# DEVELOPMENTS OF GERMAN OFFSHORE OIL AND GAS PRODUCTION

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## ABSTRACT

German activities in the development of oil and gas production with emphasis on the offshore part in North Sea and Baltic Sea are overviewed.

A number of offshore production facilities, most in the state of planning, partially on stream, are described in their concept. Special processing technologies for the development of efficient production are highlighted.

The activities to increase domestic offshore production have to be seen in connection with the exploration activities and the German involvement in foreign offshore production areas.

Figures of production and consumption as well as development trends are given as background information.


## INTRODUCTION

It is a fact that Germany cannot be considered as an oil or gas producing country of importance - and the “run offshore” which had been so successful for Germany’s North Sea neighbours had only limited results - at least until now.

So, German offshore exploration is limited and offshore production is small, very small. However, activities are increasing and it becomes attractive to study the efforts of German petroleum industry when including their foreign activities.

Also, due to the restraints of German resources, technologies of sour gas production and enhanced and tertiary recovery have been developed, as well as new methods for the use of the offshore resource.

The authors are aware of the fact that this paper remains incomplete. Nevertheless the effort is made to give some overview and to describe some major examples of existing and planned production activities, i.e.

- existing production in the German tideland area and the shallow water
- planned oil and gas production in German North Sea and Baltic waters
- the unconventional offshore power plant
- the German involvement in North Sea projects in the neighboring sectors
- the involvement in other countries such as Egypt and Greece.

## GERMAN CONSUMPTION AND RESOURCES

According to a review of Hedemann (1) the exploration activity for oil and gas in 1980 was remarkably successful. 9 of 22 wildcats were discoveries. The main target of exploration was and still is the Rotliegend (Lower Permian) in North West Germany with 2 gas discoveries of relatively great significance. A significant oil discovery - at least for the geological conditions in Germany - was also made in the tidal flat region of the west coast of Schleswig-Holstein.

The good exploration results - on- and offshore - increased oil reserves by 9.6% (6.15 million tons) to 70.35 million tons and natural gas reserves by 7.6% (27 billion m³) to 315.7 - $10^9$ $m^3_n$ (see table 1). According to the same author there are good prospects for further positive exploration results in the near future in the Federal Republic. The increase in the reserves is not only a result of increased exploration but also due to considerable efforts in enhanced recovery.

The total oil production in Germany in 1980 was $4.5 \times 10^6$ t, the gas production $18.66 \times 10^9$ $m^3_n$.

The domestic gas production so covers 19.7% of Germany’s consumption, another 38.1% are acquired from the Netherlands, the remaining 32.2% from EEC-third countries, mainly Norway (2).

The domestic oil production supplies 3.5% of the consumption.

The total consumption per year amounts to $130.37 \times 10^6$ t of oil and $62.8 \times 10^9$ m³ gas. The importance of the North Sea oil and gas supplies from Holland, UK and Norway to the German market are described by the following figures (1980):

17.6 million tons of oil (13.5% of the total demand)
10.0 billion $m^3_n$ of natural gas (16% of the total demand).

Two examples may be representative for exploration activity in the German sector of the North Sea.

In the area of the so-called Duck’s Bill, a part of the Central Graben, Jurassic and Upper Cretaceous structures were examined.

One of the most interesting findings was the A-6-1 well in the concession area of the German North Sea Group, a consortium composed of:

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H.-M. Koepchen - Deminex
W.-D. Longrée - IMPaC Offshore Engineering

Amoco Hanseatic Petr. Comp.
Elf-Aquitaine S.N.E.A., Paris
C. Deilmann AG
Deutsche Schachtbau- und Tiefbohr GmbH
Deutsche Texaco AG
Preussag AG
VEBA Oil AG
Wintershall AG
Gewerksschaft Brigitta
Gewerkschaft Elwerath

Operator of the group is BEB (Brigitta and Elwerath Betriebsführungsgesellschaft mbH).

The most important gas bearing layer is the Dolomit, in a depth of about 3000 m. Although the location is promising, production planning will only start when two mare wells have been drilled by the jackup “Dyvi Epsilon” and have shown positive results.

Wildcats of interest include also the Mittelplate 1 well, drilled by Deutsche Texaco AG and Wintershall AG. The well was completed in summer 1970 for 500 m³/d (3000 bpd.) cumulative from three upper zones in upper Jurassic sands and 160 m³/d (1000 bpd.) from a lower zone.

The well is located in the tidal flat area west of Schleswig-Holstein (fig. 1). It was drilled to 2940 m (9676 feet) TD. Appraisal wells Mittelplate 2 and 3 delivered interesting results. An annual production of 1 million t may not be excluded.

The exploitation, however, strongly depends on further discussions on the amount of the royalties as well as possible restrictions due to environmental considerations.

## OFFSHORE PRODUCTION PROJECTS IN GERMAN WATERS

For characteristic figures refer to table 2.

### Emshörn Z1A Natural Gas Project

The first German offshore gas production started recently. The Emshörn field (fig. 2) with a water depth of 11-14 m, is located at the estuary of the river Ems, about 7.5 km off the coast (3).

BEB (Gewerkschaften Brigitta und Elwerath Betriebsführung GmbH) found gas in 1978 at a depth of about 3200 m in Rotliegend formation. In 1980, the well which at the time had been plugged was re-entered with the aid of the “Transocean I” jack-up drilling platform, for which purpose a 30" marine riser protected by a 48" outer pipe was piled into the sea bed. A Christmas tree and a small working platform were then mounted.

15 m away, a jacket was piled and a production platform with an area of about 250 m² was installed (fig. 3). An access bridge links both structures at a height of 26.6 m above the seabed.

On deck, glycol dehydration is installed with an additional small accommodation unit, a remote control station and a winching platform which can be extended to a helicopter landing platform.

The glycol unit is designed for a capacity of 1 million m³ per day at a pressure of 100 bar. Use was made of BEB’s experience in onshore fields with this type of equipment.

The gas is fed into the BEB distribution system via a pipeline of about 11 km length (1.3 km onshore, about 2.6 km over flats and 7 km offshore). In addition to the 10 ¾” gas pipeline (1500 psi design pressure), a 3 ½” condensate line (1000 psi design pressure), a 6000 Volt power cable and a control cable for supplying and controlling were laid.

All these four components were laid at sea in a single operation by a specially converted pipe-laying vessel. The trench having been excavated ahead of the pipe-layer by a cutter suction dredger.
Tie-in point ashore is close to the village of Groothusen.
The operation of the platform is fully remote-controlled from ashore at Groothusen (substation) or the main station at Visbek (Südoldenburg).

Production planning anticipates a second well to be drilled in 1984. Extension facilities on on the platform are provided.

The Emshörn field is located in a concession area which is owned (100%) by BEB. However, it crosses the border in the direction of the Dutch NAM-concession.

### The Leybucht Project

In 1976, the wildcat Leybucht Z1 found gas in the Rotliegendes at about 3700 m. In April 1977, planning and design work for a gas dehydration plant was started (4). The well is located in the southern North Sea flats, about 15 km from the village of Greetsiel.

The design flow rate is 25,000 $m^3_n$/h, at a pressure at the wellhead of about 350 bar. The gas analysis showed that the gas contained, besides the hydrocarbons (mostly methane and ethane), about 11% nitrogen and 1% $CO_2$, which is relatively high in comparison to neighboring gas fields.

Additionally, a number of trace elements, mostly mercury and cadmium were detected. This required:

- dehydration in order to avoid condensation in the pipelines
- separation of higher hydrocarbons
- extraction of the trace elements.

An early cost / performance analysis demonstrated that dehydration immediately at the wellhead was the most economic solution.

Structural Considerations

An artificial island, with an elevation of +5.5 m above NN, had been erected for the minimum requirements of the exploration phase. This level, however, was not acceptable for permanent installation, since maximum water levels in the Leybucht has already been measured during floods as 6.24 m above NN. Thus, platforms on concrete legs had to be erected which would raise the working area by another 2 m (+7.5 m above NN); (see fig. 4).

One of the design criteria was the ice force, exerted by a closed ice cover on the flats but pushed over the island during an anticipated flood. The design forces were in the order of 50 t per pile.
Due to safety precautions, the platform area was divided into 3 separate units.

Processing Considerations

- Platform N° 1 to contain auxiliary facilities, as heater and glycol regenerator
- Platform N° 2 for the high pressure generators
- The auxiliary facilities for storage and evaluation of the fluids to be installed on Platform N° 3

The general process is given in the simplified flow scheme (fig. 5). Depending on the temperature the gas flows either through the preheater or directly into the air cooler which cools the gas down to 40 °C. The water is taken by the knock out drum and stored in the water-condensate-tank. The gas then is led to the gas / gas-heat exchanger. Glycol is injected to bind the condensed water. Gas temperature after heat exchange is now 0 - 10 °C, depending on the operating conditions.

An expansion valve reduces the gas pressure of 350 bar down to 70 - 80 bar. The temperature drops to -20 to -25 °C and the remaining vapor is mixed with glycol and the heavy hydrocarbon condensate in a contactor.

After the heat exchanger the low pressure gas is conducted through a micro filter to separate remaining fluids and the above mentioned heavy metals. The gas is then transported via a 15 km pipeline 8 5/8" to the station at Krummhörn. The station is fully remote-controlled. Power is supplied through a 20 kV cable, buried in the access dam. Production started in November 1978 with an hourly rate of 11,000 $m^3_n$/h.

The concession for the field is held by the Borkum-Juist Konsortium, whose members are C. Deilmann AG, Mobil Oil AG and Gelsenberg AG. The operator is C. Deilmann AG.

**Schwedeneck-See Project**

One of Germany's most advances offshore project, however, still in the development phase, is the Schwedeneck-See project, some kilometers off Kiel in the Baltic Sea (fig. 6).

Deutsche Texaco, working in 50% partnership with the Wintershall AG decided to undertake all preparatory work to develop the 18.5 million bbl Schwedeneck-See reservoir with two small concrete platforms.

The project estimated well over DM 300 million might start up in 1983 subject to the results of the negotiations on royalties. Production is expected to build to a peak of about 8,100 b/d of 27° gravity crude in the initial phase.

Operator opted for two single-column concrete gravity platforms to stand in 54.5 and 82 ft of water to combat the problems caused by wintertime icing in the Baltic.

Platforms are being designed by the French company C. G. Doris and IMS of Hamburg. Tenders for construction were issued in summer 1981 (fig. 7).

Construction techniques for these small units would be more akin to the methods for building navigation light towers rather than those for the vastly larger North Sea concrete units built in Norway or Scotland.

Topsides for the drilling and production platforms will also look substantially different from the usual deck structures.

Processing equipment and accommodations will be kept to a minimum and housed with the wellheads on a lower deck. Main decks will be capped by a flat top.

The derrick of a workover rig will be kept horizontal when not in use. The rationale for the flat-topped, shallow deck design is governed by

- limited No. of wells platform
- type of drilling rig (MSPR)
- statical arguments
- economics.

Schwedeneck-See is on the edge of a naval exercise area. The presence of the exercise area caused Texaco to leave a portion of the reservoir untouched.

Schwedeneck, a long thin structure, extends onshore. That part has been in production since the 1950s.

Deutsche Texaco has noted that porosity and permeability in the northern part of the reservoir is better than in the onshore section. In a later stage, development of reserves east of Platform A might be considered if delineation results support a second field development phase, which would possible also incorporate the untouched reservoir section south of the B-Platform.

If appraisal work in the eastern and southern positions of the field is successful, reserves could be increased to around 26 million bbl. This would justify construction of one or two more platforms.

The environmental restrictions placed on the development are onerous. At any stage the operator will avoid spilling anything into the sea including rainfall run-off.

Special gutters will channel all liquids on the deck area of the platforms into slop tanks which will be taken ashore by bare. There is also a ban on oil-based drilling muds.

Deutsche Texaco's original plan was to move the oil from Platform A to B through a 2.7 mile, 14-in. line to the main terminal ashore. This terminal, which would house the bulk of the process equipment, would be sited about 1 ½ miles inland. The field gas / oil ratio is low, and there will be no need for flaring. Deutsche Texaco plans to use submersible pumps to produce the wells. There will be seven producers, water injection is planned from an onshore location some 6 km SW of the Schwedeneck-See field on each platform.

**Offshore Power Generation Project**

A gas find was made in 1980 by Nordwestdeutsche Kraftwerke AG (operator Gelsenberg AG), about 80 km off the coast.

The H 15 - 2 wildcat (fig. 1) encountered several good porosity gas bearing sandstone sections below the western flank of a salt dome above 4300 m (fig. 8).

Production tests yielded an influx of 1 million m³ per day. The gas composition matched the predicted figure of 60% nitrogen (5).

A first well in H 15 was drilled in 1964 showing high nitrogen content (66%), a third well is planned for 1972.

Plans are to produce electrical energy by using the combustible gas on site and to transport the energy ashore via a seabed cable, provided reserves of some 5 - 7 billion m³ can be proved.

A group, consisting of Nordwestdeutsche Kraftwerke and Deutsche Babcock has developed the EPOS-concept (Electric Power on Sea), in order to exploit 'marginal' natural gas deposits, which have so far been inaccessible to commercial exploitation.

The EPOS power station is designed for a total power output of 375 MW (6), (7). This indicates a life of at least 12 years at the envisaged location. Furthermore, this design value permits the application of large power station turbines and also corresponds to the capacity of today's largest submarine DC cables (360 MW, at 300 kV and 1200 A).

The necessity of achieving a high thermal efficiency from the plant used for offshore power generation employing natural gas, resulted in choosing a combination of gas and steam turbine process. Simple, relatively small gas turbine units, capable of being treated as modules, had to be abandoned in favor of a complex, sophisticated power station concept such as is adopted for onshore plants. Thus platform and power station plant had to be merged into on functional unit which can be transported to the location in one piece.

The design of the power station platform is based on the jack-up principle. The 375 MW design value resulted in a space demand of approximately 100,000 m³ for the total plant and a load carrying capacity of approximately 14,000 tons net. The platform body was designed for dimensions of approximately 71 x 72 x 20 m.

At each corner of the platform there is one jack-up leg of 5.5 m in diameter. The space enclosed by the box girders is freely available for installing the turbine and boiler plants. The inside of the box girders offers space for the rectifier station, the ancillary installations, personnel quarters, etc. When equipped with the total power station plant, the platform body will weigh approximately 24,000 tons.

For stability reasons the jack-up legs of the platform are kept as short as possible. They are positioned at a water depth of 10 m, on a substructure which constitutes the foundation of the power station and is pre-positioned on the seabed as a separate structural element. This substructure is designed in accordance with the individual conditions of a location (fig. 9).

Though a high thermal efficiency is aimed at, it was decided, not to recover the flue gas to the same extent as in onshore plants. In an optimization analysis, the gas outlet temperature under the EPOS project was fixed at approximately 170 °C. The gross efficiency is then 46.5%. A further increase of the efficiency would require relatively large additional heat transfer surfaces with corresponding height, weight and volume. Together with the additional expenditure required for the platform, the costs of the achievable increase in efficiency would be higher than the benefit obtained (fig. 10, 11).

Similar considerations govern all other elements of the offshore power station.

The low gas price directly at the well constitutes a compensation for the higher specific expenditure (DM/MW) which an offshore power station requires, as compared to an onshore plant. Consequently the offshore power station has the characteristic feature of a base load power station; and in order to enable its application as a base load power station, efforts should be made during the planning stage to achieve as high an availability as possible. The EPOS studies were based on an availability of 80% as a guide value, but the station would still be reasonably economical even with a much lower availability.

The 375 MW EPOS power station would represent approximately 7.5 % of the total power installed at Nordwestdeutsche Kraftwerke.

## GERMAN INVOLVEMENT IN OTHER OFFSHORE AREAS

In discussing German involvement in outside German water areas this mainly means discussing the North Sea projects Thistle and Beatrice in UK waters, where Deminex participates with 41 and 22% respectively in these BNOC operated ventures. It furthermore leads to dealing with two field developments in the Gulf of Suez in Egypt where Deminex together with BP, Shell and EGPC, the Egyptian state oil company, have founded SUCO (Suez Oil Company) to carry out such development. One other project, the Prinos oil field development, operated by Wintershall Hellas Petroleum SA, a subsidiary of German Wintershall AG completes the picture as it is at this point in time. For characteristic figures, refer to table 3.

### Thistle (UK)

The Thistle field belongs to the group of fields situated in the area of the so-called “Viking Graben” where East of the Shetland Islands exploration was successful in the early 1970s (fig.12). Thistle represents an example of a tilted horst block structure typical for this area. The reservoir rocks are of middle Jurassic age and are sealed off by Kimmeridgian shale.

Out of this area crudes of different qualities and from a variety of fields are produced and delivered through the Brent / Ninian Pipeline System to Sullom Voe Terminal on the Shetlands which terminal will be capable of handling a throughput of 75 million tons per annum (1.5 mill. bpd).

After the discovery of the field in 1972 and a subsequent appraisal drilling activity the development of Thistle was decided in 1974. Feasibility studies revealed a single central platform to be the recommended solution for field development. After a 1 ½ year construction period it was in summer 1976 that the 185 m high, 30,000 t steel jacket could be positioned at the field location in 160 m water depth and installation of the 20,000 t weight production-modules to be arranged on three different decks could commence (fig. 13).

The platform is equipped with two drilling rigs and 60 well slots for production and injection wells. Wells are drilled directionally with up to 60% deviation to reach the more distant areas of the field. Horizontal distance from the platform at reservoir level is up to 13,000 ft. Living quarters can accommodate 190 people.

The capacity of the production facilities on the platform are capable to handle 10 million to crude per year (220,000 bpd) and consist of usual facilities for gas and water separation in water treatment. The gas produced is used as fuel for power generation of 56 MW, the remainder of the gas is being reinjected into the reservoir.

In order to assist the existing aquifer drive water injection facilities with the capability to inject 240,000 bpd of water have been installed.

Another feature of the field’s installations is represented by the SALM, a single anchor leg mooring buoy which is located about 2 km away from the platform. This buoy was used during the initial 10 months of production when the Brent pipeline system was not yet ready to accept production. These days the installation is maintained as an emergency outlet for the thistle production in case of malfunctions of the Brent System and the Sullom Voe Terminal.

Thistle is now on production for 4 years. From the ultimate expected reserves of about 60 million tons 17.3 million tons have been produced up to year end 1981. the daily production stands pretty stable at 18,500 t/d (130 to 140 MBOPD). Thistle is an example of a self-sustained offshore oil field which pumps its processed crude through an underwater transport line to an onshore terminal. In case of pipeline malfunctioning the field is independent and can continue production through an offshore loading installation.

### Beatrice (UK)

A quite different field development scheme as compared to Thistle we find in Beatrice where circumstances have led to the following facilities configuration (fig. 14).

Production facilities and drilling platforms with wellhead installations are separated; there is one production platform installed in the center of the field to which the production from the two drilling platforms is bought to. The production platform separates the gas from the well streams and then transmits the wet oil for further processing and handling through a 16"-pipeline over 68 km to the processing, storage and terminalling facilities at Nigg Bay onshore. Due to environmental considerations (close to shore location) no offshore loading was considered.

The clear cut division of production and drilling facilities on separate platforms brought clear advantages since drilling activities could proceed unhampered from any production facilities installation work.

Under this concept it was possible to drill five production wells through a subsea template even before the jacket of the main complex drilling platform was installed.

The Beatrice field development as described is of course pertinent to some basic conditions as already alleged in the introductory sentence and these conditions are:

- the field is located in 46 m water depth
- the reservoirs extend over an area of about 10 km times 2 km at a relatively shallow depth of 2000 m (5600 ft).

The basic conditions have to a large extent determined the development scheme:

The shallow depth of the reservoir in combination with its areal configuration did not allow for one centrally located platform. So two sites were chosen from which most planned drainage points will be reached.

Since the water depth is only 46 m and the field is located somewhat under the coast line shelter, platform cost is not a real critical item and optimizing the development could be achieved by separately building production and drilling platforms. Since the reservoir has no high reservoir energy available, production is assisted through down hole REDA pumping.

Beatrice started production in October 1971 and has now built up to a capacity of about 40 MBOPD out of 9 wells on production.
The reserves are estimated at about 20 mill tons (120 to 140 mill. bbls).

Remains to be mentioned that the 37° API gravity oil has a wax content of 17% which leads to a pour point of +20% C and needs special treatment. So in addition to heating production facilities there are facilities pertinent to the injection of pour point depressing detergents available and in use.

**Ras Budran (Egypt)**

In 1978, the Ras Budran field in the Gulf of Suez was discovered. This field is located about 4 km off the coast of Sinai at a water depth of about 40 m.

After having appraised the field in 1978/79 to the extent necessary, the discovery was declared commercial in mid-1979 with estimated reserves of about 20 million tons (150 million bbls) in massive sandstones of the Nubian formation. Feasibility studies led to the concept of installing two 9 slot and one 4 slot drilling platforms at the location of the productive, and so far suspended, discovery and appraisal wells which will be the first wells to be completed for production.

The three platforms are standard type steel jackets with deck structure to accommodate wellhead facilities, heli-deck and small living quarters for occasional overnight stays of the operating crews.

The oil produced on the drilling platforms will in the final stage of development be transferred to a production process platform near the center drilling platform for gas separation. The crude will then be pumped to the terminal facilities on Sinai, where further treatment is foreseen before the processed crude will be stored in 5 storage tanks with a total capacity of 1.25 million bbls. Crude delivery for export will then be achieved through a 36" loading line to a CALM buoy (Catenary anchored leg mooring) which is capable of handling up to 160,000 DWT tankers.

The gas separated on the production platform will be used for gas lift in a closed system and for fuel supply of the various facilities.

After start up of production which is planned for the 2$^{nd}$ quarter of 1982 a field plateau rate of 2 million tons per year (40,000 BOPD) is expected. In order to sustain such a rate about 8 wells out of the 22 possible wells will be used for water injection.

**KK 84 (Egypt)**

Quite different from the so far presented cases is the planned development of a small 4 million tons (28 mill. bbls) reserve field which was discovered by the Deminex / BP / Shell group in 1978/79 in a riffoidal limestone of the so-called Nullipore formation.

The riffoidal body extends over 7 km times 1 km at a max. gross thickness of 125 m at a reservoir depth of about 650 m. The shape of the field and its location at a water depth of 45 m together with a shallow depth of the reservoir has led to the concept of planning 10 platforms, 9 of which are designed as small 3 leg well protector jackets with 3 drilling slots each. The 10$^{th}$ platform is foreseen to additionally accommodate a production manifold and testing facilities so that the different well streams to be gathered through this manifold platform can also be separately flow tested. It is planned to drill 10 wells at a distance of about 650 m between each other by use of a jack-up rig to be located over the wellhead protectors location by location.

The reservoir with an undersaturated 24 - 27° API oil is connected to an aquifer which is common also to the Ras Gharib field which has been on production for many years so the KK 84 reservoir pressure has been partially depleted and the KK 84 wells will have to be artificially lifted from the very beginning.

The field max. production rate is anticipated with 500,000 t per year (10,000 BOPD). The production will be processed onshore where existing facilities of GPC the Egyptian General Petroleum Company can partially be used. Partially in this context means mainly storage and loading facilities and processing of the sour solution gas in the existing Claus plant for the removal of $H_2S$.

It is expected to put the field onstream by the end of 1983.

**Prinos (Greece)**

This project encompasses the development of two hydrocarbon reservoirs, the Prinos Oil Field and the South Kavala Gas Field, with a planned production of some 8 million tons (55 million barrels) of crude oil and 800 million m³ (30 billion cubic feet) of natural gas (9).

The operating company is the North Aegean Petroleum Company E.P.E. (NAPC), incorporated in Greece and owned by the consortium composed of Denison Mines Ltd., Hellenic Oil Company, Wintershall Hellas Petroleum SA and Whiteshield Greece Oil corp.

The Prinos Oil Field, covering approximately 4 km² in area, is located in 32 m of water in the Aegean Sea, five miles west of Prinos Point on the Island of Thasos and twelve miles southeast of the city of Kavala (fig. 15). This field was discovered in February 1974 with the drilling and testing of Prinos N° 1 well and, subsequently, five additional wells were drilled to delineate the field.

The South Kavala natural gas field, located seven miles wouth of the Prinos Oil Field in water depth of 58 m was discovered in December 1972. five wells have been drilled in the South Kavala structure to delineate the presence of a sweet natural gas reserve which can be economically developed in conjunction with the Prinos Field.

The Prinos Field offshore facilities are composed of one production treatment and two producing platforms arranged in an ‘L’ configuration, connected by access bridges. The flare system includes a flare structure and a bridge from the production treatment platform (fig. 16).

Each producing platform in the Prinos Field is designed with 12 well slots; the current plan calls for a total of 18 wells comprising 10 producing and 8 injection wells leaving 6 surplus locations. These platforms are suitable for use with tender-assisted or jack-up drilling rigs.

The production treatment platform is an 8-legged steel structure. Separation and dehydration of the oil and gas streams is performed offshore, prior to piping to the process facilities on the mainland site, to ensure operability of the system by precluding hydrate formation and to eliminate uncertainties associated with corrosion and metallurgy in the pipelines.

Produced water will be treated and re-injected into the reservoir or dumped in the sea.

At the South Kavala Gas Field, a four-piled platform with two decks was built to protect and service two gas wells. Primary separation and gas dehydration equipment is located on the lower deck, the upper deck is utilized during work-over operations.

The mainland site accommodates a crude oil treatment facility, sulfur and N.G.L. extraction facilities. Storage is provided for 600,000 barrels of stabilized crude in three floating roof steel tanks and up to 5 days’ storage (depending on markets) for N.G.L. and liquid sulfur, plus 50 days solid sulfur.

The mainland facilities are connected by submarine pipeline to the production treatment platform and to a conventional spread mooring for shipment of crude oil by tankers (up to 75,000 TDW).

The construction program ran over two years with initial starting of production from both fields in may 1981.

The environmental conditions, such as the seismicity of the area, coupled with the corrosive and toxic characteristics of hydrogen sulfide (approx. 35 mole per cent) and its oxidation product, sulfur dioxide, has strong bearing on all aspects of field development.

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| | Oil | Gas |
|---|---|---|
| Estimated Reserves in 1980 (1) | $70.35 \cdot 10^6 t$ | $315.7 \cdot 10^9 m^3_n$ |
| Production in 1980 (1) | $4.6 \cdot 10^6 t$ | $18.66 \cdot 10^9 m^3_n$ |
| Consumption | $130.37 \cdot 10^6 t$ | $62.8 \cdot 10^9 m^3_n$ |
| Domestic Supply in % | 3.5 % | 29.7 % |
| Share of North Sea Oil & Gas in German Consumption 1980 (10) | $17.6 \cdot 10^6$/year<br>(13.5 %) | $10 \cdot 10^9 m^3_n$<br>(16 %) |

Table 1 - Consumption & Resources in West Germany

| Gas/Oil | Location/ Block | Water Depth in m | Operator | Discovered | On Stream | Current Production (resp. planned prod.) Gas in $m^3_n/d$ Oil in BOPD | Production System Platforms | Transport | Notes |
|---|---|---|---|---|---|---|---|---|---|
| PRODUCING FIELDS IN GERMAN WATERS | | | | | | | | | |
| GAS | Emshörn/ North Sea | 11 | BEB | 1978 | 1981 | approx. 700 000 $m^3_n/d$ | 1 steel platform<br>1 free standing marine riser | 3 1/2" condensate line<br>10 3/4" gas pipe-line<br>11 km | Expansion of produc-tion will probably be in 1984 |
| GAS | Leybucht/ North Sea | tide land | Deilmann | 1976 | 1978 | 270 000 $m^3_n/d$ | 3 concrete units on artificial islands | 8 5/8" pipeline<br>15 km | Design rate 600 000 $m^3_n/d$ |
| PROJECTED DEVELOPMENTS IN GERMAN WATERS | | | | | | | | | |
| GAS | H 15 - 2/ North Sea | 35 | NWK / Gelsenberg | 1964/ 1981 | | $10^6 m^3_n/d$ | jack up + sub-structure | electric power cable | |
| OIL | Schwedeneck | | Deutsche Texaco | | | 8 100 BOPD | 2 concrete platforms | 14" pipeline<br>4,3 km | Recoverable reserves estimated ($18.5 \cdot 10^6$ bbl) |
| FIELDS OF INTEREST IN GERMAN WATERS | | | | | | | | | |
| GAS | A-6-1 Duck's Bill North Sea' | 51 | BEB (German North Sea Group) | | | | | | |

Table 2

| Gas/Oil | Location/ Block | Water Depth in m | Operator | Discov-ered | On Stream | Recoverable Reserves Gas in $m^3_n$ Oil in bbls | Current Production (resp. planned prod.) Gas in $m^3_n/d$ Oil in BOPD | Peak Production Gas in $m^3_n/d$ Oil in BOPD | Production System - Platforms | Transport | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| GERMAN INVOLVEMENT IN FOREIGN OFFSHORE PRODUCTION AREAS | | | | | | | | | | | |
| OIL | Thistle/ 211/18 a & 211/19 North Sea | 160 | BNOC | 1973 | 1978 | $550 \cdot 10^6$ bbl* | 140.000 BOPD | 220.000 BOPD | 1 steel | a) SALM<br>b) Pipeline 16" | (*)according to Wood, Mackenzie |
| OIL | Beatrice 11/30 a North Sea | 46 | Mesa | 1976 | 1981 | $160 \cdot 10^6$ bbl* | 40.000 BOPD | 80.000 BOPD | 2 steel, 1 con-verted jack up | 16" pipeline to Nigg Bay Terminal (68 km) | (*)according to Wood, Mackenzie |
| OIL | Ras Budran Golf of Suez | 45 | SUCO | 1978 | | $150 \cdot 10^6$ bbl | | 40.000 BOPD | 3 steel Drilling Platforms | Cale | |
| OIL/ GAS | Prinos Field North Agean<br>- Prinos (Oil)<br>- South Kavala (Gas) | <br>32<br>52 | NAPC | 1974 | 1981 | <br>$55 \cdot 10^6$ bbl<br>$850 \cdot 10^6 m^3_n$ | <br>25.000 BOPD<br>160.000 $m^3$/d | <br>30.000 BOPD | <br>4 steel<br>1 steel | Pipelines<br>6" gas<br>12" gas<br>8" oil | |

Table 3

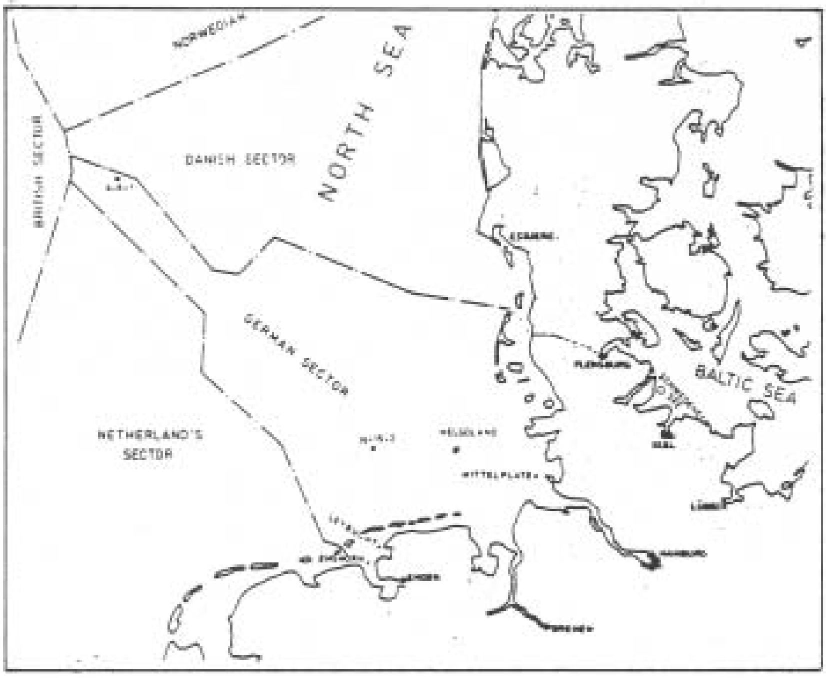


Fig. 1  German Offshore Areas

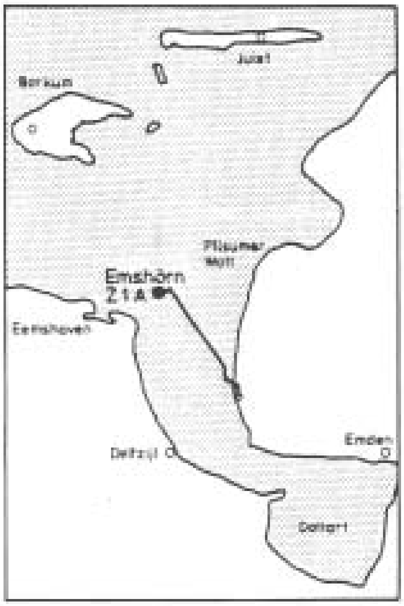


Fig. 2  Location Emshörn Z1A and Gas Pipeline

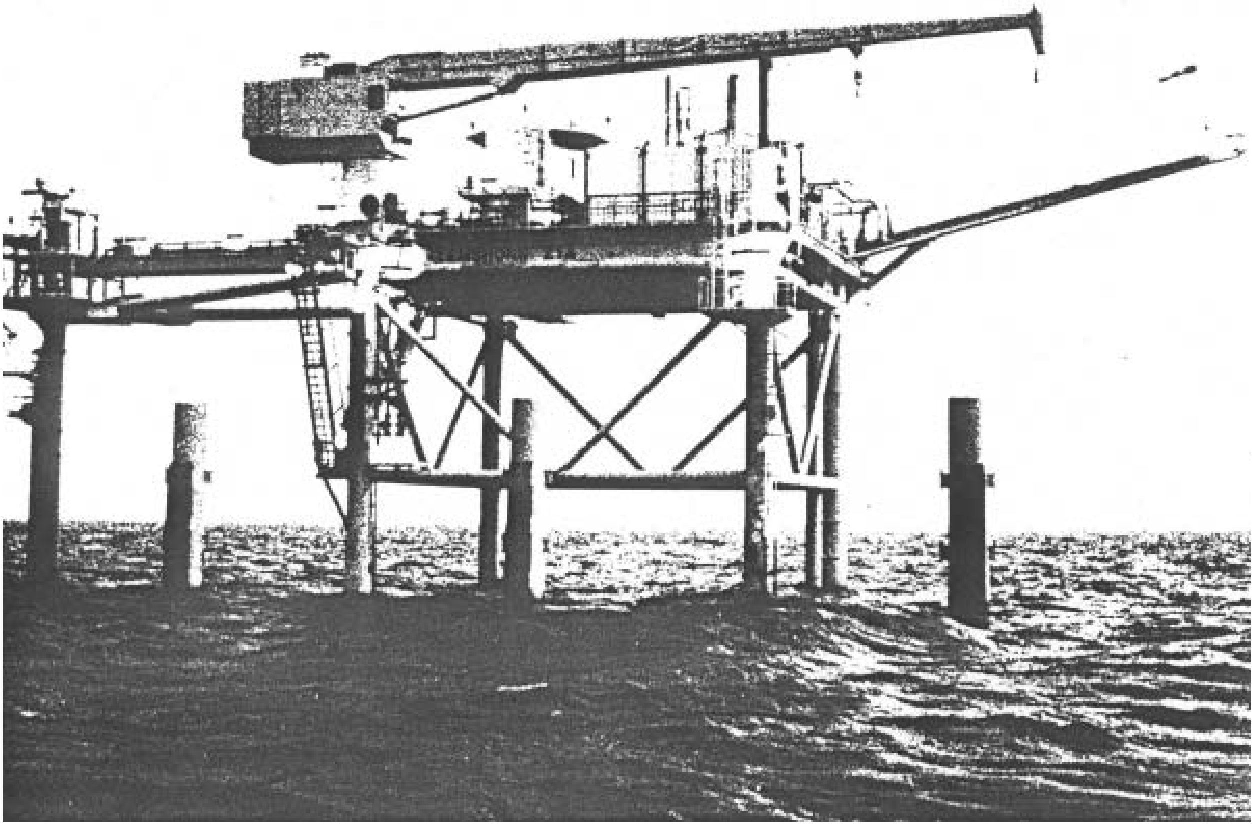

Fig. 3a  Emshörn Z1A Production Platform

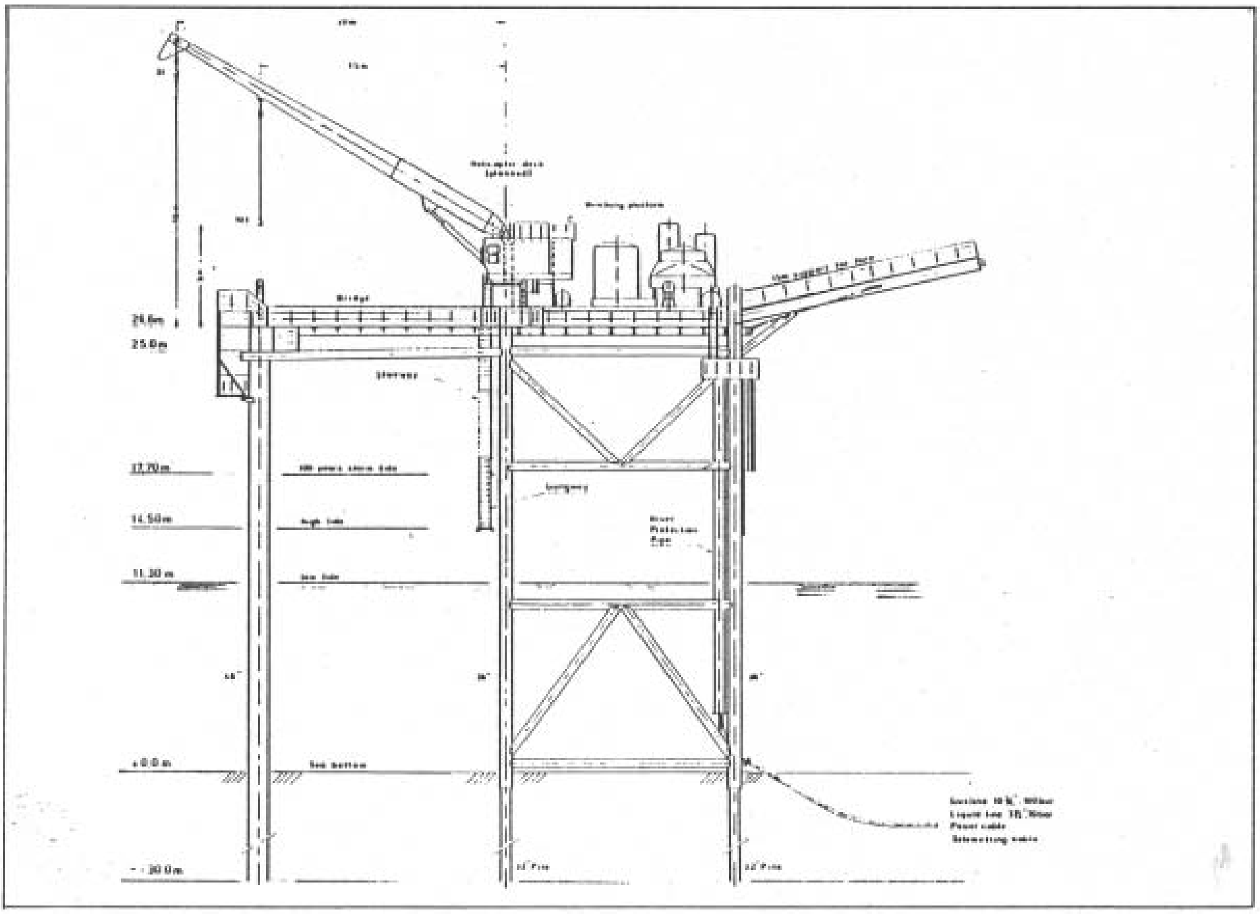


Fig. 3b  Emshörn Z1A Production Platform

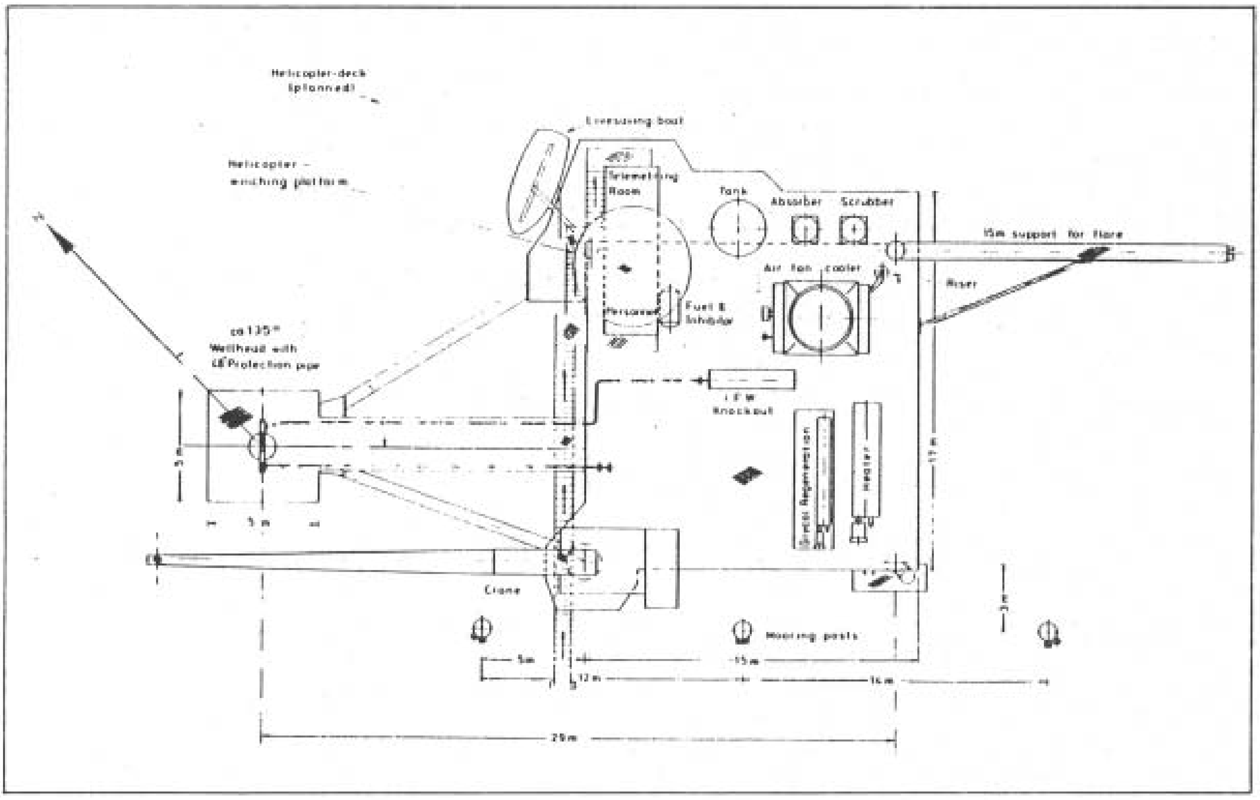


Fig. 3c  Emshörn Z1A Production Platform

Fig. 4a  Leybucht Gas Treatment Project - Artificial Island

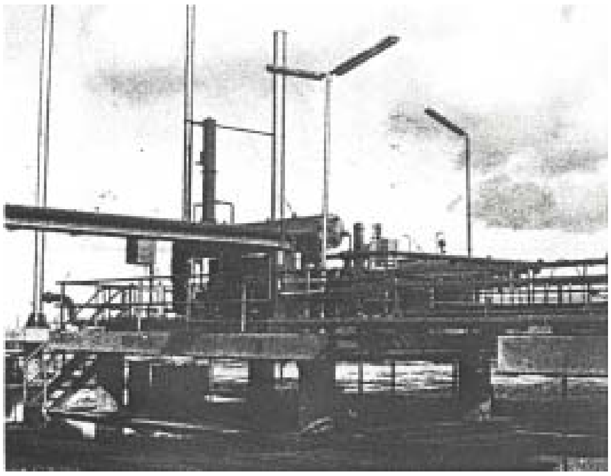

Fig. 4b  Platform No. 1

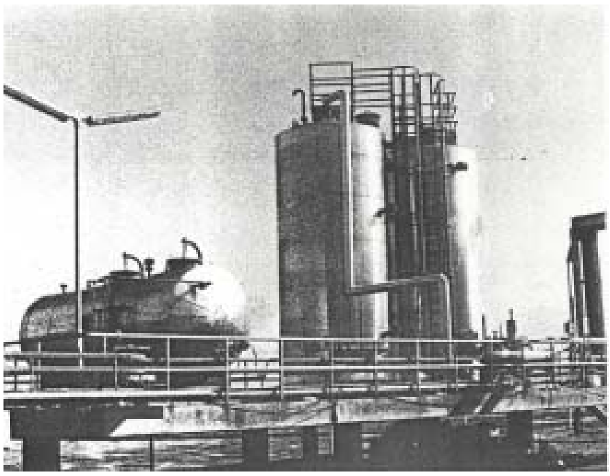

Fig. 4c  Platform No. 3

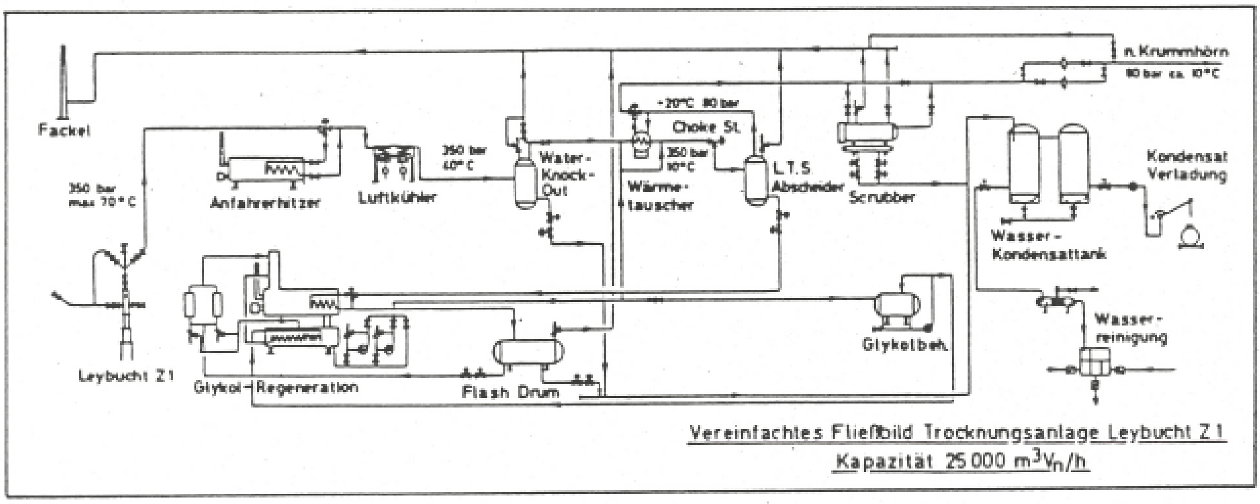


Fig. 5  Leybucht Gas Treatment Project

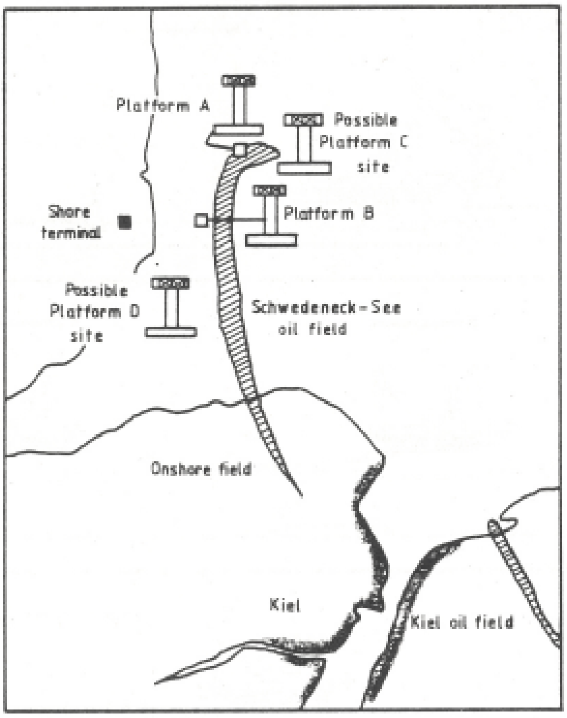


Fig. 6 Schwedeneck See Development

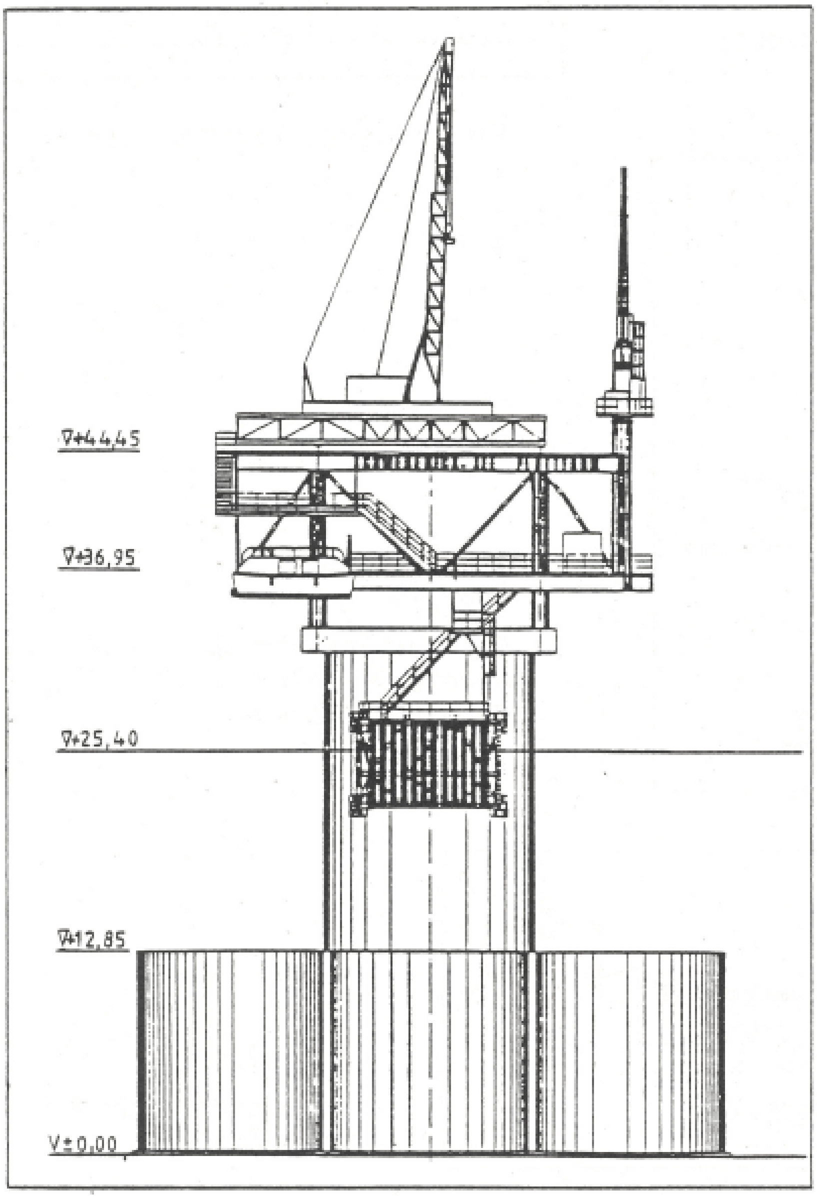


Fig. 7 Schwedeneck Platform

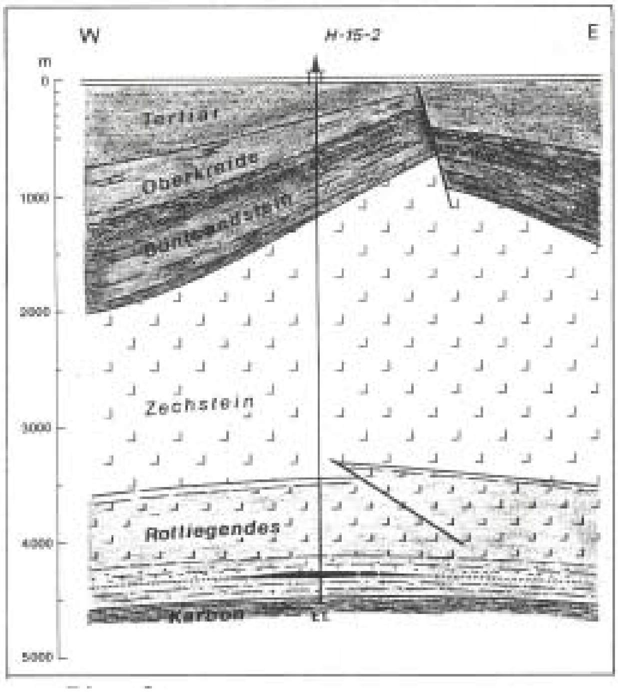


Fig. 8 Schematic Geological Section,
Gas Find H-15-2

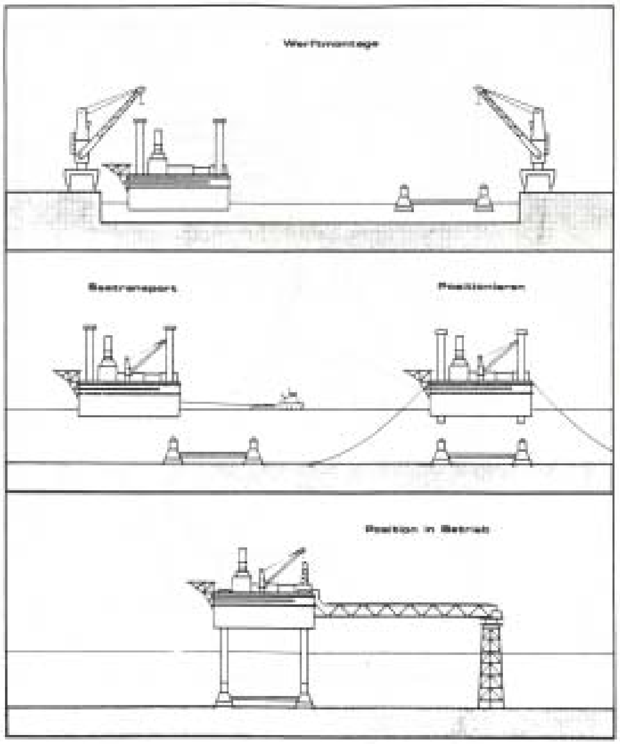

Fig. 9 Epos Construction Phase

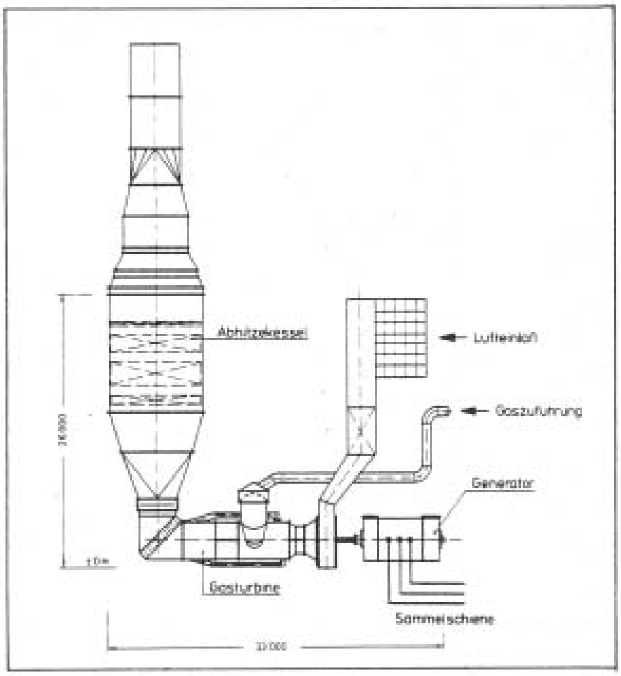


Fig. 10 Gas Turbine and Waste Heat Recovery Boiler in the Combined Process

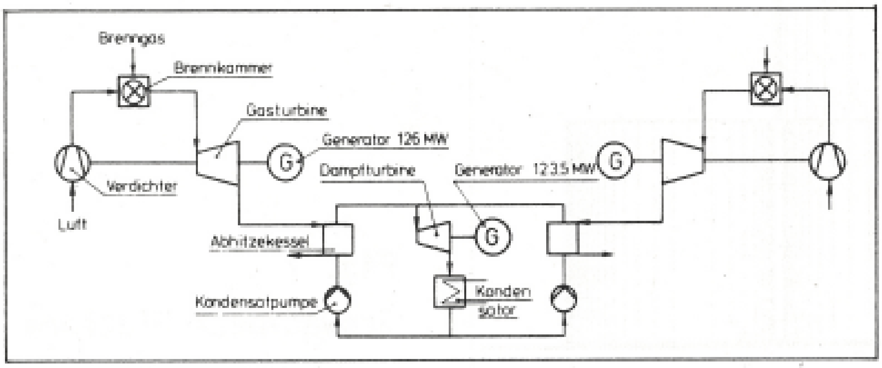


Fig. 11
Scheme of Combined
Epos Process

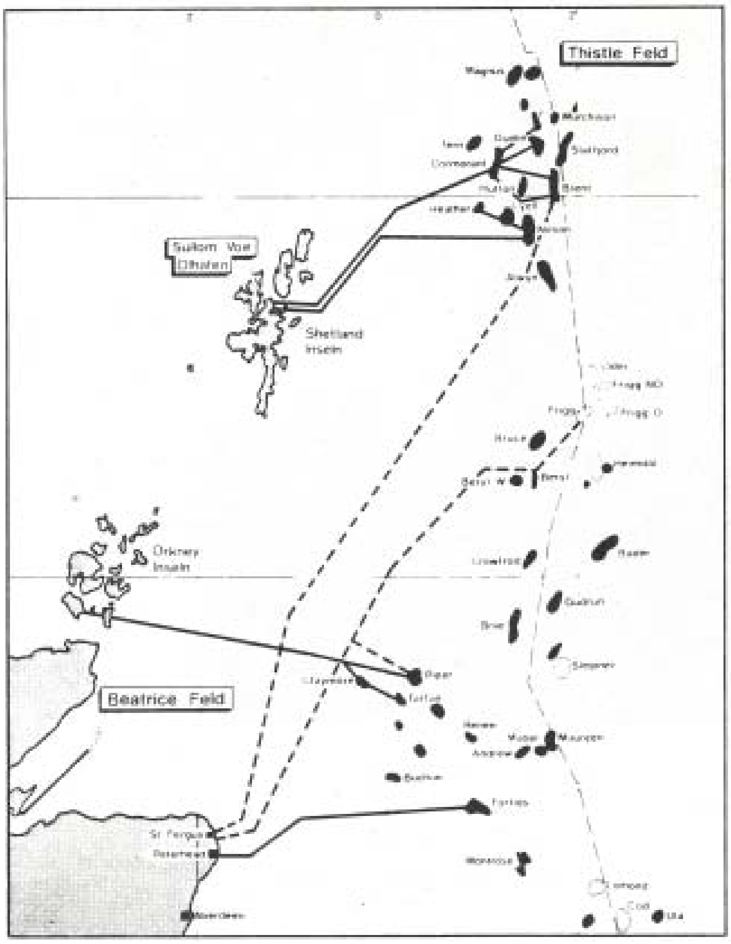


Fig. 12
Thistle and Beatrice Location

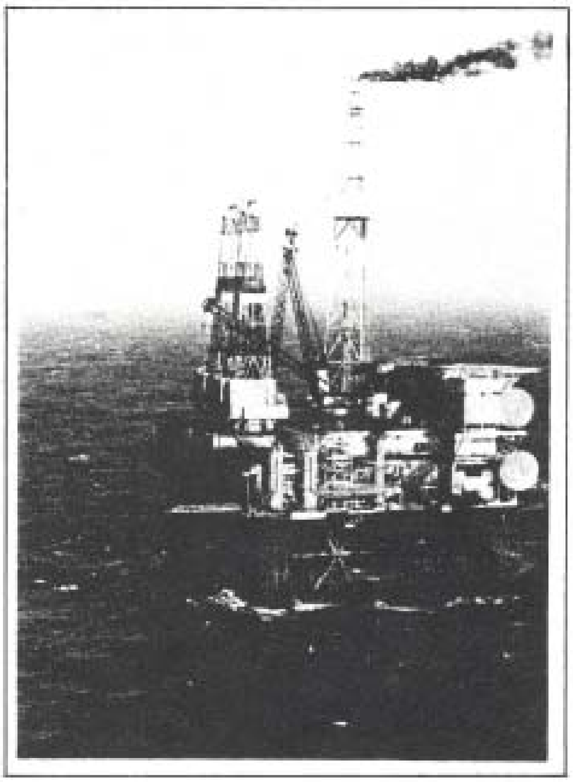

Fig. 13 Thistle Platform

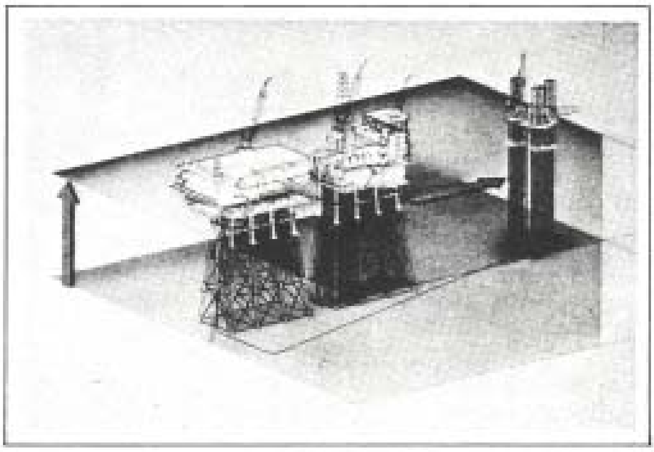

Fig. 14 Beatrice Field Installation

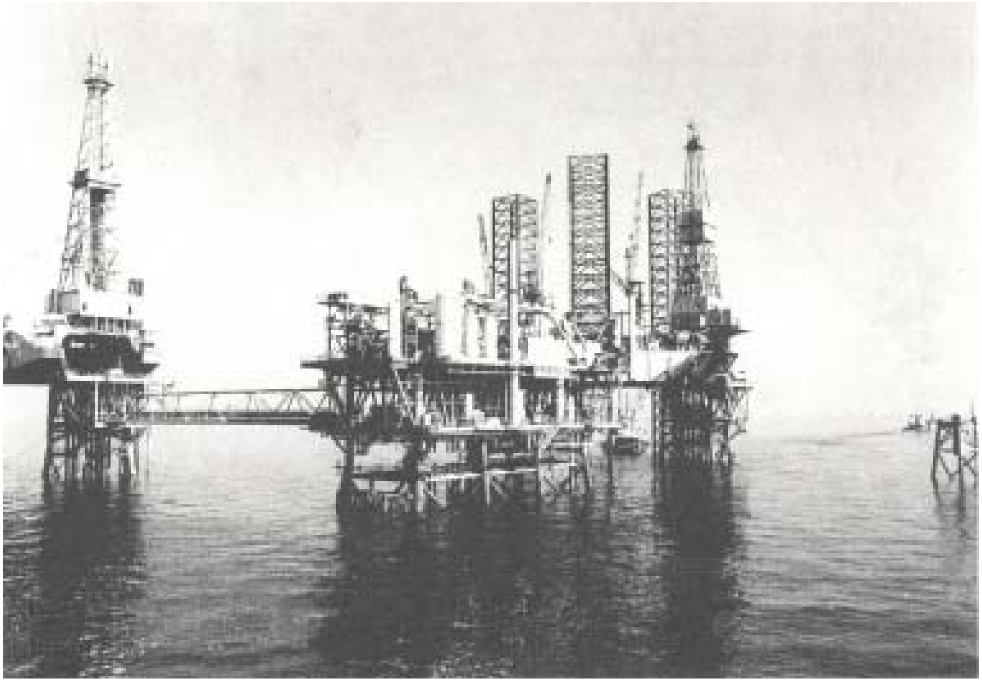

Fig. 15  Prinos Platform during Installation

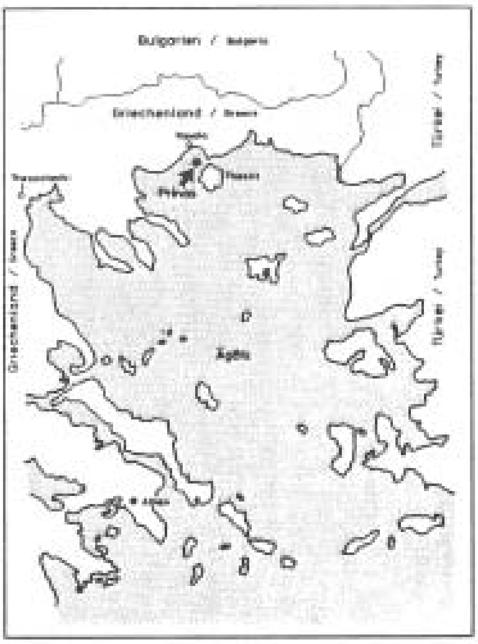


Fig. 16  Aegean Sea and Prinos Location

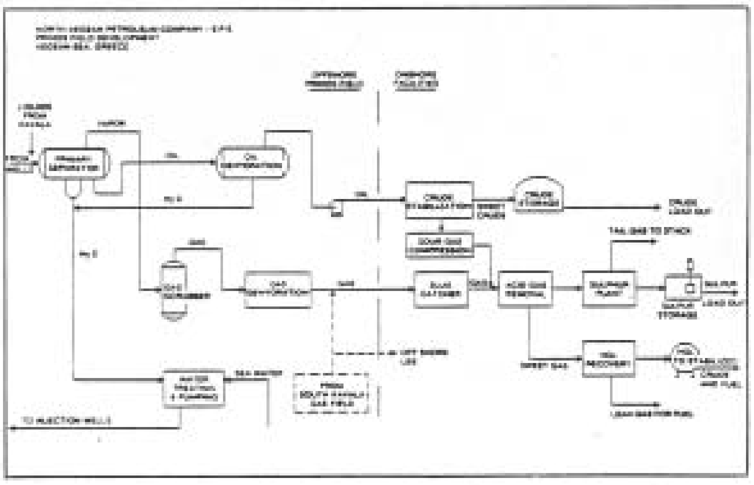

Fig. 17  Basic Flow Diagram