Economics of Undiscovered Oil and Gas in the Central North Slope, Alaska

By Emil D. Attanasi and Philip A. Freeman

Open-File Report 2005-1276

U.S. Department of the Interior
U.S. Geological Survey

U.S. Department of the Interior
Gale A. Norton, Secretary

U.S. Geological Survey
P. Patrick Leahy, Acting Director

U.S. Geological Survey, Reston, Virginia: 2005

For more information about the USGS and its products:
Telephone: 1-888-ASK-USGS
World Wide Web: http://www.usgs.gov/

Contents

Figures

Tables

Conversion Factors

Multiply	By	To obtain
barrel (bbl), (petroleum, 1 barrel=42 gal)	0.1590	cubic meter (m^3)
cubic foot (ft^3)	0.02832	cubic meter (m^3)
foot (ft)	0.3048	meter (m)

Unit Abbreviations

BBO	Billions of barrels of oil
BBL	Billions of barrels of liquids
TCF	Trillions of cubic feet
MMBO	Millions of barrels of oil
BCF	Billions of cubic feet
mcf	Thousands of cubic feet
bbl	Barrel of crude oil
BTU	British Thermal Unit

Economics of Undiscovered Oil and Gas in the Central North Slope, Alaska

By Emil D. Attanasi and Philip A. Freeman

Summary

This report summarizes the economic analysis of the U.S. Geological Survey's 2005 petroleum assessment of the Central North Slope of Alaska. The study area is located east of the National Petroleum Reserve Alaska (NPRA) and west of the Arctic National Wildlife Refuge (ANWR). It extends from the State-Federal offshore border south to the Brooks Range (figures 1 and 2). The study area includes all onshore lands (State, Federal, and Native) and the lands underlying adjacent Alaska-State waters. Past discoveries in this area have already produced about 15 billion barrels of hydrocarbon liquids (more than 12 billion barrels of crude oil (BBO)). More than 35 trillion cubic feet (TCF) of gas has also been identified to date.

Estimates of technically recoverable oil in undiscovered oil accumulations range from 2.57 to 5.85 BBO with a mean of 3.98 BBO (Bird and Houseknecht, 2005). The range in estimated volumes corresponds to the 95 percent probability (that is, a 19 in 20 chance the actual volume will exceed that 95th fractile volume) and the 5 percent probability level (1 in 20 chance the actual will exceed 5th fractile volume), respectively. Similarly, the 95th and 5th fractile estimates of technically recoverable gas volumes in undiscovered gas accumulations range from 23.9 to 44.9 TCF of gas with a mean value of 33.3 TCF. The minimum sizes of the assessed accumulations were 5 million barrels recoverable oil and 100 billion cubic feet (BCF) recoverable gas.

Characteristics of the assessment that are important for the economic analysis included the petroleum accumulation size-frequency distribution, location, and depth. At the mean estimate, 0.96 BBO is in accumulations of at least 128 million barrels. Accumulation size-frequency distributions associated with the 95th and 5th fractiles indicate slightly less than 18 percent (0.46 BBO) and 32 percent (1.89 BBO) of the assessed technically recoverable oil is in accumulations of at least 128 million barrels, respectively. The geologic analysis is consistent with the inference that the area's largest onshore oil accumulations have already been found. At the mean estimate, the undiscovered gas pool size distribution has almost 33 percent (representing 11 TCF) of the assessed gas assigned to accumulations with least 760 billion cubic feet (BCF) of gas. At the 5th fractile estimates, more than 40 percent of the gas (representing 19.3 TCF) was assigned to gas accumulations at least as large as 760 BCF.

Results of the economic analysis are presented as separate cost functions associated with the mean, 95th, and 5th fractile estimates of undiscovered technically recoverable oil. An after-tax 12 percent rate of return or hurdle rate was assumed. All calculations are in constant 2003 dollars. Transportation costs from the field to the market were included in the analysis so that prices and incremental costs are at the market rather than at the wellhead. Incremental cost functions include the full costs of finding, developing, producing, and transporting oil to market.

For resources associated with the 95th fractile, the mean, and the 5th fractile estimates, initial exploration costs are not compensated by the economic value of new finds until market prices reach at least $22.40 per barrel, $20.10 per barrel and $18.40 per barrel, respectively. Graphs are presented that show economic volumes of oil as a function of market prices for a range from $18 to $55 per barrel. At a market price of $30 per barrel, 0.79 BBO or 30 percent of the technically recoverable oil assessed at the 95th fractile, 1.9 BBO or 47 percent of the oil assessed at the mean, and 3.5 BBO or 59 percent of the oil assessed at the 5th fractile estimate is economic to find, develop, produce, and transport to market.

Available information on Arctic gas field development and operational costs are limited because there is no gas market transport system. The gas accumulations are evaluated in the economic analysis. It is estimated it would take about 10 years from the decision to construct a gas pipeline to the lower 48 states to the pipeline's completion. Recent estimates of Alaska natural gas export pipeline tariffs of just under $3.00 per thousand cubic feet (mcf) limit the effects that gas commercialization has on oil development when the after-tax net present values are discounted for 10 and 20 year delays in development. However, even with the primitive cost data used here, and with a ready but delayed market, the volumes of gas that could be identified and produced at $5 per mcf range from 7.9 to 22.1 TCF.

Introduction

The U.S. Geological Survey's 2005 Central North Slope Assessment (figures 1 and 2) posits a set of scientifically based estimates of undiscovered, technically recoverable[1] quantities of oil and gas in accumulations that can be produced with conventional recovery technology. The study area is located east of the National Petroleum Reserve in Alaska (NPRA) and west of the Arctic National Wildlife Refuge (ANWR), extending from State-Federal offshore boundary southward to the Brooks Range (figures 1 and 2). The study area includes all onshore lands and the underlying adjacent Alaska State-waters. Geologists assessed volumes of recoverable conventional oil and gas that could be added to reserves using current technology but without reference to costs or product prices. The costs and the product prices required to transform these undiscovered, technically recoverable resources into producible reserves are presented in this report.

This analysis estimates the part of the assessed distribution of undiscovered accumulations that can be commercially developed at particular market prices based on the incremental costs of finding, developing, producing, and transporting the oil and gas to a market. Incremental cost functions show cost-resource recovery possibilities and are not supply functions as strictly defined by economists. However, the incremental cost functions and the data that underlie the functions are often used in market supply models. *This analysis does not predict the revenue or bonus payments for leases in the study area nor does it attempt to estimate regional or national secondary economic benefits that may result as a consequence of development of the resource.*

The economic component of the Central North Slope assessment is intended to place the geologic resource analysis into an economic context that is informative and easily understood by policy makers and decision makers. The geologic assessment might best be described as a regional reconnaissance appraisal. The geologists assigned subjective probabilities to the occurrence of hydrocarbon accumulations to capture play and prospect risk. They also formulated subjective probability distributions for reservoir attributes of such accumulations, using data from available field studies, regional geophysical studies, knowledge about regional trends, and postulated regional geologic history. The reservoir attribute distributions are used to predict size, depth, and production characteristics of undiscovered accumulations.

The scope of the economic analysis is also general rather than site or prospect specific. The economic analysis is limited to the evaluation of general finding costs, development costs (including the costs of primary recovery and some aspects of secondary recovery), and the costs of transporting the product to market. *Undiscovered technically recoverable conventional oil and gas resources* are resources that are estimated to exist, on the basis of broad geologic knowledge and theory, in *undiscovered accumulations* outside of known fields.

Conventional oil and gas accumulations are discrete well-defined accumulations, typically bounded by a water contact, from which oil, gas, and natural gas liquids (NGL) can be extracted using traditional development and production practices. *Economically recoverable resources* are that part of the assessed technically recoverable resource for which the costs of finding, development, and production, including a

[1] Technically recoverable resources are producible using recovery technology that is currently available, but without reference to economic viability. Accumulations assessed by geologists outside of known fields were considered for the purposes of the economic analysis as separate and discrete new fields.

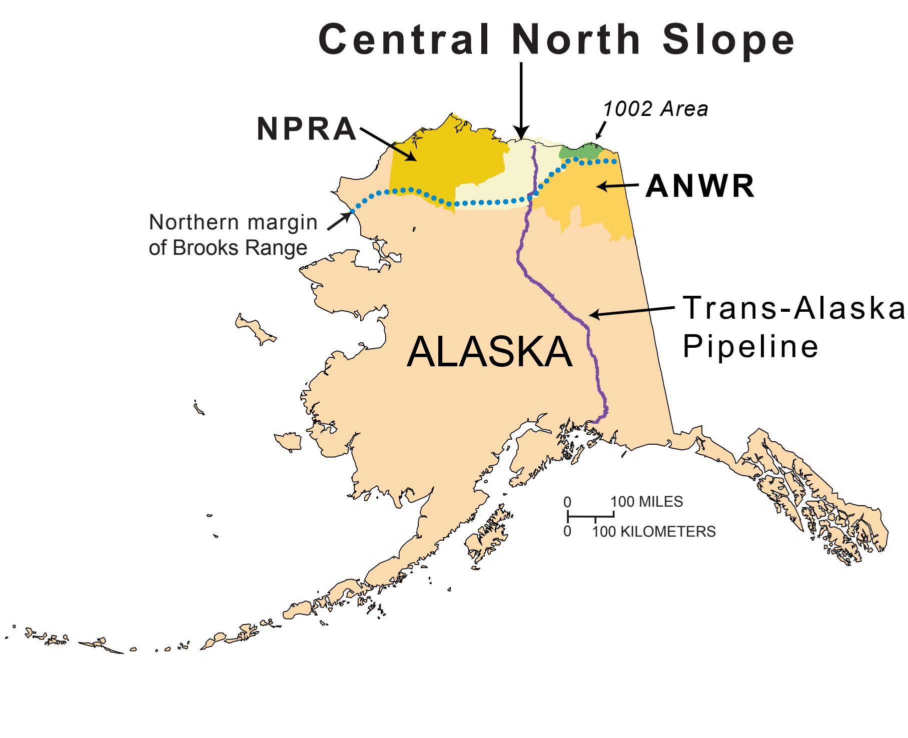

Figure 1. Location map of the Central North Slope Study Area in relation to the National Petroleum Reserve Alaska (NPRA) and the Arctic National Wildlife Refuge (ANWR) including the 1002 Area part of the coastal plain.

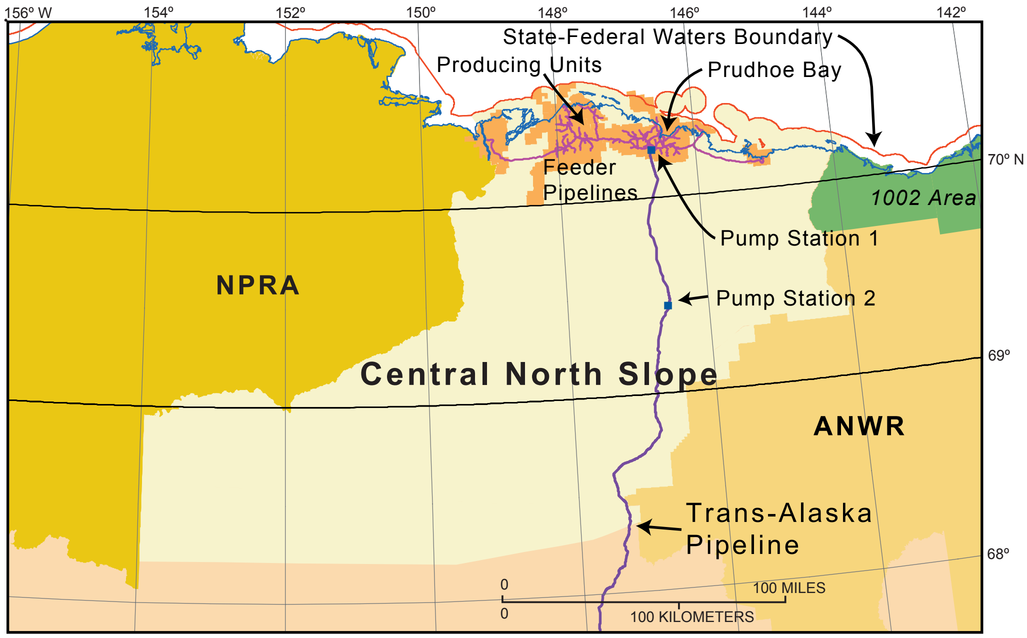

Figure 2. Map showing Central North Slope study area and the existing infrastructure and pipelines including the Trans-Alaska pipeline and pump stations. Sub-areas defined in the text are: north sub-area extends from the State-Federal waters boundary to 70°N, middle sub-area extends south from 70°N to 69°N, and south sub-area extends south from 69°N to the Brooks Range boundary of the assessment area.

return on capital, can be recovered by production revenues at a particular price.

Recent economic analyses of undiscovered hydrocarbon resources of the North Slope have not considered natural gas because there is currently no infrastructure to transport produced gas to markets located outside the North Slope. There is also a large inventory, in excess of 25 TCF of very low cost stranded gas in rapidly depleting oil fields, that may have priority access to a gas product pipeline when it is built. This study attempts to gauge, by a scenario analysis, the economic influence that potentially commercial, but currently undiscovered non-associated gas resources could have on exploration decisions.

The discussion briefly reviews the geologic assessment procedures. It then summarizes characteristics of the technically recoverable resources important for understanding the economic analysis. Assumptions about markets, pricing, costs, and the technical relationships used in computing the incremental cost functions are discussed. Results and interpretations of the economic analysis are presented in the concluding sections.

Acknowledgments

The authors thank Ken Bird, Keith Long, James Coleman and John Schuenemeyer (Southwest Statistical Consulting, LLC) for their reviews and suggestions.

Synopsis of Geologic Assessment

The geologic assessment method and results are only briefly reviewed here (Schuenemeyer, 2005). The commercial value of a newly discovered oil and gas accumulation depends on its expected size, hydrocarbon type (oil or gas[2]), depth, location, and reservoir attributes. These properties and the probability distributions used to characterize them are fundamental to understanding the results of the economic analysis.

To put the assessment into context it should be noted that past exploration in the study area has resulted in discoveries of more than 17 billion barrels of oil (BBO) and more than 35 TCF gas.[3] At the mean estimates, the assessed undiscovered oil is 3.98 BBO and 37.52 TCF gas (4.20 TCF associated gas and 33.32 TCF non-associated gas). Of the crude oil discovered about 12.4 BBO has already been produced (NRG Associates, 2004). Almost 90 percent of the assessed undiscovered oil is assigned to plays that have already had discoveries. In contrast, less than half of the undiscovered gas in gas accumulations was assigned to plays with discoveries.

Geologic Assessment Procedures

The geologic assessment used a play analysis paradigm. According to this paradigm (Baker and others, 1984), *a play is a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration patterns, timing, trapping mechanism, and hydrocarbon type*. Individual geologists were assigned known rock units within the study area. Based on geologic knowledge and results of exploration throughout Northern Alaska, each geologist defined and described the

[2] Accumulations are classified as either oil or non-associated gas on the basis of their gas-to-oil ratios. Those having at least 20,000 cubic feet of gas per barrel of crude oil were classified as non-associated gas; otherwise, the accumulations were classified as oil. Oil accumulations may have associated gas and gas accumulations may have natural gas liquids.

[3] The total liquids including oil, condensate, and natural gas liquids, are about 15 billion barrels produced and 7 billion barrels in remaining reserves (Bird and Houseknecht, 2005).

petroleum plays to be assessed. Play maps are shown in figure 1-1 after Garrity and others (2005). For each play, the assessment geologist assigned subjective probabilities to describe the play and prospect risks. He also assigned subjective probability distributions to characterize attributes of undiscovered conventional oil and gas accumulations. The minimum values of the attributes were calibrated so the smallest size of the assessed accumulations was 5 million barrels of oil (MMBO) recoverable or 100 billion cubic feet of gas (BCF) recoverable.

The geologic risk structure is modeled by assigning a *play probability* to each play. This probability is the likelihood that at least one accumulation of the minimum size (5 MMBO or 100 BCF gas recoverable) occurs. For hypothetical plays where the assessor was not confident of the occurrence of at least one accumulation of that threshold size, the play probability was computed as the product of the occurrence probabilities of the three play attributes of *charge, trap, and timing.*[4]

The geologists also assigned a *prospect probability* to each play that represented the probability that any randomly chosen oil or gas prospect contains technically recoverable resources at least as large as 5 MMBO or 100 BCF. Prospect probabilities for oil and gas were generally different. The prospect probability may be computed as the product of the occurrence probabilities assigned by the geologist to the prospect attributes of *charge, trap, and timing*. The geologists specified separate distributions for the number of oil and the number of gas prospects. The number of accumulations (meeting the threshold size) is then the product of the number of prospects, the play probability, and the prospect probabilities.

Data on reservoir attributes for plays were compiled from discoveries across the North Slope. Reservoir attribute[5] probability distributions were elicited from the geologists. The appropriate reservoir equation was applied to the simulated attribute values to compute the sizes of undiscovered accumulations. The assessors specified subjective probability distributions for the following reservoir attributes: (1) net reservoir thickness, (2) area of closure, (3) porosity, and (4) trapfill. The probability distribution for each attribute was determined by the geologist's choice of distribution shape, the distribution's minimum value (lower truncation point), the maximum value, median (50th fractile) value, and the value assigned to the upper 5th fractile.[6] Each assessor-specified subjective attribute and prospect number distribution was fit to a beta or modified beta distribution that was later used as a basis for numerical simulation.

In total, the assessment geologists defined and evaluated 24 petroleum plays for the Central North Slope Assessment (for boundaries see Garrity and others, 2005, for volume estimates see Bird and Houseknecht, 2005). Supporting studies were also prepared by the geologists and by other assessment team members to assist in characterizing play properties with probability distributions (Nelson, 1999; Kumar and others, 2002; Verma and Bird, 2005).

The sizes and numbers of oil and gas accumulations and volumes for individual plays were generated by the following simulation scheme. For each replication, i, $i=1,\ldots,N$, the play risk was evaluated. With each successful play, a variate for the risked number of oil (or gas) accumulations in the play was computed as the product of the oil (or gas) prospect probabilities and a random draw from the assessor's (subjective) distribution describing the number of oil (or gas) prospects. For each realization of the play represented by the n_{io} (oil) and n_{ig} (gas) accumulations, the probability distributions representing the reservoir attributes were sampled n_{io} and n_{ig} times, respectively, thus providing a size for each accumulation (see footnote 5). Ten thousand replications were generated to define the probability distribution describing each successful play.

In order to properly aggregate play results, that is, probability distributions, to higher levels such as the entire study area the covariance among plays must be specified. Pair wise dependencies of the characteristics of charge, trap, and timing were assigned between plays. The ranked dependencies (high, medium, low) were transformed into a measure of covariance between plays. Details of the aggregation procedure are discussed in Schuenemeyer (1999).

Characteristics of the Assessed Technically Recoverable Resources

Estimates of technically recoverable oil in undiscovered accumulations in the Central North Slope area range from 2.57 BBO to 5.85 BBO with a mean of 3.98 BBO. The ranges in estimated volumes correspond to the 95 percent probability (that is, a 19 in 20 chance of occurrence) and the 5 percent probability level (1 in 20 chance), respectively. Similarly, the 95th fractile and 5th fractile estimates of recoverable (non-associated) gas in undiscovered gas accumulations ranged from 23.9 TCF to 44.9 TCF with a mean of 33.3 TCF.

[4] The seven plays considered hypothetical are: Beaufortian Upper Jurassic Topset East, Beaufortian Clinoform, Ivishak Barrow Flank, Endicott, Lisburne Barrow Flank, Beaufortian Structural, and Ellesmerian Structural.

[5] For each oil accumulation, for example, the simulated reservoir-attribute values included the following: (1) net reservoir thickness, t, in feet, (2) area of closure, ac, in thousands of acres, (3) porosity, p, as a decimal fraction, (4) trapfill, f, as decimal fraction and (5) hydrocarbon pore space, hps, (as a function of p and S_w where S_w is water saturation as a decimal fraction). The assessors provided estimates of the oil recovery factor, rf, as a fraction of the in-place resources that are recoverable and the formation volume factor, fvf_o, was calculated as a function of trap depth and API gravity. Oil accumulation size, szo, in millions of barrels was calculated with the following equation:

$$szo = 7.758(t)(hps)(f)(rf_o)(ac)/(fvf_o) \quad \text{where} \quad hps = p(1-S_w).$$

For gas accumulations the size, szg, in billions of cubic feet is computed as:

$$szg = 4.356(t)(hps)(f)(rf_g)(ac)(fvf_g)*10^{-8}$$

where the recovery factor and formation volume factor were specifically defined for gas accumulations.

[6] Fractiles denote the fraction of area under the probability density curve to the right of the fractile value.

Table 1. Mean value of undiscovered technically recoverable volumes of conventional oil, natural gas, and natural gas liquids (NGL) in the Central North Slope study area by play as of 2005.

[BBO, billions of barrels of oil; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids]

Number	Play name	Oil accumulations			Gas accumulations	
		Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
1	Brookian Clinoform	1.63	1.82	0.03	6.44	0.08
2	Brookian Topset	0.44	0.34	0.00	0.58	0.01
3	Beaufortian Upper Jurassic Topset East	0.00	0.00	0.00	0.14	0.00
4	Beaufortian Upper Jurassic Topset West	0.15	0.14	0.00	0.29	0.00
5	Beaufortian Clinoform	0.11	0.17	0.00	0.96	0.01
6	Beaufortian Kuparuk Topset	0.18	0.14	0.00	0.54	0.01
7	Beaufortian Cretaceous Shelf Margin	0.00	0.00	0.00	0.60	0.01
8	Triassic Barrow Arch	0.40	0.50	0.01	0.00	0.00
9	Ivishak Barrow Flank	0.00	0.00	0.00	0.39	0.01
10	Endicott	0.00	0.00	0.00	0.50	0.01
11	Endicott Truncation	0.08	0.09	0.00	0.00	0.00
12	Franklinian	0.01	0.02	0.00	0.00	0.00
13	Lisburne Barrow Arch	0.13	0.13	0.00	0.00	0.00
14	Lisburne Barrow Flank	0.00	0.00	0.00	1.04	0.01
15	Kemik-Thompson	0.25	0.45	0.02	2.31	0.03
16	Basement Involved Structural	0.02	0.01	0.00	3.02	0.04
17	Beaufortian Structural	0.01	0.01	0.00	2.12	0.02
18	Brookian Clinoform Structural South	0.02	0.01	0.00	2.55	0.03
19	Brookian Clinoform Structural North	0.14	0.15	0.00	0.25	0.00
20	Brookian Topset Structural South	0.02	0.01	0.00	2.38	0.02
21	Brookian Topset Structural North	0.26	0.11	0.00	0.29	0.00
22	Thrust Belt Triangle Zone	0.05	0.03	0.00	3.84	0.04
23	Thrust Belt Lisburne	0.07	0.07	0.00	3.59	0.04
24	Ellesmerian Structural	0.00	0.00	0.00	1.50	0.02
Total		3.98	4.20	0.09	33.32	0.39

Note: Totals may not equal sum of components due to independent rounding.

Table 1 shows the mean play level estimates and the total mean estimates of oil, associated gas, associated gas NGL, non-associated gas, and non-associated gas NGL. One play, the Brookian Clinoform play, accounts for 41 percent of the total oil assessed. This play, along with the Brookian Topset and Triassic Barrow Arch account for 62 percent of total oil assessed. The Brookian Clinoform play accounts for 19 percent of the gas in undiscovered gas accumulations. Four plays, the Brookian Clinoform, Thrust Belt Triangle Zone, Thrust Belt Lisburne, and Basement Involved Structural, account for just over half of the assessed gas in undiscovered gas accumulations (table 1). Tables 1-1 through 1-4 of Appendix 1 show volumes of hydrocarbons by play for the aggregated 95th and 5th fractile estimates for oil in oil accumulations and for gas in gas accumulations, respectively.

Figure 3 shows the size-frequency distributions for oil accumulations for the aggregated 95th, mean, and 5th fractile oil volume estimates. Similarly, figure 4 shows size-frequency distributions of non-associated gas with the aggregated 95th, mean, and 5th fractile estimates of gas volumes in gas accumulations, respectively. Tables 2 and 3 show the cumulative percentages of the estimated volumes by accumulation size class for the aggregated estimates, from the largest to smallest size class. At the 95th fractile estimate there were 81 oil accumulations and 77 gas accumulations assessed. Similarly, at the mean 106 oil and 93 gas accumulations were assessed and at the 5th fractile estimate 133 oil and 106 gas accumulations were assessed.

Based on the size-frequency distributions (fig. 3) associated with the mean estimate of undiscovered technically recoverable oil, only 0.96 BBO (24 percent) of the assessed oil is assigned to accumulations of at least 128 MMBO[7] (table 2). At the 95th and 5th fraciles estimates, only 18 percent (0.46 BBO) and 32 (1.89 BBO) percent of the assessed oil were assigned to accumulations of at least 128 MMBO. Although the total volume of oil assessed is significant, most of the oil was assigned to accumulation sizes that are either only marginally economic or uneconomic under historical prices. Commercial values will depend on proximity to existing drill pads and production fluid processing facilities.

Figure 4 shows the size-frequency distribution of the assessed undiscovered gas accumulations. The magnitude of the total assessed gas in gas accumulations is significant. At the mean estimate, 10.6 TCF (32 percent of the non-associated gas assessed) was assigned to accumulations of at least 768

[7] There are two North Slope discoveries, Badami and Northstar, with recoverable oil smaller than 200 million barrels that have been commercially developed as stand-alone fields. For stand-alone fields, the size class from 128 to 256 million barrels includes commercial, marginally economic, and uneconomic fields depending on location.

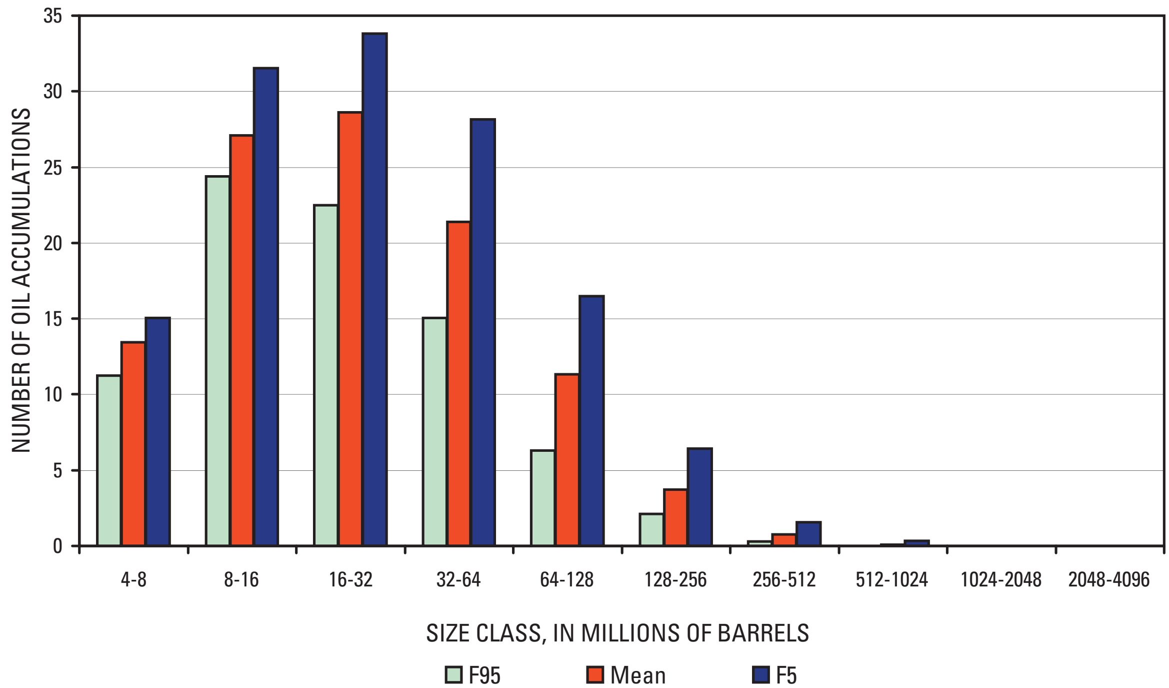

Figure 3. Size-frequency distribution of undiscovered conventional oil accumulations associated with the 95th fractile estimate, the mean estimate, and the 5th fractile estimate of the assessed distribution of technically recoverable undiscovered oil for the Central North Slope study area.

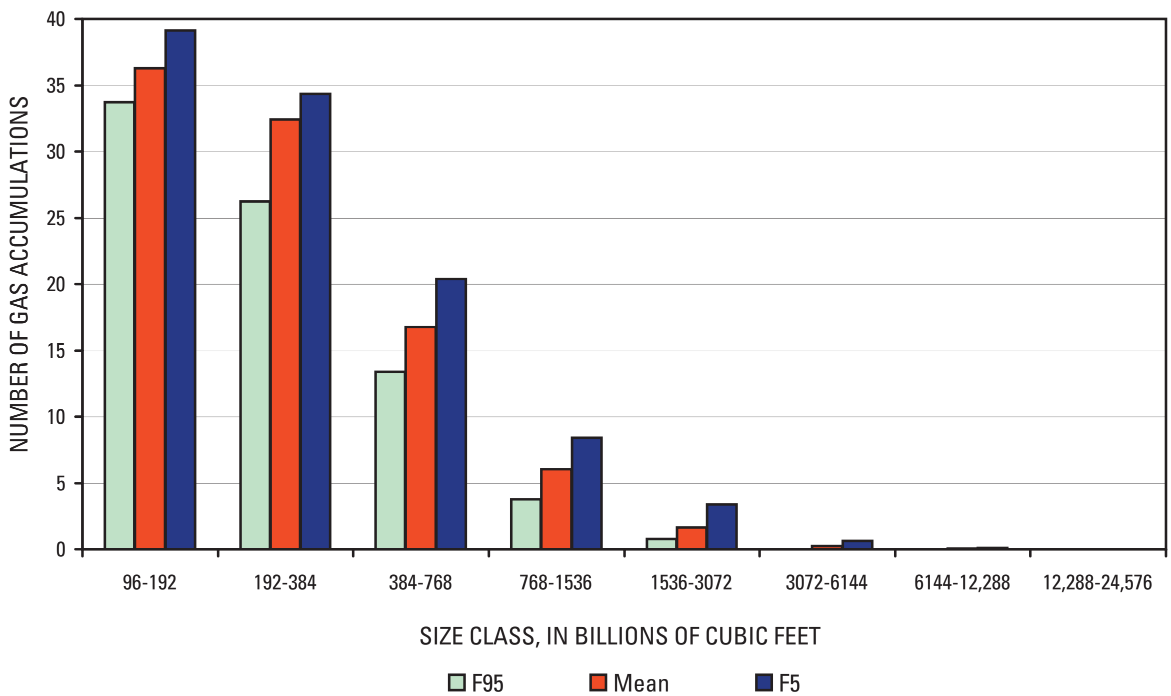

Figure 4. Size-frequency distribution of undiscovered conventional gas accumulations associated with the 95th fractile estimate, the mean estimate, and the 5th fractile estimate of the assessed distribution of technically recoverable undiscovered non-associated gas for the Central North Slope study area.

BCF. At the 95th fractile estimate about 5.2 TCF (21 percent of non-associated gas assessed) is assigned to accumulations of at least 760 BCF and at the 5th fractile estimate 19.1 TCF (43 percent of non-associated gas assessed) is assigned to accumulations of at least 768 BCF. Although large volumes of gas in northern Alaska currently have no commercial markets, the magnitudes of the assessed volumes and associated size-frequency distribution of undiscovered accumulations could be helpful to those planning a future gas transportation system.

Table 2. Cumulative percentage distribution of estimated undiscovered technically recoverable oil: Central North Slope study area by oil accumulation size class.

[MMBO, millions of barrels of oil; BBO, billions of barrels of oil]

Size class number	Oil accumulation size class (MMBO)	Cumulative percent of total oil estimate[1] F95	Mean	F05
15	512–1,024	0	2	4
14	256–512	4	9	13
13	128–256	18	24	32
12	64–128	39	49	57
11	32–64	66	73	79
10	16–32	86	90	92
9	8–16	97	98	98
8	4–8	100	100	100

[1]The 95th fractile estimate of total oil is 2.57 BBO, the mean estimate is 3.98 BBO, and 5th fractile estimate is 5.92 BBO.

Table 3. Cumulative percentage distribution of estimated undiscovered technically recoverable non-associated gas: Central North Slope study area by gas accumulation size class.

[BCF, billions of cubic feet of gas; TCF, trillions of cubic feet of gas]

Size Class Number	Gas accumulation size class (BCF)	Cumulative percent of total non–associated gas estimate[1] F95	Mean	F05
16	6,144–12,288	0	1	2
15	3,072–6,144	0	3	7
14	1,536–3,072	6	13	23
13	768–1,536	22	32	43
12	384–768	51	58	67
11	193–384	80	85	88
10	96–192	100	100	100

[1]The 95th fractile estimate of total non-associaated gas is 23.9 TCFG, the mean estimate is 33.3 TCFG, and 5th fractile estimate is 44.9 TCFG.

The size distributions show the largest part of the assessed resources in moderate size accumulations.

The assessment results also show it is not likely that a gas accumulation will be developed only for its liquids. The data in table 1 allow computation of the natural gas liquids (NGLs) to gas ratios for each play, that is, the number of barrels of liquids per million cubic feet of gas. These values range between 4.9 barrels to 13.1 barrels of NGLs per million cubic feet of gas. At 13.1 barrels per million cubic feet, a 2.0 TCF gas accumulation could have as much as 26.2 million barrels of NGLs. Gas prone areas are generally outside the region of existing infrastructure. The 26 million barrels of liquids is probably insufficient for stand-alone commercial development.

At the mean estimate, only 5 percent of the oil was assigned to the 0 to 5000 feet depth interval, 66 percent of the oil was assigned to depths between 5 and 10 thousand feet, and 27 percent to depths between 10 and 15 thousand feet. For undiscovered non-associated gas, only 7 percent was assigned to the 0 to 5000 feet depth interval, 26 percent to the 5 to 10 thousand feet depth interval, 43 percent to the 10 to 15 thousand feet depth interval and 23 percent to horizons deeper than 15 thousand feet.

The geologists also assessed the expected quality of the undiscovered resources in terms of the oil gravity and contaminants of oil and gas. The weighted average gravity for the assessed undiscovered oil was about 36 degrees API. The assessed oil gravity is lighter than oil produced from the Prudhoe Bay and Kuparuk River fields.

Only minor amounts of oil and gas were assigned concentrations of sulfur, carbon dioxide, or hydrogen sulfide that would require special remedial action. The overall (volume weighted average) recovery factor for oil is 36 percent. Similarly, the recovery factor for gas from non-associated gas accumulations is 70 percent. The oil recovery factor assumes reservoir pressure maintenance with gas and water injection but not tertiary recovery.

To summarize, the characteristics of the technically recoverable oil most important to the economic analysis are the volumes of oil, the oil accumulation-size distribution, depth of the oil, and geographical location of the resources. Distributions in figure 3 and supporting data (table 2) show that most of the assessed oil was assigned to accumulations of very modest sizes so that proximity of the assessed accumulations to operating fields will be important for commercialization. Although the barrel-of-oil equivalent sizes associated with the gas were somewhat larger than oil, most of the assessed gas was assigned to plays that are outside the area where infrastructure now exists.

ECONOMIC APPROACH

Data

Data from the assessment simulations include attributes that determine calculated accumulation size. The attributes include area, net pay thickness, depth, porosity, and recovery factor. The oil formation volume factor and gas formation volume factors were computed from depths and empirical estimated relationships (Verma and Bird, 2005). Attributes used to compute accumulation size (see footnote 5) were applied to estimate average production well recovery. Economic cost data were drawn from earlier economic studies of the Arctic National Wildlife Refuge (ANWR) 1002 Area and elsewhere on the North Slope (National Petroleum Council 1981a; 1981b; Han-Padron Associates, 1985; Young, and Hauser, 1986; Thomas and others, 1991; J. Broderick, Bureau of Land Management, written communication, 1992; Thomas and others, 1993; Craig, 2002). Data on recent cost trends were obtained from the Annual Joint Association Survey (American Petroleum Institute. 1997- 2005), Redman, (2002), Erwin, and others (2002), Craig (2002) and Craig (James Craig, Minerals Management Service, written communication, 2005) were used to update configurations and costs of posited production technologies.

General Assumptions and Scope of Analysis

The economic analysis provides the costs of transforming undiscovered resources into discovered commercially producible volumes of hydrocarbons. The results are presented as incremental cost functions that include costs of finding, developing, producing, and transporting to market resources in currently undiscovered accumulations.

The cost functions are not the same as the economist's market price-supply predictions, because at any given price the oil and gas industry will allocate funds over a number of provinces and sources of supply in order to meet market demand at lowest costs. An observed price-supply relationship represents the culmination of numerous supplier decisions over many projects and regions. Incremental cost functions represent costs that are computed independently of activities in other areas.

The incremental cost functions are time independent and should not be confused with the firm supply functions that relate marginal cost to production per unit time period. Because of the time-independent nature of the incremental cost functions and the absence of market demand conditions in the analysis, user costs or the opportunity costs of future resource use are not computed. However, the incremental cost functions and the data which underlie the functions are often used in market supply models.

Economic models are abstractions that characterize real economic systems and are typically just detailed enough to roughly approximate the outcomes of interactions between economic agents. Only the general direction and the approximate magnitude of the reaction of the system to price or cost change can be modeled.

Play analysis does not provide specific locations for undiscovered oil and gas accumulations, so generic costs were estimated. The estimates of transportation costs of oil from fields to the Trans-Alaska Pipeline System (TAPS) required partitioning the study area into sub-areas (fig. 2). Furthermore, much of the oil was assigned to accumulations that traditionally were too small for stand-alone field development, so the evaluation of commercial potential considered the opportunities for facilities sharing. Additional location information was obtained from the assessors to delineate oil prone and gas prone areas within the plays. The assessed oil and gas accumulations in each play were allocated to sub-areas described in Appendix 2.

Although there is at least 25 TCF of gas in operating oil fields located in the Central North Slope study area, there is no pipeline to bring this gas to market. There have been several studies (for example, see Thomas and others, 1996) that examine options for gas development. The State must pass enabling legislation to allow a gas pipeline to be built from the North Slope on State lands to allow use of the TAPS right of way. The Alaska natural gas transportation system (ANGTS) was originally designed to start near TAPS Pump Station 1, proceed to Fairbanks along the TAPS right of way, and then to continue southeast to Caroline, Alberta (fig. 5).

In May 2002, the "producers" (BP, ExxonMobil, and ConocoPhillips, 2002) announced the results of a feasibility study for shipping gas by pipeline to the conterminous lower 48 states using the ANGTS route.[8] The costs and tariff calculation for the ANGTS route used here are based the producers' study. Appendix 3 provides a summary statement of the features of the system.

Because of uncertainty regarding the timing, cost, and access to the gas pipeline for newly discovered natural gas, the economic analysis was based on three scenarios. It is expected that the ANGTS gas line would take 10 years to complete from the time the decision is made to begin application and environmental studies. Scenario 1 assumes no gas pipeline is built, so for planning purposes non-associated gas is valued at zero. Scenario 2 assumes that the access will occur ten years from the time of discovery and Scenario 3 assumes that access will not occur until 20 years after discovery. For Scenarios 2 and 3, the expected net present value of commercial gas finds are discounted for the time of the lag between discovery and the startup. To keep the analysis simple, it is assumed that the owner waives lease rental costs for the delay period between discovery and development.

[8] The "producers' study" also estimated cost for another route that started from Pump Station 1, traverses due east under the Beaufort Sea and then travels onshore south through the Mackenzie Delta. The costs of both systems were virtually the same.

Figure 5. Map showing the original route for the proposed Alaska Natural Gas Transportation System (ANGTS) in relation to the Trans-Alaska Pipeline System (TAPS) for crude oil transportation to the port of Valdez.

Economic Assumptions

It is assumed for this study that industry will not invest unless the full operating costs, taxes, capital, and cost of capital could be recovered. Values of physical and economic variables are assumed to be known with certainty by decision makers. It was assumed that all of the Central North Slope study area is available to exploration for oil and gas.

Economic Parameters

Costs used in this analysis represent those prevailing in the calendar year 2003. *Calculations were in terms of constant real dollars.* The discounted cash flow (DCF) analysis was specific to an individual discovery (project) and ignored minimum income taxes and tax preference items that might be important from a corporate accounting stance. A 12 percent after-tax required rate of return was assumed. Federal income tax provisions are as of the year 2003.[9]

The Alaska State taxes include the severance, income tax, and ad valorem tax (property tax). The severance tax depends on field and well productivity (see Appendix 4 for details). Although the nominal State income tax rate is 9 percent, the effective tax rate is set by a complex formula based on the individual company's production and sales. For planning purposes, State agencies use a rate of 1.4 to 3.0 percent of net income. An effective tax rate of 3 percent is used here. The State's ad valorem tax is an annual charge equivalent to 2 percent of the economic value of equipment, facilities, and pipelines. The Federal corporate tax rate used in the project analysis was 35 percent. A one-eigth royalty was assumed to be paid to the State of Alaska or the owner. This study assumed $0.25 per barrel of produced oil is set aside by operators to fund abandonment costs.[10]

This report is based on the technology and cost data of the 2003 base year. It focuses on commercial new discoveries that are in the price range of $15 to $55 per barrel in 2003 dollars. It has been our standard practice to use as the model price ceiling two times the average price of crude oil in the base year for technology and cost. Average crude oil prices during 2003 were just over $27 per barrel, so the ceiling price used for this study is $55 per barrel in 2003 dollars. During the summer of 2005, spot oil prices exceeded the high end of the price range; that is, they exceeded $60 in 2005 dollars. If such prices are sustained over the long term, new technologies would emerge that would vitiate the geologic estimate of technically recoverable by increasing the play recovery factors assumed by the geologists.

The oil price discussed is the landed U.S. lower 48 states' West Coast price rather than well-head price. It also represents a price at the market that is sustained, rather than an erratic spot price. The market price of natural gas liquids was assumed to be 75 percent of the per barrel price of crude oil. Though graphs may show additions to reserves for the higher prices, *if prices rise substantially and rapidly, it is unrealistic to assume that constant real costs would hold.* Historical experience has shown that oil and gas price increases lead to escalation in industry capital and operating costs (Kuuskraa and others, 1987). Finally, for scenarios where non-zero gas

[9] Based on the 1986 Tax Reform Act, 30 percent of development well drilling cost is classified as tangible cost and therefore capitalized over 7 years. Of the remaining 70 percent of drilling cost (that is, the intangible drilling costs), 30 percent is depreciated over 5 years and the remaining 70 percent is expensed immediately.

[10] Similarly, for gas accumulations a charge of $0.05 per mcf was taken to fund abandonment.

prices are used in the valuation of potential gas discoveries, gas is valued at the market, at two-thirds the value of oil based on calorific heating value or British Thermal Units (BTU). In recent years market prices for natural gas have been very volatile ranging mostly from $3 to $8 per mcf and in some-places even higher. However, because of the sheer size of the investment required for pipeline construction, the owners are likely to require long term contracts of shippers and buyers, so that long-term contract prices are the relevant series. Associ-ated gas in new oil discoveries is not valued at the market, but assumed to be stripped of liquids and re-injected into the oil accumulation for pressure maintenance.[11]

Transportation, Infrastructure, and Location Assumptions

Oil produced in Northern Alaska is shipped via the Trans-Alaska Pipeline System (TAPS) to the Port of Valdez in southern Alaska for ocean tanker transport to market. In 1988, the TAPS oil flow averaged 2.0 million barrels per day. For 2004, the TAPS flow rate averaged slightly less than 1 million barrels per day of oil and natural gas liquids. There currently may be one million barrels per day of unused capacity.

TAPS tariff rate and marine transport rate to market are projected semi-annually by the Alaska Department of Rev-enue. The marine transport rate represents transport cost weighted by projected sales volumes from Valdez to a set of destinations which include the U.S. lower 48 West Coast, the Far East, and the U.S. mid-continent region. These rates are projected on an annual basis to 2020 (Alaska Department of Revenue, 2004). The average projected TAPS tariff starting in 2006 through 2020 is $3.54 per barrel and similarly, the marine transport cost is $2.03 per barrel. It is assumed that produced oil is transported from the field through pipeline infrastructure to TAPS.

For the scenarios that evaluate natural gas, it is assumed that gas is transported from the discovery to the gas condition-ing plant located near Pump Station 1 of TAPS. Based on the data presented by BP, ExxonMobil and ConocoPhillips (2002), for the southern route, the maximum transport tariff, including the conditioning, to market (adjusted to 2003 dollars) is set at $2.94 per mcf.

To more accurately estimate transport costs, the study area was partitioned into three sub-areas. Distances and the associated pipeline costs for field feeder lines and regional pipelines to transport oil or non-associated gas to Pump Sta-tion 1 area of TAPS were computed. The *north sub-area* includes the lands under State waters in the Beaufort Sea and as far south onshore as 70° N. The *middle sub-area* extends south from 70° N to 69° N, and the *south sub-area* extends from 69° N to the southern edge of the assessment area (fig. 2).[12] Table 2-1 in Appendix 2, shows the sub-area allocation percentages by play. The allocations to sub-areas were based on the play outlines and supplemental information provided by geologists relating to the identification of gas and oil prone areas on plays. A centroid for oil and a centroid for gas within each sub-area were located based on the play data. Transport costs to the Pump Station 1 area were computed using the dis-tance from each sub-area product centroid to Pump Station 1.

Table 4 shows the volumes of the aggregated assessed oil and gas when allocated to the economic sub-areas. The table was derived from tables 1-1 through 1-4 in Appendix 1 and table 2-1 in Appendix 2. Tables 1-1 and 1-3 show the volumes-by-play that constitute the aggregated 95th and 5th oil fractile estimates along with the concomitant non-associ-ated gas volumes and by-product volumes. Tables 1-2 and 1-3 shows the 95th and 5th non-associated gas fractile estimates along with the concomitant oil volumes and by-product vol-umes. Table 2-1 shows the sub-area allocation percentages for each play. Figures 2-1 and 2-2 in Appendix 2 show accu-mulation size distributions for each sub-area. The sub-area accumulation size distributions and volume estimates were the basic resource data used in the economic analysis. For sce-narios where both oil and gas are economic, the cost function for oil depends, in part, on the non-associated gas assessment and similarly the cost function for non-associated gas depends in part on the oil assessment.

Table 4 shows that the north sub-area at the mean accounts for just over 52 percent of the oil volume, the middle sub-area accounts for 43 percent the volume of oil while the south sub-area accounts for about 4 percent of the oil. At the mean estimates for undiscovered non-associated gas, the north sub-area was assigned less than 1 percent, the middle sub-area almost 60 percent and the south sub-area was assigned the remaining 40 percent. The middle sub-area is assigned sub-stantial volumes of both oil and non-associated gas.

Oil Transportation

For the north sub-area, the centroid for the oil was located about 9 miles from TAPS Pump Station 1. The average distance for transporting the newly discovered oil in the north sub-area was assumed to be 9 miles. The distance between the oil centroid of the middle sub-area and Pump Station 1 is 35 miles. A regional pipeline was assumed to collect the oil at the centroid location and feeder lines (averaging 15 miles in length) were assumed to transport the produced oil from the field to the regional pipeline. Although the volume of oil assigned to the south sub-area is small, the cost of transporting the oil 147 miles for each field size category to Pump Station 1 was computed and used in the analysis.

[11] Associated gas could be recovered for sale when oil is depleted. How-ever, the discounting for delay in sales would reduce its value so at the time of discovery it would not be a significant factor in the decision to develop the discovery.

[12] The north sub-area accounted for 17 percent of the total acreage in the Central North Slope study area. The middle sub-area accounted for 41 percent and the south sub-area accounted for 42 percent of the total study area acre-age. Study area is 14.6 million acres.

Table 4. Volumes of the aggregated oil, gas, and natural gas liquids (NGL) allocated to the economic sub-areas. Total study area volumes relate to 95th and 5th fractile and mean value estimates of the oil and non-associated gas, associated by-product volumes, and concomitant resource volumes, that is, non-associated gas volumes corresponding to oil fractile estimates and concomitant oil volumes corresponding to non-associated gas fractile estimates.

[Asc., associated; Non-asc., non-associated; BBO, billions of barrels of oil; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids; Table is derived from data presented in tables 1-1 through 1-4 in Appendix 1 and table 2-1 in Appendix 2.]

Sub-area	Oil Accumulations: Oil (BBO)	Oil Accumulations: Asc. gas (TCF)	Oil Accumulations: NGL (BBL)	Gas Accumulations: Non-asc. gas (TCF)	Gas Accumulations: NGL (BBL)
Allocation of volumes at the *95th fractile oil* estimate (2.57 BBO)					
North	1.35	1.51	0.03	0.3	0.00
Middle	1.12	1.13	0.02	18.8	0.22
South	0.09	0.08	0.00	11.8	0.14
Total for study area	2.57	2.72	0.06	30.9	0.36
Allocation of volumes at the *5th fractile oil* estimate (5.85 BBO)					
North	3.04	3.45	0.08	0.3	0.00
Middle	2.60	2.34	0.05	21.4	0.25
South	0.21	0.14	0.00	14.6	0.17
Total for study area	5.85	5.92	0.13	36.3	0.42
Allocation of volumes at the *95th fractile non-associated gas* estimate (23.94 TCF)					
North	1.79	2.01	0.05	0.2	0.00
Middle	1.61	1.48	0.03	14.5	0.17
South	0.07	0.06	0.00	9.2	0.11
Total for study area	3.47	3.55	0.08	23.9	0.28
Allocation of volumes at the *5th fractile non-associated gas* estimate (44.86 TCF)					
North	2.47	2.85	0.07	0.2	0.00
Middle	2.13	2.08	0.04	24.3	0.28
South	0.19	0.14	0.00	20.3	0.24
Total for study area	4.80	5.07	0.11	44.9	0.52
Allocation of volumes at the *mean oil and mean non-associated gas* estimates (3.98 BBO and 33.32 TCF)					
North	2.10	2.38	0.05	0.2	0.00
Middle	1.75	1.71	0.04	19.7	0.23
South	0.14	0.11	0.00	13.4	0.16
Total for study area	3.98	4.20	0.09	33.3	0.39

Note: Totals may not equal sum of components due to independent rounding.

Gas Transportation

The volume of non-associated gas assigned to the north sub-area is small, but was evaluated by assuming the average distance from the new non-associated gas discoveries in the north sub-area to the gas conditioning plant is 25 miles. From the middle sub-area, a high pressure 1 bcf/day regional gas line is assumed to transport gas and NGLs 59 miles from the location of the sub-area's gas centroid to the conditioning plant near Pump Station 1. Similarly in the south sub-area, a 1 bcf/day high pressure regional gas line was assumed to transport gas 137 miles from the sub-area's gas centroid to the conditioning plant near Pump Station 1. Feeder lines to the regional collector/compression system were assumed to average 15 miles for the middle sub-area and 20 miles for the south sub-area. Appendix 3 describes the transportation cost analysis in more detail.

Exploration and Development Costs

North Slope exploration and field development procedures are designed to accommodate special requirements in an arctic environment. Wildcat drilling typically occurs in the winter when temporary ice roads, ice pads, and ice airstrips can be constructed to support drilling activities. After the ice melts there is generally no sign of the previous winter's activity. Seasonal instability of the permafrost requires construction of gravel pads to support production drilling rigs, wells, and facilities. Production wells are drilled directionally from the pads to target depths and lateral locations. Gravel drilling pads commonly accommodate as many as 40 well collars[13] spaced at 10 foot intervals along with production equipment. Sidetrack and multilateral drilling of two or more wells using a single well collar enable the maximum utilization of individual drilling pads.

The remoteness of the targets, the climate, and the absence of infrastructure result in high initial exploration and development costs. With stand-alone field development, produced oil is processed at the field's central processing facility and the final product is transported from the periphery of the field to TAPS. Because commercial North Slope discoveries are typically very large and provide large payoffs in terms of the volumes of oil that incremental increases in recovery can yield, operators typically introduce technological innovations early. For example, the application of extended reach drilling has allowed production wells access to distant reaches of the reservoir, sometimes eliminating the need for additional drill pads or allowing satellite pool development from existing drill pads. Because of this technology, it was assumed that any offshore accumulation in State waters can be developed from onshore or with shallow-water drilling pads.[14]

Field development costs include well drilling and completion costs and the cost of facilities. Actual field development costs depend on site-specific characteristics of prospects. In the process of developing generic cost functions, a number of simplifying assumptions were made to keep the economic analysis tractable. The assessed undiscovered accumulations were first grouped into accumulation size categories (table 2 provides the field size classes) and into 5000-foot depth intervals. The analysis also included the costs of vertical delineation wells for each accumulation evaluated. Development cost estimates for a representative accumulation for each size and depth class were estimated and tested against an economic screen to determine whether all the accumulations in the size and depth category were commercially developable.

Exploration Costs

Costs of geologic and geophysical studies to site exploration wells after a lease is acquired are computed as part of the costs of wildcat wells. Wildcat well drilling costs were assumed to be twice the cost of drilling production wells in the Central North Slope. Non-drilling exploration expenditures include geologic and geophysical data collection after lease acquisition, scouting costs, and overhead charges associated with land acquisition. Non-drilling exploration expenditures,[15] exclusive of lease bonuses, were assumed to amount to 50 percent of the wildcat well drilling costs (Vidas and others, 1993) and were also added to wildcat exploration expenditures.[16] Exploration was evaluated in increments of 10 wildcat wells. Actual exploration and development costs will depend on site-specific characteristics of the prospects. Because play analysis does not provide specific locations, generic costs were used. Costs are presented in Appendix 3.

Development Costs for Crude Oil Accumulations

The two principal field development cost categories are (1) drilling and completion cost of production and injection wells and (2) facilities' costs. Introduction of new procedures, materials and technology target these two categories to reduce cost and /or increase productivity. Because of existing infrastructure in the Central North Slope, opportunities exist for facility sharing. The use of horizontal wells for all development at the Alpine field was designed to enhance well productivity and thus enabled the commercial development of an accumulation with a relatively thin pay interval by North Slope standards (Gingrich and others, 2001). Greater well productivity reduces the required number of wells for field development and also reduces the size and/or number of drilling pads.

The number of required development wells assumed that the conventional drainage area was 160 acres. Well recovery for the accumulation was based on the simulated reservoir attributes (see footnote 5 where area is now 160 acres). Details of the vertical well drainage area conversion to horizontal wells configurations along with the procedure of drilling cost estimation are discussed Appendix 3.

Facilities include drill pads, flow lines from drilling sites, the central processing unit, and infrastructure required for housing workers, including amenities. Facilities design and costs depend on peak fluid flow rates and ultimately on the field size. Although little information is in the public domain, a version of the Northstar development plan, including development cost estimates, was submitted by BP to the State of Alaska for evaluation with its request for relief of profit sharing provisions of the State lease (BP, 1996). With this information and with inferred facilities cost estimates from published reports for other fields under development, a cost relationship specified investment cost per barrel as a function of expected accumulation recovery.[17]

As of the end of 2004, the eight oil fields developed on a stand-alone basis in northern Alaska are Prudhoe Bay, Kuparuk River, Lisburne, Milne Point, Endicott, Badami, Northstar,

[13] The well collar is at end of the steel well casing that protrudes at the surface of the drill pad.

[14] Maximum water depth is about 40 feet at the State-Federal offshore boundary according to USGS topographic maps of the Harrison Bay, Beechey Point, and Flaxman Island Quadrangles (Ken Bird, U.S. Geological Survey, written communication, 2005).

[15] For rank wildcat exploration, the 3-D seismic expense may range from 750 thousand to 1 million dollars per prospect (David Houseknecht, U.S. Geological Survey, written communication, 2005).

[16] *For example*, suppose a development well drilled to a depth of 7500 feet in the Central North Slope costs 3.6 million dollars. Total cost for a comparable wildcat well where non-drilling costs amount to 50 percent of drilling cost, is about 11 million dollars (that is, the product of 3.6 (base well) x 2 (wildcat factor) x 1.5 (non-drilling factor)). Some adjustments were made that reduced exploration drilling costs for the extensively explored north sub-area.

[17] The cost relation was similar in form to those presented by the National Petroleum Council (1981b) and Young and Hauser (1986).

and Alpine. Other developed fields and pools have produced fluids (oil, gas, and water) transported to the central processing unit of a nearby stand-alone field for separation. Point McIntyre, Niakuk, North Prudhoe Bay, and West Beach all use the central processing facilities of the Lisburne field. Prudhoe Bay production facilities process production from Midnight Sun, Aurora, Polaris, Borealis, and Orion. The Kuparuk River field also processes production from Tabasco, Tarn, Meltwater, and Palm. Thus far, all of the satellite and parent fields have had common ownership.

The cost reduction from facility sharing depends on physical production configurations and on the relative bargaining strength of the satellite owner in comparison to the central processing facilities owner. The State of Alaska recognizes it is important to reduce capital barriers to attract entry of additional firms to the North Slope. The State has only recently begun to study the potential regulatory issues of fair treatment of new entrants (Kaltenbach and others, 2004). It was assumed that facilities sharing would, on average, result in a 30 to 50 percent reduction in facilities investment costs and that some of that savings would be captured by the facility operator through additional charges beyond operational costs (Thomas and others, 1993) (see Appendix 3).

Production Profiles and Operating Costs for Crude Oil Accumulations

The oil accumulation production profiles posited in this study were based on historical experience from recent discoveries and from submissions of information to the State of Alaska Oil and Gas Conservation Commission for support of the operator's development plans for new discoveries.

Oil field operating costs include labor, supervision, overhead and administration, communications, catering, supplies, consumables, well service and workovers, facilities maintenance and insurance, and transportation. Some costs, such as well workover costs have declined because of the introduction of new materials such as coiled tubing (Oil and Gas Journal, 1994; Blunt and others, 1993). Annual field operating costs were estimated as a function of hydrocarbon and water fluid volumes and number of operating wells (Craig, 2002). The fluid volumes were projected annually using field production forecasts and the water cut presented as figure 3-1 in Appendix 3 (Thomas and others, 1991). As fields are depleted the water cut increases, thus increasing the per barrel cost of oil processed.

Development Costs for Gas Accumulations

One purpose of the economic analysis of the undiscovered gas accumulation was to investigate the effects, if any, that a potential gas market might have on oil exploration. Without any historical or detailed technical information, we rely on the estimates of equipment and operating costs used in the 2003 National Petroleum Council study, "Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy" (National Petroleum Council, 2003).

The costs used in the 2003 National Petroleum Council study assumed gas wells are conventional and that gas well drilling costs are similar to oil drilling costs. Here, the number of wells required to produce a new gas discovery was computed assuming a well drainage area of 640 acres (National Petroleum Council 1981a, 1981b).

Facilities include gas dehydration and if required, acid removal, but not a natural gas liquids plant. Natural gas liquids are transported with the gas through field feeder lines and also with the high pressure collector/regional lines that transport gas from the middle and south sub-areas to the gas processing facility near Pump Station 1.

Production Profiles and Operating Costs for Gas Accumulations

The production profiles of more recent discoveries in the Gulf of Mexico served as analogues for North Slope gas production. Development of a gas discovery is delayed until its gas is marketable, that is, deliverable to market via a pipeline. Production data from the NRG Associates "Significant oil and gas fields of the United States" (2004) recent Gulf of Mexico fields were analyzed to determine the relationship between peak production of gas fields and their known recoverable gas by field size categories. With these peak production rates as a function of estimated field size, it was assumed field production would be held constant until 75 to 80 percent of the field's original reserves is produced. The phase of constant production is then followed by a rapid decline at a rate of 24 percent per year. Annual production costs were based on the National Petroleum Council (2003) study. Unit costs increase rapidly after production decline occurred.

Economic Justification for Computations

Size, depth, regional costs, and co-product ratios determine whether a discovery will be commercially developable. A new discovery is *commercially developable* if the after-tax net present value of its development is greater than zero. The algorithm that calculated incremental costs used the predicted size and depth distribution of undiscovered fields (at the sub-area level) to compute quantities of resources that are commercially developable at various prices.

To compute finding costs, the geologic assessment is coupled with a finding rate model (Attanasi and Bird, 1996) to forecast the size and depth distribution of new discoveries from increments of wildcat drilling. These forecasts drive the economic field development and production process model to determine the aggregate value of new discoveries and consequently, how many successive increments of exploration effort should be expended.

Specifically, at a given price the commercial value of developing a representative accumulation from a specific size class and depth category is determined by the results of a discounted cashflow (DCF) analysis. The net after-tax cash flow consists of revenues from the production of oil less the operating costs, capital costs in the year incurred, and all taxes. All new discoveries from a size and depth category are assumed to be developed if the representative accumulation is commercially developable, that is, the after-tax DCF is greater than zero, where the discount rate (12 percent) represents the cost of capital and the industry's required return.

Production stops, that is the economic limit is reached, when operator income declines below the sum of direct operating costs and the operator's production-related taxes. Commercially developable accumulations are summed and represent an estimate of the potential reserves attainable from undiscovered accumulations at a given price and required hurdle rate of return. *The results from this procedure do not imply that every accumulation determined to be commercially developable is worth exploring for.*

Incremental units of exploration, development, and production effort will not be expended unless the revenues expected to be received from eventual production will cover the incremental costs, including a normal return on the incremental investment. Exploration continues until the incremental cost of drilling wildcat wells equals or exceeds the after–tax net present value of the commercial discoveries identified by the last increment of wildcat wells. For the last increment of hydrocarbons produced from a field, operating costs (including production related taxes) per barrel of oil equivalent are equal to price.

These two assumptions together imply that for the commercially developable resources discovered by the last economic increment of wildcat wells, that is, for those reserves found, developed, and produced at the economic margin, the sum of finding costs and development and production costs per barrel equals the well head price (price of oil to the field owner). The marginal finding costs as described here are calculated by dividing the cost of the last increment of wildcat wells (which is approximately equal to the sum of the after-tax net present value of all commercially developable fields discovered in that last increment of exploration) by the amount of economic resources discovered by the last increment of exploration. Marginal development and production cost per barrel (for the economic resources discovered in that last increment of exploration) are calculated by subtracting the marginal finding costs from the well head price.

Finding rate functions provide the critical link between the field development costs and exploration costs. The size, depth, and number of undiscovered fields were computed from the geologic assessment data. However, *finding rate functions predict the number and sizes of new discoveries as functions of cumulative wildcats drilled within each depth interval.* Because of the relatively small number of discoveries, a consistent set of finding rate coefficients could not be calculated for northern Alaska. A procedure for obtaining default coefficients is described in Attanasi and Bird (1996). Allocations of wildcat wells by depth interval were made in such a way that for each increment of wildcat wells evaluated, the after-tax net present value of the oil and gas fields discovered was maximized.

When undiscovered oil and gas accumulations occur in the same depth interval and geographic basin, exploration productivity is determined jointly by the oil and gas assessment and their economic value. If an oil search finds gas and the gas discovery has a positive after-tax net present economic value, the operator might develop the gas or sell the discovery to an operator that will develop the discovery. However, if the gas is of no value, the discovery is typically reported as a dry hole. So, when oil and gas accumulations occur in the same exploration area and depth intervals, the number of economic wildcat well increments that can be drilled depends on both the net present values of the oil and of the non-associated gas that is found. In such situations the oil incremental cost function depends on the value imputed to the gas finds and the non-associated gas incremental cost function depends on the valuation of the oil. This procedure of representing the joint nature of oil and gas exploration with finding rate functions has been applied to most U.S. provinces analyzed in the economic component of the 1995 U.S. Geological Survey's National Oil and Gas Assessment (Attanasi, 1998). Because the middle sub-area of the Central North Slope study area was assigned significant volumes of both oil and non-associated gas, the strength of the interaction between oil and gas can be observed in Scenarios 2 and 3, where non-associated gas is assigned commercial value.

This application of the finding rate model requires that oil and gas prices be specified because the present value of drilling oil prone intervals are compared with the present value of drilling gas prone depth intervals. Historically, on a caloric heating value basis (British Thermal Unit), the market prices for gas have been about two-thirds that of oil. The analysis uses this rate as the base case but also presents results for the case where oil and gas are priced at parity on a British Thermal Unit (BTU) basis.

Economic Analysis Results

Economic Framework

It is reasonable for an economic decision maker to expend resources to identify an asset that is expected to have value at some future but uncertain date. For the North Slope undiscovered gas, the question of the timing of construction of the pipeline is further complicated by the uncertainty about availability of pipeline capacity for transporting *newly discovered gas* to market.[18]

[18] According to the BP-ExxonMobil-ConocoPhillips presentation (2002), a 30 year production stream at the current design rate would use 51 TCF of gas, 16 TCF of that gas was in the yet-to-be discovered category.

To investigate a range of possibilities, three scenarios were considered. Because the incremental cost functions are time independent, scenarios are static and represent resource costs at a single instant in time. For Scenario 1, the oil incremental costs are based on the assumption that gas discoveries have no commercial value. This scenario corresponds to the approach taken in previous North Slope area studies (Attanasi, 1999, and Attanasi, 2003). For Scenario 2, it is assumed that the scale and the regulation of the North Slope gas pipeline will allow any newly discovered gas to be transported to market upon completion of the pipeline. However, the current after-tax net present value of a current new discovery is discounted for the 10 year period for pipeline permitting and construction. Specifically, the analysis shows how the incremental cost function appears to an operator who explores in 2005 and must discount the net present value of a find (based on constant cost and the assumed North Slope gas pipeline tariff) for the 10-year lag time between disbursement of exploration cost and project cash flow. The project cash flow streams consist of dispersal for development and then net revenue from production. Scenario 3 assumes a 20-year delay between discovery and project cash flow streams but is procedurally the same as Scenario 2 (and Scenario 1). Scenario 3 recognizes that the delay for development of newly discovered gas could easily lengthen an additional 10 years if stranded gas in operating oil fields is given absolute priority in the North Slope gas pipeline.

Oil in Undiscovered Oil Accumulations

Table 5 and figure 6A show the results where the oil is evaluated under the assumption that a gas market is sufficiently far in the future that it does not affect oil. The market threshold prices at which wildcat drilling and development is economic is $22.40 for the distribution associated with the 95th fractile oil estimate, $20.10 for the mean estimate, and $18.40 per barrel for the distribution associated with the 5th fractile oil estimate. Figure 6A shows the cost function for the 95th fractile estimate increasing steadily from the threshold price. With more of the resources assigned to larger accumulations at the 5th fractile oil estimate (see table 2 and fig. 3), that function shows larger increments in economically recoverable oil with price increases. The fractile estimates not only represent different volumes of oil but differences in the associated accumulation size distributions directly affect the position and shape of the cost function.

At $24 per barrel market price the computed volumes of economic oil associated with the undiscovered accumulation size distributions for the 95th fractile, the mean, and the 5th fractile oil volume estimates are 0.22 BBO, 0.86 BBO, and 2.10 BBO. This represents 8, 22 and 36 percent of the respective estimates of the technically recoverable oil estimates of 2.57 BBO, 3.98 BBO, and 5.84 BBO. By $30 per barrel economic oil amounts to 0.79 BBO, 1.9 BBO, and 3.5 BBO (30, 47 and 59 percent of the assessed technically recoverable oil) at the respective 95th, mean, and 5th fractile oil estimates. Beyond $42 dollar per barrel, increments to volumes of economic resources decline rapidly as the price increases.

The algorithm used to allocate exploration expenditures within the region assigns wildcat wells to depths based on the expected payoff in terms of net present value of the resources discovered. In the case where we have assumed a lag of 10 or 20 years in development; the net present values that are compared are discounted. The discounting not only limits the amount of exploration expenditures the industry will determine commercial but affects the assignment of wildcat wells by depth because exploration drilling is directed to depths yielding the highest net present value. Delayed development reduces the present value of a find and thus reduces the yield for drilling at depths where gas is prevalent. Table 4 shows that only the middle sub-area was assigned substantial volumes of both oil and non-associated gas. Intuitively, the

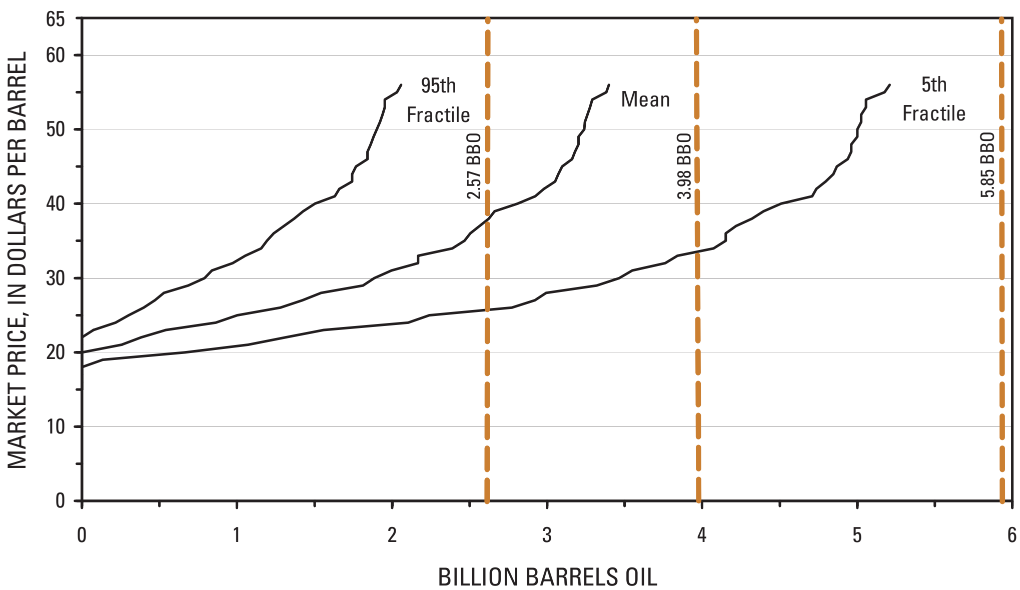

Figure 6A. Incremental costs, in 2003 dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered oil accumulations in the Central North Slope study area where computations were prepared assuming all gas is valued at zero (Scenario 1 in the text). Dashed vertical lines represent the technically recoverable oil at the 95th fractile, the mean, and the 5th fractile estimates of the geologic assessment as reported in Bird and Houseknecht (2005).

Table 5. Volumes of oil, associated gas and natural gas liquids (NGL) from undiscovered oil accumulations available as a function of specified market prices estimated to offset costs of finding, developing, producing and transporting the oil to market. Volumes represent the 95th, mean, and 5th fractile estimates of oil accumulations located in the Central North Slope study area as of 2005. Computations shown in the table assume Scenario 1 where no gas is commercially salable.

[2003 dollars; Asc. gas, associated gas; $/bbl, dollars per barrel; BBO, billions of barrels of oil; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids; boe, barrels of oil equivalent]

Oil market price	95th fractile estimate				Mean estimate				5th fractile estimate			
($/bbl)	Oil (BBO)	Asc. gas (TCF)	NGL (BBL)	Finding cost ($/boe)	Oil (BBO)	Asc. gas (TCF)	NGL (BBL)	Finding cost ($/boe)	Oil (BBO)	Asc. gas (TCF)	NGL (BBL)	Finding cost ($/boe)
North sub-area												
18	–	–	–	–	–	–	–	–	–	–	–	–
21	–	–	–	–	0.26	0.26	0.00	0.71	0.76	0.81	0.02	0.49
24	0.22	0.22	0.00	0.83	0.76	0.83	0.02	0.84	1.54	1.70	0.04	0.96
27	0.47	0.52	0.01	1.24	1.08	1.22	0.03	1.22	1.93	2.19	0.05	1.35
30	0.73	0.80	0.02	1.76	1.36	1.52	0.03	1.53	2.25	2.53	0.06	1.74
33	0.86	0.96	0.02	2.16	1.53	1.74	0.04	1.93	2.46	2.79	0.06	2.15
36	0.90	1.00	0.02	2.50	1.60	1.82	0.04	2.63	2.49	2.83	0.06	2.51
39	0.96	1.07	0.02	3.41	1.64	1.86	0.04	3.06	2.55	2.90	0.07	3.47
42	1.06	1.17	0.03	3.51	1.78	2.01	0.05	3.72	2.69	3.04	0.07	3.65
45	1.11	1.25	0.03	3.79	1.84	2.10	0.05	4.04	2.77	3.15	0.07	3.96
48	1.13	1.27	0.03	4.29	1.86	2.12	0.05	4.61	2.79	3.17	0.07	4.54
51	1.15	1.29	0.03	4.92	1.88	2.14	0.05	5.29	2.81	3.19	0.07	5.20
54	1.17	1.31	0.03	5.61	1.89	2.15	0.05	6.04	2.82	3.21	0.07	5.90
55	1.18	1.32	0.03	6.40	1.92	2.18	0.05	6.04	2.85	3.24	0.07	5.90
Middle sub-area												
18	–	–	–	–	–	–	–	–	–	–	–	–
21	–	–	–	–	–	–	–	–	0.31	0.12	0.00	0.77
24	–	–	–	–	0.10	0.05	0.00	1.26	0.56	0.28	0.00	0.99
27	–	–	–	–	0.34	0.26	0.00	1.13	0.99	0.68	0.01	1.03
30	0.06	0.05	0.00	1.53	0.53	0.46	0.01	1.47	1.22	0.93	0.02	1.43
33	0.19	0.19	0.00	2.11	0.64	0.56	0.01	1.91	1.39	1.08	0.02	2.14
36	0.34	0.34	0.01	2.02	0.90	0.82	0.02	2.29	1.66	1.35	0.02	2.18
39	0.47	0.48	0.01	2.64	1.03	0.97	0.02	2.48	1.85	1.56	0.03	2.71
42	0.60	0.61	0.01	2.80	1.20	1.14	0.02	2.70	2.05	1.76	0.03	2.96
45	0.66	0.66	0.01	3.37	1.26	1.19	0.02	3.37	2.10	1.81	0.03	3.69
48	0.73	0.75	0.02	3.83	1.34	1.30	0.03	3.82	2.17	1.91	0.04	3.70
51	0.77	0.79	0.02	4.71	1.37	1.32	0.03	4.25	2.22	1.95	0.04	4.55
54	0.79	0.81	0.02	5.13	1.40	1.36	0.03	5.21	2.24	1.97	0.04	5.06
55	0.85	0.87	0.02	5.13	1.46	1.42	0.03	5.21	2.32	2.05	0.04	5.18
Total for study area[1]												
18	–	–	–	–	–	–	–	–	–	–	–	–
21	–	–	–	–	0.26	0.26	0.00	0.71	1.07	0.93	0.02	0.56
24	0.22	0.22	0.00	0.83	0.86	0.88	0.02	0.89	2.10	1.98	0.04	0.97
27	0.47	0.52	0.01	1.24	1.42	1.48	0.03	1.20	2.92	2.87	0.06	1.25
30	0.79	0.86	0.02	1.74	1.89	1.97	0.04	1.51	3.46	3.45	0.07	1.64
33	1.05	1.15	0.03	2.15	2.17	2.30	0.05	1.92	3.84	3.87	0.08	2.15
36	1.24	1.34	0.03	2.37	2.50	2.65	0.06	2.51	4.15	4.18	0.09	2.38
39	1.43	1.55	0.03	3.16	2.66	2.83	0.06	2.84	4.40	4.46	0.09	3.16
42	1.66	1.78	0.04	3.25	2.98	3.15	0.07	3.32	4.74	4.80	0.10	3.36
45	1.77	1.91	0.04	3.64	3.10	3.29	0.07	3.77	4.87	4.96	0.11	3.85
48	1.86	2.02	0.04	4.11	3.20	3.42	0.07	4.28	4.96	5.08	0.11	4.18
51	1.92	2.08	0.05	4.84	3.24	3.46	0.08	4.86	5.03	5.14	0.11	4.92
54	1.95	2.11	0.05	5.42	3.29	3.51	0.08	5.69	5.06	5.18	0.11	5.54
55	2.03	2.19	0.05	5.87	3.38	3.60	0.08	5.69	5.18	5.30	0.11	5.58

[1]Totals may not equal sum of components due to independent rounding. South sub-area had no economic oil. 0.00 represents number < 0.005 and "–" represents null volumes.

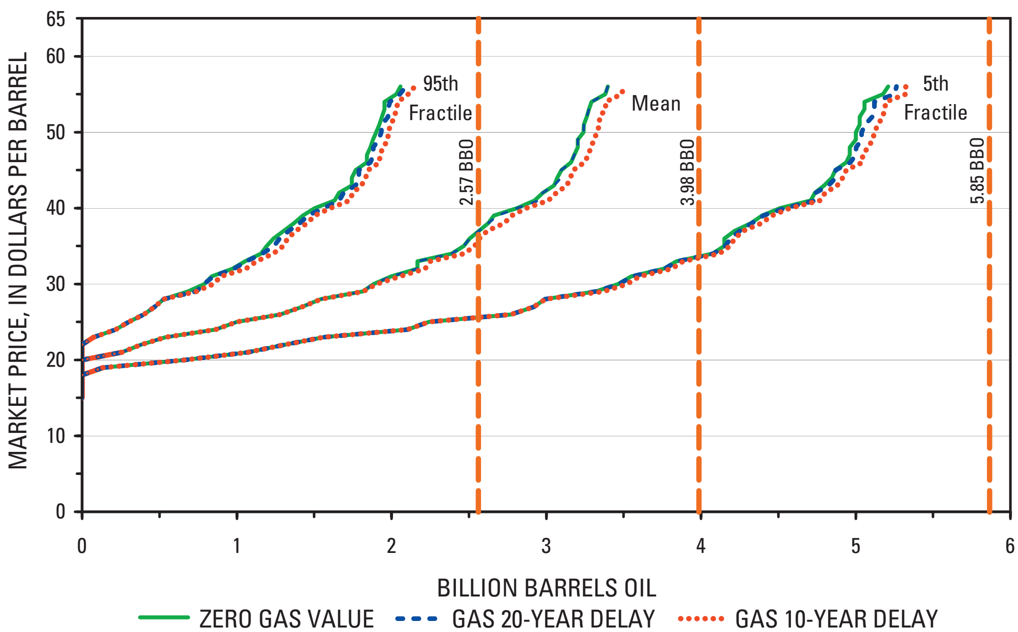

Figure 6B. Incremental costs, in 2003 dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered oil accumulations in the Central North Slope study area where computations were prepared assuming gas is valued at two-thirds the value of oil and that the present value of gas accumulations is 1) valued at zero (Scenario 1), 2) discounted for a 10-year delay (Scenario 2), and 3) a 20-year delay (Scenario 3). The 95th, mean, and 5th fractile estimates refer to the oil estimates with the concomitant gas assessed in gas accumulations (table 4 shows volumes). Vertical lines represent the technically recoverable oil at the 95th fractile, the mean, and the 5th fractile estimates of the geologic assessment as reported in Bird and Houseknecht (2005).

assignment of economic value to gas accumulations should increase the economic number of wildcat wells drilled. Figure 6B shows the shift in the oil incremental cost functions when the after-tax net present values of the gas discoveries are discounted for 10 and 20 years, respectively. The differences only begin to be noticeable above market oil prices of $45 ($5.00 per mcf for natural gas). At $45 per barrel, the difference in the curves is at most 70 million barrels. The 10-year delay has shifted the curve the greatest distance.

It was initially assumed that at the market, natural gas is priced at two-thirds the price of oil on a BTU basis. Given this assumption, the transportation cost of $2.94 per mcf from Alaska to market is equivalent to $26.46 per barrel of oil.[19] Consequently no gas is economic until its price is at least $2.94 per mcf ($26.46 per barrel of oil equivalent). As an alternative, if gas were priced at parity with oil on a BTU basis, then the equivalent of the $2.94 per mcf cost amounts to $17.64 per barrel. Figure 6C shows clearer separation in the oil curves if oil and gas were priced at parity. However, at the $45 per barrel price ($7.50 per mcf for natural gas), the difference in the curves is at most 270 million barrels of oil.

Natural Gas in Undiscovered Gas Accumulations

Computed cost estimates for facilities and natural gas operations used the generic cost functions from the National Petroleum Council study (2003). The costs are only approximate because there has been no major commercial development of non-associated gas for export out of the region. The finding rate function ties together the oil and gas accumulation discovery sequence based on the net present values of expected discoveries from the next increment of drilling. The undiscovered accumulation size distributions associated with the mean, the 95th and 5th fractile non-associated gas estimates were evaluated, along with their concomitant oil volume (Table 4) and oil size-frequency distributions.

The results for the 10 and 20-year delay scenarios (Scenarios 2 and 3) in gas discovery development are shown in figure 7. The effect of increasing the length of the delay in gas development is to reduce after-tax present value of gas prospects and thereby reduce dollar expenditures for gas prone exploration intervals. Table 6 summarizes the numerical values associated with the incremental cost functions.

Using the $2.94 per mcf ANGTS transport cost, a 20 year delay, and the cost structure discussed in Appendix 3, at $5 per mcf[20] market price the estimates of economically recoverable non-associated gas are 7.9 TCF, 12.7 TCF, and 22.2 TCF, for the 95th fractile, mean, and 5th fractile non-associated gas estimates. These estimates represent 33 to 49 percent of the technically recoverable gas assessed in gas accumulations. The cost functions in figure 7 are somewhat similar to oil cost functions, in that as 95th fractile estimate curve is

[19] Specifically, assuming 6 mcf per barrel of oil equivalent, and pricing gas at 2/3 that of oil:

$/barrel of oil = (2.94 x 6.0)/0.667 = $26.46

[20] The discussion focuses on the range of $5 to $8.00 per mcf. Over a long term, market prices above $5 per mcf in the conterminous U.S. will also likely bring forth additional gas supplies from of imported liquefied natural gas (LNG) which could be substantial.

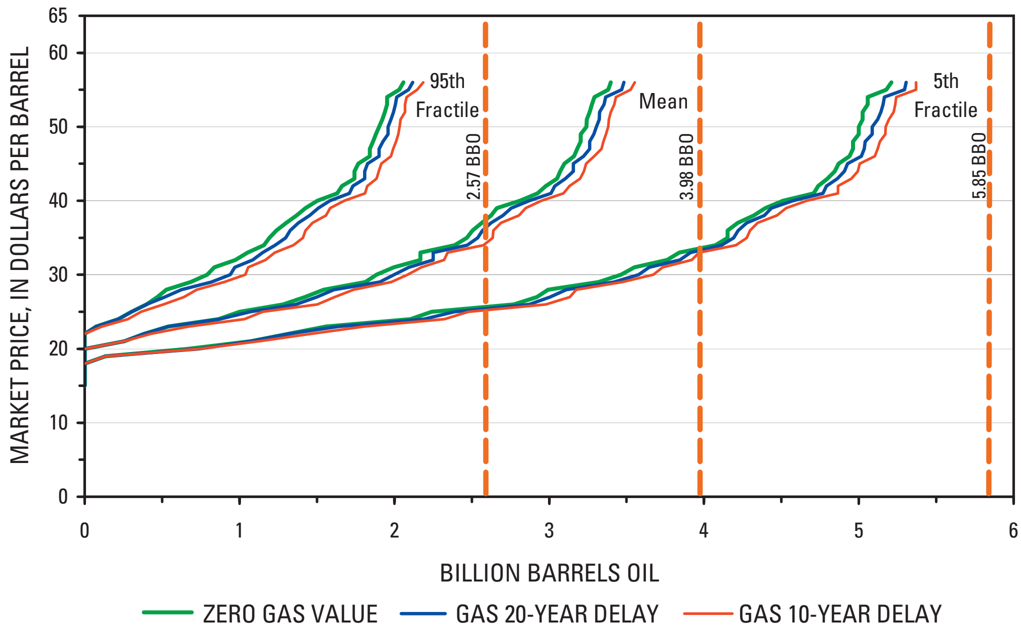

Figure 6C. Incremental costs, in 2003 dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered oil accumulations in the Central North Slope study area where computations were prepared assuming gas is valued at parity with oil price and that the present value of gas accumulations is 1) valued at zero (Scenario 1), 2) discounted for a 10-year delay (Scenario 2) and 3) a 20-year delay (Scenario 3). The 95th, mean, and 5th fractile estimates refer to the oil estimates with the concomitant gas assessed in gas accumulations (table 4 shows volumes). Vertical lines represent the technically recoverable oil at the 95th fractile, the mean, and the 5th fractile estimates of the geologic assessment as reported in Bird and Houseknecht (2005).

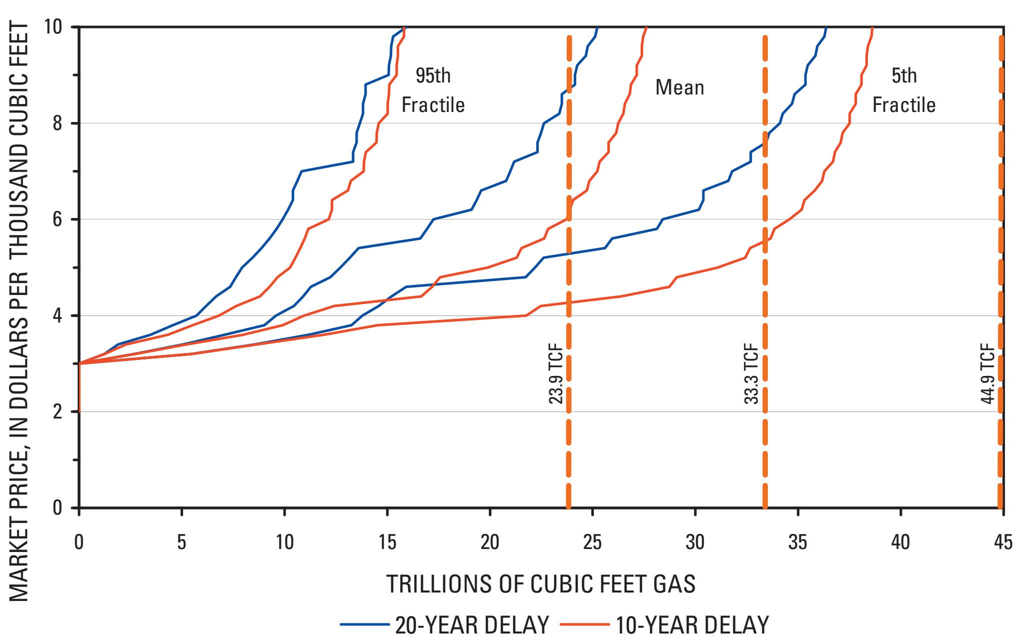

Figure 7. Incremental costs, in 2003 dollars per thousand cubic feet, of finding, developing, producing, and transporting non-associated gas from undiscovered gas accumulations in the Central North Slope study area where computations were prepared assuming gas values at two-thirds that of oil at the market and the present value of commercial gas accumulations are discounted for a 10-year delay (Scenario 2) and a 20-year delay (Scenario 3). The 95th, mean, and 5th fractile estimates refer to gas estimates (table 4 in text shows volumes of technically recoverable oil and gas). Dashed vertical lines represent the technically recoverable non-associated gas at the 95th fractile, the mean, and the 5th fractile estimates of the geologic assessment as reported in Bird and Houseknecht (2005).

Table 6. Volumes of non-associated gas and natural gas liquids (NGL) from undiscovered gas accumulations available as a function of specified market prices estimated to offset costs of finding, developing, producing and transporting the gas to market. Volumes represent the 95th, mean, and 5th fractile estimates of gas accumulations located in the Central North Slope study area as of 2005. Computations shown in the table are based on Scenarios 2 and 3 (see text), where Scenario 2 assumes gas fields are developed 10 years after discovery and Scenario 3 assumes gas fields are developed 20 years after discovery.

[2003 dollars; Non-asc. gas, non-associated gas; $/mcf, dollars per thousand cubic feet; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids]

	95th fractile estimate				Mean estimate				5th fractile estimate			
	10-yr delay		20-yr delay		10-yr delay		20-yr delay		10-yr delay		20-yr delay	
Gas market price ($/mcf)	Non-asc. gas (TCF)	NGL (BBL)	Non-asc. gas (TCF)	NGL (BBL)	Non-asc. gas (TCF)	NGL (BBL)	Non-asc. gas (TCF)	NGL (BBL)	Non-asc. gas (TCF)	NGL (BBL)	Non-asc. gas (TCF)	NGL (BBL)
Middle sub-area												
3.20	1.24	0.01	1.24	0.01	2.72	0.03	2.68	0.03	5.48	0.05	5.45	0.05
3.80	5.50	0.06	4.53	0.05	9.84	0.11	8.95	0.10	14.46	0.16	13.18	0.15
4.40	8.76	0.10	6.63	0.07	13.37	0.16	10.83	0.12	17.82	0.20	15.13	0.17
5.00	10.23	0.12	7.89	0.09	14.80	0.17	12.64	0.14	19.19	0.22	17.34	0.20
5.60	10.93	0.13	9.22	0.11	15.53	0.18	13.89	0.16	19.88	0.23	18.47	0.21
6.20	11.43	0.13	10.12	0.12	16.04	0.19	14.78	0.17	20.38	0.23	19.29	0.22
6.80	11.68	0.14	10.58	0.12	16.42	0.19	15.22	0.18	20.64	0.24	19.70	0.23
7.40	11.89	0.14	10.95	0.13	16.63	0.19	15.77	0.18	20.96	0.24	20.05	0.23
8.00	12.07	0.14	11.27	0.13	16.80	0.20	16.06	0.19	21.13	0.24	20.35	0.23
8.60	12.22	0.14	11.53	0.13	16.88	0.20	16.19	0.19	21.21	0.24	20.59	0.24
9.20	12.29	0.14	11.64	0.14	17.02	0.20	16.42	0.19	21.34	0.24	20.80	0.24
10.00	12.40	0.15	11.84	0.14	17.13	0.20	16.61	0.19	21.45	0.25	20.98	0.24
South sub-area												
3.20	–	–	–	–	–	–	–	–	–	–	–	–
3.80	–	–	–	–	–	–	–	–	–	–	–	–
4.40	–	–	–	–	3.21	0.04	–	–	8.47	0.11	–	–
5.00	–	–	–	–	5.00	0.06	–	–	11.79	0.15	4.75	0.06
5.60	–	–	–	–	7.03	0.09	2.64	0.03	13.66	0.17	7.36	0.09
6.20	0.83	0.01	–	–	7.75	0.10	4.24	0.05	14.66	0.18	10.77	0.13
6.80	1.48	0.02	–	–	8.29	0.10	5.45	0.07	15.40	0.19	11.78	0.14
7.40	2.00	0.02	2.34	0.03	9.00	0.11	6.42	0.08	15.70	0.19	12.51	0.15
8.00	2.43	0.03	2.34	0.03	9.29	0.11	6.42	0.08	16.23	0.19	13.63	0.16
8.60	2.77	0.03	2.34	0.03	9.77	0.12	7.17	0.09	16.46	0.20	14.10	0.17
9.20	3.06	0.04	3.35	0.04	9.97	0.12	7.69	0.09	16.85	0.20	14.52	0.17
10.00	3.31	0.04	4.00	0.05	10.33	0.12	8.46	0.10	17.01	0.20	15.24	0.18
Total for study area[1]												
3.20	1.24	0.01	1.24	0.01	2.72	0.03	2.68	0.03	5.48	0.05	5.46	0.05
3.80	5.54	0.06	4.57	0.05	9.92	0.11	9.02	0.10	14.53	0.16	13.26	0.15
4.40	8.81	0.10	6.67	0.07	16.66	0.20	10.91	0.12	26.37	0.31	15.21	0.17
5.00	10.27	0.12	7.94	0.09	19.88	0.24	12.72	0.15	31.07	0.37	22.18	0.26
5.60	10.98	0.13	9.27	0.11	22.64	0.27	16.61	0.19	33.65	0.40	25.94	0.30
6.20	12.30	0.14	10.17	0.12	23.89	0.28	19.11	0.22	35.16	0.41	30.17	0.35
6.80	13.22	0.16	10.63	0.12	24.83	0.29	20.78	0.24	36.16	0.42	31.61	0.37
7.40	13.97	0.16	13.34	0.16	25.77	0.30	22.32	0.26	36.80	0.43	32.69	0.38
8.00	14.58	0.17	13.67	0.16	26.23	0.31	22.62	0.27	37.50	0.44	34.11	0.40
8.60	15.09	0.18	13.94	0.17	26.80	0.32	23.50	0.28	37.80	0.44	34.83	0.41
9.20	15.45	0.18	15.08	0.18	27.15	0.32	24.25	0.29	38.33	0.45	35.46	0.41
10.00	15.82	0.19	15.94	0.19	27.63	0.32	25.22	0.30	38.61	0.45	36.36	0.42

[1]North sub-area had insignificant economic gas at less than 0.17 TCF, and so totals may not equal sum of components shown. "–" represents null volumes.

more steeply inclined than the cost function associated with the mean and 5th fractile estimates. The position and slope of the function associated with the 95th fractile reflects the higher concentration of its resource in accumulations that are smaller on average than the accumulations where the resources assessed at the mean and 5th fractile estimate are concentrated.

Figure 7 also shows that at the lower cost levels of $3 to $5 per mcf, the differences in economic resources are substantial whether one assumes a 10 or 20 year delay. *This is true because as the gas prices increase above threshold transportation costs, the largest and most easily discovered gas pools become targets for exploration and are found.* The longer discounting period reduces the overall present value of gas prospects relative to oil and thus will reduce drilling in the gas prone intervals. The effect of this difference is particularly dramatic early in the discovery process when the largest targets remain to be found.

Although the cost estimates for natural gas are not detailed nor is there experience with development to validate the approximations, it appears that from 8 to 22 TCF could be discovered, produced and transported to market at prices of $5 per mcf. This assumes the following: transport costs would be realized, uncertainty about the date of availability of transportation to market is removed, and constant costs prevail so that full development and full production would begin a maximum of 20 years after discovery. It should be understood that the models presented here are not designed to be decision tools and do not adequately consider the role of uncertainty in the future values of an asset nor other opportunities available to individual operators.

Conclusions and Limitations

In the past, oil discovered in the study area accounted for some of the largest discoveries in North America. The study area has already produced in excess of 12 BBO. The 2005 U.S. Geological Survey geologic assessment is consistent with the inference that the largest oil accumulations have already been identified.

The economic analysis takes the technically recoverable volumes, size-frequency distributions, and reservoir characteristics from the geologic assessment as the starting point. Because of the expected small sizes of the accumulations assessed, their commercial development will be challenging. At a $24 per barrel market price, 0.22 BBO, 0.86 BBO and 2.10 BBO associated with the 95th fractile estimate, the mean estimate and the 5th fractile estimates, respectively, are economic to find, develop, produce, and transport to market. For resources associated with the 95th fractile, the mean, and the 5th fractile estimates, initial exploration costs are not compensated by the economic value of new finds until respective market prices reach at least $22.40 per barrel, $20.10 per barrel and $18.40 per barrel. At a market price of $30 per barrel, 0.79 or 30 percent of the technically recoverable oil assessed at the 95th fractile, 1.9 BBO or 47 percent of the oil assessed at the mean, and 3.5 BBO or 59 percent of the oil assessed at the 5th fractile estimate is economic to find, develop, produce, and transport to market.

The play assessment provided only limited spatial information about locations of prospects, but it is likely that the smallest accumulations will be developed using drill pads and infrastructure of the larger fields. In fact, most of the oil resources in the smaller accumulations may never be reported as new discoveries but will be classified as field growth (Drew, 1997).

Questions relating to the continuing operation of the Trans-Alaska Oil pipeline make timely development of even marginal oil discoveries of particular importance. The State of Alaska has recognized the role of facilities sharing to the commercialization of the smaller accumulations. It sponsored a study to inventory existing facilities and review the nature of agreements to help it decide upon a regulatory stance (Kaltenbach and others, 2004).

Rudimentary economic analysis of the assessed gas suggests that 7.9 to 34.1 TCF of gas could be identified, produced and delivered to market at prices between $5 and $8 per mcf. This result assumes that gas transport cost from the Alaska North Slope to the Conterminous U.S. markets is $2.94 per mcf. However, there is still more than 25 TCF of stranded gas in developed oil fields that is ready to market at a cost much lower than that which must be incurred to find and develop gas in new gas discoveries. The analysis made no attempt to incorporate the market uncertainty or analytically address the issues of competing suppliers for limited pipeline capacity. Whether it is reasonable for any firm to take such risks over a long period will depend on the firm's other opportunities and its internal valuation procedures of risky projects. State authorities have recognized these issues as they search for a strategy to encourage private construction of the gas pipeline without locking-out potential new entrants to a fledgling gas industry.

Whereas the uncertainty attached to the geologic assessment is evident by the differing quantities of oil at alternative probabilities, there are also un-quantified uncertainties about the economic evaluation by virtue of the assumptions made. The 10-year gas line construction period also provides the opportunity for substantial cost reducing technological improvements in producing conventional and unconventional gas accumulations (such as hydrates).

References Cited

Alaska Department of Revenue, 2004, Fall 2004 revenue source book: Anchorage, Alaska.

American Petroleum Institute, 1997-2005, Joint Association survey of drilling costs: Amercian Petroleum Institute, Washington, D.C., pagination varies by year

Atkinson I., Theuvey B., Conort G., Lowe T., McDiarmid A., Mehdizabdeh P., Pinquet B., Smith G., and Williamson, K., J., 2005, A new horizon multiphase flow measurement: Oilfield Review, v. 16, no. 14 Winter, 2004/2005, p. 52-63

Attanasi, E.D. and Bird, K.J., 1996, Economics and undiscovered conventional oil and gas accumulations in the 1995 National Assessment of U.S. oil and gas resources–Alaska: U.S. Geological Survey Open-File Report 95-75J, 48p.

Attanasi, E.D., 1998, Economics and the 1995 national assessment of United States oil and gas resources: U.S. Geological Survey Circular 1145, 35p.

Attanasi, E.D., 1999, Economics of undiscovered oil in the 1002 Area of the Arctic National Wildlife Refuge, Chapter EA *in* The oil and gas resource potential of the 1002 Area, Arctic National Wildlife Refuge, Alaska, by ANWR Assessment Team: U.S. Geological Survey Open-File Report 98-34, 51p.

Attanasi, E.D., 2003, Economics of undiscovered oil in the Federal Lands on the National Petroleum Reserve, Alaska: U.S. Geological Survey Open-File Report 2003-044, 53p.

Baker, R.A., Gehman, H.A., James, W.R., and White, D.A., 1984, Geologic field number and size assessments of oil and gas plays: American Association of Petroleum Geologists Bulletin, v. 68, no. 4, p. 426-437

Bird, K.J. and Houseknecht, D.W., 2005, Oil and gas assessment of Central North Slope, Alaska, 2005: U.S. Geological Survey Fact Sheet 2005-3043, 2p.

Blunt, C G., Ward, S.L., Hightower, C.M., and Walker, E.J., 1993, Emerging coiled-tubing applications at Prudhoe Bay, Alaska Society of Petroleum Engineers Paper 26086, Presented at Western Regional Meeting, Anchorage, 26-28 May 1993, p. 581-585.

BP, ExxonMobil, and ConocoPhillips, 2002, Alaska producer pipeline update, May 2002, Power point presentation for a press conference announcing release of results of producer's feasibility study on construction of natural gas pipeline to the lower 48 states, 23p. at URL http://magalaska.com/materials.shtml

British Petroleum Exploration (Alaska), 1996, Northstar Development Project: Conceptual Engineering Report, Anchorage, report submitted for evaluation to the Alaska Department of Natural Resources.

Corbett, K.T., Bowen, R.R. , and Petersen, C.W., 2003, High strength steel pipeline economics, Proceedings of the Thirteenth, (2003) International Offshore and Polar Engineering Conference, Honolulu, Hawaii, May 25-30, p. 105-112.

Craig, James D., 2002, Economic analysis of the development alternatives for the Liberty prospect, Beaufort Sea, Alaska, *in* Liberty development and production plan, final Environmental Impact Statement: MMS 2002-019, v. IV, app. D-1, p. D1-1 to D1-14.

Drew, L.J., 1997, Unndiscovered petroleum and mineral resources–Assessment and controversy: New York, Plenum, 210p.

Erwin, M.D., Sanders, L.A, and Redman R.S., 2002, Multiwell interference test in the Colville River Field, Alaska: Society of Petroleum Engineers Paper 77453: Society of Petroleum Engineers Annual Technical Conference and Exhibition, San Antonio, Texas, 29 September to 2 October, 2002.

Garrity, C.P., Houseknecht, D.W., Bird, K.J., Potter, C.J, Moore, T.M., Nelson, P.H. , and Schenk, C.J., 2005, U.S. Geological Survey 2005 Oil and gas resource assessment of the Central North Slope, Alaska–Play maps and results: U.S. Geological Survey Open-File Report 2005-1182, 24p.

Gingrich. Dean, Knock, Doug, and Masters, Ron, 2001, Geophysical interpretation methods applied at Alpine Oil Field, North Slope Alaska: The Leading Edge, July, p. 730-738.

Han-Padron Associates, 1985, Beaufort Sea petroleum technology assessment–Contract report for Minerals Management Service: Technical Report 112, chapter 7-Transportation technology assessment, 54p. [Available from the National Technical Information Service, Springfield, Va. 22161.]

Joshi, S.D., 1991a, Drainage areas and well spacing, *in* R.D. Fritz, M.K. Horn, and S.D. Joshi (eds.), Geological aspects of horizontal drilling: American Association of Petroleum Geologists Continuing Education Course Note Series 33, p. 65-78.

Joshi, S.D., 1991b, Factor influencing productivity, *in* R.D. Fritz, M.K. Horn, and S.D. Joshi (eds.), Geological aspects of horizontal drilling: American Association of Petroleum Geologists Continuing Education Course Note Series 33, p. 80-90.

Kaltenbach. B., Walsh, C., Foerster, C., Walsh, T., MacDonald, J., Stokes, P., Livesey, C., and Nebesky, W., 2004, North Slope of Alaska facility sharing study, prepared for Division of Oil and Gas, Alaska Deparment of Natural Resources, by Petrochemical Resources Alaska, 66p. at URL http://www.dog.dnr.state.ak.us/oil/products/publications/otherreports/nsfacility/share.htm

Kumar, N., Bird, K.J., Nelson, P.H., Grow, J.A., and Evans, K.R., 2002, A digital atlas of hydrocarbon accumulations within and adjacent to the National Petroleum Reserve–Alaska (NPRA): U.S. Geological Survey Open-File Report 02-71, 81p.

Kuuskraa, V.A., Morra, F. Jr. and Godec, M.L., 1987, Importance of cost/price relationships for least-cost oil and gas resources: Society of Petroleum Engineers Paper 16290, Proceedings of 1987 Hydrocarbon Economics and Evaluation Symposium, Dallas, Texas, p. 25-42.

National Petroleum Council, 1981a, U.S. Arctic oil and gas: Washington, D.C., National Petroleum Council, December 1981, 286p.

National Petroleum Council, 1981b, Working papers of the Production Task Group of the National Petroleum Council's Committee on Arctic Oil and Gas Resources: Washington, D.C., National Petroleum Council, 372p.

National Petroleum Council, 2003, Balancing natural gas policy: Fueling the demands of a growing economy, v. IV, Supply Task Force Report: Washington, D.C., National Petroleum Council, 456p.

Nelson, K., 2004, Alternatives to Alpine satellite project proposed: Petroleum News Alaska, January 28, p. 1, 12-13.

Nelson, P.H., 1999, Petrophysical properties, Chapter PP *in* The oil and gas resource potential of the 1002 Area, Arctic National Wildlife Refuge, Alaska, by ANWR Assessment Team: U.S. Geological Survey Open-File Report 98-34.

NRG Associates, 2004, The significant oil and gas fields of the United States: Colorado Springs, Colo., NRG Associates. Inc. [includes data current as of December 31, 2003–database available from NRG Associates, Inc., P.O. Box 1655, Colorado Springs, CO 80901].

Oil and Gas Journal, 1994, Alaska North Slope focus shifts from wildcats to cutting production costs: Oil and Gas Journal, v. 60, p. 23-38.

Redman, R.S, 2002, Horizontal miscible water alternating gas development of the Alpine Field, Alaska, Society of Petroleum Engineers Paper 76819: Society of Petroleum Engineers Western Regional/AAPG Pacific Section Joint Meeting, Anchorage, Alaska, 20-22 May 2002.

Schuenemeyer, J.H., 1999, Methodology, Chapter ME, *in* The oil and gas resource potential of the 1002 Area, Arctic National Wildlife Refuge, Alaska, by ANWR Assessment Team: U.S. Geological Survey Open-File Report 98-34, CD-ROM.

Schuenemeyer, J.H., 2005, Methodology for the 2005 USGS assessment of undiscovered oil and gas resource, Central North Slope, Alaska: U.S. Geological Survey Open-File Report 2005-1410, 82p.

Thomas, C.P., Doughty, T.C., Hackworth, J.H., North, W.B., Roberstson, E.P., 1996, Economics of Alaska North Slope gas utilization options; prepared for the Department of Energy, Office of Fossil Energy, by Idaho National Engineering Laboratory, Contract DE-AC07-94ID13223, approximately 200 pages.

Thomas, C.P., Doughty, T.C., Faulder, D.D., Harrision, W.E., Irving, J.S., Jamison, H.C., and White, G.J., 1991, Alaska oil and gas–Energy, wealth or vanishing opportunity?: prepared by EG&G Idaho, Inc., Idaho National Engineering Laboratory, Idaho Falls, Idaho 83415, for U.S. Department of Energy, DOE/ID/01570-H1, 279p.

Thomas, C.P., Allaire, P., Doughty, T.C., Faulder, D.D., Irving, J.S., Jamison, H.C., and White, G.J.,1993, Alaska North Slope National Energy Strategy Initiative, Analysis of five undeveloped fields: Bartlesville, Okla., U.S. Department of Energy, DOE/ID/01570-T164, (DE93000142), 348p.

Verma, M.K., and Bird, K.J., 2005, Role of reservoir engineering in the assessment of undiscovered oil and gas resources in the National Petroleum Reserve, Alaska: American Association of Petroleum Geologists Bulletin, v. 89, no. 8, p. 1091-1111.

Vidas, E.H., Hugman, R.H., and Haverkamp, D.S, 1993, Guide to the hydrocarbon supply model–1993 update: Energy and Environmental Analysis, Inc., prepared for the Gas Research Institute, 272p.

Young, J.H. and Hauser, W.S., 1986, Economics of oil and gas production from the Arctic Refuge (ANWR): Anchorage, Alaska, U.S. Bureau of Land Management, Alaska State Office, 101p..

Appendix 1. Volumes Associated with Fractile Estimates

Figure 1-1 shows a schematic presentation of the geographical location of the plays assessed in the 2005 Central North Slope Assessment (Bird and Houseknecht, 2005). Tables 1-1 through 1-4 show the volumes of oil, gas, and natural gas liquids by play that constitute the fractile estimates of oil in oil accumulations and gas in gas accumulations. The play level volume distributions were aggregated probabilistically.

The probabilistic realization of the 24 plays that constituted the 95th fractile of the aggregated estimate for oil, for example, included non-associated gas accumulations. The method of aggregation of the play simulations allowed recovery of the concomitant gas accumulation results for the oil fractile estimate (and similarly the concomitant oil volume corresponding to the non-associated gas fractile estimates). Although it is possible for the 95th fractile oil volume to occur simultaneously with the 95th fractile non-associated gas volume, it is also highly unlikely because the aggregation combines thousands of simulations corresponding to each of the 24 plays. Tables 1-1 and 1-3 show the concomitant non-associated gas and non-associated natural gas liquid volumes incidental to the 95th fractile estimate for aggregated oil in oil accumulations and the 5th fractile estimate for aggregated oil in oil accumulations respectively. Tables 1-2 and 1-4 show the concomitant oil, associated gas and associated gas natural gas liquid volumes incidental to the 95th fractile and 5th fractile estimate of the aggregated gas in gas accumulations respectively.

Table 1-1. Undiscovered technically recoverable volumes of conventional oil, natural gas, and natural gas liquids (NGL) at the *95th fractile oil estimate* for the Central North Slope study area by play as of 2005.

[BBO, billions of barrels of oil; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids]

Number	Play name	Oil accumulations: Oil (BBO)	Oil accumulations: Gas (TCF)	Oil accumulations: NGL (BBL)	Gas accumulations: Gas (TCF)	Gas accumulations: NGL (BBL)
1	Brookian Clinoform	1.00	1.13	0.02	6.12	0.08
2	Brookian Topset	0.34	0.26	0.00	0.44	0.01
3	Beaufortian Upper Jurassic Topset East	0.00	0.00	0.00	0.23	0.00
4	Beaufortian Upper Jurassic Topset West	0.12	0.12	0.00	0.27	0.00
5	Beaufortian Clinoform	0.08	0.13	0.00	0.86	0.01
6	Beaufortian Kuparuk Topset	0.15	0.12	0.00	0.48	0.01
7	Beaufortian Cretaceous Shelf Margin	0.00	0.00	0.00	0.70	0.01
8	Triassic Barrow Arch	0.23	0.28	0.01	0.00	0.00
9	Ivishak Barrow Flank	0.00	0.00	0.00	0.48	0.01
10	Endicott	0.00	0.00	0.00	0.61	0.01
11	Endicott Truncation	0.03	0.03	0.00	0.00	0.00
12	Franklinian	0.00	0.01	0.00	0.00	0.00
13	Lisburne Barrow Arch	0.07	0.07	0.00	0.00	0.00
14	Lisburne Barrow Flank	0.00	0.00	0.00	1.37	0.02
15	Kemik-Thompson	0.16	0.29	0.01	1.62	0.02
16	Basement Involved Structural	0.02	0.01	0.00	2.99	0.04
17	Beaufortian Structural	0.01	0.01	0.00	2.28	0.02
18	Brookian Clinoform Structural South	0.01	0.01	0.00	2.31	0.02
19	Brookian Clinoform Structural North	0.12	0.14	0.00	0.14	0.00
20	Brookian Topset Structural South	0.00	0.00	0.00	2.17	0.01
21	Brookian Topset Structural North	0.12	0.04	0.00	0.15	0.00
22	Thrust Belt Triangle Zone	0.03	0.02	0.00	3.35	0.03
23	Thrust Belt Lisburne	0.06	0.06	0.00	2.67	0.03
24	Ellesmerian Structural	0.00	0.00	0.00	1.61	0.02
Total		2.57	2.72	0.06	30.86	0.36

Note: Totals may not equal sum of components due to independent rounding.

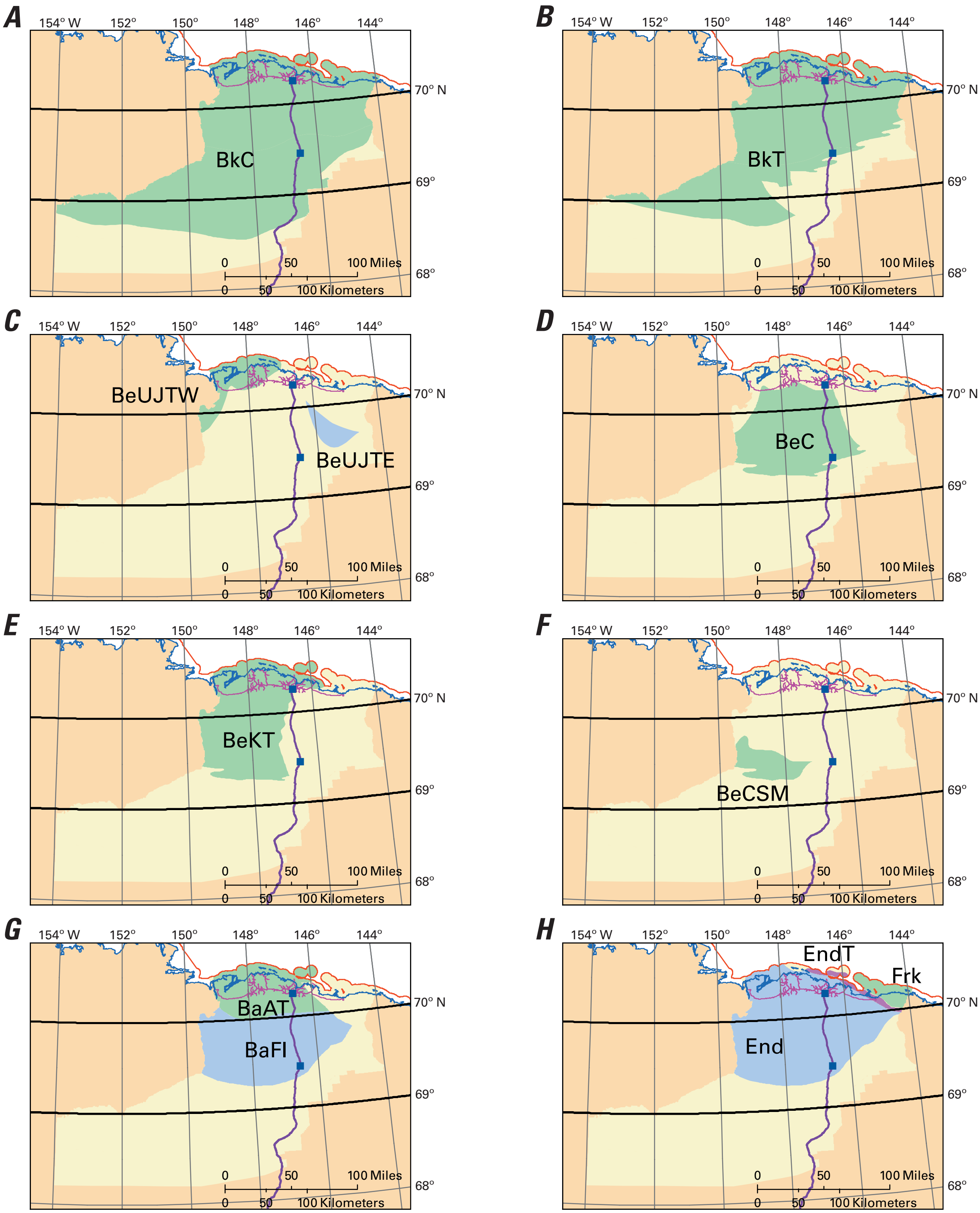

Figure 1–1. Central North Slope play boundary maps showing the Central North Slope study area (light yellow), the coastline (blue line), the Federal-State water boundary (red line) and existing feeder pipelines (magenta lines) for the Trans-Alaska Pipeline (purple line). Plays shown (in blue and green areas within the light yellow study area) are: *A*, Brookian Clinoform (BkC). *B*, Brookian Topset (BkT). *C*, Beaufortian Upper Jurassic Topset East & West (BeUJTE & BeUJTW). *D*, Beaufortian Clinoform (BeC). *E*, Beaufortian Kuparuk Topset (BeKT). *F*, Beaufortian Cretaceous Shelf Margin (BeCSM). *G*, Triassic Barrow Arch (BaAT) and Ivishak Barrow Flank (BaFl). *H*, Endicott (End), Endicott Truncation (EndT, in magenta) and Franklinian (Frk). Data are from Garrity and others (2005). Continued on next page.

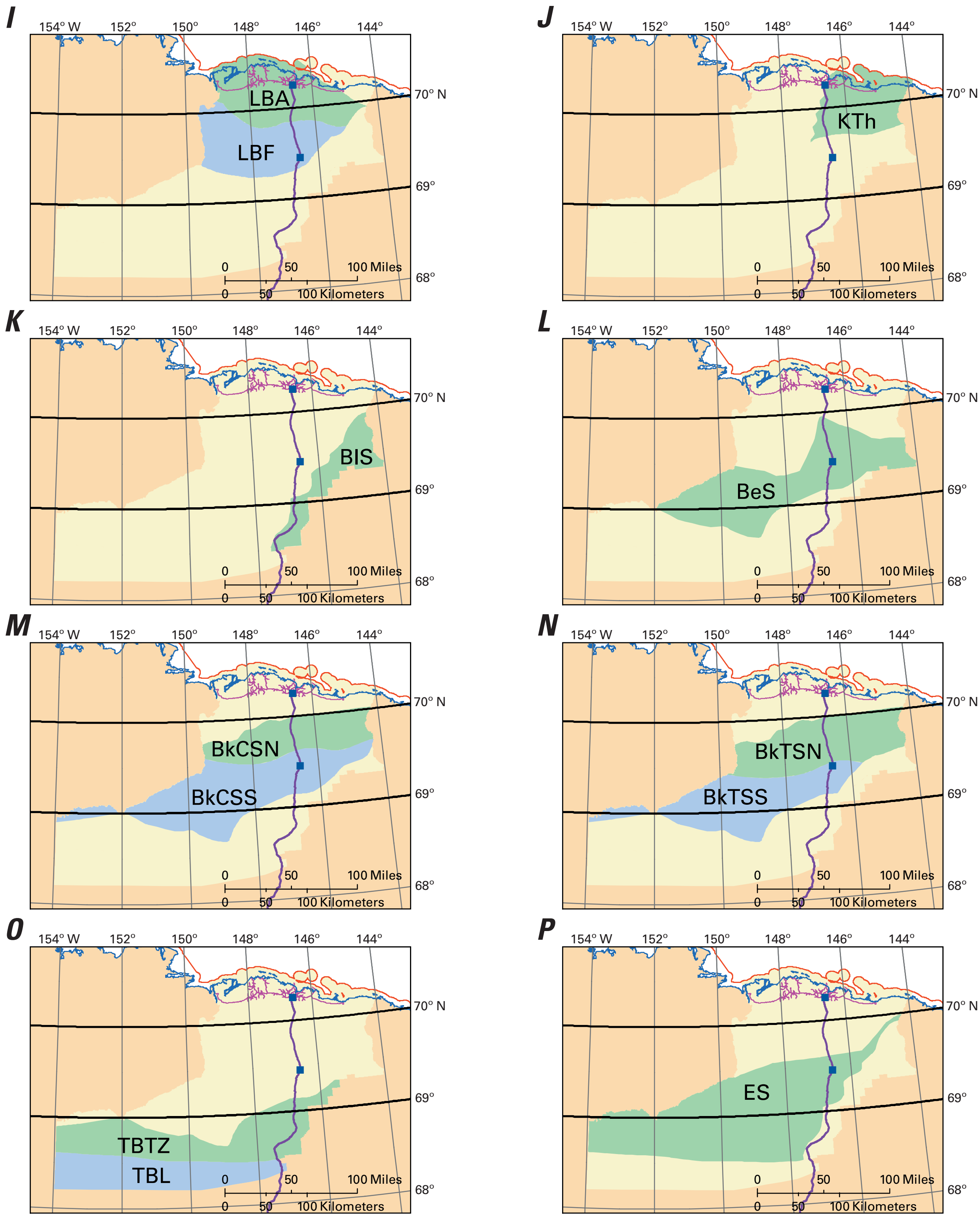

Figure 1–1. Continued. Central North Slope play boundary maps showing the Central North Slope study area (light yellow), the coastline (blue line), the Federal-State water boundary (red line) and existing feeder pipelines (magenta lines) for the Trans-Alaska Pipeline (purple line). Plays shown (in blue and green areas within the light yellow study area) are: *I*, Lisburne Barrow Arch (LBA) and Lisburne Barrow Flank (LBF). *J*, Kemik-Thomson (KTh). *K*, Basement Involved Structural (BIS). *L*, Beaufortian Structural (BeS). *M*, Brookian Clinoform South & North (BkCSS & BkCSN). *N*, Brookian Topset Structural South & North (BkTSS & BkTSN). *O*, Thrust Belt Triangle Zone (TBTZ) and Thrust Belt Lisburne (TBL). *P*, Ellesmerian Structural (ES). Data are from Garrity and others (2005) .

Table 1-2. Undiscovered technically recoverable volumes of conventional oil, natural gas, and natural gas liquids (NGL) at the *95th fractile non-associated gas estimate* for the Central North Slope study area by play as of 2005.

[BBO, billions of barrels of oil; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids]

		Oil accumulations			Gas accumulations	
Number	Play name	Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
1	Brookian Clinoform	1.27	1.42	0.03	4.48	0.06
2	Brookian Topset	0.42	0.32	0.00	0.55	0.01
3	Beaufortian Upper Jurassic Topset East	0.00	0.00	0.00	0.12	0.00
4	Beaufortian Upper Jurassic Topset West	0.14	0.14	0.00	0.28	0.00
5	Beaufortian Clinoform	0.08	0.11	0.00	0.76	0.01
6	Beaufortian Kuparuk Topset	0.16	0.12	0.00	0.46	0.01
7	Beaufortian Cretaceous Shelf Margin	0.00	0.00	0.00	0.44	0.01
8	Triassic Barrow Arch	0.36	0.45	0.01	0.00	0.00
9	Ivishak Barrow Flank	0.00	0.00	0.00	0.17	0.00
10	Endicott	0.00	0.00	0.00	0.45	0.01
11	Endicott Truncation	0.07	0.08	0.00	0.00	0.00
12	Franklinian	0.01	0.01	0.00	0.00	0.00
13	Lisburne Barrow Arch	0.12	0.12	0.00	0.00	0.00
14	Lisburne Barrow Flank	0.00	0.00	0.00	0.89	0.01
15	Kemik-Thompson	0.21	0.38	0.02	1.46	0.02
16	Basement Involved Structural	0.02	0.01	0.00	2.66	0.03
17	Beaufortian Structural	0.01	0.01	0.00	1.19	0.01
18	Brookian Clinoform Structural South	0.01	0.01	0.00	2.15	0.02
19	Brookian Clinoform Structural North	0.16	0.16	0.00	0.08	0.00
20	Brookian Topset Structural South	0.00	0.00	0.00	1.45	0.01
21	Brookian Topset Structural North	0.37	0.15	0.00	0.25	0.00
22	Thrust Belt Triangle Zone	0.02	0.01	0.00	2.27	0.02
23	Thrust Belt Lisburne	0.04	0.04	0.00	2.31	0.03
24	Ellesmerian Structural	0.00	0.00	0.00	1.52	0.02
Total		3.47	3.55	0.08	23.94	0.28

Note: Totals may not equal sum of components due to independent rounding.

Table 1-3. Undiscovered technically recoverable volumes of conventional oil, natural gas, and natural gas liquids (NGL) at the 5^{th} *fractile oil estimate* for the Central North Slope study area by play as of 2005.

[BBO, billions of barrels of oil; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids]

		Oil accumulations			Gas accumulations	
Number	Play name	Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
1	Brookian Clinoform	2.18	2.44	0.05	6.10	0.07
2	Brookian Topset	0.56	0.41	0.00	0.55	0.01
3	Beaufortian Upper Jurassic Topset East	0.01	0.01	0.00	0.15	0.00
4	Beaufortian Upper Jurassic Topset West	0.17	0.16	0.00	0.29	0.00
5	Beaufortian Clinoform	0.09	0.14	0.00	0.92	0.01
6	Beaufortian Kuparuk Topset	0.19	0.15	0.00	0.64	0.01
7	Beaufortian Cretaceous Shelf Margin	0.00	0.00	0.00	0.69	0.01
8	Triassic Barrow Arch	0.75	0.92	0.02	0.00	0.00
9	Ivishak Barrow Flank	0.00	0.00	0.00	0.51	0.01
10	Endicott	0.00	0.00	0.00	0.59	0.01
11	Endicott Truncation	0.16	0.18	0.01	0.00	0.00
12	Franklinian	0.03	0.04	0.00	0.00	0.00
13	Lisburne Barrow Arch	0.26	0.25	0.01	0.00	0.00
14	Lisburne Barrow Flank	0.00	0.00	0.00	1.01	0.01
15	Kemik-Thompson	0.32	0.57	0.03	2.89	0.04
16	Basement Involved Structural	0.03	0.02	0.00	3.40	0.04
17	Beaufortian Structural	0.03	0.03	0.00	2.14	0.02
18	Brookian Clinoform Structural South	0.04	0.01	0.00	2.86	0.03
19	Brookian Clinoform Structural North	0.21	0.22	0.00	0.33	0.00
20	Brookian Topset Structural South	0.09	0.03	0.00	2.58	0.02
21	Brookian Topset Structural North	0.58	0.23	0.00	0.61	0.00
22	Thrust Belt Triangle Zone	0.10	0.06	0.00	4.08	0.05
23	Thrust Belt Lisburne	0.07	0.07	0.00	4.47	0.06
24	Ellesmerian Structural	0.00	0.00	0.00	1.49	0.02
Total		5.85	5.92	0.13	36.29	0.42

Note: Totals may not equal sum of components due to independent rounding.

Table 1-4. Undiscovered technically recoverable volumes of conventional oil, natural gas, and natural gas liquids (NGL) at the *5th fractile non-associated gas estimate* for the Central North Slope study area by play as of 2005.

[BBO, billions of barrels of oil; TCF, trillions of cubic feet of gas; BBL, billions of barrels of natural gas liquids]

		Oil accumulations			Gas accumulations	
Number	Play name	Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
1	Brookian Clinoform	1.73	1.95	0.04	8.40	0.10
2	Brookian Topset	0.55	0.43	0.00	0.79	0.01
3	Beaufortian Upper Jurassic Topset East	0.00	0.00	0.00	0.14	0.00
4	Beaufortian Upper Jurassic Topset West	0.16	0.16	0.00	0.36	0.00
5	Beaufortian Clinoform	0.15	0.23	0.01	1.11	0.01
6	Beaufortian Kuparuk Topset	0.19	0.15	0.00	0.66	0.01
7	Beaufortian Cretaceous Shelf Margin	0.00	0.00	0.00	0.72	0.01
8	Triassic Barrow Arch	0.54	0.67	0.01	0.00	0.00
9	Ivishak Barrow Flank	0.00	0.00	0.00	0.35	0.00
10	Endicott	0.00	0.00	0.00	0.37	0.00
11	Endicott Truncation	0.09	0.10	0.00	0.00	0.00
12	Franklinian	0.01	0.02	0.00	0.00	0.00
13	Lisburne Barrow Arch	0.16	0.15	0.00	0.00	0.00
14	Lisburne Barrow Flank	0.00	0.00	0.00	1.22	0.02
15	Kemik-Thompson	0.35	0.62	0.03	2.45	0.03
16	Basement Involved Structural	0.05	0.03	0.00	4.18	0.05
17	Beaufortian Structural	0.02	0.02	0.00	2.18	0.02
18	Brookian Clinoform Structural South	0.05	0.02	0.00	3.37	0.03
19	Brookian Clinoform Structural North	0.18	0.21	0.00	0.49	0.01
20	Brookian Topset Structural South	0.05	0.02	0.00	3.21	0.02
21	Brookian Topset Structural North	0.36	0.16	0.00	0.46	0.00
22	Thrust Belt Triangle Zone	0.06	0.04	0.00	7.08	0.08
23	Thrust Belt Lisburne	0.10	0.08	0.00	5.93	0.07
24	Ellesmerian Structural	0.00	0.00	0.00	1.41	0.02
Total		4.80	5.07	0.11	44.86	0.52

Note: Totals may not equal sum of components due to independent rounding.

Appendix 2. Allocation of Resources to Sub-areas

The allocation procedure started with play boundaries published in Garrity and others (2005). For some plays, the geologists provided supplemental information that enabled subdivision of the plays into oil and gas prone areas. The *north sub-area* is defined as the area north from the State-Federal offshore boundary south to 70° N. The *middle sub-area* is defined as the area from 70° N to 69° N, and the *south sub-area* is defined from 69 N to southern boundary of the study area (fig. 2 in main text and fig. 1-1 in Appendix 1). If a play was contained entirely in a single sub-area its resources were assigned to that sub-area. If a play straddled two sub-areas, the play's resources were divided into sub-plays and the resources were allocated to each sub-area on the basis of acreage. With the ancillary information provided by the geologist regarding oil and gas prone areas within plays it was believed that the area allocations of the subdivided plays provided a reasonable way to allocate the assessed resources of these broad sub-areas. Table 2-1 shows the percentages used to allocate the assessed undiscovered oil and non-associated gas to the three sub-areas. Table 4 shows the volumes assigned for the mean estimates and each of the oil and gas fractile estimates along with the concomitant other commodities. Figures 2-1 and 2-2 show the allocated accumulation size-frequency distributions that constituted the study area mean and oil fractile estimates and non-associated gas fractile estimates.

Calculation of the distance from each sub-area's resource centroid to Pump Station 1 of the Trans-Alaska pipeline was accomplished with the following procedure. First, the plays were allocated to the sub-areas (table 2-1). For those plays contained within a single sub-area, its resources were assigned to the location of the play's centroid, the area-weighted centerpoint in the standard Alaskan Albers equal-area projection. Otherwise, each play was subdivided by the 70th and 69th standard parallels of latitude into sub-plays. Centroids and areal fractions for each sub-play were calculated and play resources were allocated by the areal fraction to each sub-play's centroid. The locations of the sub-area oil and non-associated gas resource centroids were computed as the resource weighted average of the sub-plays' centroids.

Table 2-1. Allocation percentages for resources in undiscovered oil and gas accumulations within each play to north, middle, and south sub-areas of the Central North Slope Assessment Study Area.

		Percent oil accumulations			Percent gas accumulations		
Number	Play name	North	Middle	South	North	Middle	South
1	Brookian Clinoform	52.5	47.5	0.0	0.0	56.1	43.9
2	Brookian Topset	46.1	53.9	0.0	0.0	61.8	38.2
3	Beaufortian Upper Jurassic Topset East	5.4	94.6	0.0	0.0	100.0	0.0
4	Beaufortian Upper Jurassic Topset West	90.7	9.3	0.0	0.0	100.0	0.0
5	Beaufortian Clinoform	44.5	55.5	0.0	0.0	100.0	0.0
6	Beaufortian Kuparuk Topset	70.8	29.2	0.0	0.0	100.0	0.0
7	Beaufortian Cretaceous Shelf Margin	–	–	–	0.0	100.0	0.0
8	Triassic Barrow Arch	100.0	0.0	0.0	–	–	–
9	Ivishak Barrow Flank	–	–	–	5.6	94.4	0.0
10	Endicott	–	–	–	38.9	61.1	0.0
11	Endicott Truncation	100.0	0.0	0.0	–	–	–
12	Franklinian	100.0	0.0	0.0	–	–	–
13	Lisburne Barrow Arch	73.2	26.8	0.0	–	–	–
14	Lisburne Barrow Flank	–	–	–	3.2	96.8	0.0
15	Kemik-Thompson	59.7	40.3	0.0	0.0	100.0	0.0
16	Basement Involved Structural	0.0	71.5	28.5	0.0	71.5	28.5
17	Beaufortian Structural	0.0	81.8	18.2	0.0	81.8	18.2
18	Brookian Clinoform Structural South	0.0	78.8	21.2	0.0	78.8	21.2
19	Brookian Clinoform Structural North	0.0	100.0	0.0	0.0	100.0	0.0
20	Brookian Topset Structural South	0.0	71.6	28.4	0.0	71.6	28.4
21	Brookian Topset Structural North	0.0	100.0	0.0	0.0	100.0	0.0
22	Thrust Belt Triangle Zone	0.0	9.2	90.8	0.0	9.2	90.8
23	Thrust Belt Lisburne	0.0	0.0	100.0	0.0	0.0	100.0
24	Ellesmerian Structural	–	–	–	0.0	46.6	53.4

Note: Totals may not equal sum of components due to independent rounding. "–" means assessment predicted no accumulations.

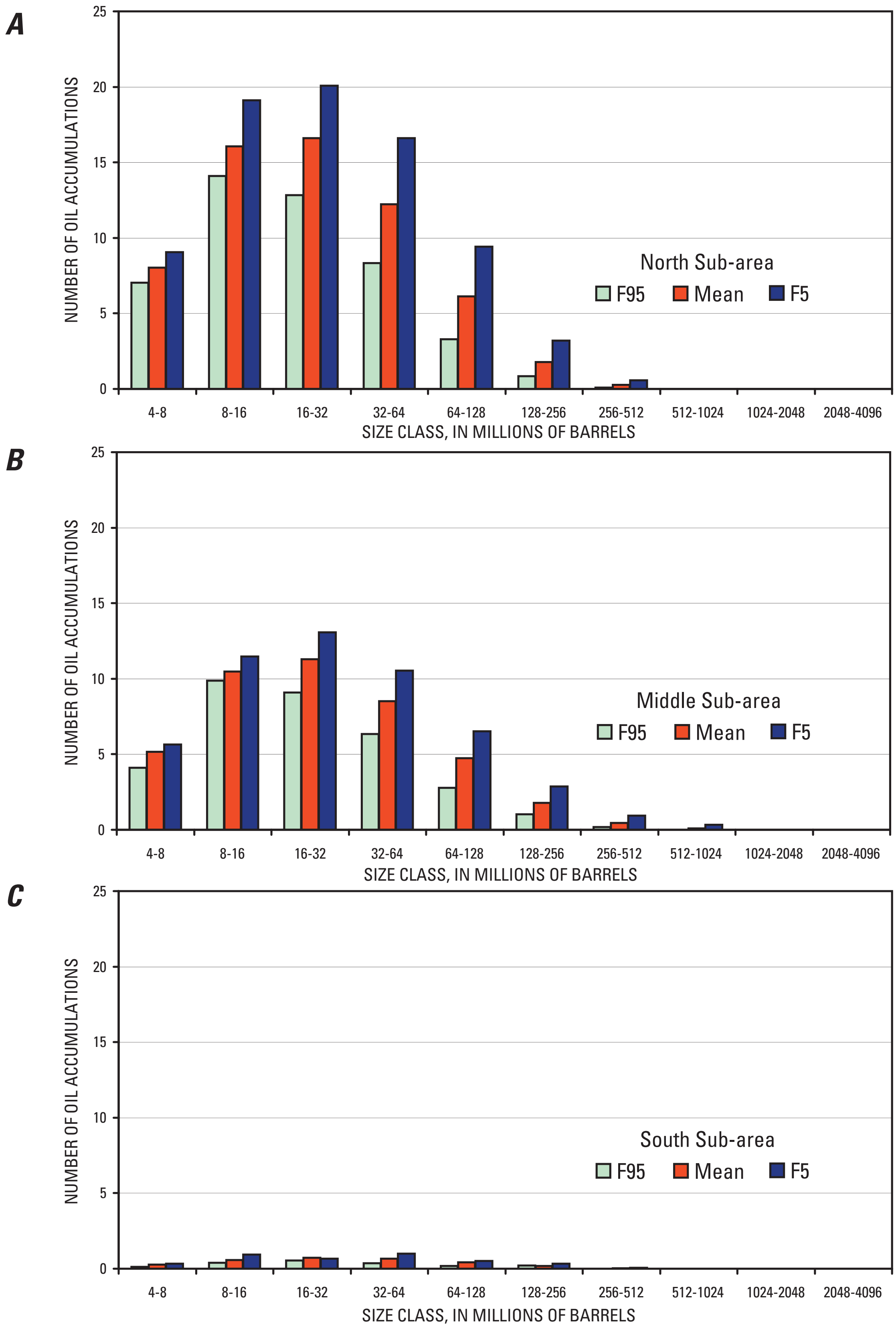

Figure 2–1. Size-frequency distribution of undiscovered conventional oil accumulations for each Central North Slope sub-area associated with the 95th fractile estimate (F95), the mean estimate, and the 5th fractile estimate (F5) of the assessed distribution of technically recoverable undiscovered oil. *A,* The north sub-area extends from the State-Federal water boundary south to 70°N. *B,* The middle sub-area extends south from 70°N and goes to 69°N. *C,* The south sub-area extends south from 69°N to the Brooks Range.

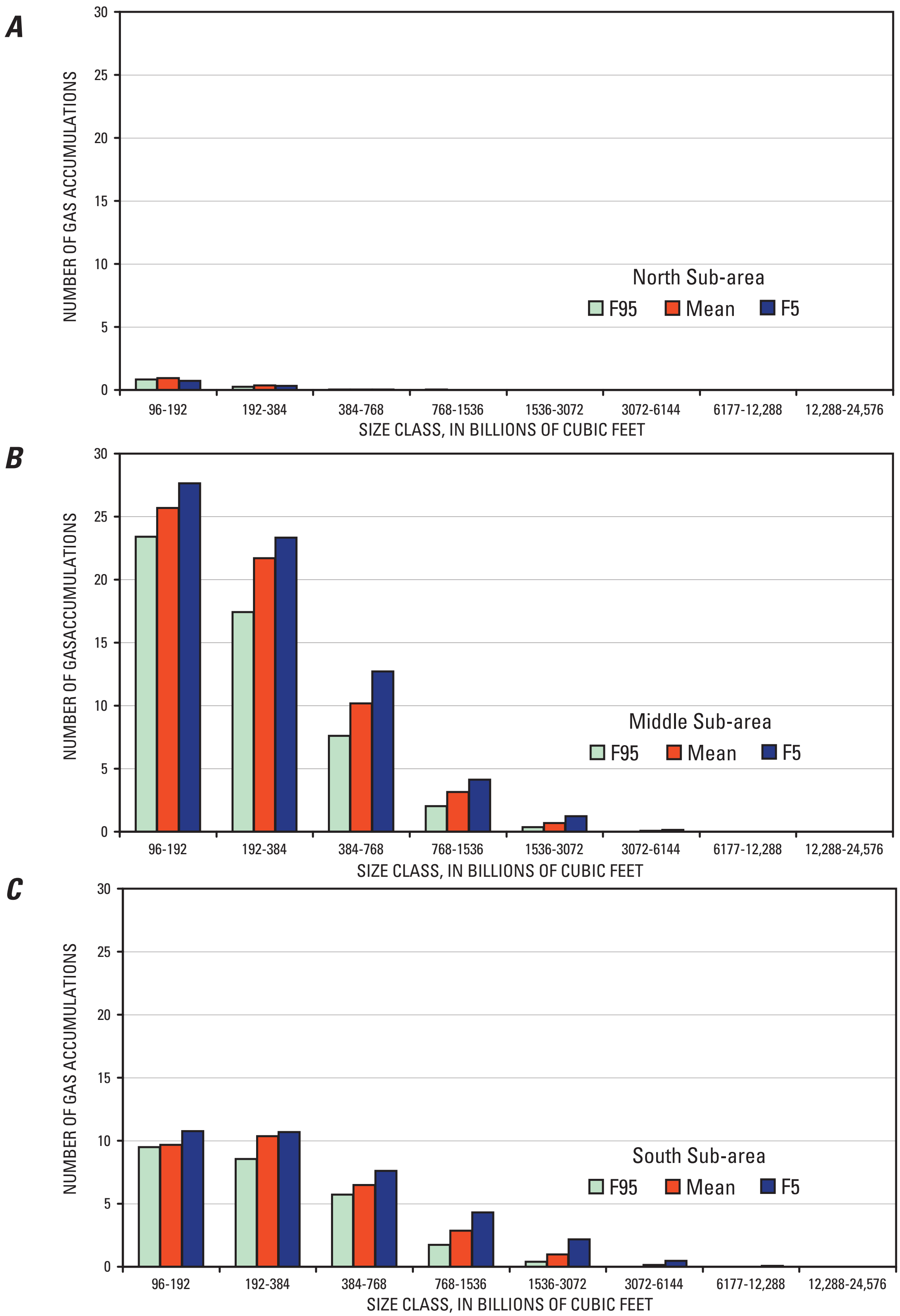

Figure 2–2. Size-frequency distribution of undiscovered conventional gas accumulations for each Central North Slope sub-area associated with the 95th fractile estimate (F95), the mean estimate, and the 5th fractile estimate (F5) of the assessed distribution of technically recoverable non-associated gas. *A,* The north sub-area extends from the State-Federal water boundary south to 70°N. *B,* The middle sub-area extends south from 70°N and goes to 69°N. *C,* The south sub-area extends south from 69°N to the Brooks Range.

Appendix 3. Documentation of Cost Estimates

Transportation Costs

General Assumptions: Pipelines to Market

For oil, the projected rates for the Trans-Alaska Pipeline system from the Alaska Department of Revenue (2004) were assumed. The average tariff[1] from 2006 to the end of the forecast period (2006-2021) is $3.54 per barrel. The projected tanker rates from Valdez to the market for the same period averaged $2.03 per barrel.

Data from Broderick (Bureau of Land Management, written communication, 1992) were updated to 2003 cost levels. More recent pipeline cost data were gathered from the following: (1) literature, (2) applications to the Alaska State Pipeline Office (Tom Braden, Alaska Pipeline Office, personal communication, 1998) and (3) information from hearings of the Regulatory Commission of Alaska. These data were analyzed and extrapolated to compute costs of pipelines of comparable sizes to those depicted by Broderick (U.S. Bureau of Land Management, written communication, 1992).

The diameter[2] for the feeder lines from individual discoveries to the regional pipeline was dependent on discovery size and the field production schedule. Feeder line diameter and length, that is, the average distance from the field to a regional pipeline, determined feeder line investment costs. The tariff or charge for transporting the oil from the discovery to a regional pipeline was computed as if the feeder pipeline were operated as a regulated common carrier and permitted a 12 percent after-tax rate of return on investment cost. The calculated tariff included the after-tax rate of return, operating costs, taxes and 15 year recovery of the initial investment.

Feeder pipeline investment costs were estimated from a procedure described by Tom Braden (Tom Braden, Alaska Pipeline Office, personal communication, 1998). Annual operating costs were assumed to be 2 percent of the initial investment costs.

Both the feeder and regional oil pipeline tariffs were adjusted to provide for the cost of construction of utility lines and the return of seawater (for water flood) to the operating field. The return lines use the same vertical support members and right of way, as well as that portion of operating cost. To account for this extra cost, the initial investment cost was increased by 50 percent. The extra operating costs are provided by the computation of annual operating cost as 2 percent of the initial investment of the entire system.

For non-associated natural gas, the high tariff scenario of the producers (BP, ExxonMobil and ConocoPhillips, 2002) presentation was $2.85 per mcf in 2001 dollars. This estimate became $2.94 per mcf when adjusted to 2003 dollars. In 2001 dollars, the estimated project capital cost is $19.4 billion and the range for the resulting tariff is from $1.90 to $2.85 per mcf.

Regional or collector gas pipelines from the sub–area to the gas conditioning plant near Pump Station 1 are assumed to be high pressure pipelines that transport both gas and natural gas liquids (Corbett and others, 2003). The feeder lines from the field to the collector were assumed to be low pressure but much shorter than the regional lines. Because the assessment indicated the gas is expected to be relatively lean in terms of entrained liquids, it was assumed that the feeder lines transported both gas and the entrained NGL to the high pressure regional pipelines. The procedure for computing the tariffs for the regional gas collector lines and the feeder lines from the field were similar to the procedures used for the crude oil pipeline tariff calculations.

Oil Transportation Cost Assumptions by Sub-area

North Sub-area

According to table 4 in the text, undiscovered resource estimates ranged from 1.4 BBO to 3.0 BBO. Nearly all North Slope infrastructure is located in the north sub-area. The north sub-area accounts for only l7 percent of total study area acreage. It was assumed new discoveries would tie into existing infrastructure. Each accumulation was assumed to incur transport costs to cover the construction, amortization, and rate of return to investment of a feeder pipeline either connecting the discovery to existing infrastructure or Pump Station 1. The distance used for computing construction and operating costs was 9 miles. For the north sub-area, each discovery was required to bear the costs of investment and operating costs for the 9-mile line over the productive life of the discovery.

Middle Sub-area

Undiscovered oil estimates ranged from 1.1 BBO to 2.6 BBO. The distance from the oil centroid on middle sub-area

[1] The term tariff, as used in this report, is a charge by a publicly regulated entity; in this case a regulated common carrier.

[2] The peak annual production volume was computed. Based on the peak annual volumes the following feeder line diameters were used for 50, 100, 200, 300, and 400 million barrel fields: 5.5 inch, 7.7 inch, 10.4 inch, 12 inch and 14 inch, respectively.

to Pump Station 1 is 35 miles. It was assumed that a 20-inch regional pipeline capable of transporting at least 200 thousand barrels per day[3] of oil would be built by a third party and operated as a regional common carrier. Along with the tariff charged by the pipeline of $0.22 per barrel, each discovery incurred the cost of its own 15-mile feeder pipeline to connect to the regional pipeline. The computed tariffs for the feeder lines went from $0.74 per barrel for a 100 million barrel accumulation to $1.49 to accommodate an accumulation of about 20 million barels.

South sub-area

Undiscovered oil resource estimates ranged from 70 million barrels to 190 million barrels. The oil centroid was located 147 miles from Pump Station 1. The combination of the long distance and small accumulations resulted in a tariff of more than $7 per barrel.

Natural Gas Transportation Cost Assumptions by Sub-area

North Sub-area

The total volumes of the non-associated gas resources assigned to this area are small, ranging from 200 to 310 BCF. Standard gas feeder pipelines were assumed to transport gas an average distance of 25 miles to the gas conditioning plant near Pump Station 1. The cost of transportation depended on the discovery size and ranged from 13 cents to 20 cents per mcf.

Middle Sub-area

The non-associated gas volumes assigned to the middle sub-area ranged from 14.53 TCF to 24.5 TCF. The distance from the non-associated gas resource centroid to Pump Station 1 is 59 miles. A high pressure line is assumed to be constructed and operated as a common carrier utility to transport about 1 BCF per day of gas to the gas conditioning plant to be located near Pump Station 1. The capital cost of the line is almost 200 million dollars but with a high utilization rate the tariff is 12 cents per mcf. If there is insufficient capacity on the export line to the lower 48, the 0.5 BCF per day tariff will be 18 cents per mcf. Both gas and liquids are assumed to be transported together. Feeder lines averaging 15 miles in length are assumed to transport the gas and NGL's to the regional pipeline. Depending on discovery size, the computed feeder tariff ranged from 4 to 12 cents per mcf.

[3] A single discovery or group of discoveries developed jointly that amount to 0.5 BBO might require a 20 inch pipeline for transporting 200 thousand barrels of liquids per day. The Alpine field which was initially considered to be 365 million barrels, required a 14-inch product pipeline that was designed to transport 90 thousand barrels of oil per day.

South Sub-area

The non-associated gas volumes assigned to the south sub-area range from 9.2 TCF to 20.3 TCF. It is assumed that a 137 mile 1 BCF per day regional pipeline is built from the non-associated gas centroid to the gas conditioning plant located near Pump Station 1. At 1 BCF per day the tariff was $0.27 per mcf. If there were only sufficient capacity for a 0.5 BCF per day the computed regional tariff was $0.41 per mcf. Feeder lines average 20 miles in length are assumed to transport the gas and NGL's to the regional pipeline. Depending on discovery size, the computed feeder tariff ranged from 6 to 16 cents per mcf.

Exploration and Field Development Costs

Exploration

The calculation of exploration costs is as described in the text. For the north sub-area, exploration cost per wildcat well was set at 85 percent of the cost of rank wildcat exploration that was estimated for the middle sub-area.

Development Costs

Field development costs include well drilling and completion costs and the cost of facilities. Actual field development costs depend on site-specific characteristics of prospects. In the process of developing generic cost functions a number of simplifying assumptions were made to keep the economic analysis tractable. The assessed undiscovered accumulations were first grouped into field size categories (table 3-1 provides the field size classes) and into 5000-foot depth intervals. The analysis also included the costs of vertical delineation wells for each accumulation evaluated. Development cost estimates for a representative accumulation for each size and depth class were estimated and tested against an economic screen to determine whether all the accumulations in the size and depth category were commercially developable.

Oil Field Design

In past studies, it has been assumed the conventional well drainage area for the North Slope to be 160 acres (Young and Hauser,1986: Broderick, U.S. Bureau of Land Management, written communication, 1992). Footnote 5 (in the text) shows how the accumulation size in millions of barrels, *szo*, was computed from the simulated reservoir attributes as:

$$szo = 7.758(t)(hps)(f)(rf_o)(ac)/(fvf_o) \text{ where } hps = p(1\text{-}S_W)$$

where for each field simulated, the reservoir attribute values are (1) net reservoir thickness, t, in feet, (2) porosity, p, as a decimal fraction, (3) hydrocarbon pore space, *hps*, as a function of p and S_W where S_W is water saturation as a decimal fraction, (4) trapfill, f, as decimal fraction, (5) recovery factor, rf_o,

Table 3-1. Recovery per well, in millions of barrels per well, by accumulation size category based on 160 acre drainage area for conventional wells.

[MMBO, millions of barrels of oil]

Accumulation size class (MMBO)	Well productivity north sub-areas (MMBO)	Well productivity middle and south sub-area (MMBO)
4–8	0.84	0.60
8–16	1.19	0.80
16–32	1.58	1.00
32–64	2.00	1.18
64–128	2.60	1.48
128–256	3.00	2.87
256–512	3.50	3.49
512–1,024	4.00	4.00
1,024–2,048	4.50	4.50

and (6) the formation volume factor, fvf_o. The area of closure, *ac*, for a single producing well as stated in thousands of acres is 0.16. The assessors provided estimates of the recovery factor or fraction of the in-place resources that are recoverable, rf_o, and the formation volume factor, fvf_o, was calculated as a function of reservoir depth (Schuenemeyer, 1999). Development well productivity (*wp*), in millions of barrels per producing well, for an individual accumulation was calculated as:

$$wp = 7.758(t)(hps)(f)(rf_o)(0.16)/(fvf_o).$$

The well recoveries shown in table 3-1 are computed as a volume weighted average of the computed play level well recoveries derived from the reservoir attribute simulations. The required number of production wells for the representative accumulation was calculated by dividing the recoverable accumulation volume of oil by the estimated well productivity. For conventional wells, each set of 10 producing wells required 4 injection wells (National Petroleum Council, 1981a, Young and Hauser, 1986).

Application of horizontal well technology is attractive, because it can reduce the number of required production wells, reduce drill pad numbers and sizes, and increase the proportion of the in-place oil that is recoverable. The drainage area and thus well productivity assigned to a horizontal production well depends on the natural drainage area of vertical wells and the length of the horizontal section of the well bore that is in contact with the formation. If a vertical well has a 160 acre (circular) drainage area, a horizontal well having a horizontal section of 3000 feet would theoretically increase the drainage area to 365 acres (Joshi, 1991a).[4] It was assumed that each producing horizontal well would require a horizontal injection well.

Well productivity values for conventional directional well configuration are shown in table 3-1. It is assumed that per acre (drainage area) well productivity for the conventional and horizontal wells is the same. For this assumption to be true, the formation's vertical permeability should be at least as great as horizontal permeability (Joshi, 1991b). In as much as this type of reconnaissance analysis does not capture all the tradeoffs in applying horizontal technologies (such as the increase in recoverable in-place oil and reduction in pad costs), the cost estimates presented here may be higher than costs from a more detailed analysis.

Drilling Costs

Total development well costs are computed as the product of the number of wells required for field development and of the sum of drilling, completion and non-drilling well costs. Development well drilling and completion cost data were compiled from several sources including industry reports (Gingrich and others, 2001; Redman, 2002; National Petroleum Council, 2003) and historical costs for Alaska oil wells reported in the Joint Association Survey(American Petroleum Institute, 1997-2003).[5] Costs were estimated for representative wells within the following vertical intervals: up to 5,000 feet, from 5,000 feet to 10,000 feet, from 10,000 feet to 15,000 feet and greater than 15,000 feet.

The following example illustrates the cost estimation procedure for horizontal wells. Production wells at North Slope fields are typically drilled from gravel pads that accommodate as many as 40 well collars spaced at 10-foot intervals along with production equipment. Even conventional production wells must be deviated or drilled directionally to reach target locations that are horizontally offset from the drilling pad. This directional component adds on average 20 percent to drilling length that is beyond or greater than the vertical depth at the target location. At the target depth, a lateral extension of 3,000 feet is drilled. Suppose the average per foot drilling

[4] If a vertical well drains 160 acres, its ideal drainage area radius is 1489 feet. The horizontal extension of the well of 3000 feet adds 205 acres, [3000 x 2 x 1489)/(43250)], to the original 160 acre drainage area. This method of computing the drainage area follows Joshi (1991a). It assumes vertical permeability is at least that of horizontal permeability.

[5] In some years, the number of wells drilled in Alaska far exceeded the number of wells reported in the Joint Association Survey. Further, data appear to be presented in vertical depth intervals whereas most North Slope production wells have a significant directional component, so actual footage drilled is greater than vertical depth.

and completion cost of $400 per foot is assumed to be characteristic for the more accessible Central North Slope areas. The following relation was used to estimate horizontal development well drilling and completion costs for targets at a vertical depth of 10,000 feet (James Craig, Minerals Management Service, written communication, 2005):

$$[10{,}000\text{ft} * (1.2) * (\$400/\text{ft}) + 3000\text{ft} * \$400/\text{ft})] = \$6.0 \text{ million per well}$$

In this example, the horizontal well adds 25 percent to the costs of drilling and completing a conventional development well, but the horizontal wells reduce the required number of producing wells by more than half, that is, productivity per producing well is more than doubled. Because each horizontal well is assumed to have one horizontal injector and the conventional well is assumed to require only 4 injection wells per set of 10 producers, the overall drilling investment per barrel recovered in the example for horizontal wells is about 89 percent of the per barrel drilling cost with the conventional well investment. For vertical depths less than 10,000 feet, the deviation factor is 30 percent rather than 20 percent as shown in the example (James Craig, Mineral Management Service, written communication, 2005.)

Estimated costs, in 2003 dollars, by 5000 foot depth interval for conventional wells in the accessible Central North Slope area are $2.0 million (with vertical depth 4200 ft), $3.60 million (7500 ft), $5.76 million (12000 ft), and $7.68 million (16,000 ft). Estimated costs of corresponding horizontal wells with 3000-ft lateral extensions in 2003 dollars are $3.38 million, $5.10 million, $7.79 million, and $12.08 million. For the less accessible south sub-area it was assumed drilling costs would be 20 percent more than the other sub-areas.

Facilities Costs–Oil Development

Production facilities include drill pads, flow lines from drilling sites, the central processing unit, and infrastructure required for housing workers, including amenities. Facilities design and costs depend on peak production rates and field size. As of the beginning of 2004, there are eight stand-alone fields operating in Northern Alaska. These fields are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Badami, Northstar, and Alpine. The Liberty field, formerly Tern Island, is in the latter planning stages for commercial development as a stand-alone field. Expected recovery for Liberty is in the 150 million barrel range.

Table 3-2. Facilities investment cost, in 2003 dollars.

[MMBO, millions of barrels of oil; bbl, barrel of crude oil]

Field size (MMBO)	Cost ($/bbl)
32	8.29
48	6.24
64	5.10
96	3.84
128	3.18
192	2.60
256	2.25
384	1.84
512	1.59
768	1.30
1,024	1.13
1,536	0.92
2,048	0.80

Although little information is in the public domain, a version of the Northstar development plan, including development cost estimates, was submitted by BP (1996) to the State of Alaska for evaluation with its request for relief of profit sharing provisions of the State lease. With this information and with inferred facilities cost estimates from published reports for other fields under development, a cost relationship that specified investment cost per barrel as a function of peak fluid flow rates for facilities for fields in the Prudhoe Bay area was calibrated.[6] Table 3-2 shows estimates of the facilities investment costs by accumulation size class.

Since the mid 1980's, a number of newly discovered accumulations were developed as satellite units, where their wellhead production fluids are separated and recovered at the central processing facility of a nearby field. The Point McIntyre and Niakuk accumulations share the central processing facilities at the Lisburne field. Prudhoe Bay production includes the following satellites: Midnight Sun, Aurora, Polaris, Borealis, and Orion. Kuparuk River production includes the following satellites: Tobasco, Tarn, Meltwater, and Palm. Thus far, all of the satellite and parent fields have common ownership. The cost reduction from facility sharing depends on physical production configurations and on the relative bargaining strength of the satellite owner in comparison to the central processing facilities owner. The State has only recently begun to study the potential regulatory issues of fair treatment of new entrants (Kaltenbach and others, 2004).

Two recent examples of innovations have demonstrated the potential North Slope application of satellite and cluster development to commercially produce discoveries that ordinarily would not be economic. The central processing facility at the North Slope Alpine field ia expected to process the produced fluid mixtures (oil, gas, and water) of wells belonging to several different smaller new discoveries located up to 25 miles away (Nelson, 2004). In deep-water offshore areas elsewhere in the world, small accumulations, even under different ownership, are produced using sub-sea well completion technology with their production fluids processed at a common production platform or facility many miles away. The advances in multi-phase flow measurement of production fluids, have enabled these cluster and satellite production systems to monitor production in different environments and under a variety of ownership situations (Atkinson and others, 2005). Therefore, it is probably physically possible for the production of most of the accumulations assessed in north sub-area of the Central North Slope study area to be developed

[6] The cost relation was similar in form to those presented by the National Petroleum Council (1981b) and Young and Hauser (1986).

either as cluster developments or be connected to a currently operating production facility.

In the middle sub-area, respectively 38 and 47 undiscovered oil accumulations were assigned at the 95th and 5th oil fractile estimate. Consequently, it was assumed that accumulations smaller than 130 million barrels of technically recoverable oil would be considered for facilities sharing. The procedure for accounting for facility-sharing charges follows an arrangement used by Thomas and others (1993).[7] Specifically, it was assumed that facilities sharing would, on average, result in a 30 percent reduction[8] in the initial facility investment cost for the satellite owner. The annual operating cost paid by the satellite owner is the sum of the annual operating cost per barrel that would be incurred if the satellite were developed as a stand-alone field plus the undiscounted per barrel investment cost that was saved originally. Although resulting charges to the satellite owner are in all likelihood in excess of the marginal costs incurred by the central processing facility operator, the scheme does reduce the minimum or threshold price at which a satellite becomes commercially developable while reducing risk as well.

Field Production Profile–Oil Accumulations

Future discoveries are assumed to attain peak annual rates of production equal to a percentage of the accumulation's ultimate oil recovery. Table 3-3 shows the assumptions relating to the discovery production profile. An accumulation with less than 65 million barrels of recoverable oil is assumed to reach peak production in the year production starts. For the accumulations with sizes between 65 and 500 million barrels, peak production occurs in the second production year, and for larger fields peak production occurs in the third year of production. Peak production is maintained for several years and thereafter, annual production declines 12 percent per year.

At first glance the 12 percent field production decline rate appears unduly steep. Observed field decline rates are typically more subdued because of the application of enhanced recovery techniques to prolong field life. However, the appropriate enhanced recovery application and its success often depends on site-specific conditions.

The volume of produced water was projected by using the field production profile for oil, the degree of field depletion, and the water cut functions presented by Thomas and others (1991). Figure 3-1 shows percentage water expected in production with depletion of the field. Produced volumes of natural gas and natural gas liquids were projected using annual oil production, the expected values of the gas to oil ratio, and NGL to gas ratios associated with the representative field's size and depth classification.

Operating Costs–Oil Accumulations

Annual operating costs include labor, supervision, overhead and administration, communications, catering, supplies, consumables, well service and workovers, facilities maintenance and insurance, and transportation. Some of these costs, such as well workover and labor costs have declined dramatically during the last decade due to the introduction of coiled tubing technology and introduction of automation in field operations.

Annual operating costs expressed on a per barrel of crude oil basis were estimated as a function of hydrocarbon and water fluid volumes and number of operating wells (Craig, 2002). The produced fluid hydrocarbon and water volumes were projected annually using field production forecasts and a water cut function presented in figure 3-1 (Thomas and others, 1991), so that per barrel costs of produced oil reflected increases in costs that result from a higher water cut as the field is depleted.

[7] The scheme suggested by Thomas and others (1993) assumes the facility owner's bargaining position is stronger than that of the satellite owner.

[8] Because of the substantial existing infrastructure in the north sub-area, the reduction in investment when facilities sharing occurs was assumed to be 50 percent of the initial investment. The annual operating cost incurred by the small field operator is the sum of the annual operating cost per barrel that would be incurred if the satellite were developed as a stand-alone field plus the undiscounted per barrel investment cost that was saved originally.

Table 3-3. Oil accumulation production profiles assumed in the economic analysis.

[MMBO, millions of barrels of oil]

Field size (MMBO)	Years to reach peak production	Peak as percent of ultimate	Years of peak production
8–16	0	11	3
16–32	0	11	3
32–64	0	11	3
64–128	1	11	3
128–256	1	10	3
256–512	1	10	3
512–1,024	2	9	4
1,024–2,048	2	9	4
2,048–4,096	2	7.5	5
4,096–8,192	2	7.5	5

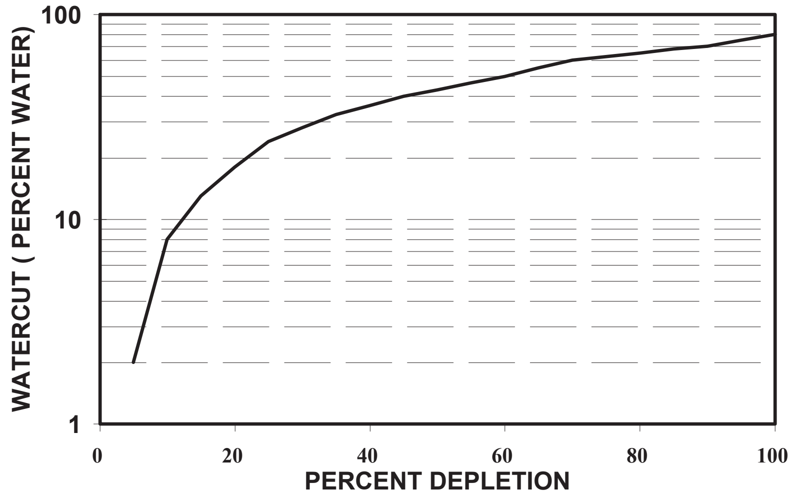

Figure 3-1. Percentage of water in production stream as a function of reservoir depletion. Data are from Thomas and others (1991).

Gas field design

A 1981 National Petroleum Council study (1981a and 1981b) on Arctic oil and gas development based its representative field designs on the assumption that the typical gas well drainage area would be 1 square mile (640 acres). Footnote 5 (in the text) shows how the accumulation size in billions of cubic feet, szg, was computed from the simulated reservoir attributes as:

$$szg = 4.356(t)(hps)(f)(\,rf_g)(\,ac)(\,fvf_g)*10^{-8}$$
$$\text{where } hps = p(1\text{-}S_W)$$

where for each field simulated, the reservoir attribute values are (1) net reservoir thickness, t, in feet, (2) porosity, p, as a decimal fraction, (3) hydrocarbon pore space, hps, as a function of p and S_W where S_W is water saturation as a decimal fraction, (4) trapfill, f, as decimal fraction, (5) gas recovery factor, rf_g, and (6) the gas formation volume factor, fvf_g. The area of closure, ac, for a single producing gas well as stated in thousands of acres is 0.64. The assessors provided estimates of the recovery factor or fraction of the in-place resources that are recoverable, rf_g, and the gas formation volume factor, fvf_g, was calculated as a function of reservoir depth (Verma and Bird, 2005). Development well productivity (wp_g), in billions of cubic feet per producing well, for an individual accumulation was calculated as:

$$wp_g = 4.356(t)(hps)(f)(rf_g)(0.640)(\,fvf_g)*10^{-8}$$

The well recoveries shown in table 3-4 are computed as a volume weighted average of the computed play level well recoveries derived from the reservoir attribute simulations. The required number of production wells for the representative accumulation was calculated by dividing the recoverable accumulation volume of gas divided by the estimated gas well productivity. Gas accumulations do not require water injection wells. Horizontal drilling was not applied to the gas field development.

In the costs presented in the 2003 National Petroleum Council study (2003), there was no distinction made between the drilling and completion cost of oil or gas wells drilled in Arctic areas.

Facilities Costs–Gas Development

The costs presented in the National Petroleum Council report amounted to $5.871 million per development well (National Petroleum Council, 2003). The cost estimates were adjusted to about $6.6 million per development well to reflect 2003 cost levels.

Table 3-4. Recovery per well, in billions of cubic feet per well, by accumulation size category based on 640 acre drainage area for conventional wells.

[BCF, billions of cubic feet of gas]

Accumulation size class (BCF)	Well productivity north and middle sub-areas (BCF)	Well productivity south sub-area (BCF)
96–192	38	32
192–384	52	45
384–768	66	60
768–1,536	88	82
1,536–3,072	119	113
3,072–6,144	155	158
6,144–12,288	180	180

Table 3-5. Gas accumulation production profiles assumed in the economic analysis.

[BCF, billions of cubic feet of gas]

Accumulation size class (BCF)	Years to reach peak production	Peak as percent of ultimate	Years of peak production
96–192	0	7	11
192–384	0	7	11
384–768	1	6.5	12
768–1,536	1	6.5	12
1,536–3,072	1	6.5	12
3,072–6,144	1	6.5	12
6,144–12,288	2	6	14

Field Production Profile–Gas Accumulations

The text describes the procedure used to examine gas field production profiles of Gulf of Mexico discoveries. These production profiles were used as an analogue for the Central North Slope gas production profiles. Table 3-5 shows the pattern assumed for the Central North Slope study.

Operating Costs–Gas Accumulations

The annual field operating costs presented in the National Petroleum Council report amounted to $1.585 million per development well (National Petroleum Council, 2003). The cost estimates were adjusted to about $1.82 million per development well to reflect 2003 cost levels.

Appendix 4. Federal and Alaska Taxes

State Taxes

Severance Tax for Oil:

12.25 percent for years 1 through 5 adjusted for the economic limit rate, *elr*

15.00 percent after year 5 adjusted for the economic limit rate with a floor of \$0.80 per barrel (also adjusted for the economic limit rate)

$$elr = (1-(300/ADWR))^{a}$$

where: $a = (150000/ADFR)^{1.5333}$,

ADFR= average daily field production (bbl/d), and ADWR = average daily production per producing well (bbl/d).

If *elr* is less than or equal to zero, then severance tax is zero

Severance Tax for Gas:

10.00 percent adjusted for the economic limit rate, *elr,* with a floor of \$0.064 per thousand cubic feet (also adjusted for the economic limit rate)

$$elr = (1-(3000/ADWR))$$

where ADWR = average daily production per producing well (mcf/d).

If *elr* is less than or equal to zero, then severance tax is zero.

Ad Valorem Tax

Tax equals 2 percent of the economic value of pipelines, facilities, and equipment. For pipelines, a 20-year life was assumed. For tangible well costs, oil field equipment costs, and facilities costs, depreciation of the asset was based on the unit of production method.

State Income Tax

For planning purposes, the Alaska State agencies use 1.4 to 3.0 percent of net income. The rate used here was 3.0 of net income. Depreciation of capital assets associated with oil field development is permitted on a unit of production basis. For other capital, depreciation depends on the economic life of the equipment.

State Conservation Tax

State conservation surcharge tax is assumed to be set at \$0.05 per barrel.

Federal Taxes

Federal Income Taxes

Federal income tax rate of 35 percent of taxable income was assumed. Based on the 1986 Tax Reform Act, 30 percent of development well drilling costs is classified as tangible cost and therefore, capitalized over 7 years. Of the remaining 70 percent of drilling cost (that is, the intangible drilling costs), 30 percent is depreciated over 5 years and the remaining 70 percent is expensed immediately.