Undiscovered oil resources in the Federal portion of the 1002 Area of the Arctic National Wildlife Refuge: an economic update

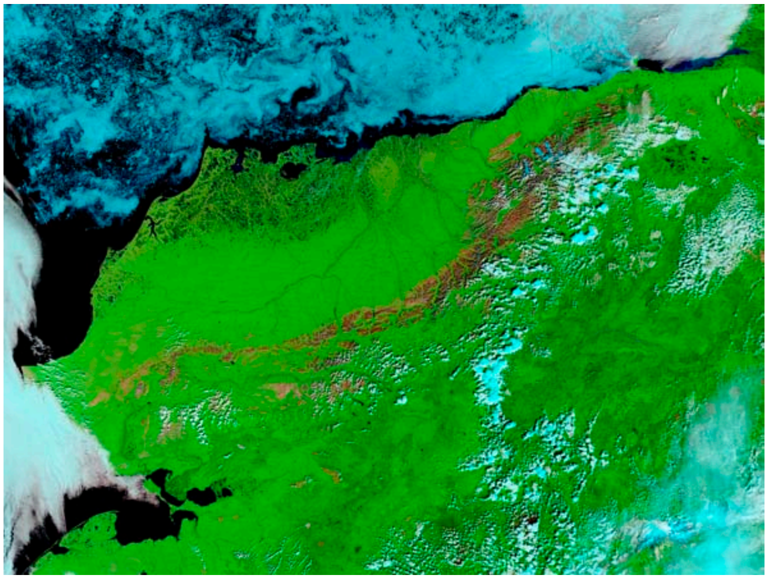

Photo by NASA

By E. D. Attanasi

Open-File Report 2005-1217

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

U.S. Department of the Interior
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U.S. Geological Survey
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TABLE OF CONVERSIONS TO SI UNITS

Multiply unit	By	To obtain metric unit
barrel	0.159	cubic meter
cubic foot	0.02832	cubic meter
foot	0.3048	meter

Undiscovered oil resources in the Federal portion of the 1002 Area of the Arctic National Wildlife Refuge: an economic update

E. D. Attanasi

SUMMARY

This report updates an economic analysis of the U. S. Geological Survey's 1998 petroleum assessment of the Federal 1002 Area of the Arctic National Wildlife Refuge (Attanasi, 1999). Whereas the 1998 geologic assessment evaluated Federal and Native lands in the 1002 Area and adjacent State waters (Bird, 1999), the economic analysis (Attanasi, 1999) published at that time, as well as this update, considered just the Federal part of the 1002 Area. The update includes newer field development practices based on horizontal development wells and alternative area development schemes, as well as an update of the 1996 base costs to a new base year of 2003. However, no changes were made to the 1998 geologic assessment.

In the 1998 assessment, geologists assessed volumes of undiscovered technically recoverable oil and gas in accumulations having at least 50 million barrels of oil or 300 billion cubic feet gas in-place. Estimates of technically recoverable oil in undiscovered accumulations in the Federal 1002 Area range from 4.25 billions of barrels of oil (BBO) to 11.80 BBO with a mean of 7.69 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. Estimates of the technically recoverable non-associated gas in undiscovered gas accumulations range from 0 to 10.02 trillion cubic feet of gas (TCFG) with a mean value of 3.48 TCFG. The economic value of non-associated gas resources was not examined in the 1998 evaluation and in this analysis because those resources are not expected to be a target of exploration in the near-term future.

This economic analysis uses the accumulation size-frequency distributions 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 is assumed. All calculations are in constant 2003 dollars. Transportation costs from the field to the market are included so that prices and incremental costs are at the market rather than well-head. Incremental cost functions include the full costs of finding, developing, producing, and transporting oil to the historical North Slope crude oil markets in the lower 48 west coast and the Far East.

The updated economic analysis focuses on two development option scenarios. In the first (*Scenario 1*), all but the smallest accumulations are developed as stand-alone fields, where each field has its own central processing facility. In *Scenario 2*, all produced fluids are processed at central processing facilities outside of the Federal 1002 Area and the processing facilities operate as independent regulated utilities. *Scenario 2* thus limits industry activity inside the Federal 1002 Area. For scenario 1 at $21 per barrel, 2.7 BBO associated with the mean and 0.8 BBO and 5.9 BBO associated with the 95th and the 5th fractiles can be found, developed, produced and transported to market. At $30 per barrel, the computed economic volumes are 6.1 BBO (associated with the mean), 3 BBO (associated with the 95th factile), and 9.7 BBO (associated with the 5th fractile). The economic volumes for scenario 2 were quite similar. Except when prices were below $25 per barrel, economic volumes for *Scenario 2* were within 10 percent of the *Scenario 1* economic volumes.

The accumulation size-frequency distributions for the mean and 5th fractile estimates have most of the resource contained in large accumulations. The resulting incremental cost functions showed large reserve additions as market prices increase above the threshold prices (between $16 and $18 per barrel) that trigger commercial exploration. At market prices of $30 per barrel about 3.0 BBO or 70 percent of the technically recoverable oil assessed at the 95th fractile is economic. For the mean estimate, 6.1 BBO or 79 percent of the assessed oil is economic, and for the 5th fractile estimate 9.7 BBO or 82 percent of the assessed oil is economic. Sensitivity studies show economic results to be robust (stable) with respect to reasonable changes in economic and technical assumptions. When adjusted to constant dollars, these estimates of economically recoverable oil are generally within 10 percent of the estimates published in the earlier analysis (Attanasi, 1999), suggesting that improvements in productivity, such as those brought about by horizontal drilling, have largely offset increased costs that occurred between the 1996 and 2003 base years.

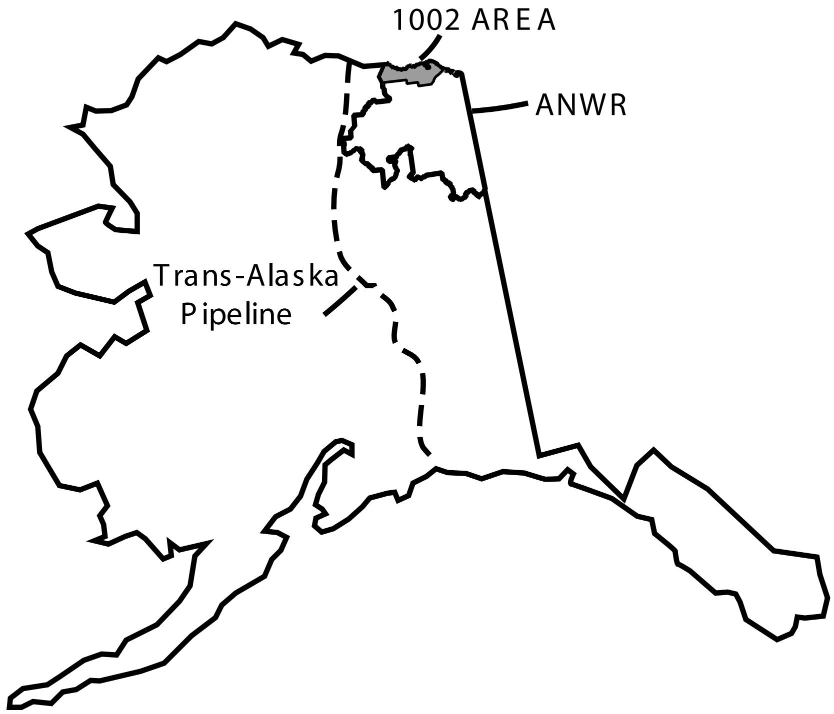

Figure 1. Location map of the Federal and Native 1002 Area in relation to the entire Arctic National Wildlife Refuge and Alaska's North Slope.

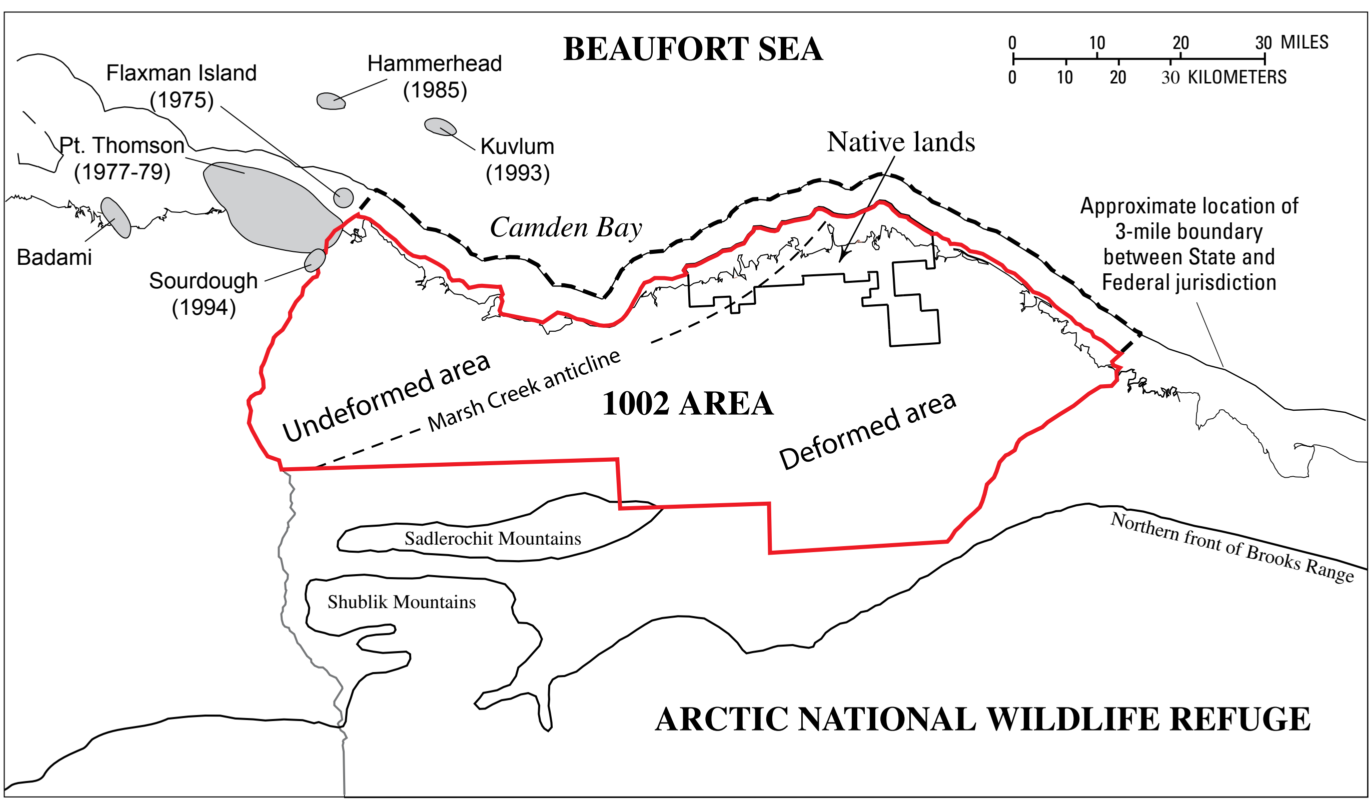

Figure 2. Map showing geologic study area (Federal 1002 Area), Native lands and adjacent state waters, recent discoveries, the Arctic National Wildlife Refuge, and the Undeformed and Deformed areas of the 1002 Area. Petroleum plays occurring principally in the Undeformed area are the Topset, Turbidite, Wedge, Thomson, Kemik, and Undeformed Franklinian. Plays occurring principally in the Deformed area include the Thin-Skinned Thrust Belt, Ellesmerian Thrust Belt, Deformed Franklinian, and Niguanak/Aurora.

INTRODUCTION

This study is an update of the economic analysis of the undiscovered, technically recoverable conventional oil resources assessed for the Federal 1002 Area (see figures 1 and 2) of the Arctic National Wildlife Refuge (reported in US Geological Survey Open File Report 98-34, 1999). The geologic assessment is described in terms of numbers, sizes, and volumes of undiscovered, but potentially producible, oil and gas accumulations. Estimates of costs and the required product prices for transforming these undiscovered resources into discovered, commercially producible, volumes of oil are presented here. The update includes newer field development practices based on horizontal development wells and alternative area development schemes, as well as an update of the 1996 base costs to a new base year of 2003. The results of the economic analysis are summarized as incremental or resource cost functions.

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 which underlie the functions are often used in market supply models. *This economic analysis is confined to the resources in the Federal part of the 1002 Area. The analysis does not predict the revenue or bonus payments for leases in the Federal 1002 Area nor does it attempt to estimate regional or national secondary economic benefits.* The economic component of the Federal 1002 Area assessment places the geologic resource analysis in an economic context that is more informative and easily understood by government policymakers and industry decision makers. The geologic assessment and economic analysis is regional in nature rather than prospect specific.

Undiscovered technically recoverable conventional oil and gas resources are resources posited to exist in *undiscovered accumulations* outside of known fields on the basis of geologic knowledge and theory. Technically recoverable resources are producible using current recovery practices, but without reference to economic viability. *Conventional oil and gas accumulations* are discrete well-defined accumulations, typically bounded by a downdip water contact, from which oil, gas, and natural gas liquids (NGL) can be extracted using traditional development and production practices. *Accumulations assessed by geologists outside of known fields were considered for the purposes of the economic analysis as separate and discrete new fields*. *Economically recoverable resources* are that part of the assessed technically recoverable resource for which the costs of finding, development, and production, including a return to capital, can be recovered by production revenues at a given price.

The discussion starts with a brief review of the geologic assessment. It then summarizes characteristics of the assessed technically recoverable resources that are important for understanding the economic analysis. Assumptions about markets, pricing, costs, and the technical relationships used in estimating the incremental costs functions are considered. Results and interpretations of the economic analysis update are discussed in the concluding sections.

Acknowledgements

The author thanks Ken Bird, Keith Long, James Coleman and Brenda Pierce for their reviews and suggestions that improved the description of the analysis. He also thanks Donna Foulke for her patience in putting the original manuscript in its present form.

GEOLOGIC ASSESSMENT

Procedure

The details of the geologic assessment protocol and its statistical foundations are described in Schuenemeyer (1999a). The commercial value of a new discovery depends on its expected size, whether it is oil or gas[1], its depth, location, and reservoir properties. Characteristics of the assessment results, such as the accumulation size-frequency distribution, the depth distribution, and the expected geographical distribution of assessed resources are fundamental for understanding the economic analysis. Numbers of accumulations and accumulation properties were assessed at the level of the geologic play. A play is defined as 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.

For each geologic play, the assessment geologist assigned probabilities and probability distributions to attributes of undiscovered conventional oil and gas accumulations having at least 50 million barrels of oil (MMBO) or 300 billion cubic feet of gas (BCFG) in-place. These distributions include number of prospects, depth of accumulations, and reservoir attributes that included net pay thickness, area of closure, porosity, and percentage trap fill. Play and prospect probabilities of success were also estimated by the geologists[2].

[1]Fields and accumulations are classified as either oil or non-associated gas on the basis of gas-to-oil ratios. Those having at least 20,000 cubic feet of gas per barrel of crude oil are classified as non-associated gas; otherwise, were classified as oil with by-product associated gas.

[2]A play probability is the likelihood that at least one accumulation of the minimum size exists. Prospect probability is the probability that any randomly chosen prospect results in an accumulation at least as large as the minimum size.

Table 1. Mean values of undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids (NGL) in the Federal 1002 Area of the Arctic National Wildlife Refuge as of January 1998.[BBO, billions of barrels of oil; TCF, trillions of cubic feet gas, BBL, billions of barrels of NGL (source Schuenemeyer, 1999b).

Area/Play Name[1]	Oil Fields			Gas Fields	
	Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
Undeformed					
Topset	4.325	1.193	0.010	0.000	0.000
Turbidite	1.279	1.120	0.065	0.000	0.000
Wedge	0.438	0.226	0.005	0.000	0.000
Thomson	0.246	0.314	0.026	0.156	0.013
Kemik	0.047	0.060	0.005	0.056	0.005
Undeformed Franklinian	0.085	0.150	0.015	0.150	0.014
Subtotal	6.420	3.063	0.127	0.361	0.032
Deformed					
Thin-Skinned Thrust Belt	1.038	0.283	0.003	1.325	0.014
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.876	0.018
Deformed Franklinian	0.046	0.044	0.003	0.816	0.043
Niguanak/Aurora	0.183	0.168	0.010	0.105	0.006
Subtotal	1.267	0.496	0.016	3.121	0.080
Total Federal 1002 Area	7.687	3.558	0.143	3.483	0.112

[1]Geologic characteristics of plays are defined Bird (1999)

Probability distributions describing the sizes[3] of accumulations and numbers of accumulations and volumes of hydrocarbons for individual plays were calculated by the following simulation scheme. For each replication, *i*, $i=1,\ldots,N$, the play risk was evaluated. For each successful play, a value for the risked number of accumulations in the play was computed as the product of the prospect probabilities and a random draw from the distribution of the number of prospects specified by the assessor. For each realization of the play represented by the n_i accumulations, the probability distributions representing the reservoir attributes were sampled n_i times, thus providing a size for each accumulation.

Geologists also specified pairwise dependencies (as high, medium, low) across plays for the occurrence of charge, reservoir, and timely trap formation. The probability distributions for individual plays were combined - conditioned on the play dependencies - with computer simulations. From the resulting aggregate estimates of the distribution of volumes, the associated numbers and sizes of undiscovered accumulations were recovered by play.

Each of the 10 play definitions included a description of the geographic location and geologic characteristics (see Bird, 1999). Most of the plays thought to occur in the 1002 Area are found in adjacent State lands, under State and Federal waters, or elsewhere on the North Slope. Supporting studies were prepared by the assessment geologists and other members of the Assessment Team to assist in the task of characterizing play attributes with probability distributions.

Results

Estimates of technically recoverable oil in undiscovered accumulations in the Federal lands of the 1002 Area range from 4.25 BBO (95th fractile) to 11.80 BBO (5th fractile) with a mean of 7.69 BBO. Estimates of technically recoverable non-associated gas in undiscovered gas accumulations range from zero (95th fractile) to 10.02 TCFG (5th fractile) with a mean estimate of 3.48 TCFG. Table 1 presents play level and total mean estimates of oil, associated gas, associated gas natural gas liquids (NGL), non-associated gas, and non-associated gas NGL for the 1002 Area. The Topset Play accounts for 56 percent of total oil, and the Topset, Turbidite, and Thin-Skinned Thrust Belt plays together account for more than 86 percent of the total oil assessed. Results suggest that the likelihood is very low of a single large gas field occurring with a NGL to gas ratio sufficiently high for an accumulation to be developed solely for its liquids. Technically recoverable oil accumulation size-frequency distributions, shown in figure 3, convey the economic implications of the oil estimates. Few small

[3]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 Sw where Sw 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, 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:

$$szo = 7.758(t)(hps)(f)(rf)(ac)/(fvf) \text{ where } hps = p(1-Sw).$$

A similar approach was taken for simulating gas accumulation sizes. Schuenemeyer (1999a) provides a more detailed discussion of this approach.

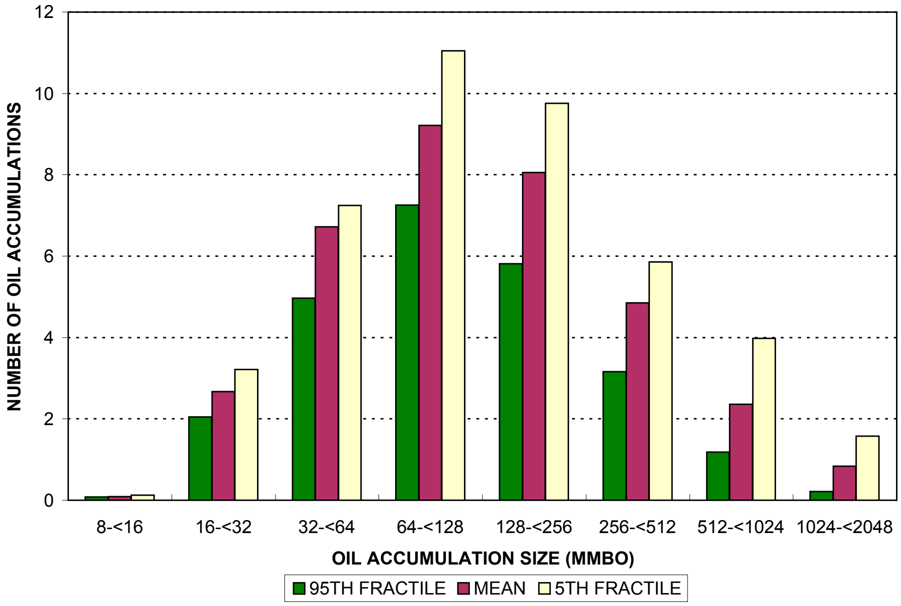

Figure 3. Size frequency distribution of undiscovered conventional oil accumulations associated with the 95th fractile estimate, the mean estimate, and the 5th fractile estimate of the assessed distribution of technically recoverable undiscovered oil for the Federal 1002 Area (MMBO, millions of barrels of oil).

accumulations are shown because only accumulations having at least 50 million barrels oil in-place were assessed.

Stand-alone fields of the size of 150 million barrels (recoverable) are considered for development in the coastal areas of the Central North Slope, for example the Liberty Field (Craig, 2002). Based on the accumulation size-frequency distribution associated with the *mean* estimate of undiscovered technically recoverable oil, 3.26 BBO (42 percent) of the assessed oil is assigned to accumulations of at least 500 million barrels of oil (MMBO). Similarly, accumulations of at least 500 MMBO account for 1.12 BBO (26 percent) and 6.43 BBO (54 percent) of the undiscovered volume of oil associated with the 95th and 5th fractile estimates, respectively (see table 2). Table 2 also shows that accumulations larger than 256 MMBO account for 52 percent (2.22 BBO), 65 percent (4.99 BBO) and 72 percent (8.52 BBO) of the oil assessed at the 95th fractile, mean, and 5th fractile estimates, respectively. In short, significant oil volumes were assessed in accumulation sizes of economic interest.

Assessment results (Bird, 1999) show, at the play level, that most of the oil is expected to be concentrated in plays located in the geographically confined Undeformed area (see figure 2: area between Staines River and Marsh Creek Anticline). At their mean estimates, these plays - Topset, Turbidite, Wedge, Thompson, Kemik, and Undeformed Franklinian - account for 6.46 BBO in 31 accumulations (or about 84 percent at the mean oil estimate and 88 percent of the mean number of accumulations). Furthermore, 6 BBO or 78 percent of the total oil estimated at the mean was associated with accumulations with depths shallower than 10,000 feet. Less than 6 percent of the oil was assigned to accumulations at depths greater than 15,000 feet.

The average gravity for the assessed oil was about 30 degrees API; somewhat lighter than oil found near the Prudhoe Bay area. This difference is attributed to measurements from wells drilled at undeveloped discoveries near the 1002 Area. There was also no indication that contaminants in the assessed oil would present production problems or require special treatment (for play assessment data see Schuenemeyer, 1999b).

In summary, the characteristics of the assessed technically recoverable oil important to the economic analysis are the volumes of oil, the oil accumulation-size distribution, and depths. The geographical location of the assessed resources was not specified but is the consequence of the play locations and play endowments. Distributions in figure 3 and supporting data show most of the assessed oil in the 1002 Area assigned to accumulations sufficiently large to be of economic interest. Also, more than three-fourths of the oil assessed is expected to be in accumulations at depths of less than 10,000 feet. Finally, more than 80 percent of the oil was assigned to the western part of the Federal 1002 Area, the area closest to existing infrastructure.

Table 2. Distribution of Assessed Federal 1002 Area Resources of crude oil[1] based on field size distributions associated with estimates of oil at the 95th fractile, the mean, and the 5th fractile.

USGS Class	Oil Field Size	Cumulative Volume Percentage		
		95TH	MEAN	5TH
	(MMBO)	(PERCENT)	(PERCENT)	(PERCENT)
18	4096-8192	0.00	0.56	1.36
17	2048-4096	1.39	5.90	12.60
16	1024-2048	7.83	20.82	31.34
15	512-1024	26.30	42.43	54.49
14	256-512	52.18	64.87	72.19
13	128-256	77.29	83.84	87.36
12	64-128	93.29	94.94	96.26
11	32-64	98.77	99.11	99.28
10	16-32	99.97	99.98	99.98
9	8-16	100.00	100.00	100.00

[1]The 95th fractile estimate is 4.25 BBO, the mean estimate is 7.69 BBO, and 5th fractile estimate is 11.8 BBO.

ECONOMIC APPROACH

Data

Data from the assessment simulations include the accumulation size and attributes that determine size. The attributes include area, net pay thickness, depth, porosity, recovery factor; for oil accumulations: the oil formation volume factor. Attributes used to compute accumulation size (see footnote 3) were applied to estimate average production well recovery.

Economic cost data were drawn from earlier economic studies of the Federal 1002 Area and elsewhere on the North Slope (National Petroleum Council 1981a, 1981b, J. Broderick, Bureau of Land Management, 1992, personal communication, Han-Padron Associates, 1985, Young and Hauser, 1986, Thomas and others, 1991, Thomas and others, 1993, Craig, 2002). Additional data on recent cost trends obtained from a variety of sources including 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. The empirical relationship presented in Thomas and others (1991) predicted the water cut of produced oil as a function of field depletion.

General Assumptions and Scope of Analysis

Results of the economic analysis are presented as the costs of transforming undiscovered resources into discovered commercially producible volumes of oil. These 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.

Furthermore, the incremental cost functions are assumed to be 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.

Undiscovered non-associated gas fields were not evaluated in the original economic analysis because a viable gas market appeared to be at least two decades into the future. A supporting study did consider the option of transporting North Slope gas to the south and selling the gas as LNG to the Far East (Attanasi, 1994). It concluded that at least until 2015, North Slope gas would be at a competitive cost disadvantage to other existing and potential suppliers to that market. In Northern Alaska about 30 TCF of associated gas has already been discovered that can be produced cheaply if a gas market develops. Gas that is currently produced with oil is typically stripped of its liquids and re-injected into the oil accumulation or used as fuel on the lease. For the purposes of this update, the economic value of the undiscovered non-associated gas was not considered.

Economic Assumptions

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. It was assumed that the 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 areas considered in the economic analysis were available to exploration for oil.

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 individual discoveries, that is projects, 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.[4]

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 B 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-sixth royalty was assumed to be paid to the Federal government (Young and Hauser, 1986).

[4]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.

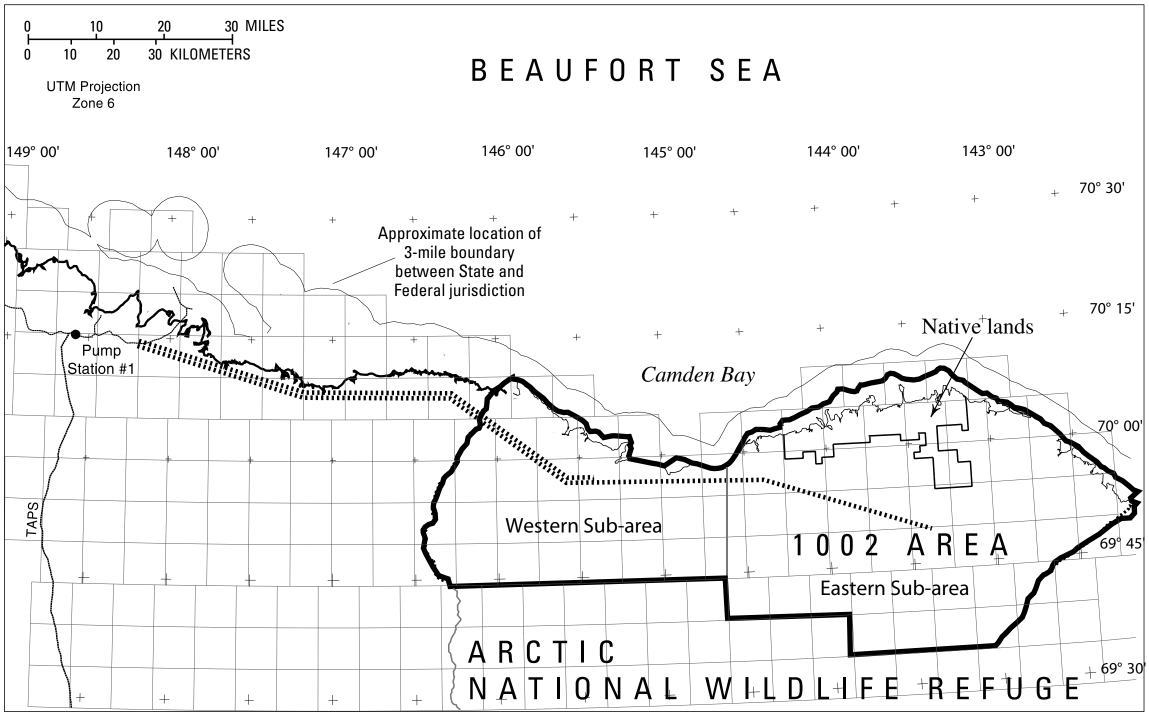

Figure 4. Map showing the partitioning of the Federal 1002 Area into the western and eastern sub-areas and the possible regional pipeline transport system (dashed lines from the eastern sub-area of the Federal 1002 Area to Pump Station 1 where double lines show part where east and western sub-area regional pipelines are parallel). The placement of the pipelines shown in this figure is for the purpose of cost analysis in this study and does not imply a suggested route for the actual system.

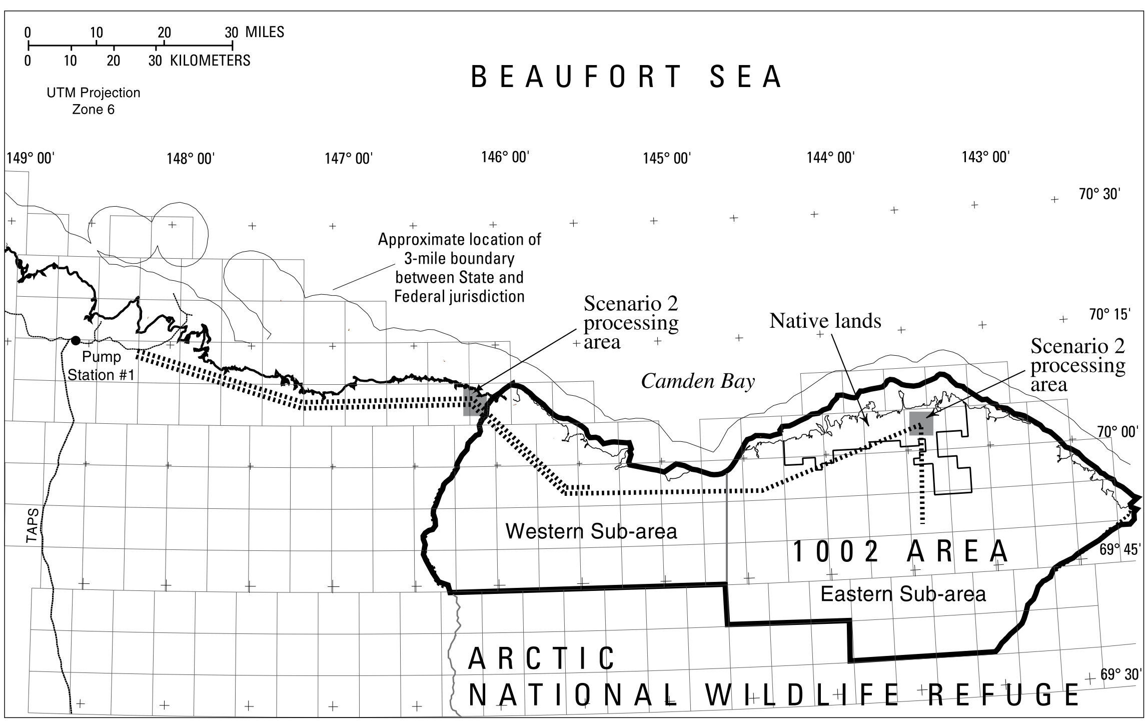

Figure 5. Map showing the partitioning of the Federal 1002 Area into the western and eastern sub-areas and the possible regional pipeline transport system from sub-areas to production facility area and then to Pump station 1 near Prudhoe Bay. Scenario 2 processing areas are shaded in gray. The placement of the pipelines in this figure if for the purpose of cost analysis in this study and does not imply a suggested route for the actual system.

A charge of $0.25 per barrel produced is also taken to cover abandonment costs.

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 $55 per barrel in 2003 dollars. During the summer of 2005, spot oil prices exceeded the high end of the price range; that is, 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 resources by increasing the play recovery factors assumed by the geologists and also permitting commercial development of smaller accumulations that occur but that were not assessed by the geologists.

The oil price discussed is the landed U. S. lower 48 states' West Coast price rather than the well-head price. It also represents a price at the market that is sustained, rather than an erratic spot price. In the absence of gas markets the well-head price of gas was assumed to be zero (non-associated gas was not considered). The well-head 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).

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 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 Revenue. The marine transport rate represents transport cost weighted by projected sales volumes from Valdez to a set of destinations which include the US lower 48 West Coast, the Far East, and the US mid-continent region. These rates are projected on an annual basis to 2020 (Alaska Department of Revenue, 2004). The average projected TAPS tariff for the period starting in 2014 (assumed to be the earliest time of Federal 1002 Area development) is $3.90 per barrel and similarly, the marine transport cost is $2.23 per barrel.

For this study, the Federal 1002 Area was partitioned into two sub-areas (see figures 4 and 5) from which regional pipeline costs to transport oil to pump station 1 of TAPS were computed (figure 4). The assessment geologists allocated resources at the play level to the western and eastern sub-areas. Overall, approximately 80 percent of the assessed oil was assigned to the western area. The sub-area allocations of technically recoverable resources by play are presented in Appendix A in tables A-1 though A-3. Of the 1.526 million acres representing the entire onshore Federal lands of the 1002 Area, there are 0.581 million acres in the western sub-area and 0.945 million acres in the eastern sub-area.

Cost functions were computed based on two very different configurations regarding field development (identified as *Scenarios 1* and *2*).

Scenario 1. It was assumed in the original study (Attanasi, 1999) that a major regional pipeline would be built from TAPS Pump Station 1 to a central location in the western sub-area of the 1002 Area a distance of 85 miles. Transportation of oil from the eastern sub-area would come with a parallel regional pipeline originating about 50 miles to the east of the terminus of the western sub-area pipeline. The regional pipeline business entity is assumed to be a regulated common carrier. Pipeline tariff charges were set to meet all operating costs, taxes, and to assure investors a 12 percent after-tax return on investment. The assumed pipeline flow capacity from the western sub-area is at least 500,000 barrels per day. If a larger diameter pipeline is required, then because of scale economies, the unit cost levels and tariffs will be lower than those used in this study.

The distances from the designated central points within the two sub-areas (shown as ends of regional pipelines in figure 4) to Pump Station 1 were used for estimating investment cost. Pipeline investment cost functions, originally presented in Young and Hauser (1986) and later updated by Broderick (1992), were adjusted to 2003 cost levels. Annual pipeline operating costs are computed as 2 percent of the initial investment cost. The pipeline business entity, operated as an independent regulated utility, is assumed to be subject to all Alaska State taxes as well as Federal taxes.

Discovery-specific smaller diameter feeder lines[5] were assumed to be built from the periphery of the discovery to the regional pipeline. In the western sub-area feeder lines were assumed to be of maximum length of 12 miles. In the eastern sub-area, the maximum length of the discovery-specific feeder pipeline is 16 miles. Details of the investment cost functions are presented in Appendix B[6].

Scenario 2 An alternative development configuration is to designate the western and eastern sub-areas as two separate

[5]The smaller diameter feeder lines were sized according to the field size; see appendix B.

[6]It is also assumed that there are smaller diameter pipelines from the coastal areas outside of the 1002 Area that transport diesel fuel and seawater to the feeder lines. The seawater processing and fuel storage facilities for western sub-area are assumed to be located on coastal State land outside of the Federal 1002 Area. For the eastern sub-area, fuel and seawater could be transported from that facility or from facilities located in coastal Native lands in to the eastern sub-area. These lines will use the right of way and vertical support members (VSMs) of the regional pipeline and feeder lines.

operating areas and require the produced fluid mixture of oil, gas, and water to be transported and processed outside of the Federal 1002 Area in one or more central processing facilities. Recent technological advances have reduced costs of monitoring and transporting multiphase (mixture of water, oil, and gas) fluids longer distances than in the past (Atkinson and others, 2005). Such advances have allowed commercial development of moderate-size deep water discoveries (50 to 200 million barrels) that may not have been developed if each discovery required construction of a new production platform. The produced fluid mixture of oil, gas, and water is transported to a shared production platform under pressure so the gas is maintained in solution with the oil. On the North Slope, the proposed satellite developments to the Alpine field are examples where multiphase production fluids will be transported over moderate distances. The operating area (field management area) proposed for the main Alpine accumulation and its satellite operations covers 0.890 million acres (Nelson, 2004).

Scenario 2 requires that the mixture of oil, water, and gas produced at the wells be transported to central processing facilities outside the Federal 1002 Area. For accumulations in the western sub-area the produced liquids are transported by the feeder lines to a regional line that terminates in the State land coastal area just outside of the Federal 1002 Area where the mixture is processed. Gas, fuel, and seawater could be returned to the field by return lines utilizing the right of way and vertical support members (VSMs) of the lines to the central processing facilities. For the western sub-area the processed oil is then transported 65 miles west to Pump Station 1 by a regional pipeline (figure 5).

Production from the eastern sub-area is assumed to be transported through the feeder lines to a regional pipeline to its own processing facility located on Native lands near the coast (figure 5). An alternative to processing on Native lands is to add booster pumps to maintain multiphase flow and to transport the mixture west to a location near the western sub-area processing facilities. If the product is processed in the Native lands it then could be transported by regional pipeline 135 miles west to Pump Station 1. Additional details of the analysis are presented in Appendix B.

Exploration and field development costs

Exploration, field design, and field development methods on the North Slope differ from that of the lower 48 States. 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 wells and facilities. Typically, 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[7] 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. Following Young and Hauser (1986) and Broderick (1992), costs of wells and facilities are assumed to be at least 30 percent greater in the Federal 1002 Area than the costs that prevail in the Central North Slope Area.

For a stand-alone field, 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 oil recovery can yield, operators typically introduce technological innovations relatively quickly. 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 accumulations of the Federal 1002 Area that occur beneath the lagoonal areas between the shoreline and barrier islands can be developed from onshore or with shallow-water drilling pads.

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 Federal 1002 Area. 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[8], 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[9]. The first twenty wildcat wells drilled in the Federal 1002 Area were assigned a minimum cost of 15 million dollars per well. Exploration was evaluated in increments of 10 wildcat wells. Actual exploration and development costs will depend on site-specific characteristics of the prospects. *Play analysis does not provide specific locations, so generic costs were used.*

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

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

[9]*For example*, suppose a development well drilled to a depth of 7500 feet in the Central North Slope costs 3.6 million dollars. Total costs for a comparable wildcat well in the western sub-area of the Federal 1002 Area, including non-drilling costs that amount to 50 percent of drilling cost are about 14 million dollars (that is, the product of 3.6 (base well) x 1.3 (remoteness) x 2 (wildcat factor) x 1.5 non-drilling factor).

Field development costs

The two principal field development cost categories are (1) drilling and completion cost of production and injection wells and (2) facilities' costs. During the 1980's and 1990's the reduction in development and operating costs for new discoveries on the North Slope has been substantial and well documented (Harris, 1987a, 1987b Nelson, Thomas and others, 1993). More recently, the use of horizontal wells for all production wells at the Alpine field has, by increasing development well productivity, permitted commercial development of an accumulation with a relatively thin pay interval by the 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. Details for cost estimation procedures are presented in Appendix B.

Field development well investment costs are based on the number of wells required to develop a discovery, the associated number of injection wells, and the cost per well. Per well drilling cost estimates used here should be understood to represent expected costs based on an established industry operating within the capacity of its service industry. Drilling costs were estimated using data from Annual Joint Association Surveys (American Petroleum Institute 1997- 2005), Redman, (2002), National Petroleum Council (National Petroleum Council, 2003) and Craig (2002). Prudhoe Bay area costs for drilling and completing wells became the basis for estimating well costs for the Federal 1002 Area.

The estimated Prudhoe Bay area 2003 base costs for conventional well $2.0 million for wells less than 5,000 feet, $3.6 million for 5,000 feet to10,000 feet, $5.8 million for 10,000 feet to 15,000 feet, and $7.9 million depths greater than 15,000 feet. For the western and eastern sub-areas of the Federal 1002 Area, drilling costs are increased 30 percent over the Prudhoe Bay area costs to compensate for the Federal 1002 Area's lack of infrastructure and special environmental precautions (Young and Hauser, 1986). Horizontal well costs were, in part, based on the conventional well cost to target depth, along with the additional cost of the horizontal lateral section of 3,000 feet and a cost penalty of total drilling length beyond 15,000 feet (James Craig, Minerals Management Service, written communication, 2005) . Extra costs are incurred when fixing down-hole problems when drilling beyond 15,000 feet. Production well drilling-cost levels are assumed to represent long term averages for the industry in constant dollars, rather than the costs associated with first field development.

The number of wells required to develop a discovery depends on well productivity. For each accumulation size and depth category, average oil well recovery was computed with the assumed production well spacing and calculated from the simulated reservoir attribute values for each successful prospect. For each field size class, at a given depth interval, the representative (sub-area) well recovery is a weighted average (weight by volume) of the corresponding play well recovery values estimated from the simulation data (Schuenemeyer, 1999a). Well recovery estimates varied substantially across different depth intervals within the same field size category, reflecting variations in assessed reservoir quality attributes of each play occurring in the depth interval.

Conventional wells were assumed to be drilled on 160 acre spacing (Young and Hauser, 1986). Based on the 160 acre conventional well drainage area and if vertical and horizontal well permeability are roughly equivalent, horizontal production wells having 3000 foot horizontal sections will have drainage areas of at least 365 acres. For each set of 10 conventional production wells, 4 injection wells (water or gas) would also be drilled (National Petroleum Council, 1981a, Young and Hauser, 1986), but for the horizontal wells, each production well is matched by a horizontal injector well in a 'line drive configuration' (Redman, 2002). Appendix B discusses the field design and estimation of the associated drilling costs.

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. Appendix B discusses the procedure applied to recalibrate the facilities cost functions used in earlier studies. Table B-4 presents the cost estimates by field size class used in this study.

As of the end of 2004, the eight oil fields developed on a stand-alone basis in Northern Alaska are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Badami, North Star, 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.

Development of accumulations as satellites to established fields can reduce substantially capital requirements for field development, as well as the time to first production. Actual savings are site-specific because certain facilities costs, such as drill pads, internal roads, and product transportation, are location dependent. It was assumed that facilities sharing would, on average, result in a 30 percent reduction in facilities investment costs (Thomas and others, 1993).

For *Scenario 1*, as in the earlier analysis (Attanasi, 1999), facilities sharing was limited to discoveries smaller than 130 million barrels in the western sub-area. In the eastern subarea, the small numbers of assessed fields and possibly greater distances between fields make facilities sharing less likely. For *Scenario 2* cost analyses assumed the produced fluids are transported from the wellhead to common central processing facilities outside of the Federal 1002 area. Details are presented in Appendix B.

Field operating costs

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). 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 a water cut function presented in figure B-2, Appendix B, (Thomas and others, 1991). As fields are depleted the water cut increases, thereby increasing the per barrel cost of oil processed. The specific formulation used to estimate operating costs is discussed in Appendix B.

Economic rationale 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 subarea 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 of a particular size and depth category are assumed to be developed if the representative accumulation is found to be 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. It is assumed that when operator income declines below the sum of direct operating costs and the operator's production-related taxes, the economic limit rate is reached and production stops. Newly discovered 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.*

The basis for the estimates of recoverable undiscovered petroleum as a function of price is that the incremental units of exploration, development, and production effort will not take place unless the revenues expected to be received from the eventual production will cover the incremental costs, including a normal return on the incremental investment. Exploration is assumed to continue until the incremental cost of drilling wildcat wells is equal to or greater than the net present value of the cost of the commercially developed fields discovered 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 fields discovered was maximized.

ECONOMIC ANALYSIS

Incremental costs: finding, development, production and transportation

The full costs include costs of finding, developing, producing and, in the case of northern Alaska, transporting oil to market. Incremental costs are linked to development, production, and transportation cost by finding rate functions that predict the discovery size distributions generated by increments of wildcat wells. Computations were based on successive increments of 10 wildcat wells. All computations were prepared for the western sub-area and eastern sub-areas independently.

The results of computations are presented for the two scenarios described earlier. For Scenario 1, all discoveries in the eastern sub-area and all discoveries except those smaller than 130 million barrels in the western sub-area are developed as stand-alone operations[10]. Alternatively, for Scenario 2, it is assumed that fluids produced from all discoveries would be transported to common processing facilities located outside the Federal 1002 Area (see figure 5). Sensitivity studies show that it would be less costly to develop fields using horizontal drilling than the standard directional drilling practices assumed in the earlier Federal 1002 Area economic study (Attanasi, 1999), so for both scenarios horizontal drilling was assumed to be implemented.

Figure 6 shows the incremental cost functions for crude oil for the Federal 1002 Area based on the undiscovered field size distributions associated with the 95th fractile, the mean, and 5th fractile estimates under Scenario 1 and Scenario 2, respectively. Tables 3 and 4 summarize the sub-area and (Federal) study area estimates of incremental costs, expected reserve additions, and finding costs. Along with crude oil, the tables show the associated gas and associated gas liquids in developable oil discoveries.

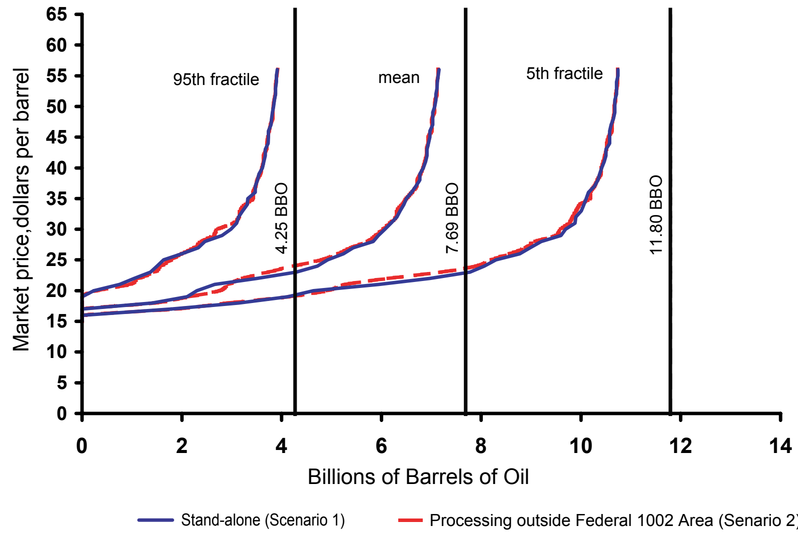

Figure 6. Incremental costs, in dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered accumulations in the Federal 1002 Area of Northern Alaska, where computations were based on discoveries developed (1) predominately as stand-alone fields, each with processing facilities, (Scenario 1, figure 4) and alternatively, (b) where production fluids are transported to two central processing facilities located outside of the Federal 1002 area (Senario 2, figure 5). Vertical lines represent the technically recoverable oil at the 95th fractile, the mean, and the 5th fractile estimates as reported in Bird (1999). The dollar values have a 2003 base year.

Not only is the 95th fractile estimate smaller in the volume of oil assessed but the oil is distributed in smaller fields that in many cases are not only harder to find but may not even be commercially developable. For the Scenario 1 development scheme, the threshold prices at which wildcat drilling and development is economic under the assumptions used in this analysis are $19.90 per barrel for the 95th fractile distribution, $17.50 per barrel of the distribution associated with the mean, and $16.40 per barrel for the distribution associated with the 5th fractile estimates. For Scenario 2 (processing outside the Federal 1002 Area), the threshold prices at which wildcat drilling and development is economic under the assumptions used here are $19.70 per barrel for the 95th fractile distribution, $17.40 per barrel of the distribution associated with the mean, and $16.50 per barrel for the distribution associated with the 5th fractile estimates. The two scenario incremental cost curves based on the same mean or fractile size distribution will be almost indistinguishable as the comparison of tables 3 and 4 show. At per barrel prices of $35 or greater, there is only a few percent difference in the computed economic oil volumes based on development alternatives of Scenario 1 and Scenario 2.[11]

The incremental cost functions associated with the mean and 5th fractile accumulation size-frequency distribution (figure 6) show large additions to reserves as prices initially increase beyond the threshold price at which exploration is initiated because a large part of the total oil associated with the accumulation size-frequency distributions is in large fields (greater than 500 million barrels, see Table 2). Discovery rates decline rather rapidly after the initial increments of wildcat drilling are completed and the large, low cost discoveries are depleted. Table 3 shows for the accumulation size distribution for mean estimate that at $21 per barrel it is economic to find, develop, and produce 2.7 BBO; at $30, 6.1 BBO; at $42, 6.9 BBO; and at $51, 7.1 BBO.

Figures 6 highlights the uncertainty attached to the geologic estimates of technically recoverable oil, regardless of the scenario assumptions. At $21 per barrel economically recoverable oil ranges from 0.75 BBO to 5.95 BBO. The incremental cost functions are relatively flat to $30 per barrel. For scenario 1, at $30 per barrel, 70 percent of the oil assessed at the 95th fractile is economic, 79 percent of oil assessed at

[10]The negotiated sharing costs between the facility operator/owner and the owner of the new discovery followed a scheme presented by Thomas and others (1993). In this scheme the facility owner captures some of the potential savings that would accrue to the small field owner if the facility owner had to price services on a marginal cost basis.

[11]For the case where production fluids are processed outside the Federal 1002 Area (Scenario 2), the eastern sub-area discoveries appear to be somewhat more costly to develop than as stand-alone fields.

Table 3. Incremental cost of finding, developing, producing, and transporting oil and natural gas liquids (NGL) from undiscovered oil fields in the Federal 1002 Area of the Arctic National Wildlife Refuge and associated and finding costs: Scenario 1. [BBO-billions of barrels of oil, TCF-trillions of cubic feet of gas, BBL-billions of barrels of NGL, Asc. gas-Associated gas, boe-barrels of oil equivalent. Find., finding]

	95th FRACTILE ESTIMATE				MEAN ESTIMATE				5th FRACTILE ESTIMATE			
Sub-area $/bbl	Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Find. Cost $/boe	Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Find. Cost $/boe	Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Find. Cost $/boe
Western												
18	0.00	0.00	0.00	0.00	1.40	0.37	0.00	0.38	3.14	0.92	0.01	0.34
21	0.75	0.20	0.00	0.63	2.66	0.76	0.01	0.64	5.10	1.58	0.02	0.69
24	1.51	0.46	0.01	0.83	4.01	1.42	0.03	0.84	6.72	2.50	0.06	0.76
27	2.23	0.98	0.03	0.79	4.54	1.81	0.05	1.09	7.31	2.92	0.08	1.13
30	2.64	1.35	0.06	1.27	5.06	2.26	0.08	1.49	7.95	3.53	0.12	1.34
33	2.83	1.51	0.07	1.68	5.32	2.48	0.10	1.97	8.16	3.67	0.13	1.85
36	3.00	1.64	0.08	2.39	5.42	2.55	0.10	2.77	8.26	3.74	0.14	2.64
39	3.05	1.68	0.08	2.78	5.55	2.65	0.11	2.91	8.45	3.92	0.15	2.82
42	3.15	1.77	0.09	3.61	5.66	2.75	0.12	3.71	8.54	3.98	0.15	3.61
45	3.18	1.79	0.09	4.16	5.69	2.77	0.12	4.20	8.57	4.00	0.15	4.16
48	3.20	1.81	0.09	4.71	5.71	2.79	0.12	4.86	8.63	4.04	0.15	4.68
51	3.24	1.84	0.09	5.42	5.75	2.82	0.12	5.37	8.65	4.06	0.15	5.25
54	3.26	1.85	0.09	5.99	5.78	2.85	0.12	6.07	8.67	4.07	0.16	5.86
55	3.26	1.85	0.09	5.99	5.78	2.85	0.12	6.07	8.70	4.09	0.16	6.54
Eastern												
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.85	0.20	0.00	0.63
24	0.00	0.00	0.00	0.00	0.70	0.18	0.00	0.98	1.34	0.36	0.00	0.88
27	0.10	0.02	0.00	1.41	0.90	0.23	0.00	1.38	1.67	0.48	0.01	1.53
30	0.34	0.08	0.00	1.97	1.01	0.27	0.00	2.00	1.74	0.51	0.01	1.79
33	0.39	0.10	0.00	2.33	1.05	0.28	0.00	2.40	1.85	0.54	0.01	2.53
36	0.47	0.12	0.00	3.09	1.19	0.35	0.01	2.18	1.89	0.56	0.01	2.97
39	0.50	0.13	0.00	3.64	1.23	0.37	0.01	2.81	1.92	0.57	0.01	3.50
42	0.53	0.14	0.00	3.62	1.26	0.39	0.01	3.37	1.96	0.59	0.01	4.06
45	0.56	0.17	0.00	4.15	1.29	0.41	0.01	4.12	2.00	0.61	0.01	4.62
48	0.59	0.19	0.00	4.19	1.32	0.42	0.01	4.21	2.03	0.62	0.01	5.34
51	0.62	0.20	0.00	4.74	1.34	0.44	0.01	5.01	2.03	0.62	0.01	5.34
54	0.64	0.21	0.00	5.77	1.34	0.44	0.01	5.01	2.04	0.63	0.01	6.24
55	0.64	0.21	0.00	5.77	1.36	0.45	0.01	6.04	2.04	0.63	0.01	6.24
Total												
18	0.00	0.00	0.00	0.00	1.40	0.37	0.00	0.38	3.14	0.92	0.01	0.34
21	0.75	0.20	0.00	0.63	2.66	0.76	0.01	0.64	5.95	1.78	0.02	0.68
24	1.51	0.46	0.01	0.83	4.72	1.60	0.03	0.86	8.06	2.85	0.06	0.78
27	2.33	1.00	0.03	0.82	5.43	2.04	0.06	1.14	8.98	3.40	0.09	1.20
30	2.98	1.44	0.06	1.35	6.07	2.53	0.09	1.57	9.69	4.03	0.13	1.42
33	3.22	1.60	0.07	1.76	6.37	2.76	0.10	2.04	10.01	4.21	0.14	1.97
36	3.47	1.77	0.08	2.48	6.60	2.90	0.11	2.67	10.15	4.30	0.14	2.70
39	3.55	1.81	0.08	2.89	6.77	3.03	0.11	2.89	10.38	4.49	0.15	2.94
42	3.67	1.91	0.09	3.61	6.92	3.14	0.12	3.65	10.50	4.56	0.16	3.69
45	3.74	1.96	0.09	4.16	6.97	3.18	0.12	4.19	10.58	4.61	0.16	4.24
48	3.80	1.99	0.09	4.63	7.03	3.21	0.13	4.74	10.65	4.66	0.16	4.80
51	3.86	2.04	0.09	5.32	7.09	3.26	0.13	5.30	10.68	4.68	0.16	5.27
54	3.90	2.06	0.10	5.96	7.12	3.29	0.13	5.88	10.71	4.70	0.17	5.93
55	3.90	2.06	0.10	5.96	7.14	3.30	0.13	6.06	10.74	4.72	0.17	6.48

the mean is economic, and 82 percent of the oil assessed at the 5th fractile is economic.[12]

Sensitivity studies

Several numerical exercises tested the sensitivity of the economic results to specific economic and technical assumptions. The details are summarized in Appendix C. The specific parameters examined included drilling costs, facilities costs, required rate of return, and the effect of recognizing required redundancy in facilities for the Scenario 2. All tests were based on the undiscovered accumulation size distribution associated with the mean estimate. Like a comparison of results to the Scenario 1 and Scenario 2 (see Tables 3 and 4), most of the effects on the predicted volumes of economic resources due to cost increases in drilling, facilities, and required rate of return rapidly are dissipated as the market prices increased beyond $30 per barrel. The robustness of the economic volumes is a consequence of the geologic assessment; that is, the size distributions of undiscovered accumulations. The differences in the assessed distributions of undiscovered resources remain the primary sources of uncertainty.

[12]The corresponding percentages for Scenario 2 at $30 per barrel were 64 percent (95th fractile), 79 percent (mean), and 81 percent (5th fractile).

Table 4. Incremental cost of finding, developing, producing, and transporting oil and natural gas liquids (NGL) from undiscovered oil fields in the 1002 Area of the Arctic National Wildlife Refuge and associated finding costs: Scenario 2. [BBO-billions of barrels of oil, TCF-trillions of cubic feet of gas, BBL-billions of barrels of NGL, Asc. gas-Associated gas boe, barrels of oil equivalent. Find., finding]

	95th FRACTILE ESTIMATE				MEAN ESTIMATE				5th FRACTILE ESTIMATE			
Sub-area $/bbl	Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Find. Cost $/boe	Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Find. Cost $/boe	Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Find. Cost $/boe
Western												
18	0.00	0.00	0.00	0.00	1.45	0.39	0.00	0.37	2.93	0.86	0.01	0.36
21	0.96	0.27	0.00	0.67	2.95	0.87	0.01	0.66	5.28	1.64	0.02	0.62
24	1.59	0.51	0.01	0.92	4.05	1.48	0.04	0.62	6.89	2.67	0.07	0.86
27	2.24	0.98	0.03	0.86	4.61	1.92	0.06	1.02	7.45	3.09	0.09	1.16
30	2.62	1.30	0.05	1.44	5.11	2.28	0.08	1.55	7.96	3.52	0.12	1.37
33	2.82	1.49	0.07	1.81	5.30	2.47	0.10	2.00	8.13	3.65	0.13	1.92
36	2.99	1.64	0.08	2.44	5.49	2.62	0.11	2.50	8.35	3.82	0.14	2.53
39	3.11	1.74	0.08	3.08	5.62	2.72	0.11	3.24	8.49	3.94	0.15	3.11
42	3.14	1.77	0.09	3.56	5.65	2.74	0.12	3.69	8.53	3.97	0.15	3.60
45	3.17	1.79	0.09	4.13	5.68	2.77	0.12	4.18	8.59	4.02	0.15	4.14
48	3.24	1.84	0.09	5.29	5.73	2.80	0.12	4.77	8.64	4.05	0.15	5.24
51	3.26	1.85	0.09	5.94	5.76	2.83	0.12	5.35	8.67	4.08	0.16	5.81
54	3.27	1.87	0.09	5.94	5.78	2.85	0.12	5.99	8.69	4.09	0.16	6.53
55	3.29	1.88	0.09	6.56	5.80	2.86	0.12	6.74	8.69	4.09	0.16	6.53
Eastern												
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.19	0.05	0.00	0.75	1.01	0.25	0.00	0.70
27	0.00	0.00	0.00	0.00	0.78	0.20	0.00	1.20	1.44	0.40	0.00	1.08
30	0.10	0.02	0.00	1.47	0.93	0.24	0.00	1.72	1.64	0.47	0.01	1.58
33	0.34	0.08	0.00	2.01	1.00	0.27	0.00	2.02	1.78	0.52	0.01	2.13
36	0.43	0.11	0.00	2.63	1.12	0.32	0.00	1.78	1.84	0.54	0.01	2.52
39	0.47	0.12	0.00	3.09	1.17	0.35	0.01	2.30	1.91	0.57	0.01	3.52
42	0.50	0.13	0.00	3.64	1.25	0.39	0.01	3.39	1.94	0.58	0.01	4.11
45	0.55	0.16	0.00	4.22	1.26	0.39	0.01	3.39	1.96	0.59	0.01	4.11
48	0.59	0.18	0.00	4.23	1.29	0.40	0.01	4.02	2.00	0.61	0.01	4.58
51	0.59	0.18	0.00	4.23	1.31	0.42	0.01	4.21	2.02	0.62	0.01	5.35
54	0.62	0.20	0.00	4.62	1.34	0.44	0.01	5.04	2.04	0.63	0.01	6.22
55	0.62	0.20	0.00	4.62	1.34	0.44	0.01	5.04	2.04	0.63	0.01	6.22
Total												
18	0.00	0.00	0.00	0.00	1.45	0.39	0.00	0.37	2.93	0.86	0.01	0.36
21	0.96	0.27	0.00	0.67	2.95	0.87	0.01	0.66	5.28	1.64	0.02	0.62
24	1.59	0.51	0.01	0.92	4.24	1.53	0.04	0.63	7.90	2.92	0.07	0.84
27	2.24	0.98	0.03	0.86	5.39	2.12	0.07	1.05	8.89	3.49	0.10	1.15
30	2.72	1.32	0.05	1.44	6.04	2.53	0.09	1.58	9.59	3.98	0.13	1.40
33	3.16	1.58	0.07	1.83	6.31	2.74	0.10	2.00	9.91	4.17	0.14	1.96
36	3.43	1.75	0.08	2.46	6.61	2.94	0.11	2.38	10.19	4.36	0.15	2.53
39	3.58	1.86	0.09	3.08	6.79	3.07	0.12	3.08	10.40	4.51	0.16	3.18
42	3.64	1.89	0.09	3.57	6.90	3.13	0.12	3.64	10.48	4.55	0.16	3.69
45	3.72	1.94	0.09	4.14	6.94	3.15	0.12	4.04	10.55	4.60	0.16	4.13
48	3.82	2.01	0.09	5.14	7.01	3.21	0.13	4.64	10.65	4.66	0.16	5.12
51	3.85	2.03	0.09	5.69	7.08	3.25	0.13	5.14	10.70	4.70	0.17	5.73
54	3.89	2.06	0.10	5.74	7.12	3.28	0.13	5.82	10.74	4.72	0.17	6.47
55	3.90	2.08	0.10	6.27	7.14	3.29	0.13	6.43	10.74	4.72	0.17	6.47

To summarize, the assessed field size distributions associated with the mean, 95th, and 5th fractile estimates, respectively, to a large part determine the threshold prices at which the exploration becomes economic to initiate, as well as, the position and shape of the incremental cost functions shown in figure 6. Estimates representing larger volumes of technically recoverable oil generally have field size distributions with greater proportions of the resources assigned to large fields that typically have lower development costs and are found early in the exploration process. In an environment such as the North Slope where minimum commercial field size is large compared to the conterminous U.S., such differences in field size distributions magnify differences in estimates of economically recoverable oil beyond what would be expected by different volumes. Although there are a number of sources of economic uncertainty, the sensitivity studies suggest the economic volumes estimated are reasonably robust when predicated on accumulation size distributions that resulted from the geologic assessment. At this level of reconnaissance analysis, not all of the details of recent technological innovations could be captured. Moreover, there could be important technological innovations that are also not included that might enhance the value of the oil resources.

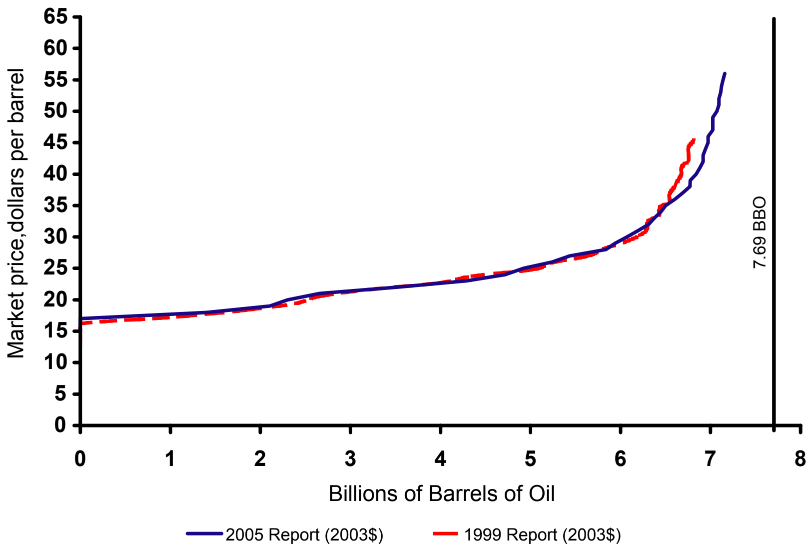

Figure 7. Incremental costs, in dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered accumulations in the Federal 1002 Area of Northern Alaska, where computations are based on stand-alone field development for the costs and technology updated to the 2003 base year compared to the earlier analysis published in Attanasi (1999). Vertical line represents the mean estimate of the technically recoverable oil for the Federal 1002 as reported in Bird (1999). The dollar value uses a 2003 base year.

CONCLUSIONS AND LIMITATIONS

Technically recoverable resources assessed for the Federal 1002 Area at the 95th and 5th fractiles estimates were 4.25 BBO and 11.80 BBO, respectively. The mean technically recoverable oil amounted to 7.69 BBO (Bird, 1999). Undiscovered size-frequency distributions corresponding to the 95th fractile, the mean, and 5th fractile estimates showed accumulations with at least 260 million barrels accounting for 2.21 BBO, 4.97 BBO, and 8.52 BBO, respectively. Most of the assessed oil is predicted to be in accumulation sizes of economic interest.

Incremental costs include the *full costs of finding, developing, producing, and transporting oil to market*. At incremental costs of $21 per barrel, 2.7 BBO associated with the mean and 0.8 and 5.9 BBO associated with the 95th and the 5th fractiles can be found, developed, produced and transported to market. Because most of the resources assigned to the mean and 5th fractile estimates were in large accumulations, the associated incremental cost functions showed substantial additions to reserves as market prices increase above threshold prices between $16 and $18 per barrel) that trigger commercial exploration. For the 95th fractile estimate, at market prices of $30 per barrel about 3 BBO or 70 percent of the oil assessed is economic. At $30 per barrel, for the mean estimate, 6.1 or 79 percent of the assessed oil is economic and for the 5th fractile estimate 9.7 BBO or 82 percent of the assessed oil is economic. The robustness of the economic results, which the sensitivity analysis showed, is a consequence of the geologic assessment, that is, the size distributions of the assessed undiscovered accumulations.

When comparing the results of this study to the earlier analysis which also considered only the Federal 1002 area (Attanasi, 1999), the 1996 dollars should be adjusted to 2003 dollars so that economic resources are compared in constant dollars. Based on the general producer price indices, the 1996 dollars would be multiplied by a factor of 1.08[13] to obtain their equivalence in 2003 dollars. Comparing the mean estimates at $21 in 2003 dollars ($19.42 in 1996 dollars), the earlier analysis shows about 2.9 BBO economic, and this analysis shows 2.7 BBO economic, at $30 in 2003 dollars ($27.74 in 1996 dollars) (see figure 7). The earlier analysis shows 6.2 BBO economic, but this analysis shows 6.1 BBO economic and at $42 in 2003 dollars ($38.82 in 1996 dollars), the earlier analysis shows 6.7 BBO economic and this analysis shows 6.9 BBO economic. When adjusted to constant dollars, these estimates of economically recoverable oil are generally within 10 percent of the estimates published in the earlier analysis (Attanasi, 1999), suggesting that improvements in productivity have to a large extent offset increased costs that occurred between the 1996 and 2003 base years.

It is important to keep in mind that until a systematic subsurface evaluation is accomplished, uncertainty about the size and nature of the resource will remain significant. Along with the geologic uncertainty, there are also important sources of uncertainty attached to the economic evaluation of the resources by virtue of the many assumptions that were required. Furthermore, wide variations in world oil prices over time increase the risks of investing in high-cost areas such as the North Slope, a factor that is beyond the scope of this analysis to capture.

This analysis was time independent. At recently prevailing rates of wildcat drilling for the North Slope it could take perhaps a decade to drill the number of well increments that might be economic at an incremental cost of $21 per barrel for either the mean estimate or the 5th fractile estimate. During that time additional improvements in technology could lower costs further. Alternatively, any attempt to rapidly increase drilling rates would undoubtedly drive up drilling rig day rates and cause increasing costs, voiding a central assumption in this analysis of constant real costs. The incremental cost functions do not show what the industry will do, but what is possible assuming the volumes and distribution of resources occur and that the economic assumptions match reality.

[13]Producer price index, (where 1982=100) for 1996, is 127.7 and for 2003 the produce price index is 138.1.

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Appendix A. Tables showing allocation of the mean, 95th and 5th fractile estimates of Federal 1002 Area to western and eastern sub-areas

Table A-1. Undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids (NGL) in the western and eastern sub-areas of the Federal 1002 Area of the Arctic National Wildlife Refuge as of January 1998 based on the mean estimate of the assessed oil in the 1002 Area. [BBO, billions of barrels of oil; TCF, trillions of cubic feet gas, BBL, billions of barrels of NGL] (Source: simulation data discussed in Schuenemeyer, 1999a)

Area/Play Name1	Oil Fields			Gas Fields	
	Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
Western sub-area					
Topset	3.707	1.022	0.008	0.000	0.000
Turbidite	1.279	1.120	0.065	0.000	0.000
Wedge	0.438	0.226	0.005	0.000	0.000
Thomson	0.246	0.314	0.026	0.156	0.013
Kemik	0.047	0.060	0.005	0.056	0.005
Undeformed Franklinian	0.085	0.150	0.015	0.150	0.014
Thin-Skinned Thrust Belt	0.288	0.079	0.001	0.368	0.004
Ellesmerian	0.000	0.000	0.000	0.088	0.002
Deformed Franklinian	0.041	0.040	0.003	0.734	0.039
Subtotal	6.132	3.011	0.129	1.551	0.076
Eastern sub-area					
Topset	0.618	0.170	0.001	0.000	0.000
Thin-Skinned Thrust Belt	0.750	0.205	0.002	0.957	0.010
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.788	0.016
Deformed Franklinian	0.005	0.004	0.000	0.082	0.004
Niguanak/Aurora	0.183	0.168	0.010	0.105	0.006
Subtotal	1.555	0.548	0.014	1.931	0.036
Total Federal 1002 Area	7.687	3.558	0.143	3.483	0.112

Appendix A. Tables showing allocation of the mean, 95th and 5th fractile estimates of Federal 1002 Area to western and eastern sub-areas - Continued

Table A-2 Volumes of undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids(NGL)in the western and eastern subareas of the Federal 1002 Area of the Arctic National Wildlife Refuge as of January 1998 based on the 95th fractile estimate of the assessed oil in the 1002 Area. [BBO, billions of barrels of oil; TCF, trillions of cubic feet gas, BBL, billions of barrels of NGL]. (Source: simulation data discussed in Schuenemeyer, 1999a)

Area/Play Name1	Oil Fields			Gas Fields	
	Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
Western sub-area					
Topset	1.795	0.499	0.004	0.000	0.000
Turbidite	1.026	0.892	0.051	0.000	0.000
Wedge	0.206	0.116	0.003	0.000	0.000
Thomson	0.157	0.200	0.017	0.000	0.000
Kemik	0.016	0.023	0.002	0.051	0.004
Undeformed Franklinian	0.083	0.178	0.018	0.155	0.014
Thin-Skinned Thrust Belt	0.138	0.035	0.000	0.325	0.003
Ellesmerian	0.000	0.000	0.000	0.093	0.003
Deformed Franklinian	0.035	0.039	0.003	1.049	0.076
Subtotal	3.456	1.981	0.099	1.673	0.099
Eastern sub-area					
Topset	0.299	0.083	0.001	0.000	0.000
Thin-Skinned Thrust Belt	0.358	0.090	0.001	0.845	0.009
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.834	0.025
Deformed Franklinian	0.004	0.004	0.000	0.117	0.008
Niguanak/Aurora	0.137	0.124	0.007	0.005	0.000
Subtotal	0.799	0.301	0.009	1.799	0.043
Total Federal 1002 Area	4.254	2.282	0.107	3.472	0.142

Appendix A. Tables showing allocation of the mean, 95th and 5th fractile estimates of Federal 1002 Area to western and eastern sub-areas -Continued

Table A-3 Volumes of undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids (NGL) in the western and eastern sub-areas of the Federal 1002 Area of the Arctic National Wildlife Refuge as of January 1998 based on the 5th fractile estimate of the assessed oil in the 1002 Area. [BBO, billions of barrels of oil; TCF, trillions of cubic feet gas, BBL, billions of barrels of NGL]. (Source: simulation data discussed in Schuenemeyer, 1999a)

Area/Play Name1	Oil Fields			Gas Fields	
	Oil (BBO)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
Western sub-area					
Topset	5.978	1.732	0.016	0.000	0.000
Turbidite	1.751	1.542	0.089	0.000	0.000
Wedge	0.804	0.410	0.009	0.000	0.000
Thomson	0.252	0.310	0.026	0.155	0.012
Kemik	0.034	0.036	0.002	0.138	0.011
Undeformed Franklinian	0.109	0.206	0.020	0.165	0.016
Thin-Skinned Thrust Belt	0.472	0.132	0.002	0.425	0.005
Ellesmerian	0.000	0.000	0.000	0.128	0.002
Deformed Franklinian	0.000	0.000	0.000	0.210	0.021
Subtotal	9.399	4.369	0.165	1.220	0.068
Eastern sub-area					
Topset	0.996	0.289	0.003	0.000	0.000
Thin-Skinned Thrust Belt	1.228	0.343	0.004	1.104	0.013
Ellesmerian Thrust Belt	0.000	0.000	0.000	1.154	0.022
Deformed Franklinian	0.000	0.000	0.000	0.023	0.002
Niguanak/Aurora	0.176	0.155	0.009	0.004	0.000
Subtotal	2.400	0.787	0.015	2.285	0.038
Total Federal 1002 Area	11.799	5.156	0.180	3.505	0.106

Appendix B. Documentation of cost estimates

Transportation costs

The assessment geologists allocated the assessed play-level resources to the sub-areas shown in figures 4 and 5. The motivation was to group resources into areas with similar transportation costs to the Trans-Alaska Pipeline System (TAPS). Tables A-1, A-2, and A-3 show the allocation of the resources to the two sub-areas by play for the mean of each play, and for the suite of play estimates that made up the 95th fractile oil estimate, and the 5th fractile oil estimate. The western sub-area accounted for 86 percent of the resources of the Topset Play, all the Turbidite, Wedge, Thomson, Kemik, Undeformed Franklinian, 28 percent of the Thin-Skinned Thrust-Belt, 10 percent Ellesmerian and 90 percent of the Deformed Franklinian. Alternatively, the eastern sub-area accounted for 14 percent of the resources in the Topset, 72 percent of the Thin-Skinned Thrust-Belt, 90 percent Ellsmerian, 10 percent of the Deformed Franklinian, and all of the Niguanak-Aurora Play resources that were assessed for the Federal 1002 Area.

Scenario 1: Production processing at discovery location:

It was assumed that at least a 24 inch regional pipeline initially would be built at a location about 18 miles into the western boundary of the Federal 1002 Area to Pump Station 1 (see Figure 4). The placement of the Scenario 1 pipelines shown in figure 4 is for the purpose of cost analysis in this study and does not imply a suggested route for the actual system. According to Han-Padron Associates (1985) such a pipeline could transport 500,000 barrels per day. If a pipeline with larger capacity is needed, the estimated tariffs[1] presented here would overstate the probable unit cost because pipelines typically exhibit declining unit costs with increasing scale. All pipelines are elevated over land and buried at major river crossings. The assumed regional pipeline from the eastern sub-area is posited to be a 20 inch diameter pipeline that starts about 50 miles to the east of the terminus of the western sub-area regional pipeline and runs for a total of 135 miles to TAPs Pump Station 1. The smaller diameter pipeline is assumed located parallel to the western sub-area pipeline. Alternatively, it could also be connected to that pipeline with appropriate upgrading of capacity. Cost estimates used here assume a separate parallel line.

The path of the regional pipeline from Pump Station 1 is assumed to be roughly parallel to the path taken by the Badami pipeline which joins the Endicott pipeline about 12 miles from Pump Station 1. The pipeline distance between the Endicott/Badami junction to the Badami field is about 25 miles. Continuing east from the area of the Badami field, the Federal 1002 Area regional pipeline proceeds just southeast toward the Sourdough prospect (28 miles), enters Federal 1002 Area western boundary, and terminates at a location about 20 miles southeast (see Figure 4). Total distance between the midpoint of the western sub area and the connection leading to Pump Station 1 is about 85 miles. From the terminus of the western sub-area pipeline, the eastern sub-area pipeline leg would run parallel to the coast line for about 22 miles and proceed southeast another 28 miles for total additional distance of 50 miles into the eastern sub-area.

Within each sub-area, it is assumed that feeder lines from the discovery to the regional pipeline would be constructed and operated as separate common carriers. In the western sub-area the feeder lines are assumed to be an average length of 12 miles and in the eastern sub-area the feeder lines are assumed to have an average length of 16 miles. A regulated common carrier pipeline entity was assumed to build and operate the regional pipeline to TAPS. For the purposes of developing practical cost estimates the feeder lines were also assumed to be operated by third parties as regulated common carriers. Pipeline tariff charges were set to assure the pipeline investors a 12 percent after-tax return on investment.

Cost functions presented in Broderick (1992) were updated to reflect reductions in costs since 1990. More recent pipeline cost data were gathered from the literature and applications to the Alaska State Pipeline Office (T. Braden, Alaska Pipeline Office, personal communication 1998) and the hearing information from the Regulatory Commission of Alaska. These data were analyzed and extrapolated to compute costs of pipelines of comparable sizes to those depicted by Broderick (1992).

These cost estimates, typical of the Prudhoe Bay-Kuparuk area, were increased by 30 percent to compensate for the absence of infrastructure and the special costs of operating in the Federal 1002 Area. Based on the Han-Padron Associates report (1985) investment costs were increased another 20 percent for construction of a haul road parallel to the pipeline. The function used to estimate investment cost is shown in figure B-1. The discrete shift in the cost function reflects the requirement for the installation of an intermediate pump station (see Young and Hauser, 1986, Broderick, 1992).

The estimated investment cost of the 85 mile regional 24 inch diameter pipeline from the western sub-area to Pump Station 1 is 434 million dollars. If a separate 20 inch parallel line were built from the eastern sub-area, construction cost is estimated to be 683 million dollars. Estimated investment costs include the materials, pipe, installation, pump stations and a parallel gravel haul road. Annual pipeline operating costs were computed as 2 percent of the initial investment cost. The pipeline business entity is assumed to be subject to all the Alaska State taxes as well as Federal taxes. Estimated tariff rate is \$0.57 per barrel for the regional pipeline originating in the western sub-area and \$1.50 per barrel for the regional pipeline originating in the eastern sub-area.

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

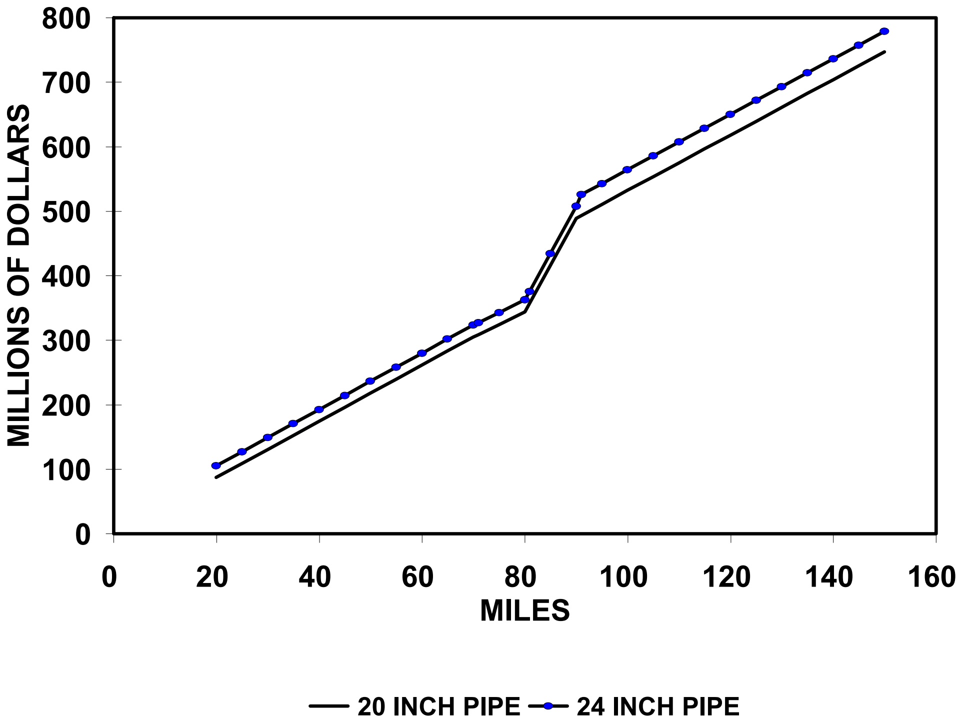

Figure B-1. Pipeline investment cost estimates for the regional pipeline as a function of distance. Function updated from Broderick (1992). The discontinuity in the function at 80 miles of length indicates a requirement for an intermediate pump station.

The diameter[2] for the feeder lines from individual discoveries to the regional pipeline was based on discovery size which along with length of the pipeline determined feeder line investment costs. The tariff or charge for transporting the oil from the discovery to regional pipeline was computed as if the feeder pipeline were run as a regulated common carrier was based on the required rate of return of 12 percent on the investment cost, operating costs, taxes and recovery of the initial investment. Table B-1 shows the distances and two examples of the pipeline system tariffs used in the economic analysis[3].

Scenario 2. Production processing facilities located outside the Federal 1002 Area

For the western sub-area the central processing facility is located at about a distance of 24 miles from the terminus of the western sub-area regional pipeline originally posited in *Scenario* 1. Central processing facilities for the eastern sub-area are assumed to be located about 22 miles north and near the coast on Native lands (Figure 5)[4]. A mixture of oil, water, and gas would be transported from the field to a regional pipeline by feeder lines. The placement of the Scenario 2 pipelines shown in figure 5 if for the purpose of cost analysis in this study and does not imply a suggested route for the actual system. The western sub-area regional crude oil pipeline would then transport the crude oil 65 miles to Pump Station 1. For the eastern sub-area, after processing at a facility located on Native lands, the crude oil would be transported west through a 20 inch diameter regional crude oil product pipeline which would eventually rejoin the course of the eastern sub-area regional pipeline as laid out *Scenario* 1. Injection seawater, natural gas, and diesel fuel for the operating fields would be transported via return regional and feeder lines using the same vertical support members of the regional pipelines that transported the produced fluids to the central processing facilities. Table B-2 shows example distances and computed tariff costs associated with *Scenario* 2.

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. Play analysis, however, is not location specific. 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 B-3 provides the field size classes) and into 5000-foot depth intervals. The analysis also included the costs of three 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.

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

[3] In the computation of total costs, the capital cost estimates of the feeder lines were increased by 50 percent in order to accommodate the return of seawater (for injection) and the diesel fuel.

[4] An alternative to processing on Native lands is transportation of the produced oil, gas, and water mixture to the production facilities in the western coastal area just outside of the Federal 1002 Area. Additional pump capacity would be required to maintain pressures to keep the gas in solution while in transport.

Field design

Young and Hauser (1986) and Broderick (1992) assumed the conventional well drainage area for the Federal 1002 Area to be 160 acres. Footnote 3 (text) shows how accumulation size was computed from simulated reservoir attributes. Because the accumulation area variable, *ac,* used in that equation was expressed in terms of thousands of acres, the per production recovery substituted *ac* with the constant fractional part of 1000 acres that would be drained by single producer, that is 0.16. For each field simulated, the reservoir attribute values associated with (1) net reservoir thickness *t*, in feet; (2) hydrocarbon pore space, *hps* as a function of porosity; (3) trapfill *f*, (decimal), recovery factor *rf* and the formation volume factor, *fvf*. The assessors provided estimates of the recovery factor or percent of the in-place resources that are recoverable, *rf*, and the formation volume factor, *fvf*, was calculated as a function of reservoir depth (see Schuenemeyer, 1999a). Development well productivity (*wp*), in millions of barrels per producing well, for an individual accumulation was calculated as:

$wp = 7.758(t)(hps)(f)(rf)(0.16)/(fvf)$.

Well productivity (ultimate recovery of oil per well) associated with the representative accumulation for each size and depth class were calculated as the weighted average of the well productivities computed for the accumulations assigned to that category. 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 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)[5]. It was assumed that each producing well would require a horizontal injection well.

Well productivity values for conventional directional well configurations are shown in Table B-3. It is assumed that the 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

Estimated field development well costs are computed as the product of the number of wells required for field development and 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 reported in the Joint Association Survey since 1996 drilling costs (American Petroleum Institute, 1997-2003[6]) for Alaska oil wells. Costs were estimated for the four 5000-foot depth intervals. The initial cost estimates which pertained to the Prudhoe Bay area were increased by 30 percent for the Federal 1002 Area to offset extra costs expected to be incurred because of the absence of infrastructure or special environmental precautions associated with operations in the Federal 1002 Area.

The following example illustrates the cost estimation procedure for horizontal wells. Suppose the target vertical depth is at 10,000 feet. The conventional well drilled from a drill pad is deviated until it reaches the target depth, adding as much as 20 percent to drilling length. At the target depth, a lateral extension of 3,000 feet is drilled. Suppose the average per foot drilling and completion cost of $400 per foot is assumed to be characteristic for the Prudhoe Bay area. This rate was increased by 30 percent for drilling in the Federal 1002 Area, so 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):

[10000ft (1.2) ($400/ft) +3000ft *$400/ft)] *1.3= $7.8 million per well

In this example, the horizontal well adds about 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, Minerals Management Service, written communication, 2005).

[5] If a vertical well drains 160 acres, its ideal drainage area radius is about 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 area drained follows Joshi (1991a). It assumes vertical permeability is at least that of horizontal permeability.

[6] 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.

Estimated costs, in millions of 2003 dollars by 5000 foot depth interval for directional wells in the Prudhoe Bay area are $2.0 (with vertical depth 4200ft), $3.60 (7500 ft), $5.76 (12000 ft), $7.68 (16,000 ft). The corresponding horizontal wells (in the Prudhoe Bay area) with 3000 ft lateral assumed in millions of 2003 dollars are $3.38, $5.10, $7.79, and $12.08.

Facilities Costs

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 standalone fields operating in Northern Alaska. These fields include 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 the Liberty is in the 150 million barrel range.

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. 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[7]. These estimates, when applied to new discoveries in the Federal 1002 Area, were increased 30 percent for the western sub-area and for the eastern sub-area to compensate for the absence of infrastructure and the additional regulations that might be associated with field development in the Federal 1002 Area. Table B-3 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 fields 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 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 that it is in its best interest to reduce capital barriers to entry of additional operators to the North Slope. The State has recently begun to study the potential regulatory issues of fair treatment of new entrants (Kaltenbach and others, 2004).

For *Scenario* 1 of this analysis, facility sharing is limited to the western sub-area[8] and to accumulations having less than 130 million barrels of technically recoverable oil. The procedure for accounting for facility-sharing charges follows an arrangement used by Thomas and others (1993)[9]. Specifically, it was assumed that facilities sharing would, on average, result in a 30 percent reduction 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 that minimum or threshold price at which a satellite becomes commercially developable while reducing risk as well.

For *Scenario* 2, it was assumed the primary processing facilities for the mixture of oil, gas, and water extracted at the wellhead are located in a coastal area outside of the western border of the Federal 1002 area and on Native lands adjacent to the eastern Federal 1002 Area. This scheme reduces activity inside the Federal 1002 Area and may reduce development costs of some accumulations. It was initially assumed that the facilities, gravel pads, and other infrastructure associated with staffing and operating the central processing facility accounted for about half of facilities investment costs. Appendix C reports on the sensitivity studies that relate to this assumption. The central processing units outside the Federal 1002 Area are assumed to be operated as separate business entities and are treated as regulated utilities.

Central processing facilities, like chemical process plants, are characterized by substantial economies of scale. For the purposes of estimating investment costs of the processing facility the scale was chosen to correspond to the technically recoverable oil volumes associated with the 95th fractile; 3.45 BBO for the western sub-area and 0.8 BBO for the eastern sub-area[10]. The tariff charged by the regulated utility included operating costs, Federal and State taxes, capital recovery in 20 years, and an after-tax return on capital of 12 percent. It is assumed that annual operating costs of the central processing facility are 5 percent of initial investment costs. The processing tariffs are added to field operating costs.

Field Production Profile

Future discoveries are assumed to attain peak annual rates of production equal to a percentage of the accumulation's ultimate oil recovery. Table B-4 shows the assumptions relating

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

[8]At the mean estimate there were more then 30 accumulations assigned to the western sub-area and about 5 assigned to the eastern sub-area, so it would be unlikely that facility sharing would be common in the eastern area.

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

[10]In terms of the peak flow the western area central processing facility is sized at 850 thousand barrels per day and the eastern sub-area facility at 200 thousand barrels per day.

to the discovery production profile. An accumulation having 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 the larger fields peak production occurs in the third year of production. Peak production is maintained for the specified number of years and thereafter annual production declines 12 percent per year.

At first glance the 12 percent field production decline rate appears very sharp. 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. Recovery factors of oil-in-place that were posited by the assessors did not include enhanced or tertiary recovery possibilities. Posited recovery factors of the oil-in-place by play are the following: Topset 40 percent, Turbidite 30 percent, Wedge 30 percent, Thomson 45 percent, Kemik 30 percent, Undeformed Franklinian 35 percent, Thin-Skinned Thrust Belt 40 percent, Deformed Franklinian 35 percent, and Naguanak-Aurora 35 percent.

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 B-2 shows percentage water expected in production with depletion of the field. Volumes of natural gas and natural gas liquids production 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

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 (see Craig, 2002). These costs were increased by 30 percent to better reflect the Federal 1002 Area locations and lack of infrastructure. The produced fluid hydrocarbon and water volumes were projected annually using field production forecasts and a water cut function presented in figure B-2 (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.

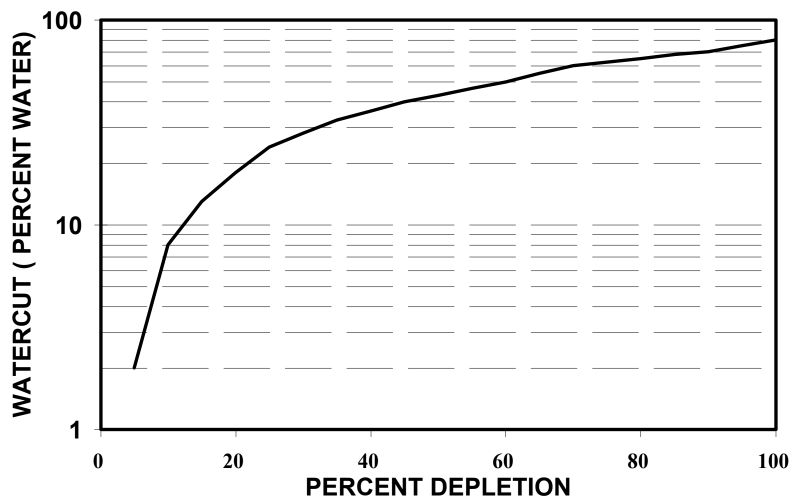

Figure B-2. Percentage of water in production stream as a function of reservoir depletion. Data are from Thomas and others (1991).

Alaska Taxes

Severance Tax for oil:

12.25 percent years 1 through 5 adjusted for economic limit rate (elr)

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

$elr = (1-(300/ADWR))^a$ where $a = (150000/ADFR)^{1.5333}$

ADWR = average daily production per producing well (bbo/d)

ADFR= average daily field production (bbo/d)

Severance Tax for gas:

10.00 percent adjusted for the economic limit rate floor \$0.064 per thousand cubic feet adjusted for the economic limit factor

elr = (1-(3000/ADWR))

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

For both cases, if elr less than or equal to zero, severance tax is zero

Ad valorem tax

Tax equal to 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 royalty rate

Royalty rate is considered to be a payment to the landowner and was assumed to be 16.7 percent of gross revenue.

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.

Table B-1. Federal 1002 Sub-areas pipeline distances from the regional pipeline to Trans-Alaska Pipeline System (TAPS), estimated pipeline tariff to TAPS and tariff from feeder pipeline to regional pipeline based on Scenario 1 for representative fields of 300 and 600 million barrels (mmbo). (bbl, barrel of crude oil).

Sub-area	Regional pipeline		Feeder Pipelines		
	distance	tariff	distance	tariff (300 mmbo)	tariff (600 mmbo)
	miles	\$/bbl	miles	\$/bbl	\$/bbl
Western	85	0.57	12	\$0.29	\$0.19
Eastern	135	1.50	16	\$0.38	\$0.25

Table B-2. Federal 1002 Sub-area and distances from the regional pipeline to Trans-Alaska Pipeline System (TAPS), estimated pipeline tariff to TAPS and tariff from feeder pipeline to regional produced fluids pipeline based on Scenario 2 for representative fields of 300 and 600 million barrels (mmbo) (bbl, barrel of crude oil).

Sub-area	Regional crude oil pipeline		Regional produced fluids pipeline		Feeder Pipelines		
	distance	tariff	distance	tariff	distance	tariff (300 mmbo)	tariff (600 mmbo)
	miles	$/bbl	miles	$/bbl	miles	$/bbl	$/bbl
Western	65	0.39	24	$0.15	12	$0.29	$0.19
Eastern	135	1.50	22	$0.17	16	$0.38	$0.25

Table B-3. Recovery per well, in millions of barrels per well, by field size, depth category based on 160 acre drainage area for conventional well (mmbo, millions of barrels of oil)

Field Size class	Recovery per production well in millions of barrels Depth class in thousands of feet			
mmbo	0-5	5-10	10-15	>15
Western sub-area				
8-16	-	1.53	1.50	1.47
16-32	3.69	2.96	1.98	1.92
32-64	5.50	4.26	2.75	2.62
64-128	8.59	6.27	3.63	3.53
128-256	12.37	9.19	4.88	4.93
256-512	15.22	11.91	6.27	6.53
512-1024	17.56	15.16	7.65	8.22
1024-2048	24.11	21.79	11.21	13.19
2048-4096	30.00	29.66	19.28	20.06
4096-8192	30.00	30.00	0.00	0.00
Eastern sub-area				
8-16	-	-	-	-
16-32	2.73	2.87	1.10	0.47
32-64	4.14	4.18	1.48	0.75
64-128	6.20	6.29	1.93	1.20
128-256	8.57	8.63	2.54	1.76
256-512	10.73	10.37	2.92	2.17
512-1024	13.58	13.23	3.21	2.85
1024-2048	20.01	19.22	3.46	4.05
2048-4096	29.86	26.50	4.57	5.29
4096-8192	30.00	30.00	5.26	0.00

Table B-4. Facilities investment cost, in 2003 dollars (mmbo, millions of barrels of crude 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
1024	1.13
1536	0.92
2048	0.80
3074	0.80
4096	0.80

Table B-5. Field production profiles assumed in the economic analysis (mmbo, millions of barrels of crude oil).

Field sizes 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
512-1024	2	9	4
1024-2048	2	9	4
2048-4096	2	7.5	5
4096-8192	2	7.5	5

Appendix C. Summary of results of selected analysis

The analysis was repeated using the undiscovered field size distribution corresponding to the *mean oil estimate* assuming alternatively an 8 percent and 16 percent required return. Reducing the required return to an after-tax rate of 8 percent increased the volume of economic oil available at $21 per barrel by 1.8 BBO and reduced the threshold price at which exploration becomes economic by $1.70 per barrel. Increasing the required return to 16 percent resulted in a reduction of economic oil at $21 per barrel by about 0.9 BBO and increased the price at which exploration becomes economic by about $1.80 per barrel. Hurdle rate changes affect minimum commercially developable field size, thus changing marginal commercial value of new discoveries, affects the number of wildcat wells that can be drilled profitably. Table C-1 shows how changes in estimates of drilling and facilities costs affect the estimates of economic oil.

For the analysis associated with Scenario 2, it was estimated that the central processing facility represented 50 percent of total facility investment cost and that no redundancy in equipment was required to operate the discovery under posited configuration. Suppose, instead there is some required redundancy so an on-site the central processing facility (fluid processing, gas plant, etc) accounts for half of on-site facilities costs, but removing that function and transporting outside only reduces on-site investment costs by only 30 percent. At the mean value assessment, the results are to increase the threshold price to $18.40 from $17.40 per barrel and reduced the economic oil so at $21 per barrel to 2.40 BBO from 2.95 BBO. At $30 per barrel economic oil was reduced to 5.83 BBO from 6.04 BBO. The effects of the alternative cost assumptions are substantially dampened as prices climb above $30 per barrel.

Finally, the calculations were repeated assuming Scenario 1 field development but all development wells are conventional rather than horizontal. The volume of economic oil is smaller without horizontal drilling, particularly, at prices below $25 per barrel. At $25 per barrel, economic oil under the horizontal well assumption will range 9 to 12 percent greater than for conventional wells. As prices increase the differences in the volumes of oil that are economic declines. At $42 per barrel there is only a 1 to 3 percent difference.

Table C-1. Summary of results of sensitivity studies: based on Scenario 1 assumptions.

	Base	rr=8	rr=16	Drilling	Drilling	Facility	Facility
	rr[1]=12			Cost -25%	Cost +25%	Cost -25%	Cost +25%
Threshold price	$17.50	$15.80	$19.30	$17.20	$17.70	$16.10	$18.70
price/bbl							
$21	2.66	4.47	1.89	3.56	2.50	4.25	2.12
$30	6.07	6.48	5.44	6.43	5.83	6.32	5.57
$40	6.84	6.97	6.52	7.02	6.69	6.92	6.77
$50	7.07	7.15	6.92	7.19	6.95	7.10	7.02

[1]rr is assumed rate of return.