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Frontier areas and resource assessment: the Case of the 1002 Area of the Alaska North Slope

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ABSTRACT

The U.S. Geological Survey's 1998 assessment of the 1002 Area of the Arctic National Wildlife Refuge significantly revised previous estimates of the area's petroleum supply potential. The mean (or expected) value of technically recoverable undiscovered oil for the Study Area (Federal 1002 Area, adjacent State waters, and Native Lands) is estimated at 10.4 billion barrels of oil (BBO) and for the Federal 1002 Area the mean is 7.7 BBO. Accumulation sizes containing the oil are expected to be sufficiently large to be of economic interest. At a market price of $21 per barrel, 6 BBO of oil in the Study area is expected to be economic. The Assessment's methodology, results, and the reasons for the significant change in assessments are reviewed. In the concluding section, policy issues raised by the assessment are discussed.

INTRODUCTION

The volatility of oil prices and their economic effects are a pointed reminder of U.S. dependence on foreign oil supplies. Decision-makers periodically require re-assessment of undeveloped and undiscovered domestic petroleum resources that could be added to supplies. Except for prospective deepwater areas off the lower 48 states, prospects for major U.S. finds are limited. Many consider the Arctic North Slope as perhaps the last frontier for domestic oil and gas exploration.

The Alaska National Interest Lands Conservation Act (1980) established the 19 million acre Arctic National Wildlife Refuge (ANWR). In section 1002 of that Act, Congress deferred a decision on the permanent status of the 1.5 million acre *coastal plain* ("1002 Area") in recognition its potential oil and gas resources and its importance as a wildlife habitat (Figure 1A). Although the Interior Department delivered a resource and environmental assessment to Congress in 1987 (Clough and others, 1987), the status of the 1002 Area has not changed since 1980. The 1987 report was criticized (Energy Information Administration, 1987; Powell, 1990) because *there was little or no relationship* between the results of the geologic assessment (Dolton and others, 1987) and the economic resource assessment (Callahan and others, 1987).

As a result of the new information generated by drilling and oil discoveries just outside the 1002 Area (see Figure 1B), the U.S. Geological Survey (USGS) in 1998 re-assessed the 1002 Area's undiscovered petroleum resources (U.S. Geological Survey ANWR Assessment Team, 1999). The new geologic assessment used reprocessed digital seismic data, making it easier to identify subtle geologic features. Data were also reinterpreted in light of advances in sequence stratigraphy, allowing geologists to predict with greater accuracy the presence and location of source rocks, reservoir rocks, and stratigraphic traps. Also, the economic evaluation is *now tied* to the geologic assessment.

This paper first briefly sketches the geologic and economic methodologies that were applied and then explores some of the policy issues. The geologic Study Area included adjacent State waters and Native Lands within the 1002 Area (see Figure 1B) in addition to the Federal 1002 Area. The economic evaluation of this broader area is presented, here, for the first time. The discussion concludes by considering both short and long term implications of the analysis for energy strategy and future land-use decisions.

GEOLOGIC ASSESSMENT PROCEDURE

Geologists initially subdivided the Study Area into the ten plays that were defined areally and stratigraphically (see U.S. Geological Survey Assessment Team, 1999, for details). Play (level) analysis models geologic settings of oil and gas occurrence. A play is a collection of geologically related known or postulated hydrocarbon accumulations that share similar geologic risks and characteristics such as source rock, hydrocarbon type, trapping mechanism, migration patterns, and time of petroleum generation and trap formation. They assess the occurrence probabilities of geologic factors necessary for the formation of hydrocarbon accumulations. The geologist also subjectively assesses the location and spread of the probability distribution that characterizes size and number of undiscovered accumulation sizes[1]. Five plays were defined in the undeformed area and five were in the deformed area (see Figure 1B). In the assessment protocol (design) pairs of geologists reported consensus subjective assessments of accumulation occurrence probabilities and parameters of probability distributions representing sizes and numbers of undiscovered accumulations.

The geologic risk structure is modeled by assigning a *play probability* to each play that is the likelihood that at least one accumulation of the minimum size occurs. The geologists also assigned the *prospect probability* representing the probability that any randomly chosen prospect is of the minimum size. In this frontier area, there are no historical data for computing parameters of the size distribution of undiscovered accumulations. Instead, reservoir attribute[2] probability distributions are assessed and a reservoir model is applied to generate the potential sizes of undiscovered accumulations.

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[1] The minimum size accumulation considered for this assessment contained at least 50 million barrels of oil in-place or 300 billion cubic feet of gas in-place.

[2] For each accumulation, the simulated reservoir-attribute values included (1) net reservoir thickness, t, in feet: (2) porosity, p, in percent (decimal fraction), (3) trapfill, f, in percent (decimal fraction), (4) cw, defined as (1-water saturation) as a decimal fraction and (5) ac, area of closure in thousands of acres. The assessors provided estimates of the recovery factor, rf, as a fraction of the in-place resources that are

Assessors specified the reservoir attributes, which include (1) net reservoir thickness, (2) area of closure, (3) porosity, (4) water saturation, and (5) trapfill, as subjective probability distributions. The subjective distribution for each attribute is built-up as the geologist associates values of the attribute with fractiles[3] of the associated probability distribution.

Probability distributions describing the sizes and numbers of fields 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 variate for the risked number of accumulations in the play was computed as the product of the prospect probabilities, and a random draw from the assessor's (subjective) distribution describing the number of prospects. 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 (see footnote 2). Ten thousand replications defined the probability distributions describing each play.

Pairwise dependencies of the characteristics of charge, reservoir, and trap were assigned between plays within the Study Area. The ranked dependencies (high, medium, low) were transformed into a measure of covariance between plays. Because the play assessment results are characterized by probability distributions, the covariance among plays was assessed in order to aggregate play results to higher levels (deformed,

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recoverable and the formation volume factor, *fvf*, was calculated as a function of reservoir depth. Oil accumulation size, *szo*, in millions of barrels was calculated with the following equation: $szo = 7.758(t)(p)(cw)(f)(rf)(ac)/(fvf)$.

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

undeformed, the 1002 Area, and Study Area). Aggregation procedures for the play probability distributions are provided in detail in Schuenemeyer (1999).

ECONOMIC ASSESSMENT PROCEDURE

The economic evaluation of the assessed resources is represented as incremental cost functions. These include all costs of finding, developing, and producing hydrocarbons from undiscovered accumulations, as wells as, transporting the oil to market, as a function of cumulative discoveries. These functions are not the same as the economist's market price-supply predictions because the industry allocates funds over a number of sources of supply in order to meet market demand at lowest costs. Observed price-supply relationships are the outcome of supplier decisions over many projects and regions. Incremental cost functions are time-independent. They are computed independently of activities in other areas.

For each point estimate of undiscovered oil, there is an associated undiscovered accumulation size-frequency distribution, which has been risked at the prospect and play levels. An empirically based finding rate function is applied to this distribution to forecast the size distribution of new discoveries as a function of successive increments of wildcat drilling. The algorithm that calculates incremental costs uses these predicted discoveries to compute quantities of resources that are commercially developable at various prices. A standard application of the discounted cash flow analysis assuming an after-tax hurdle rate of return of 12 percent *determined whether a new discovery is commercial*. The finding rate forecasts drive the field development and production process models to determine (at each market price evaluated) the aggregate volume and economic value of new discoveries as well as the number of successive increments of wildcat wells that are economic. Details are available in Attanasi (1999).

Assumptions:

The industry will not undertake investment unless expected operating costs, investment costs, and the cost of capital are fully recovered. *The analysis treated each accumulation as a single field.* Areas were assumed available to exploration. Lease bonus costs were *excluded* in this analysis. Finally, undiscovered non-associated gas fields were not evaluated for their economic potential because at the time of the 1002 Area study, a viable gas market appeared to be decades away. At least 30 trillion cubic feet of competing North Slope gas has already been discovered and could be produced cheaply when a gas market develops. Gas in oil fields will be stripped of liquids and re-injected into oil reservoirs to maintain pressure or used as a lease fuel.

All calculations are prepared in real 1996 dollars. A 12 percent after-tax real rate of return on capital investment is required. Taxes included Alaska State income tax (2.2 percent of net income), Alaska *ad valorem* tax, Alaska severance tax, Federal corporate income tax (1996 provisions), and a one-sixth Federal royalty.

Developed North Slope accumulations typically are very large and incremental increases in recovery can provide large payoffs in term of the volumes of oil, so operators generally introduce technological innovations quickly. For example, the application of extended reach drilling has allowed production wells access to distant reaches of the reservoir, often eliminating the need for additional drill pads or allowing satellite field development from existing drill pads. For example the Niakuk field, located from one to three miles offshore, will be developed from onshore drilling facilities. Because of this technology, it is assumed that offshore Federal 1002 Area accumulations and those in State waters can be developed from onshore drilling pads.

Oil prices are at the market (West Coast lower 48) rather than wellhead price. No credit was given for associated gas production. Natural gas liquids were priced at 75 percent of the oil price. Based on projections to 2020 (Alaska Department of Revenue, 1997), the average Trans-Alaska Pipeline System (TAPS) tariff is estimated at $2.72 per barrel and marine transport from Alaska to a suite of markets at $1.73 per barrel. As of 1998, the TAPS pipeline had 600,000 barrels per day of unused capacity.

For purposes of computing oil transportation costs to TAPS, the 1002 Area was partitioned into the western and eastern subareas shown in Figure 2. Play resources were partitioned into these two subareas. We assumed a 20-inch diameter pipeline is built from TAPS Pump Station No. 1, 85 miles to a central location in the western subarea of the 1002 Area. Transportation from the eastern subarea requires an eastern extension of the regional pipeline of 50 miles. Transport cost to TAPS from the western part of the 1002 Area is estimated at $0.97 per barrel. Similarly, from the eastern part of 1002 Area estimated transport costs are $1.48 per barrel. Additional charges are added for feeder lines (12 miles in the west, 16 miles in the east) from fields to the regional pipeline (Attanasi, 1999).

ASSESSMENT RESULTS

Estimates of undiscovered technically recoverable oil are presented in Table 1. Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to cost or economic profitability. For the entire Study Area, resource estimates corresponding to the 95th fractile[4], mean, and 5th fractile for oil in oil fields are 5.72 billion barrels of oil (BBO), 10.36 BBO, and 15.96 BBO, respectively, and for gas in non-associated gas fields the respective estimates are 0, 3.84 trillion cubic feet of gas (TCFG), and 10.85 TCFG, but not shown in Table 1.

Similarly, for oil in oil fields in the Federal 1002 Area at the 95th, mean, and 5th fractiles resource estimates are 4.25 BBO, 7.67 BBO, and 11.80 BBO, respectively. The Federal 1002 area accounts for over 70 percent of the assessed resources. The play assessments predict almost no chance of a large gas accumulation with sufficient natural gas liquids to be developed for its liquids. At the mean, 80 percent of the assessed oil is in plays of the undeformed (western) part of the Study Area, nearest to infrastructure. Also, 80 percent of the assessed oil was assigned to depths of 10,000 feet or less.

Figures 3A and 3B show the size-frequency distributions of undiscovered accumulations for the total Study Area and Federal 1002 area, respectively. Table 2 provides the distribution of the oil volumes in each accumulation size category shown by the figures. At the mean estimates, 65 percent of the total oil was assigned to accumulations of at least 250 million barrels in size for the Study Area and the 1002 Federal area. Most of the assessed oil was assigned to field sizes that are of economic interest, but the assessed volumes are expected to occur in a number of accumulations rather than one or two very large fields.

Incremental cost functions include *full costs of finding, developing, producing, and transporting oil to market*. Figure 4 shows incremental cost functions for crude oil based on the undiscovered oil field size distributions associated with the 95th, mean, and 5th

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[4] At the 95th fractile there is a 19 in 20 chance oil volume will exceed that value a and the 5th fractile is only

fractile oil volume estimates for the total Study Area. Table 3 summarizes the incremental cost functions for the Study Area and the Federal 1002 Area and also shows the associated wildcat wells. The finding rates are well within historical experience.

The shape and position of the incremental cost functions in Figure 4 are largely determined by the accumulation size distributions shown in Figure 3A. For example, not only is the 95th fractile estimate smaller in oil volume but a relatively large proportion of this oil was assigned to smaller accumulations that are not only harder to find but may not even be commercially viable to develop. At a market price of $21 per barrel *economic oil* for the total Study Area at the 95th, mean, and 5th fractile estimates is estimated to be 1.9 BBO, 6.0 BBO and 10.7 BBO, respectively (Table 3). This represents 33 percent, 58 percent, and 67 percent of the corresponding volumes of assessed technically recoverable oil. For the Study Area, threshold prices, that is, the minimum price at which commercial exploration can begin are $17.50 at the 95th, $14.70 at the mean, and $13.20 at the 5th fractile assessment levels. Threshold prices in the Federal 1002 Area, when considered alone, are slightly higher.

The incremental cost functions show large potential reserve additions as prices initially increase beyond the threshold price at which exploration is initiated because large portions of the oil associated with the mean and 5th fractile distributions were assigned to large fields (greater than 500 million barrels, see Table 2). Discovery rates decline rather rapidly after the initial increments of wildcat drilling are completed as the large low cost discoveries are depleted and the additional exploration concentrates on smaller higher cost accumulations.

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a 1 in 20 chance of actual volume exceeding that value.

IMPLICATIONS AND POLICY ISSUES

The 1998 geologic assessment of the 1002 Area is an improvement over previous estimates. Seismic data, reprocessed to a digital format, allowed improved characterization of seismic profiles and seismic interpretations that incorporated advances in our understanding of sequence stratigraphy. The previous assessment concentrated on obvious large structures. Methodologically, the 1998 study explicitly accounted for dependencies among plays. It also directly linked the geologic and economic evaluations by accumulation frequency-size distributions. Earlier economic evaluations were based on specific prospect and were unrelated to the regional geologic assessment.

The 1998 Assessment precluded accumulations as large as the Prudhoe Bay field (15 BBO). However, the expected oil volumes and accumulation sizes are among the largest assessed for the United States and are of economic interest, even in such a high cost area. At a market price of $24 per barrel, almost three-fourths of the Study area mean estimate (10.4 BBO) and two-thirds of the 1002 Federal Area mean estimate (7.7 BBO) is economic. Estimates of economic value may be conservative if a gas market develops. Although significant accumulations in State and Native Lands may exist, they will to be difficult to develop without access to Federal land.

At prevailing rates of wildcat drilling for the North Slope, it would perhaps take a decade to drill the number of wildcat wells that are economic at a market price of $21 per barrel for the mean estimate. During that time additional improvements in technology could lower costs further.[5] In fact, the new technology implemented with development of the Alpine field is a substantial improvement over that assumed in 1998 study. This 430 million barrel field, covering 40,000 acres, will be fully developed with only 112 horizontal wells (sited on only two drilling pads). The surface footprint for the entire development will cover about 94 acres. Alpine is located 34 miles west of the Kuparuk-Prudhoe Bay complex but was developed without building a permanent haul road.

Before the 1997-98 slide in oil prices, British Petroleum announced the Sourdough discovery located near the border of the Federal 1002 Area (Figure 1B). Parts of this field may extend into the Federal 1002 Area. In such cases, the Interior Department typically holds a drainage sale of the Federal portion of the field to assure that if Federal oil is drained the bonus and royalty are paid. The USGS 1998 Assessment shifted most of the undiscovered oil from the east (deformed area) to the west (undeformed area) closer to infrastructure, so that the Sourdough situation is unlikely to be an isolated case. A long-range policy should be formulated to address such situations.

Another policy issue is related to access to any gas pipeline from the North Slope for new discoveries. With 30 TCF of low cost gas identified in the Prudhoe Bay area, there is real concerned that new discoveries will not have access to the pipeline capacity or that access will only be granted after the Prudhoe Bay area gas is produced, which will take probably 20 years. Unless new gas discoveries will be allocated some capacity in a timely fashion, there will be little incentive for gas field exploration.

North Slope experience of long-term environmental consequences of oil exploration and development should become clearer as more data on the resiliency of

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[5] Alternatively, any attempt to rapidly increase drilling rates would undoubtedly drive up drilling rig day

natural systems become available. Tussing and Halley (1999) describe such studies in progress based on the USGS resource assessment. In 2000 the Federal government leased more acreage in a single lease sale in the National Petroleum Reserve, Alaska (NPRA) than all the acreage in 1002 Area. State leasing also continues. The potential development impacts of phasing North Slope exploration and development should be purposefully assessed in a comprehensive fashion.

rates and cause increasing costs, voiding a central assumption in this analysis of constant real factor costs.

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Table 1. Estimates of undiscovered technically recoverable conventional oil in the Study Area and the Federal 1002 Area of the Arctic National Wildlife refuge as of January 1998. Estimates based on the 95th, mean, and 5th fractile estimates corresponding to the aggregated distributions.

Volume of oil, in billions of barrels			
	F_{95}	Mean	F_{05}
Entire study area	5.72	10.36	15.96
1002 Area	4.25	7.69	11.80
Undeformed	3.40	6.42	10.22
Deformed	0	1.27	3.19

1/ Includes 1002 Area shown in Figure 1B, Native lands, and adjacent State water areas within 3-mile boundary.

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

	Total Study Area				**Federal 1002 Area**		
Oil Field	**Cumulative Oil**				**Cumulative Oil**		
Size class	**F_{95}**	**MEAN**	**F_5**		**F_{95}**	**MEAN**	**F_5**
(MMBO)	**(BBO)**	**(BBO**	**(BBO)**		**(BBO)**	**(BBO)**	**(BBO)**
4960-8192	0.00	0.06	0.26		0.00	0.04	0.16
2048-4096	0.03	0.64	1.92		0.06	0.45	1.49
1024-2048	0.42	2.23	4.85		0.33	1.60	3.70
512-1024	1.63	4.49	8.62		1.12	3.26	6.43
256-512	3.16	6.80	11.86		2.22	4.99	8.52
128-256	4.42	8.73	14.02		3.28	6.45	10.31
64-128	5.26	9.85	15.34		3.96	7.30	11.36
32-64	5.66	10.27	15.85		4.20	7.62	11.72
16-32	5.72	10.35	15.95		4.25	7.69	11.80
8-16	5.72	10.36	15.96		4.25	7.69	11.80

Table 3. Incremental costs of finding, developing, producing, and transporting oil to market from undiscovered conventional oil accumulations in the Study Area and the Federal 1002 Area of the Arctic National Wildlife Refuge [oil in billions of barrels, BBO).

	Total Study Area						Federal 1002 Area					
	F_{95}		Mean		F_5		F_{95}		Mean		F_5	
$/BBL	**Oil BBO**	**Wildcat Wells**	**Oil BBO**	**Wildcat Wells**	**Oil BBO**	**Wildcat Wells**	**Oil BBO**	**Wildcat Wells**	**Oil BBO**	**Wildcat Wells**	**Oil BBO**	**Wildcat Wells**
West												
12	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0
15	0.00	0	1.09	40	4.24	100	0.00	0	0.00	0	2.69	80
18	0.66	40	3.55	140	7.66	200	0.00	0	2.40	120	5.27	180
21	1.91	120	5.14	220	8.95	280	1.03	80	3.50	180	6.56	240
24	2.94	200	6.29	280	10.80	340	2.03	160	4.45	240	7.69	300
27	3.54	260	6.94	340	11.52	400	2.45	220	5.03	300	8.30	360
30	3.74	300	7.14	380	11.72	440	2.63	260	5.22	340	8.47	400
33	3.87	340	7.27	420	11.80	460	2.75	300	5.35	380	8.54	420
36	3.97	380	7.37	460	11.91	500	2.85	340	5.40	400	8.64	460
39	4.01	400	7.41	480	11.95	520	2.89	360	5.48	440	8.68	480
42	4.05	420	7.44	500	11.99	540	2.92	380	5.51	460	8.71	500
East												
12	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0
15	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0
18	0.00	0	0.00	0	1.23	80	0.00	0	0.00	0	0.87	60
21	0.00	0	0.83	80	1.78	140	0.00	0	0.49	60	1.35	120
24	0.00	0	1.31	140	2.28	180	0.00	0	0.80	100	1.69	160
27	0.32	60	1.57	180	2.54	220	0.29	60	1.02	140	1.87	180
30	0.48	100	1.66	200	2.63	240	0.35	80	1.09	160	2.00	220
33	0.59	140	1.78	240	2.74	280	0.46	120	1.19	200	2.05	240
36	0.63	160	1.82	260	2.78	300	0.50	140	1.24	220	2.10	260
39	0.67	180	1.86	280	2.78	300	0.54	160	1.28	240	2.13	280
42	0.70	200	1.90	300	2.82	320	0.57	180	1.31	260	2.16	300
Total												
12	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0
15	0.00	0	1.09	40	4.24	100	0.00	0	0.00	0	2.69	80
18	0.66	40	3.55	140	8.89	280	0.00	0	2.40	120	6.15	240
21	1.91	120	5.97	300	10.73	420	1.03	80	3.99	240	7.91	360
24	2.94	200	7.60	420	13.08	520	2.03	160	5.24	340	9.37	460
27	3.87	320	8.51	520	14.06	620	2.74	280	6.05	440	10.16	540
30	4.22	400	8.80	580	14.35	680	2.98	340	6.30	500	10.47	620
33	4.46	480	9.05	660	14.54	740	3.21	420	6.54	580	10.59	660
36	4.60	540	9.19	720	14.69	800	3.35	480	6.63	620	10.73	720
39	4.68	580	9.27	760	14.73	820	3.42	520	6.75	680	10.81	760
42	4.75	620	9.34	800	14.81	860	3.49	560	6.82	720	10.87	800