LONDON AND SOUTHERN GAS ASSOCIATION

THE ARMADA PROJECT
THE COMMERCIAL CHALLENGES

by

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1. INTRODUCTION

BGE&P is by far the largest gas producer and owner of gas reserves on the United Kingdom Continental Shelf (UKCS) and operates huge fields such as South and North Morecambe. In addition, BGE&P holds large equity stakes in fields operated by other major oil companies such as Amoco, BP and Mobil. Such fields include Indefatigable, Leman, Everest, Amethyst, Lomond, Brae and Beryl.

In many of these fields BGE&P has the largest ownership interest but the operator is another company, appointed in the days of "Gas Council (Exploration) Limited", when BG invested in the UKCS as a non- operator. Those days have gone, replaced by a worldwide strategy focused on operated projects in which BGE&P skills and experience are used to develop the business.

The Armada Project represents the first joint venture development in the UKCS in which BGE&P has acted as Operator. For the first time BGE&P had to bring together all the commercial and technical factors to persuade both BGE&P management and a group of other major North Sea oil companies to commit £600 million to a development. This paper tells the story of the period leading up to Project Approval from primarily a commercial perspective. However, it is true of all Central North Sea developments such as Armada that the commercial and technical aspects of the Project are inextricably linked.

Other papers on the Armada Project may follow in due course as drilling and fabrication continues in the three years to first gas in October 1997.

2. BACKGROUND TO NORTH SEA EXPLORATION

In 1964, the UK Government enacted the Continental Shelf Act to extend sovereignty offshore and introduced the Petroleum Production Regulations to provide a system for licensing and control. The first round of Licences were issued and exploration began in 1965. For licensing purposes, the UKCS is divided into Quadrants – areas of one degree latitude by one degree longitude. Each Quadrant is further divided into thirty blocks of approximately 250 square km. Companies are invited to apply for the right to explore blocks selected by the Department of Trade and Industry (DTI) in Licensing Rounds held every two years.

The mechanism by which the DTI has selected successful companies in each round to explore blocks is a discretionary system whereby the operational record, the quality of proposed exploration and production plans, and a company's financial and environmental credentials are all taken into consideration.

Due to the large financial commitments involved in exploring offshore blocks and the associated risks, companies have tended to form what are commonly called "Joint Ventures" with other oil companies to share the costs and risks.

During the Licensing Round, companies come together (typically 2-4 companies) to form a "Bidding Group". The Bidding Group appoints an Operator for the group which acts as the lead company in preparing the work programme and application to the DTI for a Licence. The members of the group are bound by an agreement termed the "Bidding Agreement" which sets down the various parameters, including the parties' percentage ownership of the Joint Venture.

A successful application is rewarded with a Licence to explore in that block for a period of usually six years (which can be extended if exploration has been successful). At such time the group will enter into a "Joint Operating Agreement" ("JOA") which will govern operations on the block during the term of the Licence.

3. CENTRAL NORTH SEA ACTIVITY

In the past few years the Central North Sea has begun to be developed as a major source of gas for the UK market in order to meet the 25% increase in demand resulting from the growth in gas fired power generation. The following summarises these developments:

3.1 CATS/Everest/Lomond

In 1990, BGE&P, Amoco and Amerada Hess sold their gas from the 305 mmscfd (million standard cubic feet per day) Everest and Lomond fields to Teesside Power Limited (TPL). Together with Phillips, Fina and Agip, they invested £1.2 billion in developing the Everest and Lomond fields and the Central Area Transmission System (CATS), a 400 Km long, 36" diameter pipeline from the Central North Sea to Teesside. TPL, a consortium of Enron, ICI and 4 regional electricity companies, built a 1875 MW power station on Teesside. CATS was commissioned in March 1993 with the production of first gas from Everest and Lomond fields shortly afterwards. BGE&P owns approximately 59% of Everest/Lomond and 51% of CATS.

3.2 J-Block

In 1993, BGE&P, Phillips and Agip sold their gas from the 300 mmscfd Judy and Joanne fields (J-Block) to Enron. First gas from J-Block will come down the CATS pipeline in 1996. BGE&P owns 30% of the J-Block development which will involve a total capital expenditure of around £700 million.

3.3 Andrew

Also in 1993, the owners of the BP operated Andrew oil field agreed terms with CATS to transport some 40 mmscfd of gas to Teesside, with first gas at the end of 1996.

All the above fields have contracted to use CATS for gas transportation with onshore gas processing at Teesside carried out by Enron. The ownership in Armada, Everest, Lomond, J-Block and CATS are shown in Figure 1, which demonstrates the significance of BGE&P in this technically difficult area of the North Sea

4. THE ARMADA FIELDS

The three gas condensate fields, Fleming, Drake and Hawkins, are situated approximately 250 km northeast of Aberdeen, and contain recoverable reserves of 1.2 trillion cubic feet (tcf) of gas and 70 million barrels of condensate and natural gas liquids (NGLs). The collection of fields is known as the Armada complex and represents one of the largest undeveloped accumulations of gas in the UK sector of the North Sea (Figure 2)

For Armada, the exploration process took place during the 1980's. Reserves were discovered across five adjacent blocks, covered by five separate Licences and five JOAs. The blocks are: 16/29a, 16/29c, 22/4a, 22/5a and 22/5b (Figure 3)

The Fleming reservoir partially overlays the Drake and Hawkins reservoirs. Both Fleming and Drake were discovered by the same well, 22/5b-2, in 1982; well 22/5a-1A discovered the Hawkins reservoir in 1980.

To complicate matters even further each of the five blocks had different Joint Venture groupings. In order to turn this collection of hydrocarbon reserves with disparate ownership into a commercial development, it was necessary to bring together all the parties and consolidate the commercial arrangements. This process is known as "Unitisation" and legally binds the parties in a "Unit Operating Agreement" (the "UOA"). In many ways this agreement is similar to the JOA in that it appoints an Operator for the group, enables work programmes and budgets to be agreed and defines the ownership of the field (see section 12.4).

5. BGE&P EQUITY ACQUISITION IN ARMADA

In the years leading up to the launch of the Armada Project in 1992, BGE&P built up the largest ownership interest in the three fields. This was achieved through a series of purchases and equity swaps, the most significant of which saw BGE&P take over the 'operatorship' of the Drake block, 22/5b, from Mobil. All BGE&P's activities in the Central North Sea were focused on maximising the value of BGE&P's assets in this area.

6. THE LAUNCHING OF ARMADA

In March 1992 the six Armada Co-venturers – BGE&P, Amerada Hess, Amoco, Agip, Fina and Phillips agreed to appoint BGE&P as Operator. This was as a result of BGE&P's stated intention to operate projects in which it held a high equity interest, which, with a stake of above 45% was certainly the case for Armada.

In addition, BGE&P was the only Armada Co-venturer with the detailed technical knowledge of the entire area gained as a result of interests in all five license blocks in which the three fields were located.

The Co-venturers have extensive experience from developments both on the UKCS and worldwide. This experience helped to improve the design of the Armada facilities which should, in time, be seen to increase the profitability of Armada. Brief details of the Armada Co-venturers are given in Appendix 1.

The largest Armada field, Fleming, was at that time known by two names. Amoco had christened it "Howard" when they discovered the southern part of the field, Phillips gave the name "Maggie" when they discovered the northern extension. In 1992 BGE&P proposed Armada as the name of the Project and Fleming as the new name for Maggie/Howard (Fleming was a captain who served alongside Drake and Hawkins in the 16th century English Navy).

7. ARMADA PROJECT ORGANISATION

A Development Manager, John Sayers, was appointed to set up a Management Team with dedicated BGE&P staff from the commercial, technical and finance departments, as shown in Figure 4. It was the task of this team, working with colleagues in many other departments within BGE&P and with the Armada Co-venturers, to put together the necessary arrangements to support a £700 million project. Close liaison and cooperation ensured that the Project had the best chance of success.

8. DEVELOPMENT CONCEPT

Several feasibility studies had been undertaken on Armada prior to 1992. However, there was no clear technical consensus amongst the Armada Co-venturers as to the optimum development concept. From more than a dozen options, the leading contenders were:

- Option 1. Two platforms located over the North and South of Fleming
- Option 2 A single central platform with a small northern sub-sea development
- Option 3. A single southern platform with a large northern sub-sea development

Each Option was examined in depth, with particular attention to four major factors:

- Capital costs
- Operating costs
- Recovery of reserves
- Risks

By the end of 1992 it was agreed that Option 2 was the optimum concept for Armada. This entailed a large, centrally located platform with gas processing and compression, and a small northern sub-sea development to recover gas from the northern part of Fleming. During the first part of 1993 a conceptual design study was undertaken with the aim of producing an agreed design, cost estimate and schedule.

9. PRODUCTION START DATE

In parallel to the conceptual design on Option 2, gas sales negotiations were held during 1992/93, based on a maximum daily gas sales rate at Teesside of 350 mmscfd (the off-platform rate was 375 mmscfd, 20 mmscfd would be extracted as butane, propane and pentane and approximately 5 mmscfd would be used as fuel gas).

In April 1992 a first gas date of October 1996 represented a realistic target, allowing 12 months to complete gas sales and other negotiations and 42 months to design, build and install the facilities. At this time Amoco were asked to lead gas sales negotiations because there remained a perception amongst potential gas buyers that information could pass from BGE&P to the Gas Supplies Department of British Gas.

1992 was a time of great uncertainty in the UK gas market. The spring General election offered the possibility that an incoming Labour Government would reverse the "dash for gas-fired power stations". Later in the year, the Conservative Government conducted a "Coal Review" that could have led to subsidised coal production and a consequent reduction in demand for gas. The market uncertainty was compounded by the MMC inquiry into the gas industry during 1993.

It was decided in the summer of 1993 to move the target date for first gas to October 1997. This was a difficult decision at the time, but a number of factors suggested it was the right decision:

9.1 Capital costs

Option 2 was more expensive than had been anticipated, due mainly to facilities and drilling costs. Delay to 1997 would allow optimisation of the development concept and investigation of the feasibility of the use of extended reach drilling technology to remove the need for the northern sub-sea wells. In addition, the abolition of Petroleum Revenue Tax (PRT) for new fields in the Chancellor's budget in March 1993 meant that separate metering for the 3 Armada fields was no longer necessary. This would assist in designing a smaller platform.

9.2 Schedule

It was generally believed that additional costs would be incurred in order to achieve a production start date in 1996. Previous experience of all Co-venturers had shown that a tight design and fabrication schedule invariably lead to higher capital expenditures.

9.3 Gas sales

Attractive gas sales offers had not been received due to the uncertainty in the gas market. All Co-venturers perceived that October (*) 1997 first gas would be more attractive to purchasers

* The "gas year" is from 1 October to 30 September for historical reasons. Most projects have a start date of 1 October, though this is changing as the competitive gas market develops.

9.4 Other commercial arrangements

In the absence of strong economics, progress in all the major commercial areas had been difficult. No agreement had been reached on tariffs for gas and liquid transportation and processing nor on unitisation arrangements. Delay to 1997 would allow time to complete the commercial framework and negotiate full agreements with all the parties concerned.

9.5 Oil prices

Low oil prices (<$13 per barrel) cast a shadow over the Project, with most oil companies operating on the UKCS reducing their future oil price forecasts. This made Armada economics less attractive as approximately 50% of the revenue was expected to be linked to the oil price (25% directly due to Armada oil production and 25% indirectly as most gas purchasers offer to buy gas with a price escalation basket including oil product prices).

10. CRITICAL SUCCESS FACTORS

The following Critical Success Factors were identified after discussions with the senior representatives of the Armada Co-venturers and within BGE&P – these were vital to ensure the best chance of receiving Project Approval in Spring 1994 and first gas in October 1997:

1. Executed agreements covering:

    Gas sales

    Gas transportation and onshore processing

    Liquids transportation and processing

    Field unitisation and gas lifting

2. An agreed Development Plan and Budget
3. No major design, fabrication, drilling or other contracts committed prior to Project Approval
4. Capital and operating costs below target levels
5. An agreed Project Execution Plan

Figure 5 shows the Programme to Project Approval presented to Armada Co-venturers in Autumn 1993, containing all the activities necessary to satisfy Co-venturer and BGE&P requirements. All activities were focused on 18 May 1994 when each Armada Co-venturer was to give its Board Approval to the Project.

18 May represented a compromise target date negotiated internally within BGE&P - the commercial negotiators wanted a later date to allow more time to put in place all the agreements whilst the engineers wanted an earlier date to allow more time to complete detailed design and have a more relaxed construction schedule. Throughout 1993/4 there was often a divergence of opinion between the commercial and technical staff within the Project as to timing, priorities and strategies. This was where the Armada team demonstrated its strength in working towards the common goal of Project Approval.

11. CONCEPT, DESIGN AND ORGANISATIONAL CHANGES

To improve the profitability of the Project a number of major changes were made in the technical areas involving the development concept and design of the facilities:

> Improvements in drilling confidence allowed the small northern sub-sea to be removed from the Development Plan. All the reserves would be recovered by drilling wells from the central platform with design provision made to allow sub-sea developments at a later stage should they prove to be necessary.

> The topsides design was improved following reviews with Co-venturers' engineers and the design contractor. The BGE&P project team embraced the concept known as CRINE (Cost Reduction In the New Era). This is an initiative for operators to become more cost effective by using standard specifications and equipment and reducing the amount of repetition in engineering design when developing new fields and is a subject worthy of a separate paper to the Institution.

> The platform design was simplified following the abolition of PRT for new fields.

> By taking advantage of higher wellhead pressures in the early years of production, the off-platform rate from Armada was increased from 375 mmscfd to 450 mmscfd, accelerating revenue and hence reaching project payback earlier.

Figure 6 – Drawing of the Armada platform

Figure 7 – Cross section of the overall development

In addition, to sharpen the performance of the commercial team there were a number of changes of organisation and approach:

> BGE&P took over the lead role for gas sales negotiations which meant that all the functions normally associated with the role of Operator were carried out by BGE&P

> Key commercial and technical milestones were identified and targeted to

be met by the date of a series of regular meetings of the Project Management Board (known as the Operating Committee or OPCOM).

A dedicated commercial team was set up within BGE&P with the task of delivering all agreements for execution by 18 May 1994.

12. THE COMMERCIAL CHALLENGES

The Central North Sea is a challenging environment when it comes to developing large gas projects due to difficult geology, high capital and operating costs and relatively high tariffs to get the gas to market. For an oil field there is a well developed spot market for the product and an established pipeline infrastructure which improves the economics, reduces the risk and simplifies the development.

For gas/gas condensate fields such as Armada there is (as yet) no such thing as the "gas price". This has to be established through negotiation with purchasers and depends on the rate it is sold, where it will be landed and the flexibility of sales terms offered. In addition for gas/gas condensate fields there is effectively an "oilfield" which must be developed at the same time as the gas field.

For Armada, moving forward on both commercial and technical fronts was difficult and complicated due to the interrelationship between commercial and technical factors, for example, changing gas sales parameters could alter the development concept.

The commercial task was to ensure that Critical Success Factor No. 1 (All Agreements Executed) was satisfied at the same time as maintaining progress in all other areas.

The activities shown in the Programme, Figure 5, are discussed below:

12.1 Gas Transportation and Onshore Processing

To get Armada gas to market, there were a number of major issues to be resolved:

12.1.1 Processing on the Armada Platform:

"Wet" Armada gas, straight from the reservoirs, has to be processed to meet the entry specifications of the CATS pipeline. In addition, Armada condensate has to be processed to meet the entry specification of the Forties Pipeline System (FPS). At one extreme, there could be minimum processing producing a "rich" (high calorific value) gas with a low volume of condensate, at the other, maximum processing producing a "lean" gas and high condensate volumes. The following factors had to be considered:

- Platform capital costs
- Liquid transportation tariffs
- Capacity in liquids off-take systems

- Gas transportation tariffs
- Onshore gas processing tariffs Onshore liquids revenues
- Gas sales revenues

A specific issue concerned the removal of the Hydrogen Sulphide (H_2S) contained in Armada. This could either be removed offshore, with plant designed for 450 mmscfd, or onshore, in which case the H_2S would have to be removed from the entire CATS stream (1100 mmscfd)

Essentially, all processing decisions were a trade off between offshore and onshore capital and operating costs, tariffs and product price forecasts. After detailed economic analysis, the decision was made to have minimum gas processing on the Armada platform with a rich, sour (high H_2S) gas exported to CATS with H_2S removal carried out onshore.

Figure 8 Armada platform process design

Figure 9 Photograph of North Everest and CATS Riser Platforms

12.1.2 Onshore Liquids Recovery

Onshore, Armada gas (part of a commingled stream with Everest, Lomond, J-Block and Andrew) has to be processed to meet the entry specification of the BG TransCo National Transmission System (NTS). This is done by removing many of the natural gas liquids (NGLs) from the gas stream – primarily propane, butane and pentane. There are many ways in which this can be done, depending on a range of factors:

- % Propane extracted from the gas stream (could be as high as 90% or as low as 30%)
- Requirement for high CV (calorific value) gas or low CV gas and the cost of transporting gas in the NTS
- Fractionated or unfractionated NGLs
- Plant performance and availability
- Capital and operating costs
- Value of selling a therm of propane as a liquid product compared to selling it in the gas stream
- Price forecasts for NGLs

Studies concluded that a relatively simple processing plant should be built to utilise the pressure of the gas and the Joule-Thompson cooling effect (gas cools down as its pressure is reduced) to remove just enough NGLs to meet the NTS entry specification. This means that a high CV gas will enter the NTS. It was further agreed to pay CATS a tariff to fractionate the 8,000 barrels a day of mixed NGLs into 3 products propane, butane and a "pentane +" stream. These could then be marketed on Teesside.

CATS have announced that the plant for Armada will cost around £80 million. Detailed design is under way, with the plant expected to be completed in late summer 1997 in time to accept commissioning gas from Armada.

Figure 10 – Photograph of Teesside

Figure 11 – Armada Onshore Processing Facilities

12.1.3 Connection to the National Transmission System

Armada requested that CATS provide a physical link to the TransCo NTS in order that potential gas purchasers could take delivery of the gas in the same way that purchasers do at all the other existing UK gas terminals – i.e. filtered, metered and odourised. The logic of CATS negotiating with TransCo was that CATS needed a link for its future business and could be expected to pass on some economies of scale to Armada. Commercial terms for this service were negotiated at the same time as those for gas transportation and onshore processing.

Subsequently, CATS and Enron signed a Construction Agreement with Transco. By 1996 (for J-Block) there will be a connection from Seal Sands to Cowpen Bewley, sized to take the full CATS throughput (around 1600 mmscfd). A TransCo metering/odourising facility will be built on the CATS terminal site at Seal Sands. This will be operated by CATS on behalf of TransCo – offering significant savings in operating costs. The major challenge in this area was that there was no commercial precedent for an agreement between a terminal and TransCo for a new connection to the NTS. Previously this had been handled by BG Engineering Planning Department as part of gas purchasing negotiations the terminal operator or producer was not involved in the details of the connection.

Within the space of just over four years, the Teesside landfall for gas will have been created and expanded to be one of the major UK landing points, accounting for 15% of the market.

Figure 12 – NTS map – Seal Sands/Cowpen Bewley/Bishop Auckland

12.2 Onshore NGLs at Teesside

The three liquids products, propane, butane and pentane +, will be re-delivered to Armada Co-venturers at the boundary of the CATS terminal on Seal Sands. Armada Co-venturers are currently negotiating with various companies for the storage or direct sale of these products. The aim is to negotiate attractive product prices and secure off-take routes that will ensure that gas production is never interrupted due to liquid capacity restrictions

This activity is not considered to be on the critical path of the development as any

new storage tanks that may be required will not take as long to build as the offshore facilities. However, agreements are expected to be concluded round about the end of 1994.

12.3 Offshore Liquids Transportation

The challenge here was to secure the lowest transportation tariffs and highest oil prices consistent with maintaining gas production at all times.

After extensive negotiation, terms were agreed with BP, the owners of the Forties Pipeline System (FPS), for the transportation of Armada liquids through the FPS and with the Everest owners for transportation through the Everest to Forties pipeline. Other liquids off-take systems, including offshore loading, were considered, but the combination of Everest and the FPS offered the best solution.

The FPS has a capacity of around 1 million barrels/day and will take Armada offshore liquids from an existing pipeline that connects the Everest platform to the FPS. The Armada liquids or condensate (essentially a light crude oil) will be transported to Cruden Bay Terminal north of Aberdeen and on to Kinneil Terminal in Fyfe. There the pipeline crude oil blend is processed yielding a stabilised crude oil suitable for tanker export from the Dalmeny Storage Terminal and Hound Point jetties. For every barrel of Armada condensate entering the FPS, Armada Co-venturers receive approximately one barrel of stabilised crude oil and a small entitlement to the raw gas that arises as a result of the crude oil stabilising process. The "Forties Hydrocarbon Accounting System" allocates the appropriate amount of crude oil and raw gas to each Forties shipper. Armada Co-venturers have agreed to sell their raw gas entitlement to BP.

12.4 Basis for Unitisation

The unitisation of the three Armada fields together into a single unit (as described in section 2 of this paper), was arguably the most complex unitisation ever undertaken in the North Sea.

Traditionally for gas fields in the North Sea "Wet Gas Initially In Place" (WGIIP) has been used as the basis for unitisation.

This means that the owners review all the reservoir data and agree that the ownership of the unit shall be based on the amount of WGIIP in each block. In most cases, provision is made for "re-determination" of the WGIIP ownership as knowledge of the reservoir changes with more wells drilled and production taking place.

The WGIIP unitisation normally takes place on single or multiple reservoirs in the same geological horizon – i.e. at the same depth and pressure. For such fields, the composition of the recovered gas tends to be similar, as do the capital costs associated with drilling. For Armada, this was not the case. It could be argued that Fleming gas would be of slightly poorer quality than gas from Drake or Hawkins.

On the other hand, drilling would be more expensive for the deeper reservoirs (Drake/Hawkins) and the amount actually recovered (known as "reserves") from each reservoir would be different. The gas/condensate ratios would also turn out to be different. Unitisation as complex as Armada had never previously taken place in the UKCS. To take account of the complications, various options for the basis for unitisation were considered. These were:

WGIIP

Hydrocarbon pore volume

Gas reserves

Therms reserves (takes into account condensate)

If the "basis" could be agreed then an independent Expert could decide how much gas resulted in each licence area on the agreed basis.

Attempts were made to establish the ownership based on the above "bases" and economics were run to take into account factors including:

Cost of drilling

Gas/condensate ratio

Fluid composition (CV, CO2, H2S)

Reserve scenarios (e.g. high or low recovery)

WGIIP scenarios (e.g. large or small sized reservoirs)

Agreement on a "basis for unitisation" would allow subsequent "re-determinations" – often involving the use of an independent "expert" who would determine the new ownership.

It was not legally necessary to unite the three reservoirs together – the DTI only insisted that each individual reservoir be united and a common basis agreed for the overall development. However, in parallel to the unitisation studies, the gas sales strategy proposed by BGE&P required that the three reservoirs be united together with equity fixed for all time. This would allow maximum benefit from gas sales – gas would not have to be "held back" by an Armada Co-venturer in case such Co-venturer was found to have entitlement to less gas. The gas sales strategy meant that all Co-venturers had a common goal to agree a one off fixed equity settlement that would assist gas sales and avoid the expense associated with re-determinations

12.5 Fixed equity

After intensive discussions, a commercial basis for unitisation of the three reservoirs was agreed. This reflected the various components described above in the context of the overall development. The resulting equity was fixed as:

BGE&P	46.27%
Agip	5.58%
Amoco	18.20%
Fina	11.53%
Phillips	11.45%
Yorkshire Energy	6.97%

All Armada Co-venturers are justifiably proud of the Armada fixed equity agreement which provided a valuable boost to the project, with particular credit to Ian Stuart and the other BGE&P specialists in areas of geology, geophysics, petrophysics and reservoir engineering.

(It is interesting to note here that the DTI has discretionary powers to force Licence groups to unite their jointly held field interests if the parties are unable to agree terms for a united development. This may happen for example where a split of field ownership between the different Licence groups cannot be agreed or where the development scenario for the field cannot be agreed. The DTI has these powers in order to ensure that the "national interest" is protected – e.g. that tax revenues from the field are forthcoming as soon as possible! To date however, the DTI has not been required to impose these powers)

12.6 Other UOA issues

The UOA covers the commercial and legal arrangements between all the Co-venturers. The main Articles within the Agreement are:

Ownership

Scope of the Unit

Duties of the Operator

Investment Procedures (voting)

Budgets

Accounting Procedures

Entitlement to Unit Substances

Provision for Abandonment

Insurance

Pre-unit costs

Gas Lifting Principles

BGE&P issued the initial draft of this agreement in late summer 1993 – the execution draft followed a further 11 drafts during which time the UOA was slimmed down to under 120 pages!

One of the key sections of "deregulated gas market UOA's" relates to Gas Lifting.

12.7 Gas Lifting Principles

Prior to around 1990 all gas sold on the UKCS was bought by the monopoly purchaser – BG. Essentially, all fields developed from the mid 60's until the late 80's were sold on a group basis under a "dedicated depletion contract". This meant that BG bought all the reserves from all the field owners on a common basis. The opening up of the UK gas market to competition and the emergence of the gas for power market has given rise to the development of Gas Lifting Principles which allow gas to be produced at different rates by different owners in the same reservoir. These principles have been imported from US experience and tailored to the UK market. In concept, they allow an Armada Co-venturer the right to lift gas at different rates to suit that companies commercial position.

Initially each owner has entitlement to lift gas at a rate up to that owners equity share of available capacity. For example, if the platform can produce 450 mmscfd on a day, BGE&P will be entitled to 46.27% of 450 mmscfd = 208.15 mmscfd on that day. BGE&P can continue to lift at that rate until the field can no longer support a rate of 450 mmscfd as deliverability falls and the overall field moves into its "decline" phase. At such time, BGE&P would have a reduced entitlement to the available capacity (i.e. no longer 46.27% of what is available but a smaller % share determined by the reservoir model and defined in the Lifting Principles).

Gas lifting principles are necessarily complicated due to the possible reservoir scenarios that can be envisaged. Fortunately, the Armada Lifting Principles are confidential – which means their complexities must remain hidden! Suffice to say, after extensive negotiations Co-venturers were satisfied that the principles were equitable, practical and offered significant flexibility. This flexibility will be valuable in the new gas market, once the "Network Code" has been introduced from 1 October 1995.

12.8 Gas Sales

With equity fixed, agreement reached with CATS and Gas Lifting Principles understood, it was possible by November 1993 for BGE&P to present a detailed Gas Sales Strategy.

BGE&P was well placed to prepare the Gas Sales Strategy due to extensive experience of post-1990 gas sales . BGE&P were party to the following deals, a number of which can be considered to be landmarks in the development of the UK gas market:

Amethyst

Pickerill (first sale for power generation)

Everest/Lomond (sale to Teesside Power Limited largest CHP/CCGT power station in the world)

Brae (sale to BG on a supply contract)

Beryl 90% (sale of 90% of the Beryl field to BG)

Beryl 10% (sale of 10% of the Beryl field to various buyers)

Welland

J-Block

Ann

North Morecambe

BGE&P carried out a supply/demand analysis of the market for Armada gas from 1997 and established a firm demand in several sectors (In Figure 14, UK Supply/Demand Forecast, Armada is in the "Probable Development" category). This work, in conjunction with discussions with all potential purchasers established a healthy market for Armada gas amongst:

Established power generators

Independent power projects

Gas marketing companies

BG plc

In the past when BG held the monopoly the price they were prepared to pay for gas was calculated by BG in order to give a reasonable rate of return to the field owners. BG would estimate the capital and operating costs associated with a development, the reserves and any transportation and processing tariffs. BG would then offer a price to give, for example, a 15% real rate of return. If the owners accepted the price, then the project would go ahead. If the owners held out for a higher price, then there was a chance that BG would buy the gas from elsewhere and a competitor field would be developed. As part of the bargain, BG would take reservoir risk and offer a high "Take or Pay" commitment to underwrite the development.

In the new UK market, the above historical negotiation game that typically lasted 2 - 3 years - has been replaced by a new dynamic known as supply/demand. The major supply/demand relationship in the UK has been driven in recent years by the new gas for power market. In addition there are many secondary supply/demand relationships for all the emerging gas marketers and existing and potential power generators and for, of course, BG itself.

To capitalise on these dynamics and to reinforce the credibility of Armada compared to competing projects, BGE&P produced a Gas Marketing Brochure.

12.9 Gas Marketing Brochure

BGE&P persuaded Co-venturers of the merits of producing an informative brochure giving details of Armada including in the hitherto "top secret" areas of capital costs and project schedules. It was possible for a potential purchaser to take the brochure and estimate Armada's economics for a given gas price. BGE&P's view was that the Armada gas price would have no relation to Armada's economics in much the same way that the oil price is not related to the profitability of an oil field. The gas marketing strategy for Armada was to establish the best price and terms for Armada gas. If this was not sufficiently attractive to make the project go ahead then so be it. Under this scenario, Armada would not be developed, nor would it deserve to be developed.

12.10 Evaluation model

With strong competition for Armada gas it was clear that "picking the winners" would be difficult. To aid this process, BGE&P produced a "transparent evaluation model". The model was transparent in that it represented a consensus of all Co-venturers based upon an agreed oil price scenario. It was not the corporate model of any of the Co-venturers. The model contained forecasts for the future prices for all the escalators likely to be offered by potential purchasers, including:

- PPI (Producer Price Index)
- HFO (Heavy Fuel Oil)
- GO (Gas Oil)
- IE (Industrial Electricity)
- RE (Retail Electricity)

For each offer, an overall Net Present Value for the revenue associated with the offer could be established based on:

- Annual contract quantity
- Take or Pay
- Effects of maintenance
- Base price
- Price escalation
- Assessment of Force Majeure risks

12.11 Basis for sale

Armada Co-venturers agreed to sell their gas on the basis of a five year supply contract. The reservoir risk would be carried by the sellers. After the five year period, the sellers anticipated that there would be opportunities in the UK gas

market – and possibly via the interconector to Europe for further gas sales. The reserves would not be dedicated to any purchaser.

From analysis by BGE&P it was clear that gas buyers could purchase their peak requirements (swing) from Southern North Sea fields or TransCo (eg Rough) at a lower price than the cost to Armada Co-venturers of providing such peak. Hence, Armada gas was marketed with a high "take or pay" level (this means the buyer pays for a certain amount of gas whether or not it is actually taken) and low swing (ratio of maximum sale on any day to the average sale on every day) of 120%.

12.12 Amerada Hess – withdrawal from the group

During the early stages of gas sales negotiations, Amerada Hess announced that they were selling their 6.97% of Armada to Yorkshire Energy (YE), a subsidiary of Yorkshire Electricity. YE wanted to use their share of Armada gas to target the domestic market in the Yorkshire area as competition begins in this market sector in 1997. Hence, Amerada Hess withdrew their gas from the group sale. Because this happened early in the negotiations with potential purchasers it did not cause any problems. Indeed, the Yorkshire purchase actually helped the development in that it established the market price for Armada equity (around £4 million per %).

12.13 Gas sales – the result

After an initial screening of potential purchasers in the period November 1993 to January 1994 a short-list of purchasers was established. Full Gas Sales Agreements were then negotiated with all these purchasers until in early March 1994 final offers were received. Evaluation of these offers on the transparent model, on the individual corporate models of the Co-venturers and detailed reviews of all the other clauses in the agreements led to a consensus amongst the group that the optimum purchase combination was BG plc and National Power plc.

The "handshake" with BG took place in the office of Freshfields – the lawyers representing the sellers – on the evening of 23 March 1994, followed by champagne in the great traditions of gas sales. This was not as extravagant as it sounds in that BG were agreeing to buy gas worth around £1,000 million!

For the next 2 months the details of the agreements with BG and NP were defined.

Figure 15 – Gas sales profiles

13. PROJECT APPROVAL

During the early part of 1994, in parallel to the commercial activity, Armada's engineers were satisfying the other Critical Success Factors by producing an agreed Development Plan ("Annex B"), Budget and Project Execution Plan. The Annex B contained all the technical details of the development and had to be approved by the DTI. The trigger in the DTI for approving the Annex B was submission of Board Letters by each Armada Co-venturer, individually offering its support to the project.

14. PROGRAMME FOR 18 MAY

Projects never seem to be executed exactly on schedule. However, Armada 1997 made such good progress that by April 1994 it was "not inconceivable" that the crescendo forecast in August 1993 could actually take place as predicted on 18 May. In early May, with a combination of wit, confidence, style and arrogance, John Sayers the Project Development Manager sent a letter to Co-venturers' OPCOM representatives "confirming arrangements for 18 May":

10.30 OPCOM – approve £700 million budget send Board Letters to DTI

12.00 Execute Unit Operating Agreement

12.30 Execute CATS/Armada Transportation and Processing Agreement

13.00 Lunch

14.30 Execute Gas Sales Agreements with BG plc

15.30 Execute Liquids Transportation Agreements

16.00 Execute Gas Sales Agreements with National Power plc

16.30 Celebratory drinks

A photograph from the day is shown in Figure 16. Achieving so much on 18 May was the result of a great deal of hard work and commitment by many people in BGE&P, the Co-venturers, the gas buyers, CATS, BP, the engineering design contractor and the DTI with a little good fortune thrown in.

15. DTI CONSENT

Following submission of the Board Letters and Annex B on 18 May, the DTI did not take long to give their full consent to the development – received on 23 June. All Armada Co-venturers would agree that the DTI officials who worked on Armada were of great assistance in achieving timely approval and made a significant contribution to the success of the Project.

16. PRESS RELEASE

During early June BGE&P prepared a detailed press release which was approved by the Armada Co-venturers. On 23 June the International Public Affairs Department of BGE&P came in to its own and sent press packs to 50 organisations and copies of the press release to a hundred more. The press coverage was excellent as it should have been based upon two years of hard work by many people within BGE&P and Co-venturers.

17 SCHEDULE TO FIRST GAS

Figure 17 gives the overall Project Schedule to 1st gas in 1997. So far, major orders have been placed as follows:

Topsides design	AMEC Engineering
Topsides fabrication	Trafalgar House
Jacket design	John Brown
Installation	Heeremac

The Project Team has every confidence that 450 mmscfd of gas will flow from Armada on 1 October 1997, as scheduled.

18. CONCLUSION

There is no doubt that the major achievement of Armada is to demonstrate the benefits of joint ventures in bringing experience and best practice to a project.

Co-venturers provide a constructive audit of the project team's performance – all Co-venturers want the project to be a success to maximise the profit to their company.

For future BGE&P Operated Joint Ventures in the UK and throughout the world, the commercial lessons to be learned from Armada can be summarised as follows:

18.1 Define Objectives

Establish Co-venturer's overall project requirements

Agree unified overall commercial and technical schedule with Co-venturers.

Identify deliverables for regular milestone OPCOMs

Have target dates for all activities (commercial and technical) and maintain these targets

18.2 Customer Orientation

Recognise that Co-venturers are customers

Establish good personal relationships with all Co-venturers

Be open and honest with Co-venturers to gain their confidence/trust

Generate team spirit within BGE&P and with the Co-venturers in an enjoy able atmosphere

18.3 Communication

Invite Co-venturers to all meetings with 3rd Parties

Listen to Co-venturers, adopt their best ideas

Issue meeting notes/action points within 24 hours of all meetings

Issue monthly report to Co-venturers, DTI

Issue very detailed strategies for gas sales, gas processing, gas lifting, NGL storage etc. based upon BGE&P experience/knowledge

Ensure complete cooperation/exchange of information between commercial, reservoir, facilities and finance subcommittees

BGE&P has an unrivalled combination of technical and commercial skills in the gas business through being a major player in all areas of the gas chain from reservoir geology, through offshore facilities, gas and liquid transportation, onshore gas processing, TransCo issues and gas marketing. These skills are particularly at a premium in the development of complex gas/condensate projects in the Central North Sea.

19. ACKNOWLEDGEMENTS

Within BGE&P, particular thanks go to John Sayers, Armada Development Manager, and all the many colleagues who worked hard and well in the 2 years leading up to Project Approval.

Thanks go to Colin Friedlander, BGE&P Director (UK and Western Europe) for permission to publish this paper and to all Armada Co-venturers for their consent. The "story" represents my perspective on events leading up to Project Approval and does not represent the official interpretation held by BGE&P or any Co-venturers.

Finally, thanks to members of the Armada Project who contributed to this paper and to my wife who put up with quite a bit from Armada!

Appendix 1

British Gas Exploration and Production Limited

BGE&P, the Operator of Armada, has the second highest reserve portfolio on the UKCS and discovered, owns and operates the 7tcf South Morecambe field which can produce up to 1800 mmscfd. BGE&P has recently developed its 520 mmscfd North Morecambe field and holds major equity interests in CATS (51%), Everest/ Lomond, (59%), J-Block (30%), Indefatigable, Leman, Amethyst, Beryl, Brae. BGE&P owns or operates onshore processing plant with a capacity of around 5000 mmscfd, by far the biggest gas processor in Europe. BGE&P is active in over 20 companies worldwide.

Agip (UK) Limited

This is the subsidiary of the world's sixth largest oil company Agip SpA, the Italian State oil company, working in some thirty counties around the world. Agip (UK) Ltd. is operator of the four field T-Block development which came on stream in 1993 as well as seven exploration blocks. In addition, it has interests in sixteen other UKCS fields including a major interest in J-Block

Amerada Hess Limited

This is the UK subsidiary of Amerada Hess Corporation which has been active in oil and gas activities since 1919. The company operates five oilfields on the UKCS - Ivanhoe, Rob-Roy, Hamish, Scott and Angus and is also active in 12 oil or gas fields in the UK sector, including an ownership of 17.7% in CATS

Following Project Approval, Amerada Hess completed the sale of their 6.97% interest in Armada to Yorkshire Energy, a subsidiary of Yorkshire Electricity Board

Amoco (UK) Exploration Company

A subsidiary of Amoco Corporation which is one of the world's largest integrated energy and petrochemical companies.

Amoco (UK) Exploration operates three oilfields: North West Hutton, Montrose and Arbroath. It also operates the Indefatigable and Leman gas fields, a processing terminal at Bacton, the CATS pipeline and the Everest and Lomond gas fields.

Fina Exploration Limited

Established in 1964, Fina Exploration is a member of the publicly quoted Brussels based Petrofina group. It has interests worldwide in all aspects of the petroleum industry. Fina's UKCS interests include Alba, Ann, Audrey, Hewett, Maureen and the T-Block fields. Fina also has a major interest in the large Britannia development.

Phillips Petroleum Company United Kingdom Limited

The company operates five producing fields on the UKCS; Ann, Audrey, Hewett, Moira and Maureen, as well as a gas processing plant located at Bacton on the north Norfolk coast. Phillips is currently developing the Judy/Joanne fields in the central North Sea. These are due on stream in 1996. The company also has interests, both operated and non operated, in a significant number of other discoveries

Yorkshire Energy Limited

A subsidiary of Yorkshire Electricity Board. The company is aiming to build up a share of the domestic gas market in the Yorkshire area from 1997 onwards.

Figure 1

CENTRAL NORTH SEA ASSET OWNERSHIP

	Everest	Lomond	CATS	Armada	J - Block
B G E & P **	57.789	61.1111	51.1835	46.2	30.5
Amoco	21.1439	22.2222	29.5289	18.2	
Amerada Hess	18.6667	16.1667	17.7174	6.9*	
Phillips	1.0134		0.6630	11.45	36.5
Fina	0.8688		0.5684	11.53	
AGIP	0.5178		0.3388	5.58	33
	100.0000	100.0000	100.0000	100.0000	100.0000

* Sold to Yorkshire Energy.
** Includes equity held by BG North Sea Holdings

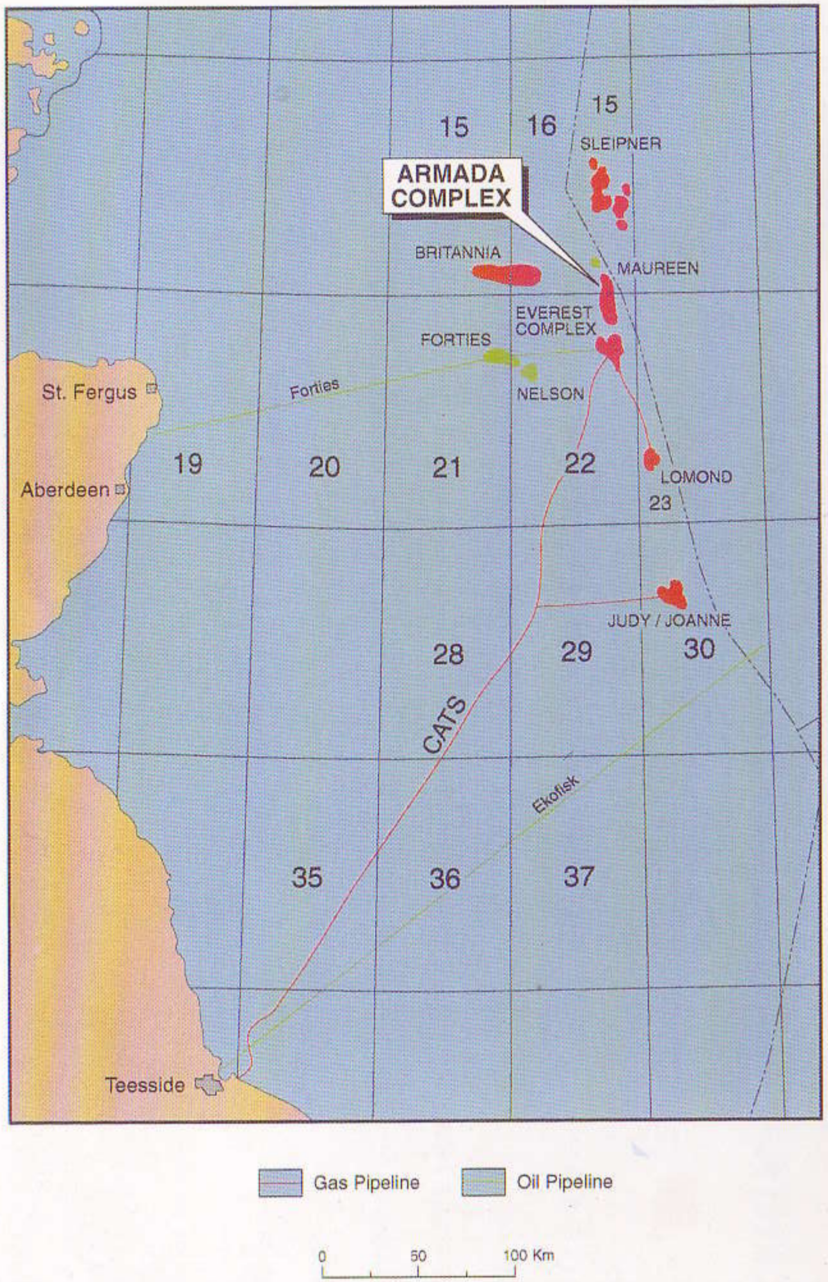

Figure 2

November 1994

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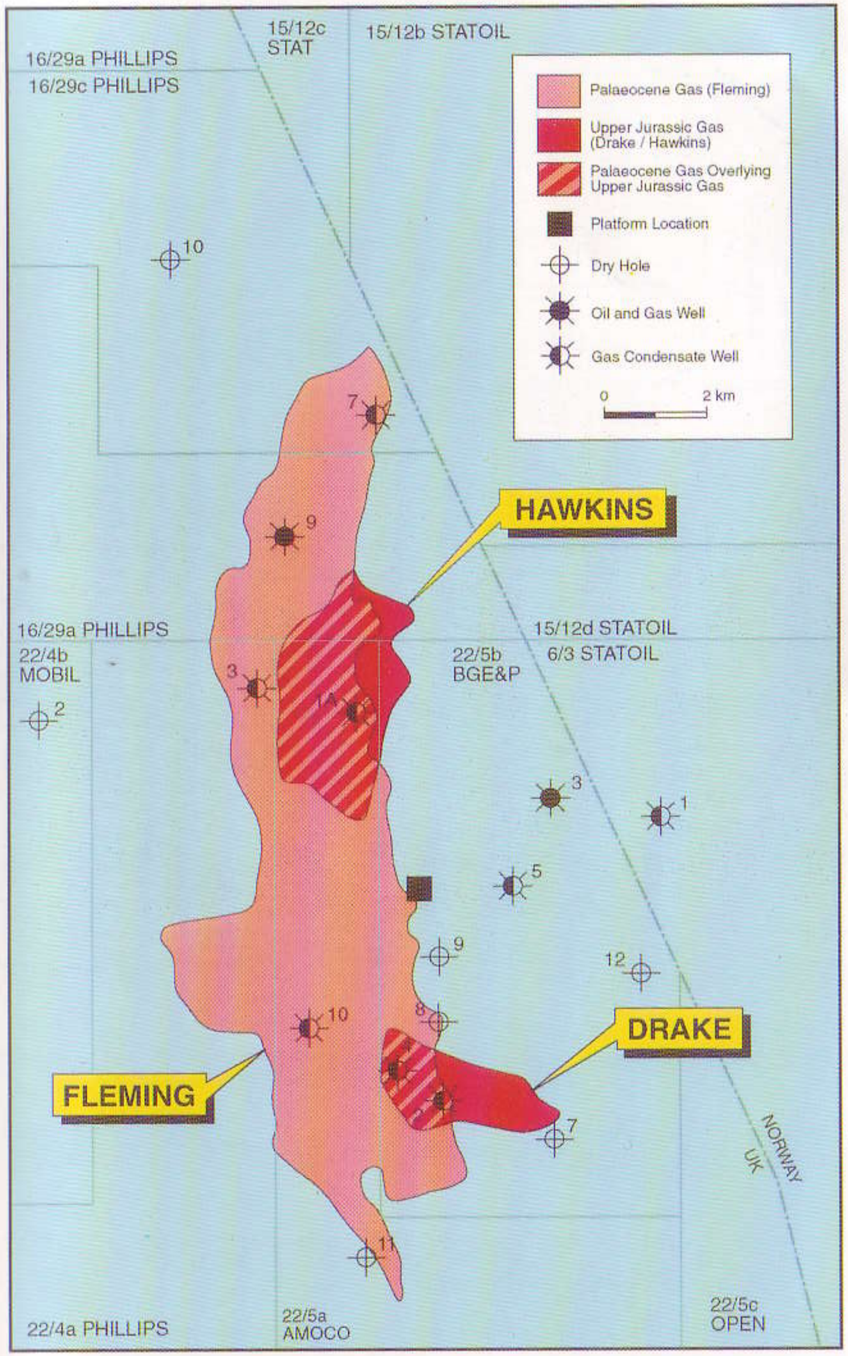
Armada Area Location Map

British Gas



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Armada Development
Fleming / Drake / Hawkins Gas / Condensate Fields

Figure 3

British Gas

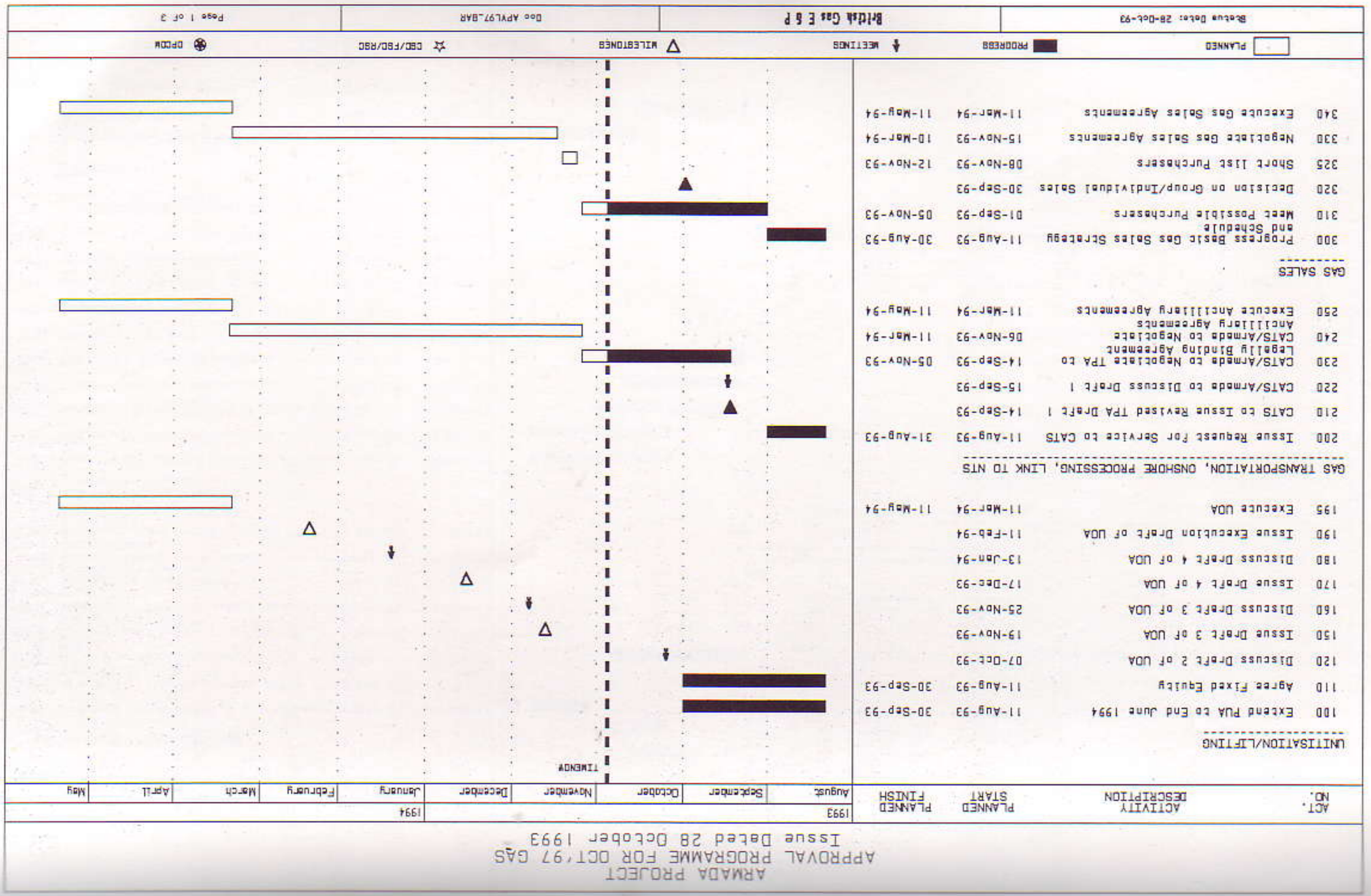
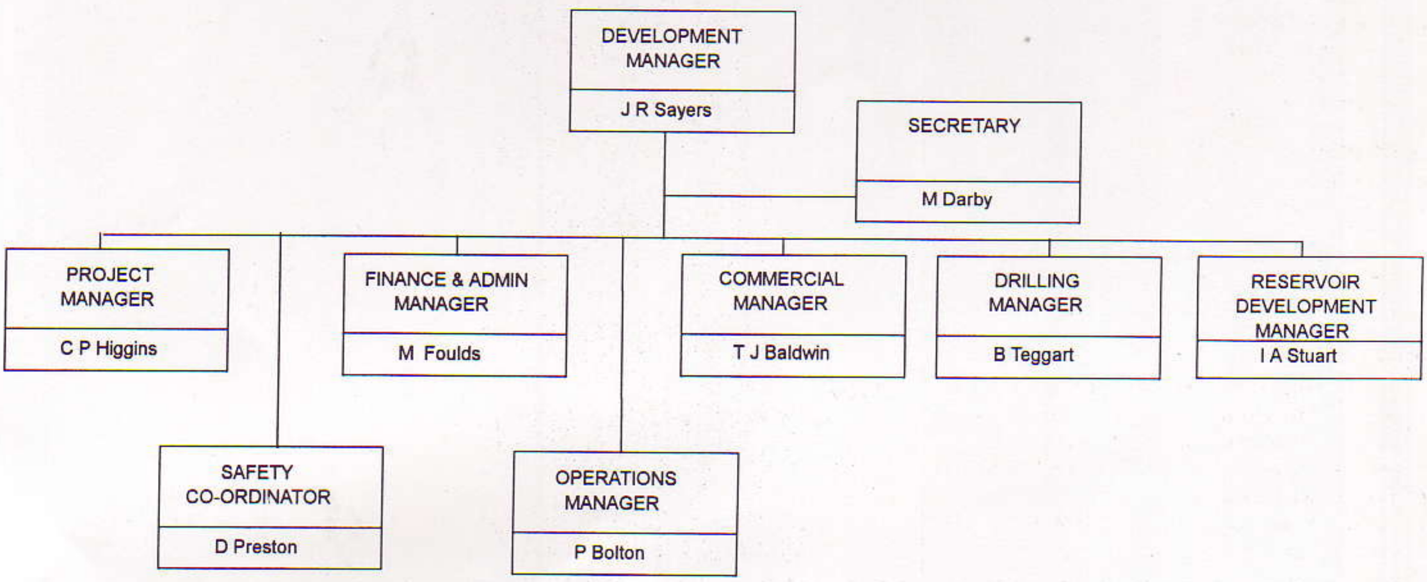


Figure 5

Figure 4

ARMADA
Development Management Team



ARMADA PROJECT
APPROVAL PROGRAMME FOR OCT'97 GAS
Issue Dated 28 October 1993

ACT. NO.	ACTIVITY DESCRIPTION	PLANNED START	PLANNED FINISH
	OFFSHORE LIQUIDS TRANSPORTATION		
400	Progress Basic Strategy and Schedule	11-Aug-93	31-Aug-93
405	Armada to Formally request Offer For 1997	09-Sep-93	
410	BP FPS to Issue Capacity/Tariff Offer	09-Sep-93	19-Nov-93
415	Co-Venturers to meet with BP FPS (to be confirmed)	19-Nov-93	
420	Negotiate TPA to Agreement with BP FPS	19-Nov-93	28-Jan-94
425	Everest to Issue Draft 1 of ELS-Forties Agreement	22-Oct-93	
445	Everest/Armada to Negotiate to Agreement	22-Oct-93	28-Jan-94
450	Execute Liquid Transportation Agreements	11-Mar-94	11-May-94
	FACILITIES ENGINEERING (Phase 1)		
500	Development Concept (Central Pltfm) Agreed	11-Aug-93	30-Sep-93
505	450 mmscfd From Day 1 Agreed	11-Aug-93	30-Sep-93
510	Complete Tender Evaluation, Stage 2	02-Sep-93	18-Oct-93
515	Prepare Contract Documentation	13-Sep-93	31-Oct-93
520	Contracts Committee Approval	25-Oct-93	
525	Partners' Approval	27-Oct-93	05-Nov-93
530	Award Design Contract	08-Nov-93	
535	Undertake Concept Definition	08-Nov-93	07-Feb-94
540	Prepare Execution Strategy	22-Nov-93	21-Feb-94
545	Prepare Cost Estimate/Schedule	22-Nov-93	21-Feb-94
550	Partners' Approve Concept Definition Strategy, Cost & Schedule	08-Feb-94	18-Mar-94
	BUDGETS/APPROVALS		
600	Prepare/Issue Budget to Project Approval	11-Aug-93	17-Sep-93
610	Partners Review	17-Sep-93	05-Nov-93
620	Buget Approved by OPCOM	05-Nov-93	

1993: August, September, October, November, December; 1994: January, February, March, April, May — TIMENOW

PLANNED — PROGRESS — MEETINGS — MILESTONES — CSC/FSC/RSC — OPCOM

ARMADA PROJECT
APPROVAL PROGRAMME FOR OCT'97 GAS
Issue Dated 28 October 1993

ACT. NO.	ACTIVITY DESCRIPTION	PLANNED START	PLANNED FINISH
630	Issue AFEs	30-Sep-93	05-Nov-93
640	Partner Approval of AFEs	05-Oct-93	15-Nov-93
650	Review Progress against Budget	30-Nov-93	
660	Present Remainder of '94 Budget	18-Mar-94	
670	Board Approve Project/Budgets/AFEs	18-Mar-94	18-May-94
	OPCOMS, SUB-COMMITTEES & WORKSHOPS		
700	CSC/FSC Meeting	11-Aug-93	
705	OPCOM No 1	19-Aug-93	
710	CSC Meeting	09-Sep-93	
715	Drilling Workgroup	21-Sep-93	
720	CSC Meeting	22-Sep-93	
725	FSC Meeting	24-Sep-93	
730	RSC Meeting	27-Sep-93	
735	OPCOM No 2	30-Sep-93	
740	FSC Meeting	27-Oct-93	
745	OPCOM No 3	05-Nov-93	
750	Commercial/Facilities Workshop	10-Nov-93	12-Nov-93
755	CSC Meeting	23-Nov-93	
760	FSC Meeting	25-Nov-93	
765	OPCOM No 4	30-Nov-93	
770	CSC Meeting	13-Jan-94	
775	FSC Meeting	21-Jan-94	
780	OPCOM No 5	27-Jan-94	
785	OPCOM No 6	18-Mar-94	

1993: August, September, October, November, December; 1994: January, February, March, April, May — TIMENOW

PLANNED — PROGRESS — MEETINGS — MILESTONES — CSC/FSC/RSC — OPCOM

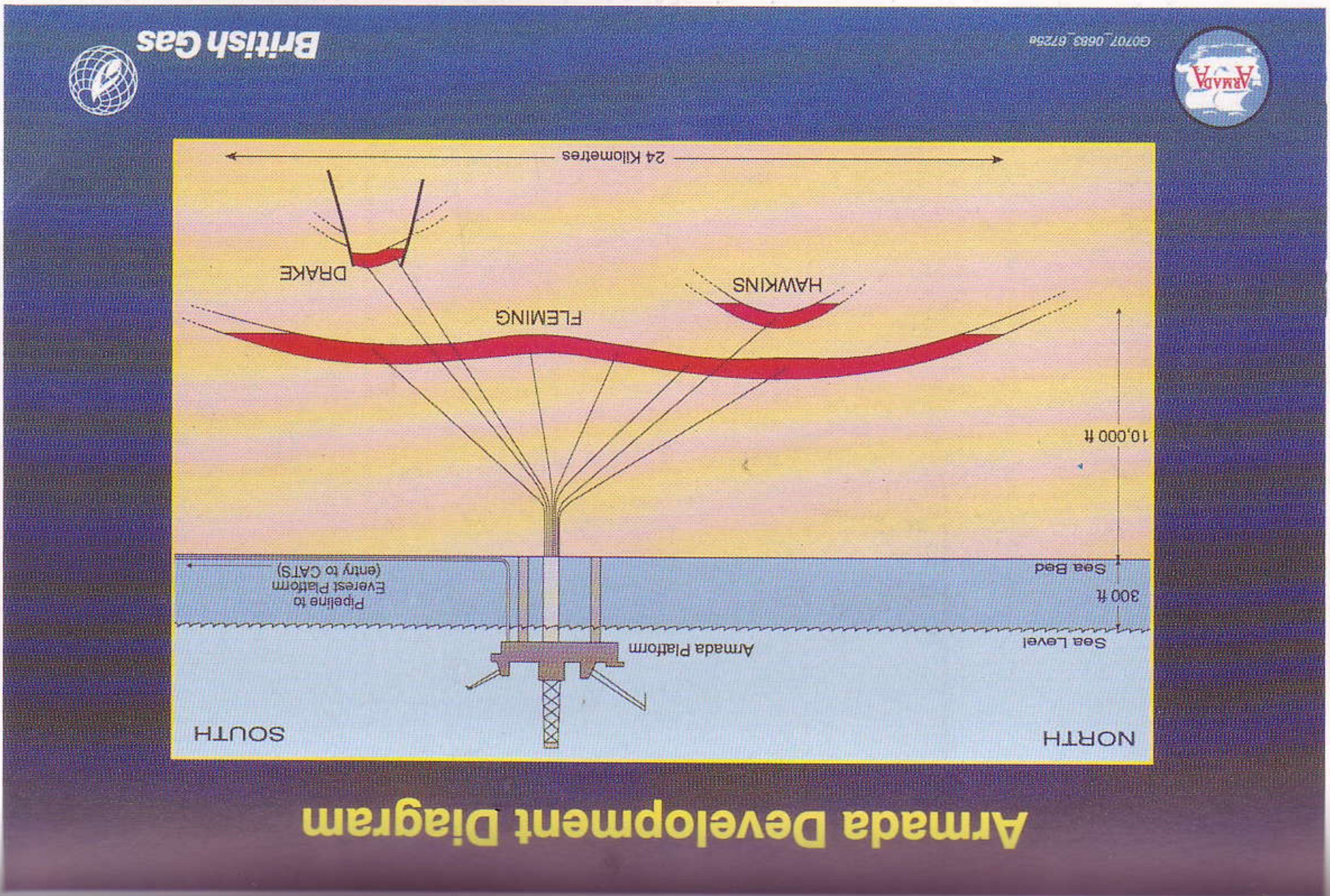


Figure 7

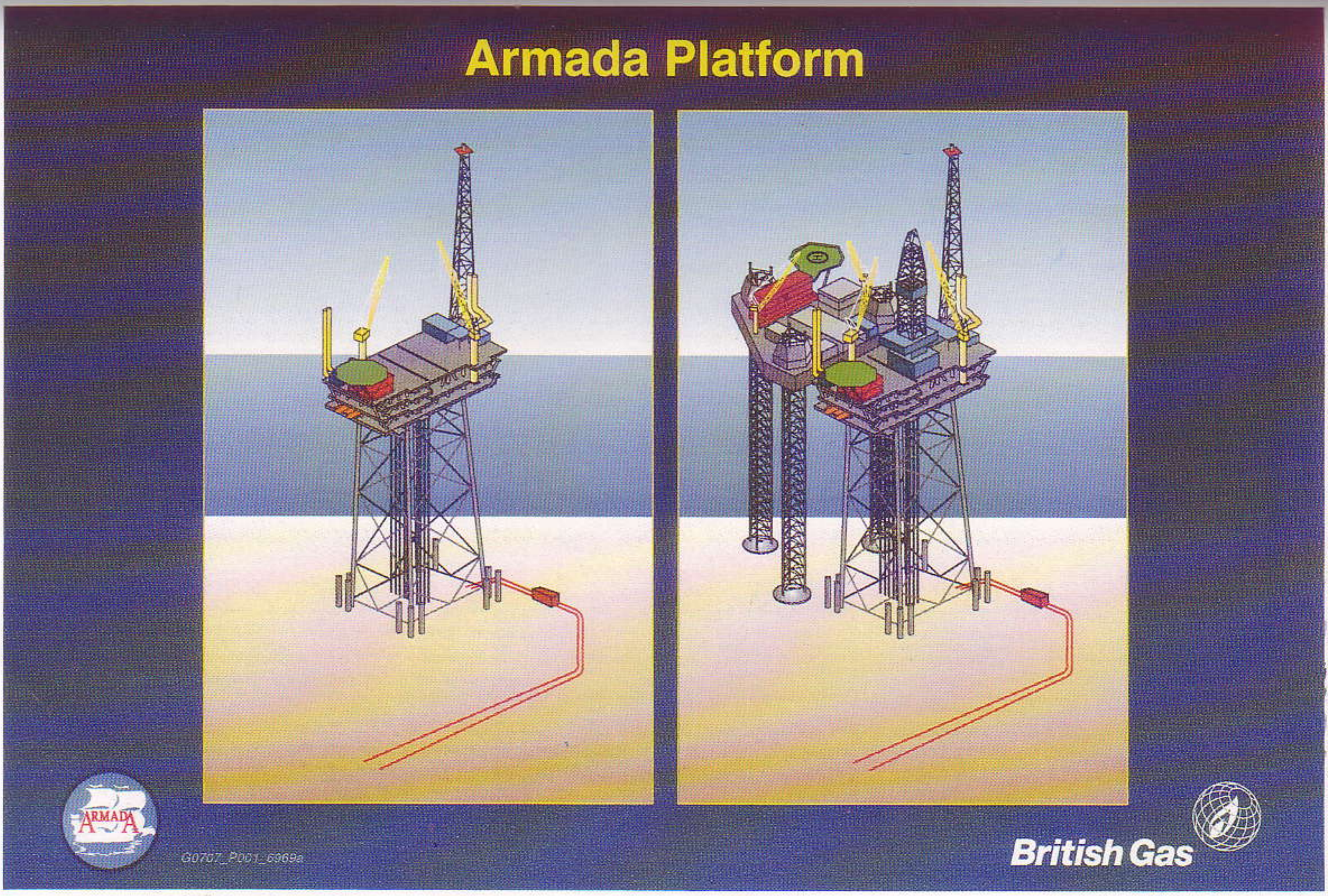


Figure 6

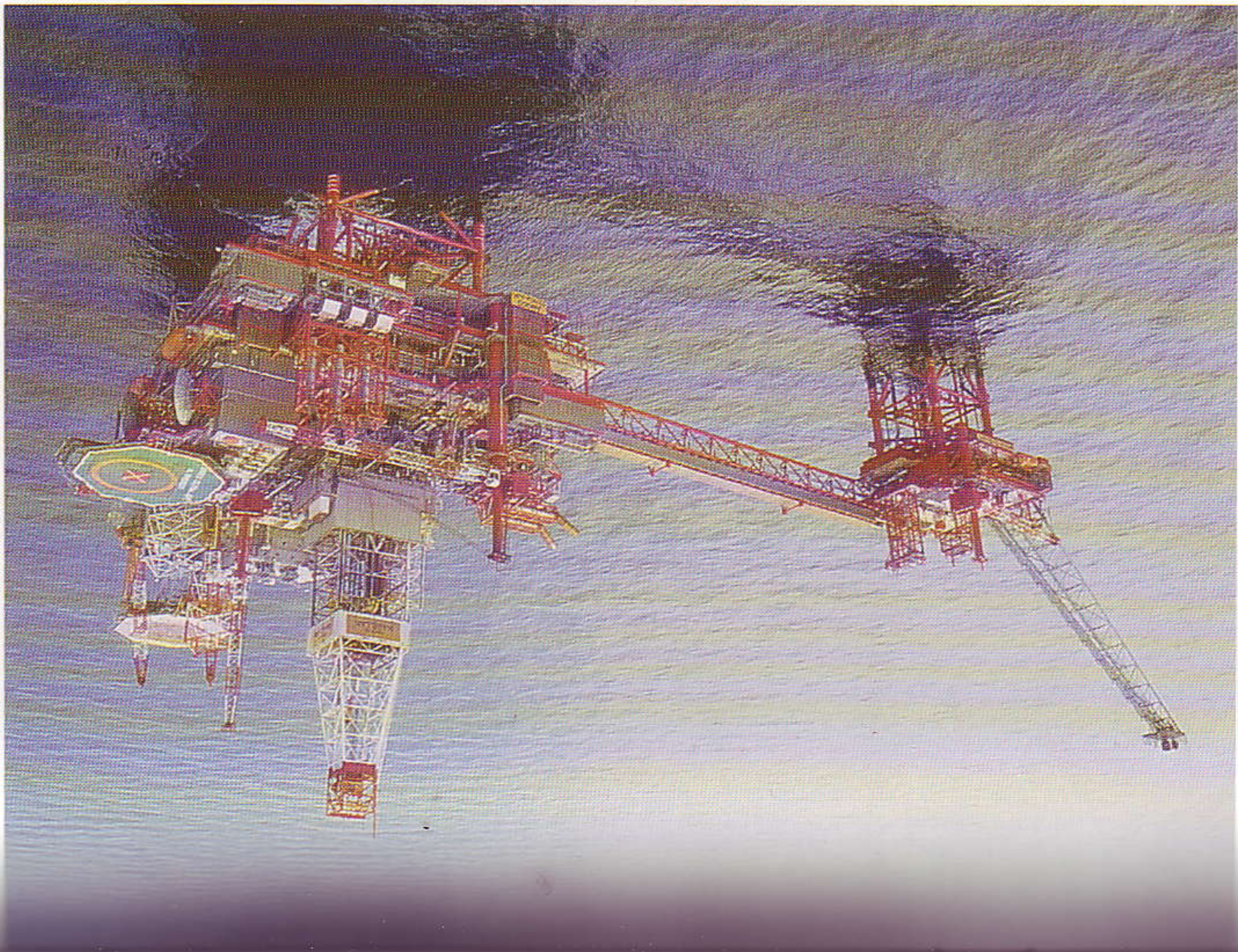


Figure 9 : North Everest and CATS Riser Platforms

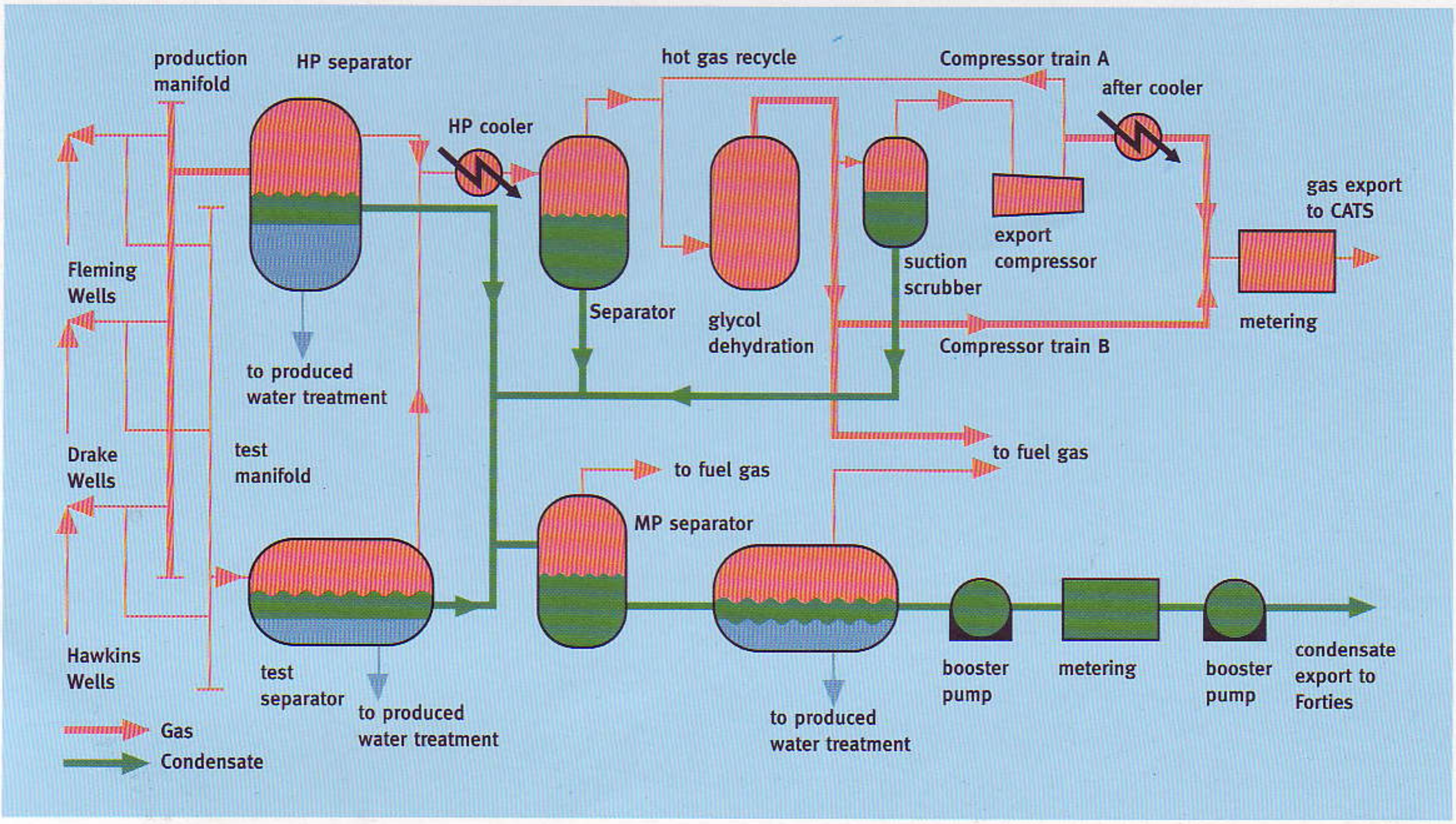
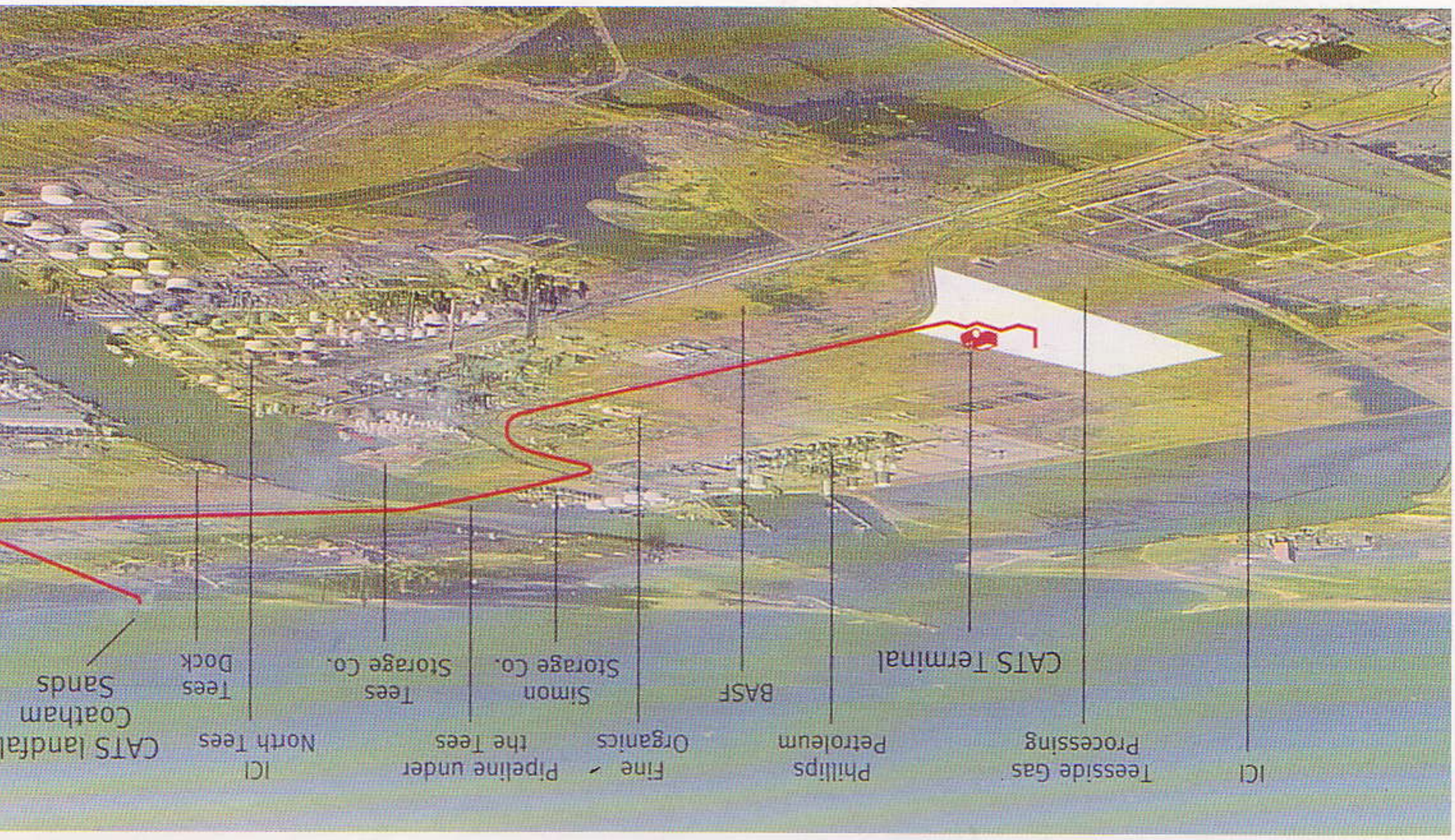
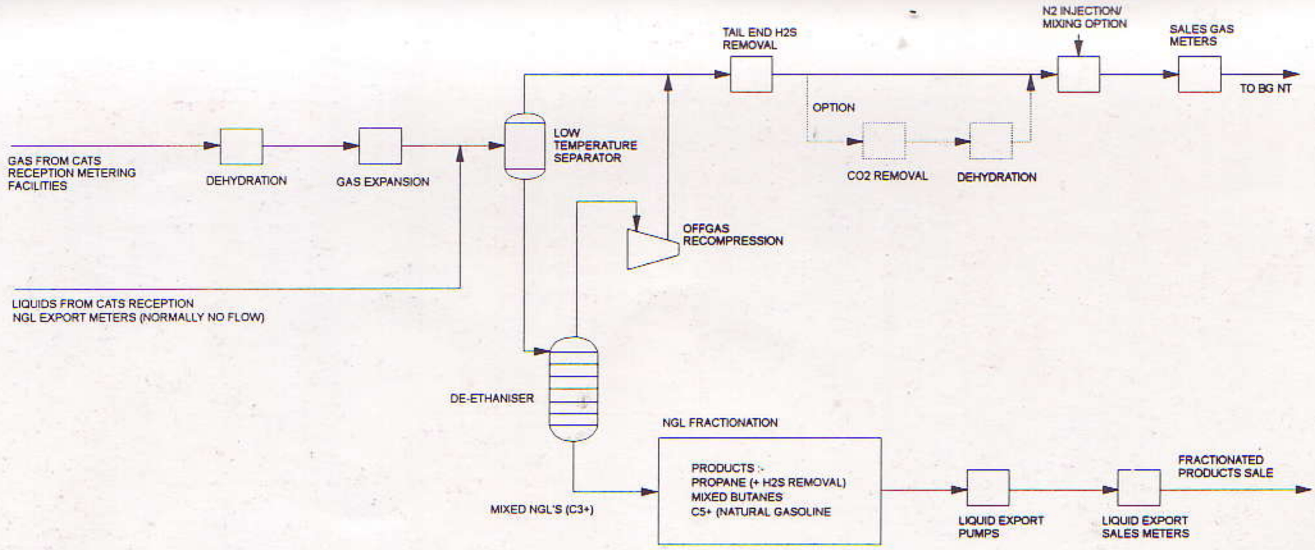


Figure 8 Platform Process Schematic



Teesside Terminal

ARMADA ONSHORE PROCESSING FACILITIES

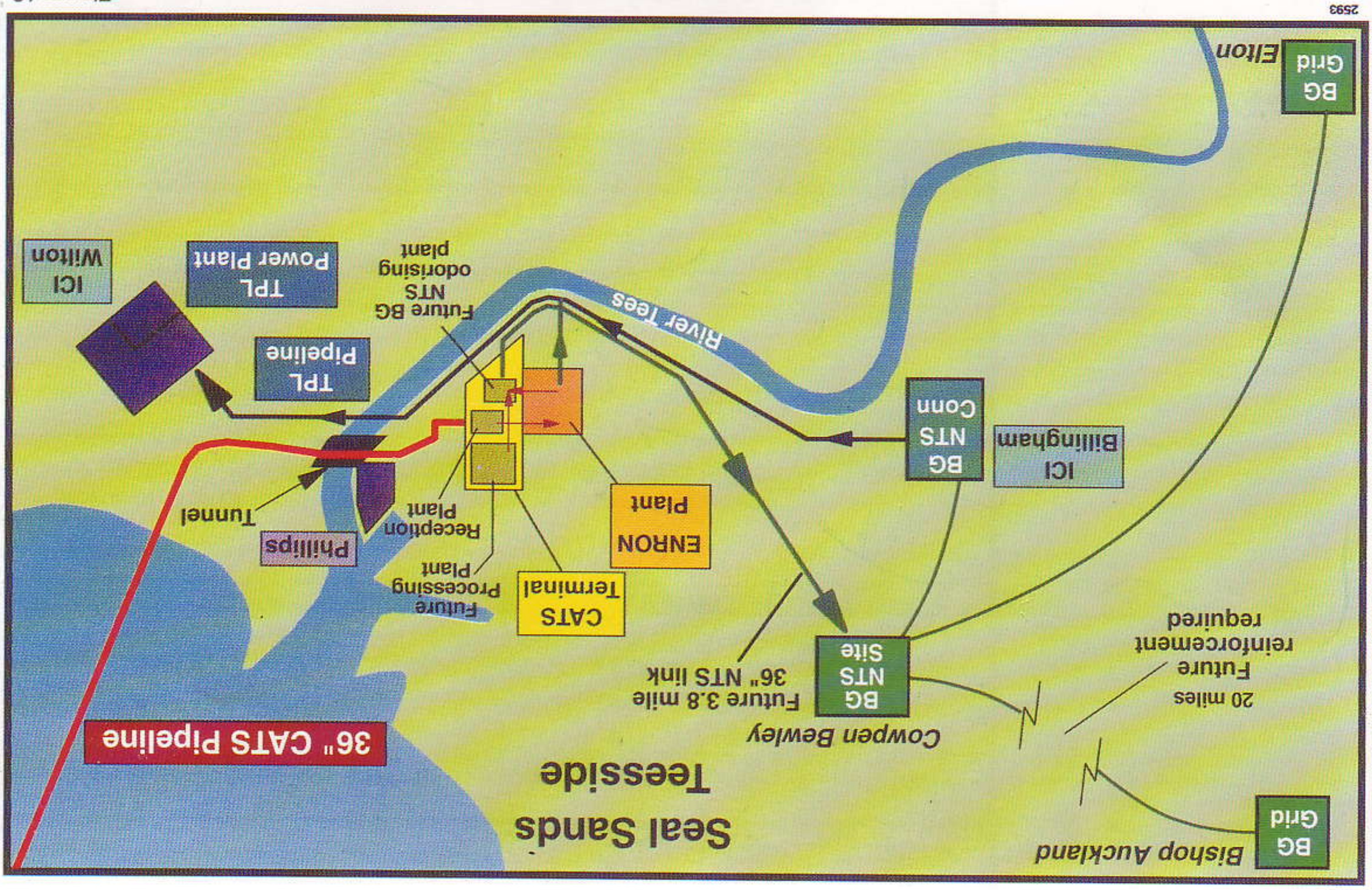


450 MMSCFD - Armada Throughput Only

STREAM		FEED	SALES GAS	PROPANE	BUTANE	C5+
PRESS	BARG	110	68	10	6	8
TEMP	DEG C	4	5	30	30	30
FLOW	KMOL/HR	22413.2	21975.8	130.9	106.0	135.7
	KG/HR	431277	406470	5763	6155	11553
MOLE %						
N2		0.77	.78			
CO2		1.74	1.77			
C1		86.60	88.1			
C2		6.43	6.48	2.86		
C3		2.55	2.03	94.69	1.14	
C4		1.12	0.64	2.45	98.27	1.00
C5		0.43	0.15		0.59	46.31
C6+		0.36	0.04			52.66

Figure 11

Figure 12



NTS Connection to Seal Sands

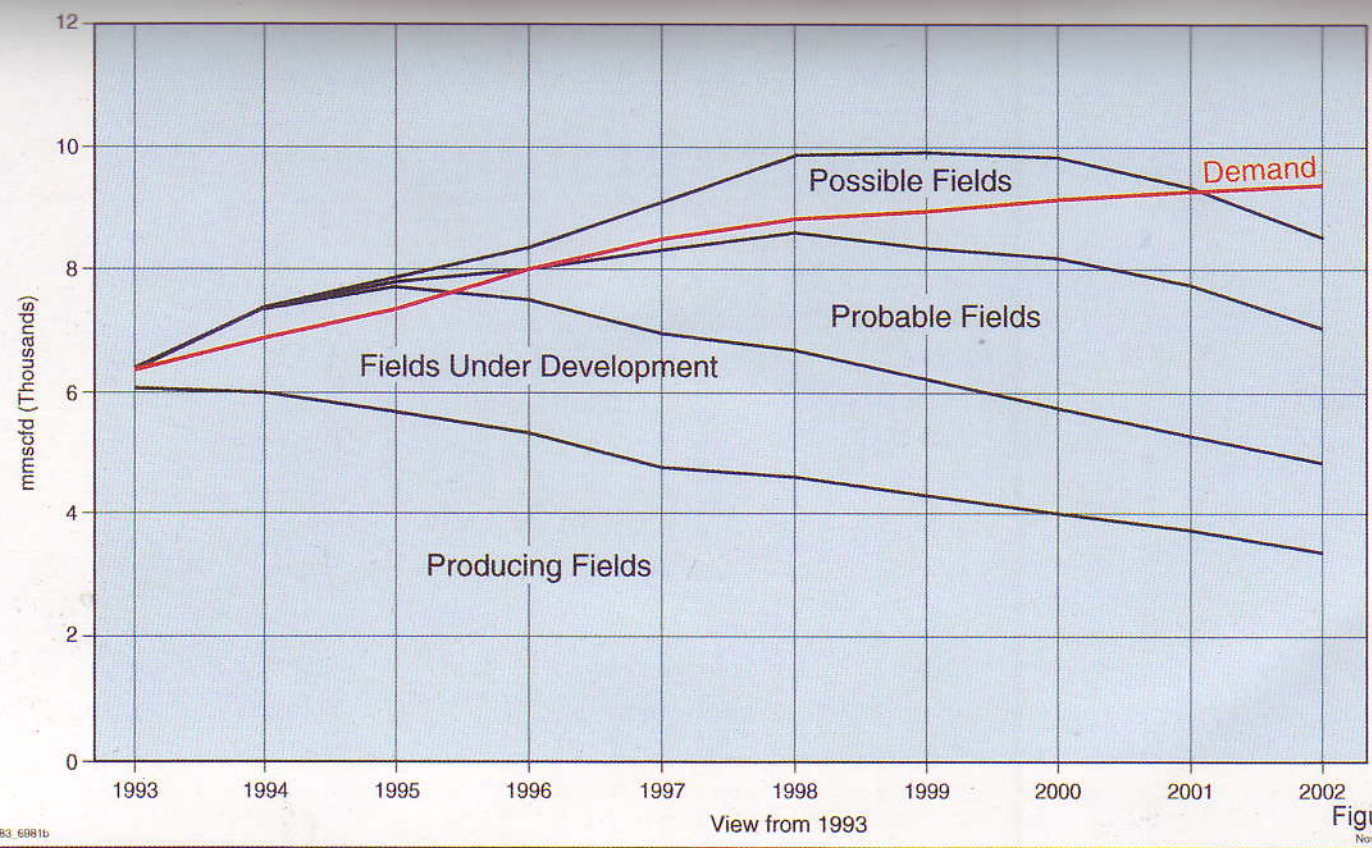


Figure 13
November 1994

UK Gas Supply / Demand

British Gas

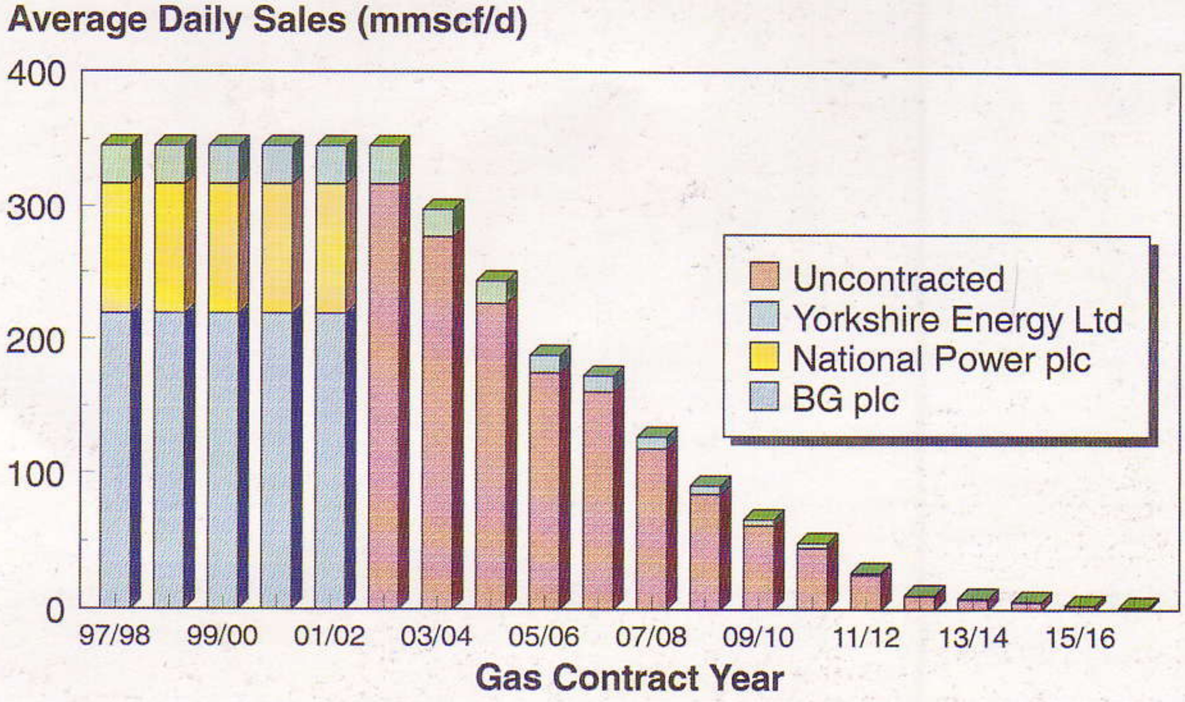
Figure 15

British Gas

ARMADA

Armada Gas Sales Profile

Figure 14



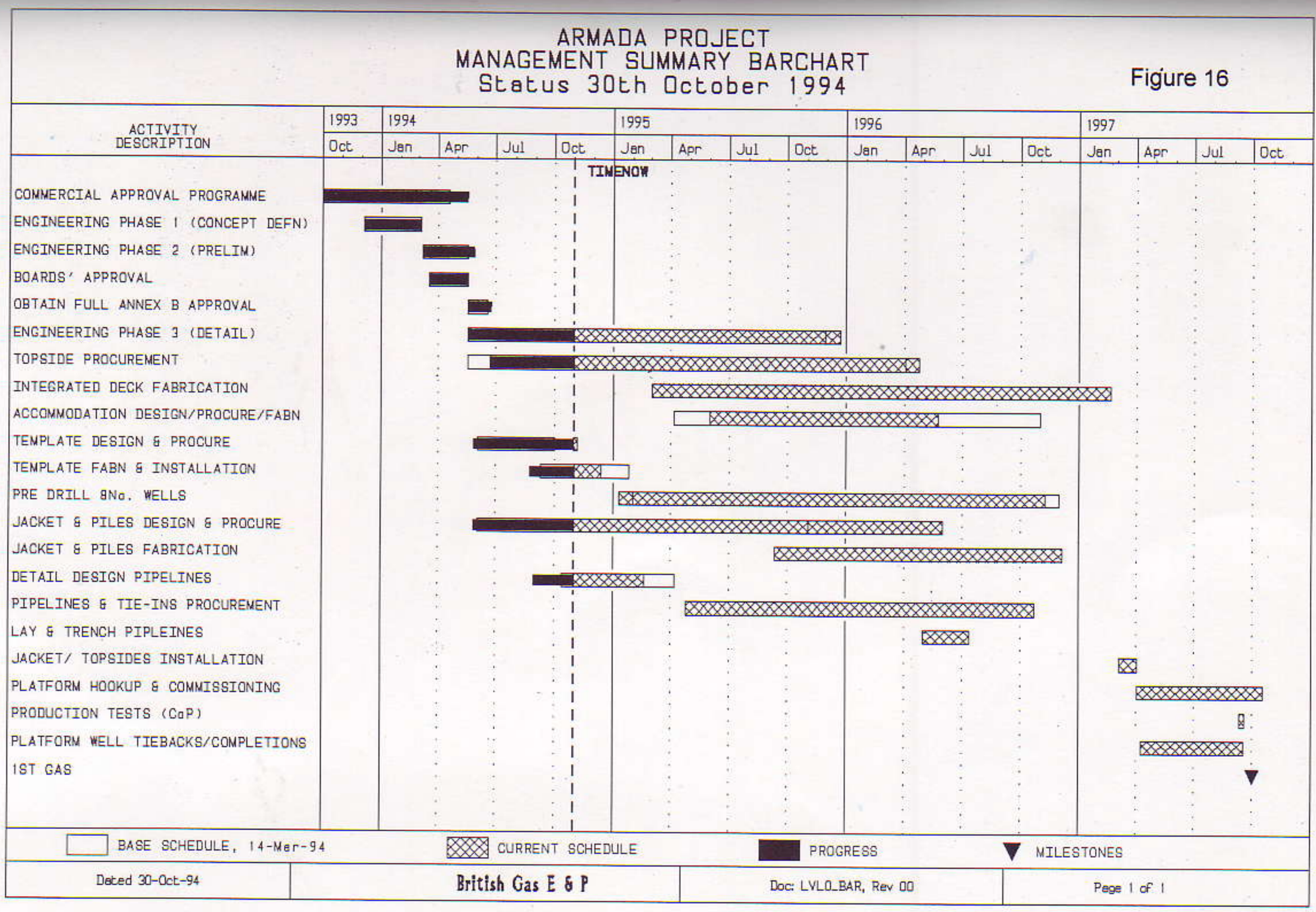

ARMADA PROJECT
MANAGEMENT SUMMARY BARCHART
Status 30th October 1994
ACTIVITY DESCRIPTION
1993
1994
1995
1996
1997
Oct
Jan
Apr
Jul
Oct
TIMENOW
COMMERCIAL APPROVAL PROGRAMME
ENGINEERING PHASE 1 (CONCEPT DEFN)
ENGINEERING PHASE 2 (PRELIM)
BOARDS' APPROVAL
OBTAIN FULL ANNEX B APPROVAL
ENGINEERING PHASE 3 (DETAIL)
TOPSIDE PROCUREMENT
INTEGRATED DECK FABRICATION
ACCOMMODATION DESIGN/PROCURE/FABN
TEMPLATE DESIGN & PROCURE
TEMPLATE FABN & INSTALLATION
PRE DRILL 8No. WELLS
JACKET & PILES DESIGN & PROCURE
JACKET & PILES FABRICATION
DETAIL DESIGN PIPELINES
PIPELINES & TIE-INS PROCUREMENT
LAY & TRENCH PIPLEINES
JACKET/ TOPSIDES INSTALLATION
PLATFORM HOOKUP & COMMISSIONING
PRODUCTION TESTS (CoP)
PLATFORM WELL TIEBACKS/COMPLETIONS
1ST GAS
BASE SCHEDULE, 14-Mar-94
CURRENT SCHEDULE
PROGRESS
MILESTONES
Dated 30-Oct-94
British Gas E & P
Doc: LVLO_BAR, Rev 00
Page 1 of 1

Figure 16