Section 7

THE POTENTIAL CHARACTERISTICS OF PETROLEUM EXPLORATION AND DEVELOPMENT ON GEORGES BANK

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FISHING AND PETROLEUM INTERACTIONS ON GEORGES BANK

VOLUME II: THE CHARACTERISTICS OF THE TWO INDUSTRIES, POTENTIAL FUTURE TRENDS, AND AN ASSESSMENT OF FORESEEABLE CONFLICTS

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INTRODUCTION

Background

A total of 15.6 million acres on Georges Bank were made available for nomination by the Bureau of Land Management (BLM) in June, 1975. As a result of this call, 18 companies nominated 10.9 million acres of Georges Bank as areas of petroleum interest. The tracts* nominated are distributed over a wide area but tend to be concentrated in the southeastern section of Georges Bank (see Vol. I Plate 1).

In December, 1975, BLM selected 206 tracts, covering some 1.17 million acres, to be the subject of study for a draft environmental impact statement (EIS) for a first lease sale. The tracts selected by BLM for study for the first sale include most of those of high interest to the oil industry. The tracts are concentrated in the southeastern part of Georges Bank, but a number are along and to the west of the Great South Channel as close as approximately 55 miles from shore (see Vol. 1 Plate 2).

The approximate center point of a circle encompassing the major concentration of tracts of interest to the petroleum industry is some 155 miles from southeastern New England.** Water depths in this area range from about 100 to 600 feet, but the majority of tracts are in depths ranging from 150 to 400 feet. The concentrated area of petroleum industry interest, at its closest point, is some 85 miles from Cape Cod and 125 miles off the coast of southeastern New England.

Depending on the outcome of the EIS and the subsequent hearings process, perhaps 100 to 150 of the selected tracts will be offered at the first sale. A review of BLM leasing statistics for previously undeveloped areas reveals that the fraction of tracts sold was 52 percent for the Oregon-Washington sale (October, 1964), 59 percent for the Mississippi-Alabama-Florida (December, 1973) sale and 40 percent for the recent (April, 1976) lease sale in the Gulf of Alaska (BLM, 1976, pp. 1-3). In the recent mid-Atlantic sale, 63 percent of the tracts offered were

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*Under current regulations an individual tract may not exceed 5,760 acres.

**Measured from a point on Georges Bank with the reading 40°40'N, 67°45"W to a location on the coastline at the border of Massachusetts and Rhode Island.

actually sold. If the past can be used as a guide, perhaps as few as 40 or as many as 90 tracts could be sold in an initial sale on Georges Bank.

Allowing for all the pre-sale procedures that must be followed, it now appears that the first sale of leases on Georges Bank may not take place until mid-1977. A second sale has been scheduled to be held 24 months after the first. No additional sales of leases on Georges Bank have been scheduled at the present time, although other sales will follow if exploration and development as a result of the first two sales create sufficient industry interest in the remaining unexplored sections of Georges Bank.

Purpose and Scope

This section provides a review of potential petroleum activity on Georges Bank. First, a brief description of offshore petroleum operations is presented. An evaluation of the potential economic returns to the nation and New England from developing hypothetical individual oil and gas fields is made next. The discussion of economic returns is restricted to the net returns from development. Given the specific scope of this study, no attempt is made to provide a comprehensive assessment of employment or other direct or secondary regional impacts.[1] However, selected employment effects and other impacts relevant to the scope of the study are treated in sections 10 and 11.

Finally, three Georges Bank petroleum cases are adopted in order to provide estimates of the potential level of offshore oil and gas operations. When viewed in conjunction with the estimates of possible additional commercial fishing activity, the results of this section provide a basis for arriving at some judgments regarding possible offshore and onshore interactions between the two industries.

Estimates of Oil and Natural Gas Reserves

USGS Resources Estimates: The most recent public estimates of possible oil and gas reserves on Georges Bank are those made by the USGS (1975) and are based on a series of resource appraisal techniques. They make use only of available data and use pre-embargo oil and gas prices and costs.

The USGS estimates are given in terms of aggregate recoverable reserves, which usually are only a fraction of the actual oil and gas in place. It is noted now, and re-emphasized at a later point, that the economic returns to offshore oil and gas development will depend critically on the reserves of individual fields rather than on aggregate reserves for Georges Bank as a whole.

The USGS approach assigns subjective or judgmental probabilities to a range of estimates of recoverable oil and gas reserves. Total recoverable reserves are hypothesized to follow a distribution reflecting a fairly high likelihood that a province will contain a small amount of recoverable oil or gas, but only a small chance that the area will contain large reserves.

The USGS estimates of total recoverable reserves on Georges Bank are presented in Table 1; estimates for the mid-Atlantic are given also for purposes of comparison. There is one chance in 20 (5 percent) that the recoverable reserves of oil will be greater than 2.5 billion barrels. For natural gas there is a 5 percent probability that Georges Bank may contain more than 13.1 trillion cubic feet of natural gas. The statistical mean for Georges Bank is .9 billion barrels of oil and 4.5 trillion cubic feet of gas. Using the mean values for comparison, the mid-Atlantic area is expected to contain considerably more oil, but only somewhat more natural gas, than Georges Bank. In addition, individual structures in the mid-Atlantic are expected to be larger than in Georges Bank.

Clearly, present estimates of possible oil and gas reserves for Georges Bank must be viewed with considerable caution. The estimates are based on a high degree of uncertainty, reflected in the probabilities assigned, since there has been no discovery of hydrocarbons offshore or on adjacent onshore lands. This is quite different from the situation in the Gulf of Mexico or more recently in the North Sea, where the presence of oil and/or gas onshore, together with a knowledge of the geology offshore, provided strong indications that commercial quantities of hydrocarbons would be discovered. The results from the Continental Offshore Stratigraphic Test (COST) wells and initial exploratory drilling will create vastly improved geological information for Georges Bank. Until this information becomes available, however, petroleum reserve estimates for Georges Bank must continue to be regarded as highly uncertain.

TABLE 1

USGS ESTIMATES OF UNDISCOVERED RECOVERABLE OIL AND NATURAL GAS FOR GEORGES BANK AND THE MID-ATLANTIC, 1975

AREA	Crude Oil[a] (billions of barrels)		Natural Gas[a] (trillions of cubic feet)	
	5% Probability[b]	Statistical Mean	5% Probability[b]	Statistical Mean
Georges Bank	2.5	.9	13.1	4.4
Mid-Atlantic	4.6	1.8	14.2	5.3

Source: U.S. Geological Survey, "Estimates of Undiscovered Recoverable Oil and Gas Resources, United States Offshore Areas," unpublished xerox, 1975.

[a]Includes water depths to 200 meters.

[b]Indicates a 5% chance that at least the indicated amount of recoverable reserves exists.

Summary of Resource Assumptions Used in Earlier Studies: A number of studies have been made of possible Georges Bank oil and gas development. For reference, the resource assumptions that have been used in earlier works are summarized in Table 2.

The oil and gas reserve estimates used in the most recent studies, those by Kalter et al., the New England River Basins Commission and the Bureau of Land Management, are based on the resource appraisal work of the U.S. Geological Survey described above. The other studies in Table 2 were undertaken prior to the publication of the 1976 USGS report on estimated oil and gas resources. The reserve estimates used by BLM, it is emphasized, are for the first Georges Bank lease sale only.

Petroleum Cases Used in This Report: Three Georges Bank petroleum cases are evaluated: exploration only, low development cases and high development cases. The resource assumptions used in the two development cases are indicated below:

	Low Case	High Case
Crude Oil (billion barrels)	.18	1.3
Natural Gas (trillion cu. ft.)	1.2	8.6

The resource assumptions used are within the range estimated by the USGS, and are considerably less than the estimates used in many earlier studies of Georges Bank (Table 2). The actual amount of oil and gas reserves will not be known until considerable drilling and indeed actual development takes place. The first indication of industry's assessment of the petroleum potential of Georges Bank will come when the bids for the first lease sale are announced.

OFFSHORE OIL AND GAS DEVELOPMENT

Description of Offshore Petroleum Operations

It is traditional and convenient to distinguish three stages of offshore petroleum operations: exploration, development and production. This distinction is maintained in the following sections in which the technical aspects of offshore petroleum operations, particularly as they relate to potential activity on Georges Bank, are discussed briefly. The primarily shoreside impacts of offshore oil and gas activity relevant to this study are discussed in Section 11.

TABLE 2

SUMMARY OF MAJOR OIL AND GAS RESOURCE ASSUMPTIONS CITED IN VARIOUS STUDIES OF GEORGES BANK PETROLEUM DEVELOPMENT

SOURCE	RECOVERABLE RESOURCE ASSUMPTIONS[a]: Crude Oil (billions of barrels)	Natural Gas (trillion cubic feet)
M.I.T., (1973) (Note: oil and gas in place)[b]	.05 - 10.[b]	.08 - 10.[b]
Ahearn (1973)[c]	.9 - 6.[c]	6 - 30.[c]
Resource Planning Assoc. for C.E.Q. (1974)[d]	2.57 - 7.54[d]	7.8 - 15.1[d]
Grigalunas (1975)	.4 - 3.	2.0 - 10.0
Arthur D. Little, Inc. (1975)[e]	8.9[e]	28.6[e]
Kalter et al. (1975)[f]	.44 - .48	2.5 - 3.1[f]
Bureau of Land Management (1976) (first sale)	.18 - .65	1.2 - 4.3
NERBC (1976)	.9 - 2.4	4.2 - 12.5

[a]Excludes natural gas liquids.

[b]The M.I.T. figures are for oil and gas in place, only a fraction of which is recovered.

[c]Medium and high estimates.

[d]Inferred resource assumptions obtained by summing the annual output figures for the 20 year period given, 1980-2000. Since all annual output figures for the 20 year period are not given, and since substantial output is indicated for the post - 2000 period, the figures in the above table understate considerably -- perhaps by as much as 30 percent -- the resource assumptions used by R.P.A. for the C.E.Q. report.

[e]Base case, Vol. 11, pp. V-27,35.

[f]The estimates are for the low and high price cases used by Kalter et al., \$11/bbl for oil and \$.60/Mcf for gas and \$16/bbl for oil and \$2.00/Mcf for gas.

Geophysical Exploration: Geophysical techniques include reconnaissance work, seismic analysis, bottom sampling and bottom coring. In addition, participating companies will have available drilling data from Continental Offshore Stratigraphic Test (COST) holes for the mid-Atlantic and for Georges Bank.[2]

Seismic analysis is the most useful and frequently used pre-lease sale exploratory technique. Sound waves are artificially generated and are reflected from various strata back to the surface and recorded. The seismic mapping of an area is used to identify promising traps that might contain accumulations of oil or gas.

In offshore areas seismic exploration takes place from vessels which follow set routes, towing specialized gear. Under current OCS regulatory arrangements, a potential developer bases his assessment of the prospective value of an offshore tract on geophysical data, unless there is ongoing or prior development in the area.

Exploratory Drilling: Exploratory drilling takes place from drilling rigs mounted on mobile platforms. The purpose of exploratory drilling is to determine whether or nor oil or gas exists in suspected petroleum traps and to provide a preliminary indication of the extent of oil and gas in place, possible recoverable reserves and the characteristics of the deposit. Present procedures permit the drilling of exploratory wells only after a lease has been granted.

Exploratory drilling on Georges Bank probably will be undertaken in either semi-submersible or jack-up rigs rather than drilling ships. Both types of rigs are capable of drilling in heavy sea. For example, the mobile rig SEDCO J, used to drill the first two COST holes off the East Coast, was able to maintain continuous drilling operations in 34-foot seas with winds of 50 knots. The SEDCO J was unable to drill because of rough weather less than 2 percent of the total time in position in the mid-Atlantic (Norwood, 1976).

Jack-up rigs are usually limited to 300-foot water depths or less, and are sensitive to bad weather when being moved. In addition, jack-up rigs are prone to damage while the rig legs are being lowered to the touchdown postion. Semi-submersibles, on the other hand, can operate in water depths of 600 feet or more, are stable when in transit and operate independent of bottom conditions (Tubb, 1975). Moreover, semi-submersibles at present are readily available, a fact reflected in the sharp decline in the rental rate for rigs. These considerations, together with weather conditions in the North Atlantic and water depths over large sections of Georges Bank, suggest that most exploratory drilling off the New England coast probably will be done by semi-submersibles, with the use of jack-up rigs restricted to shallower portions of Georges Bank.

A mobile rig can drill three to six exploratory wells per year, depending on drilling conditions. Thus a rig may be on location for about 60 to 120 days per well. Assuming it takes 60 days for a mobile rig to drill an exploratory well, the total cost of the well could amount to $3 million.

While a single dry well may be sufficient to condemn a geologic structure, usually several exploratory wells will be drilled on a structure before it is abandoned, particularly where there is a show of hydrocarbons or evidence that the structure is fractured. If an initial exploratory well indicates a potential commercial find, one or more additional exploratory wells may be drilled to confirm the find and delineate the geographic extent of the field.

Shortly after a lease sale, a company will contract with a drilling company and plan an extended drilling program for Georges Bank. The developer may have a rig drill an exploratory well on one tract and while the well data are being analyzed, the rig will move on to a second tract and drill another exploratory well. If necessary, the rig can return to the first tract and sink an additional well, or the rig may move to a third tract. Under current leasing arrangements an operator is expected to explore a tract within five years of the granting of a lease. Companies may have an incentive to accelerate initial exploratory drilling on Georges Bank, however, to acquire resources information for the second lease sale currently scheduled to follow the first sale by 24 months.

Exploratory wells usually are not later used for production purposes. In this case OCS Order 3 for the mid-Atlantic (which is expected to be the same for Georges Bank) requires that the operator plug the abandoned well(s) with cement, and sever and remove all casing and piling below the ocean floor to a depth specified by the Area Supervisor of the USGS. The operator must verify that the location has been cleared of all obstructions. If an exploratory well is to be re-entered once a platform is installed, the well is referred to as "temporarily abandoned" and must be identified "...in accordance with a design approved by the Supervisor and shall not be inconsistent with applicable U.S. Coast Guard regulations" (OCS Order 1).

Each exploratory rig requires the use of two supply boats* to tow the rig (if it is not self-propelled), to haul the nine anchors used to moor a semi-submersible rig and to transport materials and supplies during drilling operations. In addition, one supply boat may serve as a standby safety vessel for the rig. The trend in the United Kingdom sector of the North Sea has been to use large, converted side trawlers for standby vessels. More than 60 such vessels are reported to be in use in support of U.K. offshore oil and gas operations (Offshore, 1975, p. 200).

Many economies can be achieved in the use of support vessels. For example, two supply boats are needed to support a single rig, but an operator of two rigs working in close proximity can pool supply boat services and thereby use only two or three vessels.

Because of severe weather conditions, support operations on Georges Bank are likely to use the largest class of offshore supply vessels, over 190 feet in length and 5,000 horsepower. The supply boats used to support the COST drilling on Georges Bank are both over 190 feet in length and draw 14½ feet of water when fully loaded. The day rental fee for this class of vessel is over $3,000, excluding fuel costs.

Development: Development refers to the range of activities related to bringing a discovered field into production. Major development activities include:

1. Design, Fabrication and Installation of Field Platforms. Platforms include the main jacket structure, and the deck and living quarters section. The design and fabrication of the platform sections may take two years. Installation includes towing each section to the site, emplacement of the jacket, the driving of piling several hundred feet into the floor of the ocean and lifting the deck and living quarters sections of the platform onto the jacket. Installation must be done during periods of calm seas, and may take several weeks to complete. A single platfrom in 200 feet of water on Georges Bank may cost $28 million (1976 dollars).

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*For convenience all work boats used to support offshore oil and gas operations are referred to in the text simply as "supply boats" or "supply vessels".

The optimum number of platforms used to develop and produce a field depends on the amount of recoverable reserves. For example, the results of Devanney's (1975) simulation of offshore oil development indicate that one platform could be used to produce a field containing 100 million barrels of oil in place, but only five platforms may be employed to produce a field 10 times as large, i.e., with one billion barrels of oil in place (Devanney, 1975). The potential for economies of scale here, and with other investment/operating activities, is thus substantial. As we shall see, economies of scale play an important role in assessing the economic returns to OCS development.

The use of subsea production systems (SPS) on Georges Bank is technically feasible in water depths of 600 feet and beyond. Over 200 subsea systems have been installed or are in the process of installation worldwide, including the North Sea (Ocean Industry, July, 1976). Essentially, an SPS involves the use of single or multiple well facilities on the ocean bottom. These facilities allow for satellite wells on the ocean floor, and are typically used in conjunction with a conventional platform.

There may be substantial economic incentives to use an SPS in deeper waters to avoid the investment in additional fixed platforms for fields that extend over a wide area. However, if an area is known to have extended periods of rough weather, conventional platform development may prove economically superior to an SPS because of less drilling down time and improved accessibility to wells for major repairs and maintenance work (Reeds and Trammell, July, 1976, pp. 44-45).

Whether or not SPS will be used on Georges Bank appears to be an open question; economic studies undertaken to date have focused on conventional field development from platforms. To the extent that subsea production systems are used in place of one or more additional platforms, considerably larger sections of ocean bottom could be occupied by oil and natural gas production and pipeline systems.

There may be an economic incentive to employ concrete rather than steel platforms in areas of Georges Bank, provided that the bottom is sufficiently level and soil conditions are suitable to accommocate the enormous weight of the structure. In the past, the usual view was that concrete platforms could compete with steel platforms only in water deeper than 300 feet. However, concrete platforms recently have been designed for water depths of 75 to 100 feet, although industry sources report that shallow-water concrete platforms have the shortcoming of not allowing for offshore storage of a large amount of oil (Ocean Industry, May, 1976, p. 76). Four potential concrete platform construction sites have been identified in Newfoundland, Canada, should this type of structure be used on Georges Bank or elsewhere along the East Coast (Ocean Industry, May, 1976, p. 99).

2. Drilling and Completion of Production Wells. The optimal configuration will differ from field to field, but a single platform may have 20 or more oil and gas production wells. Individual wells from a platform may exploit oil or gas at various depths in the same reservoir or different reservoirs in the same field. The more productive reservoirs are usually developed first. Assuming a drilling depth of 10,000 feet, industry sources indicate each well could take 43 days to drill and cost $1.9 million each.

Directional drilling may be used whereby a well is drilled down 800 to 1,000 feet below the ocean bottom, and is then slanted off at an angle, usually less than 50 degrees. Directional drilling can be twice as costly as vertical drilling but allows the developer to exploit oil or gas reserves located at considerable distances from a platform without investing in an additional platform. In general, the more geographically extensive and deeper a field, the more opportunity the developer has to use directional drilling.

Drilling can affect the economics of development and production in other ways. Shallower depths mean lower drilling costs, other things being equal. However, natural gas fields found at shallow depths are likely to have pressure problems and additional compression may be called for early in the life of shallow fields. In addition, very shallow gas fields may mean that the operator will recover less high-value natural gas liquids. The geological characteristics of a field thus influence the flexibility companies have in siting production platforms, and also influence the economics. These considerations can prove to be relevant to Georges Bank petroleum development if oil and gas fields are found at shallow depths.

Even when a field has been discovered, perhaps as many as one out of four development wells will prove to be dry holes. Moreover, it is not at all uncommon for initial estimates of field reserves to be revised years after discovery as a result of the information gained through development and production. The distinction between exploration and development thus is not as clear-cut as many popular discussions of offshore oil and gas would lead one to believe.

3. Production Processing Equipment. This includes compressors, pumps, separators and so forth. Platform production processing equipment represents a sizable development cost and can amount to $10 million per platform.

4. Oil and Natural Gas Transportation System. The shipment of gas necessarily involves a pipeline with one or more compressor stations en route to maintain pressure in the lines. A gas plant will be located onshore to strip liquids from the gas before the methane enters the natural gas transmission network.

Oil transportation will involve either a pipeline to shore or offshore storage and shipment by tanker to a petroleum refinery. The amount of reserves, the geographic proximity and configuration of individual fields and distance from shore are the major factors that will determine whether offshore storage and tankers or a pipeline are used to transport Georges Bank oil. In general, the smaller an oil field and the farther it is offshore, the more economical the use of offshore storage and tankers (Devanney, 1975). Because it can be less costly to transport large quantities of oil by pipeline, separate fields may be interconnected to a common carrier pipeline to shore. This is a frequent practice in the Gulf of Mexico, and this approach is used also in the North Sea.

Because of weather conditions and the considerable distances involved, the laying of oil and gas pipelines off the coast of New England is likely to resemble the experience in the North Sea more than in the Gulf of Mexico. In the North Sea, lay barges operate from May to October. One technical rule of thumb is that 125 miles of pipe can be installed in a lay season. However, cases have been reported where as much as 60 miles of pipeline have been laid in the North Sea in a 50-day period (Oil and Gas Journal, 1976, page 72). On this basis, it could require the equivalent of one, or more likely two, lay barge seasons to install an oil or natural gas pipeline from Georges Bank to shore.

An example of the newest generation of lay barges is Exxon's semi-submersible barge, scheduled to be launched in July, 1976. This barge has a theoretical maximum laying rate of 8,000 feet per day, and may be able to operate up to 10 months of the year in New England weather conditions (Brannon, 1976). The use of the newest generation of lay barge may reduce the amount of time required to lay a pipeline from Georges Bank.

Pipelines are covered with a concrete-aggregate coating at a shoreside facility before they are transported to a lay barge and installed. The coating is used to weight the pipeline and to protect it from damage from fishing gear, anchors or other impacts.

In water depths less than 200 feet, common carrier pipelines usually are required to be buried. The water and burial depth figures are evolved from experience in the Gulf of Mexico. In the North Sea, other rules are applied to pipeline burial. For example, in the vicinity of platforms (two miles for a single platform, five miles around a complex of platforms), pipelines must be buried about nine feet. Also, pipelines must be buried to a depth of nine feet approaching shore in water depths less than 150 feet. In other offshore areas burial is required to a depth of three feet, where bottom conditions are judged suitable for burial (Kowalski and Saila, 1976, p. 3).

Burial takes place from a barge that uses a high-pressure water-jetting process to form a trench, which creates a temporary spoils bank along the pipeline route. Backfilling typically is accomplished over time by natural processes that deposit sediments over the entrenched pipeline.

In the past, smaller gathering or flow pipelines were not required to be buried,* although these lines may partly bury themselves in soft bottoms because of their small diameter. The special stipulations in the environmental impact statement (EIS) for the mid-Atlantic sale hold that all pipelines, including flow lines and gathering lines, shall be buried. This is to be done "whenever technically and economically feasible" (BLM), 1976b, p. 465), terms nearly impossible to interpret in the abstract.

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*Gathering pipeline networks are usually used with in field to interconnect production among platforms or between a subsea production system (SPS) and a conventional fixed platform. Flow lines are used to tie in the production from various fields to a common carrier pipeline to shore.

According to one industry source, burial costs for a trunk line can be \$20 per foot (\$106,000 per mile) under favorable conditions and up to \$630,000 per mile under unfavorable conditions (for example, extended severe weather conditions or a hard ocean bottom). Other pipeline protection schemes, e.g., deeper burial, burial plus backfill or the use of special protection systems for a submarine pipeline, will involve considerably higher costs than normal burial (Sturges, 1976, p. 29). Burial costs for pipelines less than 10 miles in length, which would include most gathering and many flow line networks because of their comparatively short length, may cost three times as much per mile as normal pipeline burial.

As noted, one or two lay barges will be used to install a single pipeline from Georges Bank. Each lay barge may use as many as 12 supply boats to haul pipe, transport other materials and equipment, handle the barge anchors and for other activities. A bury barge may use three supply boats (Trimble, 1975, pp. 21-22).

Production Activities: Production includes the primary and secondary recovery activities involved with lifting the oil and gas, preparing the oil or gas for shipment (for instance, separating the oil from the gas and the salt water from the oil) and shipment to shore. The initial or primary production from a single offshore oil well may range up to several thousand barrels per day, depending on the characteristics of the reservoir, the associated optimum investment/production plan and federal regulations regarding allowable maximum rates of production.

During the production phase, facilities must be continuously maintained and inspected. The output of individual wells declines over time, and after several years, producing wells may need to be reworked by a drilling rig put in place on the platform to maintain or increase output. During the later stages of the life of a field, an investment may be made in secondary recovery or reservoir pressure maintenance projects such as gas injection and water-flood techniques to maintain or increase field production.

Field Life: Eventually, individual wells and, finally, the entire field will be shut down when the unit operating costs exceed the revenue to the firm for a well or the field. When the field is shut down, platforms are dismantled and removed. Wells are plugged with cement and cut off below the floor of the ocean, and the operator must verify that the location has been cleared of obstructions (mid-Atlantic OCS Order 3). The cost of dismantling a platform may be as high as $13 million for an area like Georges Bank. Pipelines are left in place when the field is shut down.

Based on the simulation results of Kalter et al. (1975), described in the next section, the production period for large oil and gas fields on Georges Bank could be 10 to 15 years, respectively. Assuming a five-year development period, the overall economic life of individual large fields on Georges Bank could be 15 to 20 years.

POTENTIAL ECONOMIC RETURNS TO GEORGES BANK PETROLEUM DEVELOPMENT

Introduction

This section contains a discussion of the possible economic returns from oil and gas development on Georges Bank. In keeping with the principle that an assessment of the benefits and costs of offshore development is to be done on a site-specific or "incremental" basis, attention is restricted to the potential economic returns from developing individual oil or natural gas fields. First the potential national economic returns are described. The share of economic returns accruing to the region are reviewed next. Only the direct economic returns are considered in this section. Selected employment effects and other regional impacts that relate to an assessment of interactions are discussed in sections 9 and 10. Detailed evaluations of employment and other regional impacts may be found in other studies (Grigalunas, 1975; M.I.T., 1973; A. D. Little, 1975; C.E.Q., 1974 and the N. E. River Basins Commission, 1976).

National Returns

It is useful to digress for a moment to define several key economic terms that will be used repeatedly in the remainder of this section. The national economic returns from Georges Bank development measure the net returns or payoffs to society resulting from the exploitation of offshore oil and gas fields. National economic returns can have two components: (1) economic rent and (2) consumer real income benefits.

Economic rent is defined as the excess of revenues over the costs of the inputs or resources used in production. As discussed in more detail later, the economic rent is divided between the potential developer of a field and the federal government because the OCS lands are under public ownership and management.

Consumer real income benefits will result if the additional natural gas from Georges Bank is sold at, say, \$.60 or \$1.50 per thousand cubic feet (MCF) when the true value of the gas may be a good deal higher. Those who receive the \$.60 or \$1.50 per MCF gas thus, in effect, realize an increase in real income. The increase in consumer real income benefits should be combined with the economic rent to arrive at the total national economic returns.

One other economic concept must be noted. All the dollar estimates of economic rent and consumer real income benefits presented below are in present value terms. That is, a future stream of returns is converted to an equivalent single amount of money payable today. Implicitly or explicitly, such a present value calculation is made when a decision is reached about how much to pay today for a share of stock or a tract of land, all of which are expected to yield returns in the future. An oil company makes a similar calculation in deciding how much to bid for an offshore tract by converting all estimated future economic returns into their present value.

The potential national economic returns and the amount of oil and gas production from development of individual Georges Bank oil and gas fields will be influenced by a combination of interrelated geological, economic, technical and institutional factors, including:

- the reserves of an individual field
- the expected price of oil and gas, and development and production costs
- the characteristics of the field in terms of such factors as the quality (e.g., sulfur content) of the oil and the type of reservoir (e.g., water drive is considerably more efficient than pressure created by a gas cap pressure system)
- water depth and planned-for weather conditions at the field
- the distance of the field from shore
- leasing and taxation terms
- government regulations and requirements

The current system for leasing oil and gas reserves on offshore federal lands is based on the OCS Land Act of 1953. The essential economic features of this system consist of a fixed royalty rate, which historically has been set at one-sixth the value of production at the wellhead; a fixed, per acre rental fee; and the auction of offshore tracts to the highest bidder based on sealed cash bids.

Kalter, Tyner and Hughes (K-T-H) (1975) have constructed an economic model of the OCS leasing and development process which is the most useful reference for our immediate purposes. Their results are interesting because they indicate the potential economic rent that can result from the development of single hypothetical oil and natural gas fields on Georges Bank. K-T-H provide results for three assumed prices of oil ($11, $13 and $16 per barrel) and natural gas ($.60, $1.50 and $2.00 per thousand cubic feet). K-T-H also uses three assumed sizes for individual oil and natural gas fields (Table 3).

Economic Rent

The estimates by K-T-H of the potential economic rent from developing hypothetical single oil fields are contained in the upper section of Table 4. Three individual oil field reserve sizes are used and three alternative prices for oil and gas are considered. As indicated, the economic rent and the amount of production increase with the price assumed and the size of the field. While it does not pay to produce the small oil field at even the highest prices assumed, the economic rent for a single medium or large field can range from $40 million to as much as $779 million, depending on the price and the size of the field assumed.

Estimates of the potential economic rent for hypothetical single natural gas fields, for alternative prices, are summarized in the bottom section of Table 4. The estimates of potential economic rent range from zero for a single small natural gas field (and for the medium-sized field, at the lowest price used) to $652 million for the large single field with the highest price considered, $2 per MCF. Again, it is evident that the potential economic rent with development--and, in fact, whether or not it will pay to develop a field at all--depends on the size of the field and the price of natural gas*.

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*In August, 1976, the Federal Power Commission (FPC) established a $1.42 per MCF rate for natural gas committed to the interstate market after January 1, 1975. This decision, if it withstands legal challenges, would apply to natural gas from Georges Bank, since gas from the OCS is interstate gas.

TABLE 3

SIZE OF INDIVIDUAL OIL AND NATURAL GAS FIELDS USED BY
KALTER, TYNER AND HUGHES

Size of Individual Fields	Recoverable Reserves[a]	
	Oil (million barrels)	Natural Gas (trillion cubic feet)
Small	18.5	.11
Medium	70.2	.42
Large	321.8	1.93

Source: Kalter, Tyner, and Hughes (1975, pp. 33-34).

[a]Average values used by K-T-H.

As noted, the true national economic returns from the development of potential Georges Bank natural gas fields will exceed the estimated economic rent, if the price of natural gas sold interstate continues to be controlled. Those fortunate enough to receive natural gas from Georges Bank at $.60 or $1.50 per MCF when its real value is, say, $2.00 per MCF or more, in effect receive an increase in their real income. The potential gains to consumers of natural gas are not reflected in an offshore gas field developer's income accounts, nor in the estimates of economic rent presented in Table 4. Nonetheless, the increase in consumer real income benefits is a true increase in national economic returns and can be substantial. The important economic implications of this argument for New England will be pursued in the next section.

To illustrate the magnitude of potential consumer real income benefits, assume all of the natural gas to be found on Georges Bank is contained in a single large field with reserves of about one trillion cubic feet, the large gas field in Table 4. Assume further that the regulated price of natural gas is $.60 per MCF. The economic rent for the field, measured at the price the producer receives, $.60/MCF, amounts to $156 million (Table 4). Obviously the field is worth a good deal more to society than $156 million, since the purchaser of the gas would be willing to pay far more than $.60 per MCF for natural gas. The relevant question is: How much more than $156 million is the field worth to the nation?

The Federal Energy Administration (1976, pp. 143-6) uses 1985 reference equilibrium prices for non-associated natural gas of $1.90 to $2.16 per MCF at the wellhead, depending on the assumed, related world price of oil. We use $2 per MCF as the value of gas. It can be argued that the true marginal value of gas may in fact exceed $2 per MCF. Many gas distribution companies in New England, for example, presently are paying considerably over $2 for supplemental sources of natural gas. To the extent that Georges Bank gas displaces these higher cost sources, the value of offshore gas will exceed $2 per MCF.

Using the $2 per MCF figure to represent the true value of the gas, and assuming the gas is sold by the developer at only $.60 per MCF, the present value increase in consumer real income benefits from the hypothetical field amounts to $628 million. The total national economic return therefore is $784 million ($628 plus the $156 million in economic rent). If the regulated price of the gas is

TABLE 4

TOTAL PRODUCTION AND ECONOMIC RENT FOR INDIVIDUAL HYPOTHETICAL GEORGES BANK OIL AND NON-ASSOCIATED GAS FIELDS

Oil (per bbl)	Gas (per Mcf)	Amount of Oil Produced By[a] (million bbls) Small	Medium	Large	Amount of Natural Gas Produced[a] (million Mcf) Small	Medium	Large	Economic Rent (Present Value million $)[a,d] Small	Medium	Large
INDIVIDUAL OIL FIELDS										
$11	$.60	0	23.8	140.1	0	27.4[b]	161.4[b]	$0	$40.0	$419.4
$13	1.50	0	27.5	147.1	0	31.7[b]	169.5[b]	0	74.9	588.8
$16	2.00	0	29.8	148.4	0	34.4[b]	171.0[b]	0	117.7	779.1
INDIVIDUAL GAS FIELDS[c]										
$11	.60	-	-	-	0	0	1000.9	0	0	156.2
$13	1.50	-	-	-	0	202.4	1141.7	0	55.9	462.0
$16	2.00	-	-	-	0	238.6	1163.4	0	100.3	652.0

SOURCE: R. Kalter, W. Tyner and A. Hughes (1975, Appendix B). The results are calculated for the cash bonus one-sixth royalty leasing system.

[a]The mean value of the three size categories of the fields used by Kalter are (pp. 33-34):

	Oil (millions of bbl)	Natural Gas (millions of Mcf)
Small	18.5	111.0
Medium	70.2	421.2
Large	321.3	1,927.8

[b]Associated natural gas

[c]Excludes natural gas liquids which K-T-H. estimate could range from 6.7 to 38.4 million barrels for the medium and large gas fields depending on the price.

[d]Using a discount rate of 12 percent.

increased to $1.50 per MCF, consumer real income benefits fall to about $259 million in this case. The loss of consumer real income benefits is transferred initially as a larger economic rent to the prospective developer of the field ($462 million in Table 4). The developer, in turn, transfers some fraction of the higher economic rent to the federal government in the form of a higher cash bid for the tract, and higher royalty and income tax payments.[3]

The above argument suffices to make the point raised here--national economic returns from developing possible natural gas fields on Georges Bank can exceed considerably the estimate of economic rent calculated with regulated prices. In reality, however, natural gas issues are far more complex than the simple example above suggests. If natural gas is found on Georges Bank, it probably will be contained in more than one field. Consumers pay more (and producers and the government receive higher revenues) at higher prices, but more gas may be produced, and therefore, made available for consumption. In fact, unless prices exceed some minimal levels, it may not be commercially worthwhile for a company to develop some small fields at all (see Table 4). Natural gas pricing issues clearly extend beyond Georges Bank and New England and involve complex considerations that do not warrant further attention in a report of this scope. A more detailed discussion of the issues raised here can be found elsewhere (see Devanney, 1976, pp. 202-3; and Syron and Browne, 1976).

It is interesting, finally, to look at the potential value of Georges Bank as a source of petroleum production in another way; by converting the national economic return figures described above for a single field into an equivalent value per acre (Table 5). Individual fields are assumed to extend over two, four or six separate tracts (11.5 to 34.6 thousand acres or 18 to 54 square miles). The intermediate prices of $13 and $1.50 are used, but consumer real income benefits are included by assuming that the true value of natural gas is $2 per MCF.

In the case where an oil field is assumed to extend over four tracts, the implied value per acre ranges from $0 to $28,000 depending on the reserves in the field. Per acre value estimates for other cases are presented in Table 5. The estimates differ from case to case, but the results indicate that in economic terms sections of Georges Bank may be worth a good deal to society as potential areas of petroleum production.

TABLE 5

IMPUTED NATIONAL ECONOMIC VALUE PER ACRE FOR HYPOTHETICAL INDIVIDUAL OIL FIELDS ON GEORGES BANK[a]

Assumed size of field (in acres)	Oil Reserves:[b] small	medium	large
11,520 (2 tracts)	0	$7,248	$55,469
23,040 (4 tracts)	0	3,624	27,734
34,560 (6 tracts)	0	2,416	18,490

[a]The results are based on the $13/bbl and $1.50 case in Table 4, adjusted to include consumer real income benefits, assuming the equilibrium value of natural gas is $2/MCF.

[b]See Table 3 for the definitions of small, medium and large fields.

The reader is cautioned that the figures in Table 5 are value per acre to the nation, not to a company and not to the region. The operator in this example is assumed to receive \$1.50 per MCF, while society values the gas at \$2.00. Moreover, a company will bid on areas of Georges Bank based on its estimate of after-tax returns. For these and other reasons, a company's bid per acre will be considerably less than the value of an area to society at large. For perspective, the highest amount bid in the recent mid-Atlantic sale was \$180 million for a tract, or \$18,750 per acre. In light of the figures presented in the text, the high bidder is betting heavily that a field with substantial reserves will be found.

In summary, the information presented in this section provides an indication of the direct national economic returns that can result with the development of single oil or natural gas fields on Georges Bank. Looked at another way, the results can be viewed as the national economic cost (in terms of benefits foregone) of not developing a particular field, unless equivalent resources in another OCS area are substituted as part of the leasing schedule process.

Economic Returns to the Region

The economic rent resulting from the development of individual fields on Georges Bank will be distributed (a) to the federal government in the form of the cash bonus made at the lease sale, royalty payments on production and corporate income taxes and (b) as company profits. New England shares in the economic returns to the extent (a) and (b) accure to the region as additional federal expenditures or reduced taxes and direct and indirect payments resulting from the ownership of oil company shares in the region. New England also will experience a direct increase in consumer real income, as noted above, to the extent that natural gas from Georges Bank is sold in the region at a price less than its real value. The potential returns to New England resulting from the development of individual fields on Georges Bank are described below.

Economic Rent: The increase in income consists of New England's share of federal government revenues and company profits. For consistency with earlier work, the region's share is assumed to be 5 percent of the total economic rent for each field, New England's approximate share of the national population and wealth (MIT, 1973; Devanney, 1975 b).[4] The estimated increase in income from sharing in the economic rent of single fields is presented in Table 6.

TABLE 6

SUMMARY OF NEW ENGLAND'S POSSIBLE SHARE OF FEDERAL REVENUES AND COMPANY PROFITS FOR HYPOTHETICAL INDIVIDUAL GEORGES BANK OIL AND NATURAL GAS FIELDS[a]

($ millions, present value)

Price: Oil (barrel)	Price: Natural gas (MCF)	Individual Oil Fields: small	Individual Oil Fields: medium	Individual Oil Fields: large	Individual Gas Fields: small	Individual Gas Fields: medium	Individual Gas Fields: large
$11	$ .60	0	$2.0	$21.0	0	0	7.8
13	1.50	0	3.7	29.4	0	2.8	23.1
16	2.00	0	5.9	39.0	0	5.0	32.6

[a]New England is assumed to receive 5 percent of all economic rent (federal government revenues and company returns). The estimates of total economic rent are contained in Table 4.

The gain to New England for individual, developed oil fields ranges from $2 million to $39 million, depending on the size of the field and the price assumed. The region's share of economic rent from individual, developed gas fields ranges from $2.8 million to $32.6 million, again depending on the price and the reserves in the field. Looked at another way, these figures can be viewed as a cost to the region if development does not take place, unless equivalent substitute resources are leased elsewhere.[5] The estimates of the amount of federal revenue and company profits received by New England from the development of individual fields thus are reasonably modest in comparison with the economic rent received by the nation (see Table 4), because New England receives only a small share of these returns.

Consumer Real Income Benefits: While New England's share of federal revenues and company profits for individual fields is comparatively modest, the potential gain to the region from a natural gas field on Georges Bank may be another story altogether. As discussed earlier, consumers will receive a real income benefit if they receive gas priced at less than its true value.

Table 7 summarizes the possible gain to New England from the development of hypothetical single fields on Georges Bank. The gain consists of the region's share (assumed to be 5 percent) of federal revenues and company profits and the consumer real income benefits. For the non-associated natural gas fields, the present value of the possible gain ranges from as much as $635 million to as little as $5 million, depending on the size of the developed field and the price at which it is sold. For the oil fields, the potential regional gain ranges from about $6 million to $155 million.

It is noteworthy that the consumer real income gain dominates the estimate of the potential benefits to the region. At a controlled price of $.60 per MCF, the region gains $627.6 million in real income from development of a large natural gas field; when the controlled price of gas is raised to $1.50, the region's potential gain drops to $259 million and disappears entirely at a price of $2 per MCF. Consumer real income gains also dominate New England's potential returns from the development of oil fields. For example, consumer real income benefits from the sale of natural gas produced in association with oil could be as high as $133 million for the large oil field, provided that the gas is sold at $.60 per MCF.

TABLE 7

SUMMARY OF NEW ENGLAND ESTIMATED CONSUMER REAL INCOME AND SHARE OF GOVERNMENT REVENUES AND COMPANY PROFITS, FOR HYPOTHETICAL INDIVIDUAL GEORGES BANK OIL AND NATURAL GAS FIELDS

($ millions, present value)

PRICE oil per/bbl	PRICE natural gas per/mcf		Individual Oil Fields[c,d] medium	Individual Oil Fields[c,d] large	Individual Gas Fields[c,d] medium	Individual Gas Fields[c,d] large
$11	$ .60	C.R.I.[b]	$18.9	$133.8	$0	$627.6
		Rev. share[a]	2.0	21.0	0	7.8
		Total	$20.9	$154.8	$0	$635.4
$13	$1.50	C.R.I.[b]	$ 8.7	$ 50.2	$45.1	$259.2
		Rev. share[a]	3.7	29.4	2.8	23.1
		Total	$12.4	$ 79.6	$47.9	$282.3
$16	$2.00	C.R.I.[b]	$ 0	$ 0	$ 0	$ 0
		Rev. share[a]	5.9	39.0	5.0	32.6
		Total'	$ 5.9	$ 39.0	$ 5.0	$ 32.6

[a]Assumes New England receives 5 percent of federal revenues and company profits (see Table 6) and that all the natural gas from each hypothetical field is consumed in region.

[b]Consumer real income benefits estimated as the present value (with a 12 percent discount rate) over the life of each field of the difference between the assumed value of natural gas, $2 per/mcf, and the indicated price of gas in the above table. The estimated field life is from K-T-H, Appendix B. For convenience annual production is assumed to occur uniformly over the life of the field.

[c]None of the small fields are commercially worthwhile to develop over the range of prices considered.

[d]The assumed recoverable reserves for each field are summarized in Table 4.

It is emphasized that the possible regional income gains discussed here are for individual hypothetical fields only. No attempt is made to estimate the possible total number and size of fields, or the total potential gains from development. (It is possible, of course, that no large fields, or no commercially viable reserves, will be found on Georges Bank). In addition, the assumption has been made that natural gas from Georges Bank will be consumed in New England; if gas is shipped to other sections of the country, the region receives only the share of federal revenues and company profits (Table 7).

While no attempt is made to estimate the total potential gains to the region from oil and gas development on Georges Bank, the results underscore the potential benefits to the region from the development of particular areas of Georges Bank, if natural gas is found and sold in the region at less than its full value. Consumer real income benefits are not reflected in the income accounts of the offshore developer and are not as visible as the physical features of development--men, equipment, drilling rigs, and so forth. Nonetheless, these benefits are real and can be major. As Devanney (1976) has pointed out, the consumer real income gains from a large find of natural gas on Georges Bank in total may exceed all other forms of gain to the region (share of federal revenues and company profits and other taxes under the existing rules and employment net income benefits).

In summary, the implications of this section are as follows. First, the national economic returns resulting from the development of individual oil and natural gas fields on Georges Bank can be considerable if oil and gas are discovered in large fields. A large portion of national economic returns, especially in the case of natural gas, may come in the form of consumer real income benefits, if natural gas is sold at less than its full value.

Second, New England will receive only a small share of federal government revenues and company profit, so that the increase in income to the region from these sources will be comparatively modest compared with the gains to society as a whole. However, to the extent that New England receives natural gas from large fields on Georges Bank under some form of price control, consumer's real income benefits in the region from the availability of natural gas can be substantial. New England may be more likely to have access to natural gas from Georges Bank than from additional gas production in other OCS areas under controlled price conditions. A decision not to develop fields containing natural gas, therefore, could result in a cost to the region, even if equivalent substitute resources are leased elsewhere. Accordingly, it is paramount that any arguments for the withdrawal of particular tracts from development recognize the potential costs of such a policy along with an assessment of the benefits of tract withdrawal.

ALTERNATIVE OIL AND GAS CASES FOR GEORGES BANK

Development of Alternative Georges Bank Petroleum Cases

Three Georges Bank petroleum alternatives are used in this study:

1. no development (exploration only)

2. a low development case

3. a high development case

The purpose of using the three cases is to derive selected indications of oil and gas activity that could result with each alternative. Instead of a series of development cases, two development hypotheses are advanced to bracket the range of Georges Bank oil and gas activity that seems reasonable in the light of currently available data. The exploration only, and the low and high cases thus allow us to make some conditional statements -- "if this happens, then this may follow" -- in order to assess possible offshore and onshore interactions.

The Bureau of Land Management has constructed high and low development cases for Georges Bank. However, BLM's cases apply to a first Georges Bank lease sale only, and not with what the total level of development on Georges Bank could be. Accordingly, in the high find case, we specifically include development that could occur beyond the first lease sale.

BLM has developed a series of technical relations that relate the amount of recoverable resources to the level of specific activities offshore: mobile rigs, platforms, wells, pipelines and so forth. BLM's technical relations, adjusted on the author's judgment, are used to provide indications of oil and gas activity offshore for our petroleum development cases. In general, the approach adopted leads to very conservative, high estimates of the level of activity offshore. The resource assumptions used in the development cases are described next.

Development -- Low Case: The low development case adopted for this study corresponds with the low offshore development resource assumptions used by BLM for the first sale, 180 million barrels of oil and 1.2 trillion cubic feet of natural gas. These resource assumptions are used to describe a lower limit petroleum development case for Georges Bank in which recoverable reserves prove to be only a fraction of the present mean or 5 percent of USGS estimates.

In reality, the discovery of oil and gas resources, even as modest as those assumed here, very likely would be adequate to generate sufficient industry interest for a second lease sale and, at a minimum, some additional exploratory drilling. The low development case, therefore, must be viewed in the context of the approach used -- to characterize a minimum level of Georges Bank oil and gas activity.

Development -- High Case: BLM's high offshore development case (650 million barrels of oil and 4.3 trillion cubic feet of gas) may materialize from the first lease sale on Georges Bank. In this case, there will be industry interest in tracts not leased at the first sale.

Most of the tracts indicated by industry to be of high interest are being studied as part of the environmental impact statement process, and most will likely be included in a first sale. The most promising tracts probably will be leased first, so that later development would be expected to produce lower recoverable reserves. The working assumption used is that subsequent development amounts to the indentical amount of reserves as with the first sale. All additional reserves are assumed to be found in a second lease sale. The resulting levels of activity on Georges Bank, described below, are conservative and in fact exceed what would result from a find considerably larger than that used here.

The total reserves in the high development case, therefore, amount to 1.3 billion barrels of oil and 8.6 trillion cubic feet of natural gas. These resource figures are considerably higher than the mean USGS estimates for Georges Bank, but less than the 5 percent probability estimates of 2.5 billion barrels and 12.5 trillion cubic feet.

In summary, throughout the remainder of this study, three Georges Bank petroleum cases are used to assess possible interactions:

1. no development (exploration only)

2. development

	Low Case	High Case
Oil (bill. of barrels)	.18	1.3
Natural gas (tril. cu.ft.)	1.2	8.6

Offshore Development Implications of Alternative Cases

This section contains a summary of possible petroleum activity on Georges Bank based on the three alternative cases described above. Relevant shoreside impacts are discussed in section 8.

No Development: If wildcat exploration yeilds on hydrocarbon at all, one estimate is that as few as 30 exploratory wells may be sufficient to condemn Georges Bank as non-productive (USGS, 1975). With a show of oil or gas, but no discovery of commercial quantities, 60 to 90 exploratory wells may be drilled before Georges Bank is condemned. These estimates are consistent with experience on the Scotian Shelf and with the Mississippi, Alabama, Florida (MAFLA) sale.

Assuming each mobile rig can drill four exploratory wells per year, the no-development alternative implies 7.5 to 22.5 rig years to condemn Georges Bank. At any one time, perhaps six to eight mobile rigs could be active on Georges Bank in the no-development case. The maximum number of supply boats that would be used for Georges Bank in this case is 12 to 16 boats.

Under current OCS leasing arrangements, exploratory drilling on a tract is expected to take place within five years. Therefore, even if there is interest in a second lease sale, held on schedule 24 months after the first, all exploratory drilling could be completed within seven years, and might well cease earlier with the no-development alternative.

Low Development Case: The low resource development assumption results in a peak of six to eight mobile rigs on Georges Bank. Except for tracts in shallow waters, exploration almost certainly will be undertaken from semisubmersible rigs.

A maximum of 10 platforms are assumed to be installed by 1987. No estimate is made of the extent to which subsea production systems might be used on Georges Bank.

In the low development case, one pipeline to shore would be installed from Georges Bank to transport natural gas. The recoverable reserve assumption of 180 million barrels implies one or more finds with total oil in place of perhaps 350-500 million barrels. The least-cost transportation mode for a find of this size is likely to be via tanker (Devanney, 1975). The BLM assumption that oil will be stored offshore and shipped by tanker thus appears to be reasonable.

If the use of supply boats conforms with North Sea experience (Trimble, 1975) as many as 12 supply boats may be in use in 1978, and the number would peak at perhaps 20 vessels in 1984 when the natural gas pipeline is being installed. Because of the substantial economies that can be achieved by pooling supply boat services, these figures can be regarded as a maximum for the resource find considered here.

Peak production from Georges Bank would be reached in 1990 and would amount to 19 million barrels of oil and 170 billion cubic feet of gas. Oil production from Georges Bank may be equivalent to less than 3 percent of New England's demand for oil products in 1990, while natural gas production may be equivalent to 49 percent of the region's demand for natural gas in 1990 (Table 8). Some natural gas may be shipped outside New England.

High Development Case: In this case, as many as six mobile rigs could be on Georges Bank by the end of 1977, assuming a first sale takes place early in the year. A maximum of 10 mobile rigs could be on Georges Bank following a second sale in early 1979.

The first platform would be installed by 1981. Twenty platforms are assumed to be in place by the end of 1985, and the total number of platforms installed by 1991 is 50. This is a maximum, and could occur only if virtually every field on Georges Bank is of minimum commercial size. Because of the economies of scale with large fields, we can be confident that the assumption of 50 platforms used in the high development case could accomodate a huge, multi-billion-barrel find on Georges Bank. For example, British Petroleum's Forties Field in the North Sea contains two billion barrels of recoverable reserves, but only four permanent production platforms are used to produce it.

A preliminary estimate by BLM is that three pipelines to shore would be installed as a result of its high find assumptions for an initial sale, one for oil and two for natural gas. According to BLM, as much as 980 miles of offshore pipeline could be laid, excluding gathering and flow lines between fields (BLM, 1976, p. 25). No additional pipelines to shore need be installed for the high resource case used in this report, and BLM's assumptions of three pipelines to shore and 980 miles of pipeline is adopted in the high case used in this report. This figure does not include the many miles of pipeline that will be installed as gathering lines within a field or as flow lines connecting separate fields with a common carrier pipeline to shore. It is not possible to estimate how many miles such pipeline networks will occupy without knowing the configuration of fields and company development plans. The only statement that can be made is that by the mid to late 1980s, under the high development assumptions used, the total number of miles of pipeline offshore will be considerably in excess of 1,000.

Up to 50 supply boats may be used on Georges Bank by 1984 for all activities, excluding short-term demands in connection with platform installation. This figure is likely to be a maximum for the reasons noted earlier. Because of severe weather conditions and substantial distances from shore, crew boats will see limited use on Georges Bank. An estimated 10 crew boats would be used; this may prove to be high.

Peak production from offshore fields would be reached in 1990 when 115 million barrels of oil and 766 billion cubic feet of gas would be landed. Oil production in 1990 may be equivalent to 17 percent of New England's demand for oil products in 1990. On the other hand, natural gas production in 1990 may be more than twice the region's estimated 1990 demand for natural gas (Table 8). In this case, it is very likely that at least some Georges Bank gas will be shipped outside the region, perhaps to the New York market. According to testimony by one leading New England gas distribution company official, it would be a simple matter to reverse the flow on existing gas pipelines to export gas from the region (Pryne, 1975).

Summary of Indicators of Georges Bank Petroleum Activity: Selected indicators of possible oil and gas activity on Georges Bank for each of the alternative cases are summarized in Table 9. As noted, the first Georges Bank lease sale is assumed to take place in early 1977 and the second in early 1979.

TABLE 8

COMPARISON OF POSSIBLE 1990 GEORGES BANK
OIL AND NATURAL GAS PRODUCTION
WITH ESTIMATED NEW ENGLAND CONSUMPTION

	Possible 1990 Production[a] from Georges Bank		BTU Equivalent of 1990[b] Georges Bank Production (trillion of BTU)		Estimated 1990[c] New England Demand (trillion of BTU)		Estimated 1990 Georges Bank Production as a Percentage of New England Demand	
	Oil (million bbls)	Gas (million Mcf)	Oil	Gas	Oil	Gas	Oil	Gas
Development LOW CASE	19.3	170.1	106.4	170.1	3639.0	346.1	2.9%	49.1%
Development HIGH CASE	115.0	766.5	632.4	766.5	3639.0	346.1	17.4%	221.5%

[a]SOURCE: Based on BLM production estimates for low and high cases for an initial Georges Bank sale. The high development cases used, as described in the text, assumes that a second sale follows the first by 18 months and results in recoverable reserves equivalent to BLM's high find assumptions for the first sale. The resource assumptions used are:

	Low	High
Oil (billions bbls.)	.18	1.3
Natural gas (trillion cu.feet)	1.2	8.6

[b]Conversion Ratios Used:

1 bbl of crude oil = 5.5 million BTU.
1 Mcf of natural gas = 1 million BTU.

[c]Arthur D. Little, Inc., "Preliminary Projections of New England's Energy Requirements", Boston, New England Regional Commission, Nov. 1974, p. 5. The ADL alternative used here is the medium growth case, unconstrained by fuel availability.

TABLE 9

ESTIMATED NUMBERS BY YEAR OF RIGS, PLATFORMS AND PIPELINES ON GEORGES BANK; NO DEVELOPMENT, LOW AND HIGH FIND CASES.

	No Development	Low Development[a]				High Development[a]			
Year	Mobile Rigs	Mobile Rigs	Platforms[c] Installed	Pipelines[c] Oil	Gas	Mobile[d] Rigs	Platforms[d] Installed	Pipelines[d] Oil	Gas
1977[b]	6	6				6			
1978	6-8	6 - 8				6 - 8			
1979[b]	5-8	5 - 8				10			
1980	4	4				10			
1981	3	3	1(1)			10	2 (2)		
1982	2	2	1(2)			10	2 (4)		
1983	1	2	2(4)			10	5 (9)	x[e]	
1984	0	2	2(6)		x[e]	10	5 (14)	x[e]	x[e]
1985	0	2	2(8)		x[e]	10	6 (20)	1	x[e]
1986	0	2	1(9)		1	9	6 (26)		1
1987	0	1	1(10)			8	6 (32)		x[e]
1988	0	1				6	6 (38)		x[e]
1989	0	1				6	6 (44)		1
1990	0	1				4	3 (47)		
1991	0	0				4	3 (50)		
TOTAL			10	0[f]	1		50	1	2

[a]Resource assumptions:

	Low Development	High Development
Oil(bill. barrels)	.18	1.3
Natural gas(trill.cu.ft.)	1.2	8.6

The low development case in the table uses the low resource assumptions adopted by BLM for the first Georges Bank sale. The high development case assumes BLM's high resource case for a first and second Georges Bank lease sale.

[b]The first lease sale is assumed to take place in early 1977 and the second sale of tracts is assumed to be held in early 1979.

[c]Low find offshore development results used by BLM.

[d]These figures are based on the high find BLM offshore development results as explained in footnote a, above. However, the high development case used here is assumed to employ three offshore pipelines and a maximum of 10 mobile rigs.

[e]x = installation/construction period.

[f]Tankers used to transport oil.

Footnotes

[1] Detailed assessments of the regional impacts of possible Georges Bank petroleum development may be found in Grigalunas (1975), Arthur D. Little, Inc. (1975), M.I.T. (1973), Council on Environmental Quality (1974) and the recently released report of the New England River Basins Commission (1976).

[2] A consortium of 31 oil companies has funded the drilling of two Continental Offshore Stratigraphic Test (COST) holes off the East Coast. One COST hole is off the Mid-Atlantic and one is on Georges Bank. The test hole off New England has a permit for 17,000 feet and is designed to obtain geological information, particularly regarding possible petroleum source rocks, in this previously undrilled area. The COST wells deliberately have been drilled outside the immediate areas of oil industry interest. The resulting drilling data at present are proprietary, although the U.S. Geological Survey and specific representatives of the government of coastal states will receive the data from the COST project. The Georges Bank data will be made public following the first sale.

[3] The division of revenues between the federal government and the developer will depend on the effectiveness of the leasing system in capturing anticipated returns. For an evaluation of alternative leasing systems see K-T-H (1975) and Devanney (1975).

[4] The use of population and wealth figures is a convenient and probably reasonable proxy for the region's share of OCS returns. It would be interesting in future research, however, to obtain some empirical evidence on the distribution of federal and company OCS returns.

[5] The results do not include any special regional taxation or revenue sharing schemes, nor do they include any estimates of net environmental costs or possible shoreside public sector costs.

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