function/platform.

For this analysis, the costs have been separated in 3 categories, according to the way they have been allocated.

A. Direct costs

Personnel:

Production operators for treatment and compression functions (according to time writing), maintenance technicians for all the functions (according to MIS statistics), MSD personnel for structure functions (according to MSD indications), safety, inspection, logistics personnel for utilities functions (according to time writing).

Consumables.

External works and services, spare parts:

Maintenance Request (according to MIS statistics), other works (ex. MSD works).

B. **Environmental Pool costs** (QP, CDP1 and DP2 living quarter and logistics costs)

They are expressed in offshore days, and then allocated according to a daily rate calculated by division of the environmental pool cost by the total number of offshore days spend on TP1, TCP2 and not directly allocatable (Common Pool) and 3rd parties.

C. Common Pool costs

They consist of onshore costs and offshore costs which are not directly allocatable (ex: field manager and secretary, MSI), and there are corresponding offshore days. They are allocated in 2 steps on a prorata basis (first on QP, and then on TP1 and TCP2 functions).

2. Methodology

For each scenario, there are the following steps:

1. For TP1, TCP2, CDP1, DP2 and QP functions estimation of

    a) Personnel costs according to the following categories:

Permanent:	Production Maintenance Other
Non-permanent:	Maintenance Other

    b) Corresponding offshore days

    c) Consumables

    d) Works and services in two categories:

    Maintenance
    Other

2. Spread if needed of Production personnel costs and corresponding offshore days on the different treatment/compression functions on a same platform, using a surface ratio approach for treatment areas.

3. Estimation of common costs. This is based on the level of activities on the platforms, with reference to Heimdal situation when appropriate. The corresponding offshore days are also estimated.

4. Estimation of 3rd parties offshore days. It has been taken into account only NEF (up to 1994), East Frigg (up to 1996) and TOM (QP telecom).

5. Estimation of environmental costs. The variable costs (helicopter, catering, logistics consumables) are calculated according to the average manning level estimated previously in the step 1 to 4.
   The shuttle is included up to 1994 (end of NEF).

6.3 Additional Investments

During the last few years, EAN has performed several studies about additional services which could be supplied by the Frigg Field; most of the time the available capacity was used as major incentive to investigate the possibility of using this installed capacity to accommodate gas productions from EAN operated satellite fields or third party fields.

Following this trend, Odin Field has been connected to Frigg, NEF and EF (both subsea installations) are operated from Frigg, North Alwyn is linked to the 32" UK pipeline via TP1 used as riser platform.

Apart from these already performed developments, the following additional projects have been evaluated with more or less accuracy:

- Processing of Bruce gas on Frigg
  Treatment to FTS specifications

- Processing of Beryl gas on Frigg (commercial specification) with additional third party UK rich gas liquid export through the UK pipeline

- Processing of Beryl gas on Frigg
  Commercial specifications
  Liquid export to Bruce

- CO_2 removal of Beryl gas on Frigg

- Tie-in of Bruce to TP1

- Compression of Odin low pressure gas

- Processing of Frøy associated gas

- Processing of Frøy gas and crude, Frøy water injection

- Troll tie-in to Frigg

- Pipeline connections to Frigg

Those different additional investments are presented in the attachment II: "FRIGG ADDITIONAL DEVELOPMENTS" and summarized in the table 6.3.1.

ATTACHMENT III - 6.3.1

FRIGG ADDITIONAL DEVELOPMENTS

This attachment presents some of the additional developments which could be performed on Frigg to accomodate other gas or crude oil. Figures include contingency and NOC and are expressed in MNOK 89.

1. Processing of Bruce gas on Frigg

*Main functions:

- subsea tie-in and gas arrival at TP1,
  connection to the 26" existing riser

- processing of Bruce gas to the FTS specification
  (-15^{o}C at 140 bar)
  * water/condensate/gas separation
  * gas dehydration and compression

- gas export to St. Fergus

- condensate export to Bruce

- hydrate inhibitor export to Bruce

*Design capacity:

- raw gas flow rate: 20 MMSCMD

*Investments:

- on Frigg platforms,
  modificiations and additional equipment

with methanol regeneration :	416 MNOK
without methanol regeneration:	359 MNOK
26" duplex stainless steel riser :	101 MNOK

- pipelines to and from Bruce and tie-in are excluded.

2. Processing of Beryl gas on Frigg

*Main functions:

- transportation of Bruce raw gas to Frigg
  (26" x 54 km)

- processing of Beryl gas to BG commercial specifications,
  * water/condensate/gas separation
  * liquid hydrocarbon removal (turbo-expander)

- commercial gas export to St. Fergus

- liquid hydrocarbon export to St. Fergus via the UK line

- flare and liquid burners on TP1

- no CO_2 removal

*Design capacity

raw gas flowrates:	17.4	and	11.7 MMSCMD

*Investments

capacity (MMSCMD):	17.4	11.7
- on Frigg platforms new facilities on TCP2 and modifications (hydrocarbon removal unit, gas dehydration, flare and burners on TP1)	724	603
- connection to Frigg 26" x 54km pipeline Frigg - Beryl	420	420
TOTAL	**1144**	**1023**

3. Processing of Beryl gas on Frigg

*Main functions:

- Transportation of Beryl raw gas to Frigg (26" x 54km)

- processing of Beryl gas to BG commercial specifications
  * water/condensate/gas separation
  * liquid hydrocarbon removal (turbo-expander)

- gas export to St. Fergus

- liquid export to Bruce (8" x 32km)

- Flare and liquid burner

- no CO_2 removal

*Design capacity:

Beryl raw gas flow rate: 10.0 MMSCMD

*Investments:

- On Frigg platforms, New facilities on TP1 and modifications (hru, new steam unit, gas dehydration, deethanizer, flare and burners)	:	1039 MNOK
- Connections to Frigg (2 phases),		
26" x 54km Beryl-Frigg	:	530 MNOK
8" x 32km Frigg-Bruce	:	133 MNOK
TOTAL	:	1702 MNOK

4. Removal of Beryl CO_2 on Frigg

*Main functions:
- gas arrival
- CO_2 removal (down to 2%)
- DEA process
- gas dehydration
- TEG process
- steam package

*Design capacity:
- raw gas flow rate: 11.1 MMSCMD
- sweetening: 6.35 MMSCMD

*Investments:

- New module concept (CO_2 removal and dehydration) located on TP1 with removal of module MO2, MO3, MO4

TOTAL: 1134 MNOK

- New CO_2 removal facilities integrated into M02, MO3, MO4 modules on TP1

TOTAL: 838 MNOK

5. Tie-in of Bruce to TP1

*Main functions:

- Subsea tie-in and gas arrival at TP1
- connection to one 26" existing riser

Routing to UK and/or NW 32" pipeline.

*Design capacity:

- gas flow rate: 20 MMSCMD

*Investments:

- On Frigg
- concept similar to Alwyn tie-in

  Investment: 200 MNOK

- concept using existing piping on TP1: by pass of processing facilities

  Investment: 90 MNOK

6. Compression of Odin low pressure gas

*Main functions:

to compress 8.8 MMSCMD from a suction pressure progressively declining from 42 bar down to 10 bar to a discharge pressure of 95 bar.

*Design capacity:
gas flow rate: 8.8 MMSCMD

*Investment:

On Frigg platform

Odin compression module
2 turbo-compressors 2 x 12 MW

TOTAL investment: 681 MNOK

7. Processing of Frøy associated gas

*Main functions:

- water/condensate/gas separation
  gas dehydration, gas compression metering
- electrical power supply to Frøy

*Design capacity:

Associated gas: 3 MMSCMD

TABLE 6.3.1

EXAMPLES OF ADDITIONAL INVESTMENTS

Function/Service	Design Capacity	Investment (MNOK 88) on Frigg	other (pipeline)
Bruce treatment on Frigg - FTS specifications	20 MMSCMD	359/416	0
Beryl tie-in TCP2 - no CO_2 removal - hru, liquid export via UK line	11.7 17.4	603 724	420 420
Beryl tie-in to TP1 - no CO_2 removal - dehydration, hru, liquid export to Bruce	10.0	1039	530 + 133
Beryl tie-in to TCP2 - no CO_2 removal - dehydration, hru, liquid export to Beryl	10.0	976	530 + 232
Beryl CO_2 removal unit new module, integrated alternative	6.35	1134 838	- -
Frøy gas treatment to FTS specifications	3	332	570
Frøy oil processing gas treatment to FTS specifications water injection oil export excluded	60000 BOPD 3 MMSCMD 100000 BWPD	1300	1200
Troll tie-in to Frigg	55 MMSCMD (15+40)		2760

CHAPTER IV

MARKED CONSIDERATIONS

CHAPTER IV - PART 1

UK Gas Market

1.1 Introduction

The Frigg Field with its transportation system was developed in order to enable gas from the Frigg Field Main Reservoir to reach the UK market. In the years after the first gas was delivered from this reservoir to British Gas plc additional gas reserves have made use of the Frigg Facilities and currently the following gases flow through the system:

* Frigg Main
* North East Frigg
* Piper/Tartan
* Odin
* Alwyn North
* East Frigg

Both FNA and FUKA foresee that capacity will be available at the Frigg Field and in the transportation system in the near future. The Main Frigg will probably be drained in 1992 or 1993, North East Frigg in 1996, Odin in 1997, East Frigg in 1996 while Alwyn North will produce some years into the next century.

The import to UK of Norwegian gas peaked in 1985 when some 25% of total UK demand was delivered through the Frigg system. The import has since 1985 decreased and is in 1989 estimated to be approximately 16% of total UK demand.

It is very difficult to predict whether new import of gas from Norway will come or not. This due to a lot of uncertainties of which could be mentioned

* political implications
* the abolition of the BG monopoly
* the difference between potential UK and Norwegian gas with respect to pricing mechanism and flexibility
* gas used in electricity generation
* possible imports from other countries

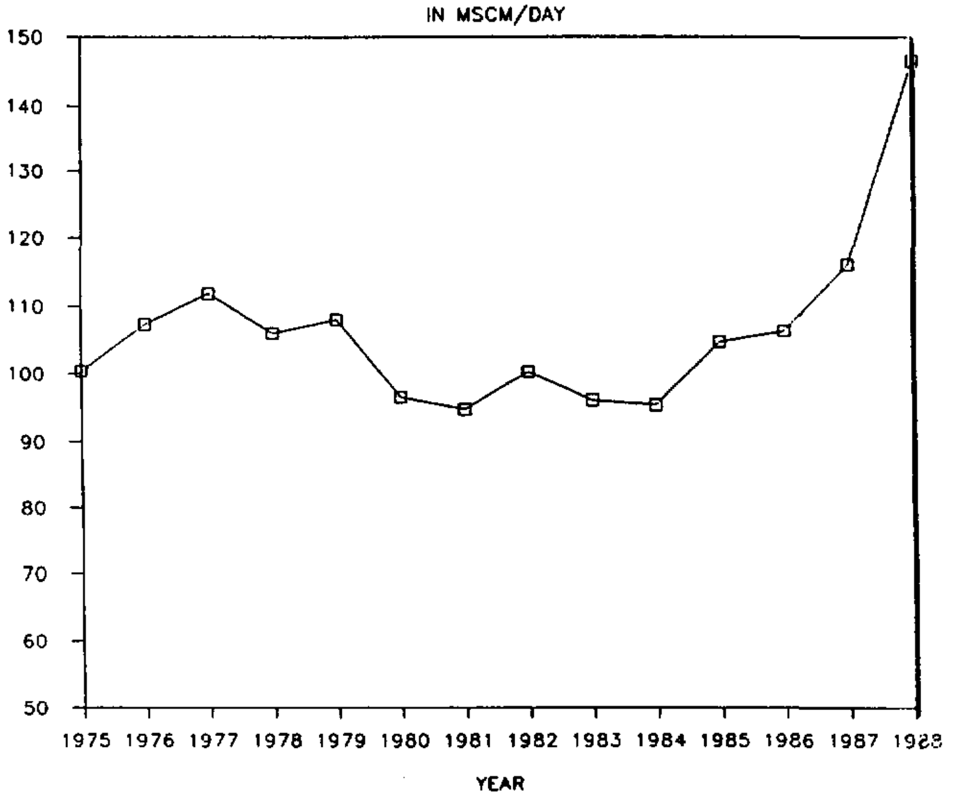
Below we have made a brief survey of the UK market in order to form a basis for the strategy of Elf of future use of the Frigg Field facilities. The possibilities of the UK market are essential when hammering out such strategy as the Frigg Facilities dependant on the market could be utilized for decades to come.

1.2 Existing UK Market

UK offshore gas production started in 1967. The offshore production developed rapidly during the years and 10 years after its first production it rose to 114 MSCM/D. Today British Gas takes gas from around 30 fields of which 5 (including the Norwegian part of Murchison) are located on the Norwegian Continental Shelf.

In attachment IV - 1.1 hereto we have made a historical table of gas committed by BG in MSCM/D during the years 1975 to 1988 inclusive. As can be seen from this table the production did not rise substantially during these years. A perceived shortfall in supply followed in the early 1980's the veto of Sleipner imports which led to the contracting of a number of new southern basin fields which came on stream around 1984/1985. In Fig. A below you will be able to read the development of gas committed in the said period.

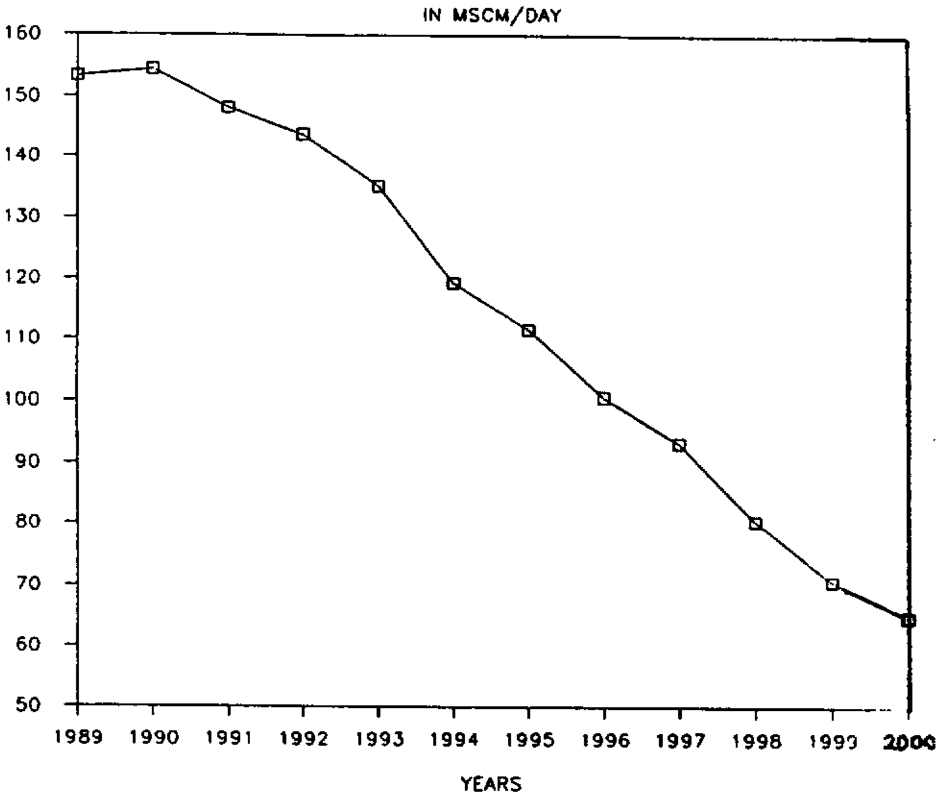
FIG A – GAS COMMITTED FROM 1975 TO 1988



UK gas demand has previously been met by a smaller number of large fields while fields contracted recently have tended to be smaller and more numerous. Gas planning may as a consequence thereof be more difficult to co-ordinate compared with earlier periods in the development of the North Sea.

In attachment IV - 1.2 hereto we have made a table of fields in A) Central and Northern North Sea and B) Southern North Sea which already are committed and sold to British Gas. As seen from this the supply of gas will decrease as of 1991. In Fig. B below you will see the same shown by a chart.

FIG B – GAS COMMITTED FROM 1989 TO 2000

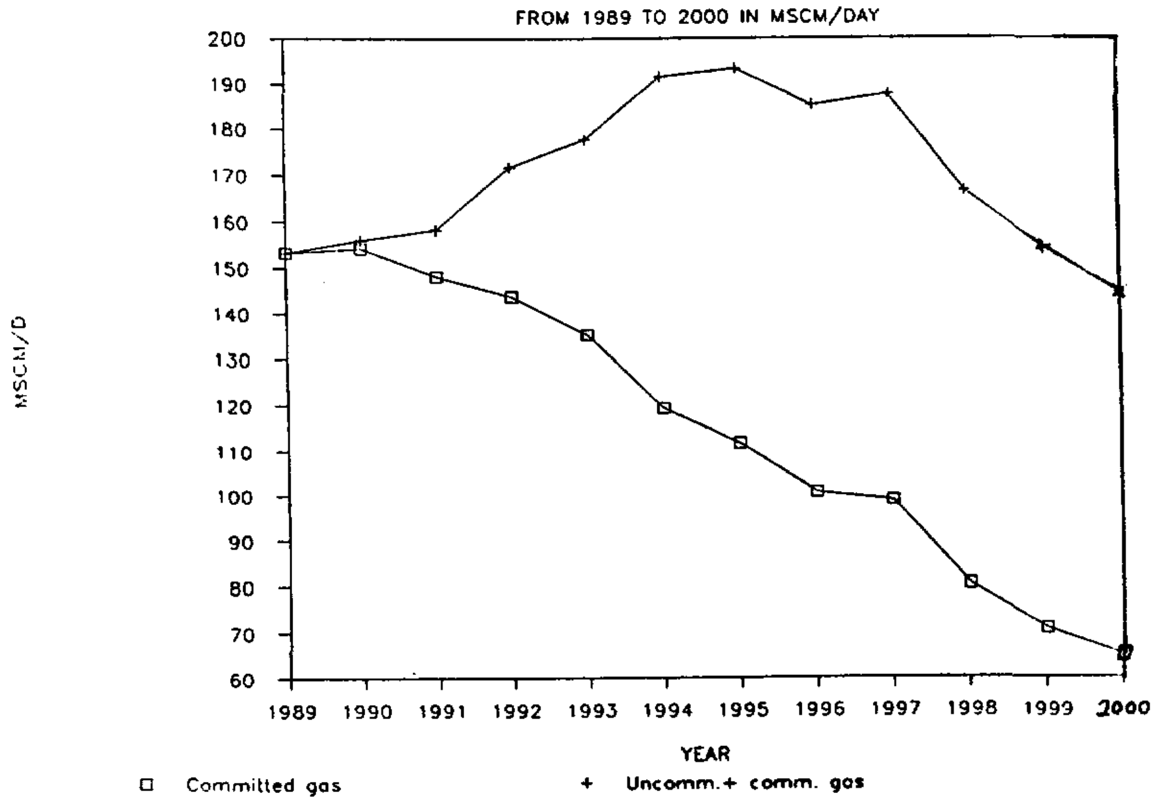


1.3. Future UK Supplies

As seen from above the committed gas supply will decrease as of 1991. We know however that British Gas is currently negotiating with several field owners in order to meet the decrease of volumes. We also know that UK oil companies are very anxious to prove that they can meet some or all of British Gas' requirements in the 1990's. UK oil companies are fully aware of both the internal competition within UK and also the possible competition from companies outside UK. Whether British Gas will elect to take UK company gas volumes will largely be a function of price, flexibility and governmental attitude.

In attachment IV - 1.3 hereto you will find a table of UK fields which may in the very near future conclude gas sales contracts with potential buyers in UK. The table is divided into fields in A) Central and Northern North Sea and B) Southern North Sea. In attachment IV - 1.4 hereto we have added committed and uncommitted gas potentials and you will see thereof that the supply of gas is fairly well covered up to year 2000. In Fig. C below we have also added the uncommitted gas to the Fig. B of committed gas which give the following graph:

FIG C – GAS COMMITTED AND UNCOMMITTED



Most of the uncommitted gas will be available to British Gas as being the major gas buyer. It should however be added that some of this gas might be available to other future buyers.

1.4 Future UK Gas Demand

As mentioned above if no more gas is committed a supply gap is inevitable. To predict the UK gas demand is very difficult. British Gas gave a forecast of gas demands by a presentation given by James Alcock during the 4th European Gas Conference in Oslo in May 1987. In September 1987 Wood Mackenzie published a demand forecast which was significantly higher than that of British Gas.

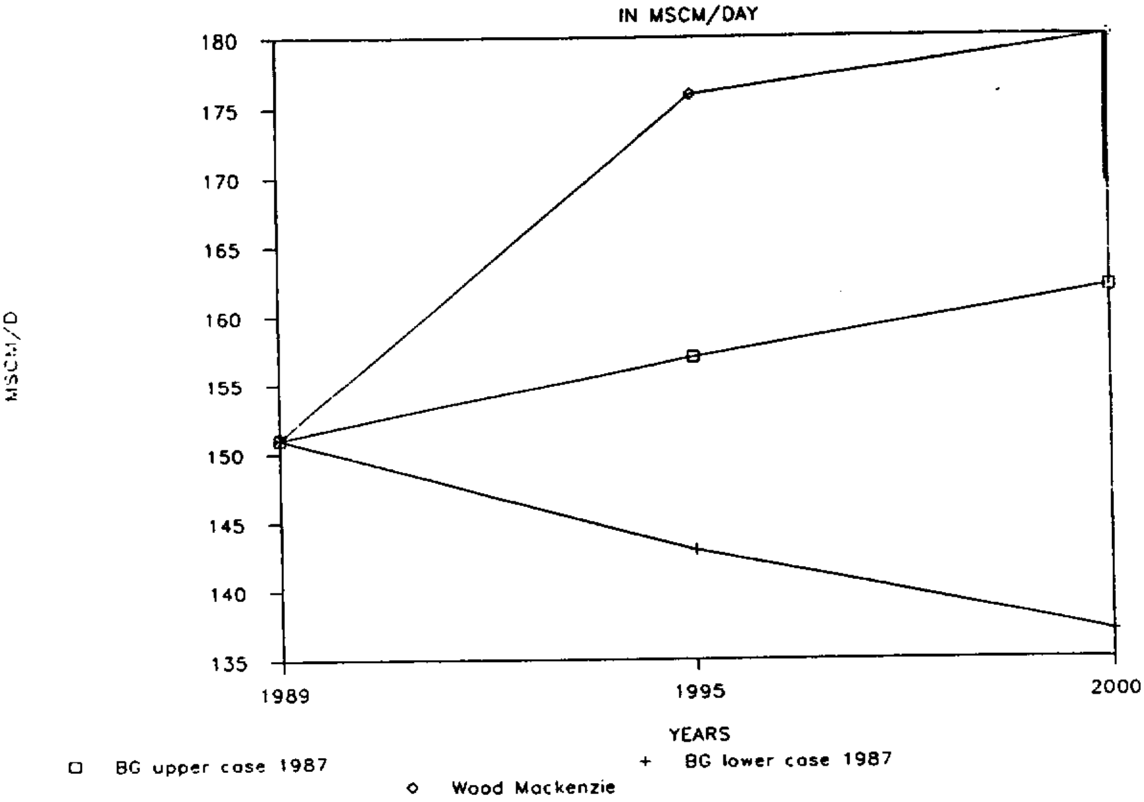
In the intervening months further forecasting has resulted in an upward movement in expected gas demand. since 1987 attention has increasingly been given to independent supply of gas fro electricity generation either using BG's network or by independent pipeline.

In May 1987 the British Gas forecast had an upper case in which, with a low oil/gas price and high economic growth, demand would increase to 157 MSCM/D in 1995 and 162 MSCM/D in year 2000. With a weak economy and high oil/gas price British Gas forecast for a lower case was 143 MSCM/D in 1995 and 137 MSCM/D in 2000. Both cases did not include gas volumes for electricity generation.

The forecast of Wood Mackenzie from September 1987 was estimating the gas demand in 1995 to be 176 MSCM/D and 180 MSCM/D by 2000. These figures did include gas demand for electricity generation. Wood Mackenzie is in 1988 of the opinion that the prediction does not differ from their 1987 estimate.

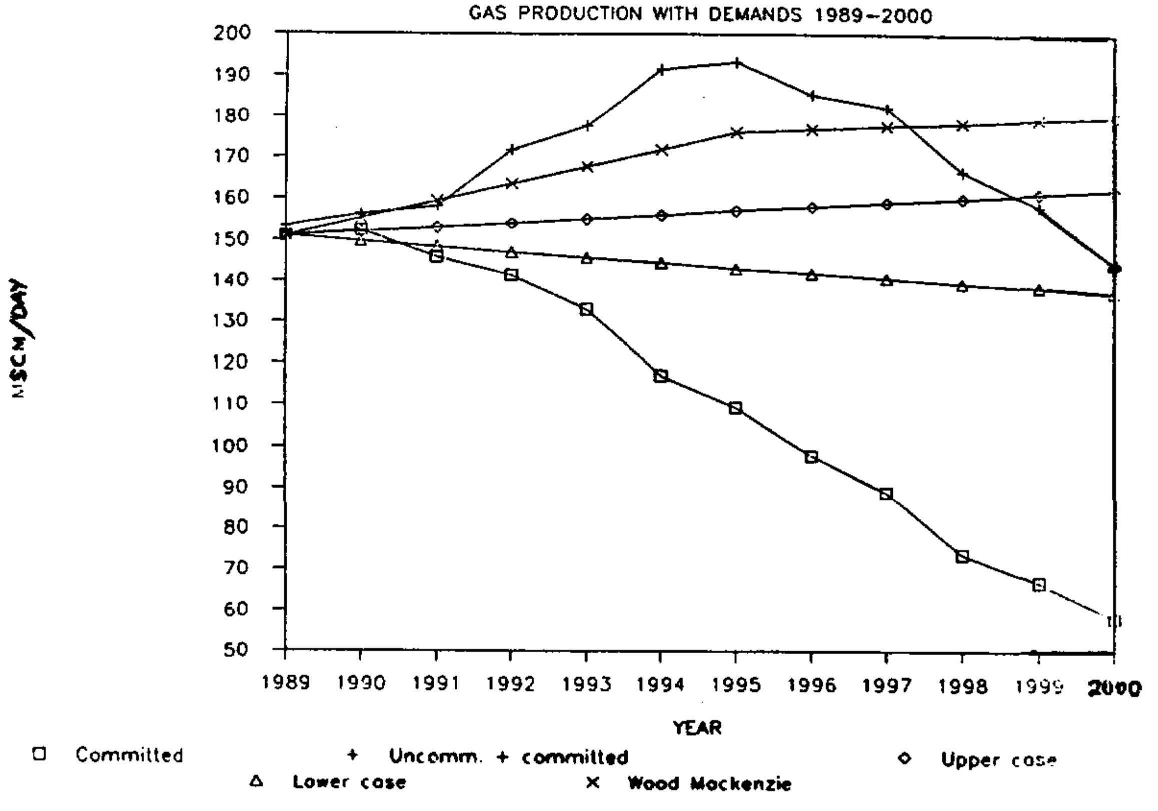
Even though British Gas has not yet published any revised forecast it is thought that the upper case will be markedly higher than in Oslo reflecting the inclusion of the potential for gas generated electricity. In 1995 demand could even be so high as some 189 MSCM/D and some 193 MSCM/D by 2000. The three existing forecasts are illustrated by chart in Fig. D below.

FIG D – FUTURE GAS DEMAND



In Fig. E below we have made a chart of the committed and uncommitted gas to UK and added the demands expressed by the upper and lower case by British Gas and the existing gas demand curve from Wood Mackenzie expressed in Fig. D above.

FIG E - COMMITTED AND PROBABLE UNCOMM.



As seen from the above chart UK gas volumes on offer and soon to be offered can easily match most UK demand cases. We see that if all the possible UK production is committed an overproduction will most likely occur during the years 1991 to 1996. It is inevitable that some projects may be delayed in order to match British Gas' original perceived demand.

1.5 Electricity Generation

The UK with its huge indigenous coal industry has never regarded gas as a serious fuel for power generation in the past. This market is presently opening up as a consequence of the privatisations og BG and CEGB and the technological progress in gas fired power stations. We have noticed that the Miller field has been sold directly to the North of Scotland Hydro Electric Board independent of British Gas network. The quantity is though rather limited.

On sight this seems to be the one remaining market for gas which is not yet mature. Provisionally, interest has concentrated on the use of gas for combined cycle generation and in combined heat and power schemes. The scope for this area of the market is limited.

The future role of gas for power generation in the UK will be directly affected by the prospects for the sales of electricity and the competition from other forms of generation. We know that the prices of gas have fallen more than coal prices since 1985, but there is still some way to go before we can expect that big quantities of gas will be taken for power generation. We should also add that British Gas might very well capture this new market as they are owning most of the UK transmission network. We think however that we will see a gradual increase in the gas flow to the power stations in the 10 years to come which by the end of the decade may reach 20 MSCM/D.

1.6 From which Area may the Gas be taken?

Currently there are two pipeline systems serving the central UK sector. These are the Frigg dry gas twin pipeline system from the northern limit of the sector, and the Fulmar wet gas pipeline operating in the dense phase from the southern limit of the sector. In the southern UK sector there are three main legs, one ending in Bacton, one in Theddlethorpe and one in Easington. In the northern part the main system is the FLAGS system (Brent).

If we divide the UK sector into the following two parts;

a) Central and Northern North Sea, and

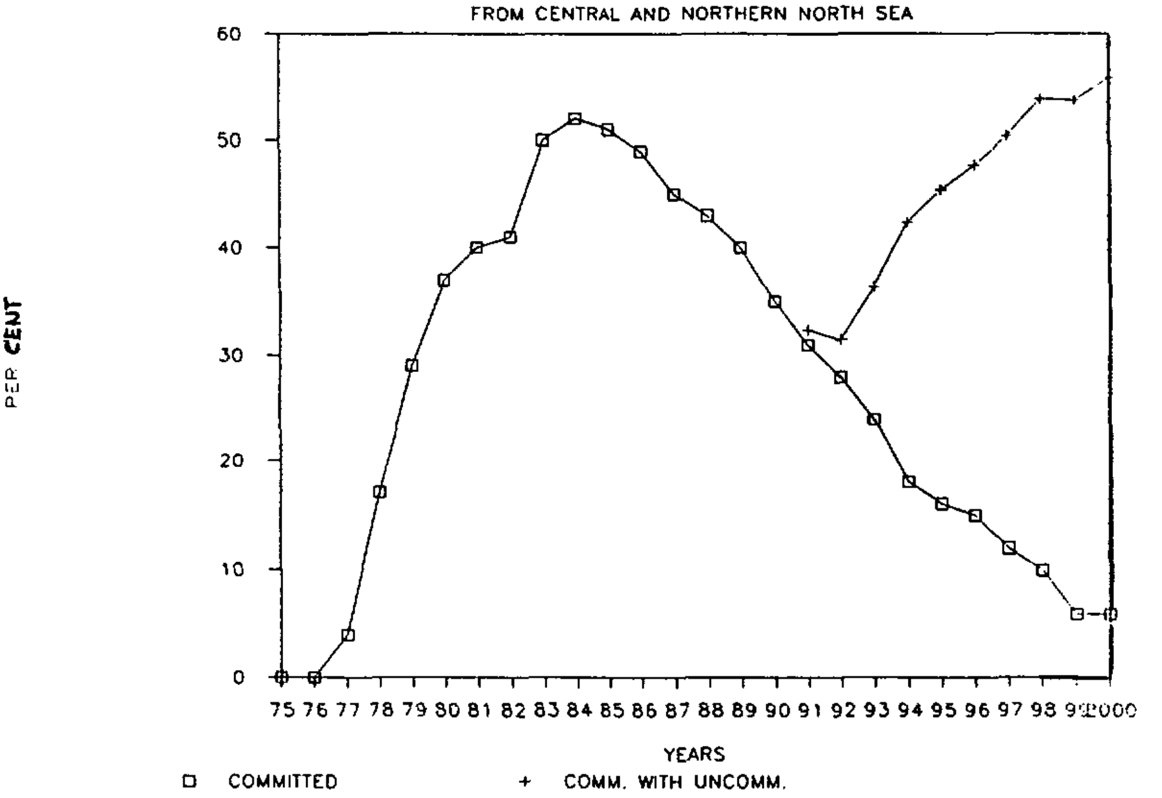
b) Southern North Sea

the gas take was at the beginning concentrated to the Southern North Sea. Up to 1977 all offshore gas from the UK shelf was landed in the southern part of the main land. As from late 1977 the Frigg system came on stream and the quantity of gas from the central and northern part of the shelf (including the Norwegian part) rose to 52 per cent in 1984 but has since that year decreased and represents today approximately 41% of total gas taken from offshore fields. Taking into consideration new sources which might be developed we see that gas from the central and northern part of UK might rise again and if all these fields are committed, the part taken from this area might within year 1997 rise again to 50 per cent of total gas taken.

Below in Fig. F you will be able to read the same by the graph.

FIG. F – UK GAS COMM. AND COM. W/UNCOM.

FROM CENTRAL AND NORTHERN NORTH SEA



As mentioned earlier the twin Frigg pipeline will have spare capacity to transport gas to UK. If UK buyers decide to commit more gas in the 1990's, the two pipes might be of interest to the potential field sellers in the area of Frigg. The two major fields being Bruce and Beryl, are in acceptable distance from the Frigg system. A lot of smaller fields are located south of Frigg and the central part of this area is a desert so far as pipelines are concerned. This gap, or vacuum, has attracted a number of proposals to serve this area but no decisions have yet been made. As we find a lot of small fields here it has been very difficult to establish an economic basis for constructing a pipe from this central area. In order to be able to do so these smaller fields have to be sold in one lot or together with a bigger source. The two biggest sources to be found in this area are presently the Beryl and the Bruce fields. We know that Mobil is considering a separate pipe to be landed in St. Fergus and if such a pipe is constructed this pipe will definitely be in keen competition with the Frigg system.

In order to maintain the balance of gas taken from the southern and northern part of the UK Continental Shelf, we ought to expect that the major part of possible new gases which will be committed, will come from the Central and Northern North Sea. This should also be of interest to the owners of the Frigg Facilities.

1.7 Will UK open up for new Norwegian Gas?

As seen from above, sufficient uncommitted gas exists on the UK Continental Shelf to cover the expected demands up to year 2000. We have however noticed that the remaining sources consist mainly of smaller fields which will clearly create an administrative burden of British Gas if all those fields are contracted.

Presently the UK oil companies are doing their best to convince both the potential buyers as well as the UK authorities that the future gas demand can be easily met by UK gas and that the development of own resources also will benefit the UK society. Imports from Norway may have the effect that the exploration of new prospects might decrease as the possibilities to sell any new UK sources then will be more difficult. It is doubtful that British Gas will take such a proportion of imports which dissuades oil companies from appraising and developing the UK Continental Shelf.

The UK government increasingly sees its indigenous oil and gas industry in terms not of government revenues but of its contribution to the balance of payment. Consequently, any major contract for substantial gas imports would be regarded by government as unwelcome on balance of payment reasons alone. As such, government may wish to delay or limit the extent of Norwegian imports.

As being viewed today, UK will need imported gas after year 2000 if it choose to commit their own gas to fill the gas demand in the 1990's. However it should be pointed out that if it becomes evident that there will be a gap in demand and supply early 2000, the UK oil companies might intensify the exploration for gas which might again result in new findings.

Based on above we do not see any major possibility to export significant quantities of Norwegian gas to UK on this side of the decade. Norway might be able to sell some small quantities but even this is very doubtful. As we see it we cannot base the strategy of future use of Frigg Facilities on an opening up of Norwegian gas exports to UK before year 2000. There are however all reasons to believe that 2000 (or around) could be a milestone as, given a proper degree of political desire from Norway, that Norwegian gas is available and that BG is interested in taking it (market will open, pipelines offshore and onshore empty, Norwegian price can be market related, Norwegian gas is a diversification to BG and government interference might be less than back at the time of the Sleipner flop).

It should however be added that the existing Frigg Norwegian Gas Sales Agreement with British Gas contains provisions which give the FNA partners an option to put gas which is found within the blocks 25/1 and 25/2 into the existing agreement. It is however a condition that such gas is able to meet the gas spacification contained in the agreement. Further the agreement stipulates a plateau level which equals 1/5000 which might create a problem for smaller deposits. The existing arrangement may also be terminated by either party with effect as of the 30th of September 2000. It is therefor most likely that even deposits found within 25/1 and 25/2 will require amendments of the existing agreement to be negotiated with British Gas.

1.8 The Price of Gas

Recent gas contracts in UK have been signed in the range of NOK 0,50 to NOK 0,60 per SCM tied to the lower of two price escalators related to oil price and general inflation. Recently we have seen a small increase in price of oil which also might result in a small increase of gas. However, as seen from above, the quantity of gas to be sold on the market seems to be somewhat higher than the demand of gas which might result in a gas price which will not follow the oil price in the years to come. In addition we have experienced that future gas prospects seems to come from associated fields and as such the price of gas might have a lesser value than earlier.

HISTORICAL COMMITTED GAS FROM 1975 TO 1988 INCLUSIVE (MSCM/D)

1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
100.4	107.3	111.8	106.0	108.1	96.5	94.7	100.3	96.0	95.3	104.7	106.3	116.2	143.4

Attachmen
IV.1.1

Committed Gas Field - Future Production (1988 - 2000) (MSCM/D)

Fields	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
A) Central and northern North Sea													
Alwyn Area	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	7.5	6.7
Brent	13.3	13.3	13.3	12.0	10.1	8.4	7.4	6.4	5.7	4.7	3.6	2.8	2.8
Clyde	0.7	0.7	0.7	0.5	0.2								
Cormorant	0.4	0.3	0.3	0.2	0.2	0.2	0.1						
Frigg UK	9.1	7.1	4.0	3.3	2.7	2.2							
Frigg NW	14.1	11.0	8.4	4.8	4.1	3.3							
East Frigg	1.0	4.0	4.0	4.0	3.6	1.8	1.4	0.7	0.1				
North East Frigg	4.7	4.1	2.3	1.2	0.7								
Odin	7.7	7.7	7.7	7.7	7.7	7.0	3.9	2.2	0.7				
Murchison UK	0.2	0.1	0.1	0.1									
Murchison NW	0.1	0.1											
Fulmar	0.8	0.8	0.7	0.4	0.1								
Ivanhoe/Rob Roy		0.4	0.8	0.7	0.6	0.5							
Magnus	1.4	1.4	1.4	1.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	
Piper	0.2			0.4	0.3								
Statfjord UK	1.5	1.5	1.5	1.5	1.5	1.3	1.1	1.1	1.1	1.0	0.8	0.7	0.7
Tartan	0.6	0.5	0.4	0.3	0.2	0.1	0.1						
Thistle	0.1	0.1	0.1										
SUB TOTAL	65.4	62.6	55.2	47.9	41.8	34.5	23.6	20.0	17.2	15.3	14.0	11.1	10.2
B) Southern North Sea													
Amethyst			1.4	2.8	4.2	5.0	5.0	5.0	5.0	5.0	4.9	4.3	3.8
Audrey	0.6	4.2	7.6	7.6	7.6	7.6	7.6	7.6	4.8	3.9	3.4	3.1	2.8
Barque & Clipper				0.6	3.1	5.6	5.6	5.6	5.6	5.2	5.0	4.9	4.6
Camelot		0.6	2.0	2.0	2.0	2.0	1.8	1.7	1.4	1.1	1.0		
Cleeton/Rav South	0.7	3.5	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.3	5.7	5.3
Esmond Area	5.6	5.6	5.6	4.8	3.9	3.1	2.2	1.8	0.6				
Hewett	6.4	6.2	6.0	5.7	5.3	4.9	4.2	3.6	3.4	2.8			
Indefatigable	14.4	13.7	10.3	8.4	7.0	6.4	5.0	4.2	3.5	3.1			
Leman	26.5	23.7	22.0	20.1	18.6	17.0	16.8	16.5	16.2	16.0	15.7	15.1	14.6
Morecambe	4.5	5.9	7.6	8.1	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Ravenspurn North			1.4	5.3	8.8	8.8	8.8	8.8	8.8	8.8	6.4	5.0	3.9
Sean	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.7
Thames Area	4.3	4.3	4.3	4.3	3.9	3.4	2.5	1.8	1.3	1.0	0.6		
Valiant Area	1.3	7.6	10.1	10.1	10.1	10.1	10.1	10.1	9.1	8.3	7.3	6.6	5.9
Victor	4.2	4.2	4.2	4.2	3.6	3.6	3.6	3.4	3.1	2.8	2.8	2.5	2.2
Viking	7.0	5.6	4.5	3.9	3.1	2.5	2.0	1.3	1.0	0.7	0.6	0.4	
West Sole	3.6	3.6	3.6	3.6	3.6	3.6	3.4	3.1	2.5	2.2	2.0	1.7	1.5
SUB TOTAL	81.1	90.7	99.3	100.2	101.9	100.7	95.7	91.6	83.4	78.0	66.4	59.7	54.7
T O T A L	146.5	153.3	154.5	148.1	143.7	135.2	119.3	111.6	100.6	93.3	80.4	70.8	64.9

Attachment IV.1.2

Uncommitted gas fields - future production (MSCM/D)

Fields	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
A. Central and northern North Sea													
Beryl				2.0	9.0	12.1	12.7	13.3	13.3	13.3	13.3	12.8	11.2
Brae (N,CBS)						2.8	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Bruce						4.1	17.0	21.0	21.0	21.0	21.0	21.0	21.0
Drake						2.3	5.0	5.6	5.6	5.6	5.6	5.6	5.6
East Brae								1.4	2.8	7.7	7.7	7.7	7.7
East Ninian			0.1	0.6	0.6	0.4	0.3	0.2	0.1				
Everest						1.8	4.0	4.5	4.5	4.5	4.5	4.5	4.5
Forth							1.3	2.5	3.4	3.4	3.4	3.4	3.4
Gannet							1.5	2.7	2.7	2.4	2.3	2.2	2.1
Guillemot						0.3	0.6	1.1	1.1	1.1	1.0	1.0	0.9
Joanne & Judy						1.1	3.9	4.6	5.3	5.0	4.6	4.0	3.4
Kittiwake				0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Lomond									1.4	3.1	3.4	3.4	3.4
Miller					1.0	2.4	3.6	3.6	3.2	2.7	2.0	1.7	1.1
Nelson					0.1	0.7	0.7	0.6	0.6	0.5	0.5	0.4	0.3
Nevis				0.7	1.5	1.5	1.3	0.9	0.6	0.4	0.4	0.3	
Tiffani & Toni						0.4							
SUB TOTAL			0.1	3.4	12.4	30.1	57.7	67.8	71.4	76.5	75.5	73.8	70.3
B. Southern North Sea													
Anglia			0.3	1.7	1.7	1.7	1.7	1.7	1.7	1.3	1.0	1.0	1.0
Lancelot				0.4	1.4	2.1	4.5	4.5	4.3	4.2	3.6	3.4	3.1
Pickerel/Valkyrie				1.4	3.9	5.3	5.3	5.3	5.3	5.3	4.6	4.2	3.9
Venture		0.1	0.6	0.6	6.1	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.1
Welland			0.7	2.6	2.6	2.6	2.6	2.0	1.7	1.4	1.1	1.0	1.0
SUB TOTAL		0.1	1.6	6.7	15.7	12.3	14.6	13.9	13.4	12.5	10.6	9.8	9.1
T O T A L		0.1	1.7	10.1	28.1	42.4	72.3	81.7	84.8	89.0	86.1	83.6	79.4

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Attachment IV.1.3

COMMITTED GAS/UNCOMMITTED DEVELOPMENTS FROM 1989 TO 2000 INCLUSIVE

IN MSCM/D

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Committed gas	153.3	154.3	148.1	143.7	135.2	119.3	111.6	100.6	98.7	80.4	70.8	64.9
Uncommitted developments		1.7	10.1	28.1	42.4	72.3	81.8	84.8	89	86.1	83.6	79.3
T O T A L	153.3	156	158.2	171.8	177.6	191.6	193.4	185.4	187.7	166.5	154.4	144.2

Attachment IV.1.4

Total UK gas committed and uncommitted (MSCM/D)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Central and northern North Sea	65.4	62.6	55.2	51.2	54.2	64.6	81.3	87.9	88.6	91.8	89.5	84.9	80.4
Southern North Sea	81.1	90.8	101.0	106.9	117.6	113.0	110.3	105.5	96.8	90.5	77.0	73.1	63.8
	146.5	153.4	156.2	158.1	171.8	177.6	191.6	193.4	185.4	182.3	166.5	158	144.2

Attachment IV.1.5

CHAPTER IV - PART 2

The Continental Gas Market

2.1 Introduction

Natural gas has come to play an increasingly vital role in European energy supply.

Between 1960 and 1970, the total Primary Energy Requirements (T.P.E.R.) grew by 5.2% per year. In the same time, the increase of gas demand was 20% per year, for the following main reasons:

* A development of domestic sources (Lacq field in France, Goningen in The Netherlands, Italien fields).

* A development of the transmission and distribution grids.

* A substitution of coal by gas, easier to stock, to transport and less polluting.

Gas consumption continued to grow during the 1970's, around 11% per year; gas continued to take share of marked to the detriment of fuel oil; the share of gas in the T.P.E.R. in continental Western Europe, rose from 6% in 1970 to 14% in 1980.

Between 1980 and 1987, the annual average growth was 2,1%, the total consumption of the continental Western Europe being 157 Mtoe.

2.2 The continental Gas Market Today

The gas markets in the European countries are very diverse and at different stages in their evolution. There are marked differences among countries and regions as to:

- the degree of energy dependence,
- gas share in the primary energy balance,
- consumption patterns in the various sectors,
- the organisational structure of the gas industry,
- the structure of supplies, the level of the domestic production,
- energy and price policies.

2.2.1 Introduction

In 1987, the average gas share in the primary energy balance is 14,1% in Western Europe (without UK). Attachment IV - 2.1 shows big disparities among the countries due to the availability of domestic sources, this share is 45,7% in The Netherlands, and only 12,7% in France. Countries such as Greece and Portugal still virtually have to set up a market or are in the process of doing so, and in others like Denmark, Ireland, Spain and Turkey, it can be substantially developed further.

We emphasize that four countries, The Netherlands, West Germany, France and Italy represent 86% of the continental market.

2.2.2 Structure of Consumption by Sector

The table hereunder shows consumption by sector and gas penetration in 1987:

	Consumption		Gas Penetration
	Mtoe	%	%
Domestic/Commercial	68,9	44,1	26,0
Industry	54,1	34,5	38,3
Power generation	24,5	15,6	5,9
Other	9,1	5,9	n.a.
TOTAL	156,7	100,0	

2.2.2.1 Domestic/Commercial Sector

This sector has known the most important growth: the increase of demand has been multiplied by 5 since 1970.

Almost half of gas consumption is used in direct premium domestic/commercial applications. However, gas represents only 26% of the demand in energy of this sector, which is fond of fuel-oils. This proportion differs according to the countries (95% in The Netherlands, 32% in West Germany, 18% in France where the importance of nuclear electricity is an exception).

70% of gas used in this sector is consumed in domestic heating.

2.2.2.2 Industrial Sector

The industrial market has grown more slowly than sales to domestic and commercial consumers in the last ten years, and accounts in 1987 for 34,5% of gas consumption, against 39% in 1977.

Gas has suffered, like the other energy sources, from the decrease of energy content in the industrial production. This sector is very sensible to the relative energy prices, outside the captive market of non energetic uses (8% of the industrial market).

2.2.2.3 Power Generating

Compared to Japan and USA, the role of gas for power generating in Europe is small. The The Netherlands were the first economy to use large quantities of natural gas in this sector, with Germany being quick to follow. Thereafter, gas burnt declined largely because its use in the power sector was felt to be an inappropriate application of gas, and because the European Commission issued a directive in 1975 prohibiting the use of gas in new power plants.

Attachment IV - 2.2 shows the differences among the main European countries with respect to the use of gas in power generating.

2.2.3 Supplies

In Western Europe, gas industry was born from domestic productions, and reached an international level at the end of the 1960's with the first exports of Groningen gas.

The development of imports from countries that do not belong to continental Western Europe is recent. That is why sufficiency is 56% when it is 43% for the other energy sources.

In 1987, the supplies are the following ones:

	BCM
Production	107,4
(The Netherlands)	(63,4)
Imports	84,0
Norway	15,8
Soviet Union	43,0
Algeria	24,4
Libya	0,8
TOTAL	191,4

Gas reserves in continental Western Europe are around 2 400 BCM, of which 1 815 BCM (75%) are localized in The Netherlands.

2.3 Future Demand

2.3.1 Global Demand

According to most of recent forecasts, Gross Domestic Product should grow in a range of 2 - 2,5 % per year from 1990 to 2000. Total primary energy demand growth is projected to be lower: 1% to 1,5% per year. Therefore, energy efficiency is projected to continue to improve.

It was agreed, up to a close past, that share of gas in energy consumption would remain steady in the future. Today, most of observers think that a greater gas penetration is probable.

In this study, we will consider that demand will be in a range:

- the low scenario corresponds to a low growth of energy needs, share of gas remaining constant.
- the high scenario corresponds to a high growth of energy demand, and to a greater gas penetration.

2.3.2 Gas Demand by Sector (Attachment IV - 2.3)

2.3.2.1 Domestic/Commercial Sector

The factors that will determine future gas demand in the domestic sector will be the growth of population, the number of new dwellings built or renovated, the development of the distribution grid.

The main competitor is gas oil, electricity is less competitive.

We are projecting an important increase of consumption until 1990, then gas penetration should be lowered by a saturation of the market. The outlets in the South Europe countries will be limited for climatic reasons.

However, the commercial sector will be an important source of growth, partly because gas is starting from a low base point.

Finally, the average growth of the domestic and commercial sector should be moderate.

2.3.2.2 Industry

Several analyses foresee limited growth in industrial energy demand; according to European Community report, the level should be stabilised by 1990. However, some growth in gas demand will be possible in the countries where the national grid continues to be expanded (notably Italy, Spain and some regions of Germany). The main strategies for increasing gas consumption would be to incorporate more areas into pipeline grids and to offer special prices to customers willing to use gas based heating systems.

In the future, a direct access to the suppliers, and the imposition of common carrier legislation by the EEC will be also factor of growth of gas consumption.

The main competitor will remain fuel oil.

2.3.2.3 Power Generating

Up to now, it has been considered that this market would continue to decline. Today, it is agreed that gas turbine combined cycle technology could revolutionise the role of gas, provided that the EC directive can be surmounted, especially with the background of difficulties which nuclear power is experiencing, and the availability of over-supplies. There is a large opportunity for gas use to expand in the power sector, specially for peak-shaving uses in urban areas where coal is considered as too polluting and too capital-expensive.

2.4 Future Continental Supply

2.4.1 Domestic Production

Domestic production will likely remain constant until the end of the century, and will decrease rather quickly thereafter.

2.4.2 Imports

If we look at the demand/supply balance (Attachment IV - 2.4), it appears that committed supplies are sufficient to cover the needs up to mid -90's.

At the end of the century, a gap from 8 BCM to 45 BCM appears, and the reduced domestic production coupled with a power gas market leave a growing gap.

Even if there is a fair chance for the existing contracts to be reconducted at the present level (110 BCM), the non covered demand will account from 43 to 184 BCM in 2010. Which countries will be able to supply volumes of this order?

The dependency vis-a-vis Soviet Union will be likely limited, and therefore Norway and Algeria will reinforce their natural role of main suppliers of Europe. As a consequence thereof the Frigg Facilities ought to have a link to the continental gas grid in order to be able to offer services to customers supplying the continental market.

In addition, new importers will have to emerge: Nigeria, Libya, Iran, Qatar...

TABLE 1 : SHARE OF TOTAL PRIMARY ENERGY REQUIREMENTS (T.P.E.R.)

IN WESTERN EUROPE (1987)

	Total Demand (Mtoe)	Gas %	Oil %	Coal %	Primary Electricity %
Belgium/Luxembourg	50,5	16,9	46,5	17,2	19,4
France	196,6	12,7	43,8	8,9	34,6
Italy	147,9	21,8	60,7	10,3	7,2
Netherlands	74,1	45,7	43,2	9,7	1,4
West Germany	266,4	16,7	43,0	27,4	12,9
Others	355,4	3,7	46,3	19,8	30,2
Total continental Western Europe	1 090,9	14,4	46,8	17,6	21,2
United Kingdom	205,4	24,3	36,6	32,8	6,3
Total Western Europe	1 296,3	16,0	45,1	20,0	18,9

Source : BP review of World Gas (1988)

ATTACHMENT B

Attachment IV.2.2

TABLE 2 : ELECTRICITY GENERATION IN WESTERN EUROPE (1986)

	Output in Twh	Gas %	Oil %	Coal %	Nuclear %	Hydro/géo %
Belgium/Luxembourg	59,7	1,5	4,3	25,0	65,5	3,7
France	294,1	0,8	1,1	9,8	69,7	18,6
Italy	192,3	14,0	40,3	16,6	4,6	24,6
Netherlands	67,2	61,8	26,8	5,1	6,3	0,0
West Germany	408,3	6,2	3,1	56,9	29,3	4,5
Others	598,2	2,2	5,0	25,3	21,8	54,3
Total continental Western Europe	1 619,8	6,8	8,7	28,6	31,3	24,6
United Kingdom	301,1	0,6	10,2	67,3	19,6	2,3
Total Western Europe	1 920,9	5,8	8,9	34,7	29,5	21,1

Source : Energy Balances of OECD Countries
Comité Professionnel du Pétrole

Attachment IV.2.3

TABLE 3 : DEMAND FORECASTS IN CONTINENTAL WESTERN EUROPE

Mtoe	1987	1990 low	1990 high	1995 low	1995 high	2000 low	2000 high	2005 low	2005 high	2010 low	2010 high	Annual Increase (%) 1987/2000 low	Annual Increase (%) 1987/2000 high	Annual Increase (%) 2000/2010 low	Annual Increase (%) 2000/2010 high
Domestic/Commercial	68,9	72,0	74,2	77,6	83,9	83,6	95,0	87,9	102,3	92,3	110,2	1,5	2,5	1,0	1,5
Industry	54,1	54,9	57,4	56,3	63,3	57,7	69,9	59,2	77,2	60,7	85,2	0,5	2,0	0,5	2,0
Power generation	24,5	25,2	26,8	26,4	31,1	27,8	36,0	28,5	40,7	29,2	46,1	1,0	3,0	0,5	2,5
Other/losses	9,2	9,5	9,8	10,0	10,8	10,5	11,9	11,0	13,2	11,6	14,6	1,0	2,0	1,0	2,0
TOTAL	156,7	161,6	168,2	170,3	189,1	179,6	212,8	186,6	233,4	193,8	256,1	1,2	2,4		
T.P.E.R.	1 091	1 124	1 140	1 181	1 228	1 241	1 323	1 304	1 425	1 371	1 535	1,0	1,5	1,0	1,5
Share of gas (%)	14,3	14,4	14,8	14,4	15,4	14,4	16,0	14,3	16,4	14,1	16,7				

DGN's forecasts

Attachment
IV.2.4

TABLE 4 : CONTINENTAL WESTERN EUROPE GAS BALANCE

BCM	1987	1990	1995	2000	2005	2010
. DEMAND low	191,1	197,1	207,6	219,0	227,6	236,3
high	191,1	205,1	230,6	259,5	284,6	312,3
. COMMITTED SUPPLIES	191,1	211,5	213,8	214,5	172,4	128,5
Domestic production	107,4	104,3	102,6	101,8	98,6	83,4
Importations	83,7	107,2	111,2	112,7	73,8	45,2
Norway	15,7	19,4	23,7	27,9	26,0	24,0
Soviet Union	43,0	57,0	56,0	54,0	32,0	6,0
Algeria	24,2	30,0	30,0	28,0	13,0	12,4
Other	0,8	0,8	1,5	2,8	2,8	2,8
. NOT COVERED	0	- 14,4/6,4	- 6,2/16,8	4,5/45,0	55,2/112,2	107,8/183,8

DGN's forecasts

CHAPTER V

PIPELINE INFRASTRUCTURE ANALYSIS

CHAPTER V

Pipeline Infrastructure Analysis

1 Purpose

The purpose of the analysis of the North Sea pipeline network has been the following:

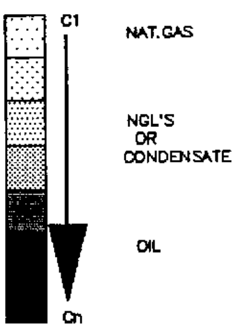
- Define future specifications for export pipelines from Frigg
- Evaluate possible pipes which could enter gas into the Frigg facilities, existing and/or by use of existing risers
- To evaluate whether the Frigg facilities and compressors could play a role in gas transportation to the continent
- Evaluate possibilities by installing a pipe between Frigg and Heimdal
- Establish which pipeline systems could be competitor to Frigg for
    1. Transport from Frigg area (UK + NW)
    2. General gas export from NW to UK
- Evaluate possible liquid export alternatives from Frigg area

The North Sea oil and gas pipeline grid is exhibited on Attachment V-1.1.

2 Gas Treatment and Transportation Specification

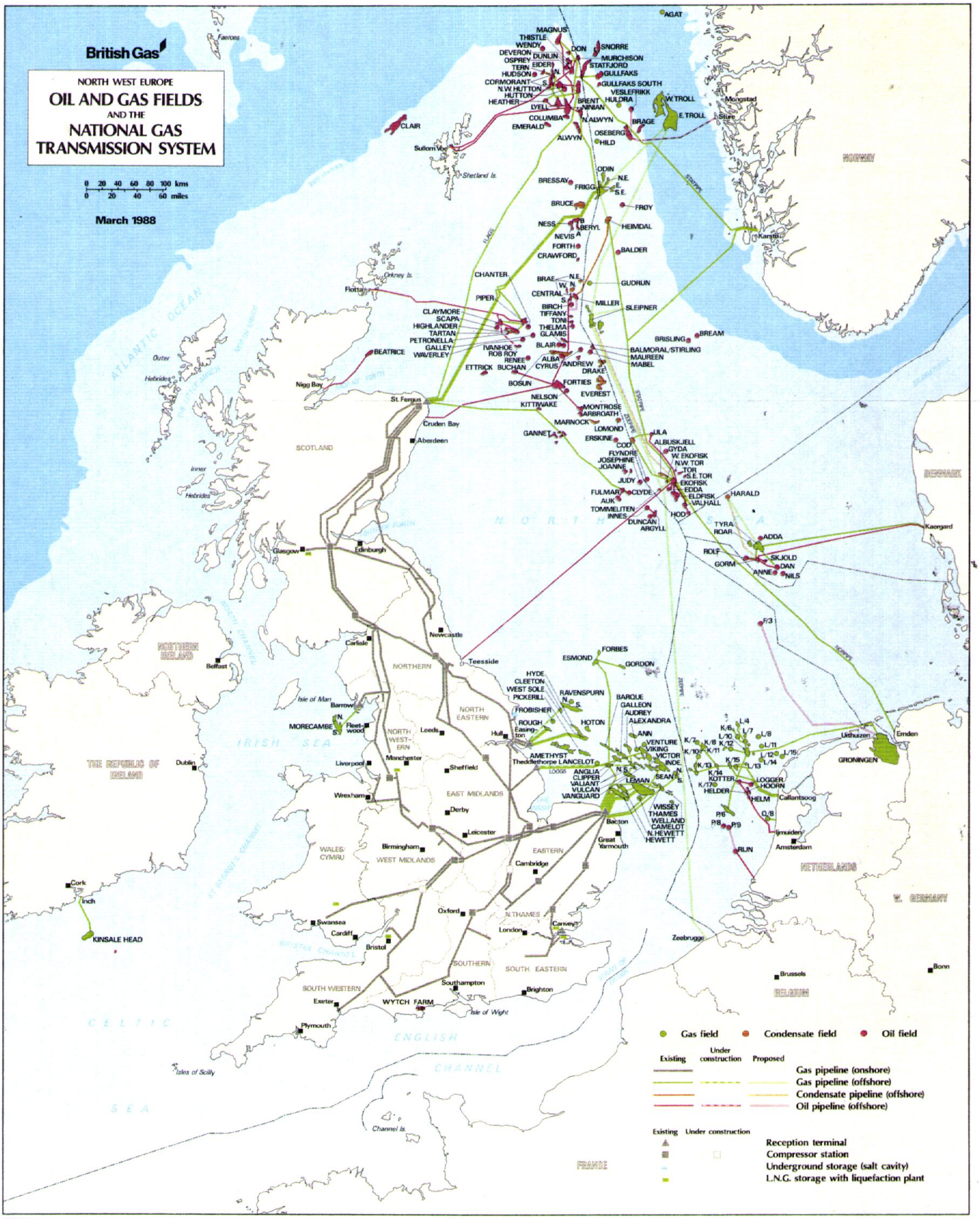
2.1 Why a Specification?

All hydrocarbon reservoirs contain a certain mixture of hydrocarbon components. Defining an offshore gas or even oil treatment and transportation specification is made for the specific fluid to be transferred to the onshore terminal for further treatment and further transfer to consumers.



Any well stream fluid can roughly be divided into three groups as shown on the figure to the left.
Defining a process for the wellstream fluid to meet the specification is simply to make a cut or separation within the components. In addition , it has to be mentioned that the reservoir fluids can include components which are not hydrocarbons and which have to be totally or partially removed to meet a specification (H_2O, H_2S, CO_2, etc...)

Attachment
V.1.1



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BG 9014

2.2 Consequences of Various Specifications

The basic principle of any offshore process is to have only two product outlets (pipe or offshore loading). The consequence of this is that one have to define in which of the two outlets the medium group (NGL's) is to be transported. As a general rule the NGL's create the transportation constraints. If the most of the NGL's are in the gas phase, one has to accept two phase flow or operate at a higher pressure where no liquid can form, but this will reduce pipe capacity.
If the NGL's are in the liquid phase offshore loading or equivalent (i.e. Stab. crude spec.) can not be used.

If stringent liquid and gas specifications are to be followed at the same, a third product outlet will be required. (ref. Frøy via Heimdal).
It should be remarked that the above statements do have exceptions like Heimdal gas which can comply with both a stringent gas and stringent liquid specification, the genuine composition is compatible with a process which allows to deliver two products with stringent specifications.

2.3 North Sea Practices (ref. Attachment V-1.2)

1) General

The entire North Sea, both UK and NW sectors, has been developed without proper planning and coordination as can be seen from the map hereafter.
To simplify the northern and central parts of North Sea can been divided in various zones.

2) UK Sector

2.1 Ninian/Brent area (Rich gas, live crude)

Oil spec :	TVP < 200 psia at 100^{O} F (i.e. < 12.8 bars at 38o C)
Terminal :	Sullom Voe (BP operator)
Pipe size:	2 x 36"
Gas spec :	Wet gas (or richgas)
Terminal :	Shell St. Fergus
Pipe size:	36"

Or in other words the oil and gas transportation has no one stringent specification (live crude and rich gas system).

2.2 Beryl area (Rich gas, stabilized crude)

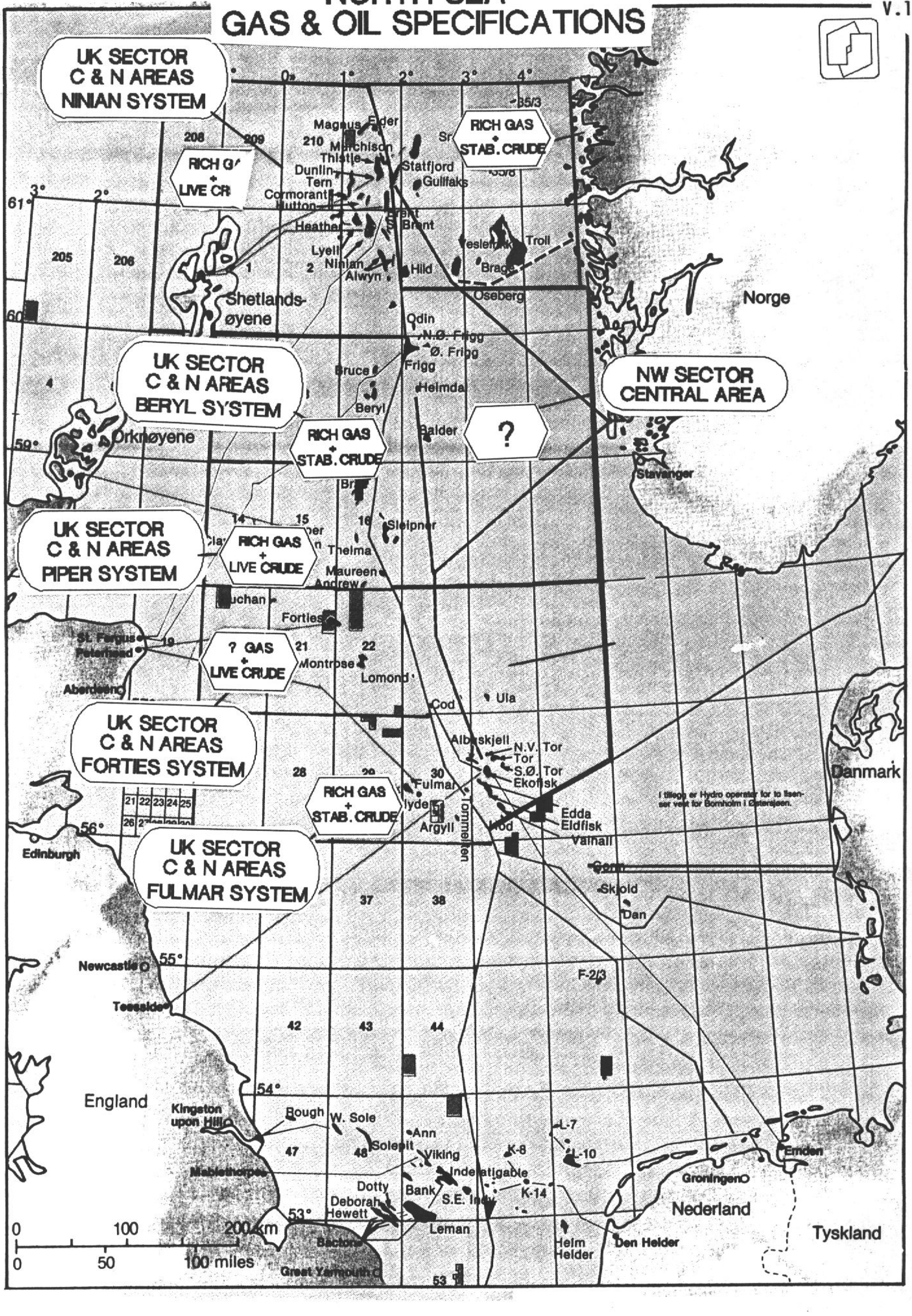
Oil spec :	Offshore loading (Mobil Operator) (i.e. RVP 10-12 psi)
Gas spec :	Rich gas (presently required)
Terminal :	Unknown
Pipe size:	Unknown

2.3 Piper area (Rich gas, live crude)

Oil Spec :	TVP approx. 10 bars (assumed)
Terminal :	Flotta (Occidental Operator)
Pipe size:	30"
Gas spec :	Rich gas
Terminal :	Total St. Fergus
Pipe size:	18"/32"

Attachmer V.1.2

NORTH SEA GAS & OIL SPECIFICATIONS



2.4 Forties area (Live crude)

Oil spec :	9.6 bara at 15.6^{o}C
Terminal :	Kerse of Kinneil (BP Operator)
Pipe size:	32"
Gas spec :	Not decided

2.5 Fulmar area (Rich gas, stabilized crude)

Oil spec :	Offshore loading (Shell Operator) (i.e. RVP 10-12 psi)
Gas spec :	Rich gas
Terminal :	Shell St. Fergus
Pipe size:	20"

3. Norwegian sector

3.1 Statfjord/Oseberg area (Rich gas, stabilized crude)

Oil spec :	Offshore loading or Oseberg - Sture line - (i.e. 10-12 psi RVP)
Terminal :	Sture (Norsk Hydro Operator)
Pipe size:	20"
Gas spec :	Rich gas
Terminal :	Kårstø (Statoil Operator)
Pipe size:	30"

3.2 Ekofisk area (Dry gas, live crude)

Oil spec :	TVP < 150 psia (9.6 bar)
Terminal :	Teeside (Phillips Operator)
Pipe size:	34"
Gas spec :	Dry gas
Terminal :	Emden (Phillips Operator)
Pipe size:	36"

4. Summary

As seen from the above examples three different practices are followed:
1. Live crude and rich gas
2. Live crude and dry gas
3. Stabilized (dead) crude and rich gas

An exception to the above practice is Heimdal, which is a gas/condensate field and not associated gas/oil field. Heimdal follows both a dry gas and a stabilized crude, but very little flexibility exists on each side.

2.4 Frigg Area Future Specifications

As seen from the analysis of the North Sea oil and gas pipeline specifications, it appears that those ones have been determined in terms of circumstances of each development.
The pipeline of the Frigg Transportation system upto now did not require any specification. Only for operational constraint, the water dew point has to be less than -15^{o}C at 140 bar. Future specifications have to be defined, but the consequences of not selecting the optimum specification have to be fully evaluated.

1) Commercial gas specification (or "dry gas")

Applying a commercial gas specification for the Frigg NW pipeline means that the gas has to meet the most stringent of HC-dew-point, Wobbe Index or GCV specified values.

Advantages

- The existing St. Fergus terminal can be bypassed.
- MCPO1 compressor can be used
- Capacity of line maintained
- Flexibility possible within rich gas operated UK-line.
- Transfer of gas via Heimdal to continent without extra treatment facilities.
- Tie-in and transport of Troll gas without retreatment.

Disadvantages:

- For rich gas of wellstream entering Frigg a new hydrocarbon dewpoint unit will be required.
- A live liquid export line will be mandatory.
- A new flare boom could be required.

2) Rich gas specification

Advantages :

- No additional equipment required on Frigg
- Flexibility with UK-line and vice versa.
- Attractive for future rich gas fields or field producing with a stringent oil specification (Beryl, Oseberg)
- A liquid export line may not be required. Offshore loading could be used.

Disadvantages:

- Additional facilities required in St. Fergus
- Reduction in capacity due to:
  . Problem using MCPO1 compressors.
  . Increased inlet pressure in St. Fergus.
  . Troll needs retreatment
- No export to the continent without extra treatment facilities.

3 Possible Pipelines Into Frigg

3.1 Risers

As seen from the description of the platforms (ref. chapter III) several risers exist and can be used, having sizes from 16 to 32". In addition smaller risers can be pulled through the J-tubes (as for EF) or smaller risers can be pulled via the existing risers and sealed by a mechanical seal.
For risers larger that 32" an additional structure will be required, either a Riser Support Structure (ref. sec. 5.3.4.2.) for risers up to 36" or a Riser Platform (ref. sec. III 5.3.4.3.) for riser up to or larger than 42".
Conclusively Frigg can tie-in risers from 2-32" with existing risers or up to 42" with an additional structure.

3.2 24" Alwyn-Frigg Line

North Alwyn B platform is connected to Frigg TP1 with a 24"x110 km sealine.
The pipe which is operated with rich gas in dense phase has a MAWP of 185 barg.
The pipe is presently booked up to year 2000 with 9.0 MS m^3/d of Alwyn gas, but spare capacity exists. If needed a split of flow between NW and UK line could easily be performed at Frigg. The capacities as a function of Frigg arrival pressure are given on figure hereafter.

As seen from the spare capacities the alternative of transporting gas from northern UK or NW sector through the Alwyn line would be feasible (see Attachment V-1.3).

3.3 16" NEF - Frigg Line

The 16" 17 km NEF pipeline to Frigg will be available at the end of NEF operation (93 present forecast) and could be reused for possible new entries. The pipe has a maximum allowable working pressure (MAWP) of 172 barg.

3.4 20" Odin - Frigg Line.

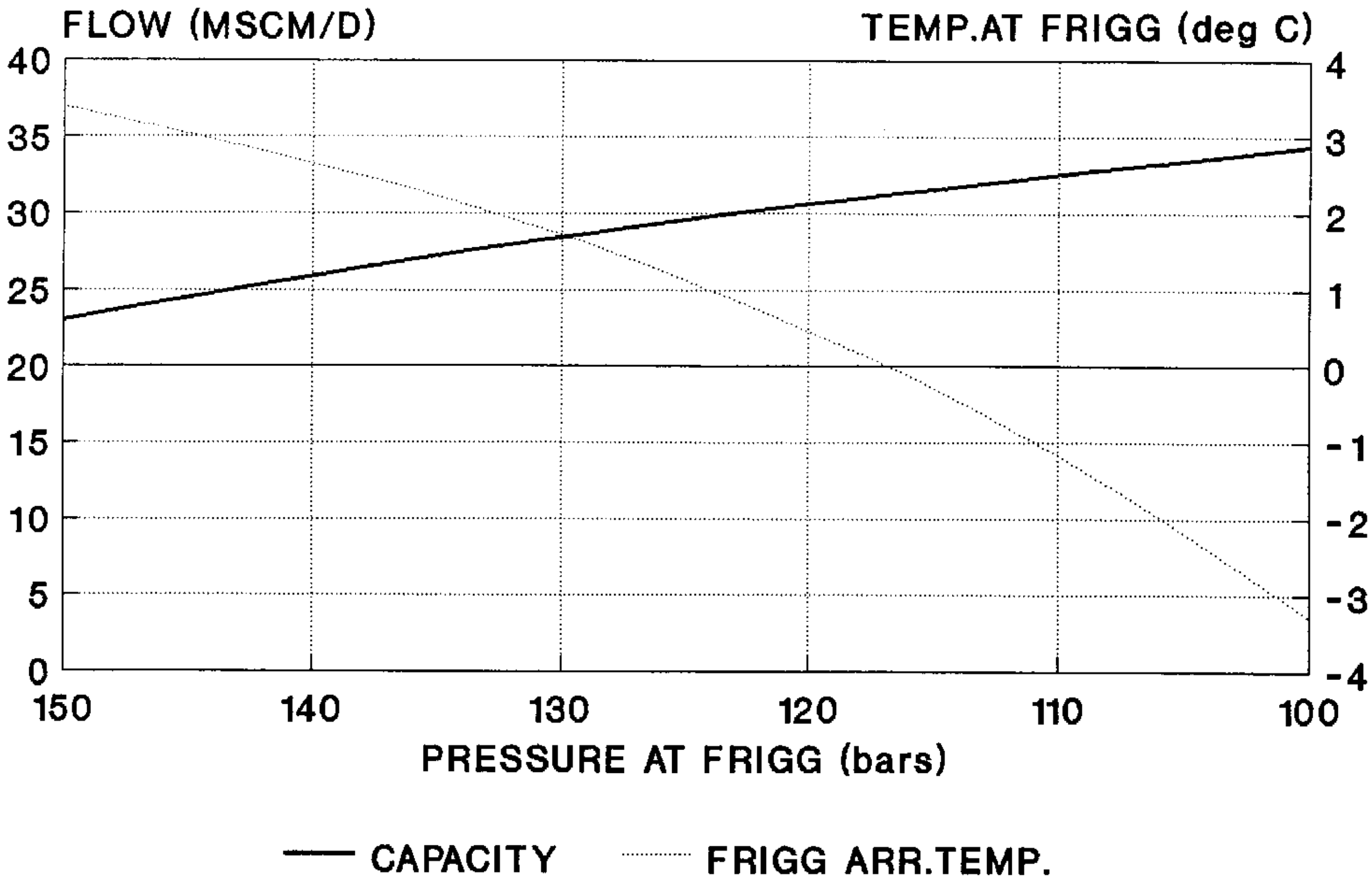
The 20" 26 km Odin pipeline to Frigg will be available in 1997/98 and could also be reused for new entries. The pipe has a MAWP of 176.5 barg.

3.5 12" EF - Frigg Line

The 12" 17 km EF pipeline to Frigg will be available in 1996 and could also be reused for new entries.

The central manifold station has a 10" connection already, which allows the tie-in of a smaller prospect even before the EF has stopped producing.
The pipe has a MAWP of 172 barg.

ALWYN-FRIGG PIPELINE
CAPACITY VS.FRIGG ARR.PRESSURES



DISC.PRESSURE NAB=183b

Attachmen
V.1.3

4 Possible Competitors for Transportation of Gas to UK

4.1 General

For future transportation of gas to UK, Frigg has to assume that competitors exist, and the two areas to compete in are:

1. Transport of UK and NW gases from the Frigg area.
2. General gas export to UK from Norway.

For the last it is assumed that future gas sold to UK, is sold as a supply contract as for the Troll sales agreement.

4.2 Competitors in the Frigg Area

1. New Beryl pipeline to St. Fergus
This pipeline which is not finalized, is supposed primarily to transport gas from the Beryl field. Several routes have been proposed where one is passing via Brae.
A 36" pipeline is planned and is (ref. Wood Mackenzie) said to have a capacity of 1.5 BSCFD. (51 MSm^3/d).
With the present production forecast of Beryl of 13.5 MSm^3/d the pipe will have significant spare capacity, and would unddoubtly be a strong competitor for transport of UK fields.

2. FLAGS system to St. Fergus
The Far North Liquids and Associated Gas System pipeline runs south from Brent to St. Fergus. It is a wet gas pipeline, carrying substantial volumes of NGL as well as gas. At St. Fergus the gas is dried and sold to British Gas while the NGL continues south overland to Mossmorran for fractionation and export.

The FLAGS system also transports gas from fields other than Brent. The WELGAS (western leg) feeder running from Cormorant adds to throughput as does the Northern Leg Gas Pipeline (NLGP).

It is a 36" pipeline with a total capacity of 1.1 BSCFD or 31 MSm^3/d, the production forecast from 1995 is maximum 8 MSm^3/d, it will be a competitor for Frigg,specially for prospects located between Frigg and Alwyn.

4.3 Competitors for General Gas Export from Norway

1. FLAGS system

The FLAGS system is also a competitor for gas export from Norway, and specially due to the fact the pipelines are closer to several of the Norwegian discoveries than Frigg is.
It should also be kept in mind that the Norwegian Statfjord Field is already connected by a 12" line to the system.
Without having real data about this pipe, it is estimated that the pipe could have a capacity of 5 MSm^3/d, and with a production forecast of only 1.1 MSm^3/d in 1995, spare capacity exists. For smaller amount the existing system can be a competitor, but one should keep in mind the short distance from Statfjord to Brent and Frigg is short.

2. MILLER PIPE
From 1993 a new 30" pipeline will be in operation between the MILLER field and St. Fergus. The pipe which is designed for the sour Miller gas will have a capacity of over 1.000 MMcfd (28 MSm^3/d), and will of course provide opportunities for the transportation of third party gas production from other Central North Sea developments, specially Brae.
No special separation or processing facilities will be installed at St. Fergus. The wet gas will then be sent via a new 26-inch diameter land pipeline to the NOSHEB's (North Scotland Hydroelectric Board) Boddam power station.

Even with no treatment facilities installed for Miller itself, a side stream could be taken out and treated, so it is believed that the system could be used for other sources than Miller. The pipeline could be of special interest for the CO_2 rich Sleipner West discovery.

3. FULMAR LINE
The 20 inch diameter pipeline runs 290 km from Fulmar to St. Fergus. The pipeline was laid down during the summer 1984 and first gas sales commenced in July 1986.

The gas and NGL are transported along the Fulmar line in dense phase. The line is somewhat unusual in that Fulmar gas contains significant quantities of hydrogen sulphide but the sour gas is transported in a conventional steel rather than a stainless steel pipeline.
In order to reduce the corrosiveness of the gas, important drying facilities had to be installed on the platform.

The pipeline has a capacity of 500 MMSCFD or 14 MSm^3/d, and will be with nearly no flow from 1995, its route is close to the Ekofisk area.

4. ZEEPIPE LEG TO BACTON
With the planned Zeepipe routing, the pipeline will pass nearby the gas fields in the southern part of the UK sector, it has been mentioned that a leg of Zeepipe could be routed via one of the fields to the BG terminal at Bacton.
As mentioned in an other chapter, the present planned capacity of Zeepipe will not give room for additional gas. Actually it could be questioned whether the planned capacity with both Norpipe and Zeepipe will be sufficient for the future quantities to the continent.
In addition it is unlikely that the riser platform will be installed that south in the system. Consequently Zeepipe is not believed to be a competior for Frigg.

5. SUMMARY OF POSSIBLE COMPETITORS
For transport of gas from the Frigg area a new line from Beryl will be the major competitor. For general gas export of gas from NW to UK the FLAGS system and maybe the Miller pipe will be competitors. At least plans for FLAGS should be watched carefully.

5 Possibilities with a Frigg - Heimdal Link (see Attachment V-1.4)

5.1 General

Due to the short distance (i.e. 35 km) between Frigg and Heimdal, installing a pipe between the two fields will open several new possibilities.

5.2 Size

The size of such a line will either be 24" due to existing risers both on TCP2 and on Heimdal, or 36" which exists on Heimdal. The large size will require a riser support structure on TCP2 or a new riser platform. An alternative could be 32" which exists on Frigg, but not on Heimdal.

5.3 Export of Gas from Norway to UK

A new Heimdal - Frigg line will open the possibility on a short notice to export gas from Statpipe and Heimdal to Frigg and further to St. Fergus. Heimdal still in production, a substitution arrangement would be required.
Other possibilities could be tie-in into Heimdal in order to reverse the gas flow from Heimdal allowing gas from Kårstø or Sleipner being exported to UK.

5.4 Export of UK Gas to the Continent

The possibility of exporting UK gases to the continent could be another alternative. Gas tied-in to Frigg or via Alwyn could then be transported further.
The greatest benefit is that gas can be offered to several customers rather then only BG. Such a scenario could be of special interest for Elf as seller and buyer.

5.5 Export of NW Gas from Statfjord Area to Continent.

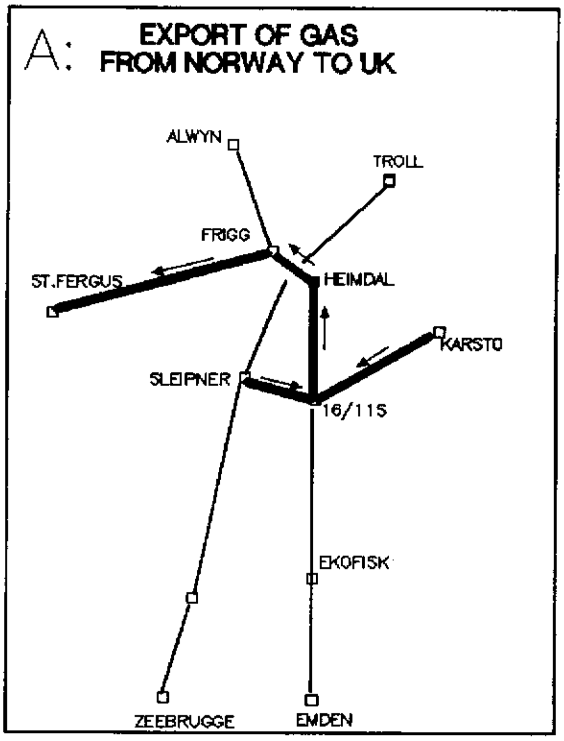
Utilizing the possibility of the Alwyn to Frigg pipeline, gas can, as a competitior to Statpipe be transported to the continent via Alwyn, Frigg and Heimdal, from the area around Statfjord.

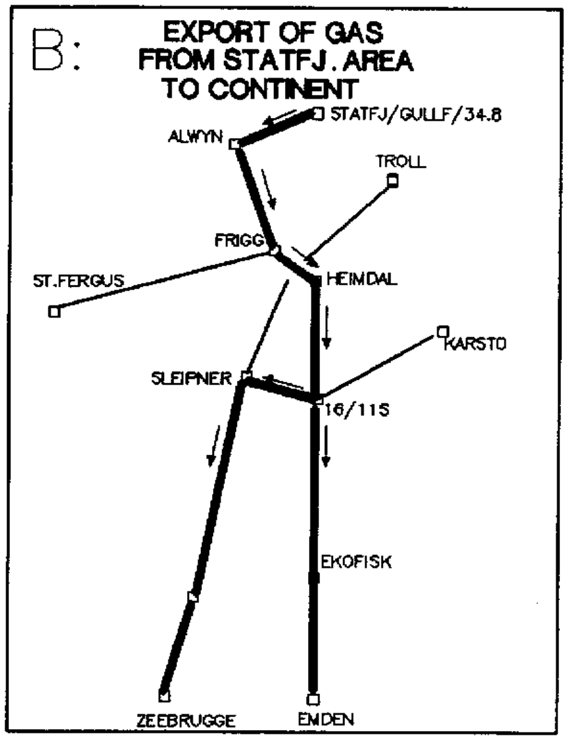
5.6 Tie-in of Troll to Statpipe and Use of Frigg Compressors

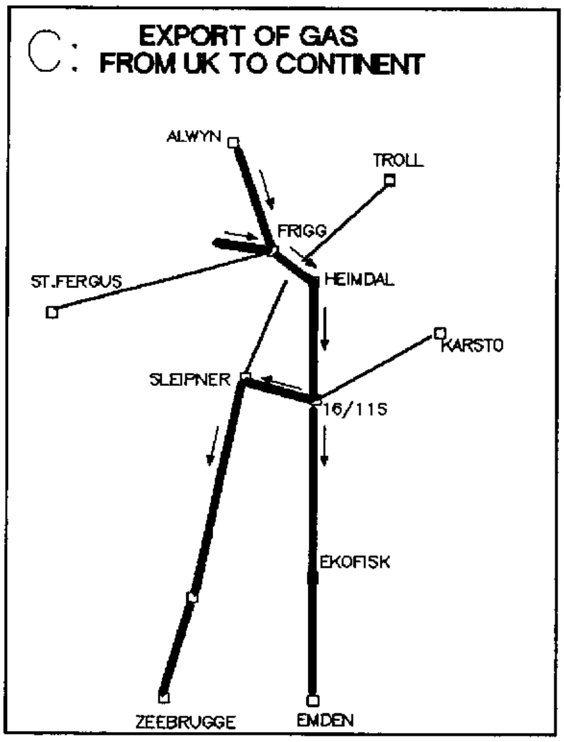
The interesting with this solution is that Troll can utilise the existing Frigg compressors for further transport to the continent. The compressors are very well suited to compress the given flowrates from Troll.

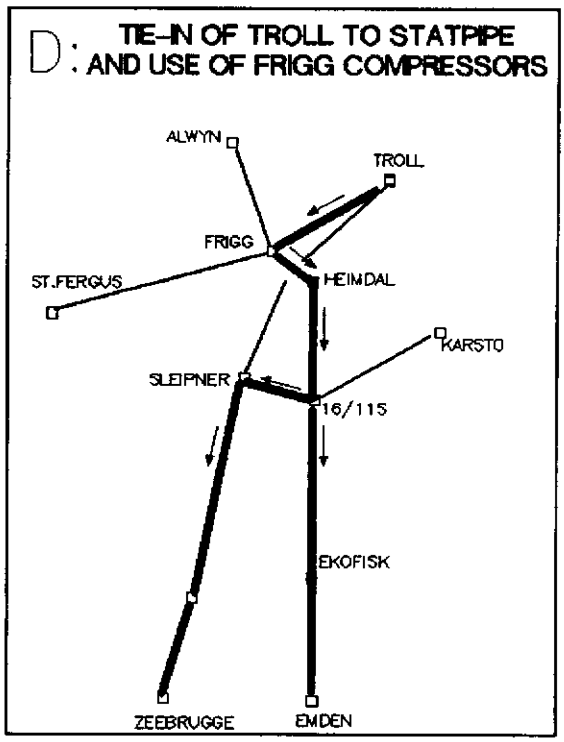
Attachment
V1.1.4

POSSIBILITIES WITH A FRIGG-HEIMDAL LINK









6 Could Frigg Play a Role for Gas Export to The Continent

6.1 Introduction

The aim of this evaluation is to comtemplate the possibilities of incorporating the Frigg Field facilities into the Zeepipe transportation system.
By integrating the Frigg compressors in the Zeepipe System it may be possible to circumvent the drawbacks of the present proposal.

To propose a viable solution it is necessary to determine the status of current development plans and to establish which bottlenecks they are intended to alleviate. As well as to predict where future bottlenecks if any, will occur. This will entail an evaluation of the present system capacities.

6.2 Bottlenecks

The original development plan for Troll, Zeepipe and Sleipner is plagued by several bottlenecks during the period 1993 - 2005. The first bottleneck occurs during 1993 with the overbooking of Norpipe, and continues throughout the period.

The next major conjuncture occurs in 1996 with the capacity limitation of the Statpipe system between 16/11S and 2/4-S.
Implementing the Frigg compressors as a part of Zeepipe will slightly increase the overall capacity, and will actually optimize the capacity of the Sleipner-Zeebrugge leg, since departing Frigg with 165 bars will give an arrival pressure on Sleipner around 150 bars or close to the max. available pressure. Using the Frigg compressors will however not remove bottlenecks in Norpipe and Statpipe, but eventual redundant compressors on Sleipner could be used to increase capacity of Statpipe.

6.3 Present Capacities

6.3.1 Norpipe

The present transportation capacity of the Norpipe system is 55.1 MSm^3/d, and it is decided to increase this to 56.4 MSm^3/d prior to the start-up of Sleipner. A further increase to 59.9 MSm^3/d is under evaluation at present. However, since it entails some modification of the facilities it is not certain that this will be implemented.

6.3.2 Statpipe

The Statpipe system (dry gas) capacity must be considered as a special case. The 16/11S platform is a junction node with two stream-in legs and the future Sleipner leg, it is easy to see that the combined capacities of these three upstream legs exceed the capacity of the 16/11-S to 2/4 leg. Then this leg becomes the critical component in the Statpipe.

Since the capacity is dependent upon the pressure at 16/11-S it then becomes the arrival pressure of the various legs which monitor the capacity. Therefore at any given time the capacity is determined by the lowest arrival pressure of anyone of the upstream legs. The Statpipe capacity is entirely dependent upon the chosen scenario, but the ultimate capacity are as follows:

Gas from Kårstø and Heimdal	:	max. cap. 38 MSm^3/d
Gas from Kårstø leg only	:	max. cap. 53 MSm^3/d
Gas from Heimdal leg only	:	max. cap. 47 MSm^3/d
With compressors on 16/11-S	:	max. cap. 65 MSM^3/d

6.3.3 Zeepipe

The stated capacity of Zeepipe is 39.3 MSm^3/d without compression on Sleipner. Our own calculations gives a value of 41.3 MSm^3/d.
The ultimate capacity with compressors on the riser platform and in Zeebrugge is stated to be 62.2 MSm^3/d, which is defined by the minimum acceptable temperature of the pipe.
For this maximum flowrate, compressors are also required in Zeebrugge.

6.4 Alternatives with Frigg Compressors Included

The basis of the Frigg alternatives is to utilize the available compression capacity on Frigg, in order to boost the pressure up to the maximum of the pipeline and also to reduce the installed power needs on Troll. As seen from Attachment V-1.5 the Frigg compressors are very suited to compress the given flowrate for Troll. It should be noted that the lub. and seal oil systems could need upgrading to operate at 165 bars as specified. The barrel and pipe can however stand this pressure.

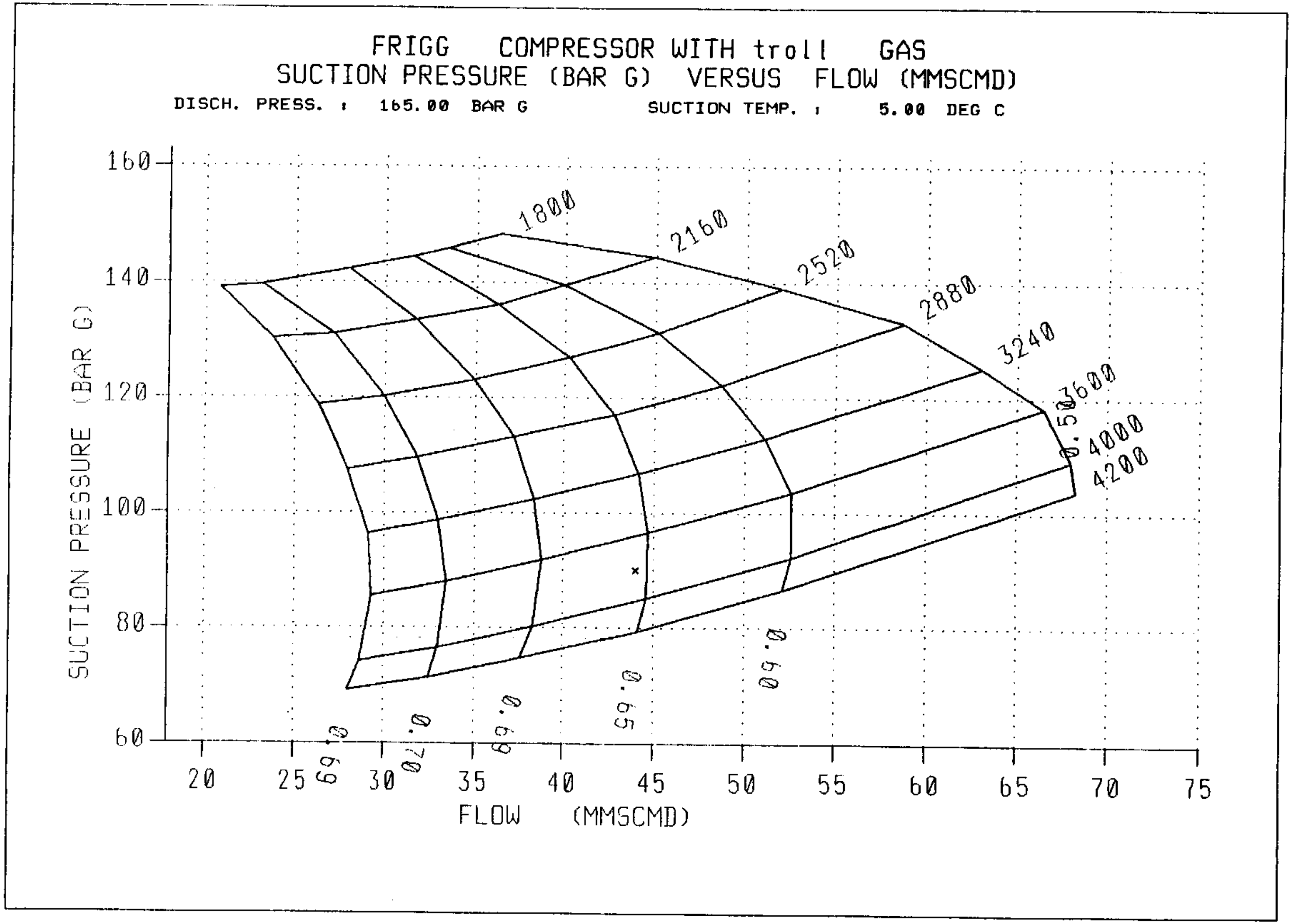
Alt. 1: Troll (40") - Frigg (40") - Sleipner - Zeebrugge
This proposals assumed that a 40" pipe is laid between Troll and Frigg and that a new 40" pipe is installed to Sleipner (MAWP = 172 bars).
The Frigg inlet pressure is set at 95 bars, giving a maximum discharge pressure of 165 barg arriving at Sleipner with 152 bars).
The total system capacity is calculated to 44.15 MSm^3/d and no recompression is needed at Sleipner.
The main advantage of the solution is a reduction in required compression power (i.e. assuming 65 bar suction pressure) of 40 %.
In addition to the above pipes the Frigg - Heimdal link could be installed and a second pipe from Troll would not be needed before year 2000.

Alt. 2: This alternative assumes a 40" Troll to Frigg pipe, a new 36" pipe between Frigg and Heimdal. The ultimate capacity of this alternative is 33.4 MSm^3/d.
This solution can only be acceptable up to year 1998, with the present booking of Troll. The uncertainty here will be the future flowrate from Heimdal due to ongoing discussion about substituting Heimdal with other NW fields, which will prolong the production on Heimdal and take some of the above capacity.

Alt. 3: This alternative is similar to alt. 2, but the objective will here be to increase the maximum capacity of Statpipe by utilizing the Frigg compressors.
In this alternative, it is assumed that the first pipe to be installed will be the direct sealine from Troll to Sleipner. The compression will probably not be needed before year 2000.

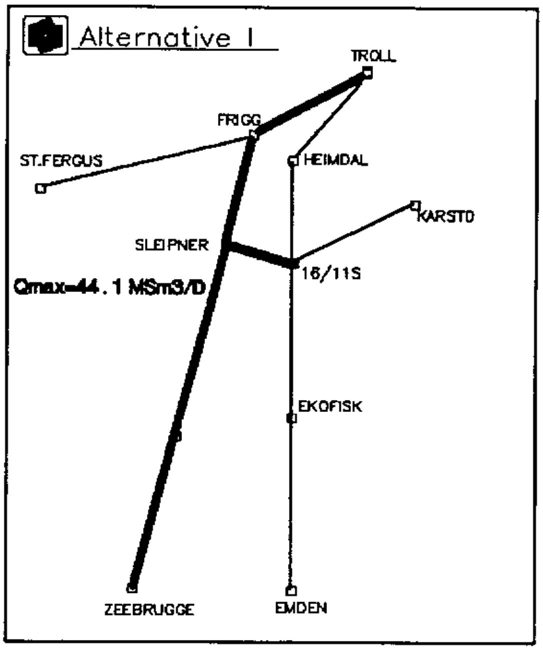
Alt. 4: This alternative is similar to alt. 1, with the same capacity for the Troll - Frigg - Sleipner line.
In addition it is proposed that gas is produced from the Troll - Oseberg - Gas injection (TOGI) Subsea manifold, which will no longer be used when Oseberg starts producing gas.
The gas is assumed to be transported in dense phase to Frigg for further treatment.
With the assumed production level from Oseberg and the production capability of TOGI, a total production from and via Oseberg could be as high as 25 MSm^3/d.
Totally this alternative could give a gas throughput via Frigg of close to 70 MSm^3/d.

Sketches of these four alternatives are showed in the joined attachment V-1.6/7/8/9.



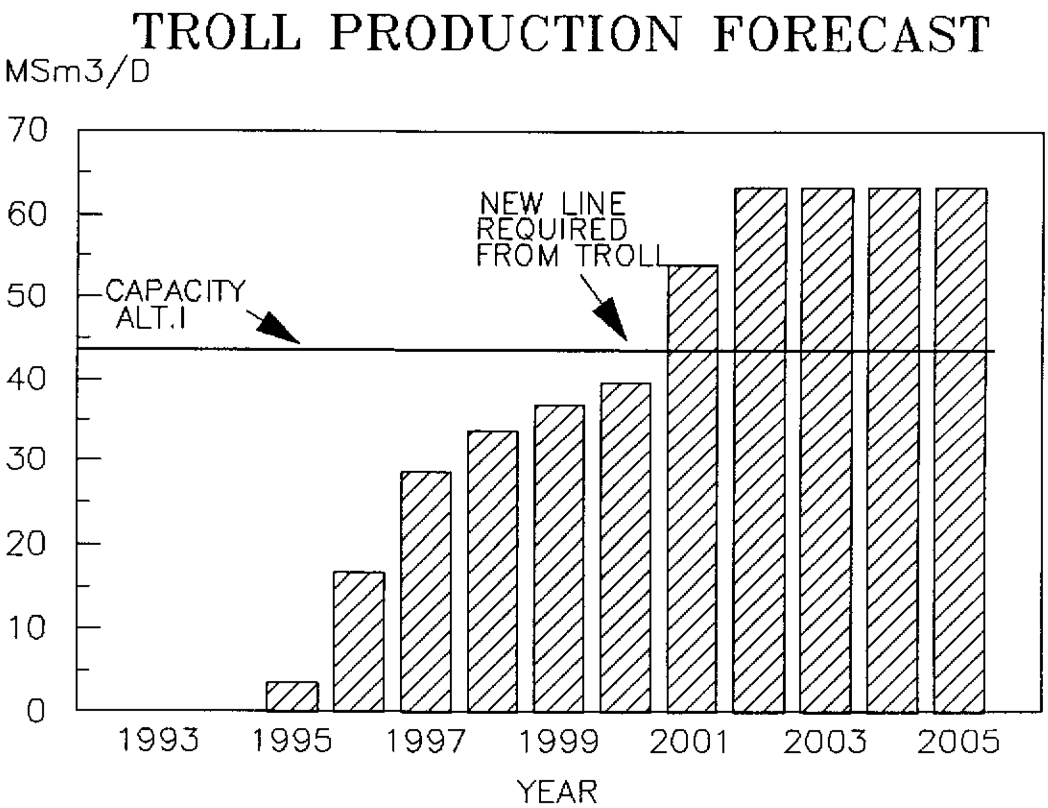
Attachment
V.1.5

TROLL VIA FRIGG ALT. I

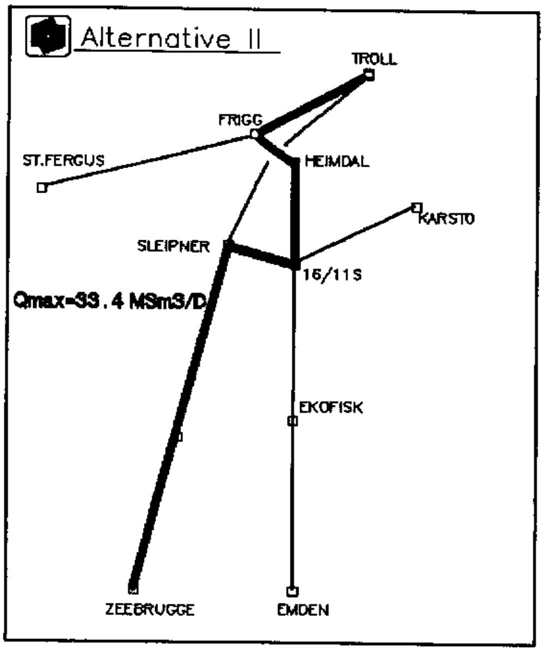


INSTALLATION SCHEDULE

1995: 40" PIPE TROLL-FRIGG
1995: NEW RP FRIGG
1995:40" PIPE FRIGG-SLEIPNER
2000:36" PIPE TROLL-HEIMDAL



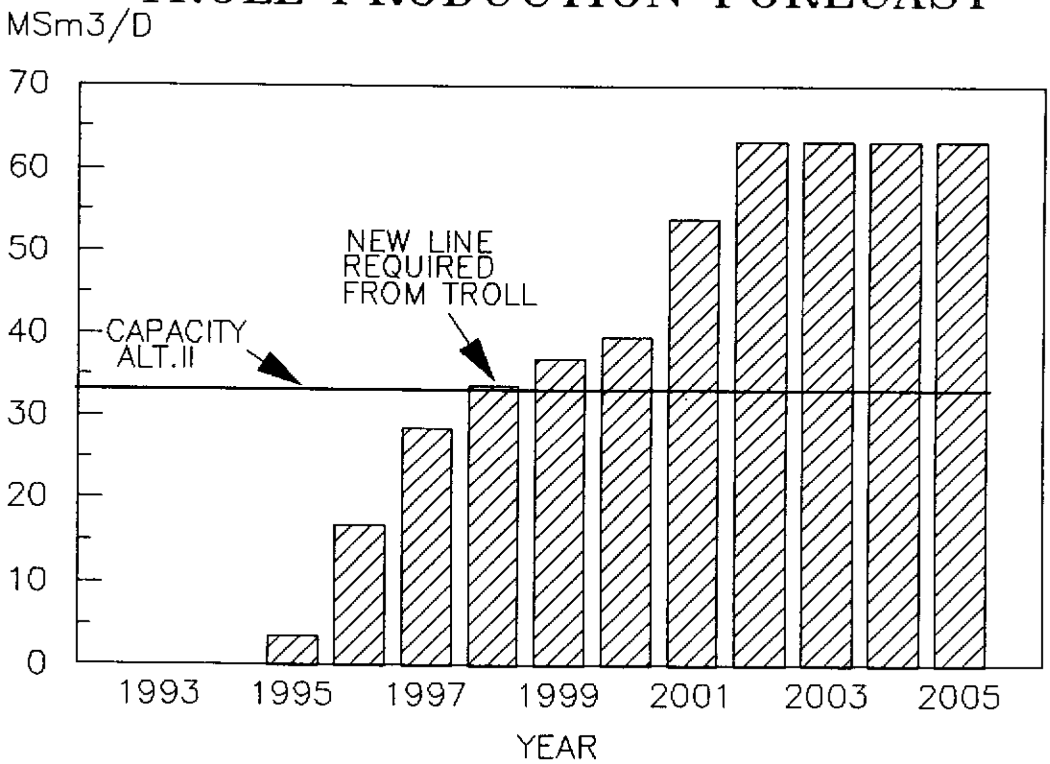
TROLL VIA FRIGG ALT. II



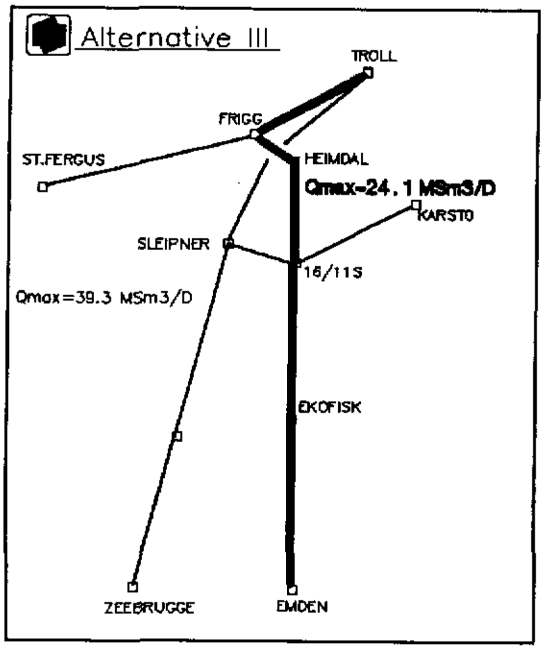
INSTALLATION SCHEDULE

1995: 40" PIPE TROLL-FRIGG
1995: NEW RP FRIGG
1995:36" PIPE FRIGG-HEIMDAL
1997:40" PIPE TROLL-SLEIPNER

TROLL PRODUCTION FORECAST



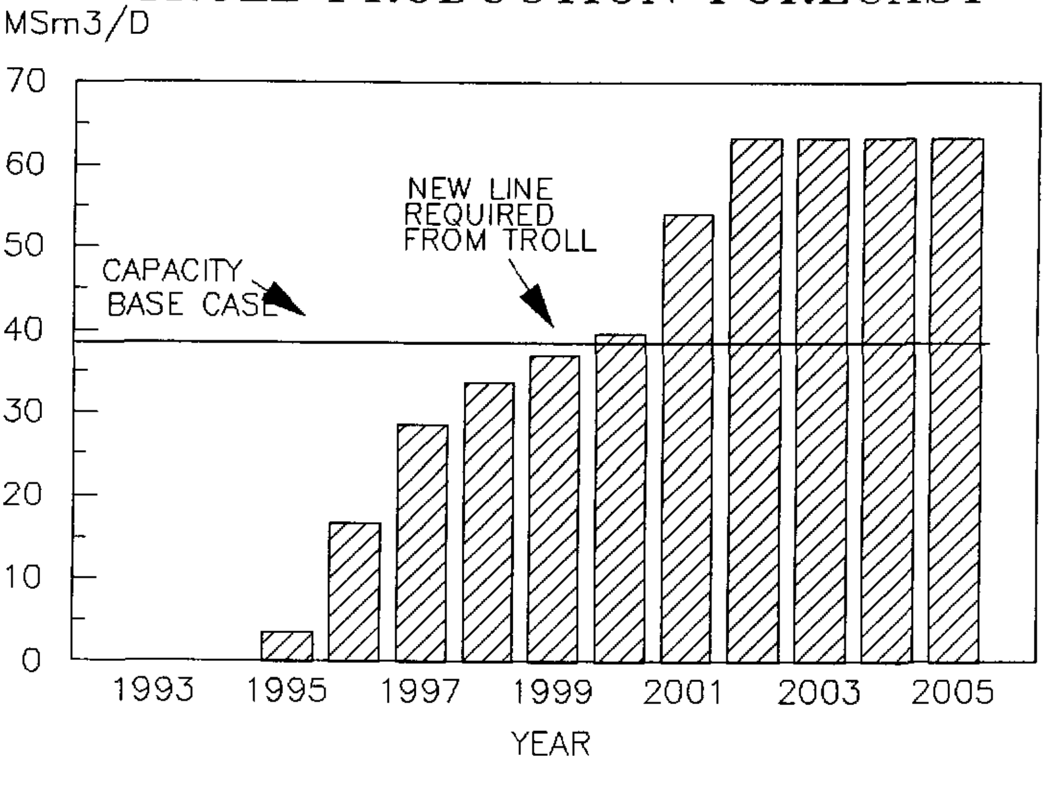
TROLL VIA FRIGG ALT. III



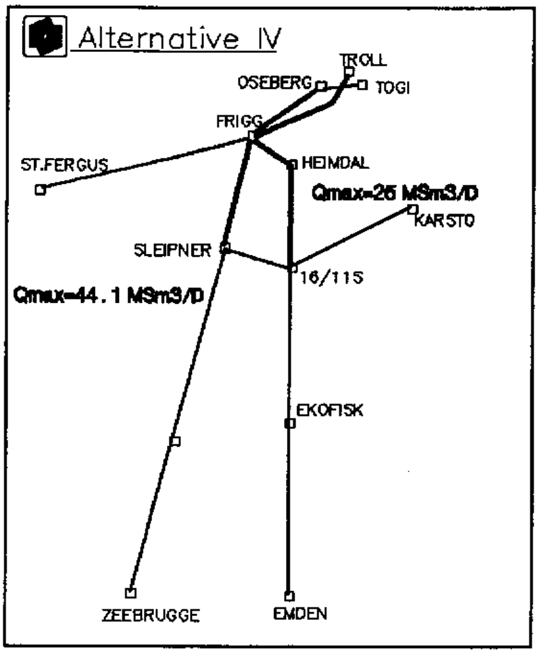
INSTALLATION SCHEDULE

1995: 40" PIPE TROLL-SLEIPNER
1999: NEW RP FRIGG
1999:40" PIPE TROLL-FRIGG
1999:36" PIPE FRIGG-HEIMDAL

TROLL PRODUCTION FORECAST



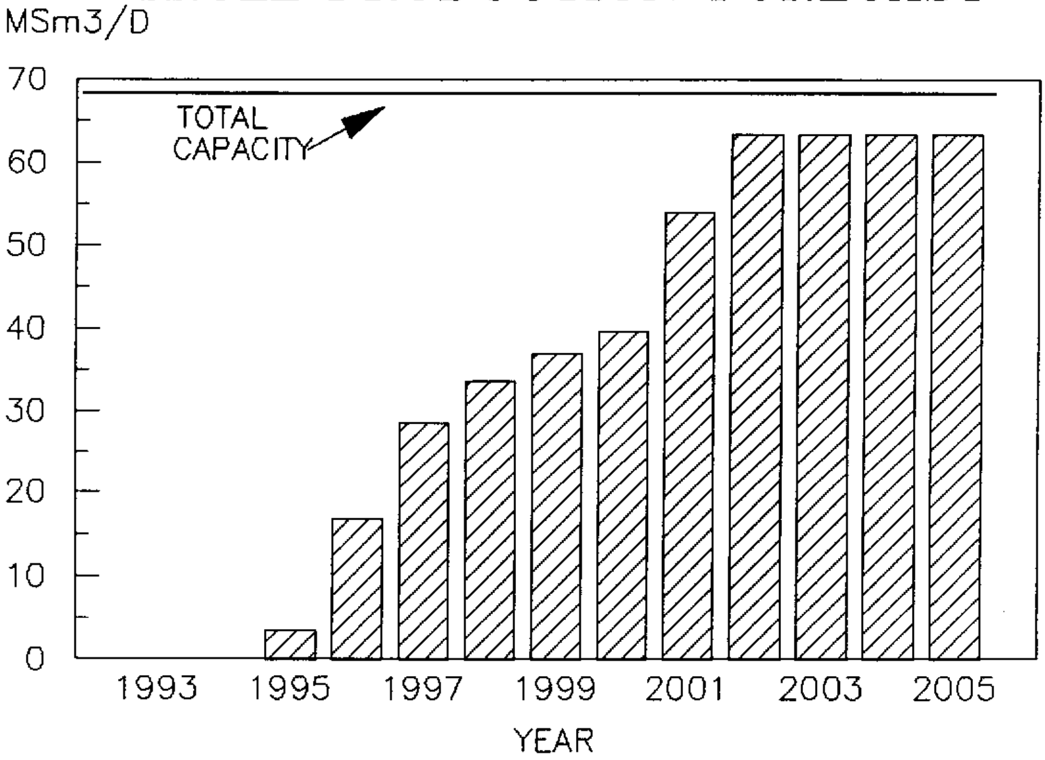
TROLL VIA FRIGG ALT.IV



INSTALLATION SCHEDULE

1995: 40" PIPE TROLL-FRIGG
1995: NEW RP FRIGG
1995:40" PIPE FRIGG-SLEIPNER
2000:32" PIPE OSEBERG-FRIGG
2000:36" PIPE FRIGG-HEIMDAL

TROLL PRODUCTION FORECAST



6.5 Summary of Frigg as a Role in Gas Export to The Continent

As seen from the four hereabove alternatives, Frigg could play a role in gas export from Norway to the continent, the following can be concluded:

- Use of Frigg compressors will not remove present bottlenecks in the gas grid to the continent, which are in Norpipe and Statpipe.
- Use of the Frigg compressor will optimize the capacity of the Sleipner-Zeebrugge leg and slightly increase the capacity.
- Use of the Frigg compressors can postpone investment for the Zeepipe/Troll projects.
- Use of the Frigg compressors can reduce the compression power requirement on Troll.

7 Liquid Export Solutions from Frigg

7.1 General

This analysis is performed to evaluate liquid export possibilities from the FRIGG area if required. As described in section 2.1 if a commercial Frig gas export pipeline specification is applied onto the Frigg export gas pipeline(s), a live crude export system will be required for the liquid.

7.2 Liquid Grid NW Sector (see attachment V-1.10)

NW Alt.1: Frigg - Sleipner - Ekofisk

This alternative is the "so called" base case solution for the Sleipner development. The solution from Sleipner consists of a 20" pipe between Sleipner and "Ula pipe" to Ekofisk. For the Frigg area the alternative is the one in NW sector with the longest pipe to lay. (i.e. 170 km). In addition capacity problems could occur in the pipeline between Ula and Ekofisk.
The solution is therefore not recommended.

NW Alt. 2: Frigg - Sleipner/Kårstø pipe - Kårstø

This alternative is a new alternative under study for Sleipner, where a new line is laid between Sleipner and the Kårstø terminal. Since the Kårstø terminal is a rich gas terminal, NGL treatment facilities already exist, but extension of the terminal will be needed.
Two different routes are assumed, a northern route would require 90 km of pipe to link Frigg to the Sleipner-Kårstø line, a southern route would require a leg of 145 km.
The advantages of this alernative is that the pipeline can be designed with a capacity to fit the future needs of the area.

NW Alt. 3: Frigg - Kårstø

This alternative assumes the laying of a separate 200km long line (16") to Kårstø. This proposal will not have the synergy with liquid from Sleipner, so all cost needs to be covered by potentials users of the Frigg area.
The alternative can of course also be designed to fit the needs.

NW Alt. 4: Frigg - Oseberg - Sture

This alternative requires a 90 km pipe to Oseberg for further transport to the Sture terminal. This alternative is not very attractive due to the presently applied stringent specification (i.e. Stab. crude spec. = 12 psi RVP and 0.5 % water content, BSW).
Such a specification would not be compatible with a dry (commercial) gas specification.
The tariff could be high and capacity problem could exist around 1995.
This alternative is not recommended.

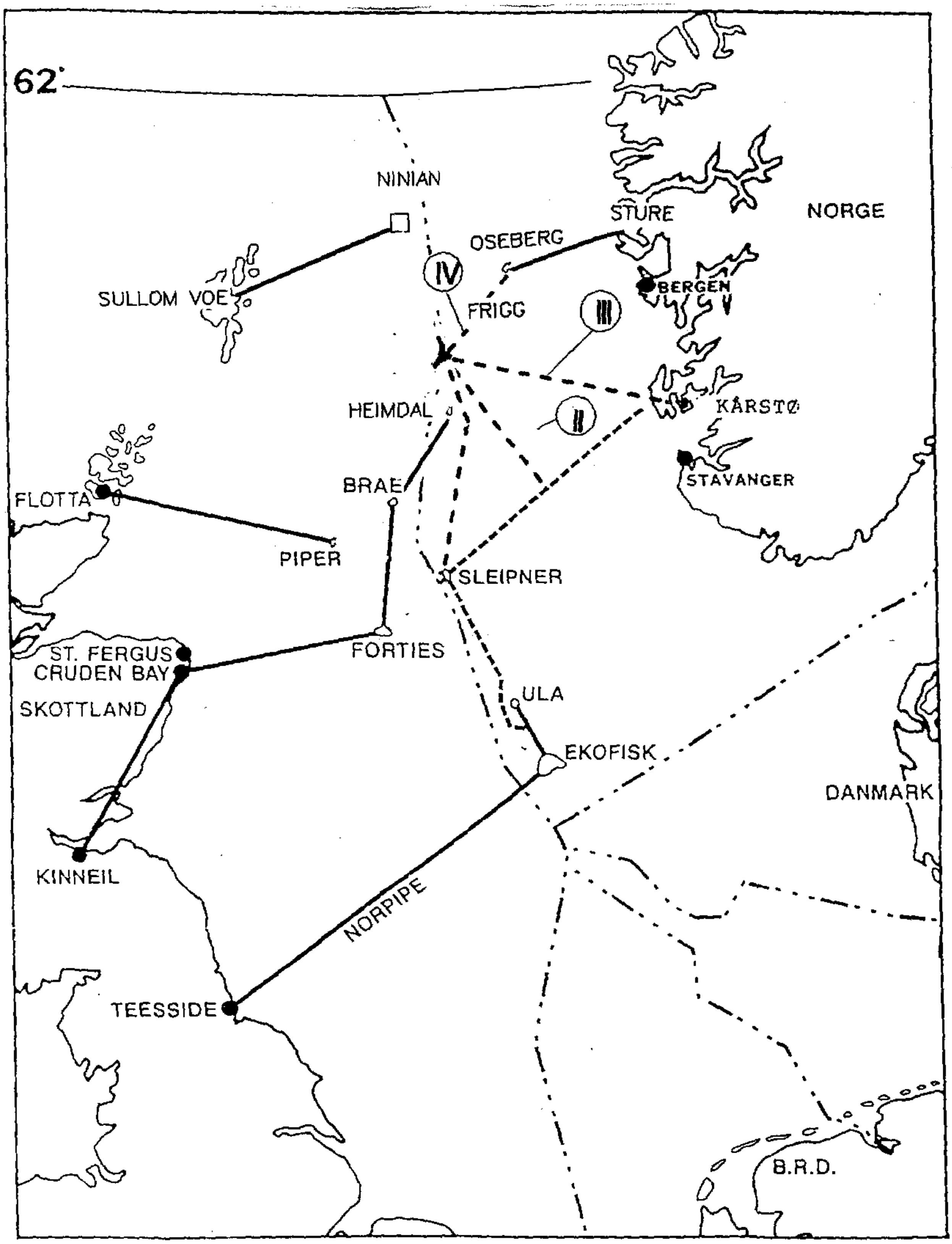
7.3 Liquid Grid UK Sector (see attachment V-1.11)

UK Alt.0 Reinjection into FRIGG UK-line

Studies have indicated that reinjecting smaller amounts of NGL's into the rich gas operated UK line could be feasible. The amount which could be injected is difficult to estimate and needs to be evaluated case by case. It will however affect the St. Fergus processing.
The total quantity is highly dependent on the acceptable liquid hold-up, which is not yet defined.
The capacity of liquid transportation of such a senario is limited.

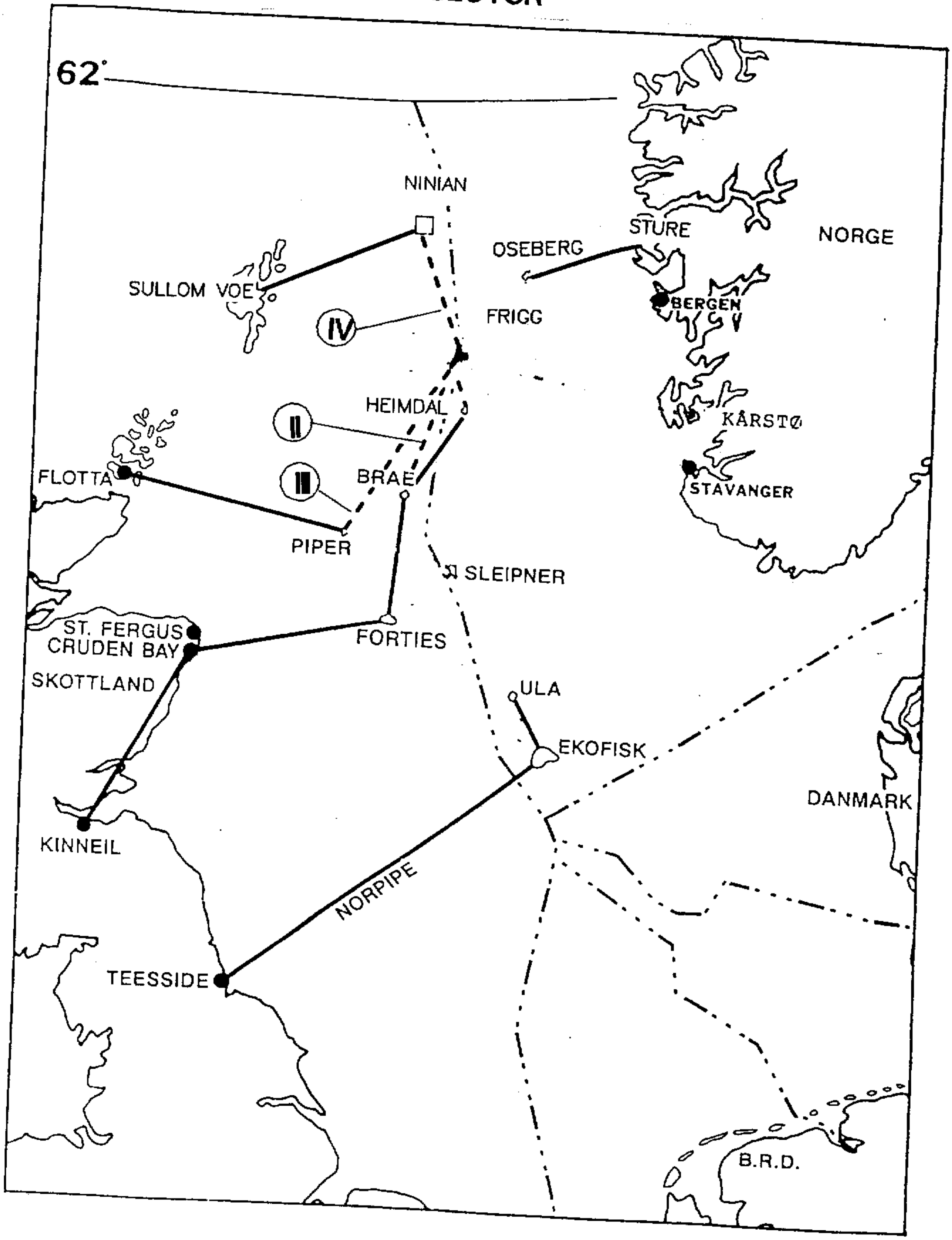
Attachment
V.1.10

FRIGG LIQUID EVACUATION
POSSIBLE ALTERNATIVES
NW SECTOR



Attachmer
V.1.11

FRIGG LIQUID EVACUATION
POSSIBLE ALTERNATIVES
UK SECTOR



UK Alt.1 Frigg - Heimdal - Brae

This alternative assumes an extension of the existing 8" pipeline from Heimdal to Brae, to Frigg for liquid export to Forties via Heimdal and Brae.

Capacities of system

Pipeline Size	Capacity (in)	(bbl/D)
Heimdal - S.Brae	8"	28 500 *
S.Brae - Forties C	30"	400 000
Forties - Cruden Bay	32"	650 000

* Note : The capacity of the HMP-Brae pipe depends highly on the specific gravity of the liquid, but in our calculation the Heimdal pipeline was simulated for transportation of both Heimdal and Beryl liquids (condensates). For these calculations it was assumed that Heimdal condensate production would be at present rates of 1255 T/day and Beryl production at 2405 T/day. The sum of the two rates 3660 T/D was very close to maximum capacity. With a sp. gravity of 0.8 this gives a total capacity as indicated.

Pipeline specification

The Forties system itself has a specification for TVP of 125 psi at 60^{O}F and is consequently a live crude line. The Heimdal-Brae pipe is however a stabilized crude with a specification of 12-14 psi RVP, which needs to be changed to the general Forties specification if it is going to be a good alternative for Frigg as a liquid export route. Since Forties and all the other entries are following this specification except Heimdal, no conversion problem is assumed.

Future booking

The future booking in the Forties system is uncertain, and depends highly on fields like Sleipner and Bruce, but with the present bookings (source Wood Mackenzie + BP) the following values could be indicated.

Year	Forties-Cr.Bay	Brae-Forties	HMP-Brae
1995	<200 000 bbl/D	<160 000 bbl/d	<10 000 bbl/D

In addition to several possible prospects are evaluated in the Forties area, which would increase the above values, but major increases could come if Bruce (85000 bbl/D, 1993) and/or Sleipner (105 000 bbl/D, 1993) are tied into the system.

Transportation tariffs

The tariff in the Forties system consist of two elements:

a) transportation tariff
b) treatment tariff

With reference to Heimdal, the transportation tariff could be as high as 4.5$/bbl.
The treatment tariff is based on the amount of raw gas at the Kerse of Kinneil terminal, and is defined as gas flashed off from the crude at the inlet separators of the terminal. The tariff could be as high as 35-40 pounds/tonnes. Having a light liquid exported through the system the total tariff could then end up as high as 10$/bbl.

Conclusion alt.1

Since the capacity of the Heimdal-Brae line could be limited and the total tariff could be very high this alternative would have limited application.

UK Alt.2 Frigg - Brae/Miller

This alternative assumes a new 148 km line to Frigg directly to Brae or Miller. Selecting 24" as pipe size gives a total capacity of 200 000 bbl/D of this line. With reference to arguments under alt.1 (i.e. Frigg-Hmp-Brae) the capacity of the Brae-Forties line could be a bottleneck, and is dependent on whether Bruce or Sleipner is tied in.
If Bruce is tied in it would also be simpler to route the new line to Bruce (35km) and then further to Forties.
This alternative with a direct line to Brae/Miller (or via Bruce) is certainly a better solution than using the limited Heimdal-Brae line in terms of transportation capacity. The main argument against export via Forties is as for Alt.1 the tariff and capacity, and would probably need a reduction if the solution is going to be attractive.

UK Alt.3 Frigg - Piper - Flotta

Connection to the Piper-Flotta system will require a new pipe of approximately 200 km.
The Piper platform was the starting point for the 210 km 30 inch diameter pipeline to the Flotta terminal in Orkney. The capacity of the pipeline is a nominal 560,000 b/d of oil.
Addition volumes of oil from Claymore joined the main pipeline via a T-junction. Several other fields pumped liquids into the Flotta system via Claymore : Scapa; Tartan, Highlander and Petronella. In addition, oil from the Ivanhoe/Rob Roy development is to be throughput from late 1989.
On the destruction of the Piper platform the entire Flotta system was necessarily closed down and the leg to piper was blinded off.

Future tie-ins to the system would probably need to enter via Tartan or by a sub-sea T.
Due to the distance from Frigg and complication for tie-in, the alternative is not believed to be attractive.

UK Alt.4 Frigg - Ninian - Sullom Voe

This proposal assumes a new 125 km pipeline to Ninian, either via Alwyn or directly.
The Ninian system, runs directly from Ninian Central to Sullom Voe. Production from Heather and Magnus is piped to the Central platform via 16 inch and 24 inch diameter pipelines respectively. Alwyn North is transported in a 12 inch diameter line to the Ninian Central platform. The resultant cocktail is pumped through a 36 inch line to Sullom Voe. The main Ninian oil pipeline has a theoretical capacity of 1 million b/d.

The Ninian system has significant spare capacity from 1993. with only a booking forecast of 220 000 bbl/D, decreasing drastically the years after.
It has been indicated a tariff of 0.8 pound/bbl as transportation tariff from Ninian to Sullom Voe (compared to 2.80 pounds/bbl for Heimdal to Forties). For gas off treatment the tariff is 25 pounds/tonnes compared to 35 - 50 pounds/tonnes for Alwyn and Bruce.

Comparing the possible tariff level, spare capacity and distance from Frigg the solution exporting via Ninian is prefered to any of the Forties solutions.

It should be noted that if Bruce is given a better offer than the indicated pound 1.25 pounds/bbl and 40 pounds/tonnes, the Forties solution could become more attractive due to shorter distance to Bruce (i.e. 35km). But if Bruce is selecting Ninian, this will be even better.

CHAPTER VI

POTENTIAL FUTURE CUSTOMERS

CHAPTER VI - PART 1

Ordinary Field Service

1.1 Introduction

The basic potential users of Frigg Facilities are gas or oil fields, for which use of facilities that Frigg could offer, would make economics more attractive. In order to be able to identify these fields, an inventory of the existing and potential fields within a large area around Frigg has been conducted.

Table 1 of attachment A gives a list of these fields, on the Norwegian side, with some of their main characteristics. They have been listed according to the following four types:

* **developed fields** : fields which have either been developed or for which decision of development has already been taken,
* **undeveloped fields** : fields whose extension is relatively well known and for which development schemes have been studied but decision of development not taken yet,
* **discoveries,**
* **prospects** : potential accumulations not yet drilled.

Apart from these identified objects, the area still presents exploration potential, mostly at jurassic level, with high pressure condensate gas as the most likely fluid.

From the above table we have defined the following three different types of potential clients:

- fields which are far from Frigg, but which could use Frigg Facilities mostly because it is the starting point of gas export pipelines. These fields are:
    * **Troll**
    * **Oseberg**
    * **Gullfaks South**
    * **34/8**
    * **Huldra**
- small gas fields with gas composition similar to Frigg:
    * **30/10 Paleocene**
- small fields with high condensate content gas. These fields can be either gas condensate fields or oil fields:
    * **Frøy**
    * **25/2 -12**
    * **30/10 Jurrasic**
    * **Hild**

* 25/4 FF'

* 25/2 -5

* 25/3

* 24/6

Table 2 of attachment B gives possible gas profiles for these fields.

Below each group of fields have been reviewed in more detail in order to define what kind of service these fields would like to see provided by Frigg, which alternative they have and what could be the timing.

A similar inventory of fields on the UK side is being performed by Elf UK. Apart from the large fields (Alwyn, Bruce and Beryl) for which Frigg Facilities are or could be used for gas transit, no discovery or defined prospect worth developing for which Frigg Facilities could be used has been identified. Total estimated recoverable reserves for existing discoveries are less than 5 BSCM of gas in several accumulations. Neverthless, the area still presents exploration potential, mostly at the Jurassic level with high pressure condensate gas as the most likely fluid.

1.2 Fields far from Frigg

These fields could be developed independently of Frigg. However, gas from these fields might be sent to Frigg as long as pipelines from Frigg provide them with an attractive access to the market they shall serve. Gas arriving at Frigg from these fields will most likely already have been dehydrated.

1.2.1 Troll

This giant gas condensate field is about 125 km North-East of Frigg. At the present time, plans are to process the gas to commercial specification at the field and to send it to Emden and Zeebrugge through a direct Troll - Sleipner pipeline with production starting 1. October 1996. This pipeline would be supplemented later when necessary by a Troll - Heimdal pipeline (these two pipelines constitute phase 2 of the Zeepipe, which is not yet firm).

With the present field development scheme, Troll gas will most likely be sent to Frigg if new Norwegian gas is sold to UK. The Frigg Norwegian pipeline will in such case be the most logical transportation route.

Troll gas may also be sent to Frigg if a pipeline via Frigg is more attractive to the Troll partners than a direct Troll - Sleipner or Troll - Heimdal pipe. The potential use of available Frigg compression capacity could make this scheme attractive to the Troll partners.

As Troll gas will be of commercial specification, services that Frigg Facilities could provide are:

- transit

- transportation

- recompression

Services to be provided by Frigg will not be of a very high unit value, but this might be compensated by large quantities.

An alternative development scheme which is being looked at by the operator consists of installing all the process onshore with direct transfer of the raw wellstream to shore. One direct competitor to this scheme would be to send the raw wellstream to Frigg and process it on Frigg.

Partners at the Troll field are:

Shell,	Operator of development phase I :	8.288%
Statoil,	Operator of production phase I :	74.576%
Norsk Hydro,	Operator of phase II:	7.688%
Saga:		4.080%
Elf:		2.353%
Conoco:		2.015%
Total:		1.000%

1.2.2 Oseberg

This oil and gas field is located about 85 km North-East of Frigg. When oil has been depleted, gas will be produced for sale. About 80 BSCM of gas will be produced for sale starting around 2002. Planned production rate at present is about 5.3 BSCM/year.

No sales contract has yet been entered into for sale of this gas.

When the initial Field Development Plan was issued in 1983, a preliminary study of the modifications which would be required to process 5.3 BSCM/year of gas to Continental commercial specification was performed and the corresponding investments included in the total field investment schedule. Since then, the development scheme has been modified in a way which could make this processing more difficult. Despite of this, the above mentioned study has not been updated

During the oil production phase, gas from a subsea cluster on the Troll field (TOGI) is being supplied to Oseberg for injection. During the gas production phase this will still be available for gas production, thus increasing the potential requirement for gas process capacity.

In the Field Development Plan it was envisaged to send the gas via Frigg if the gas was sold to the UK market. If so this would require construction of a 85 km pipeline to Frigg or a 50 km pipeline tied to the Alwyn - Frigg line (rich gas solution).

Gas could also be sent via Frigg for sale to the Continent if a pipeline between Frigg and the Statpipe - Zeepipe network exists (Frigg - Heimdal or Frigg - Sleipner).

If gas is processed to commercial specification on Oseberg, the services which could be provided by Frigg are:

- transit

- transportation

- recompression (although the compression power installed on Oseberg might be enough).

Hydrocarbon removal on Frigg is also a possibility that might be of interest to the Oseberg partners as when Oseberg gas production starts it could prove to be cheaper (existence of part of such facilities on Frigg at that time, high modification cost on Oseberg, technical problems with liquid export).

The other alternatives for Oseberg are:

- send rich gas to the Statpipe dense phase line through an already installed subsea connection,

- send commercial gas to Statpipe via Heimdal,

- send rich gas to UK via Brent and the FLAGS system (this solution is not mentioned in the FDP).

Partners at the Oseberg field are:

Norsk Hydro, Operator:	13.75%
Statoil:	65.04%
Elf:	5.60%
Total:	2.80%
Mobil:	4.20%
Saga:	8.61%

1.2.3 Gullfaks South

This oil and gas field is located about 130 km due North of Frigg, but only 5 km South of Gullfaks. No Field Development Plan has yet been filed. Plans for this field are very vague as oil reserves have recently been upgraded following the results of a new appraisal well. Gas could be processed either on site on a new platform or on Gullfaks facilities. It appears now that gas delivery could not start before 1997/1998. After this date it will depend on the market.

Commercial gas sold to UK could go to Frigg through a direct 135 km pipeline. An attractive solution for gas sold to UK could be to send the gas in dense phase to Alwyn only 45 km away and on to Frigg. Final export to UK could be either in dense phase or as commercial gas after processing on Frigg, depending on the lines configuration. Accordingly the services to be provided by Frigg could be:

- transit,
- transportation,
- recompression,
- hydrocarbon removal.

A direct competitor to the above solution would be to send rich gas to UK via Statfjord and the FLAGS system.

Gas sold to the Continent would normally be exported in dense phase through Statpipe. Capacity limitation between 16/11 S and Ekofisk or high Statpipe tariff could also make a route via Frigg attractive if Frigg - Sleipner link exists already.

Partners at Gullfaks South are:

Statoil, Operator:	85%
Norsk Hydro:	9%
Saga:	6%

1.2.4 34/8

This discovery is located about 165 km North of Frigg, 25 km from Gullfaks C and 30 km from Statfjord in 380 m water depth. It consists of two structures, one containing essentially gas, the other (discovered in October 1988) containing oil and gas. Uncertainties in reserves estimate are high.

The operator, Norsk Hydro, wanted to push development of this field in order to be able to deliver gas to the UK market as early as 1994. This to take advantage of the Frigg decline before Troll being ready. Their plan called for gas to be sent in dense phase to Frigg through a direct 165 km pipeline from a floating production ship. The plan was based on optimistic reserves estimate and a very optimistic schedule.

At the present time, reserves are being evaluated and a start-up earlier than 1995 is unrealistic.

The alternatives for gas export from 34/8 are similar to those for Gullfaks South, although as development will most probably be based on a floater, gas would be exported in dense phase. In the competition towards a sale contract to UK, the only advantage of 34/8 with respect to other Norwegian competitors (Troll, Gullfaks South) is a slightly earlier possible start-up.

The services that Frigg could provide to 34/8 are:

- transit
- transportation
- recompression
- hydrocarbon removal

Partners at 34/8 are:

Norsk Hydro, Operator:	18%
Statoil:	50%
Conoco:	13%
Elf:	13%
Saga:	6%

1.2.5 Huldra

No Field Development Plan has been filed for this relatively small condensate gas field. It will most probably be developed as a satellite of Gullfaks South: Therefore its production will go through Frigg only if the production of the field which it will be tied to goes via Frigg. It has to be noted that the high CO_2 content of this gas (3.5 to 4 %) will require either dilution or CO_2 removal.

Partners at Huldra Are:

Statoil, Operator:	50%
Union Oil:	25%
Conoco:	25%

1.3 Small Gas Fields With Gas Composition Similar to Frigg

1.3.1 30/10

There is only one prospect of this type for the time being. The prospect is located on block 30/10 about 30 km from the Frigg platforms.

Due to its small size the most attractive scheme is to develop it as a full satellite with direct wellstream transfer to Frigg. The services to be provided by Frigg would be the same as the ones provided to East-Frigg.

Assuming a discovery mid. 1990, production could start in 1996.

The prospect could also contain oil.

Partners on this prospect are:

Elf, Operator:	40%
Statoil:	50%
Saga:	10%

1.4 Condensate Gas Fields

1.4.1 25/2-12

This discovery is located about 23 km North-East of the Frigg complex. A DST has recently been performed on the second well drilled on the structure which contains high pressure condensate gas. Although the fluid composition is not fully known, the most likely development scheme will be as a full subsea satellite of Frigg. Raw wellstream will arrive at Frigg and will have to be processed to export specifications. A condensate export line from the area will most probably be required.

After having evaluated the result of well 25/2-12, decision of development will have to be taken. Earliest possible start-up date is mid. 1996.

Partners on this discovery are:

Elf, Operator:	41.42%
Norsk Hydro:	32.87%
Total:	20.81%
Statoil:	5.00%

1.4.2 30/10 Jurassic

This prospect is located about 23 km from the Frigg platforms. If it is gas bearing it will most probably contain high pressure and high condensate content gas.

The most attractive development scheme will be as a full satellite to Frigg using either subsea wells or satellite wellhead platform. Services to be provided by Frigg will be similar to those for 25/2-12.

Seismic interpretation will be completed mid. 1989 with well location defined end of summer. Production start-up may come at end of 1995 at the earliest.

Partners are the same as on the 30/10 Paleocene prospect.

1.4.3 Hild

Five wells have already been drilled on this accumulation discovered in 1978. It is located about 65 km North of Frigg and contains high pressure gas (740 bars at 3750 m MSL) with about 160 g/SCM of condensate and 3.5 % CO_2. It is very complex on a reservoir point of view and uncertainty on reserves is high. A preliminary study based on an independent development with a jacket showed this solution to be uneconomic.

A preliminary two phase flow analysis indicate that a development of Hild as a full satellite of Frigg might be a feasible solution. The scheme would then be very similar to 30/10 Jurrasic with the increased difficulty of the CO_2 content.

The only other possibility would be to develop the field as a satellite of Alwyn.

There are no firm plans concerning future work on this field.

Hild accumulation is on licence no 040 (blocks 29/9 and 30/7) and no 043 (blocks 29/6 and 30/4) and might even extend in UK waters. Assuming a split of 25% in Pl no 040 and 75% in Pl no 043, the partners shares would be:

BP, Operator on Pl no 043:	37.5%
Statoil:	50.0%
Norsk Hydro, Operator on PL no 040:	1.7%
Elf:	7.2%
Total:	3.6%

1.4.4 25/4 FF'

This prospect is located about 22 km South-East from Frigg and 16 km North of Heimdal. If it is gas bearing it will contain gas at relatively high pressure (590 bars at 3500 m) and with a high condensate content. A preliminary evaluation study assuming this prospect developed as a satellite of Frigg with subsea wells and full wellstream transfer directly to Frigg shows attractive economic results.

Services to be provided by Frigg would be the same as for 25/2-12.

Assuming discovery mid. 1990, production could start mid. 1996.

This prospect could also contain oil.

The partners on this prospect are:

Elf, Operator:	26.32%
Marathon:	46.90%
Sunningdale:	7.38%
Norsk Hydro:	6.92%
Total:	5.54%
Saga:	6.61%
Ugland:	0.32%

1.4.5 24/6

High pressure, high condensate content gas has been discovered on this block operated by Total Marine Norsk A.S. Very likely, the accumulation straddles the boarder to UK. Elf UK is a partner on the UK part. The discovery is located about 30 km South of Frigg and 18 km from Heimdal. The distance to Bruce and Beryl is about the same. Because of the limited reserves, development as a satellite with full wellstream transfer to one of these fields is the most likely solution.

Partners on the Norwegian side are:

Total, Operator:	30%
Statoil:	50%
Union Oil:	20%

1.5 Oil Fields

The known oil field or prospects are too far from Frigg to assume full wellstream transfer to Frigg with all the facilities on the Frigg platforms, thus requiring some on-site facilities. Associated gas from these fields have a high NGL content. The services that Frigg could provide to such fields, apart from gas export, have been extensively studied for the field Frøy. These studies (which assume that Frigg Facilities are as today), show that it is difficult, but not impossible depending on the circumstances, for Frigg to provide such services on an economically attractive basis.

From these studies it also appears difficult to make combined development of all the presently known discoveries and prospects with minimum facilities (wells and first stage separation) on each field and all other facilities on Frigg, economically more attractive than separate developments with on-site facilities.

1.5.1 Frøy

This oil field is located about 35 km South-East from Frigg.Extensive preliminary development studies have been conducted for the last 18 months. The present base case assumes water injection; separator gas will arrive at Frigg at about 40 to 50 bars and will have to be processed to export specifications. Power will be supplied by Frigg. Nevertheless, gas reinjection seems to present some interest and the attractiveness of power supply from Frigg is marginal.

According to present plans, production start-up would take place at the end of 1995.

The Frøy accumulation is on licence no 102 (block 25/5) and no 026 (block 25/2) but has not been unitized yet. Assuming a 75/25 split between both licences, the partnership would be:

Elf, Operator on both licences:	33.4%
Shell:	15.0%
Statoil:	37.5%
Norsk Hydro:	8.65%
Total:	5.45%

1.5.2 25/2-5

This small discovery is located between Frøy and Frigg at about 8 km from Frøy. It will most probably be developed as a satellite of Frøy and might have an impact on Frigg only through Frøy.

The partners are the same as on the 25/2-12 dicovery.

1.5.3 25/3

This oil prospect is located about 38 km East of Frigg. It is very similar to Frøy and the conclusion of the development schemes studies performed for Frøy will apply.

Assuming a discovery in 1989, start-up could take place in 1997.

The partners are:

Elf, Operator	20%
Statoil:	50%
Norsk Hydro:	12%
Esso:	10%
DNO:	8%

1.6 Conclusions

From the above analysis, we can conclude the following:

- We have identified a good number of fields, discoveries or prospects on the Norwegian side for which Frigg Facilities could be used, either as they are today or after modifications more or less extensive.

- Fields for which Frigg Facilities could be used are of three main categories:

  * fields far from Frigg for which use of Frigg Facilities is one of several possible alternatives. The services which could be provided to such fields on Frigg Facilities are:

    - transit

    - transportation to UK

    - gas compression

    - removal of heavy components to put gas to commercial specification.

  * small gas fields for which use of Frigg Facilities is the only economic scheme. They would be developed as full satellites of Frigg,

  * small oil fields close to Frigg from which associated gas could be sent for process and export.

- Whether or not the identified potentialities concerning fields far from Frigg will materialise is quite uncertain today. Outcome of decision on most of them will depend to a large extent on future decisions or opportunities unrelated to Frigg. They will also be influenced by decisions concerning Frigg.

- Most of the small accumulations for which Frigg Facilities could be used are only prospects. Until they are drilled, uncertainty on the services to be provided by Frigg will remain high.

- Possibilities of using Frigg for activities other than those related to gas processing and export appear marginal.

- Linking Frigg by a gas pipeline to the Statpipe - Zeepipe network would greatly increase the probability of using Frigg Facilities for other fields. The best solution would be a Frigg - Sleipner pipe.

- Development of the small fields or prospects close to Frigg would require that facilities for processing high condensate content gas to export specification are available on Frigg. This would require most probably a high vapour tension liquid export line from Frigg.

ATTACHMENT VI - 1.1

TABLE 1

Potential users of Frigg Facilities

NAME	TYPE	HYDROCA.	RESERVES Gas BSCM	RESERVES liquid MT	DISTANCE TO FRIGG km	OPERATOR	EARLIEST START-UP
Troll	Dev.	Cond.gas	1300	39	125	Statoil	1996
Oseberg	Dev.	Oil/gas	80	156	85	NH	Gas:2001-2003
Gullfaks S	Undev.	Oil/gas	70	35	130	Statoil	Gas: 1997?
Frøy	Undev.	Oil/gas	5.4	17	35	EAN	Gas: Dec.1995
Huldra	Undev.	Cond.gas	14	4	110	Statoil	
34/8	Disc.	Oil/gas	40	14	165	NH	1995
25/2-5	Disc.	Oil/gas	1 to 2	4 to 8	25	EAN	
25/2-12	Disc.	Cond.gas	8	3.3	23	EAN	1995
Hild	Disc.	Cond.gas	11.1	1.46	65	NH	
24/6	Disc.	Cond.gas	6		32	TMN	
30/10 jur	Pros.	Cond.gas	14 to 34	5.8 to 14	31	EAN	1996
30/10 pal	Pros.	Cond.gas?	8 to 15	0.03 to 0.05	33	EAN	1996
25/3	Pros.	Oil/gas	4.3	13	37	EAN	Dec.1995
24/4 FF'	Pros.	Cond.gas?	10 to 14	3 to 4	22	EAN	1996

Dev. = Developed fields
Undev. = Undeveloped fields
Disc. = Discoveries
Pros: = Prospects

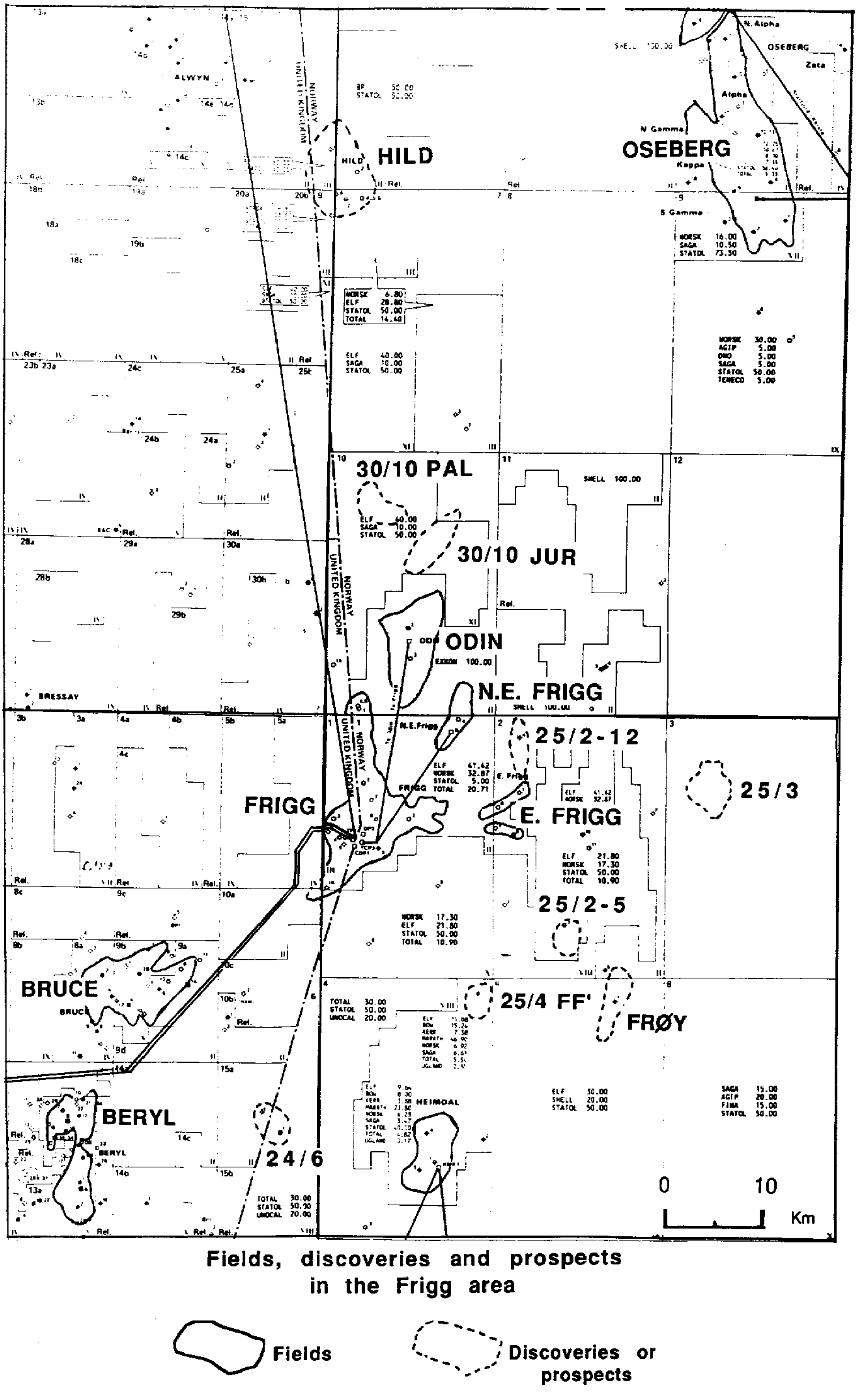
ATTACHMENT VI - 1.2

TABLE 2

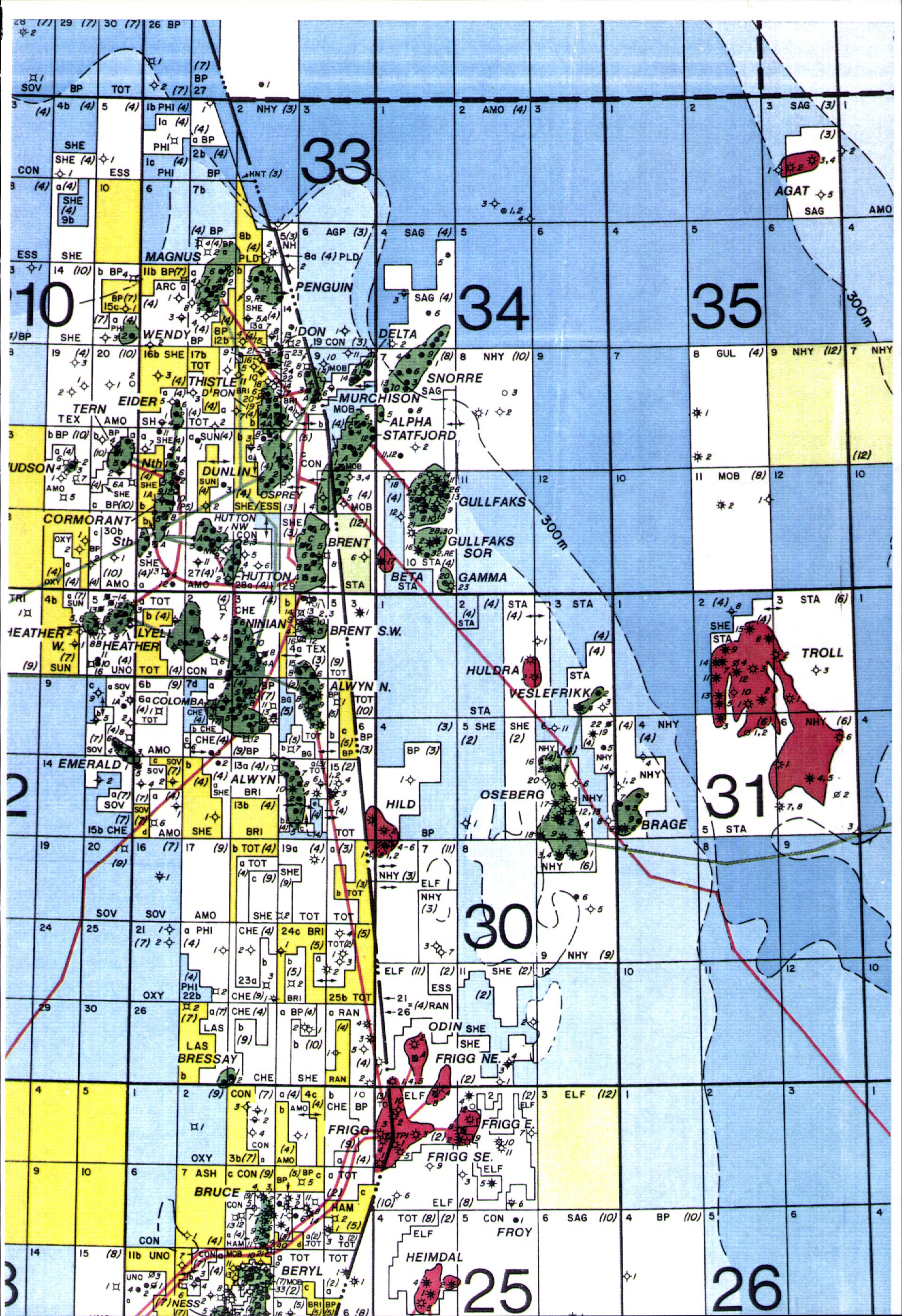
Possible Production Profiles

YEAR	25/2-12		FRØY		24/4 FF		30/10 JUR	
	Gas BSCM	Cond MT	Gas BSCM	Cond. MT	Gas BSCM	Cond MT	Gas BSCM	Cond. MT
1	1.2	0.74	0.81	0.174	1.5	0.6	2.1	1.15
2	1.2	0.69	0.81	0.174	1.5	0.52	2.1	1.00
3	1.2	0.55	0.81	0.174	1.5	0.47	2.1	0.90
4	1.2	0.46	0.81	0.174	1.5	0.42	2.1	0.81
5	1.2	0.38	0.65	0.139	1.5	0.37	2.1	0.71
6	1.0	0.29	0.52	0.111	1.05	0.24	1.47	0.46
7	0.6	0.19	0.42	0.090	0.73	0.17	1.022	0.33
8	0.4	0	0.33	0.071	0.51	0.12	0.714	0.23
9			0.25	0.054	0.21	0.09	0.294	0.17
Total	8	3.3	5.41	1.16	10	3	14	5.77

YEAR	30/10 PAL		HILD		25/3	
	Gas BSCM	Cond MT	Gas BSCM	Cond. MT	Gas BSCM	Cond MT
1	1.2	0.0042	1.55	0.285	0.648	0.139
2	1.2	0.0042	1.55	0.285	0.648	0.139
3	1.2	0.0042	1.55	0.260	0.648	0.139
4	1.2	0.0042	1.55	0.226	0.648	0.139
5	1.2	0.0042	1.24	0.168	0.520	0.111
6	1.0	0.0035	0.99	0.116	0.416	0.089
7	0.6	0.0021	0.79	0.067	0.336	0.072
8	0.4	0.0014	0.64	0.024	0.264	0.057
9			0.51	0.009	0.200	0.043
10			0.41	0.009	0	
11			0.33	0.009	0	
Total	8	0.028	11.1	1.46	4.3	0.93



Fields, discoveries and prospects in the Frigg area



33
34
35
10
2
31
30
25
26
AGAT
MAGNUS
PENGUIN
WENDY
DON
DELTA
SNORRE
THISTLE
TERN
EIDER
MURCHISON
ALPHA
STATFJORD
HUDSON
DUNLIN
OSPREY
GULLFAKS
CORMORANT
HUTTON NW
HUTTON
BRENT
GULLFAKS SOR
BETA
GAMMA
HEATHER
NINIAN
LYELL
BRENT S.W.
TROLL
HULDRA
VESLEFRIKK
ALWYN N.
COLOMBA
EMERALD
ALWYN
HILD
OSEBERG
BRAGE
ODIN
FRIGG NE.
BRESSAY
FRIGG
FRIGG E.
FRIGG SE.
BRUCE
FROY
HEIMDAL
BERYL
NESS
300m

CHAPTER VI - PART 2

Frigg as a Gas Storage

Introduction:

The Frigg reservoir has shown good characteristics for gas containment and drainage, process and export facilities will be available once the original reserves have been exhausted. Therefore, the question of using Frigg as a gas storage comes naturally to mind.

2.1 Technical Aspects

The technical aspects concerning the use of Frigg as a gas storage relate to:

- reservoir considerations
- wells
- process requirements
- compression requirements

They will depend on:

- the total volume to be stored
- the maximum storing rate
- the maximum destoring rate
- the injected and sold gas specifications

2.1.1 Reservoir Considerations

Past experience shows that good reservoir sealing and good reservoir properties, which are key characteristics for a gas storage are present in the Frigg Reservoir.

Once Frigg reservoir has been fully depleted, pressure in the aquifer will tend to equalize and increase back to the original static reservoir pressure of about 190 bars. Gas corresponding to a residual saturation of 30% at abandonment pressure will remain trapped throughout the reservoir.

When gas is injected into Frigg, it will migrate towards the top of the reservoir and push down the horizontal gas-water contact at constant pressure. As this contact goes down, injected gas will mix with residual Frigg gas.

There are two structural tops on Frigg: the highest one below CDP1 platform and a secondary one below DP2 separated by a saddle. If only wells below DP2 are used, the volume of gas above the saddle below CDP1 top will be a dead volume. Figure 1 shows a CDP1-DP2 cross section of the field. To fill up the volume above the saddle under CDP1 top, about 900 10^6 Sm^3 of gas will have to be injected. Figure 2 gives the net injected (total injected minus total produced) gas volume expressed in Sm^3 versus depth of the gas-water contact (at two different scales).

Potential gas losses in the reservoir are due to trapping of gas, but if we assume that swept volumes are identical for two successive cyles of storing and production, gas losses will occur only once. In fact, there will already be a significant volume of trapped gas left in the reservoir at the end of original production, the total gas loss will be roughly equal to the volume lost by compression by this original trapped gas in the swept volume. Assuming an original abandonment pressure of 150 bars and a residual gas saturation of 30%, the lost gas volume will be about 10% of the total net injected (injected minus recovered) volume.

2.1.2 Wells

Of course, wells must be available for gas injection and production. As present plans are to abandon CDP1 wells, we will assume that only wells from DP2 will be used. This implies that DP2 will remain a "hot" platform.

Present DP2 wells can be used without any modification for gas withdrawal, unless corrosive gas is stored. (Frigg gas contains about 0.3% CO_2). The possible production rates will depend on the gas-water contact level, but rates will be similar to the ones achieved during initial field decline.

It should also be possible to use the same wells for injection. A minimum injection wellhead pressure of about 190 bars will be needed, giving an average injection rate of 2 10^6 Sm^3/day/well. This should be confirmed by injection tests.

If only a small storage volume is required, it might be worthwhile to use a well located under the CDP1 structural top. Such a well could be drilled from DP2 or even be a subsea well.

2.1.3 Process Requirements

Unless arriving from a very close nearby field, incoming gas at Frigg will be at a temperature close to sea-water temperature, it will have been processed or treated in such a way that it will be outside the hydrates formation domain and that no significant hydrocarbon condensation will have occurred in the line. Methanol or glycol could have been injected in order to prevent hydrates formation. The gas would go through a scruber which will recover any trace of liquid and then directly to the compressors, some injection of hydrate inhibitor might be required downstream the compressor to avoid hydrates formation in the TCP2-DP2 line if small quantities of non-dehydrated gas are injected. No other processing of incoming gas before storage should be required.

Stored gas will saturate with water at reservoir conditions, it will then have to be dehydrated when produced.

Also, any gas stored in the Frigg reservoir will mix with residual Frigg gas, because of the nature of the heavy components in the Frigg gas, gas produced from the storage will not meet hydrocarbon dew point specification for commercial gas, even if it met such specification before storage. Of course, final process requirement will depend on the composition of injected gas and the specification of export gas.

2.1.4 Compression Requirements

Gas will have to be compressed before injection to a pressure in the range of 190 to 200 bars. We might have problems to use existing equipment as the maximum compressor outlet service pressure is 150 bars. A detailed engineering study will be necessary to see if it can be increased to the required level. The 26" lines between TCP2 and DP2 also have a maximum service pressure of 170 bars, although with minimum modifications, moderate gas quantities could be injected through the 8" kill line.

During production, gas pressure regime will be close to what it was during early field production, no compression will be required upstream the glycol contactors. Depending on the type of hydrocarbon removal process (if any) and the flow rate, export compression might be needed. But, as injection and production will never occur at the same time, it should be possible to use the same compressors for injection and export.

2.2 Commercial Aspects

The main point concerning the commercial aspect is the ownership of the gas present in the reservoir at any time once injection has begun: the gas cushion (the minimum gas volume necessary in the reservoir) represents a sizeable amount of money which can be recovered only when the storage is no longer in use. If it is owned by the storage, it represents a large front-end investment.

2.3 Possible Types of Gas Storage

A gas storage is used when the gas flow required by the end consumers is different from the one which can be provided by the supplying field (or fields) at the end consumers locations.

Frigg could be used as a gas storage for the following cases:

- transform an oil field associated gas profile into a gas profile which could be sold easily, this could even involve storing gas until a gas sale contract is found

- provide modulation for a gas field above the maximum instant capacity. Such a field could then deliver, on a yearly average, a flow rate equal to its maximum capacity

- provide substitution during field shut down, thus avoiding any supply interruption

- provide any combination of the above mentioned services for several fields

Because of its location far from the end consumer, it would be difficult for Frigg, as a storage, to provide unplanned modulation like short term peak-shaving or spot sales which are economically very attractive.

Of course, storing gas to provide modulation for a gas sale contract to the continent would require a pipe link between Frigg and the Statpipe-Zeepipe network

Examples:

In order to illustrate the possible use of Frigg as a gas storage, let us look at two possible different cases:

- storage of Frøy associated gas for use as fuel gas
- storage of Troll gas to allow increase of the possible maximum ACQ

- Frøy gas:

  A total of about 5.4 10^9 Sm^3 of associated gas will be produced by Frøy, this gas could be difficult to sell. A solution could be to sell it to Frigg as fuel gas. But Frøy will produce about 2.2 10^6 Sm^3/day at plateau, and the need for fuel gas on Frigg will range from 0.2 10^6 Sm^3/day to 0.7 10^6 Sm^3/day depending on the activity on Frigg (compression will require the highest quantities), storing of excess gas will allow to secure fuel gas for use after the end of production of Frøy.

  Storage rate will vary between 2 10^6 Sm^3/day and 0. Gas will arrive Frigg at a pressure between 40 and 60 bars and will have to be compressed to injection pressure (190 bars). Because of the compression ratio and the low flow rate, it will not be possible to use the compressors presently installed on Frigg. The unit planned to be installed for Odin compression could fit if its pressure discharge rating is high enough. But it would be available only in 97, about 2 years after the planned start-up of Frøy.

  Not more than two wells will be needed for storage and production, but in order to avoid losing too much gas at the end of production, one of them will have to be located at CDP1 structural top.

The whole gas production from Frøy represents at least 20 years of fuel gas for Frigg, therefore, the above defined scheme should be contemplated only if we are sure that requirements for fuel gas are on the high side, which means a high level of activity on Frigg. Even then, the potential requirement for new compressors, the gas losses (in the reservoir and for compression), the delay between gas purchase and use and the induced operating expenses (linked to use of wells) combined with the relatively small quantities involved make this case only marginally attractive. It should nevertheless be investigated further if activity requiring high quantities of fuel gas is foreseen for Frigg.

- Troll gas:

In the present base case, Troll process facilities have a design capacity of 90 10^6 Sm^3/day at 90 bars and 75 10^6 Sm^3/day at 60 bars; this means that, for the first 10 to 13 years (up to 2006 to 2009), the facilities would be able to supply about 32.2 10^9 Sm^3/year of commercial gas if there were no constraints on modulation and about 26.8 10^9 Sm^3/year in subsequent years. Because of the required modulation and the need to gain operating experience, the maximum ACQ (Annual Contracted Quantity) has been set at 24.4 10^9 Sm^3. Use could be made of the extra available capacity by storing gas; an extra 2.4 10^9 Sm^3/year of gas could then be sold without increase in investment on Troll.

Assuming a modulation between 0.5 and 1.5 for this extra sale, the storing rate can vary between 0 and 44.3 10^6 Sm^3/day and the production rate between 0 and 10 10^6 Sm^3/day. The maximum active storage volume is about 2.25 10^9 Sm^3. Due to the shape of the reservoir, at least 4.5 10^9 Sm^3 of gas cushion will be required. This quantity is high compared to the yearly extra volume which can be sold, but can be supplied by Troll without any problem. It will have a negative economic impact.

With minor modifications, it should be possible to use existing Frigg compressors for gas injection, provided the discharge pressure rating can be increased to 190 bars. Unless the pressure rating of the risers and pipes between TCP2 and DP2 can be upgraded to 190 bars, new risers and pipes will have to be installed.

Because of the maximum possible injection rate, practically all the wells on DP2 will have to be kept active. Either DP2 will have to be manned or remote control of the wells from the central complex will have to be installed.

With the present gas contracts, Troll plateau production will start in 2001-2002 and will be at a maximum level of 22.9 10^9 Sm^3/year with a modulation of 0.4 to 1.1. Before year 2001, unless new contracts are secured, there will be no need for storage; after this date, it will depend on the options exercised by the buyers. As there is a trend to use Troll as a guarantor for gas sales contracts applied to other fields, use of Frigg as a storage could extend this capacity.

The level of modulation on Troll gas contract is unfavourable for use of a gas storage and limits the gas quantity which might be needed to store. Use of Frigg as a gas storage for Troll will not be attractive unless it can be done as a marginal activity. A good example would be the case where Frigg is used for compression of Troll gas, the compressor could be used to send gas to the pipe when the nomination is high, or to send it to the storage when the nomination is low and that gas can be stored.

2.4 Conclusion

Use of Frigg field as a gas storage appears technically feasible but could require important modifications of existing facilities like new compression facilities. Good reservoir sealing and the existing residual gas saturation will keep losses to a minimum. But, the high reservoir pressure is a major drawback, another being the fact that wells are on platforms not connected by bridge to the central complex.

But the potential needs for Frigg as a gas storage seem limited and would be attractive only as a marginal activity.

FIG. 1

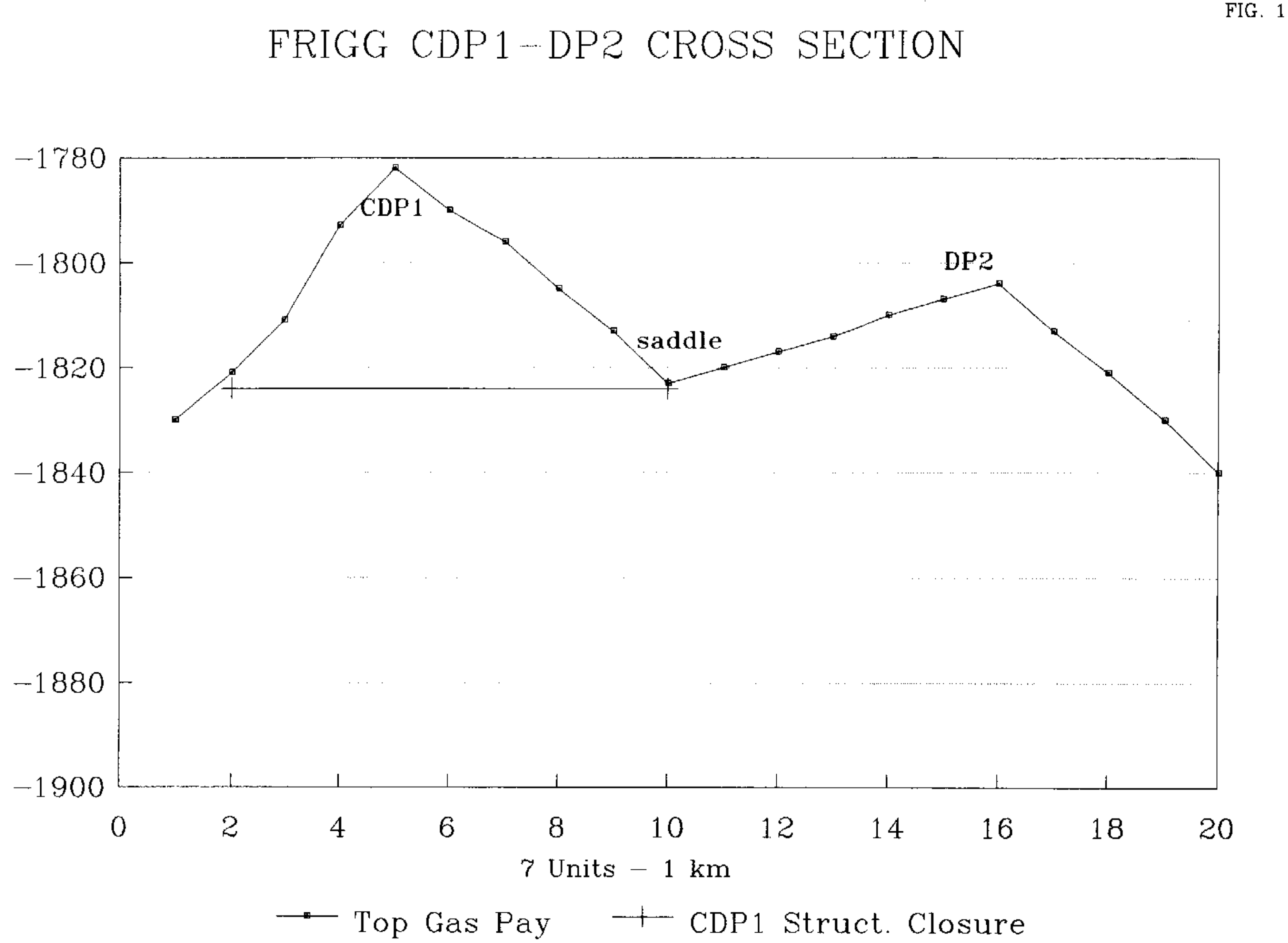
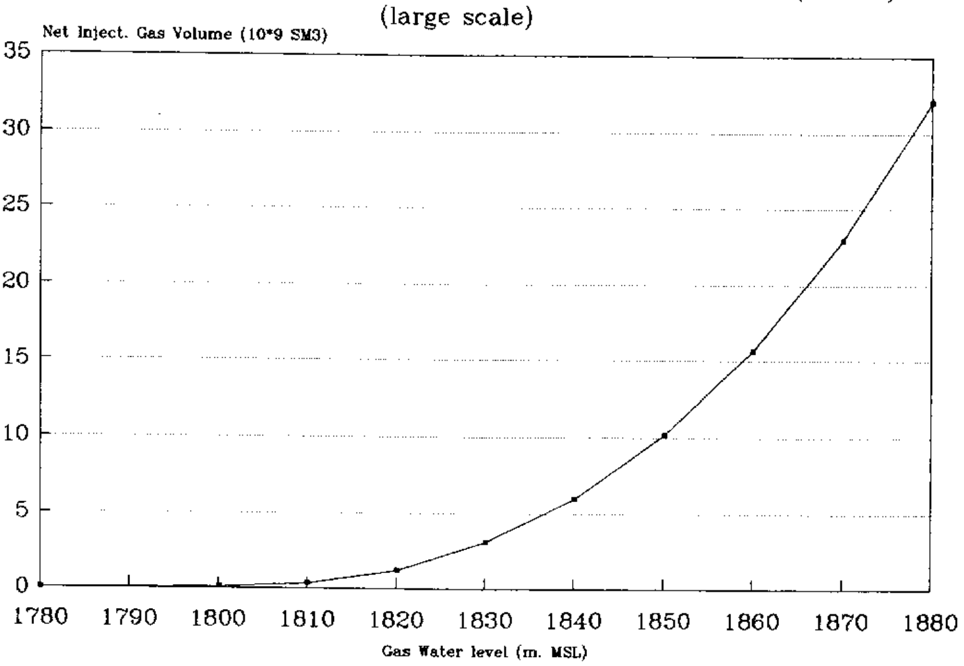

FRIGG CDP1 – DP2 CROSS SECTION
-1780
-1800
-1820
-1840
-1860
-1880
-1900
0
2
4
6
8
10
12
14
16
18
20
7 Units – 1 km
CDP1
saddle
DP2
Top Gas Pay
CDP1 Struct. Closure

FIG. 2

FRIGG STORAGE CASE

GAS–WATER CONTACT LEVEL VERSUS NET INJECTED VOLUME (IN SM3)

(large scale)



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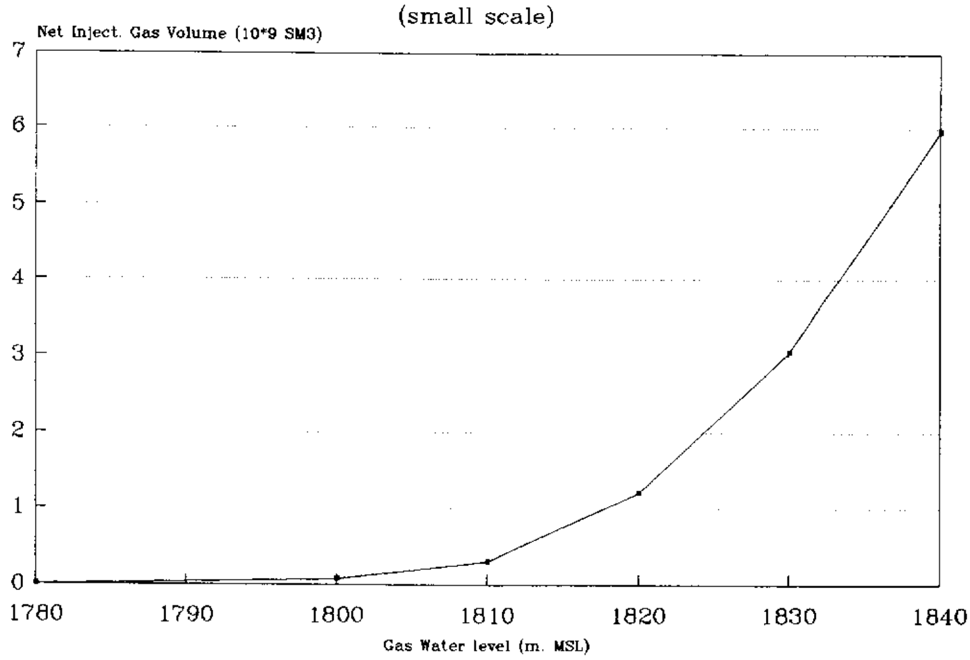
FRIGG STORAGE CASE

GAS–WATER CONTACT LEVEL VERSUS NET INJECTED VOLUME (IN SM3)

(small scale)



CHAPTER VII

FINANCIAL CONSIDERATIONS

CHAPTER VII

Financial Considerations

1. Financial Status

Frigg System Definition

We have assumed that the English pipe would be fully utilised; it has thus been excluded from the reasoning. The system to be analysed is then the sum of the platforms, Norwegian pipe and terminal and MCP01.

1.1 Frigg Value

After Frigg has finished producing, the system will keep residual value and cost:

- abandonment represents a potential cost (2 BNOK +) which would drastically affect Group results, simply delaying the abandonment issue has a financial value. If bypassing Frigg may look attractive for transportation reasons, it should not risk to reinforce the willingness of authorities to accelerate final abandonment: that would clearly be self-defeating.

- the value can also be approached in terms of replacement cost of the topsides and pipe (10 to 15 BNOK). While the structures represent more a burden than a value, the topsides have a high replacement value: to install the same type of topsides on an other field would cost so much that trying to use existing infrastructures is a clear alternative (Troll, Oseberg raw gas), within the Norwegian tax system.

- the competitive residual value is what potential profits could be obtained by offering services to different customers.

The competitive value seems to exist for the UK pipe, not yet for the Norwegian one. For the platforms the competitive value is high for satellites since they have little choice. When it comes to bigger fields each alternative will be analysed by potential customers in financial terms but also autonomy, control, operatorship...

Oil and gas transportation grids represent a double opportunity for the Frigg system:

- on one hand Frigg could possibly optimise the existing grids by providing compression and power,
- on the other hand Frigg and its customers would benefit from a liquid export line and an additional link to the continental market.

1.2 FNA/FUKA Financial Positions

As a base case both associations cover their share of cost on a fixed basis (60/40). The last cubic meters of Frigg will merely pay for platforms cost. After such a point the financial situation of the two associations will diverge:

- The Frigg Norwegian Association will still receive revenues from Odin, NEF and East Frigg. These revenues will cover likely cost up to 1997.

- The Frigg UK Association will not receive any platform revenues; its only operation would be at that time Alwyn Transit. An operating deficit will then occur.

The link between economy and the termination of the Frigg Field Main Agreement (FFMA see VIII-1.2.1.1) does exist; it is not fully clear it could be utilised by one association against the other.

Before we look at Frigg financial scenarios, some analysis should be made as to what it requires to offer services and make a profit out of them. The best example for that in Norway is Ekofisk.

2. Ekofisk

An offshore petroleum system in the North Sea is usually composed of platforms/evacuations handling oil, NGL and gas. In order to attract customers such a system should have unused capacities for different types of services;

Such customers will usually be geographically close due to polyphasic flow limitations. The services offered should be indispensable or at least competitive.

2.1 Role of Physical Specifications

As it has been described in chapter V-1.2, it is where you put the NGL which determines the type of treatment and evacuation used,

EVACUATION SYSTEMS SPECIFICATIONS		OIL SPECIFICATIONS	
		NARROW (Stabilized crude)	LARGE (oil + NGL)
GAS	NARROW (commercial)	HEIMDAL exception	EKOFISK
SPEC	LARGE (rich)	STATFJORD BERYL BRUCE	NINIAN/BRENT ALWYN

While technical flexibility favours large/large systems, it need not be so in terms of financial success with service customers. Offshore loading solutions are generally very competitive, in addition oil fields generally need to separate oil and gas flow in any case due to polyphasic transfer difficulties. On the contrary for gas only pipe evacuation exists: if the pipe transports commercial gas then customers NEED to treat that gas to specifications. Unused capacities of gas treatment can therefore have a high value.

If the objective is to make profit from offshore treatment, then the best system is one where the gas outlet carries commercial gas; this requires usually the existence of a liquid pipe with large specifications (120 psi).

On the fiscal side, UK system favours investment against tariff; it is more attractive to invest in a terminal than to pay tariff to one; on the Norwegian side tariffs are favoured, which in turn gives an advantage to prime (usually big) fields with unused capacities.

The Ekofisk example will therefore be used here to show a successful service system and try to draw some orientations in the Frigg context.

2.2 Ekofisk Customers

IN 1994	NUMBER OF FIELDS	TOTAL QUANTITY
Oil treatment	4	0.7
Oil transportation	9	21 MT/Y
Gas treatment	6	3
Gas transportation	9	21 GM3/Y

Usual treatment tariffs are of the order of 1 to 1.5 $/bbl for oil and 10 to 15 øre/m^3 for gas; put in percentage to oil and gas values gas requires twice as much tariff to be treated (15-20% against 7-10%).

The biggest gas customers pay tariffs but some oil fields see their gas bought at around 50% of the gas price, for fuel purposes.

The treatment income totals around 800 MNOK per year, most of it coming from the gas customers. Such an amount for extra services is what we should try to obtain on Frigg.
On the oil side the margin between cost and income is quite low due to the competitivness of autonomous schemes.

2.3 Ekofisk Lessons

Ekofisk is still producing: this of course limits the degree of duplication we can perform using that example. However, some aspects deserve attention:

- Associated gas from small oil fields is a primary profit target
- Gas fields not owned by the Phillips Group are today at the economic limit (Albuskjell/Tommeliten), thereby indicating the treatment tariff valid for prices above 15 $/bbl--->15 øre/m^3.
- Oil prospects may utilize capacities if close and small enough
- Fuel gas is both a need for the system (power/compression) and a opportunity generally opened by gas contracts
- NGL transportation is more efficient with an oil pipe but the cost of extraction from oil or gas is always high.

The financial success comes from the effective combination of evacuation specifications and spare capacities for a wide range of services.

3. Frigg Area System

We would then recommend, on financial grounds, to propose that the Frigg area tries to use the proper combination of specifications for its system:

- dry Norwegian pipes downhill of Frigg either to St. Fergus or to The Continent (Zeepipe or Heimdal leg),
- rich gas to Frigg (from satellites or Troll/Gullfaks/Oseberg)
- liquid export line with large specs from Frigg (via Bruce or Sleipner/Frøy to Karstø for example
- increase the spectrum of services: high <u>and</u> low compression, water <u>and</u> hydrocarbon new point units, subsea control, power supply.

From the potential gas customers point of view, it will also be important that several potential markets be available: British gas via the Frigg Norwegian pipe, continental market via Zeepipe or Statpipe in that respect the Troll Gas Sales Agreement may prove useful for associated gases of the Frøy area.

Finally, but not the least important, the Elf Group is heavily involved in an area going from Oseberg/Alwyn to Bruce/Frøy for which Frigg is the natural center. This area has however no connection to the Group gas buying possibilities: the creation of a link via Heimdal or via Zeepipe would probably have strategic consequences.

4. Financial Scenarios

4.1 The Accommodation Agreement

The application of the classical unit share method to divide operating cost between FUKA and FNA crates, after 1993, a significant deficit for FUKA. At the time the only operation is assumed to be Alwyn transit on TP1. The resulting transit cost per SCM is well above standards. If one is to take a competitive approach towards FUKA, a lower share of total cost of the platforms opex should be allocated when there are diverging activity levels for both associations.

This is one of the purposes of the accommodation agreement. The principle would be that outside a base operating cost (here taken as 90 MNOK per year) to be shared between FUKA and FNA, the opex share would depend on activities and operations performed by each association.

The result, shown in next page graphs, is to lower significantly the cost for FUKA to stay in Frigg Unit for Alwyn purpose.

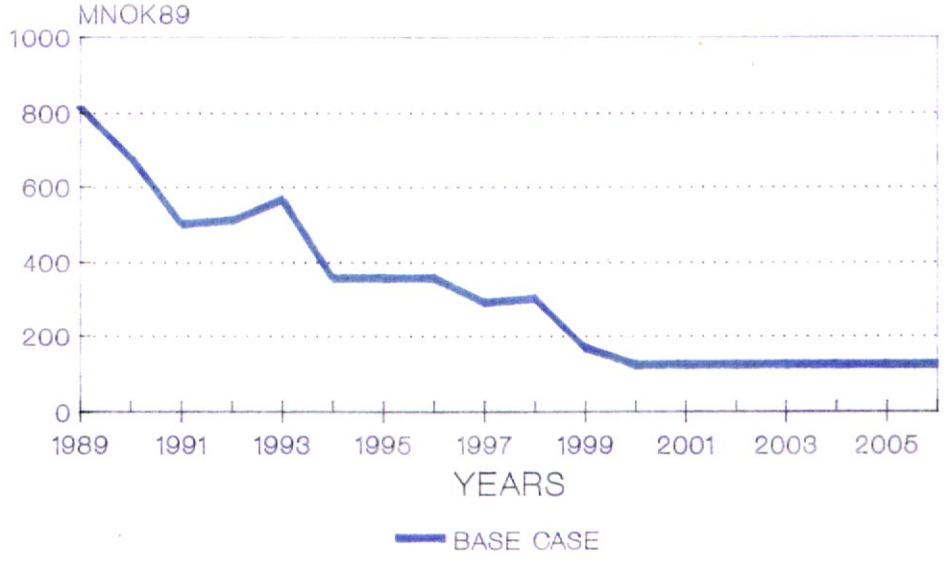
This accommodation agreement is so far only a proposal from EAN and a reactivation of the discussions with all partners will be needed in order to achieve a workable arrangement.

Such discussion would be facilitated by the early recognition of each association activity potential.

Assuming that FNA will take most of the cost burden (80%+), two typical scenarios for Frigg future are then proposed.

1. Integrating Frigg in the Norwegian grid (Zeepipe) of gas transportation (Troll - Frigg - Sleipner).
2 Treating up to 20 MSCM/D of rich gas on Frigg.

FRIGG OPERATING COST
BASE CASE



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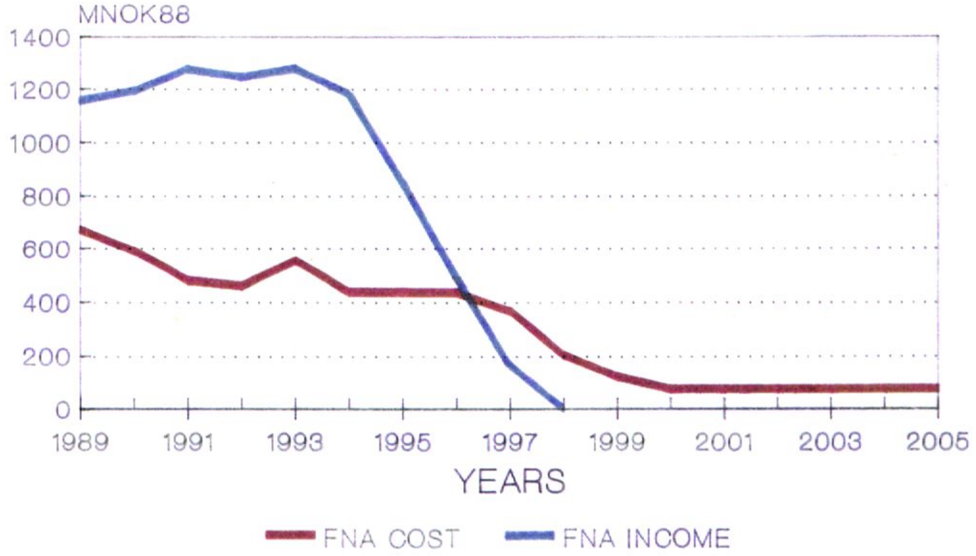
FNA FINANCIAL SITUATION
FROM 1989 TO 2002



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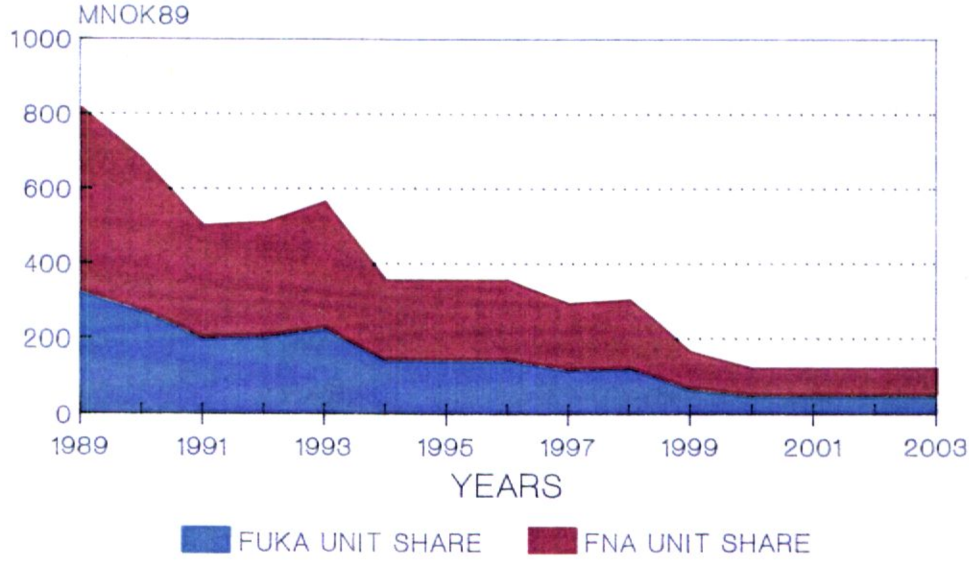
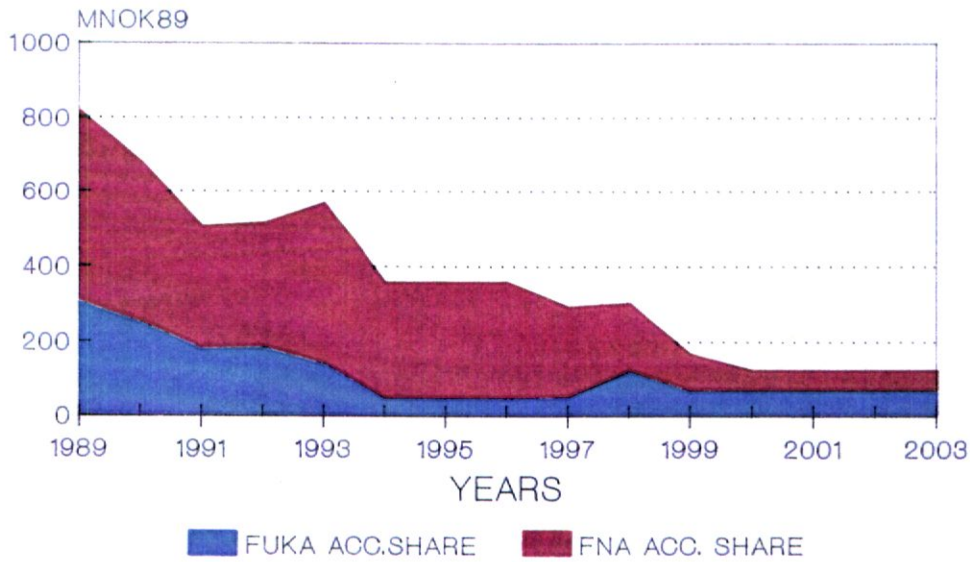
BASE OPERATING COST
UNIT SHARING



BASE OPERATING COST
ACCOMODATION AGREEMENT



4.2 The GRID Scenario

The GRID scenario is based on a configuration of Zeepipe where Troll commercial gas goes through Frigg on its way to Sleipner. The technical basis for such a scenario is described in chapter V, item 1.6 (either alternative 1 or 4 could be taken).

4.2.1 Customers Point of View

The first phase of Zeepipe will build a pipeline between Sleipner and Zeebrugge as well as establish a link with Statpipe (16-11S Platform). In the second phase the actual plan is to lay a Troll - Sleipner pipe, followed by a Troll - Heimdal pipe. By doing s Trill looses the opportunity to sell small quantities of gas to UK (f.e. 5 MSCM/D). It will have to wait bigger quantities to justify laying a new pipe probably in combination with Oseberg.

If the initial pipe (1996) is done between Troll and Sleipner via Frigg, Troll will be in a very good position to sell at marginal cost by using its spare production capacity. This only possibility outweighs by far the supplementary tie-in cost zeepipe would have to bear.

In addition Zeepipe would see its capacity increase by several MM3/day and power needs for troll would be reduced.

4.2.2 Frigg Financial Evaluation

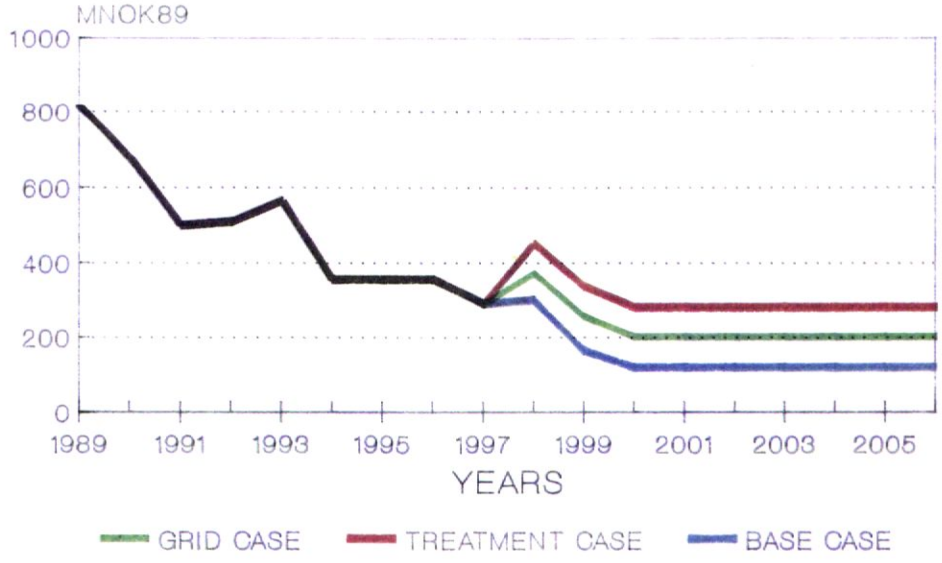
From Frigg point of view, TCP2 and QP would be used:the operating cost to be covered by FNA on plateau would be 200 mnok 89 per year(FUKA 45 mnok).
A realistic tariff per m3 (real volumes)could be in the range of 3 ore/m3 for transit and compression.

Fuel gas is needed to operate Frigg platforms and compression facilities;it is assumed here to come from associated gases from the Frøy area;the gas would be sold under the troll Gas Sales Agreement(specific provisions for oil fields);FNA would get part of the gas as a treatment take-in-kind.Buying these gases at a fraction of their value could also be envisaged.

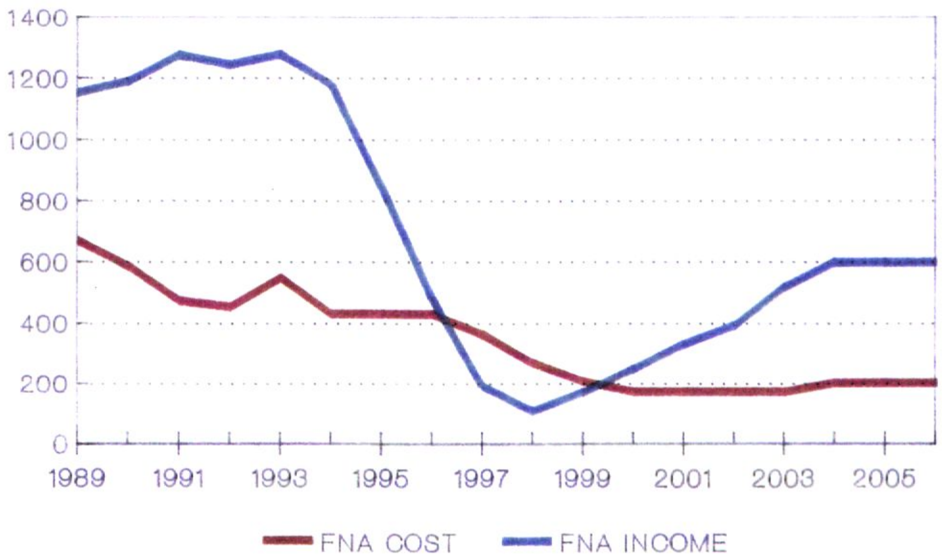
The troll quantities are huge ,thus lowering the unitary cost to competitive levels but it is clear that the UK commercial incentive will be a powerful one for Norwegian authorities even if today nothing is sold. In this minimal scenario, no investment is made by FNA, Frigg would become a small money-maker (see graph).

Frigg center would at the same time be available for smaller gas satellites treatment at a marginal cost(25/2-12 or northern frigg area UK/Norway prospects).For such prospects,the Zeepipe link will open new markets possibilities,thus increasing the likelihood of their development.

FRIGG OPERATING COST
BASE,GRID AND TREATMENT CASES



GRID CASE
FNA COST AND INCOME



BASED ON 3 ORE/M3 TRANSIT + COMPRESSION TARIFF

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4.3 A Treatment Scenario

The treatment scenario is based on investing around 1 BNOK to treat rich gases during 3 periods:

. from 1.10.93 to 2002 an UK overspill
. Frigg satellite (25/2-12 or others) from 1996to 2004
. Oseberg (Gullfaks south) from 2002 onwards

These potential customers never exceed a MDD of 20 MM3/day(see graph Frigg provides then a full range of services and receives tariffs of:

- 8 ore/m3 for UK customers
- 15 ore fro frigg satellites
- 10 ore for bigger Norwegian sources

Operating cost would reach 235 mnok for FNA(45 mnok FUKA). FNA would need to invest in additional equipments on Frigg (Turbo-expander) in order to reach commercial gas specifications.

A liquid outlet will be needed: Bruce - Forties or Sleipner - Kårstø are the most likely candidates in the time frame considered. The Norwegian liquid outlet will have to propose reasonable tariffs if it is to compete with UK possibilities. The liquid outlet problem will require a global look taking into account Frøy and possible satellites, and financial impact on Sleipner.

Investment is unlikely for one customer alone; two customers will be sufficient or even one if Frigg opex is covered by the GRID scenario.

While the calculation has been made for the best case, it should be clear that certainties are needed to be able to invest. Exploration results in the Frigg area will have a strong impact on the profitability of rich gas treatment potential.

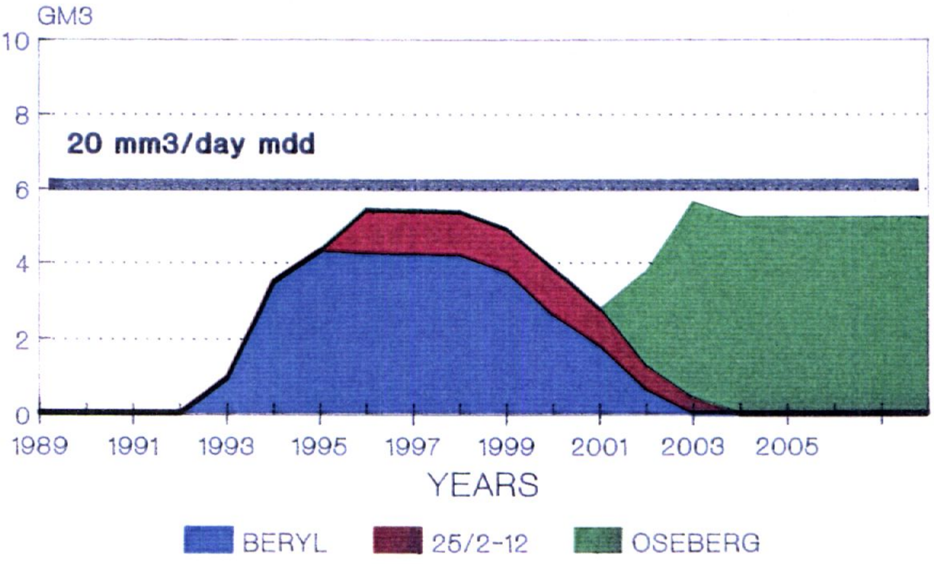
If a sufficient number of customers is treated on Frigg, it may remain a profit center for a long period (see graph).

Finally the possibility of treating Raw Troll gas on Frigg has not been studied: its technical feasibility is not yet established, but it would financially solve most of our problems. It would in fact be a type of combination between the two scenarios analysed hereabove.

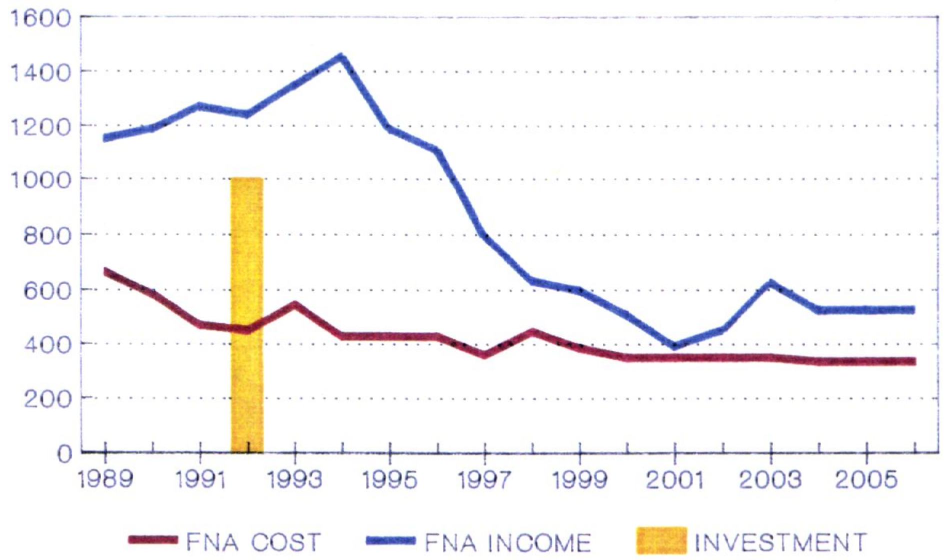
The financial consequences are so huge that a dilution of our percentage in FNA would need to be considered: the non-state partners of Troll would probably require to get a percentage in Frigg in order to accept such an alternative; a dilution of 25% for EAN, NH, Total would allow Statoil, Shell, Saga and conoco to have the same percentage in Troll and in FNA, thereby clarifying the financial situation.

But most of the possible short term actions required evolve around an essential theme: break the isolation of Frigg (desenclavenent) in terms of infrastructure and markets.

TREATMENT CASE
CUSTOMERS PROFILE



TREATMENT CASE
FNA COST AND INCOME



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CHAPTER VIII

FUTURE ORGANISATION

CHAPTER VIII - PART 1

Status of Existing Titles and Agreement

The first part of this Chapter VIII contains a review of the status of the existing Frigg production and transportation titles (paragraph 1.1). It further examines the status of the existing agreements between FNA and FUKA and the consequences of their automatic termination upon the depletion of the Frigg Field Reservoir in the event these agreements are not amended or replaced by new contractual arrangements (paragraph 1.2).

1.1 Legal Environment

The legal environment is constituted essentially by the following titles and public documents:
- the two UK production licences (P.404 and P.118),
- the Norwegian production licence (PL 024),
- the pipelines licences and permits,
- the Treaty, and
- the respective petroleum legislations of Norway and the UK.

1.1.1 Duration of titles

The matter of the duration of titles has been studied on several occasions.

Suffice it to say that:
(a) the Norwegian production licence 024 will expire on May 22, 2015,
(b) the UK licences will expire on November 23, 2011 (P.404) and June 7, 2016 (P.118)
(c) the Norwegian permit to construct and operate the Frigg Norwegian pipeline will expire in September 2003,
(d) the two consents granted by the UK authorities to construct the two Frigg pipelines will remain in full force until at least 2026, and
(e) the UK licence agreement to lay the pipelines in UK territorial waters will expire in 2026.

The Frigg installations are located on the area of UK production licences P.118 and Norwegian production licence 024 which expire respectively in 2016 and 2015. Both in the UK and Norway there is no automatic right to the renewal of production licences but a renewal or extension of the production licences is not ruled out.

FUKA's ownership and right to operate the Frigg UK pipeline should remain undisturbed until 2026.

The future status of the Frigg Norwegian pipeline however requires special attention.

1.1.2 The Frigg Norwegian Pipeline Titles

The main considerations are:

(a) The Norwegian permit to own and operate the Frigg Norwegian pipeline will lapse 25 years from the time the pipeline was "taken into use" (assuming this means first delivery to St. Fergus, the permit will expire in September 2003),
(b) the Norwegian government is entitled to take over the pipeline in 2003 or may require the dismantling (in whole or in part) of the pipeline and related facilities in 2003,

(c) one supposes that the Norwegian government may alternatively renew its permit on the same or different terms,
(d) the permit is related to Licence 024 and the question is raised as to whether the permit lapses automatically upon the cessation of transportation of gas produced under that licence (1993),
(e) the UK licence agreement to lay the Norwegian pipeline in the UK territorial waters provides for the transfer of ownership to the UK authorities in May 2026,
(f) whether or not the Norwegian government has taken over the Frigg Norwegian pipeline in 2003, ownership of that pipeline will revert to the UK authorities in 2026,
(g) the UK licence agreement excludes assignment of the rights granted by that licence agreement other than between the Frigg owners themselves. This conflicts with the Norwegian government's right to take over the Norwegian pipeline in 2003. It would seem however that the Norwegian state could secure ownership of the Norwegian pipeline in 2003 by forcing a transfer to Statoil, one of the Frigg owners.

In summary the status of the Frigg Norwegian pipeline after 2003 is confused and continued ownership of that pipeline by FNA is uncertain in the long run.

It would be difficult to obtain now an undertaking by the Norwegian government that they will not exercise their right to take over the pipeline in 2003. However it is recommended that the matter be raised at the first appropriate opportunity and in any case prior to entering into any transportation contract which would extend past 2003. Such opportunity could materialize soon if it is decided to offer capacity in the Frigg norwegian pipeline to the Beryl group.

1.1.3 Treaty

The Treaty deals with the exploitation of the Frigg Field Reservoir and the transmission of gas from the Frigg Field Reservoir. The Treaty will therefore loose its main purposes upon the depletion of the Frigg Field Reservoir.

The Treaty may be terminated at any time by mutual agreement between the two governments. The Treaty may therefore remain in force after the depletion of the Frigg Field Reservoir but may not be then adequate to govern the relationship between the two governments regarding the new activities of the Frigg installations. Therefore it will be appropriate to discuss any proposal for future use of the Frigg installations with the two governments so that they are in a position to supplement or revise the Treaty as may be necessary.

If the Treaty is not supplemented or revised after 1993 it will nevertheless continue to have relevance in respect of certain activities of the Frigg installations and in relation to the pipelines (taxation of licensees' income, prior consultation between governments before approval is given for use of the installations, etc.).

1.1.4 General Legal Environment

The Frigg activities are also regulated by the general legislation of the UK and of Norway, primarily by the petroleum legislation of those two countries. This legislation is adapted regularly to the nature and level of the petroleum activities. The tax laws are frequently adjusted to add incentives when the exploration activity is regarded as too low to achieve self-sufficiency in petroleum needs or to achieve the desired level of exports. The tax laws are also regularly adjusted to maximize the government take (directly or through the national oil company) when world oil prices raise.

Similarly the petroleum act is regularly amended both in the UK and in Norway. Substantial overhauls of the petroleum legislation have taken place approximately every ten years in both countries.

It is therefore difficult at this stage to figure out the general legal environment in the period 1993-2015.

Changes are expected however in one area of critical importance for the future of Frigg: the legislation regulating the abandonment of offshore installations.

In 1988 the governments of the UK, Norway and the USA have made a joint submission to the International Maritime Organization ("IMO") concerning draft guidelines and standards for the removal of offshore installations on the continental shelf and exclusive economic zone. In essence these guidelines and standards once approved by the IMO, will provide for the partial removal, on a case-by-case basis, of heavy structures in deep water and for the entire removal of lighter structures in shallow water. Under the guidelines, as from the beginning of 1998 no installation should be emplaced on the continental shelf unless its design and construction are such that its entire removal, upon abandonment or permanent disuse, would be feasible.

In Norway, the principle is that the State takes over the installations upon permanent disuse or after the termination of the licence covering the area in which the installations are located (art. 30 of the Petroleum Act 1985). However, as an alternative, the government may request that the installations by removed.
If the IMO draft guidelines are adopted, the Frigg installations would probably qualify for partial removal only. The costs of this partial removal will of course need to be taken into account when devising tariffs for use of the installations to accommodate third party's gas in the future.

It is anticipated that the forthcoming abandonment of several offshore installations in the UK sector of the North Sea in the 1990's will compel the UK parliament to enact legislative requirements concerning their removal in the near future. It is assumed that the UK legislation will constitute a precedent for the other North Sea states and that the UK and Norwegian legislations applicable to the Frigg installations will be consistent.

1.2 Contractual Arrangements

The current contractual arrangements (assuming they are not amended to prepare for the Frigg future) can be classified in two categories:

- the contractual arrangements which will terminate upon the depletion of the Frigg Field Reservoir (2.1)
- the contractual arrangements which will survive the depletion of the Frigg Field Reservoir (2.2)

1.2.1 Contracts to Terminate

Upon the depletion of the Frigg Field Reservoir the Frigg Field Main Agreement dated 9 July 1973 which created the Frigg Unit will terminate.
This termination will trigger the termination of nearly all the agreements governing the relationships between the two Frigg owners groups both in relation to the Frigg Field and the Frigg Transportation System (FTS).
The contracts to terminate at the same time as the Frigg Field Main Agreement are listed in attachment VIII - 1.1 hereto.

The termination of the Frigg Field Main Agreement will therefore cause the collapse of a substantial part of the contractual edifice in which the Frigg co-venturers currently operate.

1.2.1.1 Termination Mechanism

(a) As between the Frigg Co-venturers

Article 20.1 of the Frigg Field Main Agreement ("FFMA") provides that the FFMA will terminate when the parties unanimously decide that the "Unitized Substances" are no longer "economically and technically recoverable".

A further ground for termination is the termination of one of the production licences. We will assume here that the production licences will continue beyond the period of production of the Frigg Field Reservoir (see paragraph 1.1 above).

It results from Article 20.1 of the FFMA that:

- the termination of the FFMA is subject to all the Frigg co-venturers agreeing that the Unitized Substances are no longer economically and technically recoverable, and
- no co-venturer may oppose the termination of the FFMA as long as they all agree that the Unitized Substances are no longer economically and technically recoverable (the continuation of the FFMA after they have all agreed that the Unitized Substances are no longer economically and technically recoverable would require the agreement of all the Frigg co-venturers).

It should however be noted that any one or more of the Frigg co-venturers may decide to pursue the exploitation of the Frigg Field Reservoir and therefore oppose the termination of the FFMA. Such exploitation will be subject to the relevant governmental authorities granting to this co-venturer(s) the required production permits and will be limited to the production of the reserves attributable to his group (Statoil, for instance, will be entitled to continue the production of the Unitized Substances remaining in the Frigg Field Reservoir but only to the extent of 60.82% of these substances).

Whilst the operating committee of the Frigg unit is empowered to determine the amount of recoverable reserves in the Frigg Field Reservoir, the assessment of the economic and technical feasibility to recover those reserves therefore rests with each individual co-venturer.

(b) Vis-a-vis the Two Governments

(i) prior to approving the termination of the FFMA both governments will have to acknowledge that no satellite gas is flowing or capable of flowing into the Frigg Field Reservoir. If this was the case, art. 3.4 of the Treaty would apply and would result in the requirement that the FFMA be kept in force.

(ii) both governments routinely approve their respective licensees' application for approval of plugging and abandonment of producing wells as well as their respective licencees' production schedules. They will therefore be appraised of their licencees' plans for cessation of production from the Frigg Field Reservoir. This will be a process extending over several years prior to the Frigg co-venturers' decision that all reserves capable of being economically and technically recovered have been recovered. Whether or not the UK and Norwegian legislation will permit that the governments interfere in the phasing out of the Frigg Field Reservoir production and therefore prevent or delay the termination of the FFMA ought to be investigated. (In particular, will the governmental authorities be entitled, under their respective petroleum legislations, to challenge our plugging and abandonment programme of producing wells for technical reasons? Will these authorities be entitled to claim that our operating costs are unduly high and that recovery of Frigg gas is still possible economically?)

Therefore the two governments will be closely associated with, and informed of, the process leading to the termination of the FFMA.

1.2.1.2 Consequences

The termination of the FFMA will result in the automatic termination of all the ancillary agreements to the FFMA: All agreements entered into by the Frigg co-venturers in pursuance of the FFMA (except one, see paragraph 1.2.2.2 below) have either expressly or impliedly tied their existence to that of the FFMA.

(a) Express Termination Provisions

(i) The Frigg Field Transportation Agreement ("FFTA") terminates upon the cessation of production from the Frigg Field Reservoir (art. 12.3). It therefore terminates on the same date as the FFMA.

(ii) The Frigg Norwegian Pipeline Operating Agreement term is geared to the duration of the FFTA and therefore terminates on the same date as the FFMA and the FFTA.

(b) Implied Termination Provisions

(i) The Frigg Field Terminal Agreement and the Frigg Field Intermediate Platform Agreement contain provisions making them supplemental to FFTA. They therefore terminate automatically upon the termination of the FFTA even though they do not contain express terms to that effect.

(ii) The Heads of Agreement (Field Part) and the Heads of Agreement (Transportation Part) do not contain provisions making them supplemental to the FFMA and the FFTA nor do they contain express termination provisions.
However each of these agreements contain in their formal introductory statements (Recitals) the reason upon which these agreements are grounded:
- the Heads of Agreement (Field Part) states that FNA and FUKA enter into that agreement "as Parties to the Frigg Field Main Agreement";
- the Heads of Agreement (Transportation Part) states that FNA and FUKA enter into that Agreement "as Parties to the Frigg Field Transportation Agreement".

Whilst the scope of these agreements is not limited to matters relating to the Frigg Field Reservoir, the premises upon which they were made indicate that they will not extend beyond the termination of the FFMA and the FFTA. Moreover they do not contain provisions for their renewal after the termination of the FFMA and FFTA.
The major consequence of the termination of the two Heads of Agreement are that, from the date of the depletion of the Frigg Field Reservoir:
- the allocations of surfaces and risers on the platforms,
- the allocation of capacities (production, treatment, compression), and
- the right to use those surfaces, risers and capacities,

will be terminated.

In these conditions one does not see how FNA could continue after the depletion of the Frigg Field Reservoir to comply with its obligations towards Esso (treatment and compression of Odin gas and, possibly NEF gas) which necessarily require that FNA is entitled to use the TCP2 installations and equipment, notwithstanding that the required facilities are separately-owned by FNA and located on surfaces allocated to FNA.

1.2.2 Contracts to Survive

There are three categories of contracts that will survive the termination of the FFMA:
- the treatment and transportation agreements made between FNA and/or FUKA and third parties,
- the Frigg Field Operating Agreement, and
- the Frigg Gas Sales Contract.

(The contents which survive the termination of the FFMA are listed in Attachment VIII - 1.1 hereto)

1.2.2.1 The Treatment and Transportation Agreements ("TTA's")

(a) Two TTA's were entered into in 1980 between FNA and Esso on the one hand (Odin TTA), and Esso, FNA and FUKA on the other hand (NEF TTA).

The term of these agreements extend until the cessation of deliveries of gas from the two fields to the buyer (British Gas). Each of these agreements however may be terminated by FNA "upon the permanent cessation of deliveries of gas to British Gas under the Norwegian Frigg Gas Sales Contract". The Norwegian Frigg Gas Sales Contract with British Gas may continue until 2000 (and possibly beyond 2000) and will therefore normally continue after the depletion of the Frigg field Reservoir, the gas from the North East Frigg Field is partly sold under that contract and deliveries may continue until 1994.
These two TTA's (or at least the Odin TTA, if NEF is depleted before 1993) will therefore continue after the depletion of the Frigg Field Reservoir and the concomitant termination of the FFMA. We have noted at the end of paragraph 1.2.1.2 above that FNA's obligations under these TTA's may be impossible to satisfy after the termination of the FFMA.

The Odin TTA was recently extended until 1997.

(b) The East Frigg Treatment Extra Services and Transportation Agreement will continue until the end of the production from the East Frigg Field. According to current plans that production will continue until 1995 i.e. after the termination of the FFMA. We are currently attempting to alleviate the problems that may arise if the FFMA should terminate before the East Frigg Field is depleted by obtaining the agreement of the parties that in the event of a change in contractual circumstances the East Frigg TTA will be adjusted. The termination of the FFMA will certainly constitute a change in contractual circumstances. The door may therefore be opened in this case for an adjustment of the contract, if necessary, in 1993. Moreover the members of the East Frigg Association being also (for the time being) the members of FNA, it is expected that (as long as the parties remain the same) the parties concerned will attend to settle this matter when it arises.

(c) We have no indication on the conditions for termination of the Piper gas and Tartan gas transportation contracts (both these gases use currently unitized facilities at MCP01 and St. Fergus) nor how FUKA is proposing to handle Beryl and Bruce gas after 1993. (The draft TTA for Beryl however contain provisions which will permit a renegotiation if FUKA is obliged to discontinue the transportation services due to "a material change in circumstances (whether legal, fiscal, economic or otherwise howsoever)". Any contractual impossibility for FUKA to use the unitized facilities on MCP01 for instance would therefore entitle FUKA to revise the proposed Beryl TTA in 1993).

(d) To our knowledge, no specific agreement exist for the transportation of Alwyn gas. The draft TP1 and Transit Agreement (which should normally continue well after 1993) does not address expressly the issue of its continuation after 1993 but refers in two articles to an "Accommodation Agreement between FNA and FUKA" and therefore seems to contemplate that it may be adjusted in the future to reflect any new arrangements between FNA and FUKA.

1.2.2.2 The Frigg Field Operating Agreement ("FFOA")

The existence of this agreement is geared to the FFMA. However it will survive the termination of the FFMA (art. 14) until (inter alia) all the assets of the Unit have been disposed of and all obligations under the Frigg licences have been satisfied.

(a) the disposal of the Unit assets may be effected in several ways. Either
   (i) by transfer of ownership to a third party (by way of sale to a third party, or take over by the Norwegian State of the installations located in the Norwegian sector, in the case these installations are permanently abandoned), or
   (ii) by assignment to FNA and/or FUKA, or
   (iii) by demolition and removal.

The Norwegian State has a preemptive right to take over and must therefore be consulted before demolition and removal. This preemptive right however has no application in case of sale or assignment to third parties or between FUKA and FNA. Such sale or assignment may therefore be effected freely, subject only to governmental approval.
The disposal of the Unit assets must be made "in accordance with the instructions of the Operating Committee". As the Operating Committee decisions are made by a vote of 85% of the participating interest there is scope for a disposal to take place against the wishes of Statoil. The availability of the FFMA preemptive rights would therefore be critical for Statoil in this kind of situation. Whether the disposal of Unit assets to third parties or to the groups or to a member of a group is subject to the two-tier preemptive rights contained int the FFMA (then, by definition, terminated) should be investigated. In principle, these preemptive rights should not then be available.

(b) The FFOA will also continue after the termination of the FFMA until "(d) the governments agree this agreement may terminate when all licence obligations have been fulfilled". (This ground for continuation of the FFOA was added at the request of the two governments in 1976). This provision is ambiguous as it seems to limit the rights of the two governments to agree to the termination of the FFOA: effectively this right would arise only when all licence obligations have been fulfilled. One of the Norwegian licences obligation is to remove the installation if the State has not wished to take them over (either temporarily or permanently) (art. 30 of the Norwegian petroleum act). It would therefore seem that the Norwegian government for instance could oppose the termination of the FFOA until DP2 and TCP2 are removed. The Norwegian government however cannot demand removal until these installations are permanently abandoned or licence 024 expires. Theoretically, therefore, the FFOA could continue until permanent abandonment of TCP2 and DP2 or until 2015. Other licence obligations yet unsatisfied in 1993 include the payment of areas fees between 1993 and 2015. It seems however that if the UK and Norwegian licences are in good standing in 1993 (as opposed to all future obligations being satisfied), the two governments should be in a position to agree to the termination of the FFOA. This point however is unclear.

(c) As long as the FFOA continues after the termination of the FFMA, EAN remains the operator of Unit operations. These operations however will be limited to those authorized by the Operating Committee. it is doubtful that the operating committee could authorize operations which could encompass operations other than those required to close down the Unit (final accounting, abandonment of wells, disposal of Unit assets, demolition or removal if required, etc.).

1.2.2.3 The Frigg Gas Sales Contracts

(a) These are the sales contracts entered between FNA and British Gas and FUKA and British Gas in 1973. These agreements may continue until 2000 (and possibly beyond 2000). However the inability of the sellers (FNA and FUKA) to use the installations (Frigg, MCP01, St. Fergus) as a result of the termination of the FFMA and ancillary agreements would result in a failure to deliver the required quantities of East Frigg Gas (and possibly NEF, 25/2-12 and Frøy gas if those fields are on-stream at the time) without this failure being capable of being excused by a force majeure situation. The damages due by FNA to BG in that case would be considerable.

(b) The Odin gas sales contract between Esso and British Gas would also be jeopardized if FNA is rendered incapable to perform its obligations under the Odin TTA by the termination of the FFMA. The damages due by FNA to Esso in that case would also be considerable.

1.3 Conclusion

The above developments (which admittedly leave a number of issues unresolved) at least tend to indicate that radical consequences will flow from the termination of the FFMA upon the depletion of the Frigg Field Reservoir; the main consequence for FNA will be the impossibility to meet its obligations under the Odin TTA; the main consequence for FUKA will be the impossibility to meet its obligations under the Bruce and/or Beryl TTA's and to continue the use of previously unitized installations for Alwyn.

It is therefore unlikely that the members of the Frigg Unit will let the FFMA terminate without having taken the necessary precautions to avoid all the problems such a termination would involve. If a party should oppose that precautionary steps be taken by way of amendment to the existing agreements such opposition could probably be considered as unreasonable and would give rise to an action for damages.

If however the Frigg co-venturers themselves should prove unable to re-organize satisfactory operations of the Frigg system after the depletion of the Frigg Field Reservoir, then the governments will not be in a position to accept the termination of the FFMA. Before accepting the termination of the FFMA both governments will ensure that:

- deliveries to BG will continue normally under the NEF, East Frigg, Odin and Alwyn sales contracts
- the rights of third parties to have their gas treated or in transit at Frigg (a matter that the governments consider under article 3.4 of the Treaty) are not jeopardized, and
- the installations (platforms and pipelines) continue to be safely maintained and operated.

It is therefore imperative that the Frigg co-venturers either amend the FFMA to allow it to continue after the depletion of the Frigg Field Reservoir or alternatively that the Frigg co-venturers agree on an agreement that will be substituted for the FFMA with effect from the depletion of the Frigg Field Reservoir. Having done this, they will then submit this new arrangement to the two governments for approval. Before they grant their approval the governments will have to be satisfied that the proposed new arrangements meet their respective political, commercial and financial interests.

ATTACHMENT VIII - 1.1

CONTRACTS TO TERMINATE

Upon the termination of the Frigg Field Main Agreement the following contracts (and ancillary amendments, side letters and supplements) will terminate:

Frigg Field Transportation Agreement dated 30 July 1974
Frigg Field Terminal Agreement dated 24 June 1976
Frigg Field Intermediate Platform Agreement dated 20 March 1980
Heads of Agreement (Field Part) dated 20 March 1980
Heads of Agreement (Transportation Part) dated 20 March 1980
Frigg Norwegian Pipeline Agreement dated 20 March 1980

Note: A Frigg UK Pipeline Agreement in draft form was prepared in 1977. This draft stipulated that the Frigg UK Pipeline Operating Agreement would terminate upon the termination of the Frigg Field Transportation Agreement. We have not sighted an executed copy of this document.

CONTRACTS TO SURVIVE

Accord pour la Zone Norvegienne de la Mer du Nord dated 1 September 1965 (1)
UK Joint Venture Agreement dated 30 April 1968
Norwegian Joint Venture Agreement dated 31 March 1971
Frigg Field Operating Agreement dated 9 July 1973
NEF Treatment and Transportation Agreement dated 26 November 1980 (2)
Odin Treatment and Transportation Agreement dated 26 November 1980
East Frigg Treatment Extra Services and Transportation Agreement (not yet executed)

(1) partly terminated in 1977
(2) if NEF production continues after the depletion of the Frigg Field Reservoir

Note: FUKA's arrangements, if any, for the transportation of Alwyn North gas will also survive as well as any agreement entered into by FUKA and/or FNA for the transportation of Beryl and/or Bruce gas.

CHAPTER VIII - PART 2

SCHEMES OF COOPERATION BETWEEN FNA AND FUKA

It is apparent from the conclusion in paragraph 1.3 of Part 1 above that the Frigg co-venturers cannot just ignore their relationship after the depletion of the common resource and let the FFMA lapse. We have concluded above that if the Frigg co-venturers should prove unable to agree on future arrangements between them, the UK and Norwegian authorities would in all likelihood take themselves the necessary steps to avoid that the operations of the Frigg Field installations and the pipelines be jeopardized.

Several alternative arrangements have been studied in the past. They range from extreme schemes to more realistic schemes including the continuation of the current arrangements. These various schemes are reviewed below:

- extreme schemes (paragraph 2.1)
- intermediate schemes (paragraph 2.2)

(For the sake of convenience we use the word "Unit" to refer to the Frigg Field Joint Venture formed between FNA and FUKA - "Unitized" has the corresponding meaning.)

2.1 Extreme Schemes

The schemes reviewed below in this paragraph 2.1 are at the extreme ends of the spectrum of possible schemes of cooperation between FNA and FUKA.

2.1.1 Joint Ownership of All Installations

2.1.1.1 Joint Ownership of All Field Installations

Joint ownership of all field installations would suppose that all installations currently separately owned by each of the two groups are transferred to the Unit.
The main features of this scheme are:

(a) all third party contracts are made by either FNA or FUKA, each in its sector, and not by the Unit,

(b) management organization (operating committee, operator-EAN) unchanged,

(c) all maintenance and operating costs are shared,

(d) surfaces are "technically" allocated for use by UK customers and Norwegian customers respectively (this allocation does not impact of the principle of that all parties share the profits derived from services to third parties),

(e) for additional investments the options are either:

(i) additional investments for third parties contracts are shared and all benefits are shared, or
(ii) additional investments are made by the contracting group, a maintenance fee is paid to the Unit, other benefits are retained by the contracting group.

Unresolved issues:
- are the Unit equities to be shared between FNA and FUKA as to 60.82% FNA and 39.18% FUKA or revised to 50/50 with corresponding adjustments for past expenditure?
- priority for use of unit installations when those are not sufficient to service two competing third party contracts?
- veto right of NH to block accommodation of UK gas at Frigg (the current 19.9% interest of NH would grant them a veto right if the passmark for decisions-currently 85%-is not changed)
- conciliation of complete unitization of Field facilities with the autonomy of the pipelines,
- fee to be paid by UK customers (including Alwyn) to the Unit's Norwegian participants, and vice versa.

2.1.1.2 Joint Ownership of All Transportation Installations

The joint ownership of all transportation installations would suppose that the pipelines and facilities currently separately-owned (MCP01 compressors, Terminal extensions) are transferred to the Unit.

Supported by NH at the outset, this alternative has several advantages:

(a) a single contractual scheme (joint ownership) throughout the Frigg system (from platforms to St. Fergus),
(b) elimination of competition between the two pipelines, thus minimizing conflicts of interest between FNA and FUKA,
(c) strengthening of the pipeline owners vis-a-vis both governments,
(d) strengthening of the pipeline owners vis-a-vis both the gas producers and BG,
(e) minimization of challenge by NH or Statoil for the pipelines operatorship
(f) sharing of all costs and benefits by all parties, also minimizing potential conflicts of interest.

This alternative which would prolong the field arrangements described in paragraph 2.1.1.1 presents however a number of distinct disadvantages:

(a) difficult financial adjustment of past expenditures and receipts (particularly in respect of the MCP01 compressors),
(b) difficult sharing of capacities among UK gas and Norwegian gas so that the financial and commercial interests of both States are protected,
(c) the participation of Statoil in the ownership of the UK pipeline may create a critical imbalance as long as the UK authorities cannot claim the participation of a British governmental agency in the Norwegian pipeline (the participation of the Norwegian State in licence 024 was never intended to extend to a participation in the transportation of UK gas in the UK pipeline),
(d) the principle of unanimity created in 1974 in respect of several major decision affecting the Norwegian pipeline would be hardly acceptable if the pipelines were unitized (veto right of Statoil and NH in respect of the transportation of UK gas in the pipelines would not be acceptable to the UK authorities, and vice-versa),
(e) the necessary amendment of the Treaty which stipulates that the Norwegian pipeline shall be owned by Norwegian entities (art. 13.2),
(f) the discrepancy in the pipelines licences terms (2003 for the Norwegian pipeline, 2026 for the UK pipeline) would give rise to delicate problems of compensation to the UK partners.

2.1.2 Separate Ownership of All Installations

This is a scheme achieving complete autonomy of each of the two groups both at the Frigg Field and in its transportation activities.

2.1.2.1 Separate Ownership of All Field Installations

This scheme supposes the discontinuation of any joint ownership of the field facilities upon the termination of the Frigg Field Main Agreement.

This alternative was considered in the past by Norsk Hydro who proposed the dissolution of the Unit and the creation of two "Gas Transportation and Additional Services Companies" (GATAS) with the following main features:

(a) All facilities and capacities would be splitted as to 50% each between the two GATAS
(b) Total, Elf and Hydro would have an equal ownership in both GATAS (one GATAS would be incorporated in the UK, the other in Norway)
(c) one of the GATAS would own the UK facilities (TP1 and the UK pipeline), the other would own the Norwegian facilities (TCP2 and the Norwegian pipeline)
(d) a third company would be incorporated and would own the common facilities (QP, flare column, compression and power plant).

This proposal was never further elaborated. Several issues were not at all considered: position of Statoil, operatorship of the installations, cooperation between the three companies etc.

It remains that the dissolution of the Unit contemplated in this scheme was the consequence desired at the outset by the parties to the Frigg Field Main Agreement. This sort of scheme would satisfy those parties to the Unit which have displayed a desire to operate autonomously.
However a scheme which would achieve complete autonomy of FNA and FUKA at the Frigg Field would require not only the distribution of the assets but also the elimination of the overlaps (QP, power generation plant, TCP2 compression) by inter alia the installation of compression facilities on TP1 and the installation of living quarters on the Norwegian side.
This sort of scheme would:
- permit that TP1 and QP be operated by a UK operator (nominally or effectively),
- facilitate the obtaining of UK government approvals for treatment of UK gas on TP1 (however if UK gas requires compression, the UK authorities may react to the gas crossing the borderline to be compressed at TCP2)
- correspond to the historical trend to de-unitize over time.

This scheme would require a distribution of the current joint property to each of the groups. The distribution of field assets is discussed in paragraph 2.2.2 below.

2.1.2.2 Separate Ownership of All Transportation Installations

The full autonomy of the Frigg pipelines can be achieved by the connection of Alwyn on Bruce, the connection of Bruce on the Frigg UK pipeline and a by-pass of MCP01 by the Frigg UK pipeline.
If this scheme was pursued, TP1 and MCP01 would no longer be used by FUKA for services to UK gases. It is therefore anticipated that FUKA would be in a position to request that, upon the depletion of Frigg, FNA take over TP1 and MCP01 as these platforms would no longer be used by FUKA.
If all agreements would have then terminated, FNA would have no other choice than to either take over, or agree to pay a rent for, these platforms if FNA should wish to continue to use them. Alternatively FNA could also discontinue their use and agree with FUKA to abandon them.

TP1 being located on a FUKA licence, FUKA has primary responsibility to the UK government for the removal of TP1 and would not therefore be in a position to simply pull out of TP1 leaving FNA with the burden to ultimately abandon and, if required, remove TP1 at its own expense. As noted before, the disposition of the Frigg installations after the depletion of Frigg is a matter for the Operating Committee to decide under the Frigg Field Operating Agreement; FNA will therefore always be in a position to oppose a disposition of TP1 which would go against FNA's interests.

In the case of MCP01, the Frigg Field Intermediate Platform Agreement will terminate upon the termination of the Frigg Field Transportation Agreement itself terminating upon the depletion of the Frigg Field Reservoir. Until such termination FUKA is bound to share in the annual fixed operating costs of MCP01 as well as variable operating costs (which latter costs are apportioned on the basis of volumes transported in each pipeline during the relevant year) whether or not FUKA by-passes MCP01.
After the depletion of the Frigg Field Reservoir however, FUKA should be in a position to decide they no longer wish to use MCP01 and request the abandonment, and if necessary the demolition, of MCP01. In this case FNA would, if FNA wishes to continue to use MCP01, have no choice but to effectively take-over the 50% of MCP01 FNA does not already own. FNA on the other hand may decide in 1993 to terminate its use of the St. Fergus Terminal. In that case FNA would have to carry all treatment operations at Frigg (including the extraction of hydrocarbon liquids) so that the product meets British Gas' specifications prior to its transportation to St. Fergus. FNA would then be in a position to request the abandonment of the St. Fergus Terminal. FUKA would then have no other choice but to take over from FNA the 50% of the Terminal FUKA does not already own.

A complete independence of the pipelines would, inter alia:

- eliminate the current flexibility in the use of the pipelines, reduce the reliability of the system as a whole, and thus seriously affect FNA's and FUKA's marketing clout both vis-a-vis new gas shippers and buyers,
- require a revision of the regime of priorities under the Odin TTA and East Frigg TTA (where access to the other pipeline is possible in cases of Force Majeure) with a corresponding revision of the price paid by the shippers for transportation services,
- raise the question of TOM's continued operatorship of the Frigg Norwegian pipeline which may result in a change of operator and thus also raise the question of EAN's continued operatorship of the Frigg Field,
- add operating costs generally but particularly for the group continuing alone the operation of MCP01.

The two extreme schemes reviewed above (complete autonomy, joint ownership of all installations) both require a radical departure from the present arrangements. Intermediate schemes allowing for sufficient autonomy of actions coupled with a cooperation between the two groups may better correspond to the future needs of the groups. Three basic intermediate schemes are reviewed below. (We have purposedly limited our review to three intermediate schemes it being understood that several sub-schemes can be envisaged in each case.)

2.2 Intermediate Schemes

2.2.1 Continuation of Current Arrangements

2.2.1.1 Field Arrangements

This scheme would maintain the joint ownership of the Frigg central complex and the separate ownership of certain additional surfaces and risers. Basically it would involve the renewal of the current field arrangements in an amended form to emphasize the new nature (mainly customer service) of the Frigg activities:

(a) all third party contracts are made by either FNA or FUKA, each in its sector, not by the Unit,
(b) management organization (operating committee, operator-EAN) unchanged for unit operations and management of Unit assets,
(c) each group is free to use its own additional facilities and surfaces,
(d) each group is free to use Unit facilities up to its equity percentage,
(e) each group has a priority right to use the available capacity in the other group's share of Unit facilities and to rent unused installations and surfaces separately-owned by the other group,
(f) the Unit will invoice each group fixed operating costs, variable costs being charged on the basis of use by each group, and

(g) third parties never own installations at Frigg.

This alternative is well known to us; it has been studied at length by EAN and is embodied in the draft Accommodation Agreement presented to FNA and FUKA in 1987-88.

The main drawback of this scheme is that, whilst this type of cooperation has proven workable, the depletion of the common wealth (the Frigg Field Reservoir) may justify a greater degree of autonomy for each of the groups in particular by a complete control and undisturbed ownership of their own assets on either side of the border.

2.2.1.2 Transportation arrangements

This scheme corresponds to the maintenance of the separate ownership of the pipeline coupled with a number of cooperation rules.

This alternative would require the renewal of the current arrangements (to the exception of the provisions relating specifically to the transportation of the frigg Field Reservoir gas), emphasis being placed on the shift in the nature of the Frigg pipelines (from flowlines to trunklines).

The issues involved in that alternative are as follows:

(a) Extent of Commercial Freedom of Each Group:

(i) the current arrangements have attempted to limit the competition between the two pipelines. The main aspect of this limitation is the definition of a third party tariff (a tariff never approved by the governmental authorities and now unilaterally repudiated by FNA),

(ii) the arrangements currently proposed by Statoil (draft Letter of Intent of November 1988) would further limit the competition between the two pipelines by allocating a "catching area" to each pipeline: the UK sector for the UK pipeline, the Norwegian sector for the Norwegian pipeline. This limitation would prevent EAN and TMN from shipping their future Norwegian productions in the UK pipeline. This limitation would be detrimental to the interest of these two companies as long as they own a larger interest in the UK pipeline than in the Norwegian pipeline,

(iii) the need of commercial cooperation between the two groups is reduced to the bare minimum if FUKA is able to secure the saturation of their pipeline for the next 15-20 years: In that case the cooperation will be limited to the provision by FNA of overspill transportation services to FUKA and, possibly, to the assistance of FUKA in the marketing of the Norwegian pipeline in the UK sector.

(b) Extent of Technical Cooperation

(i) the extent of the technical cooperation between the two groups is severely affected by the choices now being made. The decision made by FNA (irreversibly?) to dedicate the Norwegian pipeline to the transportation of lean or dry gas whilst the UK pipeline will transport rich gas for the next 15 or 20 years will prevent the continuation of:
(aa) the current optimisation of the use of the lines, and
(bb) the current regime of priorities,

(ii) the prospect of a third pipeline on the Frigg to St. Fergus route for the transportation of Beryl rich gas would limit the cooperation between the FNA and FUKA pipelines: in all likelihood Beryl and FUKA would cooperate primarily between them (same nationality, rich gas in both lines, use of St. Fergus terminal etc.),

(iii) several point of technical cooperation will remain:
(aa) the use of jointly-owned installations: MCP01, St. Fergus terminal,

(bb) the continued operatorship of both Frigg pipelines by TOM (TOM's tenure as operator of the Frigg Norwegian pipeline is opened to challenge by NH or Statoil at any time; it is doubtful however that EAN and TMN could see any advantage in that change of operatorship),

(cc) subject to technical feasibility, the transportation of liquids extracted at Frigg in the UK pipeline,

(dd) possible use of the MCP01 compression capacity on the FUKA pipeline.

(c) This autonomy-with-cooperation alternative will require an overhaul of the Frigg Field Transportation Agreement in particular. The Intermediate Platform Agreement and the Terminal Agreement could however be extended more or less in the same form.

2.2.2 Distribution of Assets and Cooperation

The pipelines being already separately-owned, this alternative concerns the field installations only.

The objective of that scheme would no be to achieve the complete autonomy of the two groups as envisaged in paragraph 2.1.2.1. However this scheme would also involve a transfer of ownership from the Unit to each of the groups.

2.2.2.1 Distribution of assets

If the Unit is dissolved upon the termination of the Frigg Field Main Agreement the Unit assets could be distributed to each of FNA and FUKA in accordance with the following principles:

(a) the Unit assets (the platform and current common facilities) lying in the UK sector are assigned by the Unit to FUKA and those lying in the Norwegian sector are assigned by the Unit to FNA.

(b) if these two assignments result in FUKA and FNA receiving a percentage of the Unit assets different from their current interest in the Unit assets (39.18% and 60.82% respectively) a compensation must be made.
A compensation supposes that a valuation of the Unit assets has been made. This valuation should be based on either the investment costs, or the operating costs or the removal costs or a combination of these costs.
The compensation may be paid upfront upon the assignment or paid in several instalments or paid in kind by the group owing the compensation making available its facilities to the other group.

(c) in consideration of the assignment FNA would agree to remain liable for 60.82% of the removal costs of the installations assigned to FUKA and FUKA would agree to remain liable for 39.18% of the removal costs of the installations assigned to FNA. The liability to share the removal costs of the other group will only arise to the extent the other group is compelled by law to remove its installations. This liability will not arise when the other group decides voluntarily to remove its installations.

(d) in consideration of the assignment, FNA and FUKA would agree to enter into a cooperation agreement for the use of the overlapping facilities.

2.2.2.2 Cooperation Between the Groups

The basis for this cooperation would involve the agreement of each group to:

(a) maintain the overlapping facilities assigned to it in good operating condition throughout the duration of the cooperation agreement (each group however would be entitled to mothball these facilities when they are not used by either group),
(b) offer booking in the overlapping facilities to the other group with reasonable advance notice (one could assume that FNA would have a permanent booking of part of QP and that FUKA would have a permanent booking of part of the power generation plant capacity; the TCP2 compression facilities could however be mothballed from time to time),
(c) pay a fixed rent to the other group when the other group facilities are booked.

2.2.2.3 Discussion

The scheme outlined in this paragraph 2.2.2 raises the following difficulties:

(a) Financial Difficulties

(i) determination of the cost elements to be used in the calculation of the compensation of one group by the other if the Unit assets distributed to it do not correspond to its current interest in those assets,
(ii) identification of all overlaps and determination in each case of specific rules for the right-to-use/right-to-rent granted to the group which does not own them,
(iii) determination of the rules for payment by one group of the compensation due to the other group as a result of the distribution of the Unit assets: up-front payment, instalment payments, grant of additional booking rights, exemption from rent of overlaps owned by the group owing the compensation etc.

(b) Operating Difficulties

If the Unit assets are distributed with a view to organising a maximal extent of autonomy for each group, the operatorship issue will be raised.
Assuming EAN retains the operatorship of FNA, the continued operatorship of EAN over the whole of the Frigg facilities is in doubt:
(i) is TOM prepared to delegate the operatorship of the Frigg UK assets to EAN?
(ii) is the UK government prepared to accept that a foreign company (being a resident of another state and therefore subject to the laws of that state) operate UK offshore facilities?
(iii) is the UK government prepared that the Frigg UK facilities be operated by EAN using a Norwegian labour force?

It remains that the appointment of a single operator would be practical and make economic sense.

(c) Limits

This scheme would limit the number of options for the future use of the Frigg installations. In particular the possible use of the Frigg Field Reservoir for base-load gas storage would be condemned.

(d) Political Difficulties

The unit has so far permitted that the Frigg operations enjoy a certain degree of extraterritoriality.

The distribution of the assets and separate operations on either side of the borderline will weaken the status of each group vis-a-vis its national authorities. (For instance, the granting of authorizations by the Norwegian government for the treatment at Frigg by FNA of Norwegian gas could be made expressly subject to a transfer of operatorship to Norsk Hydro or Statoil.)

2.2.3 Limited Distribution of Assets and Cooperation

As a further alternative, the scheme described in paragraph 2.2.2 (distribution of Unit assets on either part of the borderline) could be combined with the scheme currently selected for the draft Accommodation Agreement.
The draft Accommodation Agreement proposes the continuation of the Unit associated with separate facilities and separate services to third parties by each group.

A combination of the Accommodation Agreement proposal and the scheme described in this paragraph 2.2 would involve:

(a) distribution of TP1 and CDP1 to FUKA,
(b) distribution of TCP2 and DP2 to FNA,
(c) maintenance of joint ownership but limited to QP,
(d) to secure a more balanced distribution, the TCP2 compression would be assigned in whole to FNA whilst FNA would assign its interest in the MCP01 compression to FUKA.

This scheme would achieve a prolongation of the current transportation arrangements to the field installations:

(a) autonomy
(b) minimal joint property (MCP01, St. Fergus and QP).

This scheme would also justify that the field installations be operated by a single operator (EAN), the transportation being operated by a single operator (TOM).

Maximizing the autonomy of FUKA and FNA, this scheme could probably be acceptable to the governmental authorities.

However, this scheme would present the same difficulties as the scheme described in the foregoing paragraphs, in particular:

(a) compensation by one group to the other if the value of the installations distributed to each group is not identical,
(b) need to agree on rules for booking of capacities in the other group's installations,
(c) acceptability for the UK government that UK installations be operated by a Norwegian operator (EAN) employing a Norwegian labour force.

2.3 Conclusion

Of the five schemes reviewed above (ranging from full autonomy to complete integration of interests) one has been selected by EAN as best suited to the future use of the Frigg facilities.

That scheme (briefly described in paragraph 2.2.1) was embodied in a draft "Accommodation Agreement" as concerns the field facilities, that draft was submitted to the Frigg co-venturers. Whilst the Frigg co-venturers have so far refrained from submitting comments to EAN's draft, there is currently no conclusive evidence that the proposed scheme will not be accepted (whether or not in amended form) by the members of FNA and FUKA.

It seems therefore meaningful in the absence of any negative reaction from the Frigg co-venturers to maintain our position. We have no reason to believe that our draft agreement has now become inadequate. The only drawback is that we are not currently in a position to propose an alternative solution if our co-venturers should reject the principles of the draft Accommodation Agreement.

It seems therefore appropriate that we now proceed to:

- update the draft Accommodation Agreement to the extent that our perception of the future use of the Frigg installations so require
- prepare an alternative draft which would embody the scheme reviewed in paragraph 2.2.3 above which somewhat prolong the cooperation arrangements between the two pipelines, as a fallback proposal.

On the other hand the definition of a transportation scheme for the future rests primarily with TOM.

The alternative briefly described in paragraph 2.2.1.2 has proven workable whilst not minimizing the conflicts of interest between the two groups. If the current proposals of booking in the Frigg UK pipeline are confirmed (full booking of rich gas stretching well into the next century) then the joint ownership of the two pipelines cannot be seriously considered. The full autonomy alternative is extremist and does not seem justified (at least on FNA's side). The only viable alternative would therefore be a continuation of the current arrangements and should be directed towards the maintenance of maximal flexibility between the two lines so that the extraordinary reliability of the FTS is preserved.

CHAPTER VIII - PART 3

ALTERNATIVE STRUCTURE FOR FUTURE COOPERATION

The selection of the appropriate structure for future field and pipeline services will necessarily be influenced by the present relationship between the parties involved and their respective financial standing. Oil and gas exploration and production in Norway is typically carried on through the medium of an unincorporated joint venture. Being already associated in an unincorporated joint venture, the successful explorers have generally favoured a similar structure for their pipeline projects. This is the case for the Frigg pipelines and for Statpipe. The one exception is Norpipe A/S.

The future situation of the Frigg installations and pipelines will however be specific in that:
- the installations and pipelines are already fully depreciated (the financing options and requirements will not impact on the future structure adopted by the owners),
- once the Frigg Field Reservoir is depleted, the nature of the future business of the frigg installations and pipelines will be essentially customer service (however it is anticipated that customers will include some or all of the current Frigg owners in association with third parties),
- the long-term nature of field and transportation services agreements will call for uniform and consistent management, and
- field and transportation services agreements will provide an immediate and steady cash flow.

It is therefore relevant to consider whether the specific nature of the future activities may require that a specific legal structure be adopted.

3.1 The Choice

The choice of structure seems to lie between:
- an incorporated structure, being a special purpose company (a "pipeline company" or a "field and transportation services company") where the owners of the field installations and/or of the pipeline(s) become shareholders in a corporate vehicle to pursue common business objectives, or
- an unincorporated structure, in the nature of the familiar joint venture, where the participants contribute their respective shares of costs and individually receive a share of the output.

The current Frigg operations involve three joint ventures (each covered by one or more agreements): FNA, FUKA and the Frigg Unit.

An incorporated structure could be either:

(a) a treatment and transportation company involving the members of FNA and FUKA, which company would own the Frigg field installations and the two Frigg pipelines, or

(b) a treatment and transportation company involving the members of FNA, which company would own a share (say, 60.82%) of the Frigg installations (or certain specific installations: TCP2 and DP2) and the Frigg Norwegian pipeline, or

(c) a transportation company involving the members of FNA, which company would own the Frigg Norwegian pipeline, whilst the Frigg installations would be owned by one joint venture (the Unit) or alternatively two joint ventures (FNA and FUKA separately).

In each of the above cases the company could own and operate its facilities or alternatively own the facilities and entrust the operatorship of the facilities to an operator, this operator being one of the shareholders in the company or a third party.

The above cases do not address the choices that may be made by FUKA if the field installations are separately owned. FUKA could make their own choice of structure. At this stage it does not seem that the choices of FNA should be influenced by those of FUKA or vice versa. In other words it should be possible for instance that FUKA maintain the joint venture structure for its pipeline operations whilst FNA elect to create a transportation company.

The above cases are not all capable of being implemented. It appears in particular that case (a) where a single company owns all field installations and both pipelines will involve serious legal difficulties:

- the Treaty requirement that the Frigg Norwegian pipeline be owned by Norwegian entities indicates that FNA may transfer the ownership of the Norwegian pipelines and its attendant licences to a Norwegian entity only. This means that the company would have to be incorporated in Norway. In addition, in order for the Norwegian pipeline to be effectively controlled by Norwegian entities (as the Treaty impliedly requires), the shareholders would have to agree on decision-making procedures eliminating the interference of the UK shareholders in decisions affecting the Norwegian pipeline

- in parallel, the participation of Norwegian companies, Statoil in particular, in the ownership of the Frigg UK pipeline and its attendant licences, may not be regarded favourably by the UK authorities.

It seems therefore that this proposal has little or no chance of being approved by the authorities and by those participants whose rights to participate in decisions would be restricted.
In addition the extra-territoriality of the Norwegian pipeline for tax purposes may also raise difficult questions for the UK and Norwegian authorities to sort out.

Cases (b) and (c) where FUKA do not participate in the company owning the Norwegian pipeline and FNA do not participate in the ownership of the Frigg UK pipeline do not present the same difficulties.

Cases (b) and (c) are the only ones considered in the paragraphs which follow.

3.2 Company

3.2.1 Corporate Citizenship

If all the shareholders are Norwegian residents the company should be incorporated in Norway. This would be consistent with the Treaty (Norwegian entities to own the Frigg Norwegian pipeline) and should be acceptable by the Norwegian authorities.
The UK authorities should not be concerned as long as all the field assets owned by the company are in Norway and the Norwegian pipeline continues to enjoy its special status of extraterritoriality.

3.2.2 Share Capital and Financing

The participants would simply hold all the shares in the company. The company would be transferred all the field assets and pipeline assets owned by the participants as well as all attendant production licences and pipeline licences. This transfer could be made for a monetary consideration or without monetary consideration.

The company would make calls on its shareholders to contribute funds for operating expenses, and the company would either call on shareholders or enter into borrowing to underwrite the capital costs of additional equipment whenever necessary.

3.2.3 Commercial Aspects

The company itself would enter into contracts with shippers to treat and/or transport their product and would charge a tariff for that service. (For existing contracts - Odin, East Frigg - the company would receive assignment of those existing contracts, if economically possible).

Alternatively the company might trade-in the product by purchasing from producers upstream and on-selling to customers or end-users downstream. If the shareholders are themselves potential shippers they may move to establish a priority against third-party users by separate shareholders agreement or by a provision in the Articles of Association of the company.

Where the field installations and pipeline are used by third parties other than the participants the financial objectives would be expected to include some return on initial investment and to cover the prospective costs of removal of field installations.

Any profit would be distributed to the shareholders by way of dividend.

3.2.4 Operations

The Operations could be carried on by the company itself or entrusted to one operator or alternatively two operators (one for field services and one for transportation services).

The company would be entirely discrete from the participants. The shareholders would therefore be protected from any liability to third parties (except however where banks or other lending agencies would require performance guarantees from the shareholders as a condition of a loan agreement).

3.3 Joint Venture

The essential difference between a company and a joint venture is that a company is generally formed with a view to profit to be shared among the participants. A joint venture is generally formed in the oil and gas industry in order to generate a product to be shared among participants.

In the case of the Frigg future the association of the participants will not be primarily to derive a profit or generate a product but rather to provide a service to third party users.

The advantages of the joint venture are essentially flexibility of structure and independence of action for taxation purposes.

3.3.1 Flexibility

The flexibility is principally associated with the freedom for each participants to undertake operations separately from the others.

Typically all joint venture agreements provide for sole risk operations in which less than all the joint venturers participate.

In the Frigg context, the Heads of Agreement (Field Part) of 1980 has enabled the members of the Frigg Unit to undertake separate operations and own separate facility on the jointly-owned platforms. This was achieved simply by agreement between the members of the Unit. Had the Unit been a company the legal technicalities to achieve the same result would have been more complex and more formal (if at all possible). This would have involved in particular the issuance of preference shares to the group undertaking separate operations so that the profits derived from these operations could be channelled towards the member of the group undertaking these operations rather than towards the Unit. The creation and administration of several classes of shares is cumbersome and costly.

This procedure would also be required to reserve to certain shareholders (FNA) the benefit of certain continuing contracts (the Odin TTA in particular).

A joint venture is also more flexible than a company due to the fact that a joint venture is formed and functions simply by contract whereas a company has a separate legal existence and, as such, is strictly regulated by law.

Other flexibility aspects include:

(a) a joint venture may be terminated by mere agreement between its members whereas the winding-up of a company involves lengthy administrative steps,
(b) companies are subject to strict financial reporting requirements,
(c) companies are managed by bodies similar to those managing a joint venture but the appointment of directors, duties of directors and liabilities of directors are regulated in a manner which do not apply in the joint venture context, where these questions are freely negotiable.

3.3.2 Independence of Action for Taxation Purposes

The tax freedom attached to the joint venture structure is even more critical.

The joint venture structure enables the participants to avoid company tax on the profits of the operating vehicle which would have been payable had it been a company in which the participants simply hold shares.
Where the operating vehicle is a joint venture, all operating income is derived directly by the participants and taxed according to the tax position of each participant.

As the future tax position of each participant in the future activities of Frigg is unlikely to be exactly the same, each of the participant will wish to remain free to claim depreciation, investment allowances, deductions and the like directly and independently.

3.4 Effects of the Proposed Structure

The choice of a legal structure will have an effect as the relationship of the participants and the management of the business.

(a) Relationship of the Participants

In a joint venture structure the participants' relationship is essentially that of contracting parties. In an incorporated structure their relationship is that of shareholders.

As pointed out before the relationship between the shareholders would be subject to strict legal requirements that do not apply in the joint venture context.

These legal requirements add to the rigidity of the structure and would not result in simpler arrangements between the participants. Indeed the formal Articles of Associations (which define the purpose of the company, the appointment of directors, the rules for general meetings, share capital increases and share capital reductions, transfers of shares, and the like) would have to be supplemented by extensive documentation (called shareholders agreement) which would by and large reproduce the existing joint venture agreements and their attendant accounting procedure to regulate contributions of funds, the distribution of dividends, the staffing of the company, etc.

Moreover the re-organization of the Frigg activities under a company structure would require the amendment of all existing agreements between the Frigg co-venturers.

Finally the company structure would impose an unfamiliar legal environment for oil and gas activities. The joint venturers relationship has been satisfactorily tested in the Frigg context; it is uncertain that a more formal relationship would be more adequate in the future. The experience of Norpipe A/S would tend to prove that the shareholders' relationship is not best suited for oil and gas operations: the shareholders in NOrpipe A/S are currently seeking alternative organizational structures including going back to a joint venture structure.

(b) Management of the Business

By incorporating a company to run the Frigg activities, the participants will surrender control of the activities to that company.

They would create a shield (the so-called "corporate veil") between themselves and the activities, thereby limiting their liability to their involvement in the proposed activities of the company, but also their ability closely to control those activities.

In particular the company would normally have its own staff to conduct the Frigg activities. This staff would report directly to the management structure of the company. The members of the board of directors would not have a direct control on the staff in charge of day-to-day operations. For instance, even if third party contracts (field services agreements, transportation agreements etc.) were made subject to the company's board's approval, the members of the board (i.e. the shareholders) would not be directly involved in the negotiations and would therefore be unable to closely monitor the progress of these negotiations so that their respective interests are protected.

It is the experience of Norpipe A/S that the creation of a separate corporate structure has resulted in increased expenses compared to the joint venture structure where work is performed within already existing organizations.

3.5 Conclusion

Due to its formalism and rigidity the company structure does not seem, at this stage, to be an advantageous alternative to the joint venture structure for the Frigg activities.

CHAPTER VIII - PART 4

IMBALANCE IN FIELD OWNERSHIP AND PIPELINE OWNERSHIP

Since the 1988 swap arrangement between EAN, TMN and Statoil, the matter of the equalization of the interest of Statoil in the Frigg installations and the Frigg Norwegian pipeline has been evoked on several occasions.

The imbalance of the interest of Statoil in the Frigg Norwegian pipeline (24% now, and 29% in 1996) and in the Frigg installations used for services to Norwegian third party's gas (5%) called for corrective arrangements to avoid that Statoil favour high tariffs for transportation services and low tariffs for field services in negotiations with Norwegian third parties.

EAN's concerns are that:

(a) the agreed corrective arrangements (the so-called "fair-split" covenant) are arguably unprecise and may not constitute a sufficient protection in all cases, and

(b) an equalization of Statoil's interest in the pipeline and in the field installations would remove this type of difficulties and any conflict of interest between the pipeline joint venture and the field joint venture.

We will outline the procedure for achieving an equalization Statoil's interest (paragraph 4.1 below) and review the impact of this equalization (paragraph 4.2 below).

4.1 Procedure

Assuming EAN wishes to proceed with the assignment to Statoil of an additional interest (15% now and another 5% in 1996) in the Frigg installations this would require effectively an assignment of interest under licence 024, as well as:

(a) TMN's agreement to divest a proportionate interest to Statoil (as they did for the Frigg Norwegian pipeline)

(b) the waiver of preemptive right by NH (as member of the Norwegian group)

(c) the waiver of preemptive rights by TOM and Elf UK (as members of the Unit)

(d) approval of the Norwegian government (after consultation of the UK government if the Treaty is still in force).

The Norwegian joint venture agreement of 1971 would have to be amended reflect the new interest of Statoil in Licence 024.

Assuming a two-step scheme (identical to the pipeline arrangement) is followed in this assignment, the resulting interest of EAN in FNA in 1996 would fall to 21.4%. EAN, current operator of FNA with a 41.42% interest, enjoys a veto right to oppose any change of operatorship. This veto right would be lost in 1996 (75% majority only for change of operator).
Additionally the resulting interest of Statoil in the Frigg Unit would grant Statoil a right to veto any decision of the Operating Committee. No doubt this result would be carefully considered by the UK government when their approval is sought. Indeed, a veto right of Statoil in the Unit would enable Statoil to oppose, or otherwise interfere, with the treatment or transit of UK gas at Frigg.

4.2 Discussion

Further to the 1988 swap arrangement between EAN and Statoil (and in parallel, between TMN and Statoil), Statoil has acquired an additional interest in the Frigg Norwegian Pipeline. (Ultimately in 1996, Statoil will own a 29% interest in the Frigg Norwegian pipeline).
Statoil's interest in the Frigg production licences (5%) and, consequently, in the Frigg installations remained unchanged.

This discrepancy has given rise to an arrangement between the members of FNA (the "fair split" principle) to avoid any inclinations of Statoil towards maximising transportation revenues to the detriment of field services revenues when both the Frigg installations and the Frigg Norwegian pipeline are used to accommodate new gas.

The fair split principle has so far been respected in the determination of the treatment and transportation tariffs for East Frigg gas.
If these tariffs are approved by the Norwegian authorities and taken into account in the royalty assessment for East Frigg gas, one can consider that the fair split principle has been satisfactorily tested and therefore that there is no immediate incentive to assign an additional interest in the Frigg installations to Statoil.

It remains that the ownership by Statoil of a larger interest in the Frigg installations could constitute an incentive for Statoil to obtain that Norwegian gas be treated at Frigg or transit by Frigg.
The relative weight of this incentive is to be assessed in light of the economics of alternative solutions for Statoil and the other owners of the gas concerned.

In itself the level of interest of Statoil in the Frigg installations will not open the UK market for Norwegian gas and may not be in all cases a decisive factor to attract new gas at Frigg.

In my view the assignment of an additional interest in the Frigg installations to Statoil cannot be properly considered as long as:

(a) we do not know whether the joint ownership of the Frigg installations will survive the depletion of the Frigg field Reservoir,
(b) the future arrangements are not defined,
(c) EAN and Total are not offered an acceptable consideration for the sale of an additional interest to Statoil,
(d) we do not know whether the assignment will clearly assist in attracting Norwegian gas at Frigg,
(e) the resulting veto right of Statoil in the Unit decisions may be regarded as detrimental to the UK commercial interests, and
(f) the operatorship of EAN for the future activities at Frigg is not confirmed.

It is considered however that an increased participation of Statoil in the Frigg installations may in the longer term constitute a key factor to attract new business to Frigg. Ideally that participation could be offered by EAN in exchange of an interest in the gas field proposing to use the Frigg installations for treatment or other services.

4.3 Newcomers

The question of whether or not the imbalance of ownership in the Frigg installations and the Frigg Norwegian pipeline should be rectified raises a further question: would it be advisable to invite new companies to participate in association with the current owners in the future activities of Frigg?

It is probably vain at this stage to attempt to answer this question as a matter of principle. Proper consideration will be given to the matter when potential newcomers are identified so that the consequences of the participation of a particular company can be assessed in light of the perceived or proposed future activities at Frigg: the use of the Frigg field Reservoir at base-load storage, for instance, may warrant the participation of either (or both) the buyer or the producers of the gas stored in Frigg Field Reservoir.

The following general considerations however are relevant at this stage:

(a) the proposed assignment of an interest in the Frigg installations by anyone or more of the current Frigg owners will, if the present principles remain, be subject to preemptive rights. It is therefore apparent that, in order to achieve the desired result, all the Frigg owners will have to agree beforehand on the participation of a new company,

(b) the proposed assignment of an interest in the Frigg installations to a newcomer will immediately raise the question of a new imbalance in the ownership of the installations and the pipelines. If the imbalance was not rectified then a prerequisite of the assignment would be to obtain the assignee's agreement to a strict principle of "fair-split" of income for the field services and the transportation services,

(c) if EAN (in the case of the Frigg installations) and TOM (in the case of the UK pipeline) should participate in the assignment of an interest to a newcomer their resulting participating interest may, compared to Norsk Hydro's or Statoil's, affect their ability to claim continued operatorships,

(d) prior to any assignment of an interest to a newcomer it would be advisable that all agreements for the Frigg future be in place between the current Frigg owners so that they can be imposed on the newcomer. That way, one may expect minimal interference of the newcomer in the definition of the rules governing the future and ensure that these rules will continue to be satisfactory to the current Frigg owners,

(e) in order to attract a customer to Frigg it may not be sufficient to offer a participating interest to one company (the operator of the customer field, for instance), if several companies participate in the customer field; in that case it will be appropriate to decide what is the minimum interest EAN wishes to keep, and

(f) an assignment to Statoil of an additional interest in licence 024 may leave EAN (and TMN) with too small an interest to contribute in any assignment of interest to a newcomer.

As previously noted it is difficult to go beyond these preliminary general considerations. Each proposed new participation will have to be studied on a case by case basis in light of the situation of the prespective new participant and of the conditions which can then be offered to that prospective new participant.

SCOPE OF WORK

EVALUATE ALL POSSIBLE FUTURE USE AND ORGANISATION OF THE FRIGG FIELD FACILITIES.

FOLLOWING AREAS TO BE CONSIDERED:

* POSSIBLE FUTURE STATUS OF THE FRIGG FACILITIES
* EVALUATION OF FUTURE OPERATING COST OF THE FRIGG FACILITIES
* POTENTIAL CUSTOMERS FOR MAKING USE OF THE FRIGG FACILITIES
* FINANCIAL CONSIDERATIONS
* LEGAL AND CONTRACTUAL ASPECT

THE PURPOSE OF THE WORK IS TO ESTABLISH A BASIS FOR A FRIGG FUTURE STRATEGY

CONTENT OF REPORT

FORGET ME NOT
TECHNICAL ASPECTS

I. TECHNICAL DESCRIPTION OF FRIGG

- FRIGG FIELD FACILITIES
- FRIGG TRANSPORTATION SYSTEM

II. POTENTIALS FOR THE FUTURE

- FRIGG CENTRAL COMPLEX AVAILABILITY
- LIFETIME ANALYSIS
- FUNCTIONS AVAILABLE ON FRIGG
- POSSIBLE ADDITIONAL FUNCTIONS

III. COST ASPECTS

- OPERATING COSTS
- INVESTMENT COSTS

TECHNICAL DESCRIPTION OF FRIGG

LOCATION: NORTH-SEA NW/UK BORDER
190 KM FROM THE NW COAST
340 KM FROM THE SCOTTISH COAST
WATER DEPTH: 100M

RESERVOIR: INITIAL GAS IN PLACE: 235 BSm3
FLUID:NAT.GAS(METHANE 95%)
SP.GRAVITY=0.58

GENERAL ARRANGEMENT:

*FRIGG FIELD FACILITIES

- -2 DRILLING PLTF(S) : CDP1 AND DP2
- -2 TREATMENT " : TP1 AND TCP2
- -1 QUARTERS " : QP
- -1 FLARE " : FP

*TRANSPORTATION AND TREATMENT SYSTEM

- -2 x 32" PIPELINES IN PARALLEL (363km FRIGG-ST.FERGUS,SCOTLAND)
- -1 INTERM.COMPRESSION PLTF: MCP01
- -1 TERMINAL AT ST.FERGUS (Processing to sales specification)

DESCRIPTION OF FRIGG FIELD FACILITIES

	TP1	TCP2	TOTAL
WATER/COND/GAS SEPARATION	60	60	120 MSm3/D
GAS DEHYDRATION	>60	>60	>120 MSm3/D
FISCAL GAS METERING	45	60	105 MSm3/D
COND.EXPORT CAPACITY	900	900	1800 m3/D
WATER DISPOSAL TREATMENT	2500	2500	5000 m3/D
POWER GENERATION	7.5	4.2	11.7 MW
GLYCOL REGENERATION	45	45	90 m3/H
MAIN COMPRESSION POWER		3x40 3x32 MW	80 MSm3/D
LOW PRESSURE COMPRESSION POWER		2x4.5 2x12MW	9 MSm3/D 2x12 MW
COMPRESSION UTILITY POWER GENERATION		2x12	2x12 MW
SATELLITE EXTENSION		10 7 6	23 MSm3/D

FRIGG TRANSPORTATION SYSTEM

* PIPELINES
  2 X 32" PIPELINES - 363 KM LONG

* MCPO1 (MANIFOLD COMPRESSION PF)
  2 COMPRESSORS 38000HP

* ST. FERGUS TERMINAL
  PROCESSING TO COMMERCIAL SPECIFICATIONS
  FREON CHILLING (-18/-22 DEG.C)

* TRANSPORTATION CAPACITY
  - 1 BARE LINE : 33.3 M Sm3/D
  - WITH ONE MCPO1 COMPRESSOR : 40.8 M Sm3/D
  - WITH TWO MCPO1 COMPRESSORS: 43.8 M Sm3/D (SERIAL)

* TREATMENT CAPACITY AT ST. FERGUS

  - EXISTING TERMINAL
    . GAS : 108 M Sm3/D (6 X 18)
    . LIQUID: 600 m3/D

  - PHASE III TERMINAL
    . RICH GAS: 20 M Sm3/D (2 X 10)
    . LIQUID : 1000 T/D

POTENTIALS FOR THE FUTURE
FRIGG CENTRAL COMPLEX AVAILABILITY

LOAD CAPACITY (T)

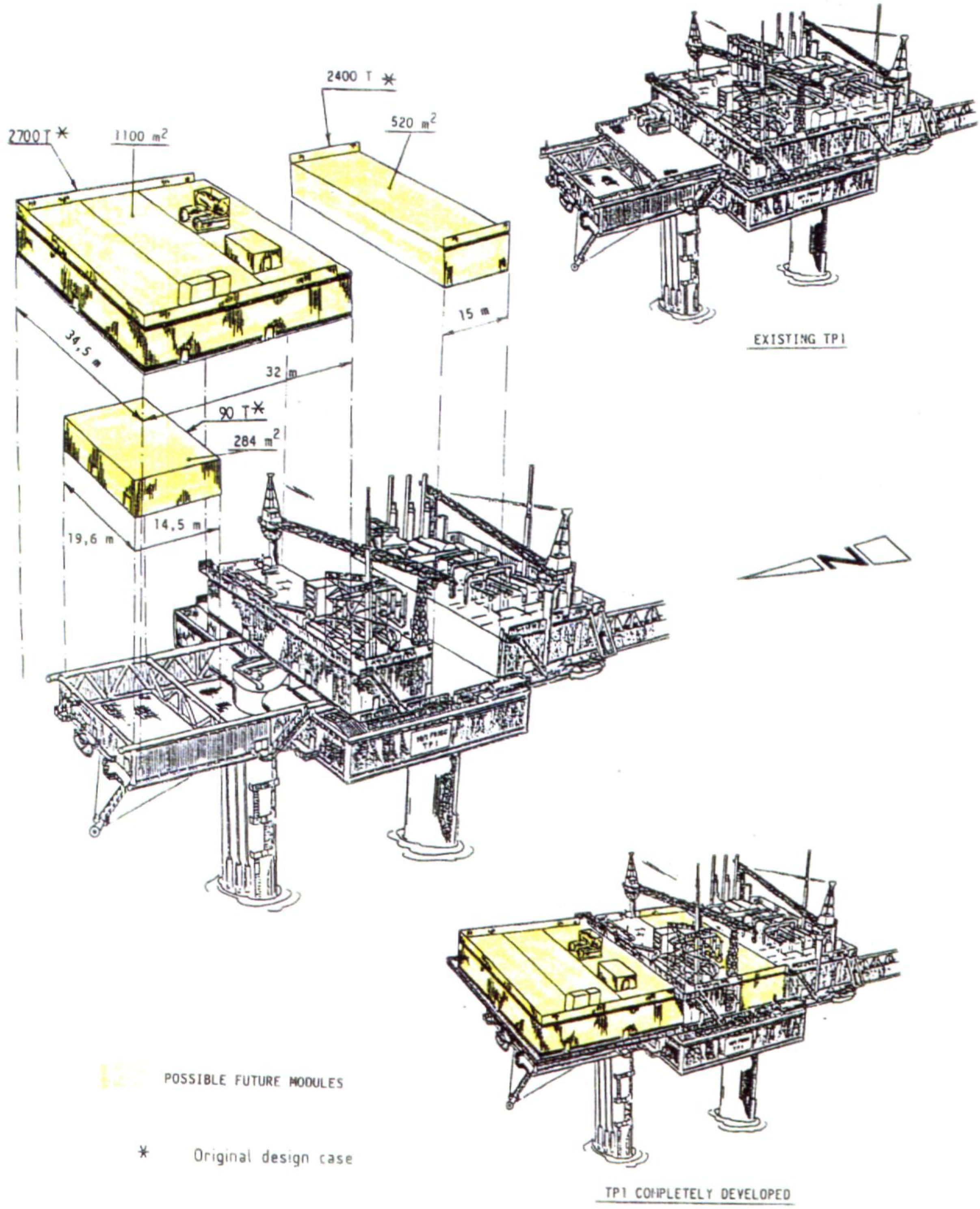
	TP1	TCP2	TOTAL
- INITIAL CAPACITY	10800	21300	32100
- PRESENT OCCUPANCY	8000	17350	25350
- PRESENT AVAILABILITY	2800	3950	6750
- POSSIBLE AVAILABILITY	7250	3950	11200

AVAILABLE AREAS (m2)

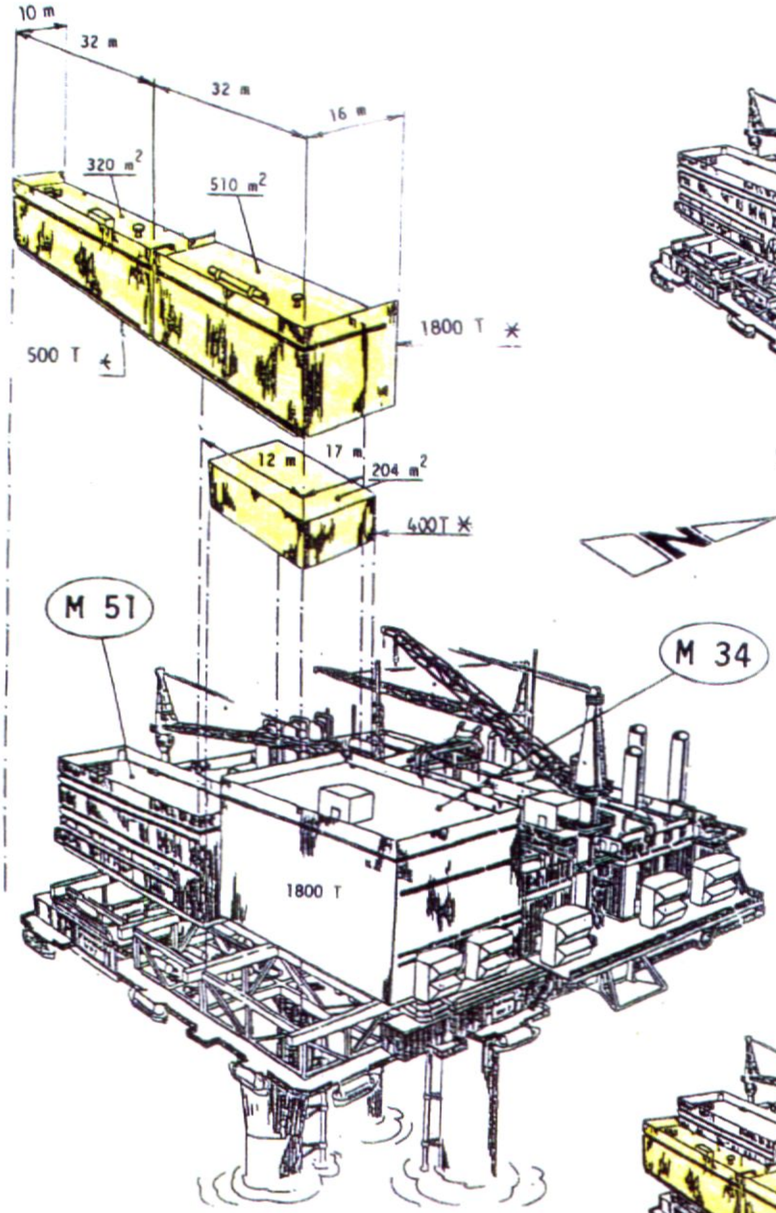
- CELLAR DECK	290	275	
- MAIN DECK	1100	830	
TOTAL	1390	1105	2495

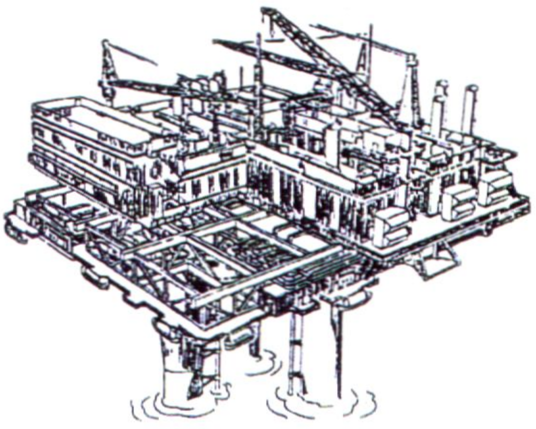
CONNECTIONS (TP1/TCP2)

- AVAILABLE RISERS: 24", 26", 32", 18"
- AVAILABLE J.TUBES: 10.75", 12"
- CONNECTIONS WITH RISER SUPPORT STRUCTURE (36", 42")

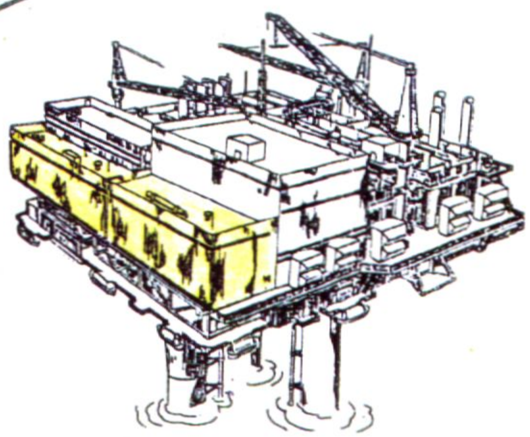


Rev.	Date	DESCRIPTION	by	app.	Contractor				
0	07.03.88	First issue	MO	TBr.		elf aquitaine norge a/s P.O. Box 168 4001 Stavanger	FRIGG FIELD	Installation: TP1 System: ARC. Job no: Scale: ~ FUTURE MODULES TP1	Drwg. no. FA 85 00 00 10 09 Rev. 0 Sheet 1/1





EXISTING TCP2
INCLUDED M 51



TCP2 COMPLETELY DEVELOPED

POSSIBLE FUTURE MODULES

* Original design case

				Controller	elf aquitaine norge a/s p.o box 168 4001 Stavanger	Installation TCP2	System ARC.
						Job no	FUTURE MODULES TCP2
						Scale ~	
0	15.02.88	First issue	MG		FRIGG FIELD	Drwg no FF 85 00 00 10 08	Rev 0 Sheet 1 1
Rev	Date	DESCRIPTION	by	app			

POTENTIALS FOR THE FUTURE
LIFETIME ANALYSIS

STRUCTURES

TP1 ›
TCP2 › TO AT LEAST 2025
QP ›

CDP1 ›
› LIFETIME EXTENSION TO BE PERFORMED
DP2 ›

TOPSIDE EQUIPMENT

TP1/TCP2 ›
MAIN ROTATING EQUIPMENT › TO AT LEAST 2025
MAIN PROCESSING EQUIPMENT ›

POTENTIALS FOR THE FUTURE
ADVANTAGES OF FRIGG

* GEOGRAPHICAL LOCATION
* DUAL EXPORT SYSTEM TO UK
  60-80 MSCM/D
* HIGH PROCESSING CAPACITIES
  FOR "LEAN" GAS: 80-120 MSCM/D
* HIGH EXPORT CAPACITY
  COMPRESSION: 80-120 MSCM/D
* AVAILABLE SERVICES
  - POWER
  - TELECOM
  - FIELD CONTROL AND DATA AQUISITION
  - REMOTE CONTROL
* LIFETIME TO AT LEAST 2025
  STRUCTURES: TP1, TCP2, QP
  EQUIPMENT: ROTATING AND PROCESSING
* POSSIBILITY OF ADDITIONAL FACILITIES
  11000 TONNES
* SAFETY
  SEPARATE PLATFORMS

POTENTIALS FOR THE FUTURE FUNCTIONS OF FRIGG

MINOR MODIFICATIONS
- TIE-IN AND TRANSIT OF LEAN OR COMMERCIAL GAS
- PROCESSING OF FRIGG GAS TYPE
  DEHYDRATION, METERING
- COMPRESSION OF EXPORT GAS
- COMPRESSION OF LOW PRESSURE GAS
- CONDENSATE EXPORT (SMALL QUANTITY)

MEDIUM SIZE MODIFICATIONS
- GAS CONDENSATE SEPARATION WITH CONDENSATE RETURN
- RESIDUAL GAS COMPRESSION
- STABILIZED OIL STORAGE (TCP2 COLUMNS)

MAJOR MODIFICATIONS
- PROCESSING OF RICH GAS TO COMMERCIAL SPECIFICATIONS
  WATER DEW POINT, HC DEW POINT
  DEHYDRATION, HRU (TURBO-EXPANDER),
  LIQUID EXPORT
- CO2 REMOVAL
- OIL PROCESSING (SEPARATION, STABILIZATION)
- WATER INJECTION
- EXTERNAL RISER STRUCTURES

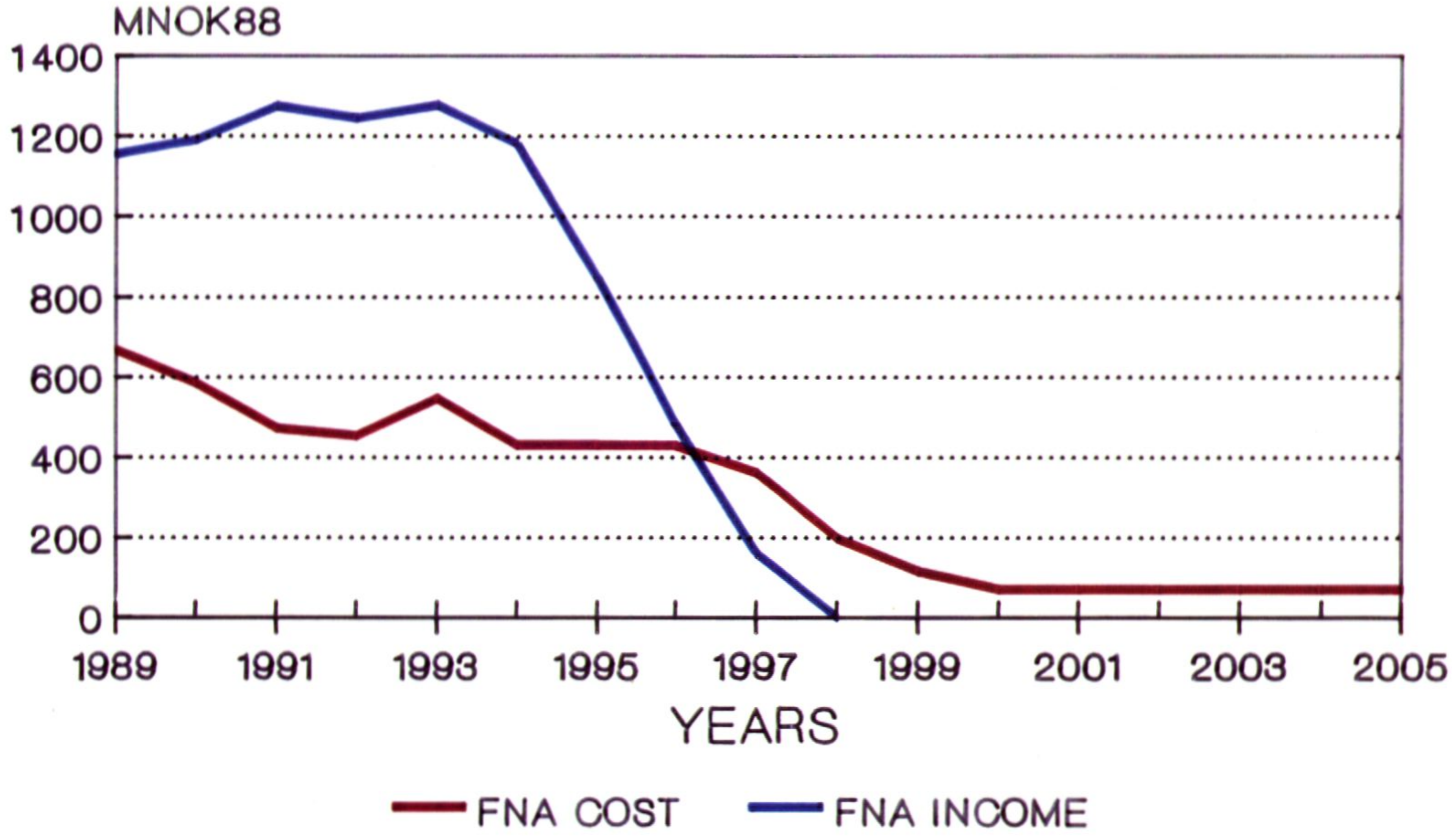
FORGET ME NOT

* OPERATING COSTS

  - ALLOCATION PROCEDURE
  - OPERATING COST EVALUATION
    . BASE CASE
    . REFERENCE CASE
    . POSSIBLE FUTURE SCENARIOS

* ADDITIONAL INVESTMENTS

FNA FINANCIAL SITUATION
FROM 1989 TO 2002



AA/2.3.89

ALLOCATION PROCEDURE
FOR FUTURE OPERATING COST

FRIGG UNIT PERIOD

- SPEC. FNA/FUKA ALLOCATION
- UNITIZED OPERATION ACC.TO LIFTING

88 89 90 91 92 93 94 95 96 97 98

POST FRIGG UNIT PERIOD

PRINCIPLES OF
ACCOMADATION AGREEMENT

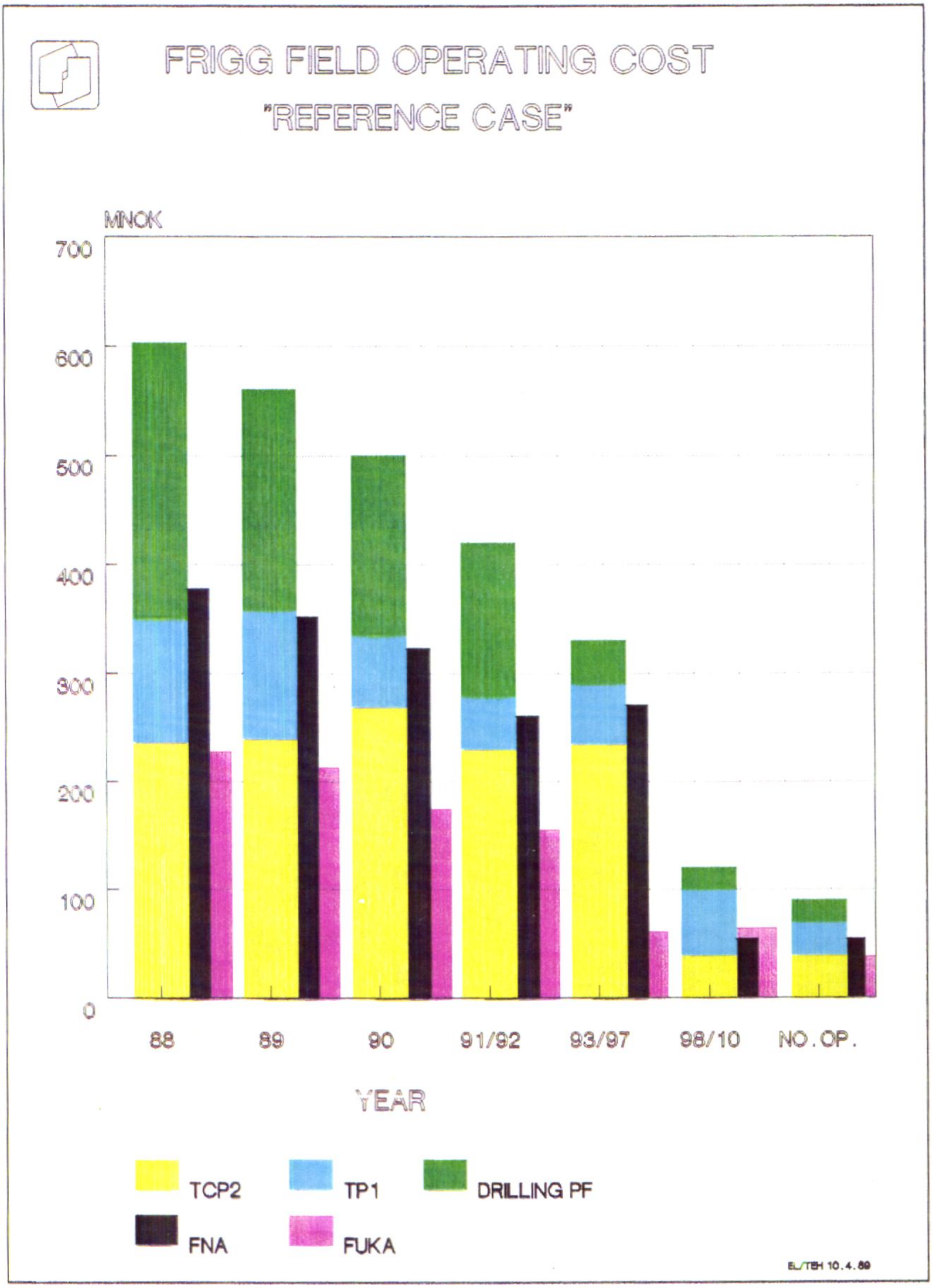
- BASE CASE (shut-in status)
- REFERENCE CASE
  OPEX ALLOCATED TO
  FUNCTIONS AND THEN
  TO THROUGHPUT

FRIGG FUTURE

POSSIBLE
OPERATIONS

REF:BASE CASE

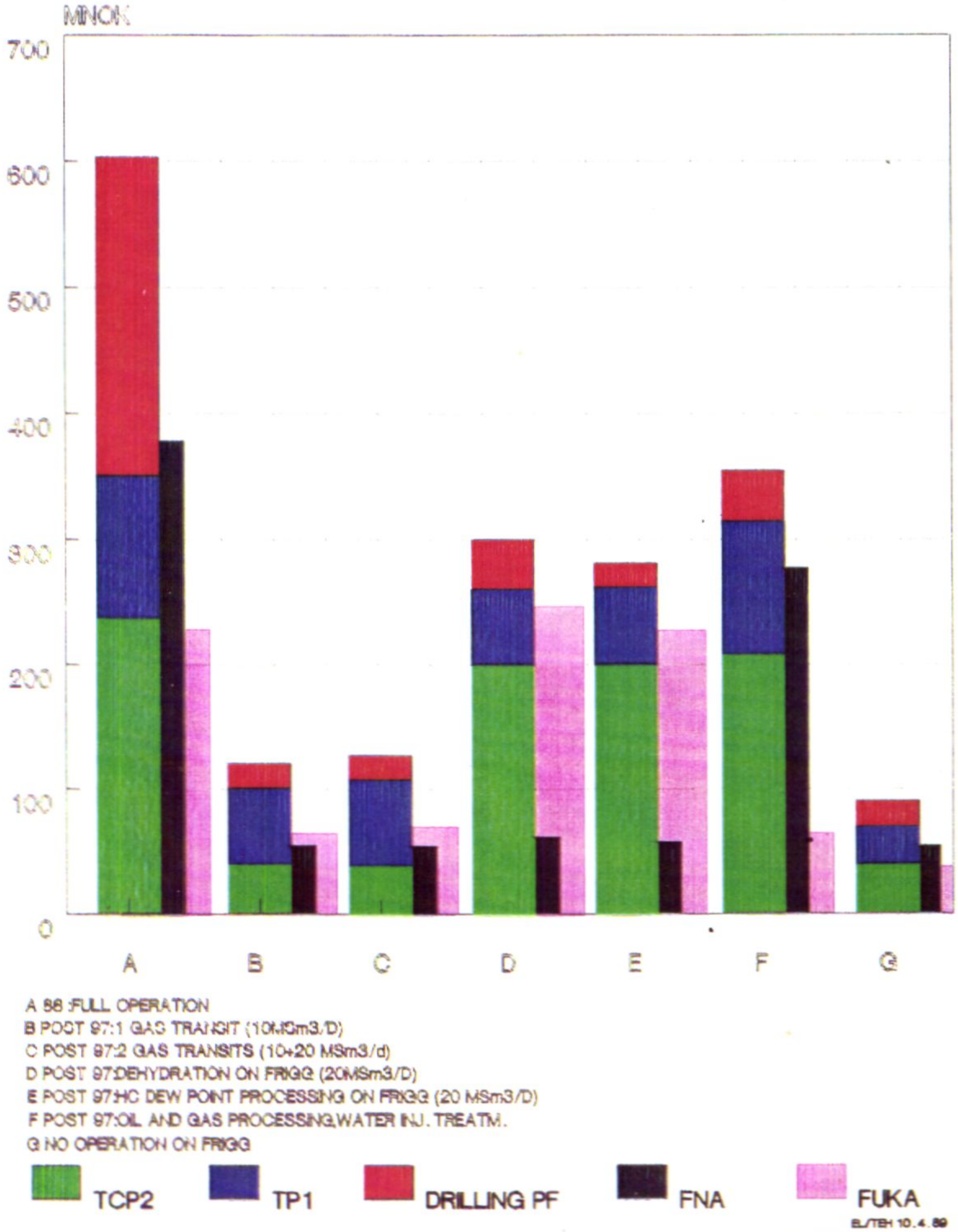
EL 10.4.89



FRIGG FIELD OPERATING COST
"REFERENCE CASE"
MNOK
700
600
500
400
300
200
100
0
88
89
90
91/92
93/97
98/10
NO. OP.
YEAR
TCP2
TP1
DRILLING PF
FNA
FUKA
EL/TEH 10.4.89

FRIGG FIELD OPERATING COST

COMPARISON OF POSSIBLE OPERATIONAL SCENARIO



FORGET ME NOT
POSSIBLE ADDITIONAL INVESTMENTS (I)

- PROCESSING OF 20 M Sm3/D RICH GAS
  TO FTS SPECIFICATIONS (-15 DEG.C AT 140 BAR)

  WITHOUT METHANOL REGENERATION: 360
  WITH METHANOL REGENERATION: 420

- PROCESSING OF RICH GAS TO COMMERCIAL SPECIFICATIONS.
  CHILLING TO -35 DEG.C, NO LIQUID STABILIZATION

CAPACITY (M Sm3/D)		12	18
INVESTMENTS	FRIGG PLATFORMS	600	725
	PIPELINE	420	420

- PROCESSING OF RICH GAS TO COMMERCIAL SPECIFICATIONS
  CHILLING TO -35 DEG.C, LIQUID STABILIZATION

  CAPACITY: 10 M Sm3/D

INVESTMENTS	FRIGG PLATFORMS	1040
	PIPELINES (GAS AND CONDENSATE)	660

- CO2 REMOVAL
  SWEETENING CAPACITY: 6.5 M Sm3/D
  INVESTMENT: 1000

FORGET ME NOT
POSSIBLE ADDITIONAL INVESTMENTS (II)

- TIE-IN TO EXISTING FACILITIES
  - CAPACITY: 20 M Sm3/D
  - INVESTMENT: 90/200
- COMPRESSION OF LOW PRESSURE GAS
  - CAPACITY: 10 M Sm3/D
  - INVESTMENT: 680
- PROCESSING OF ASSOCIATED GAS
  - CAPACITY: 3 M Sm3/D
  - INVESTMENT ON FRIGG: 330
- PROCESSING OF CRUDE AND ASSOCIATED GAS
  - CAPACITY: 50000 BPD
3 M Sm3/D
100,000 BWPD
  - INVESTMENT ON FRIGG: 1300

THE FRIGG

CENTRAL COMPLEX

CAN ACCOMODATE

ANY TYPE

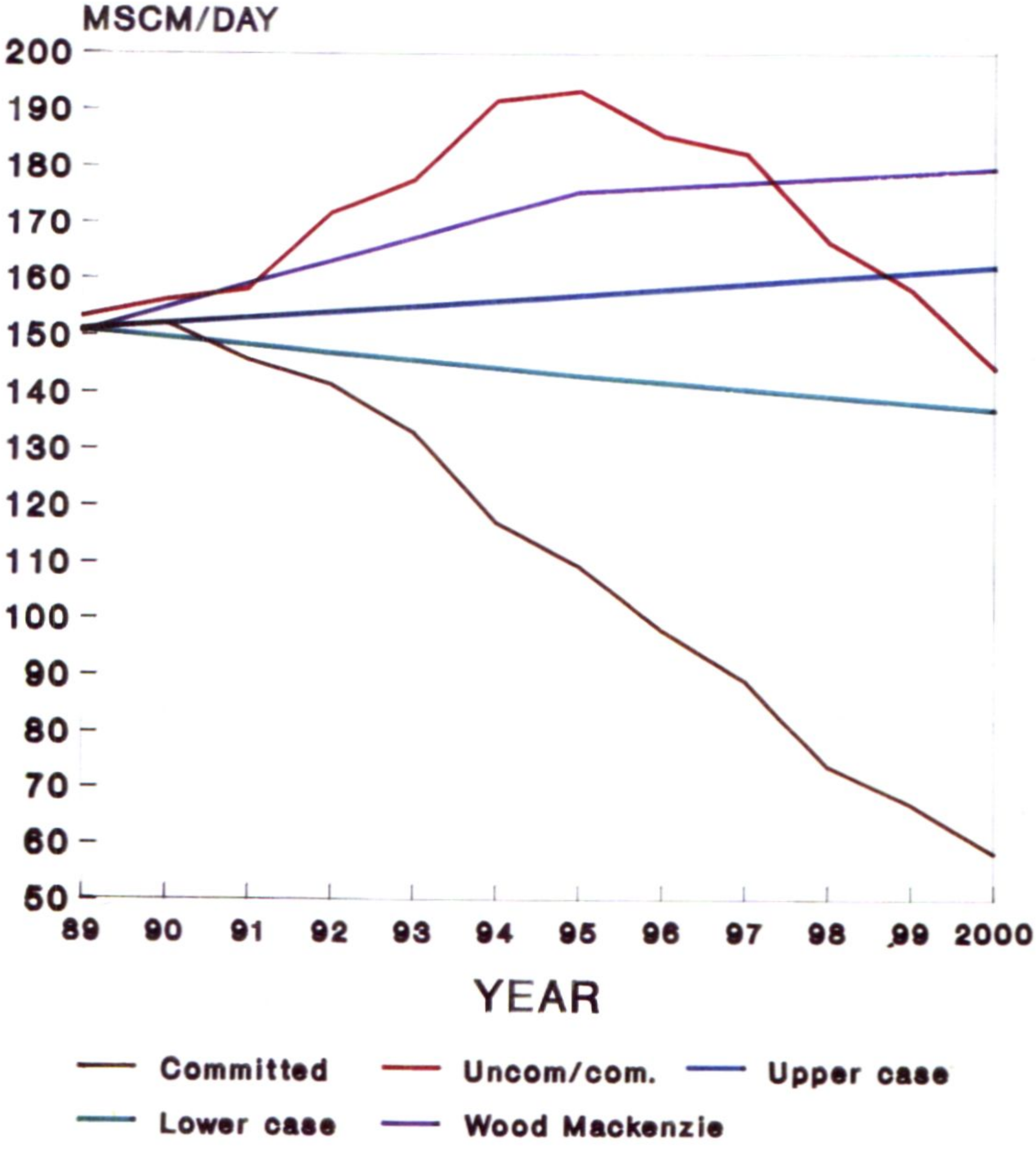
OF

CONVENTIONAL

OFFSHORE HYDROCARBON

PROCESS

THE UK MARKET
GAS PRODUCTION WITH DEMANDS 1989-2000



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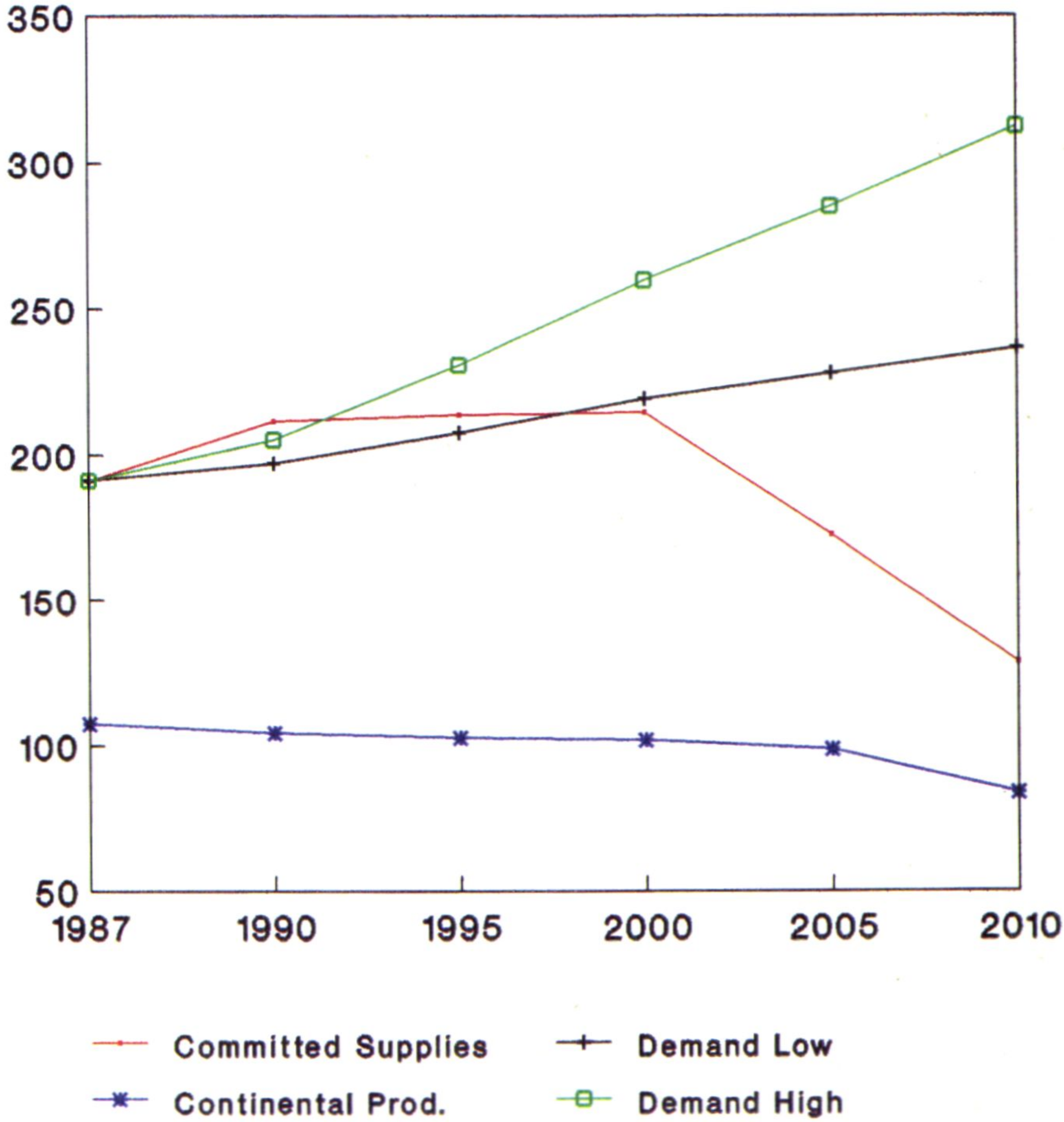
CONTINENTAL GAS BALANCE
1987 - 2010



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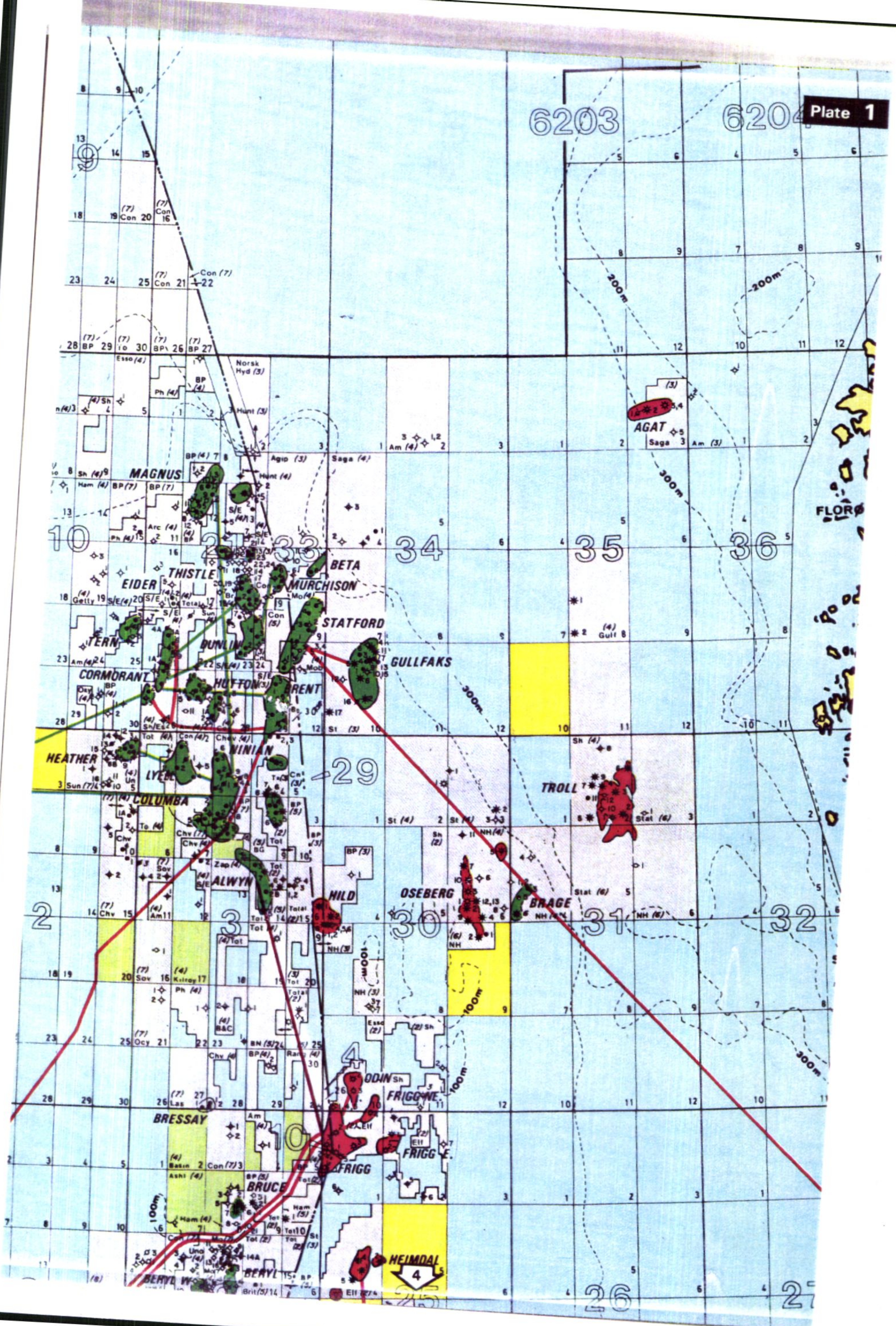
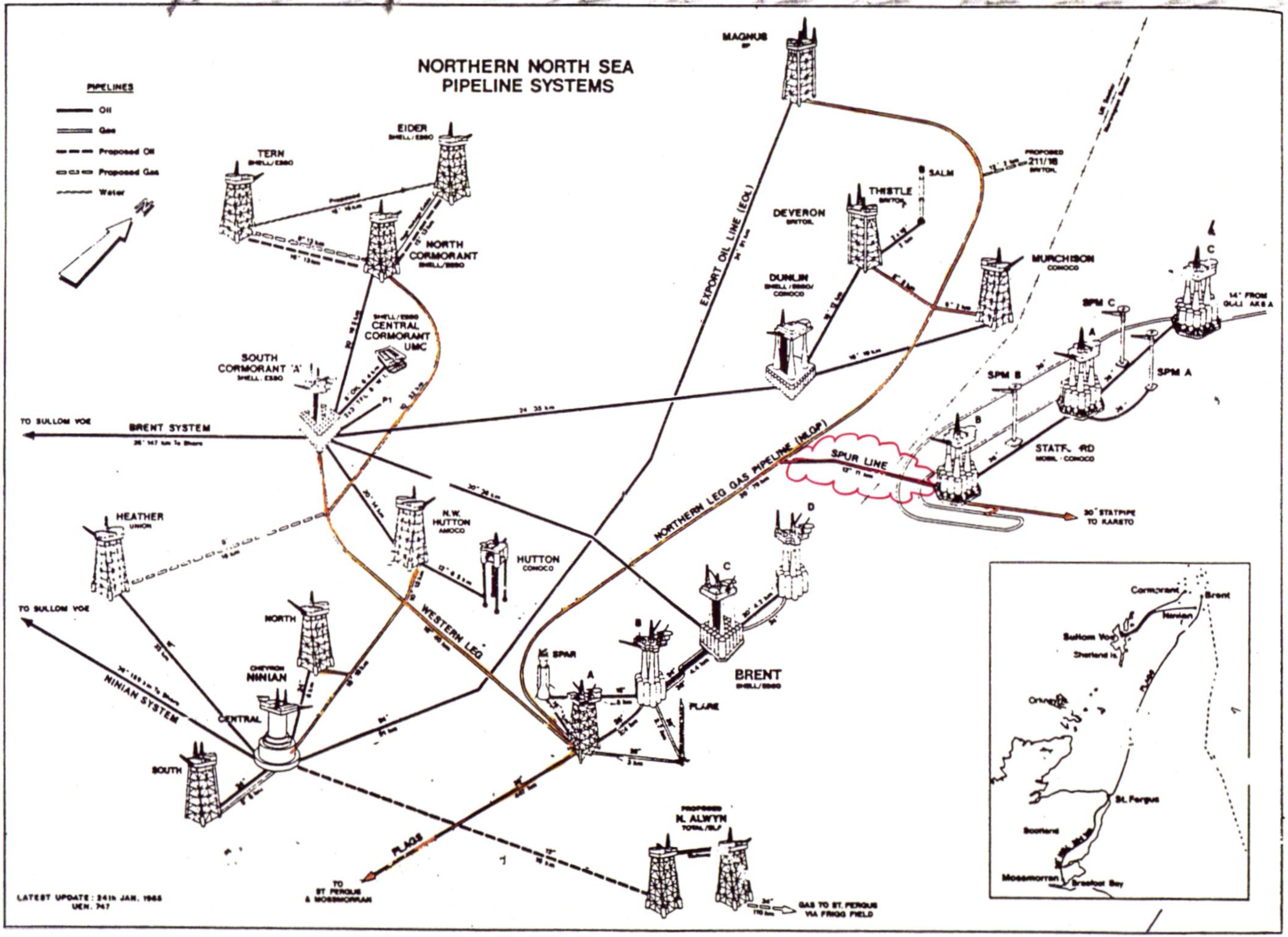
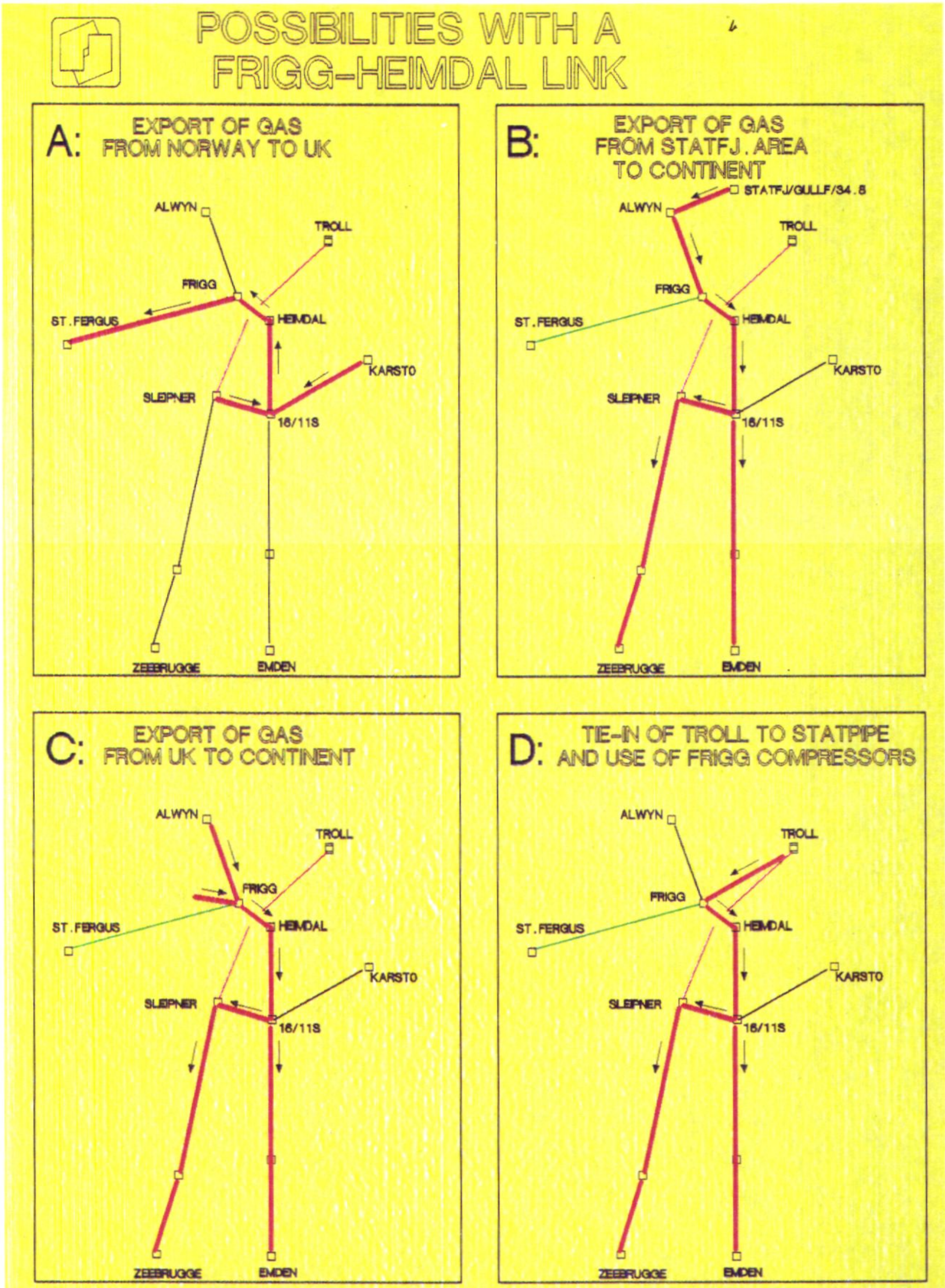
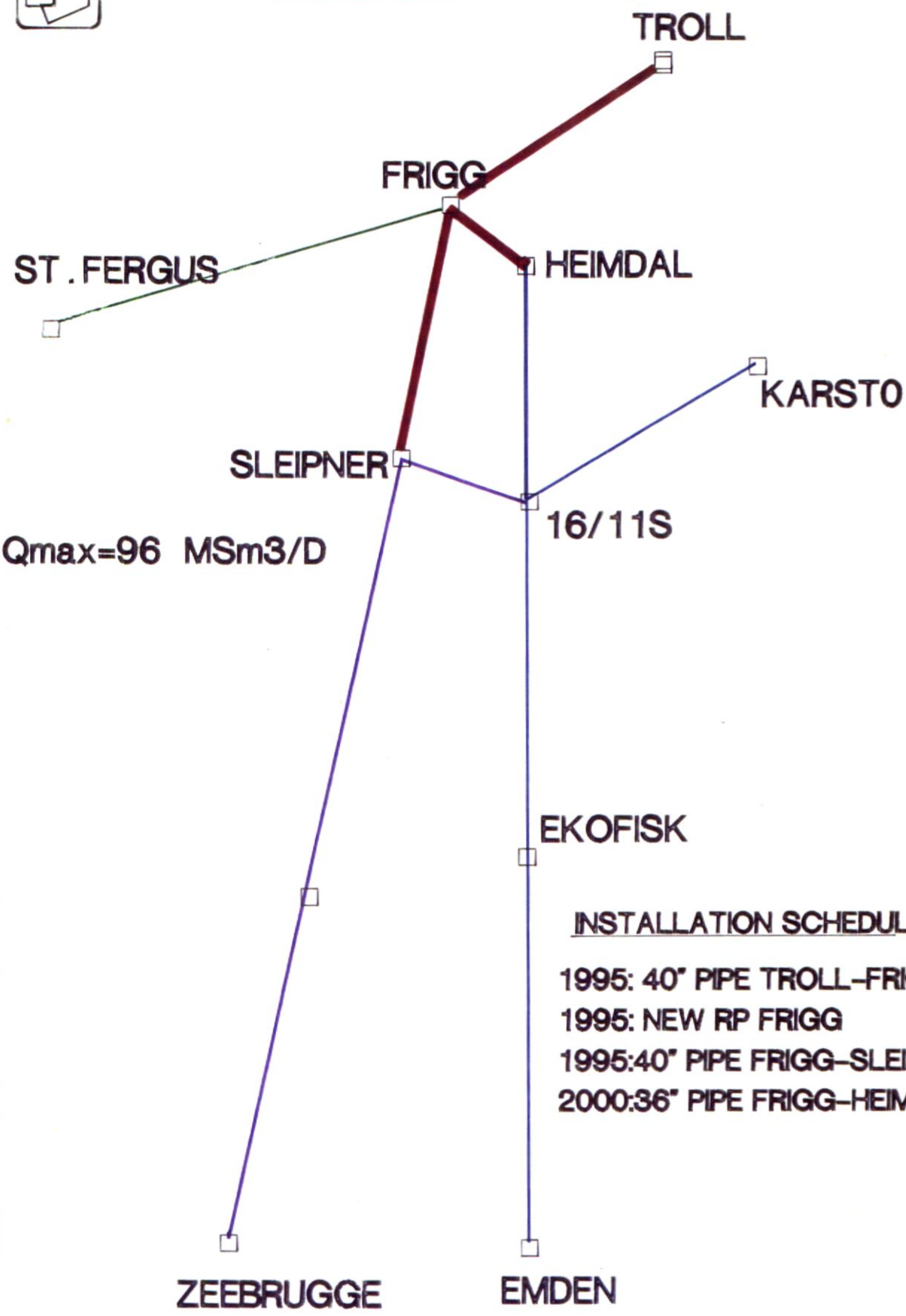


Plate 1
6203
6204
AGAT
MAGNUS
THISTLE
EIDER
TERN
CORMORANT
BETA
MURCHISON
STATFORD
DUNLIN
HUTTON
BRENT
GULLFAKS
HEATHER
NINIAN
LYELL
COLUMBA
TROLL
ALWYN
HILD
OSEBERG
BRAGE
ODIN
FRIGG NE.
FRIGG E.
FRIGG
BRESSAY
BRUCE
BERYL W
BERYL
HEIMDAL
FLORØ
200m
300m
100m


NORTHERN NORTH SEA
PIPELINE SYSTEMS
PIPELINES
Oil
Gas
Proposed Oil
Proposed Gas
Water
TERN
EIDER
NORTH
CORMORANT
SOUTH
CORMORANT 'A'
CENTRAL
CORMORANT
UMC
TO SULLOM VOE
BRENT SYSTEM
HEATHER
UNION
N.W.
HUTTON
AMOCO
HUTTON
CONOCO
WESTERN LEG
NORTH
CHEVRON
NINIAN
CENTRAL
SOUTH
NINIAN SYSTEM
FLAGS
TO
ST FERGUS
& MOSSMORRAN
PROPOSED
N. ALWYN
GAS TO ST. FERGUS
VIA FRIGG FIELD
MAGNUS
EXPORT OIL LINE (EOL)
DEVERON
DUNLIN
THISTLE
SALM
PROPOSED
211/18
MURCHISON
CONOCO
SPM C
SPM B
SPM A
STATF. RD
MOBIL / CONOCO
SPUR LINE
NORTHERN LEG GAS PIPELINE (NLGP)
30" STATPIPE
TO KARSTO
BRENT
SPAR
FLARE
Cormorant
Brent
Ninian
Sullom Voe
Shetland Is.
Orkney
St. Fergus
Scotland
Mossmorran
Braefoot Bay
LATEST UPDATE : 24th JAN.
UEN. 747


POSSIBILITIES WITH A
FRIGG-HEIMDAL LINK
A: EXPORT OF GAS
FROM NORWAY TO UK
ALWYN
TROLL
FRIGG
ST.FERGUS
HEIMDAL
KARSTO
SLEIPNER
16/11S
ZEEBRUGGE
EMDEN
B: EXPORT OF GAS
FROM STATFJ. AREA
TO CONTINENT
STATFJ/GULLF/34.8
ALWYN
TROLL
FRIGG
ST.FERGUS
HEIMDAL
KARSTO
SLEIPNER
16/11S
ZEEBRUGGE
EMDEN
C: EXPORT OF GAS
FROM UK TO CONTINENT
ALWYN
TROLL
FRIGG
ST.FERGUS
HEIMDAL
KARSTO
SLEIPNER
16/11S
ZEEBRUGGE
EMDEN
D: TIE-IN OF TROLL TO STATPIPE
AND USE OF FRIGG COMPRESSORS
ALWYN
TROLL
FRIGG
ST.FERGUS
HEIMDAL
KARSTO
SLEIPNER
16/11S
ZEEBRUGGE
EMDEN

ZEEPIPE VIA FRIGG



INSTALLATION SCHEDULE

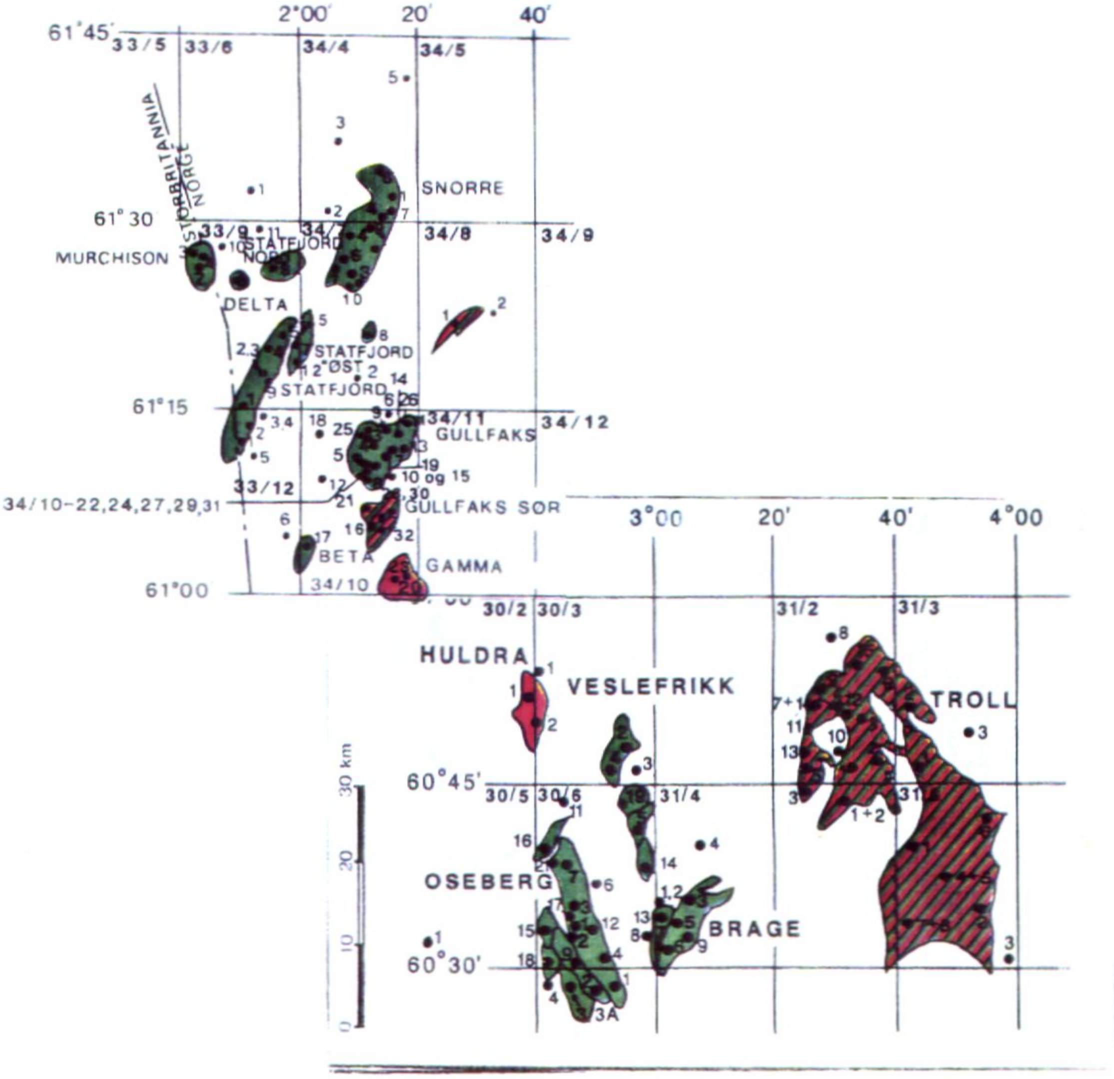
1995: 40" PIPE TROLL–FRIGG
1995: NEW RP FRIGG
1995:40" PIPE FRIGG–SLEIPNER
2000:36" PIPE FRIGG–HEIMDAL

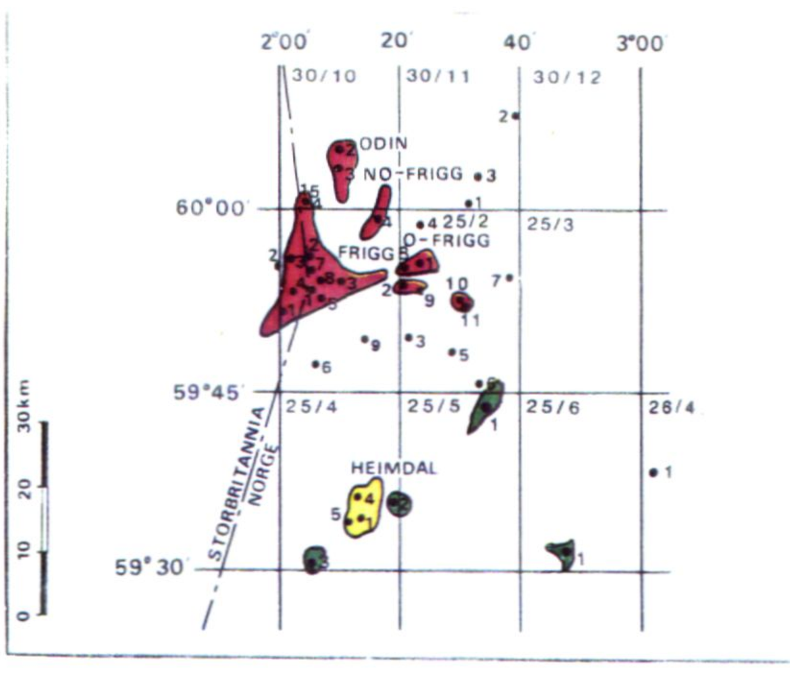
FRIGG IN ZEEPIPE

THE FRIGG COMPRESSORS IF INSTALLED AS A PART OF ZEEPIPE,COULD INCREASE THE CAPACITY AND ACTUALLY OPTIMIZE IT. IN ADDITION THE REQUIRED POWER ON TROLL CAN DRASTICALLY BE REDUCED.

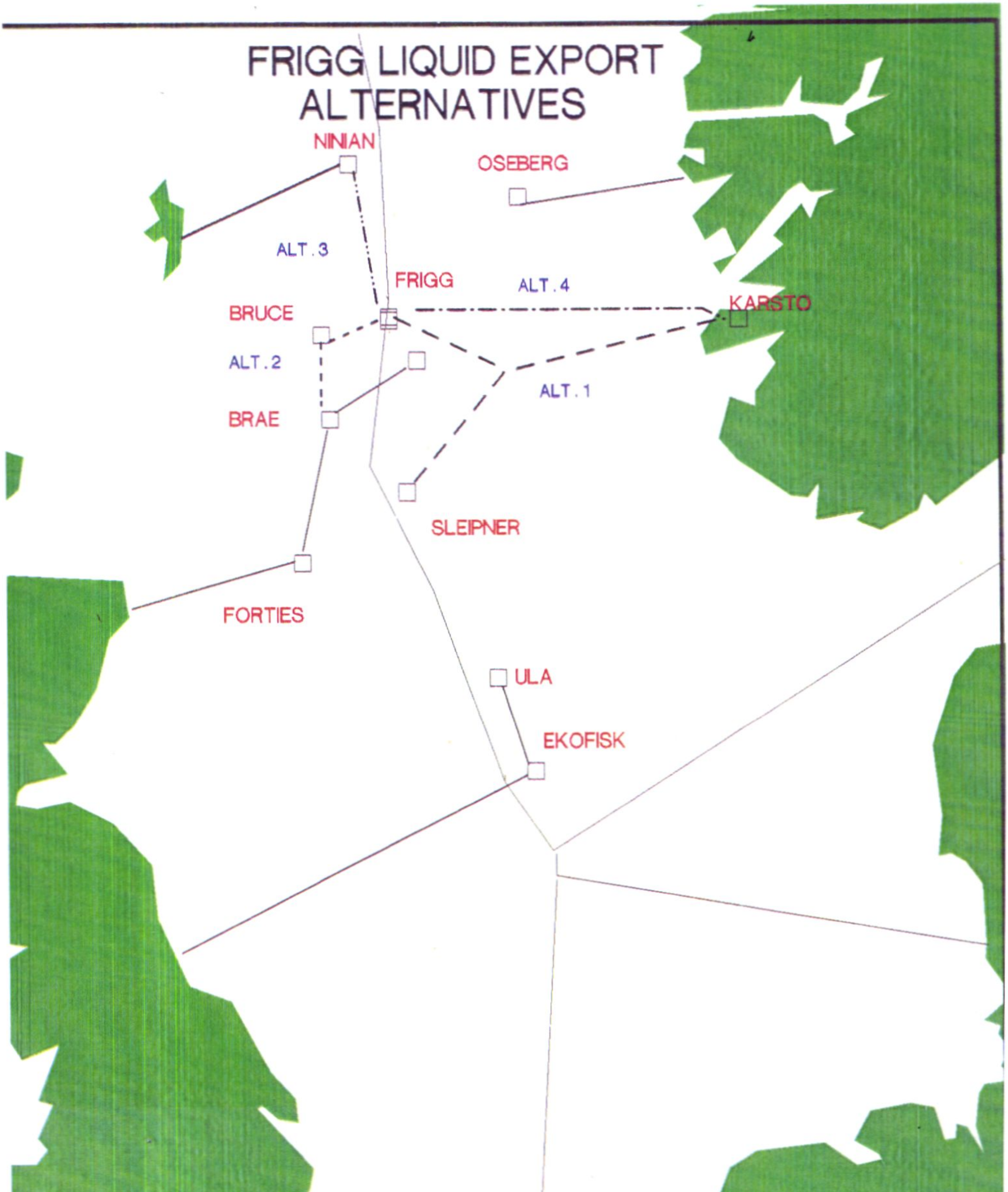
THE FRIGG COMPRESSORS ARE VERY WELL FITTED FOR THE GIVEN PRODUCTION RATE RATE IN ZEEPIPE.

POTENTIAL FUTURE CUSTOMERS





FRIGG LIQUID EXPORT ALTERNATIVES



Potential future customers

- A good number of fields, discoveries or prospects on the Norwegian side could make use of Frigg facilities either as they are today or after modifications

- Three main categories of fields could make use of Frigg facilities:

  A) Fields far away from Frigg which have several possibilities. Services provided by Frigg could be:

  - transit
  - transportation to UK
  - gas compression
  - removal of heavy components to put gas to commerical specification

  B) Small fields which use of Frigg is the only economic scheme. Satellites of Frigg.

  C) Small oil fields close to Frigg from which associated gas could be sent for process and export

- Linking Frigg by a gas pipeline to Statpipe - Zeepipe network would greatly increase the probability of using Frigg facilities for other fields.

- Need facilities for processing high condensate content gas. A high vapour tension liquid export line from Frigg is important to achieve.

Future organisation

Consequences of no actions

- The depletion of the main reservoir will trigger the automatic termination of all agreements (with ancillary amendments, side letters and supplements) between the two groups.

- FUKA will need to use unitized facilities (as structure of TP1, QP, MCP01 etc.) in order to meet its obligations vis a vis Alwyn and Piper/Tartan.

- FNA will need to use unitized facilities (as structure of TP1, QP, MCP01 etc) in order to meet its obligations vis a vis NEF, Odin and EF.

- No arrangements will exist for sharing of costs of jointly-owned facilities.

- No arrangements will exist for pipeline priorities.

- No arrangements will exist for optimizing the Frigg transportation system.

Future organisation
Consequences of no actions

- The Frigg unit will be dissolved.

- The licences will still remain, the UK licences and the NW licences.

- Installations located on the UK and Norwegian Continental Shelfs will remain under the primary responsibility of the respective groups.

- As conclusion, both groups have a clear incentive to start on a work which regulates the future situation

Statement of facts

- The Frigg Facilities have spare capacity to treat and transport new gases to UK. Such services can be given without any new investments if the gas received at Frigg is of the same quality as the Frigg type gas

- The Frigg Central Complex is able to accommodate any type of conventional offshore hydrocarbon process subject to the necessary investments.

- The Frigg Central Complex (QP, TP1, TCP2) has a fatigue lifetime to at least year 2025.

- TP1 and TCP2 have an additional load availability of 6800 tonnes on existing free spaces.

- Future pipes up to 32" can enter the Frigg Central Complex by utilizing existing risers and J-tubes

- The replacement value of Frigg Topsides is from 10 to 15 BNOK (1989 value).

Statement of facts

- FUKA and FNA will around 1995 not be able to cover operating expenses with income if no new customers are served.

- It might be difficult to sell larger quantities of new Norwegian gases to UK before year 2000.

- New customers are needed from around 1995 in order to keep up with the income while waiting for larger activities.

- Accumulations around Frigg exist and these might make use of Frigg around 1995. Most of these accumulations will, however, need processing and a liquids hydrocarbon outlet from Frigg. Some of these accumulations cannot be developed unless services can be given from Frigg

- A liquid export line in the neighbourhood of Frigg would increase the attractiveness of Frigg

- A connection from Frigg to the continental grid would increase the future attractiveness of Frigg

RECOMMENDATIONS

* ESTABLISH A TASK FORCE IN ORDER TO EVALUATE THE TECHNICAL AND ECONOMICAL POSSIBILITIES OF TREATING TROLL RAW GAS AT FRIGG

* ESTABLISH A TASK FORCE IN ORDER TO EVALUATE THE TECHNICAL AND ECONOMICAL POSSIBILITIES OF INTEGRATING FRIGG INTO THE ZEEPIPE SYSTEM, BY USING EXISTING COMPRESSORS.

* ASSESS THE BEST LIQUID SOLUTION FOR FRIGG.

* CONFIRM AN AGGRESSIVE EXPLORATION STRATEGY IN THE FRIGG AREA (ON BOTH SIDES OF THE BORDER) AND CONSIDER TO ACCELERATE THE DRILLING ACTIVITY.

* REACTIVATE THE CONTRACTUAL NEGOTIATIONS WITH THE FRIGG UNIT PARTNERS TO SECURE SIGNED ACCOMMODATION AGREEMENTS (FIELD AND TRANSPORTATION) WITHIN THE DEPLETION OF THE FRIGG MAIN RESERVOIR.

* MARKETING THE FRIGG FACILITIES TOWARDS BRITISH AND NORWEGIAN GOVERNMENTS AND TOWARDS POTENTIAL FUTURE CUSTOMERS.