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North Sea Gas: Development Options

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An Intelligence Assessment

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September 1982

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North Sea Gas: Development Options [redacted]

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An Intelligence Assessment

This assessment was prepared by [redacted] Office of Global Issues. Comments and queries are welcome and may be directed to the Chief, Energy Issues Branch, OGI, [redacted]

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North Sea Gas: Development Options [redacted]

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Key Judgments

Information available as of 25 August 1982 was used in this report.

Exploratory drilling during the last several years has revealed huge gas reserves in the North Sea—particularly in the Norwegian sector—which could provide sizable additional gas supplies to the European continent. Given long leadtimes, technical problems, and political constraints, however, these supplies are unlikely to come on stream before the early 1990s. Continental gas import requirements are expected to increase by about 1.2-1.3 million barrels per day of oil equivalent in the 1990s as demand grows and production from older fields declines. Under favorable circumstances, North Sea and Dutch gas could meet about 80 percent of these requirements and forestall further increases in purchases from the Soviet Union. [redacted] 25

Multinational cooperation will be critical in bringing sizable new volumes of North Sea gas to the Continent by the early 1990s. Projects to boost North Sea gas exports will require enormous capital investments—$15-20 billion may be required to develop Norway's Troll gasfield alone—and will have to compete with other North Sea oil and gas projects for a share of the approximately $100 billion to be spent during the next decade. Interest rate subsidies similar to those offered for the construction of the Soviet pipeline could substantially speed development of North Sea gas reserves; an interest rate subsidy of about 2 percentage points could cut 15 percent from total investment costs. [redacted] 25X

Cooperative agreements to transport gas to the marketplace will be equally important. A gas swap agreement, for example, would involve increased Norwegian gas deliveries to the United Kingdom in exchange for delivery of equal volumes of British gas to the European continent. This could save $1-2 billion in facilities investments and shorten leadtimes by two to three years. Similarly, Dutch participation in a coordinated gas marketing strategy could vastly simplify Norway's efforts to increase future gas sales. [redacted] 25

Although the commercial advantages of such arrangements are sizable, numerous political obstacles must still be overcome, including Norwegian

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reluctance to become overly dependent on hydrocarbon development. Other critical factors determining the timing and size of new North Sea projects include:

- *Tax policies.* The current UK tax regime is a serious deterrent to the development of small fields. Norway's petroleum taxes are also high, and development has been slowed further by short drilling seasons and generally cautious government policies.

- *Market prospects.* An unprecedented decline in West European gas consumption during the last two years has clouded the outlook for the future size of the European gas market. Present uncertainties could cause North Sea producers to hesitate before launching new projects, especially in view of the possibility of being undercut by cheaper Soviet gas.

- *Revenue needs of producing countries.* If the budget crisis in the Netherlands worsens, pressures to increase gas sales will increase. Similarly, Norway may be inclined to speed gas development because of lowered expectations of future oil revenues [redacted] 25X1

Without subsidies, the price of Norwegian gas is likely to be about 15 percent higher than the price of Soviet gas. Hence, the market share for North Sea gas could be constrained by limited European willingness to pay a premium for long-term security of supply. [redacted] 25X

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Contents

	Page
Key Judgments	iii
European Gas Needs	1
Political Factors	1
Key North Sea Projects	3
Sleipner Field	5
Troll Field	5
Other Fields	5
Financial Requirements	5
Outlook	6

Appendixes

A.	The Troll Gasfield Project	7
B.	Triangular Gas Deal	9

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Tables

1.	North Sea Drilling Activity	3
2.	Projected Expenditures for North Sea Oil and Gas Development	6

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North Sea Gas: Development Options [redacted]

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European Gas Needs

An unexpected decline in West European natural gas consumption in recent years has reshaped the strategies of players in the European gas market. North Sea producers, seeing gas demand and prices of competing fuels rising more slowly than previously expected, are now [redacted] making more cautious appraisals of the profitability of expensive gas development projects. European gas buyers have sharply reduced purchases of Dutch gas, stepped back [redacted] from participation in Nigeria's Bonny liquefied natural gas (LNG) project, and trimmed proposed imports of Soviet gas from Siberia. Uncertainties about the future may lead décisionmakers on both sides to stall new commitments for development of North Sea gas. Because of long leadtimes in developing these projects, doing so would strengthen Soviet leverage to increase gas sales in the 1990s. [redacted]

We expect the falloff in West European gas consumption to end this year and demand to revive as economic recovery begins.[1] We estimate that demand for gas in Western Europe will increase from 3.6 million barrels per day of oil equivalent (b/doe) in 1980 to about 4.1 million b/doe in 1990 and to 4.5-5.0 million b/doe by the year 2000. Provided some new deliveries of Soviet gas begin by the late 1980s, most West European countries expect to meet projected demand through 1990 from domestic production and imports they have already lined up. [redacted]

In the 1980s European gas buyers expect sizable new supplies to come from Algeria and the Soviet Union, while deliveries of North Sea gas will increase only slightly under current plans. If the West Europeans were to forgo increases in Soviet gas deliveries because of sanctions or unforeseen political events, they technically could still balance supply and demand through the decade. However, the economic and political decisions necessary to bring about this combination of events would require a reversal of existing policies and a sharp acceleration of North Sea development. [redacted] 25X1

For the 1990s, however, we project that West European countries will have to line up new supplies of 1.2-1.3 million b/doe. North Sea gas could supply the bulk of this increment, with Norway alone [redacted] potentially supplying an additional 700,000 to 850,000 b/doe. Dutch gas exports can also play a role in filling Western Europe's natural gas requirements but will do so only if current policies change. By supplying additional gas in the late 1980s and early 1990s—before additional Norwegian gas becomes available—the Dutch might enable some countries, notably Belgium, to avoid purchasing Soviet gas. [redacted] 25X1

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Political Factors

Political decisions made in Oslo, The Hague, and other European capitals during the next year or two will heavily influence the pace of European gas development. In our view, if differences in petroleum taxation and pricing policies among Norway, the United Kingdom, and the Netherlands can be reconciled, cooperative agreements for gas development could be achieved that would yield sizable economic and security benefits for Europe. Budget pressures on the governments of these countries will probably increase the incentives for them to reach agreement. [redacted] 25X1

The Netherlands's large gas production capacity is the key to European security of supply both now and in the future. Dutch gas policy has long been torn between keeping Groningen gas as a reserve for future domestic use and increasing gas sales to finance new social programs. Since 1980 the official Hague policy has been aimed at restricting gas production and conserving reserves by:

- Linking prices more closely to those of competing fuels, such as residual fuel oil, to promote gas conservation. 25X1

[redacted]

Petroleum Revenues and Government Budgets

During the past 10 years, petroleum revenues have come to play a central role in government budgets of the Netherlands, the United Kingdom, and Norway. Recently, those governments have discovered that the influx of petroleum revenues can be a mixed blessing; government incomes have proved vulnerable to the volatile fluctuations of energy prices.

In the Netherlands, *government earnings from gas sales accounted for 17 percent of total revenues in 1981. Moreover, total public-sector expenditures amounted to two-thirds of national income. The sharp drop in gas sales in recent years has disrupted budget plans and pushed government deficits to record levels. This year's deficit, which is projected to exceed $7 billion, should increase pressures for a reevaluation of gas sales policies.*

The United Kingdom, *with the highest petroleum taxes in the North Sea, claimed about half of the $24 billion earned from oil and gas production in 1981. Although petroleum revenues were less than had been projected, they accounted for about 9 percent of government revenues. The marginal tax rate for oil producers in the British sector of the North Sea exceeds 90 percent; the average tax rate is 85 percent. Oil company officials claim that these taxes have deterred development of numerous small oil and gas fields in Britain's offshore waters.*

Norway's *central government earned $4.9 billion from taxes on oil and gas production in 1981—roughly 27 percent of total revenues. Norway's average tax rates are slightly less than British taxes. Declining oil prices, increased development costs (tax deductible), and lowered production forecasts have combined to reduce sharply Oslo's projected petroleum tax revenues. In May 1981, the Labor government forecast petroleum tax earnings of about $28 billion for the 1982-85 period. The estimate has since been revised downward three times, and now stands at about $10 billion. Less-than-expected oil revenues, coupled with a growing public appetite for petroleum earnings, may give the current government more leverage to accelerate gas development.*

[redacted] 25X

- Phasing out gas for power generation and other nonpremium uses.
- Meeting present export contracts but allowing no new export sales.
- Promoting coal gasification and conversions of power plants to coal. [redacted]

Under current contracts, foreign customers of Gasunie—the state gas company—may purchase from 580,000 to 1.1 million b/doe of gas annually. Because the Dutch allow customers to take less than the maximum amounts contracted, Gasunie has borne the brunt of the recent drop in European gas consumption. [redacted]

Dutch gas sales dropped by 6 percent in 1980 and by another 8 percent in 1981. Total gas sales in first-quarter 1982 were 9 percent below levels a year earlier. The sharp drop in gas sales has increased government deficits and prompted a reexamination of Dutch gas policies. [redacted] 25X1 25X

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[redacted]

Table 1 *Number of wells*
North Sea Drilling Activity [a]

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	1978	1979	1980	1981	1982
Total	**60**	**43**	**58**	**76**	**101**
United Kingdom	32	19	26	32	49
Norway	9	8	16	21	20
Netherlands	10	10	15	13	24
Denmark	0	0	1	2	2
Ireland	8	5	0	6	2
Germany	1	1	0	2	4

[a] Well starts in first six months of specified years.

[redacted] 25X1

Norway has traditionally held a "go-slow" attitude toward petroleum development and has moderated the pace of activities with a number of restrictive policies. The new conservative government has recently relaxed some of these policies but is still concerned that rapid development would have negative effects on the Norwegian economy. In addition, Oslo recently indicated its sensitivity to outside pressures to accelerate development. Norwegian Energy Minister Hvedding told the press that he resented "arm twisting" by the United States to have Norway deliver more gas to market in the 1980s than it considers feasible [redacted]

Nonetheless, Norwegian Government officials are optimistic about gas exports in the 1990s. Oslo has already taken some measures to facilitate development by:

- Announcing a willingness to adopt a less hawkish attitude in future gas price negotiations.
- Relaxing some restrictions on the length of the drilling season and allowing foreign companies to operate concessions north of the 62nd parallel.
- Declaring that the 660,000-b/doe-production ceiling for oil and gas could be reconsidered.
- Expressing a desire to keep the Norwegian continental shelf fully open for international competition and to limit the role of the state oil companies [redacted]

The United Kingdom will probably not be a net exporter of natural gas in the foreseeable future but could be instrumental in a gas swap with Norway. Consequently, development of British gasfields in the southern part of the North Sea could affect the timing of new gas deliveries to the Continent. Oil companies have not launched any major field development projects in the United Kingdom in the last two years because they claim taxes are too high, but exploratory drilling has, nonetheless, remained at high levels (table 1). London's decision to end the monopsonistic purchasing power previously granted to the British Gas Corporation will probably raise gas prices for new projects in the UK sector and encourage development. [redacted] London is considering making some changes in tax policies to stimulate development. Together, these moves could encourage development of the smaller gasfields and complement efforts to arrange a gas swap by increasing the amount of gas available for transport to the Continent from nearby southern gasfields. [redacted]

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Key North Sea Projects

Gas projects already under way in the North Sea will link several new fields to the Continent in the 1980s, but only modest increases in gas deliveries are expected. Norway currently exports almost 300,000 b/doe of gas to continental Europe via a pipeline from the Ekofisk field to Emden, West Germany, and about 280,000 b/doe to the United Kingdom via the Frigg pipeline (see map). Norway's Statpipe system, which

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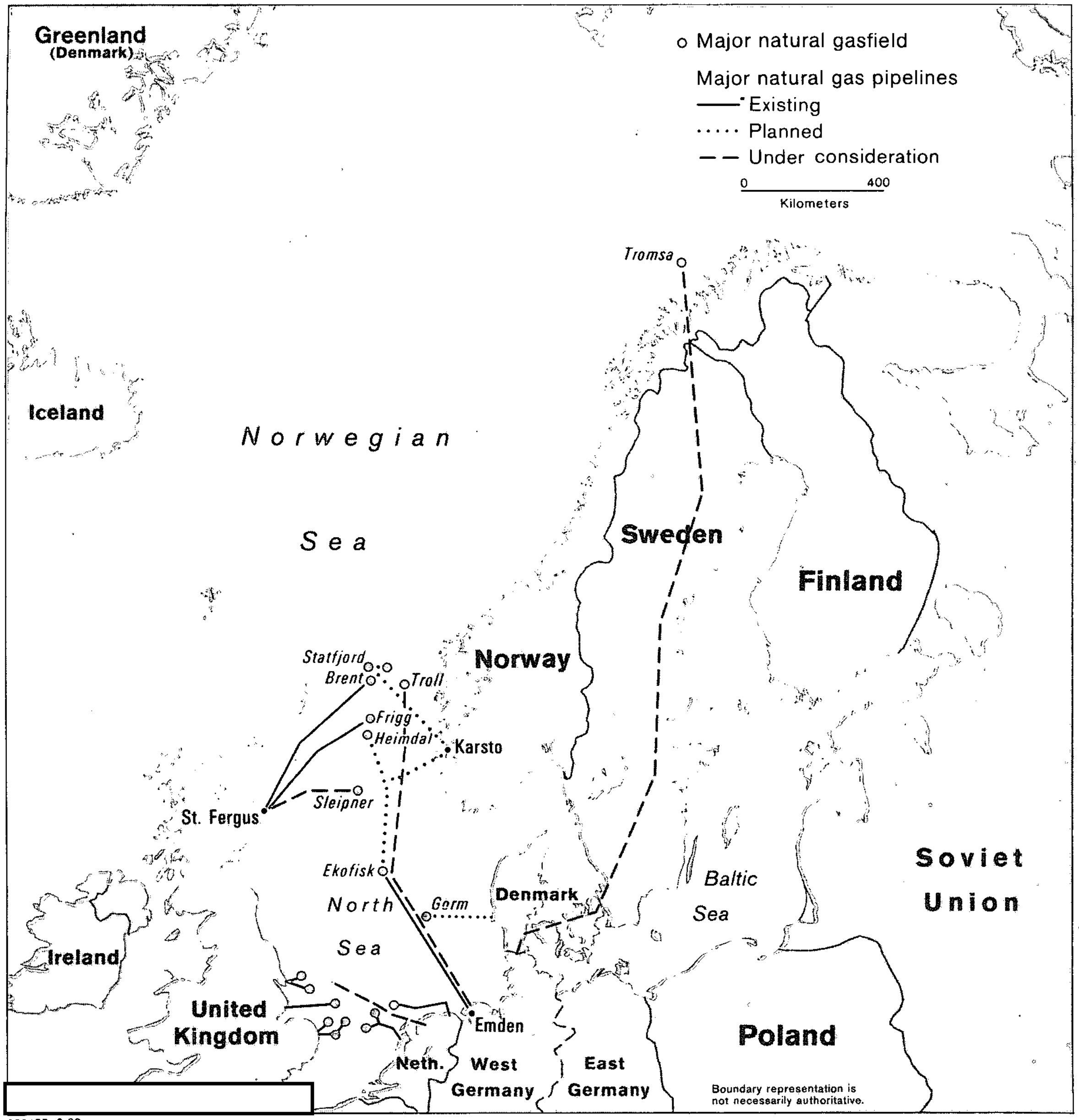
North Sea: Natural Gas Systems



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will connect Statfjord, Heimdal, and other fields to the Ekofisk-Emden pipeline, is expected to be completed by 1986 but will do little more than compensate for declines in gas production from Ekofisk. To increase gas supplies in the 1990s, major development projects are under consideration for Sleipner, Troll, and the far-northern Tromsa region [redacted]

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Sleipner Field. The Sleipner field is the most promising field to link to the United Kingdom in exchange for British gas deliveries to the Continent. Statoil has decided on a policy of rapid depletion of the field—forgoing possible gas recycling for recovery of condensates—and foresees gas production startup by 1990. A swap for UK gas would allow substantial savings of time and money in delivering 170,000 to 250,000 b/doe of gas to Europe. [redacted]

Troll Field. [redacted] deliveries of gas from the field could reach 500,000 to 670,000 b/doe by the mid-1990s if sufficient demand materializes. Given water depths of 340 to 350 meters and the shallow, broad reservoir, technical challenges of field development will be enormous. [redacted] Linking Troll to the existing Frigg pipeline to the United Kingdom might allow deliveries of up to 450,000 b/doe to begin in the early 1990s. Otherwise, construction of a new trunkline to Europe will delay startup until the mid-1990s. [redacted]

Other Fields. Another area for potential development is the Tromsa area off the northern coast of Norway. Although the remoteness of the area would make gas transportation costly, both Norwegian and Swedish officials are optimistic about the eventual construction of a pipeline through Sweden that could deliver up to 250,000 b/doe in the 1990s. [redacted]

Development of other, smaller fields in both the British and the Norwegian sectors, linked to existing or proposed pipelines, can provide additional gas. Heimdal, block 34/10, and other Norwegian gasfields will be developed and linked to the Statpipe system which will connect Statfjord to the Continent via the existing pipeline from Ekofisk, West Germany. In the Dutch sector, [redacted] Mobil's P-6 field to come on stream in 1984, producing about 10,000 b/doe. With the production from this and other small fields, Dutch Government officials expect the share of non-Groningen production to increase, stretching the lifetime of Groningen reserves. [redacted]

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Financial Requirements

North Sea oil and gas development projects during the next decade could require investments of more than $100 billion (1982 dollars) on top of the $85 billion already invested (table 2). Commitments to projects already under way in the Norwegian sector will entail expenditures of about $5 billion annually through the mid-1980s, including $3-4 billion in capital investments and $1-2 billion in exploration and operational expenses. Norwegian banks and other credit institutions are allowed to lend only a total of about $500 million annually to finance petroleum activities. The Bank of England has estimated that more than $6 billion must be spent annually in the UK sector in order to keep pace with growing demand for gas during the next decade. Additional investments in the Netherlands and Denmark could push total North Sea investments to more than $10 billion annually. [redacted]

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Most development projects for the late 1980s are still under review, including major gas development projects. A decision to bring gas production from Sleipner on stream by the 1990s could require investment of more than $7 billion in the late 1980s and early 1990s. Development of Troll gas reserves could cost as much as $15-20 billion during the 1980s and 1990s. [redacted]

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All of these projects will have to vie for investment funds against other development projects. Given the long leadtimes before production can begin, high interest rates can easily deter development. For a project financed over a 15-year period, an interest rate subsidy of less than 2 percent can reduce by 15 percent the overall costs of a project that is entirely debt financed. Hence, favorable financing terms for gas projects could substantially boost incentives for development. [redacted]

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Table 2
Projected Expenditures for North Sea Oil and Gas Development

Billion 1982 US $

	1982-85	1986-92
Total	**26 to 29**	**65 to 72** [a]
Norway	14.4	30 to 40
Frigg	0.8	—
Statpipe system	3.5	1 to 2
Statfjord	3.4	2 to 7
Sleiper	0.5	7 to 8
Troll	—	15 to 20
Tromsa	—	0 to 7
Other	6.2	5 to 10
United Kingdom	10 to 11	30 to 35
Denmark, West Germany, Netherlands	2 to 3	5 to 7

[a] Total is less than the sum of the maximum investments for individual projects because it is unlikely that all the projects would be undertaken during the period.

[redacted]

Outlook

While North Sea gas exports could technically be expanded by more than 900,000 b/doe by the mid-1990s, the market share for this gas will be limited by the high cost, even if subsidies are offered. If European gas buyers are serious about diversifying gas supplies and limiting dependence on Soviet gas, they may be willing to buy more than 700,000 b/doe of Norwegian gas—enough to support development of Sleipner and Troll but not enough to warrant simultaneous development of Tromsa resources. The profitability of the Tromsa and Troll projects depends on high volume deliveries. Completing both projects at the same time would provide a larger increment of high-cost gas than Europe could absorb. Moreover, we believe that Oslo will act to spread development activity as evenly as possible over the next decade in order to minimize potential adverse effects on the Norwegian economy. [redacted]

Both French and West German utilities have expressed an interest in securing additional Norwegian gas and have indicated a willingness to pay a small premium for these supplies. The volume they would be willing to purchase, however, will depend in large part on the growth in gas demand. With much of the incremental demand expected to come from the industrial sector, gas prices will have to be competitive with coal and residual fuel oil prices to guarantee additional sales. [redacted] 25

Given the economic uncertainties confronting producers, European cooperation in guaranteeing reduced interest rates for development projects or arranging a gas swap to minimize transportation costs could be critical to full-scale North Sea gas development. The long-term benefits of such cooperation would be substantially enhanced diversity and security of gas supplies. [redacted] 25X1

In the absence of such European cooperation, Norway's gas development might still proceed apace, if the Norwegians were to moderate their price demands and accept a lower return on their gas than they receive on existing contracts. Such a move, however, would be a reversal of Oslo's previous objectives. In any case, if the Dutch can be persuaded to extend gas export contracts in the late 1980s and early 1990s, they will effectively hold a share of the European gas market until new supplies of Norwegian gas come on stream. Otherwise, because of the timing of the new projects, the market for Norway's gas might be preempted by increased sales of gas from other sources, especially the Soviet Union. [redacted]

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Appendix A

The Troll Gasfield Project

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[redacted] Norway's Troll gasfield contains recoverable gas reserves of 1.4-2.0 trillion cubic meters—roughly the size of the Netherlands's Groningen field. The Troll structure—which covers nearly 700 square kilometers—is located in blocks 31/2, 31/3, 31/5, and 31/6, of which only 31/2 has been drilled by the operator, Royal Dutch Shell. The three undrilled blocks are likely to contain up to 75 percent of Troll's reserves. Norway's new conservative government has recently appointed Statoil, a Norwegian state oil company, as operator in the exploration phase for blocks 31/3 and 31/5. Norsk Hydro, another Norwegian company, will be the operator in the exploration phase of block 31/6. While these two Norwegian companies are expanding their capabilities to handle major development projects, they still must rely on major international oil companies for technical expertise in many areas [redacted]

In addition to the gas reserves [redacted] the Troll structure contains oil reserves of up to 2 billion barrels. Since the oil lies in a relatively thin layer below the gas reservoir, however, it is not yet clear that the oil can be economically produced. [redacted] a preliminary proposal for developing Troll oil indicated unit costs of $35,000 per peak daily barrel of capacity and a maximum real rate of return of 6 to 8 percent. Since the completion of the study, however, drilling results indicate that the oil layer in the western part of the field is thicker than had been expected—as much as 30 meters in some areas—and might be commercially producible. Farther to the east, the oil layer varies in thickness from 0 to 10 meters and probably is not recoverable. A decision to produce the oil could delay the startup of natural gas production by several years, since recovery of the oil will probably precede gas production [redacted]

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Field Development

Shell is moving smoothly toward a development plan for block 31/2 and expects to make a formal declaration of commerciality for the field by late 1983. It has already awarded contracts to six companies for feasibility studies on the main development alternatives, some of which are thus far untried in the North Sea. Both fixed and floating platform concepts are being evaluated and, given the water depth of more than 300 meters and the shallow, broad reservoir, subsea production techniques are certain to play a significant role in development. Feasibility studies are under way to evaluate:

- The Condeep T300 concrete platform (Norwegian contractors).
- A tension leg platform (VO Offshore).
- A steel tripod platform (Heerema).
- A multiwell subsea production template (Kvaerner Engineering and Can Ocean).
- Alternative riser configurations—the conduit that delivers oil or gas from the wellhead to the surface (Kongsberg Engineering).
- Offshore gas, oil, and NGL (natural gas liquids) treatment facilities (S. H. Landes). [redacted]

Because new technologies must be employed, it is difficult to estimate development costs before detailed feasibility studies are completed. The Condeep platform is a gravity-based platform with three concrete legs joined below the waterline and a single leg supporting the deck. [redacted] If each platform produced 4-5 billion cubic meters (bcm) [2] per year over a 15-year period, production costs alone (exclusive of transportation costs and a real return on the resource) would be $3.40 to $4.25 per million BTU:

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Annual operating cost	$140 million
Interest on investment (15 *percent*)	$330 million
Depreciation (15 *years*)	$140 million
Total	**$610 million**
Annual volume produced	4-5 bcm
Unit cost	0.12 to 0.15 *($ per cubic meter)*
	3.40 to 4.25 *($ per million BTU)*

[2] Europeans usually measure gas quantities in billion cubic meters. One billion cubic meters per year is approximately 16,700 b/doe. [redacted]

Notably, interest costs play a large role. A 1-percent interest rate subsidy would lower unit costs by 35 to 45 cents per million BTU. [redacted] 25X1

Pipeline Alternatives

Scenario A. The quickest way of initiating gas deliveries from Troll would entail linking the field to the existing Frigg pipeline to the United Kingdom. In return, comparable amounts of UK gas would be delivered to the Continent via a new pipeline in the southern sector of the North Sea [redacted] a link to the existing Frigg line would allow deliveries to begin in the early 1990s and would probably cost less than $500 million. The contract between Norway and the United Kingdom specifies that production from Frigg will drop to nearly zero by 1992, leaving spare pipeline capacity of about 20 bcm per year. Moreover, with additional compressors the capacity of the Frigg line could be expanded to 27 bcm per year. [redacted] 25

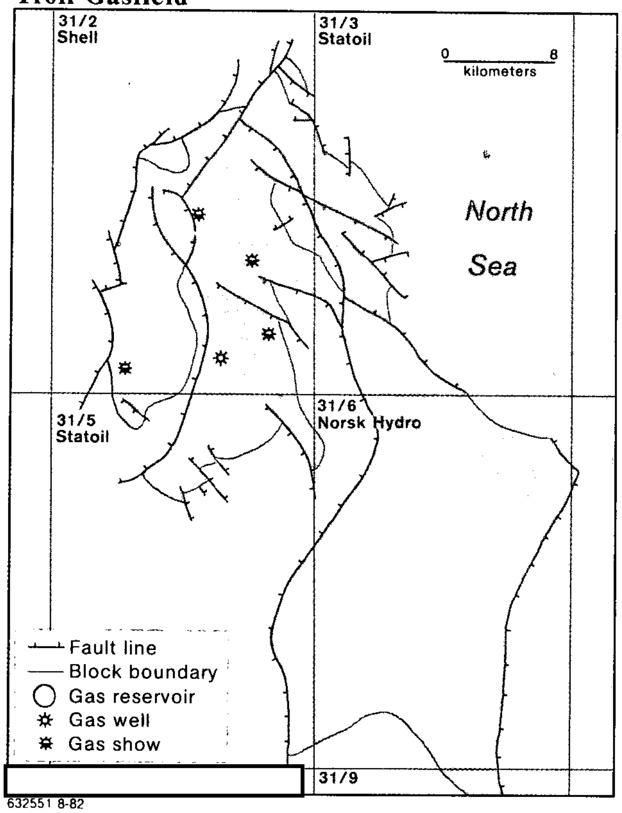
Although this alternative would probably allow a lower delivered cost for gas, it has some drawbacks for the Norwegians:

- An agreement for the gas swap would have to be reached with both UK and continental buyers, weakening competition between them for Norwegian gas.
- Deliveries would be constrained by the capacity of the Frigg system and the volume of gas the British are willing to swap. [redacted] 25

In the mid-to-late 1990s, spare capacity should become available in the Statpipe system, which will be linked to the West German gas grid. At that time, gas from Troll could be delivered to Europe via a link to Statpipe. The Statpipe system has a total planned capacity of 17 bcm and could be expanded to deliver about 20 bcm with additional compressors. [redacted] 25

Scenario B. Norway could build a new gas trunkline capable of delivering 30-40 bcm directly to the Continent. While this alternative would free the Norwegians from the constraints mentioned in scenario A, we estimate that it would probably entail capital costs of more than $3 billion and could take two to three years longer than building a link to the Frigg system. The new trunkline would be more than 1,200 kilometers long and would require more than 800,000 metric tons of steel. [redacted] 25

Troll Gasfield



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Appendix B

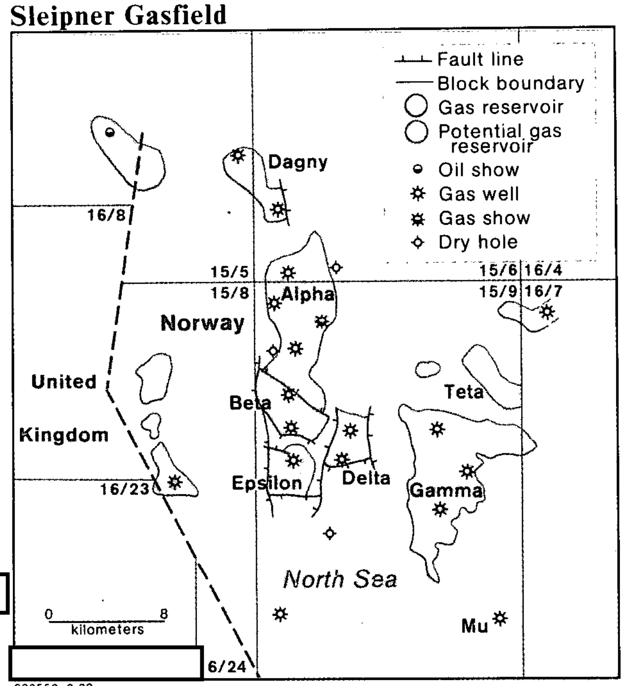
Triangular Gas Deal

Using the United Kingdom as a conduit for delivering Norwegian gas to the Continent could save both time and money compared to the alternative of building a major new trunkline. Norwegian gas delivered to Scotland could be swapped with UK gas in the southern basin, providing at least 10-15 bcm annually. [redacted] 25X

In the near term, Norway's Sleipner field—with reserves in excess of 280 million cubic meters—is the most logical field to link to the United Kingdom. Exploratory assessment of the field is nearly complete, and a development decision will be made in the next one to two years. Moreover, the gas has a high concentration of carbon dioxide—6 to 9 percent—and will probably require a separate distribution system. Because several small fields in the UK sector have a similar problem with carbon dioxide content, a link to the United Kingdom would be a logical step. [redacted] 25X

According to government estimates, proved gas reserves in the southern sector of the UK offshore waters are 370 bcm. [redacted] 25X reserves are actually much higher and that substantial additional reserves remain to be proved. The southern sector provides the ideal link to Western Europe because of its proximity to the Continent. British tax policy is an important consideration in estimating the future availability of gas from the United Kingdom. If tax policies that currently discriminate against development of relatively small fields were to be modified, the profitability of developing the numerous small gasfields in the southern basin could improve. [redacted]

Sleipner Gasfield



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Field Development and Pipelines

Because the reserves of the Sleipner complex are distributed among seven reservoirs, five platforms would probably be required to exploit the field fully. The field is in about 650 meters of water, and technologies previously tested in North Sea waters will largely be employed there. Statoil, operator for the field, has recently decided on a policy of rapid depletion of the field, ruling out gas recycling for enhanced condensate recovery. Statoil has estimated the capital costs of field development at $5-6 billion and has indicated that gas deliveries might begin by 1990. Including operating and transportion expenses, the cost of producing and delivering the gas (presumably via pipeline to the United Kingdom) is estimated at about $3.50 per million BTU. The Norwegians are expected to demand a price comparable to that received for Statfjord gas—about $5.50 per million BTU. [redacted] 25X 25X

A major Dutch oil company has estimated a cost of $500 million for constructing a pipeline from Sleipner to the United Kingdom. By contrast, construction of a separate pipeline from Sleipner to the European continent would cost $2-3 billion. [redacted] 25X

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