North Aleutian Basin OCS Planning Area

Assessment of Undiscovered Technically-Recoverable Oil and Gas

As of 2006

U.S. Department of the Interior
Minerals Management Service
Alaska OCS Region
Anchorage, Alaska

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February 2006

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Summary

The North Aleutian Basin Outer Continental Shelf (OCS) Planning Area encompasses an area of 52,234 square miles and includes most of the southeastern part of the Bering Sea continental shelf (fig. 1). The North Aleutian basin proper is about 17,500 square miles in area and underlies the northern coastal plain of the Alaska Peninsula and the waters of Bristol Bay. North Aleutian basin is sometimes also referred to as the "Bristol Bay" basin. Water depths range from 15 to 700 feet and in the area of the most important prospects the water depths are approximately 300 feet.

The North Aleutian basin is filled with approximately 20,000 feet of Tertiary-age strata. In the southwest corner of the Planning Area, the Amak basin is separated by an arch (Black Hills uplift) from the North Aleutian basin (figs. 2, 3). The Amak basin is filled with up to 12,500 feet of Tertiary-age strata. The North Aleutian and Amak basins, the intervening Black Hills uplift, and the Mesozoic rocks beneath these features all contribute resources to the 2006 oil and gas assessment of the North Aleutian basin.

Most mapped prospects in the North Aleutian basin proper are simple domes draped over the crests of fault-bounded basement uplifts. These domes range up to 133,000 acres in closure area. In the central part of the North Aleutian basin 65 miles northwest of Port Moller, these domes are surrounded by deep parts of the basin where the lowermost strata are heated to temperatures sufficient for conversion of organic matter to oil and gas. Oil and gas generated in these basin deeps should have migrated upward into the domes.

The prospects in the central part of the North Aleutian basin have long been the focus of exploration interest in North Aleutian basin

and several were leased for total high bids of $95.4 million (23 blocks) in OCS lease sale 92 in 1988. All of the 1988 leases have been returned to the U.S. Government and are no longer active. In this assessment, as well as in past assessments, most of the hypothetical, undiscovered oil and gas resources of the North Aleutian Basin OCS Planning Area are associated with the simple domes draped over basement uplifts in the central part of the North Aleutian basin.

Onshore, nine exploration wells have tested fold and thrust-fault structures along the southern edge of the North Aleutian basin. Several offshore wells tested age-equivalent strata in the St. George basin to the west. The principal point of geological control for the Tertiary-age fill in the North Aleutian basin is the North Aleutian Shelf COST 1 well, drilled in 1983 by an industry consortium led by ARCO Exploration Company. None of these wells encountered any sizeable accumulations of oil or gas, although several wells detected oil and gas shows and two onshore wells tested minor gas pools at rates up to 90 thousands of cubic feet per day. No wells have tested the Amak basin. North Aleutian and Amak basins are covered by gridded (1 to 5 mile spacing in prospective areas) two-dimensional seismic data mostly acquired in the period from 1975 to 1988.

Well and seismic data indicate that thick, highly porous, and highly permeable sandstones of Oligocene-Miocene age (Bear Lake-Stepovak Formations) are present within the key prospects in the North Aleutian basin. Geochemical analyses of well samples indicate that Tertiary strata are primarily sources for natural gas, possibly with some condensates. Minor oil shows were detected within Tertiary rocks in the lowermost part of the North Aleutian Shelf COST 1 well. Geochemical studies of extracts of these oil shows indicate origination within coaly, Tertiary-age rocks like those sampled by the well. The southwest part of the North Aleutian Basin OCS Planning Area is underlain by Mesozoic rocks that might form a source for oil. However, the North Aleutian Basin OCS Planning Area is primarily a gas province.

The 2006 assessment was completed in November 2005 and incorporates data and information available as of 01 January 2003. The risked, technically-recoverable, undiscovered hydrocarbon energy endowment of the North Aleutian Basin OCS Planning Area ranges up to 6,647 millions of barrels (oil-energy-equivalent, at F05, the 5% fractile, or 5% probability), with a mean value or expectation of 2,287 millions of barrels (oil-energy-equivalent). The Planning Area is gas-prone, with sixty-seven percent of the undiscovered hydrocarbon energy endowment consisting of natural gas. Mean risked, undiscovered total gas (sum of “non-associated” [free] gas and solution gas in oil) resources total 8.622 trillions of cubic feet but could range up to a maximum (F05) potential of 23.278 trillions of cubic feet. Mean risked, undiscovered liquid petroleum (sum of free oil and condensate from gas) resources are estimated at 753 millions of barrels but could range up to a maximum (F05) potential of 2,505 millions of barrels.

North Aleutian Basin OCS Planning Area, Undiscovered Technically-Recoverable Oil & Gas			
Assessment Results as of 2006			
Resource Commodity (Units)	**Resources ***		
	F95	**Mean**	**F05**
BOE (Mmboe)	91	2,287	6,647
Total Gas (Tcfg)	0.404	8.622	23.278
Total Liquids (Mmbo)	19	753	2,505
Free Gas (Tcfg)	0.401	8.393	22.487
Solution Gas (Tcfg)	0.003	0.229	0.791
Oil (Mmbo)	9	545	1,948
Condensate (Mmbc)	10	208	556

** Risked, Technically-Recoverable*

F95 = 95% chance that resources will equal or exceed the given quantity

F05 = 5% chance that resources will equal or exceed the given quantity

BOE = total hydrocarbon energy, expressed in barrels-of-oil-equivalent, where 1 barrel of oil = 5,620 cubic feet of batural gas

Mmb = millions of barrels

Tcf = trillions of cubic feet

The 2006 assessment of the North Aleutian Basin OCS Planning Area identified six exploration plays. Most (61%) of the hypothetical, undiscovered oil and gas resources are associated with play 1—termed the Bear Lake-Stepovak play. Play 1 captures most of the key prospects in the central part of the North Aleutian basin. The *mean* conditional (un-risked) size of the largest pool in play 1 (and the North Aleutian basin overall) is 4.65 trillions of cubic feet of natural gas (or 827 millions of barrels [oil-energy-equivalent]), nearly twice the size of the largest gas field in Cook Inlet (Kenai gas field, 2.427 Tcfg EUR). At *maximum* (F05) size, the largest pool in play 1 could contain 14.02 trillions of cubic feet of natural gas (or 2.495 billions of barrels [oil-energy-equivalent]).

The 2006 MMS economic assessment of the North Aleutian basin models production infrastructure that originates at offshore platforms where gas, condensate, and crude oil are gathered by subsea pipelines from several surrounding fields. Subsea pipelines carry natural gas and petroleum liquids from an offshore hub to onshore facilities and a liquefied natural gas (LNG) plant constructed in Balboa Bay on the south side of the Alaska Peninsula (fig. 10). In our model, natural gas is converted to LNG and then transported by marine LNG carriers to new receiving terminals either in the northern Cook Inlet (550 mi.) or on the U.S. West Coast (2,600 mi.; fig. 48). Minimum transportation tariffs in the economic model represent a Cook Inlet destination while the maximum tariffs reflect a U.S. West Coast landing. The Cook Inlet market (total approximately 200 Bcfg/yr; Sherwood and Craig, 2001, tbl. 5) is probably too small to accept the entire North Aleutian production stream (approximately 150 Bcfg/yr) but nonetheless offers an alternative market.

The lowest (or "threshold") prices that yield positive economic volumes in the North Aleutian basin are $14/barrel of oil and $3.63/Mcf of non-associated gas. (Solution gas is linked to oil development and first becomes "economic" at $2.12/Mcf or the threshold price for oil [$14/barrel].) However, higher prices are required to economically recover meaningful fractions of the oil and gas endowment. Significant quantities (>300 Mmbo) of oil become economic to recover at prices approaching $30/bbl. This could represent a standalone offshore oil field. Significant quantities (>1 Tcfg) of gas become economic at prices exceeding $4.54/Mcf. However, a minimum total gas reserve of 5 Tcfg would probably be required to justify a grassroots LNG export operation. This economic volume is recoverable at an approximate gas price of $6.50/Mcfg and represents 58 percent of the total recoverable gas endowment (8.622 Tcfg).

North Aleutian Basin OCS Planning Area, Undiscovered Economically-Recoverable Oil & Gas				
Assessment Results as of 2006				
Price ($2005) Per Unit	**Resource Commodity (Units)**	**Resources ***		
		F95	**Mean**	**F05**
Threshold Prices ($2005, Mean Resource Case) for Positive Economic Results = $14/Barrel of Oil and $3.63/Mcf of Non-Associated Gas				
$18/bbl	Oil & Condensate (Mmbo)	0	45	200
$2.72/Mcf	Solution Gas (Tcfg)	0.000	0.017	0.053
$30/bbl	Oil & Condensate (Mmbo)	2	378	1,371
$4.54/Mcf	Free Gas & Solution Gas (Tcfg)	0.001	0.909	2.780
$46/bbl	Oil & Condensate (Mmbo)	11	631	2,180
$6.96/Mcf	Free Gas & Solution Gas (Tcfg)	0.132	5.852	16.548
$80/bbl	Oil & Condensate (Mmbo)	19	738	2,468
$12.10/Mcf	Free Gas & Solution Gas (Tcfg)	0.392	8.396	22.767

ECONOMIC ASSUMPTIONS: 2005 base year; oil price is indexed to Alaska North Slope crude landed on the U.S. West Coast; gas price is LNG landed on the U.S. West Coast; 0.8488 BOE-basis gas value discount relative to oil; flat real prices and costs; 3% inflation; 12% discount rate; 35% Federal tax.

** Risked, Economically-Recoverable*

F95 = 95% chance that resources will equal or exceed the given quantity

F05 = 5% chance that resources will equal or exceed the given quantity

Mmb = millions of barrels

Tcf = trillions of cubic feet

Current prices exceed $6.50/Mcf by a wide margin (recent gas prices at the Los Angeles city gate have exceeded $13.00/Mcf; Natural Gas Week, 19 December 2005). If the current high prices are sustained, a significant fraction of North Aleutian basin gas resources are economically attractive.

Locally, the proposed "Pebble" gold mine (estimated gas demand of 66 Mmcfg/day to feed a 200 Mw power plant) north of Iliamna Lake may form a potential future market for North Aleutian basin gas resources. However, the Pebble project site is located approximately 400 miles northwest of the key prospects in the central part of the North Aleutian basin and the estimated gas demand may be too small to support a pipeline of this length.

In October 1989, the North Aleutian basin was placed under a Congressional moratorium which banned U.S. Department of Interior expenditures in support of any petroleum leasing or development activities in North Aleutian Basin as well as the Atlantic, Pacific, and eastern Gulf of Mexico OCS Planning Areas. Bristol Bay is the center of a very important commercial salmon fishery. The North Aleutian moratorium reacted to widespread demands for fisheries protection in Bristol Bay by Native organizations, Native villages, local fishing interests, and the State of Alaska following the March 1989 *Exxon Valdez* grounding and oil spill in Prince William Sound, Alaska. This moratorium was extended by Congress several times during the 1990's. Offshore leases that had been issued in the 1988 OCS Sale 92 in the North Aleutian basin were returned to the Federal government in a 1995 buy-back agreement. On 12 June 1998, President William Clinton issued an Executive Order reinforcing the moratorium, as a *Presidential Withdrawal*, on North Aleutian Basin as well as the Atlantic, Pacific, and eastern Gulf of Mexico continental shelves until 30 June 2012. The *Presidential Withdrawal* still stands but can be revoked by the President. In the FY-2004 Congressional bill appropriating the budget for the U.S. Department of Interior, the language forbidding funding of oil and gas activities (i.e., the "Congressional moratorium") in the North Aleutian Basin OCS Planning Area was dropped. The moratoria language in the bill was retained for the other moratoria areas listed above. This action effectively ended the Congressional moratorium on oil and gas activities in the North Aleutian Basin OCS Planning Area.

Location and General Geology of North Aleutian Basin OCS Planning Area

The North Aleutian basin, located in figure 1, is one of several basins of primarily Tertiary age that dot the Bering Sea shelf. The Bering Sea shelf is relatively flat and featureless except near the modern shoreline where Pleistocene glacial and relict shoreline features occur. The outer shelf and slope are incised by large submarine canyons near the shelf edge west of the St. George and Navarin basins. These submarine canyons empty westward into the deep abyssal plains of the western Bering Sea.

The North Aleutian basin underlies the waters of Bristol Bay north of the Alaska Peninsula (located in fig. 1) and is sometimes also termed the "Bristol Bay" basin. The basin underlies the southern part of the North Aleutian Basin Outer Continental Shelf (OCS) Planning Area. The basin is roughly 100 miles wide and 400 miles in length and reaches depths of 20,000 feet in its deepest parts. The North Aleutian basin extends onshore beneath the lowlands along the north shore of the Alaska Peninsula, where it has been penetrated by several wells. At its west end, a series of arches isolate the basin from the similar St. George and Amak basins, where Tertiary sediment thicknesses reach 40,000 feet and 12,500 feet, respectively (Comer et al., 1987). Along the southern margin of the North Aleutian basin, the Tertiary basin fill is deformed in fold and thrust-fault structures like those widely exposed on the Alaska Peninsula. The interior of the North Aleutian basin is dominated by uplifted fault blocks that have domed the overlying strata. Prospects associated with these dome structures are the primary exploration objectives in the North Aleutian basin. Although minor quantities of gas were recovered by flow tests at an onshore well, no significant accumulations of hydrocarbons have been located by exploration in the North Aleutian Basin OCS Planning Area or on the Alaska Peninsula.

Exploration History of North Aleutian Basin

Past Exploration Onshore

Beginning with the first wells drilled in 1903, a total of 27 wells were drilled onshore on the Alaska Peninsula to the southeast of the North Aleutian Basin OCS Planning Area (table 1; fig. 2). All the 10 earliest wells (1903-1940) were drilled in the vicinity of local oil seeps. The last 17 wells, completed since 1959, were located based primarily on considerations of geologic structure and stratigraphy. The wells are spread over a distance of approximately 260 miles along the Alaska Peninsula, extending from the Pacific, Costello, and Great Basins wells in the northeast to the Cathedral River 1 well to the southwest (fig. 2). Although these wells are mostly located at moderate distances from the North Aleutian Basin OCS Planning Area, they are important for making correlations and inferences about the hydrocarbon potential of the stratigraphic section offshore.

None of the onshore wells encountered producible oil and gas; however, at least 6 of the wells completed since 1959 have encountered minor shows of oil and/or gas. A seventh, the Amoco Becharof Lake 1, tested gas in measurable but non-commercial amounts.

Leasing Onshore

On 26 October 2005, the State of Alaska received 37 bids on 37 tracts in the Port Moller area (fig. 2). High bids totaled $1.27 million and all bids were submitted by either Shell Offshore Inc. (33 tracts, $0.95 million) or Hewitt Mineral Corp. (4 tracts, $0.31 million). The tracts cover areas where thrust faulted and folded Mesozoic and Cenozoic rocks are exposed at the surface (Wilson et al., 1995). The new State of Alaska leases presumably offer exploration objectives in fold structures that are unlike the simple domes that form the key prospects in the Federal offshore.

In 2003, the State of Alaska proposed a sealed-bid licensing program focusing on shallow gas resources north of their proposed lease area, as outlined (2003 area) in figure 2. Based upon industry interest, the licensing program area was later contracted to the 2004 area of 329,000 acres also shown in figure 2. A license was to be awarded (supplemental notice of 22 December 2004, AKDO&G, 2004) to Bristol Shores LLC. However, financing efforts to bond the exploration commitment failed (P. Galvin, pers. comm., 2005) and the license lapsed. Bristol Shores LLC has submitted a new license application for a reduced area of 20,154 acres (Bailey, 2005).

The proposed *Northern Dynasty* "Pebble" gold mine north of Iliamna Lake (located in fig. 2) forms a potential new market for North Aleutian basin gas resources and may drive interest in future lease sales on State of Alaska lands in the region. In the Federal offshore, the best prospects lie approximately 400 pipeline miles southwest of the proposed Pebble mine. *Northern Dynasty* representatives have indicated that the Pebble project will require a 200 megawatt (Mw) power supply (Ede, 2005). This translates to a potential gas demand of about 66 Mmcf/day[1] and may be too small to support a 400 mile pipeline.

Offshore/OCS Exploration

Only one well has been drilled offshore in the North Aleutian Basin OCS Planning Area. This was a "Continental Offshore Stratigraphic Test" (COST) well, the North Aleutian Shelf COST 1 well (tbl.1; fig. 2). Eighteen companies participated in financing the well, with ARCO Exploration Company as the operator. It was drilled from the SEDCO 708, a self-propelled semi-submersible drilling rig, and was spudded (began drilling) on September 8, 1982, in 285 feet of water. The well was plugged and abandoned on January 14, 1983, after bottoming at 17,155 feet in sedimentary rock of Eocene age. Below 15,300 feet, minor gas peaks appeared on the mud log and drill cuttings showed some oil stain and fluorescence (Turner et al., 1988), but no pools of oil or gas were encountered.

Seismic data coverage for the North Aleutian Basin OCS Planning Area is shown in figure 3. Seismic data gathered to date within the North Aleutian Basin OCS Planning Area consists of 64,672 combined line miles of conventional, two-dimensional, common-depth-point (CDP) and shallow-penetrating, high-resolution (HRD) data. Of the seismic data held by MMS, 95% is CDP and 5% is HRD. Airborne magnetic data in the area covers 9,596 line miles. Approximately 6,400 miles of airborne gravity data have also been gathered in the Planning Area.

Past OCS Leasing

The only OCS lease sale in the area, the North Aleutian Shelf Sale 92, was held in October of 1988, with a total offering of 990 lease blocks (area of offering shown in fig. 2). The bidding resulted in the awarding of 23 leases (blocks shown in fig. 2) covering 121,757 acres. Proceeds from the sale totaled $95,439,500.

Following the March 1989 grounding of the *Exxon Valdez* tanker and subsequent oil spill, a drilling ban was instituted in the North Aleutian basin Federal offshore in 1989. The drilling ban and moratorium on all exploration recognized widespread opposition from Native organizations and villages and concerns about impacts on the lucrative salmon fishery. As a result, none of the 23 leases in the area were ever drilled. In 1992, 11 oil companies filed a joint lawsuit (Conoco Inc. vs. USA) in an attempt to end the ban or receive compensation. An out of court settlement and a Federal buyback of the leases was reached in 1995. On 12 June 1998, President William Clinton issued an Executive Order extending the moratorium (as a *Presidential Withdrawal*) on North Aleutian basin (and the Atlantic, Pacific, and eastern Gulf of Mexico continental shelves) until 30 June 2012 (Alaska Report, 1998). The *Presidential Withdrawal* still stands but can be revoked by the President. However, the Congressional moratorium on petroleum-related activities in North Aleutian basin has been lifted. In the FY-2004 Congressional bill appropriating budget funding for the U.S. Department of Interior, the language

[1] *Estimated as follows: One Mw capacity matches one Mw·h (megawatt-hour) demand. Assume 3,412 btu/kwh energy equivalence (AEO, 2001, tbl. H1, p. 248) and 1,000 btu/cf gas; substitutions obtain 3,412 cf/Mw·h. At 25% efficiency* and 200Mw·h demand, we obtain 2.73 Mmcfg/h or 65.51 Mmcfg/day in gas demand.*

* *AEO (2001, tbls. 19 & 20, p. 103) reports a 1984-1999 range in efficiencies of delivered electricity of 15% to 38% for various sectors.*

forbidding funding of oil and gas activities (i.e., the "moratorium") in the North Aleutian Basin OCS Planning Area was dropped (but retained for other moratoria areas).

Productive Analog Basin—Cook Inlet Basin

In southern Alaska, the most successful basin from the standpoint of oil and gas is the northern part of Cook Inlet basin, located in figure 4. The first field was discovered in 1957, and exploration programs continuing into the early 1970's located original recoverable reserves of 1.4 billions of barrels of oil and 11.6 trillions of cubic feet of gas (AKDO&G, 2004). Most of these reserves have been depleted, with remaining reserves as of late 2003 estimated at 0.0751 billions of barrels of oil (5% of original reserves) and 2.039 trillions of cubic feet of gas (18% of original reserves) (AKDO&G, 2004, tbls. 3.2, IV.2, IV.6).

Like the North Aleutian basin, the principal fill of the Cook Inlet basin is of Tertiary age and reaches maximum thicknesses of roughly 26,000 feet (Hite, 1976; Fisher and Magoon, 1982, fig. 4). The most prolific Cook Inlet basin petroleum reservoirs are of Oligocene, Miocene, and Pliocene ages. Age-equivalent strata in the North Aleutian basin are also the best candidates for petroleum reservoirs.

The structural style of prospects differs between the North Aleutian and Cook Inlet basins. Oil and gas fields in Cook Inlet occupy transpressional anticlines of Oligocene to Pliocene age that formed near strike-slip faults that pass from northeast to southwest through the basin (Haeussler et al., 2000). In contrast, North Aleutian basin prospects are drape anticlines developed in Eocene through Pliocene time over basement uplifts that were elevated while sediments in flanking deeps compacted, thereby doming shallow strata over the basement uplifts.

One of the more compelling points of analogy between the Cook Inlet and North Aleutian basins is the potential role of underlying Mesozoic rocks in the generation of oil and charging of prospects in overlying Tertiary strata. Both basins overlie an older Mesozoic basin that contains the oil source rocks that generated the oil fields of northern Cook Inlet basin. The petroleum system in northern Cook Inlet succeeded because a deep Tertiary basin was superposed on a thermally immature Mesozoic assemblage that was buried and heated to temperatures appropriate for oil generation at the same time that fold traps grew in the overlying Tertiary basin fill (Magoon, 1994). The Middle Jurassic Tuxedni Group was the source for the oil that migrated upward into the Tertiary basin fill, generally charging fold structures in the Oligocene Hemlock Conglomerate (Magoon, 1994). The "Tuxedni-Hemlock" petroleum system that created the prolific oil fields of northern Cook Inlet basin is featured as a case study by Magoon (1994).

Critical to the success of the "Tuxedni-Hemlock" petroleum system are the facts that the Mesozoic assemblage beneath northern Cook Inlet basin was both: 1) compositionally appropriate (endowed with rocks rich in organic matter and able to generate oil); and 2) thermally immature (retained ability to generate oil through 100 million years following deposition and not deeply buried until about 65 Ma [Magoon, 1994, fig. 22.7]). Correlative potential oil source rocks with a similar burial history may be found in the Mesozoic basin in areas beyond northern Cook Inlet.

The Mesozoic rocks beneath Cook Inlet basin were deposited in a Mesozoic (Jurassic to Cretaceous) basin that was coupled to a Jurassic to Cretaceous volcanic arc to the north (Bally and Snelson, 1980). This Mesozoic basin extends at least 600 miles from interior Alaska to the southwest through the Alaska Peninsula (Imlay and Detterman, 1973, p. 8-9). From the Alaska Peninsula the Mesozoic basin probably extends an additional 300 miles northwesterly beneath St. George basin (Worrall, 1991, fig. 15). The approximate area of this Mesozoic basin is highlighted in figure 4 as the "Mesozoic basin with Jurassic oil source rocks?" The Cook Inlet basin, the North Aleutian basin, and the St. George basin are all superposed on the Mesozoic basin. Magoon (1994) has shown that this superposition was critical to the creation of the oil accumulations of the northern Cook Inlet basin. On the other hand, St. George basin was tested by 12 wells, none of which encountered any oil or gas accumulations. It seems that the Mesozoic strata beneath St. George basin were somehow incapable of generating oil into the overlying St. George basin fill. Perhaps early deep burial caused generation and expulsion of petroleum from the Mesozoic rocks prior to formation of the Tertiary-age St. George basin. Perhaps the Mesozoic rocks beneath St. George basin simply lack the appropriate organic matter for oil generation.

To the northeast of the North Aleutian basin we have a successful analog (northern Cook Inlet basin) and to the southwest of North Aleutian basin we have a failure analog (St George basin). The existence of substantive oil sources in the part of the Mesozoic basin that lies beneath North Aleutian basin remains unproven. However, this assessment assumes some capability (appropriately risked, given the uncertainty) of Mesozoic oil source rocks for providing oil to traps within both Mesozoic and contiguous Cenozoic rocks.

Petroleum Geology of the North Aleutian Basin

Regional Geology

Alaska Peninsula

The Alaska Peninsula is the site of tectonic-plate convergence between the Pacific oceanic plate and the North American continental margin. The resulting magmatic arc is a continuation of the Aleutian islands volcanic arc to the west, where convergence involves two oceanic plates. Plate convergence has been occurring at this margin episodically since the Early Jurassic. As a result, the peninsula is geologically complex and includes both Mesozoic and Cenozoic igneous and sedimentary rocks. The modern Alaska Peninsula volcanic arc is built upon earlier volcano-plutonic arcs. Intrusive plutons from both Jurassic and Tertiary magmatic events occur in many places on the Alaska Peninsula. The oldest sedimentary rocks on the Alaska Peninsula are Late Triassic carbonates at Puale Bay to the east (located in fig. 2) along Shelikof Strait, but most of the Mesozoic strata consist of arc-derived clastic rocks of Jurassic and Cretaceous age. Those rocks are mostly of marine origin and are extensively folded and thrust faulted. The Tertiary section includes interbedded volcanic and volcaniclastic sedimentary rocks of continental origin. The Tertiary strata are less deformed than the Mesozoic strata. Both the Mesozoic and Cenozoic rock units of the Alaska Peninsula extend under the North Aleutian Basin OCS Planning Area.

Formation of North Aleutian Basin

The North Aleutian Basin OCS Planning Area contains two main depocenters: the North Aleutian basin and the Amak basin. Those two sedimentary depressions are separated by the Black Hills uplift, which extends westward under the Bering Sea shelf from the Alaska Peninsula. The North Aleutian basin is primarily a Tertiary-age basin that was filled with sediments derived from uplifted areas in the Alaska Peninsula to the south and the western Alaska Range (located in fig. 1) to the northeast. The North Aleutian basin contains as much as 20,000 feet of Cenozoic strata. The basin is less than 3,000 ft thick on the northwest and thickens southeastward to about 20,000 near the Alaska Peninsula. This asymmetric profile has the appearance of a foredeep, possibly caused by tectonically thickened crust under the volcanic arc of the Alaska Peninsula (Bond et al., 1988).

The North Aleutian Shelf COST 1 well did not penetrate "basement" but reached total depth in Lower Eocene rocks of the lower part of the Tolstoi Formation (Detterman, 1990; Turner et al., 1988). The oldest known strata within the basin fill are Late Paleocene rocks of the Tolstoi Formation exposed on the Alaska Peninsula (Detterman et al., 1996). Detterman et al. (1996, p. 42) note that in most parts of the Alaska Peninsula, the base of the Tolstoi Formation is a prominent Paleocene unconformity that places the Tolstoi on a variety of older Mesozoic formations. Wilson et al. (1995) and Detterman et al. (1996) indicate that in the vicinity of the Black Hills uplift and east to Port Moller, the Tolstoi Formation and underlying Cretaceous Hoodoo Formation (or equivalent Chignik Fm.) are concordant across a disconformity. Offshore on the Black Hill uplift, we observe structural discordance between Tolstoi strata and underlying Mesozoic rocks in seismic data.

From regional geological data and seismic interpretation, Worrall (1991) infers a late Eocene age for the unconformity (his "red" seismic horizon; approximately our seismic horizon "D" at 10,380 ft bkb [below Kelly bushing, or measured depth] in the COST well) flooring North Aleutian basin proper. The angular unconformity separating the two sequences was formed when plate reorganization in the north Pacific resulted in a change from convergent to strike-slip movement along the continental margin (Marlow and Cooper, 1980; Lonsdale, 1988; Worrall, 1991). Worrall (1991, fig. 38) assigns all of the Eocene rocks below 10,660 ft bkb in the North Aleutian Shelf COST 1 well to an older (his "carapace" sequence) group of Campanian to Eocene rocks that was deposited and folded prior to the late

Eocene or "red" unconformity. However, it is our view that Worrall's "carapace sequence" in the North Aleutian basin instead represents the earliest basin fill deposited in faulted grabens during the initial rift phase of basin subsidence. Rather than the roots of fold synclines (Worrall model), we view these bodies of rock as fill within grabens established at the onset of transtensional rifting, most likely in Paleocene time. The Upper Eocene unconformity ("red" horizon of Worrall; our seismic horizon "D") marks the transition from a rift phase (accompanied by faulting) to a foredeep phase with southward tilting governed by thrust loading on the south (Bond et al., 1988).

The North Aleutian Shelf COST 1 well reached total depth at 17,155 ft bkb in Lower Eocene rocks of the Tolstoi Formation, but seismic data suggest an additional 2,000 to 3,000 feet of stratified rocks below the base of the well. Because of the widespread Paleocene unconformity at the base of the Tolstoi Formation on the Alaska Peninsula, we infer that the oldest deposits in the North Aleutian basin, dating the onset of rift faulting and basin subsidence, are Paleocene in age.

Structures of Amak Basin, Black Hills Uplift, and North Aleutian Basin

The principal structures of the North Aleutian Basin OCS Planning Area and contiguous areas are mapped in figure 5. The context for these structures is compressive deformation on the south and a diffuse zone of strike-slip deformation and extension that passes through the Alaska Peninsula, the western part of the North Aleutian basin, and along the flanks of the Black Hills uplift. All structures are ultimately rooted in the interactions between the Alaska Peninsula volcanic arc and the Aleutian trench and subduction zone.

The Amak basin is a relatively small structural depression south of the Black Hills uplift on the outer Bering Sea shelf. This basin contains as much as 12,500 feet of Cenozoic strata overlying folded and faulted Mesozoic sedimentary rocks. The Cenozoic strata within the Amak basin are less deformed than in the North Aleutian basin. Wrench faults and normal faults commonly cut the basement and lower Tertiary horizons, but the horst and graben structural style characteristic of the North Aleutian basin is absent in the Amak basin.

The Black Hills uplift is the dominant positive structural feature of the southwest part of the North Aleutian Basin OCS Planning Area. This uplift plunges westward from the Alaska Peninsula through the southern Bering Sea shelf and continues into the St. George Basin Planning Area. The Black Hills uplift is probably a transpressional feature formed by strike-slip motion along the Bering Sea margin. The Naknek Formation (Late Jurassic) is exposed at the crest of the Black Hills uplift onshore. The Naknek Formation and older (as old as Late Triassic) formations probably form the core of the Black Hills uplift. The crest of the uplift is draped by Upper Eocene through Miocene strata. The uplift is fault-bounded on both the North Aleutian basin side (to the north) and the Amak basin side (to the south). Wrench fault zones pass along the north and south flanks of the Black Hills uplift, as illustrated in a seismic profile published by Worrall (1991, pl. 2G). The wrench fault zones are 10 to 15 miles wide, extend through Plio-Pleistocene strata to the seafloor, and are associated with both transpressional (or "positive") and transtensional (or "negative") flower structures. Normal (probably transtensional) faults are observed between the wrench zones across the crest of the Black Hills uplift. The sense of displacement on the wrench faults is believed to be right-lateral on the basis of context and regional structural patterns (Worrall, 1991).

We recognize two general structural domains in the North Aleutian basin: 1) transtensional grabens and horsts in the basin interior; and 2) fold and thrust-fault structures along the south margin. From a petroleum exploration standpoint the transtensional horsts in the basin interior and overlying drape structures form the most attractive prospects in the basin.

In the southwest half of the North Aleutian basin, transtensional faults bound horsts with several thousands of feet of structural relief at the basement level. Tertiary strata younger than Late Eocene are domed upward over these horsts, partly because of fault movements and partly because of compaction subsidence within sediment-filled grabens flanking the horsts. Some examples of these drape anticlines are illustrated in the seismic line of figure 6 (full scale image available as plate 1). Drape anticlines over basement uplifts extend from the Upper Eocene unconformity (seismic horizon "D"--truncates the crests of basement uplifts) at about 10,000 ft ssd (subsea depth) upward to a Lower Pliocene unconformity (seismic horizon "A") at about 2,500 ft ssd. Displacements on uplift-bounding faults abruptly diminish above the Upper Eocene unconformity, but very small (possibly compaction-driven) offsets are observed up to about 5,000 feet in figure 6 (and pl. 1). These drape anticlines are the primary exploration targets in the North Aleutian basin. Because of their large closure areas and involvement of the thick, porous Bear Lake-Stepovak reservoir sandstones, these drape anticlines host most of the undiscovered, hypothetical oil and gas potential of the North Aleutian basin.

The overall structure of North Aleutian basin is illustrated by structural contours on an Upper Oligocene datum in figure 5. The basin is basically a southward-thickening wedge that is abruptly terminated in a series of fold and thrust-fault structures that are the northern limit of the compressional deformations that dominate the Alaska Peninsula. The Alaska Peninsula is a fold and thrust belt that grades from simple, open structures on the northeast to highly shortened and complex structures in the southwest (Burk, 1965, figs. 21, 22). In its overall shape, the North Aleutian basin resembles a foredeep, in which the south flank has been depressed by thrust loading and in which shallow thrust structures abruptly terminate in a system of duplexes and triangle zones. This view is supported by modeling studies of the deep structure of the North Aleutian basin and the Alaska Peninsula volcanic arc by Bond et al. (1988) and Walker et al. (2003). The Bond study concluded that basin subsidence was driven by downward flexure of the back-arc lithosphere beneath a load imposed by subduction-driven crustal thickening of the arc and forearc of the Alaska Peninsula. The Walker study concluded that early extension and fault-controlled subsidence was succeeded by flexural subsidence due to loading on the south by stacking of volcanic materials on the Alaska Peninsula.

The southeast margin of the North Aleutian basin is deformed by folds, thrust faults, and antiformal duplexes that represent the northern front of the Alaska Peninsula fold and thrust belt. Proprietary seismic data indicate that the fold and thrust-fault structures along the southwest margin of the basin terminate northward in triangle zones that have tilted rocks as young as Pliocene over duplex roofs. The David River 1/1A, Hoodoo Lake 1, Hoodoo Lake 2, and Sandy River 1 wells were all drilled into antiformal duplexes that back triangle zones that taper northward beneath north-dipping Miocene to Pliocene basin fill. We speculate (as shown in fig. 5) that similar structures extend along strike to the northeast and form the targets drilled at the Port Heiden 1, Ugashik 1, Great Basins 1, Great Basins 2, and Becharof Lake 1 wells. However, we do not have access to any seismic data through these latter wells. Southwest of the Sandy River 1 well, proprietary seismic data indicate that the fold, thrust-fault, and duplex structures do not extend offshore into Federal waters. Therefore, these fold and thrust-fault structures do not form an oil and gas play in our assessment of the North Aleutian basin.

Nature of Basement Beneath North Aleutian Basin

In the western Alaska Range, the Bruin Bay fault forms a regional contact between Mesozoic volcano-plutonic rocks on the north and Mesozoic sedimentary rocks on the south (Magoon et al., 1976). The volcano-plutonic rocks on the north are the roots of a Mesozoic volcanic arc and range in K-Ar ages from 179 to 107 Ma (Magoon et al., 1976, sh. 3), or Middle Jurassic to mid-Cretaceous, respectively, in equivalent stratigraphic ages. The Mesozoic sedimentary rocks south of the Bruin Bay fault represent a Mesozoic basin that flanked the contemporary volcanic arc to the north (Bally and Snelson, 1980).

The Bruin Bay fault system is a series of high-angle reverse faults with the upthrown side on the northwest (Detterman and Reed, 1980). The Bruin Bay fault is truncated north of Cook Inlet by the presently-active Castle Mountain fault. To the southwest, the fault system is mapped at the surface through the Alaska Peninsula to Becharof Lake, where the fault trace passes southwest beneath Quaternary volcanic and glacial deposits (Detterman et al., 1987). Fault movement was primarily in Middle and Late Jurassic time, when the Alaska-Aleutian Range batholith was being unroofed, providing clastic detritus to the Late Jurassic Naknek and younger formations. The Bruin Bay fault is intruded by a plutonic stock on the Alaska Peninsula that was age-dated at 25.0-26.7 Ma, indicating no movement since the Oligocene in that area (Reed and Lanphere, 1972; Magoon et al., 1976, sheets 2, 3, sites 66 & 67; Detterman and Reed, 1980). To the north, the subsurface trace extends very close to the complexly-folded and reverse-faulted structures of the Middle Ground Shoal, McArthur River, Beluga River and other oil and gas fields of upper Cook Inlet (Boss et al., 1976). According to Haeussler et al. (2000), those fault-cored folds are Miocene and younger, with most of the deformation occurring in the Quaternary.

Penetrations of Mesozoic granitic rocks beneath the North Aleutian basin fill north of the Bruin Bay fault occurred at the Great Basins 1, Great Basins 2, Becharof Lake 1, and Port Heiden 1 wells. Penetrations of Mesozoic sedimentary rocks south of the Bruin Bay fault occurred at the Cathedral River 1, David River 1/1A, and Hoodoo Lake 2 wells. Five wells in the St. George basin to the west encountered Mesozoic sedimentary rocks beneath Tertiary basin fill. The North Aleutian Shelf COST 1 well did not reach any pre-Tertiary rocks. These well penetrations of the Mesozoic substrate are sparse and only provide fragmentary information about the subsurface distribution of the component terranes.

Southwest of Becharof Lake, as noted above, the Bruin Bay fault passes beneath volcanic rocks and glacial sediments of Quaternary age of the Bristol Bay lowlands. The lowlands are dotted with numerous semi-circular magnetic anomalies that Case et al. (1988) interpret to locate buried granitoid to gabbroic plutons of Jurassic to Tertiary ages. None of these buried igneous bodies have been sampled or dated and speculations about their ages are based on regional context. A narrow, north-northeast-trending belt of high magnetic intensity (anomaly 8C of Case et al.) south of Becharof Lake is interpreted to locate a buried anticlinal limb of Naknek Formation (Jurassic) (Case et al., 1988, fig. 4, p. 4). This "Naknek" anomaly is truncated on the north at a projected buried strand of the Bruin Bay fault 15 miles southwest of Becharof Lake (Case et al., 1988, sheet 2).[2] Farther southwest, the location of any extension of the Bruin Bay fault is unknown and a matter for speculation.

A regional magnetic intensity map for the southern Bering Sea shelf published by Childs et al. (1981) is reproduced with annotations in figure 7. The map shows two principal magnetic domains with very different field characters. In the north, the map shows high-frequency, high-intensity magnetic anomalies. In the south, the map shows low-frequency, low-intensity magnetic anomalies. The two magnetic domains are clearly separated by a sharp, west-trending line that may represent the extension of the Bruin Bay fault into the southern Bering Sea.

We speculate that the northern magnetic domain in figure 7 is the southwestward, offshore extension of the Mesozoic magmatic arc terrane exposed north of the Bruin Bay fault in the western Alaska Range. In support of this notion we observe that magnetic data over the exposed magmatic arc terrane north of the Bruin Bay fault (in a regional compilation published by Godson, 1994) show a high-frequency, high-intensity field character much like that of the northern magnetic domain illustrated in figure 7. Along the Alaska Peninsula proper, there are numerous magnetic anomalies related to Tertiary-age intrusives and modern volcanoes. West of 162º WL, the projected extension of the Bruin Bay fault diverges northwest away from the Tertiary arc and the contrast in magnetic domains north and south of the Bruin Bay fault is more clear (fig. 7).

In marine seismic data over the Black Hills uplift, we observe coherent, folded reflections that extend up to 2 sec below a prominent angular unconformity at the base of Tertiary rocks. These coherent, folded reflections are interpreted to correspond to Mesozoic strata that are exposed onshore to the east along the crest of the Black Hills uplift (fig. 5; Wilson et al., 1995). Some examples of these coherent, folded reflections are observed within the "Peninsular terrane" in a seismic panel published by Worrall (1991, pl. 2, line "G") and in the southwest end of a seismic panel published by Turner et al. (1988, fig. 65). The "Peninsular terrane" corresponds to the Mesozoic sedimentary rocks southeast of the Bruin Bay fault.

North of the Black Hills uplift, Worrall

[2] *Similar relationships are shown on geologic maps (Magoon et al., 1976, sheet 2) to the east near Kamishak Bay. In the latter area, the exposed Naknek Formation is confined to the block southeast of the Bruin Bay fault, which also truncates the axes of large folds within the Naknek (Magoon et al., 1976, sheet 2). Naknek folds and the Bruin Bay fault are both truncated by a 25.0-26.7 Ma (Oligocene) granodiorite/quartz diorite stock (Magoon et al., 1976, sheets 2, 3, sites 66 & 67), which sets the minimum age for the deformation.*

(1991, pl. 2) shows deeply buried synclines in a folded "carapace" sequence of Late Cretaceous to Eocene age that underlies his "Red" Upper Eocene unconformity. Worrall's synclines are associated with coherent seismic reflections that are lost through the intervening anticlines. We interpret these features somewhat differently. We view Worrall's "synclines" as grabens that record the earliest rift subsidence of the North Aleutian basin and that are filled with Paleocene to Eocene age strata. We interpret Worrall's "anticlines" as horsts that are decapitated by an Upper Eocene unconformity corresponding to our seismic horizon "D" (fig. 6). Our horizon "D" correlates to Worrall's "Red" unconformity. The horizon "D" unconformity separates the rift phase from the subsequent sag phase of basin subsidence. The horsts are acoustically transparent (lack coherent reflections) in their central areas (fig. 6 and lines "F" and "G" of Worrall, 1991, pl. 2). We interpret the horsts to be cored by primarily Mesozoic magmatic rocks with sparse surviving bodies of unabsorbed Mesozoic sedimentary rocks. The acoustic transparency of the substrate below the "Red" unconformity north of the graben field in North Aleutian basin is illustrated at the north ends of lines "F" and "G" of Worrall (1991, pl. 2).

We have not attempted to map the southwestward extension of the Bruin Bay fault in seismic data, instead relying on magnetic character to separate the northern magmatic terrane from the southern sedimentary terrane. But, it is our general experience that the acoustic appearance of the Mesozoic substrate on the north (transparent) is fundamentally different from the Mesozoic substrate on the south (stratified/folded). Offshore seismic data therefore support our partitioning of the Mesozoic substrate into magmatic and sedimentary terranes juxtaposed along a southwestern extension of the Bruin Bay fault.

Figures 5 and 7 show that the most important gas and oil prospects in the North Aleutian basin (partly located by Sale 92 leases) occupy the part of the basin that overlies the Mesozoic magmatic terrane north of the Bruin Bay fault. This observation is very significant to conceptual models for petroleum charge for these important prospects. Any analogy to the petroleum system of northern Cook Inlet, where oil generated in an underlying Mesozoic basin has charged shallower traps in Cenozoic rocks, cannot be extended to this part of the North Aleutian basin. It is very unlikely that hydrocarbons in any quantity can be sourced out of the Mesozoic magmatic terrane beneath the part of the North Aleutian basin north of the Bruin Bay fault. These important prospects must instead depend entirely upon potential sources within the Tertiary-aged North Aleutian basin fill, mostly gas-prone, for petroleum charge.

<u>Mesozoic Stratigraphy and Reservoir Formations</u>

A stratigraphic chart for the Mesozoic rocks of the Alaska Peninsula is presented in figure 8. Sandstones and conglomerates that might form reservoirs for petroleum include the Talkeetna, Naknek, Staniukovich, Herendeen, and Hoodoo (or equivalent Chignik) Formations. Because the Mesozoic basins in which these strata were deposited flanked a volcanic arc, most clastic sediments contain great quantities of volcanic and plutonic rock fragments. Upon burial, the volcanic material readily degraded into laumontite and other zeolite-group minerals that fully occluded intergranular porosity. Dutrow (1982, p. 1) describes typical Jurassic-age sandstones in the Cathedral River 1 well as follows:

> "Petrographic examination of 43 samples from Amoco Cathedral River No. 1 sand, showed the lithology to be predominately volcanic-rich litharenites or feldspathic litharenites with only minor amounts of arkose, lithic arkose, and quartzite (the classification scheme used is Folk, 1968). Typically the sands were compacted with no remaining porosity. Often volcanic rock fragments became incoherent with compaction, molding around grains to form an interstitial matrix. Where compaction did not reduce all intergranular voids, authigenic cements formed. The cements are chlorite/smectite, laumontite, and carbonate. Veins of laumontite/heulandite cut the volcaniclastic sands. These phases also replace pre-existing minerals. The most common accessory minerals were a green hornblendic amphibole, epidote and opaques (clasts and pyrite framboids."*(sic)*

Generally, younger sandstone formations contain less volcanic debris because of re-cycling of older clastic formations and winnowing of volcanic particles made susceptible to disintegration by chemical and physical weathering (Burk, 1965, fig. 10). Younger formations have also been less deeply buried because of their position at the top of the sedimentary stack and have presumably suffered less from compaction and thermally-driven pore-filling diagenesis. For both of these reasons, the Staniukovich and Naknek Formations and younger Cretaceous units form the best candidates for viable petroleum reservoirs among the Mesozoic assemblage (fig. 8).

The prolific oil fields of northern Cook Inlet are underlain by the Upper Jurassic Naknek Formation sandstones, which are underlain by the Middle Jurassic Tuxedni Group oil source beds, which are in turn underlain by the Lower Jurassic Talkeetna Formation sandstones (Magoon, 1994). Despite this close association with the Tuxedni Group oil source beds (proven to have generated 1.6 billion barrels of oil reserves now residing in overlying Tertiary reservoirs), there is virtually no oil production in northern Cook Inlet from the associated Mesozoic sandstone formations. The Naknek and Talkeetna Formations are completely cemented and barren of hydrocarbons. We note a single exception at the McArthur River oil field where a small amount (<300,000 bbls) of oil was produced over a 9-year period from fractured Lower Jurassic rocks (Talkeetna Formation) below the main Tertiary-age oil reservoir (AOGCC, 2001, p. 183). The generation of oil out of the Middle Jurassic oil source beds occurred mostly in Tertiary time (Magoon, 1994, fig. 22.7), after 100 million years of burial stasis during which diagenesis and compaction completely destroyed the pore systems in Mesozoic sandstone formations. An intriguing concept for petroleum exploration of Mesozoic sandstones postulates that in some areas an early (presumably Cretaceous) cycle of burial sufficient to generate hydrocarbons might have charged the still-porous Mesozoic sandstones with petroleum and protected the pore systems from destruction. However, this was not the case in the Cook Inlet area.

Cenozoic Stratigraphy, Reservoir Formations, and Play Sequences

The most complete point of stratigraphic control for the North Aleutian basin fill is the North Aleutian Shelf COST 1 stratigraphic test well that was drilled in 1983 by an industry consortium. Detailed descriptions of the results of that well are given by Turner et al. (1988). The stratigraphy of the COST well is presented in figure 9 (full-scale version available as plate 2).

Three play sequences based on COST well stratigraphy are defined for purposes of this assessment. Each play sequence embraces groups of rocks that share some commonality in reservoir formation characteristics and relationships to prominent unconformities and seismic markers. The play sequences considerably overlap biostratigraphic boundaries but correspond sufficiently to established stratigraphic units to permit co-opting the formal nomenclature into our play sequence terminology (shown in fig. 9, right column). Detterman (1990) extended Alaska Peninsula stratigraphic nomenclature to the North Aleutian Shelf COST 1 well and we adopt his correlations for this assessment (shown in fig. 9, left column). A stratigraphic correlation chart in figure 10 (full-scale version available as plate 3) shows the relationship of the North Aleutian Shelf COST 1 well to several onshore penetrations of Tertiary rocks.

The Milky River Biogenic Gas (play 4) play sequence ranges in age from Early Pliocene to Holocene and includes the upper part of the Milky River Formation and overlying unnamed Quaternary-age rocks. The play sequence is 2,148 feet thick at the North Aleutian Shelf COST 1 well. The play sequence overlies seismic horizon "A", which generally is not domed over basement uplifts. The play sequence consists of middle to outer neritic unconsolidated lithic pebbly sands, mud, ooze, and clay (Turner et al., 1988, p. 14).

The Bear Lake-Stepovak (plays 1, 3) play sequence ranges in age from Late Oligocene to Early Pliocene in the North Aleutian Shelf COST 1 well and includes the upper part of the Stepovak Formation, the entire Bear Lake Formation, and the lower part of the Milky River Formation. The play sequence is 5,390 feet thick at the COST well and thickens to approximately 7,300 feet in seismic data along the north coast of the Alaska Peninsula (Turner et al., 1988, figs. 66, 67). The Bear Lake-Stepovak play sequence overlies seismic horizon "C" which is a regional mid-Tertiary unconformity. On parts of the Black Hills uplift, seismic horizon "C" places Oligocene rocks directly upon Mesozoic rocks. Seismic horizon "C" does not contact basement over the basement horsts in the southwest half of the North Aleutian basin, but overlies a sandy sequence and a regional shale sequence in the lower part of the Stepovak Formation (fig. 10). Seismic horizon "D" incises basement on the horsts in the southwest half of the North Aleutian basin. The seismic profile in figure 6 (and pl. 1) shows that most of the strata in the Bear Lake-Stepovak play sequence are domed over the basement horsts in the southwest half of the North Aleutian basin.

The Bear Lake-Stepovak play sequence at the North Aleutian Shelf COST 1 well is rich (61% of play sequence) in thick (up to 277 feet), porous (up to 40+% porosity), and permeable (up to 7,722 md) sandstones. Some statistics for sandstone beds in the Bear Lake-Stepovak play sequence are summarized in figure 11. The play sequence contains a total of 3,120 net feet of sandstones in beds greater than 10 feet thick (an assumed practical minimum thickness for productive reservoir) and 1,443 net feet in beds over 100 feet thick. Figure 12 shows core porosity versus depth for sandstones in the North Aleutian Shelf COST 1 well. Core porosity is also posted with density log sandstone porosity in figure

9 and plate 2. For the Bear Lake-Stepovak play sequence, core porosity ranges between 20% and 40%. Figure 13 summarizes core porosity and permeability data and we note that the 20% to 40% porosity range is associated with multi-Darcy permeability values. Figure 14 summarizes core permeability data versus depth and we observe that the statistical fit forecasts preservation of permeability at tens of millidarcies (at the mean) down to the base of the Bear Lake-Stepovak play sequence. A core porosity histogram for the Bear Lake-Stepovak play sequence is shown in the upper panel of figure 15. A core permeability histogram for the Bear Lake-Stepovak play sequence is likewise presented in the upper panel of figure 16. Because of the ample, thick sandstones and the excellent preservation of porosity and permeability, the Bear Lake-Stepovak play sequence is the most attractive reservoir target in the North Aleutian basin.

The Tolstoi (play 2) play sequence ranges in age from Early Eocene to Early Oligocene in the North Aleutian Shelf COST 1 well and includes the Tolstoi Formation and the lower, shaly part of the Stepovak Formation (9,555-10,380 ft bkb) that forms a regional seal (fig. 10 and pl. 3). The minimum thickness (base not penetrated) of the Tolstoi play sequence is 9,255 feet at the North Aleutian Shelf COST 1 well. The Tolstoi play sequence probably extends through Paleocene strata down to Mesozoic volcano-plutonic "basement" beneath the COST well. Seismic horizon "D" occurs within the upper part of the Tolstoi play sequence and corresponds to a regional Upper Eocene unconformity that truncates the crests of basement uplifts in the southwest half of the North Aleutian basin (fig. 6 and pl. 1). As shown in the sandstone thickness histograms of figure 11, the Tolstoi play sequence is characterized by sparse (10% to 30% of interval), thin (maximum = 57 ft) sandstones. In the upper part of the Tolstoi play sequence, from 7,900 to 10,380 feet in the COST well, the sandstones are porous and permeable (figs. 12, 14, 15, and 16). This part of the sequence, like the overlying Bear Lake-Stepovak play sequence, is draped over the basement uplifts. Below 10,380 feet, the sandstones are largely impermeable (fig. 16, lower panel) because diagenesis (to clay and zeolites) has softened volcanic clasts and the sandstone grain framework has collapsed, as described in petrographic studies by AGAT (1983, p. 2) and Turner et al. (1988, p. 23-24). This collapse post-dates some early pore-filling cement, around which formerly rigid volcanic framework grains (softened by diagenesis) have flowed (AGAT, 1983). The abrupt loss of permeability in sandstones approximately coincides with the onset of overpressure at 11,200 feet bkb (fig. 9 and pl. 2) in the North Aleutian Shelf COST 1 well. The diagenetically-induced implosion of the intergranular pore system and expulsion of fluids may be a prime driver for the overpressure (Turner et al., 1988, p. 217). Core porosity data for the Tolstoi play sequence are summarized in the histograms of figure 15. Most of the measured core porosity in the Tolstoi play sequence below 10,380 feet bkb in the COST well is microporosity in altered volcanic rock fragments.

The lower part of the Tolstoi play sequence (below 10,380 ft/seismic horizon "D") is truncated by faults at the flanks of basement uplifts and would form the primary reservoir targets for prospects ringing uplift flanks. The probable absence of porous sandstones in the lower part of the Tolstoi play sequence forms an area of great risk for the flank prospects.

Petroleum Systems in North Aleutian Basin Plays

Thermal Maturity of North Aleutian Basin Fill

The first important concern about the viability of any potential petroleum systems in North Aleutian basin is whether or not any rocks have been buried to depths and temperatures sufficient to convert organic matter to oil or gas. Figure 17 summarizes vitrinite reflectance data for the North Aleutian Shelf COST 1 well and offers statistical fits to data sets above and below a discontinuity at 15,620 feet bkb. The vitrinite reflectance discontinuity has been cited as evidence for an unconformity at 15,620 ft bkb (Turner et al., 1988, p. 192; Robertson Research, 1983). If so, the statistical fits indicate "erosion" of 647 feet of section at the "unconformity." As an alternative interpretation, we suggest that the discontinuity at 15,620 ft bkb is a 647-foot sequence gap at the point where the well penetrated an unrecognized normal fault. We note that no vitrinite reflectance discontinuities are associated with known regional unconformities corresponding to either seismic horizon "B" (5,675 ft; Upper Oligocene), seismic horizon "C" (7,900 feet, Upper Oligocene), or seismic horizon "D" (10,380 ft; Upper Eocene). A 20-degree structural dip first noted in core 19 (Turner et al., 1988, p. 26) probably indicates the presence of an angular unconformity between flat-lying strata at the base of core 18 (16,028.5 ft bkb) and dipping strata at the top of core 19 (16,701 ft bkb). This is the "Lower Eocene unconformity" posted in the seismic profile of figure 6 (pl. 1) and in the stratigraphic column of figure 9 (pl. 2). As with the shallower regional unconformities, no discontinuity in vitrinite reflectance is associated with this angular unconformity (fig. 17).

The statistical fits to the data sets above and below the fault gap at 15,620 ft bkb in figure 17 were used to forecast depths to various isograds[3] that correspond to critical stages in source maturation, as tabulated (inset) in figure 17. These isograds are posted on the seismic profile in figure 6 (and pl. 1) and show that the principal reservoir section (between seismic horizons "A" and "C") in the sequence domed over the basement uplifts is thermally immature (pre-oil generation). Only the much deeper rocks in the grabens flanking basement uplifts are thermally mature and capable of having generated oil or gas. Rocks within the Mesozoic substrate may be sufficiently thermally mature to have generated oil or gas, but in this area these rocks are interpreted to consist of mostly volcano-plutonic arc rocks. Successful charging of prospects in the strata domed over basement uplifts will require generation of petroleum in flanking deeps, lateral migration to the flanks of basement uplifts, and vertical migration up faults through the regional shale sequence (approx. the interval between seismic horizons "C" and "D" in fig. 6 and pl. 1) in order to reach sandstone reservoirs in the Bear Lake-Stepovak play sequence (between seismic horizons "A" and "C").

The basement uplift to the southeast of the North Aleutian Shelf COST 1 well in figure 6 (and pl. 1) won 73% of the sum of all high bids in OCS Lease Sale 92 in 1988. All of the remaining bids in Sale 92 were placed on tracts over nearby basement uplifts that similarly dome the overlying Bear Lake-Stepovak play sequence and that are also adjoined by areas of deep subsidence where

[3] *"Isograd" is used here to denote a surface of fixed thermal maturity. Any single thermal maturity index value (TTI, Ro%, etc.) can be used to represent an isograd.*

the basin fill lies within the oil and gas[4] generation zone. It appears that the energy companies that placed bids on tracts in Sale 92 embraced the basic framework of the hypothetical petroleum system described above as that most likely to create significant petroleum accumulations within North Aleutian basin.[5] The model requires generation of large quantities of petroleum in flanking grabens and migration of the petroleum several thousands of feet upward into porous strata domed over basement uplifts. The minor (small displacement) faults extending upward from the major (large displacement), older faults along uplift flanks are the only faults that penetrate the regional lower Stepovak shale seal (overlying seismic horizon "D"; fig. 10 and pl. 3). These faults may provide the critical pathways from deep areas of petroleum generation to shallow traps domed over uplifts.

Figure 18 presents regional well data for thermal maturity compiled into a structure map for the 0.6% vitrinite reflectance isograd, which generally coincides with the onset of oil generation (depending on organic matter composition, oil or gas generation can begin as low as 0.5% vitrinite reflectance [liptinitic or Type 1 kerogens]; Dow, 1977, fig. 3). Areas highlighted in gray represent Tertiary basin fill that exceeds 0.6% vitrinite reflectance. If rocks with appropriate organic matter for creation of oil and gas lie within the gray areas, the latter then become the "oil (and gas) kitchens" for the basin. Figure 19 maps the thicknesses of Tertiary-age strata within the oil generation zone and we note that the maximum penetrated thickness (minimum, 4,758 ft) is at the North Aleutian Shelf COST 1 well.

The North Aleutian basin hypothetical "oil kitchen" is segmented by the presence of a massive volcanic center at the Port Heiden 1 and Ugashik 1 wells. This volcanic center produced a thick pile of volcanic flows and volcaniclastic sediments 33 to 39 millions of years ago. The volcanic pile is represented by the Meshik Formation. The Meshik Formation is age-equivalent to the Stepovak Formation (Brockway et al., 1975) or Tolstoi Formation (Detterman, 1990), with which the volcanic rocks interfinger at the margins of the volcanic center (fig. 10 and pl. 3). The segmentation by this volcanic center of the thermally-mature rocks flooring North Aleutian basin leaves the southwest part of the basin with the largest continuous volume of potentially oil-generative rocks. This part of the basin has accordingly formed the primary area of exploration interest in the past.

The Amak basin fill reaches a maximum thickness of about 12,500 feet, scarcely 200 feet deeper than the depth to the 0.6% vitrinite reflectance isograd (12,312 ft subsea) in the North Aleutian Shelf COST 1 well. It appears that only a very small volume of rock at the floor of the Amak basin lies within the oil generation zone. It is therefore unlikely that significant quantities of hydrocarbons have been generated in the Amak basin.

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[4] *Boreham and Powell (1993, p.149-50) point out that "humic coals and terrigenous kerogens can form appreciable quantities of gas over the maturity range of oil generation…." and "…significant yields of gas generation before the onset of intense liquid generation have been experimentally observed for both hydrogen-poor and hydrogen-rich organic matter."*

[5] *Some may have relied upon oil generated in the Mesozoic substrate. For reasons explained in previous sections, we believe that the Mesozoic substrate beneath the key prospects shown in figure 6 is composed of volcano-plutonic rocks.*

Source Rock Potential

The second important concern about potential petroleum systems in the North Aleutian basin is whether or not any rocks have the type of organic matter appropriate for conversion to oil or gas upon heating. We recognize two groups of potential source rocks: 1) Mesozoic sedimentary rocks that underlie the southwest part of North Aleutian basin and the Black Hills uplift; and 2) Cenozoic rocks that comprise the North Aleutian basin fill.

Mesozoic Source Rocks

The principal point of control for the source rock potential of Mesozoic rocks in the North Aleutian Basin OCS Planning Area is the Cathedral River 1 well. Some indicators for source rock potential of the Mesozoic rocks in this well are plotted in figure 20.

Mesozoic rocks extend across southern Alaska (fig. 4) but are known to have generated significant quantities of oil only in the northern Cook Inlet area. The Kialagvik Formation in the Cathedral River 1 well (fig. 20) is age-equivalent to the Middle Jurassic Tuxedni Group that generated the oil in northern Cook Inlet producing fields (Magoon, 1994). The Kamishak Formation in the Cathedral River 1 well is age-equivalent to unnamed Upper Triassic rocks at Puale Bay that are suspected of contributing oil to some minor accumulations and seeps in southern Cook Inlet and the Alaska Peninsula (Magoon and Anders, 1992; Magoon, 1994). The Upper Triassic rocks at Puale Bay form excellent oil-prone source rocks (Wang et al., 1988, fig. 4), but are only known from that outcrop locality and the penetration at the Cathedral River 1 well.

For most of the Mesozoic sequence penetrated by the Cathedral River 1 well[6], the rocks are rated as poor to fair sources (TOC) for gas (Hydrogen Index). Two significant anomalies are observed in figure 20. Shales and tuffaceous limestones in the interval from 8,700 to 9,300 feet in the Kialagvik Formation appear to rate as "good" potential sources for oil and wet gas. Cherty shales and marlstones in the interval from 12,000 to 12,700 feet in the Talkeetna Formation also appear to form "good" sources for oil and wet gas[7]. These anomalies are somewhat suspect because the elevated thermal maturity (>3.0 T.A.I., or greater than approximately 1.0% vitrinite reflectance below 7,300 ft bkb) of much of

[6] *The logged shows and geochemical data in the Cathedral River 1 well are somewhat problematic in that oil-base additives were introduced into the drilling mud at about 7,500 feet. However, no geochemical anomalies are observed at the first reported (Borst & Giddens mud log) point of introduction of "Soltex" at 7,500 feet (fig. 20). The deeper anomalies rise from an established "background" and could be reflecting rock compositions rather than drilling mud contamination, unless other additives were introduced. An annotation on the Borst & Giddens mud log at 8,770 feet reports that "abundance of tar noticed in samples are determined to be contamination as results (sic) of mud additive reactions of 'HME' and 'SuperLubFlow'". The anomalies in the TOC and HI profiles may reflect authentic rock properties, but the potential contamination clouds the issue (Peters, 1986, p. 324-5) and in this case blocks any straightforward conclusions. Geochem Laboratories (Geochem, 1976) reported that samples deeper than 8,600 feet were contaminated, possibly with "Gilsonite". We note that Peters (1986, fig. 12) specifically discusses the Cathedral River 1 case and concludes that the anomalies are entirely artifacts of contamination by drilling mud additives.*

[7] *Oil staining is reported (Detterman, 1990) in rocks immediately above these anomalies. Modest "S1" (resident hydrocarbons thermally distilled out of rocks during pyrolysis experiments) anomalies (rise from 0.2 to 0.7 mg/g [upper zone] or 0.2 to 1.07 mg/g [lower zone]) suggest a possible association of the TOC and Hydrogen Index anomalies with migrated oil.*

the Cathedral River 1 sequence indicates that most of the original oil generation potential of the Mesozoic rocks has been depleted. A single vitrinite reflectance analysis (6 measurements) at 10,650 feet yielded a mean value of 1.47%, well past the 1.35% vitrinite reflectance isograd marking exhaustion of all oil generation potential. The top of the prominent geochemical anomaly within the Talkeetna Formation lies at 12,000 ft bkb, 1,350 feet below the lone vitrinite reflectance measurement.

The pyrolysis data are inconclusive because of doubts about analytical results (possibly distorted by mud additive contaminants, as footnoted) and the high thermal maturity of the Mesozoic sequence (original generative potential largely depleted). However, the Cathedral River 1 data are at least permissive of the potential existence of oil sources within the Mesozoic sedimentary rocks beneath the Black Hills uplift. That some oil source rocks once existed within the Mesozoic sequence beneath the Black Hills uplift is supported by the observation of oil shows throughout the Cathedral River 1 well. Oil shows were first noted as shallow as 390 feet bkb, far above the first reported introduction of the troublesome drilling mud contaminants at 7,500 feet. The time of generation of this oil is unknown. Near the surface, the Cathedral River 1 well entered Mesozoic rocks with T.A.I. values of 2.5 (fig. 20), approximately equivalent to 0.65% vitrinite reflectance. A vitrinite reflectance of 0.65% corresponds to a depth of 13,287 feet bkb in the North Aleutian Shelf COST 1 well. Clearly, the rocks in the Cathedral River 1 well were previously much more deeply buried. Because the well is located on the Black Hills uplift where Mesozoic strata are unconformably overlain by Eocene-age rocks (north flank), it appears that the thermal maturation occurred during a Mesozoic cycle of deep burial. Thus, there is substantial risk that Mesozoic oil sources in this area generated and expelled their oil long before the deposition of Tertiary-age reservoir sandstones or the formation of drape anticlines in Oligocene strata atop the Black Hills uplift.

Tertiary Source Rocks

The principal point of control for the source rock potential of the Tertiary-age fill for North Aleutian basin is the North Aleutian Shelf COST 1 well. A graphical summary of source rock geochemical information is attached as plate 4. An *Excel* spreadsheet containing most available geochemical data for the COST well is included as Appendix 2. The data in Appendix 2 were extracted from the original reports by Exlog (1983) and Robertson Research (1983), which are attached as *Adobe Acrobat* (pdf) files to this report as Appendix 4 and Appendix 5, respectively.

Some indicators for source potential (TOC) and hydrocarbon type (hydrogen index or "HI") in the COST well are plotted in figure 21. Total organic carbon (TOC) data suggest that source potential ranges from "poor" to "very good." Hydrogen index (HI) values suggest mostly gas sources with some intervals where HI>300 that might be capable of generating oil. Sample descriptions reveal that most samples with TOC values exceeding 1.0% include coal, as either discrete fragments in cuttings or coaly laminations in core samples. In the several depth intervals below 8,000 feet in figure 21 where HI>300, we note that nearly all of the elevated HI values are associated with rock sequences described as containing coal. The key question then is whether or not these high-HI coals, or possibly non-coal lithologies mixed with coal material in samples, are legitimately capable of generating oil.

Source Potential of Coal-Bearing Rocks

Exlog (1983, p. 8) attempted to remove the coal (by water flotation) from a suite of cuttings samples and then conducted separate pyrolysis[8] experiments on the "coal-removed" and "coal-retained" sample suites. Both data sets are shown in the well profiles for pyrolysis data in figure 21 and plate 4. Figure 22a compares these two Exlog data sets in a modified Van Krevelen diagram. The plot fields for "coal-removed" and "coal-retained" sample suites in figure 22a essentially overlap with several samples from both suites yielding HI>300. One possible conclusion from the *Exlog* experiment is that both coal-bearing and non-coal-bearing lithologies in the COST well are capable of generating liquid hydrocarbons. A second possible conclusion is that the *Exlog*[9] method for removing coal from cuttings was unsuccessful and that the high HI values in both sample suites are associated with coal material. Clearly, a more explicit means of evaluating the source potential of the well samples is needed. We first need to establish the role of coal-bearing samples in generating the high HI values noted in parts of the COST well. We secondly need to establish the liquid-generating potential of the coals themselves.

Cuttings samples are problematic because unstable formations like coal may spontaneously collapse ("cave") into the uncased part of a wellbore at any time and mix with the actual cuttings carried away from the drill face to the surface. A cuttings sample may contain materials from any depth in the uncased or "open" part of a well and may not represent the collected drill interval. Unless "cave" materials are selectively removed, bulk analyses of cuttings samples will not truly represent the drill interval.

Sidewall and conventional core data clarify the link between the presence of coal and elevated HI values in the North Aleutian Shelf COST 1 well. Figure 22b shows a modified Van Krevelen diagram with pyrolysis data for core samples from the COST well (Robertson Research, 1983, App. III). Samples described as coal-bearing are plotted separately from samples for which descriptions did not note the presence of coal. All core samples with HI values exceeding 151 are described as containing coal by Robertson Research (1983, App. II). Among sidewall cores, the highest HI value observed for coal-free samples is 123. Among conventional core samples, the highest HI value observed for coal-free samples is 151. Coal-free core samples therefore appear to be primarily sources for gas (characterized by HI<150). But, what about the coal-bearing core samples with HI>150? Could these coal-bearing rocks form potential sources for oil?

Figure 22c shows a Van Krevelen-type[10]

[8] *Samples are heated, driving off existing petroleum (bitumen) and then cracking the organic matter and releasing petroleum-like materials. This method is fast and inexpensive compared to elemental analysis and can yield results that can be used in a similar way.*

[9] *Use of trade names or references to specific corporate entities or products in this report is for descriptive purposes only and does not constitute endorsement of these products or companies by the U.S. Minerals Management Service*

[10] *The Robertson Research (1983, App. VII) data set reports O (oxygen) and S (sulfur) as combined into a single value. The classification fields in figures 22c and 22d were extracted from a published diagram plotting H/C versus O/C (Tissot and Welte, 1984, fig. II.4.14). The presence of significant quantities of sulfur may shift the data to the right and distort*

diagram with elemental data[11] for sidewall and conventional core samples, with coal-bearing and coal-free samples plotted separately. All samples fall within (or to the right of) the classification area for Type III (gas-prone) organic matter. Samples in figure 22c with [O+S]/C elemental ratios greater than 0.6 are atypical and may contain sulfur or oxygen-rich matter like lignite or woody material[12] (Tissot and Welte, 1984, fig. II.8.6, p. 240).

Nine core samples containing coal that have HI>150 (HI range, 200-373; mean HI=289) and for which elemental data are available are plotted in figure 22d. The oil-generating potential suggested by the high HI values for these 9 coal-bearing core samples is not supported by elemental data. Figure 22d shows that none of the nine COST well core samples plot within the Type I or Type II classification fields where algal coals are usually found. All 9 core samples with HI>150 are shown by elemental data to contain primarily Type III organic matter and to therefore be gas-prone.

In pyrolysis experiments coals can yield specious results that improperly "type" organic matter. Coals sometimes yield high pyrolysis HI values that over-estimate the capacity to generate liquid petroleum (Peters, 1986, p. 322). Another problem is that thermally-mature coals may yield low oxygen index (OI) values during pyrolysis because more oxygen is released as carbon monoxide (not detected by device) rather than carbon dioxide (detected by device) (Peters, 1986, p. 322). Both of these pyrolysis responses of coals would lead to an incorrect interpretation of the type of organic matter. Robertson Research (1983, p. 9) raised another problem wherein the coal-bearing samples in the COST well may have yielded high HI values and low OI values because of the presence of solid bitumen. This has the effect of shifting data points toward the y-axis (fig. 22b) and perhaps out of the classification field for Type III kerogen and into the classification field for Type II kerogen.

Given the ambiguities of interpreting coal pyrolysis data, it seems clear that elemental data provide a more reliable way to evaluate the oil-generating potential of the coal-bearing Tertiary rocks in the North Aleutian Shelf COST 1 well. The elemental data at hand indicate dominance of gas-prone Type III kerogens in coal and non-coal lithologies alike. Oil-prone algal coals, if present, were not sampled by the North Aleutian Shelf COST 1 well.

Source Potential of "Amorphous" Interval, 15,620-17,155 ft bkb

The part of the COST well below the fault cut at 15,620 ft (fig. 17) is associated with abundant "amorphous" (oil-prone) kerogens, high H/C values, high gas "wetness,"[13] and oil shows. These outwardly signal the possible presence of potential oil sources in what is otherwise a nonmarine, coal-bearing clastic sequence (fig. 9). A review of the characteristics of what we here informally term the "amorphous" interval follows.

The part of the COST well below the fault cut at 15,620 feet drew attention soon after the well was drilled because it is associated with high fractions (30% to 55%) of "amorphous" (i.e., unstructured) kerogens as

relationships to traditional kerogen classification fields.

[11] *H, hydrogen; C, carbon; O, oxygen; and S, sulfur. Obtained by chemical analysis of isolated kerogens.*

[12] *"Woody fibers" were described in cuttings from 2,580 to 4,320 ft md (Robertson Research, 1983, App. II).*

[13] *Gas present in the tops of sealed cans containing cuttings samples.*

observed in microscope studies (upper panel, pl. 4). "Amorphous" kerogens usually signal algal origins (Type I kerogen) and in dominant proportions may form a source for liquid hydrocarbons.

The "amorphous" interval probably does not form a source for oil. The amorphous kerogen content in the COST well samples is probably insufficient to form effective oil sources. Robertson Research (1983, p. 6-7) claims that amorphous kerogens must exceed 65% by volume[14] relative to the 3 other kerogen classes to form an effective oil source. Microscopy studies indicate abundances ranging between 30% and 50% in the "amorphous" interval in the COST well (upper panel, pl. 4).

Other data indicate poor potential for generation of liquid hydrocarbons by the "amorphous" interval. The interval in the COST well is associated with low values for HI, low genetic potential (S1+S2), mostly low elemental H/C ratios (4 exceptions noted below), and high pristane/phytane ratios (upper panel, pl. 4). The latter all argue for predominantly Type III organic matter in the "amorphous" interval. To explain the curiously gas-prone character, Robertson Research (1983, p. 8) speculated that the "amorphous" kerogens between 16,009.3 and 17,143 ft are actually either oxidized relicts of original amorphous material or perhaps finely divided vitrinite that was incorrectly classified by microscopy. Tissot and Welte (1984, p. 158, fig. II.4.16) illustrate examples of poor correlation between "amorphous" kerogens and source type from elemental analysis. In either case, based on these data, the "amorphous" interval in the COST well is viewed as primarily a source for gas.

A depth profile for elemental H/C data for the COST well is shown in the upper panel of plate 4. Elemental data classify most of the strata penetrated by the well as potential sources for dry gas or wet gas. However, within the "amorphous" interval below 15,620 feet, four conventional core samples yielded elemental H/C ratios greater than 1.0,[15] suggesting some liquid-generating potential. These samples are coal-free and are described as gray or brown massive shales (Robertson Research, 1983, App. II). Vitrinite reflectance values for these four samples range from 0.98% to 1.01% (Robertson Research, 1983, App. III). At this level of thermal maturity, these H/C values would normally be associated with an oil-prone source (as classified by the profile in pl. 4). However, HI values for these four samples range from 88 to 120, indicating instead a gas-prone source.[16] Also, these four samples yielded high [O+S]/C ratios that associate them with Type III organic matter in a Van Krevelen-type diagram (the four samples are highlighted in fig. 22c). Robertson Research noted that reflected-light microscopy revealed "medium" to "high" presence of solid bitumen in these four samples and concluded that this material, rather than kerogens, may be the source of the elevated H/C ratios (Robertson Research, 1983, p. 8, 190-192; Appendix 5, this report).
Headspace gas wetness ranges up to 95% in the "amorphous" interval, but most values range between 75% and 85% and heavier gases (C5+) form less than 20% of headspace gases (lower panel, pl. 4). Robertson Research (1983, p. 10) indicate that these data suggest a wet gas source and

[14] *A large proportional volume relative to other classes of kerogens (exinite, vitrinite, and inertinite) is required because of the low density of amorphous kerogen.*

[15] *Ranging from 1.06 to 1.12; samples at 16,029.0 ft, 16,703.7 ft, 16,714.6 ft, and 16,719.6 ft.*
[16] *Oil-prone kerogens at this thermal maturity should yield HI>200 (see Baskin, 1997).*

a low probability for generation of significant quantities of oil.

Finally, the oil shows logged in and just above (15,450-15,500 ft bkb) the "amorphous" interval are actually quite sparse and are described as "slight" or "trace" in the sample ("mud") logs (lower panel, pl. 4). Detailed analyses of extracts of these oil shows and correlations to possible source rocks are described below.

Source Potential of Tertiary Basin Fill and Assessment Model

From these data, we conclude that most of the depth intervals in the COST well that appear from pyrolysis results to form potential oil sources are actually coal-bearing intervals that are dominated by Type III (gas-prone) organic matter. Although some exceptions are known,[17] coal is not commonly a source for oil because the typically modest quantities of petroleum liquids that are generated are often sequestered ("sorbed" into extensive internal pores) within the coal (Levine, 1993, p. 40, 71). Other intervals of interest for oil source potential, such as the "amorphous" interval, appear on the basis of other data to form potential sources for gas or wet gas, with possible minor quantities of liquids.

We conclude, as did Robertson Research (1983, p. 1-9) and Turner et al. (1988, p. 190-191) from consideration of all geochemical data, that the Tertiary sequence penetrated by the North Aleutian Shelf COST 1 well contains primarily Type III organic matter. This gas-prone organic matter occurs in coal beds or is dispersed as finely divided material in clastic rocks and forms poor to very good sources for gas, with minor potential for condensates and light oil. Our conclusions about the source potential for the Tertiary fill in the North Aleutian basin are reflected in our assessment models for plays 1, 2, and 6 (tbls. 3, 4, and 8), which are primarily sourced by Tertiary rocks. For these three plays, we estimate that there is a 10% chance that any pool will be filled completely with oil and an 80% chance that any pool will be filled completely with gas. For the 10% fraction of the overall pools in which free oil is overlain by a gas cap ("mixed" case), we estimate that 90% of the pool volume is occupied by gas. Although these model input values are speculative, they reflect our sentiment that the Tertiary fill of the North Aleutian basin is most likely a source for gas with some potential for minor quantities of petroleum liquids.

Oil and Gas Occurrences and Biomarker Correlations

Gas was recovered by three flow tests at rates summing to 90 Mcfg/d from 3 zones in the Tolstoi Formation in the Becharof Lake 1 well. Gas was also recovered in flow tests from two intervals in the Tolstoi Formation at rates of 5 to10 Mcfg/d (with 300-400 barrels of water per day) in the David River 1/1A well. Oil and gas shows were noted elsewhere in wells offshore and in wells on the Alaska Peninsula (annotated in fig. 2).

Gas seeps are observed as gas "chimneys" in some proprietary seismic profiles on the Black Hills uplift. Onshore, oil and gas seeps are known primarily from the area near the east end of Becharof Lake, where they are observed along the axes of exposed anticlines in Mesozoic rocks or along

[17] *In the best-known example, Upper Cretaceous and Tertiary coals in the Gippsland basin of Australia are credited as the source for liquid petroleum reserves of 3.762 billions of barrels and gas reserves of 7.8 trillions of cubic feet (Clayton, 1993, p. 187, tbl. 1).*

important faults. Gas seep samples are composed mostly of carbon dioxide and other non-combustible gases, with minor hydrocarbons, as shown in the plot and inset data table of figure 23. These gas seeps are probably the result of magmatic intrusions that are decarbonating limestones in the subsurface. Reifenstuhl (2005) however reports a gas seep from Oil Creek[18] that consists of 91% methane, 7% nitrogen, and 2% carbon dioxide. Natural gas recovered[19] from the Becharof Lake 1 well consists of 87.5% methane, 4.7% ethane, 2.3% propane, 0.8% butane, 1.0% hydrogen, and 3.7% "other" gases (AOGCC, 1985, DST data). This gas is very different from most of the nearby seeps which are mostly carbon dioxide (fig. 23). Methane carbon isotope (C^{13} and C^{12} isotope ratios) data for cuttings headspace gases in the Becharof Lake 1 well are shown in figure 24a. Above 3,000 feet, the gas is primarily biogenic in origin; below 5,500 feet, it is primarily thermogenic in origin. Gases are of mixed origins in the intermediate interval (3,000 to 5,500 ft) of Bear Lake and Stepovak Formations. Thermally-mature Tertiary strata reach thicknesses of 1,127 ft in the area of the Becharof Lake 1 well (fig. 19). The relatively dry thermogenic gas (wetness = 8.2%) recovered in the DST in the Becharof Lake 1 well (fig. 24b) is probably Tertiary-sourced.

Oil seeps emanating from Jurassic rocks along the axes of exposed anticlines attracted the earliest exploration drilling to the Alaska Peninsula in the early 1900's. Geochemical studies of these seep oils suggest that they were sourced from Upper Triassic rocks (unnamed) like those exposed at Puale Bay (locale posted in fig. 2), with possible contribution from Middle Jurassic rocks (Kialagvik Fm.) like those exposed in the same area (Magoon and Anders, 1992). The Upper Triassic rocks exposed at Puale Bay are minimally thermally mature (TMAX= ~438ºC, or about 0.7% vitrinite reflectance) and form excellent oil-prone source rocks (Wang et al., 1988, figs. 4, 16). Where age-equivalent Mesozoic sedimentary rocks underlie North Aleutian basin and the Black Hills uplift, they might form sources for oil migrating into overlying Tertiary-age rocks. The Mesozoic rocks exposed along the Black Hills uplift, like at Puale Bay, are minimally thermally mature at the surface (TAI=2.5, or about 0.65% vitrinite reflectance, Cathedral River 1 well) and any oil moving out of them into Tertiary reservoirs would probably be re-migrated from disrupted pools that formed prior to Tertiary time. Most exposures of Mesozoic rocks along the Alaska Peninsula south of the Bruin Bay fault are mapped at a level of thermal maturity exceeding 0.6% vitrinite reflectance (approximate onset of oil generation) or greater (Johnsson and Howell, 1996).

Modest oil and gas shows and gas "wetness" values of 30% to 95% (lower panel, pl. 4) were noted below 15,450 feet bkb (most prominent from 15,700 to 16,740 ft bkb) in the North Aleutian Shelf COST 1 well. These shows and the high gas wetness values may signal the presence of migrated liquid petroleum. It is therefore important to determine the source of these liquid hydrocarbons. Were they generated by Type III organic matter like that dominating the Tertiary rocks penetrated by the COST well? Or, are these minor petroleum liquids evidence for unseen oil sources within Mesozoic rocks beneath the North Aleutian basin?

To try to identify the source of the liquid

[18] *Four miles west of Puale Bay (fig. 2).*
[19] *Recovered in a DST (drill stem test) (30 mcfg/d) from the interval 7,470 to 7,550 feet (Tolstoi Fm., near top of oil window).*

hydrocarbons below 15,450 ft in the COST well, we conducted extraction and biomarker studies on “show interval” samples borrowed from the State of Alaska archive in Eagle River, Alaska. Hydrocarbons were extracted from two composites of show interval samples[20] by *Baseline DGSI* and analyzed for carbon isotopes, metals, and biomarkers (Baseline DGSI, 2003; attached as Appendix 3 of this report) for comparison to data for regional oils and source rocks published by Magoon and Anders (1992). The two extractions obtained in this study supplement a less robust data suite on 7 extractions in the show interval in the North Aleutian Shelf COST 1 well previously obtained by Robertson Research (1983, App. IX; attached as Appendix 2 and Appendix 5 of this report). Selected extract data are listed in table 2. Extract data are shown in figures 25, 26, 27, 28, and 29, and are selectively profiled on depth in plate 4.

We conclude from the extract data that the oil shows in the interval from 15,450 to 16,800 feet bkb in the North Aleutian Shelf COST 1 well originated from nonmarine Tertiary rocks rather than marine Mesozoic rocks. This interpretation extends from the following observations:

1. *Low Sulfur Content Suggests Tertiary Sources.* The sulfur contents of Mesozoic-sourced oils in the Cook Inlet range from 0.04% to 0.23% (average 0.11%) while those from the Alaska Peninsula oil seeps (from Middle Jurassic rocks) range from 0.20% to 0.21%. Sulfur contents for Tertiary-sourced condensates in Cook Inlet range from 0.03% to 0.05%, much lower than the Mesozoic oils (all data from Magoon and Anders, 1992, tbl. 13.1). In two extracts of the show interval in the North Aleutian Shelf COST 1 well, sulfur levels were below the detection limit of 0.01% (Baseline DGSI, 2003). The low sulfur contents of the COST well extracts are consistent with a source in nonmarine Tertiary rocks.

2. *Isoprenoid Ratios Are Terrestrial.* Cross-plots for ratios of pristane/n-C17 versus phytane/n-C18, as shown in figure 25, indicate a terrigenous, oxidizing source environment (i.e., Tertiary rocks) for the COST well extracts, rather than a marine source (i.e., Mesozoic rocks).

3. *Pristane/Phytane Ratios are Terrestrial.* Pristane/phytane ratios range from 2.14 to 9.30 for the 9 extracts in the show interval in the North Aleutian Shelf COST 1 well, as summarized in the histograms in figure 26. For Tertiary extracts and oils in Cook Inlet basin, pristane/phytane ratios similarly range from 2.5 to 10.0 (Magoon and Anders, 1992, tbl. 13.1). For Mesozoic (marine) oils and extracts, pristane/phytane ratios range narrowly from 2.7 to 4.0; for Alaska Peninsula oil seeps the range is from 1.5 to 1.7 (Magoon and Anders, 1992, tbl. 13.1). The pristane/phytane ratios of the North Aleutian Shelf COST 1 well extracts are ranged in a manner most similar to the range for Tertiary rocks and oils of Cook Inlet basin.

[20] *One sample composite was collected from conventional core chips every foot: cores 18 and 19, 16006-16720 ft bkb overall. A second sample composite was collected from cuttings, 10-ft intervals, 15,700-16,800 ft bkb. At the time the interval from 15,700 to 16,800 feet was drilled, the well was open below 9-5/8 inch casing set at 13,287 ft bkb (Turner et al., 1988, p. 7).*

4. *Carbon Isotopes Correlate to Nonmarine Tertiary.* Carbon isotope data for saturate and aromatic fractions of extracts from the oil show interval in the COST well group decisively with similar data for nonmarine Tertiary rocks and Tertiary-sourced condensates of northern Cook Inlet (fig. 27). The North Aleutian extracts are distinctly "heavier" (enriched in C^{13}) than all of the Mesozoic (marine) rocks and oils, including the oil seeps on the Alaska Peninsula.

5. *Deficit of Saturates Correlates to Tertiary Extracts.* Ratios among saturates, aromatics, and non-hydrocarbons for 9 extracts from the show interval in the North Aleutian Shelf COST 1 well, shown in figure 28a, are highly deficient in saturates relative to Mesozoic rocks and oils. Although highly variable as a group, the North Aleutian extracts are mostly saturate-deficient like the extracts of Tertiary rocks from Cook Inlet. The North Aleutian cuttings sample extract (MMSAK2003-2) forms an exception. It is relatively saturate-rich and plots very close to a Tertiary-sourced condensate from Cook Inlet in figure 28a.

In addition, C30 steranes are absent, C29 steroids slightly predominate (C29:C28:C27 = 43.6:22.5:33.0 [MMSAK2003-1] and 47.7:23.4:29.9 [MMSAK2003-2]), oleanane is present (oleonane/hopane= 0.22-0.29), and the carbon preference index (Bray and Evans, $CPI_{24\text{-}34}$)[21] is greater than 1.0 (CPI = 1.078-1.160). The absence of C30 steranes is consistent with terrestrial source (Peters and Moldowan, 1993, tbl. 3.1.5). Sterane ratios, plotted in the ternary diagram of figure 28b, suggest mixing of marine and nonmarine depositional environments in the source sequence. Oleananes are generally associated with Late Cretaceous or Tertiary angiosperms (flowering plants) (Waples and Machihara, 1991, p. 54) and are not found in older rocks. Unless swept up in the course of migration through Tertiary rocks, their presence in these extracts seems to preclude origination from Jurassic- or Triassic-aged sources.

Magoon and Anders (1992) and Magoon (1994) have noted that extracts from Upper Triassic potential oil source rocks exposed at Puale Bay (fig. 2) are enriched in C19 to C29 tricyclic terpanes relative to extracts from Middle Jurassic or Tertiary rocks. Some oils collected from wells and seeps in southern Cook Inlet (Magoon and Anders, 1992, spls. 37-43) are also enriched in tricyclics relative to oils in northern Cook Inlet, and Magoon (1994) suggests that the high tricyclics indicate some contribution from Upper Triassic oil sources (mixed with the more typical Middle Jurassic Tuxedni Gp. oils). In the more general case, Clayton (1993, tbls. 1, 2) notes that tricyclic terpanes are rarely abundant in oils derived from coal or coaly organic matter. If tricyclic terpanes are present in the COST well extracts, it may imply origination from Upper Triassic rocks beneath North Aleutian basin.

Figure 29a is an excerpt from an M/Z 191[22]

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[21] *Baseline DGSI (2003) calculate an "OEP" (odd-even preference) which ranges from 1.10 to 1.22. Another index reported by Baseline DGSI, CPI_{Marzi}, ranges from 1.03 to 1.07 (see Marzi et al., 1993).*

[22] *M/Z, or M/e, is the mass/charge ratio of ions fragmented by an electron beam in the GCMS device. M/Z controls how ions are separated, displaced, and sequentially detected through manipulation by the magnetic field of the mass spectrometer (Waples and Machihara, 1991, p. 11-12). M/Z 191 is most appropriate for obtaining the quantities of tricyclic*

chromatogram for terpanes from an extract from *core samples* from 16,006 to 16,720 feet in the North Aleutian Shelf COST 1 well. Figure 29b shows the entire M/Z 191 chromatogram for the extract from *cuttings* over the interval 15,700 to 16,800 ft bkb. Both chromatograms show that tricyclic terpanes are abundant in the show interval extracts, although subordinate to hopanes (tricyclic terpanes/hopanes = 0.56 to 0.80).

The presence of these tricyclic terpanes in the COST well extracts could suggest a link to Upper Triassic source rocks beneath the North Aleutian basin. But, a wide spectrum of depositional environments is associated with suites of tricyclic terpanes. Crude oils derived from paralic/deltaic (nearshore marine), deep water marine, lacustrine, and "phosphatic" environments all feature robust suites of tricyclics (Zumberge, 1987, tbl. 5). Tricyclics have been specifically linked to Mesozoic lacustrine sources (Waples and Machihara, 1991, p. 58). A condensate from the North Cook Inlet gas field, sourced from Tertiary nonmarine rocks, resembles the COST well extracts in that it is rich in C19 and C20 tricyclic terpanes (Magoon and Anders, 1992, fig. 13.9, spl. 18), the latter linked to vascular land plants (Zumberge, 1987, p. 1630). Figure 29b shows a strong unidentified peak between the C19 and C20 tricyclic terpanes; a similar unidentified peak is also present in the North Cook Inlet field condensate (and reportedly other northern Cook Inlet condensates) sourced from Tertiary nonmarine rocks (Magoon and Anders, 1992, fig. 13.9, spl. 18; p. 264, 268).

These tricyclic terpanes might point to the existence of effective source rocks within the Mesozoic substrate beneath the part of the North Aleutian basin north of the projected trace of the Bruin Bay fault (fig. 32). However, several lines of logic indicate that the probability of effective Mesozoic sources, particularly Triassic sources, in this area is low.

Both published tectonic models for the "Peninsular terrane" (Mesozoic strata southeast of the Bruin Bay fault) tie it to the Jurassic-Cretaceous magmatic arc (magmatic arc terrane north of Bruin Bay fault), but in two different ways. Moore and Connelly (1979) locate the Mesozoic sedimentary rocks in a *fore-arc basin* between the magmatic arc on the northwest and a subduction zone on the southeast. In an alternative model, Reed et al. (1983) locate the Mesozoic sedimentary rocks in a *back-arc basin* southeast of both the magmatic arc <u>and</u> subduction zone to the northwest. In either case, the Mesozoic sedimentary rocks would not be expected to extend in quantity northwest of the magmatic arc and beneath the North Aleutian basin. Both models presumably include the Triassic rocks, which contain abundant volcanic material of arc origins (Wang et al., 1988).

These tectonic models are disputed by geologic mapping that locates some Triassic sedimentary rocks in the magmatic arc terrane north of the Bruin Bay fault and "Peninsular terrane." Carbonates of the Upper Triassic Kamishak Formation are exposed at a few localities among the vast Jurassic-Cretaceous plutons north of the Bruin Bay fault in the Cook Inlet area (Magoon et al., 1976, sh. 2) and near Becharof Lake (Riehle et al., 1993).

However, even if the Upper Triassic rocks extend northwest of the Bruin Bay fault into the magmatic arc terrane, there is some question about their survival as effective

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and pentacyclic terpanes because it is the most abundant ion obtained by fragmentation of these compounds in an electron beam.

potential source rocks. Independent evidence points to a dominantly magmatic character for the Mesozoic substrate north of the Bruin Bay fault beneath the Bristol Bay lowlands and North Aleutian basin. We consider it unlikely that significant quantities of effective Triassic oil source rocks survive among the numerous magmatic intrusions inferred from regional context and magnetic data in the Mesozoic substrate north of the projected Bruin Bay fault (Case et al., 1988). Geologic mapping northwest of Cook Inlet indicates that bodies of Upper Triassic rocks are small, scattered, and isolated amid very large intrusives of Jurassic, Cretaceous, and Tertiary ages (Magoon et al., 1976, sh. 2; Riehle et al., 1993). The Upper Triassic and Jurassic sedimentary rocks among the intrusives are thermally overmature at the surface, ranging from 1.3% vitrinite reflectance (end of oil generation) to >5.0% (metamorphic) at all mapped data sites (Johnsson and Howell, 1996). Presumably, this thermal maturation was achieved in Mesozoic time in concert with pluton emplacement, before the formation of the North Aleutian basin.

Lastly, a host of other geochemical data, reviewed above, seems to link the extracts to Type III organic matter of Late Cretaceous or Tertiary age. Regional geology and geochemical data, taken as a whole, most persuasively argue for a source within Tertiary nonmarine rocks for the sparse petroleum liquids encountered in the deep part of the COST well.

Petroleum System—Critical Events

A "Lopatin"-style (Lopatin, 1971) burial history model for the North Aleutian Shelf COST 1 well[23] is shown in figure 30 along with some timelines for critical events in the hypothetical petroleum system for the offshore part of the North Aleutian basin. Vitrinite reflectance data from the COST well indicate that the lower part of the rock column has experienced sufficient thermal exposure[24] to have generated oil and gas. But, these data give no information about *when* petroleum generation might have occurred. The Lopatin burial model combines burial history with thermal environment to measure thermal exposure using established thermo-chemical principles. The purpose of creating a Lopatin model for the COST well was to obtain estimates for the *times of onset* and duration of key phases of petroleum generation. The time of petroleum generation can then be compared to the time of trap formation to ascertain whether traps were available to capture petroleum migrating upward from generation centers. For example, if petroleum generation occurred prior to trap formation, the petroleum may have simply escaped to the surface and been lost.

The Lopatin burial model in figure 30 highlights the thermal evolution of the sequence penetrated by the well and an additional 3,000 feet of unknown strata interpreted (from seismic data) to lie beneath the bottom of the COST well. These latter rocks comprise the most deeply buried strata in the basin and presumably offer the earliest opportunity for generation of petroleum.

Tolstoi Formation strata that are probably correlative to the unknown sequence

[23] *Used software "Lopatin-From Here to Maturity", version 1.0, copyright 1985, by Platte River Associates, Inc. and Douglas W. Waples.*
[24] *Temperatures experienced and residence time at maximum temperatures.*

beneath the COST well are described in surface geologic mapping onshore. There, the lower Tolstoi Formation consists of nonmarine and shallow marine sandstones and conglomerates with subordinate siltstone, shale, and coal (Detterman et al., 1996, p. 38-42). These rocks are much the same as the part of the Tolstoi Formation that was penetrated by the COST well (fig. 9). The latter rocks are dominated by coaly, Type III organic matter and are most probably sources for gas and wet gas.

Geological mapping (Wilson et al., 1995; Detterman et al., 1996) documents a widespread unconformity at the base of the Tolstoi Formation where it rests upon Cretaceous rocks in the Port Moller area. The Tolstoi Formation rocks that overlie this regional unconformity range in possible age from middle Eocene to late Paleocene (Detterman et al., 1996, p. 39-42). The offshore COST well reached total depth within lower to middle Eocene rocks (fig. 9). From stratigraphic relations onshore, we infer that the untested strata beneath the bottom of the COST well overlie Mesozoic rocks on a Late Paleocene unconformity. This unconformity probably marks the onset of subsidence of the North Aleutian basin and forms the starting point for the Lopatin burial model. We model the untested strata beneath the COST well as Tolstoi-equivalent rocks that range up to 61 Ma in age (base of Late Paleocene).

Initial basin subsidence was rift-driven and was accompanied by large-scale faulting and the elevation of horsts in the southwest half of the North Aleutian basin. The rift-driven phase of basin subsidence was concluded by the time of seismic horizon “D” (35.4 Ma), which corresponds to the regional unconformity that decapitates the basement horsts in the southwest half of the North Aleutian basin (fig. 6).

The later phase of basin subsidence was mostly unaccompanied by faulting, with some reactivation of horst-bounding faults. This phase of subsidence was more regionally extensive than the rift phase and may have been both thermally-driven (cooling following the rift phase) and load-driven (as a foredeep bending downward to the south beneath tectonically-thickened crust on the south margin of the basin [Bond et al., 1988]).

In figure 30, the rocks at the bottom of the North Aleutian Shelf COST 1 well are shown to enter the early oil generation zone (TTI>3) at about 31.7 Ma. The base of the well entered the peak oil generation zone (TTI>10) at 27.0 Ma.

The thermal maturation of the basin floor strata beneath the bottom of the COST well represents the earliest opportunity for generation of petroleum in the North Aleutian basin. This deeper package of strata would have entered the early oil generation window (TTI>3) as early as 38.5 Ma and the peak oil generation zone (TTI>10) at 34.4 Ma. Oil and gas generation from shallower strata with appropriate organic compositions has presumably taken place with progressive burial since 38.5 Ma, continuing to the present time.

The erosionally–truncated crests of the basement horsts were buried beneath the thick shaly sequence of the lower part of the Stepovak Formation (lower contact, seismic horizon “D”) at approximately 35.4 Ma, thereby sealing the deeper traps on horst flanks. The underlying strata that onlap the faulted flanks of the horsts were deposited between 61 Ma and 35.4 Ma, mostly before the earliest onset of hypothetical oil generation from basin floor strata at 38.5

Ma. Traps associated with faults and stratigraphic onlap on the flanks of these basement horsts were mostly available to capture petroleum generated in flanking basin deeps after 38.5 Ma.

Deposition of the principal reservoir—the Bear Lake-Stepovak play sequence—began about 28.5 Ma and continued up to about 4.5 Ma. The compaction-driven doming of drape anticlines over basement horsts continued through the time interval of Bear Lake-Stepovak deposition, as indicated by the thickening of strata into the grabens flanking horsts (illustrated in fig. 6 and pl. 1).

Oil and gas generated between 28.5 and 38.5 Ma preceded the formation of the drape anticlines in the Bear Lake-Stepovak sequence over basement horsts. Some early-formed generation products may have preceded drape anticline formation and escaped to the surface unless sequestered in older traps along horst flanks. But, the early fraction of the total generated product may have been relatively small. Sometime between 21.2 Ma (vitrinite reflectance data[25]) and 27.0 Ma (Lopatin model), basin-floor strata reached peak oil generation (Ro=1.00%; TTI=75), corresponding to the stage when petroleum is most abundantly created (Dow, 1977a, fig. 3; Baskin, 1997, tbl. 1). At this time, the lower part of the Bear Lake-Stepovak sequence and associated traps were certainly in place to capture migrating petroleum. Given appropriate organic compositions within the lower part of the North Aleutian basin fill, the timing of hypothetical petroleum generation is mostly appropriate for charging of the Bear Lake-Stepovak reservoirs in the 28.5-4.5 Ma drape anticlines over horsts.

The "amorphous" interval in the COST well (discussed above[26]), of past interest because of the presence of putative amorphous (i.e., oil prone) kerogens, oil shows, and elevated gas wetness (pl. 4), corresponds approximately to the interval from 15,620 ft bkb (top of fault gap in fig. 30) to total depth. The top of the "amorphous" interval entered the early oil generation window (TTI>3) at 26.4 Ma and entered the peak oil generation zone (TTI>10) at 20.4 Ma. Any hydrocarbons generated out of the "amorphous" interval therefore could have charged some of the shallow drape anticlines involving the Bear Lake-Stepovak play sequence reservoirs over basement horsts.

The timing of hypothetical petroleum generation is favorable for preservation of porosity in the principal reservoir, the Bear Lake-Stepovak play sequence. As noted, hydrocarbon generation could have begun at the basin floor sometime between 38.5 Ma and 34.4 Ma, and ostensibly reached peak oil generation (Ro=1.00%; TTI=75) between 21.2 and 27.0 Ma (fig. 30). The hypothetical oil and gas forming near the basin floor therefore could have invaded the Bear Lake-Stepovak sandstones shortly after deposition. Early entry of hydrocarbons into the pore systems of the Bear Lake-Stepovak

[25] *In figure 30 a dashed black line for the Ro=1.00% isograd has been added and is shown intersecting the basin floor at 21.2 Ma. This isograd is not a product of the model but was constructed parallel to model-based TTI isograds and hand-sketched back through time from the actual well penetration of the 1.00% Ro isograd based on vitrinite reflectance data. This was done to obtain an alternative estimate for the time when basin floor strata achieved peak oil generation (Ro=1.00%). The Lopatin model forecasts for thermal maturity below 15,000 ft bkb in the COST well do not conform with vitrinite reflectance data and are not considered reliable.*

[26] *The review of source rock geochemical data in this report discounts the "amorphous" interval as a potential oil source. It is viewed as a potential source for gas or wet gas, but is no more promising than other sequences penetrated by the COST well.*

sandstones within traps could have arrested the diagenetic processes that act to destroy porosity. We note that the Bear Lake-Stepovak sandstones in the COST well were not associated with any oil or gas shows, but nonetheless preserve excellent porosity and permeability (figs. 15 and 16).

In contrast, the older Tolstoi play sequence resided at significant burial depths for up to 22.5 m.y. (61 Ma minus 38.5 Ma=22.5) before any petroleum could have been generated out of basin-floor strata. This protracted opportunity for diagenetic destruction of pore space[27] may partly explain the overall poor reservoir quality of the Tolstoi sandstones below 10,380 ft bkb in the COST well.

The TTI isograd depths forecast by the Lopatin model conform reasonably well to vitrinite reflectance-based isograd depths in the part of the COST well above 13,000 ft bkb. Specifically, vitrinite reflectance data indicate that isograd Ro=0.5% (threshold for early oil generation) is reached at 10,372 ft bkb. The Lopatin model forecasts the equivalent TTI=3 isograd to lie 223 ft shallower, at 10,213 ft bkb. Vitrinite reflectance data indicate that isograd Ro=0.6% (threshold for peak oil generation) is reached at 12,397 ft bkb. The Lopatin model forecasts the equivalent TTI=10 isograd to lie 337 ft shallower, at 12,060 ft bkb. The depths of these isograds are compared in the right-hand columns of figure 30.

The isograd depths forecast by the Lopatin model <u>do not</u> conform to vitrinite reflectance-based isograd depths in the part of the COST well below 15,000 ft bkb. Generally, the Lopatin maturity values at a given depth are higher than the observed vitrinite-reflectance-based maturity values. For example, the observed vitrinite reflectance at modeled well total depth (17,802 ft bkb, 647 ft added for fault gap[28]) is 1.097% (fig. 17) and the appropriate corresponding TTI value is 98 (Waples, 1980, tbl. 4). At the same depth, the Lopatin model for the COST well overestimates a TTI value of 576 (equivalent to 1.80% Ro; Waples, 1980, tbl. 4).

Generally, the model-to-data discrepancies (between the Lopatin model forecasts for thermal maturities and vitrinite-reflectance-based thermal maturities) in the COST well increase with depth. The Lopatin isograd TTI=75 is forecast to lie at 15,141 feet bkb. The isograd TTI=75 normally corresponds to a vitrinite reflectance of 1.00% or peak-oil generation (Waples, 1980, tbl. 4), but the observed vitrinite reflectance at 15,141 ft in the COST well is only 0.768%. A vitrinite reflectance of 1.00% is not achieved until a depth of 17,160 ft, or 2,019 ft deeper than the Lopatin model forecast (for TTI=75). Likewise, the oil-generation-floor isograd TTI=180, forecast at 16,479 ft bkb by the Lopatin model, is 2,772 ft shallower than the equivalent vitrinite reflectance isograd (Ro=1.35%) forecast (below the data set) at 19,251 ft bkb. The large discrepancies between the depths of Lopatin isograds and vitrinite reflectance isograds are illustrated in the right-hand columns of figure 30.

The model-to-data discrepancies below 15,000 ft bkb are too large and result in erroneously high (early) Lopatin-model estimates for the onset ages of peak oil generation (TTI=75), the oil generation floor

[27] *Mostly by pore-filling chemical cements, and, replacement of volcanic clasts by clays leading to collapse of clasts, as observed in petrographic microscopy (AGAT, 1983, p.2).*

[28] *The base of the well for modeling purposes is "corrected" or extended down to 17,802 ft bkb to account for the 647 ft gap at the normal fault penetrated at 15,620 ft bkb.*

(TTI=180), peak wet gas generation (TTI=92), and the floor for survival of liquids (TTI=900). The onset ages forecast by this high-TTI part of the Lopatin model are only useful as maximum ages.[29]

In an effort to construct a Lopatin model that better conforms to observational data, we experimented with two variations on the basic model shown and tabulated in figure 30. For the first variation, we retained the geothermal model (modern gradients) but added time gaps at regional unconformities. For the second variation, we retained the stratigraphic model (without time gaps) but reduced the geothermal gradient.

As the first variation to our Lopatin model, we inserted arbitrary time gaps at the regional unconformities marked by seismic horizons A, B, C, and D (3 m.y., 3 m.y., 3 m.y., and 5 m.y., respectively). These time gaps are arbitrary because the paleontologic data do not resolve any quantifiable time gaps at these surfaces in the COST well (fig. 9), nor do we observe erosional truncation effects at these surfaces in the graben area near the well. The addition of these time gaps (hiatuses) to the basic stratigraphic model produced the general effect of moving TTI isograds to even shallower depths. Therefore, adding time gaps to the stratigraphic model increased the discrepancies between Lopatin model forecasts and vitrinite reflectance data from the well. This first variation on the Lopatin model degraded model-to-data conformance and was discarded.

As the second variation on our Lopatin model, we used the basic stratigraphic model of figure 30 but reduced the geothermal gradient for the entire well to 14.0ºF/1,000 ft, held constant through time. As shown in plate 4 and figure 30, the COST well temperature data describe a three-leg set of gradients ranging from 16.7ºF to 18.3ºF per 1,000 ft. The substitution of a lower geothermal gradient of 14.0ºF/1,000 ft produced better model-to-data conformance for TTI values of 75 and higher, but substantially decreased the model-to-data conformance for the critical oil-generation-onset TTI isograds less than 75. This second variation on the Lopatin model was also discarded.

The results of the second variation on our Lopatin model suggest that a better fit might be achieved by assuming a low geothermal gradient for the deeper (and older) part of the well and a high geothermal gradient (like that observed) in the shallow part of the well. This would retain the good model-to-data conformance in the shallow part of the well and move TTI isograds to greater depths (and better conformance to data) in the deep parts of the well. In fact, some experimentation revealed that an early (pre-seismic horizon "D") geothermal gradient of 10ºF/1,000 ft could produce reasonably good model-to-data conformance in the deep part of the well. However, this (10ºF/1,000 ft) is an extremely low geothermal gradient.[30] Even more troubling, this two-part geothermal model implies that the early history of the North Aleutian basin was characterized by a relatively low geothermal gradient that was later replaced by the higher gradients observed today. This is the opposite of what we might expect

[29] *The principal product generated in the high-TTI part of the Lopatin burial model is gas. Actual gas-generation thresholds were probably achieved much more recently than the times indicated by the Lopatin burial model in figure 30. Because gas is more likely to breach trap seals with time, a late (i.e., very recent) gas-charge charge history is probably helpful to overall trap success.*

[30] *Cook Inlet basin, a relatively "cold" forearc basin, has geothermal gradients ranging from 12ºF to 16ºF per 1,000 ft depending on proximity to the modern volcanic arc (Magoon, 1986, fig. 20, p.45).*

considering the early rift history of the North Aleutian basin. Rifting is usually accompanied by elevated geothermal gradients (Dewey and Bird, 1970; Falvey, 1974; McKenzie, 1978; White and McKenzie, 1988; Bond and Kominz, 1988), above the "world average" of 13.7ºF/1,000 ft (25ºC/km) and ranging up to 42ºF/1,000 ft (77ºC/km or higher) (Lee and Uyeda, 1965; Tissot and Welte, 1984, p. 296). At the conclusion of rifting, the crust cools and subsides, producing a shift to a lower geothermal gradient. To invoke an uncommonly low geothermal gradient during a rift event, followed by warming and a higher geothermal gradient, contradicts generally-accepted tectonic-thermal models for rift basins.

In the end, we were unable to devise a Lopatin model for the COST well that uses available geothermal and stratigraphic data, that produces a good fit at all depths to the observational data, and that is rational in the tectonic context of the well.

Despite the flaws in the high-TTI Lopatin model forecasts, the model did produce low-TTI forecasts that are vindicated by vitrinite reflectance data in the shallower parts of the COST well. Therefore, we believe that the Lopatin model of figure 30 provides useful insights into the timing of the *earliest* phases of thermal maturation and potential hydrocarbon generation in the area of the COST well. And here, amid the most important prospects in the North Aleutian basin, the Lopatin model indicates that, given appropriate organic compositions, hydrocarbon generation deep in the basin could have preceded and accompanied the formation of key reservoirs and traps,. Vitrinite reflectance data and Lopatin modeling both indicate that about 10,500 ft of strata in the lower part of the North Aleutian basin are within or have passed through the oil generation window (Ro=0.5% to 1.35%). Significant quantities of gas may also have been generated out of the coaly, Type III organic matter as the host strata passed through the thermal maturity window for oil generation (Boreham and Powell, 1993, p. 149-150). Vitrinite reflectance data indicate that over 5,100 ft of strata have passed into the wet gas generation window for mixed kerogens (Ro>0.8%). Vitrinite reflectance data indicate that over 3,300 ft of strata in the lower part of the basin have passed into the thermal maturity window for generation of dry gas from coaly/Type III organic matter (Ro>1.07%). Clearly, a large volume of rocks have experienced thermal exposures sufficient for significant petroleum generation in the lower part of the basin. The Lopatin model shows that the most attractive reservoirs and traps existed and were available to capture oil and gas at the time of most prolific oil and gas generation.

Petroleum System Elements and Oil and Gas Plays in North Aleutian Basin OCS Planning Area

Key Elements of Petroleum System

The major elements of the petroleum systems hypothesized for the North Aleutian Basin OCS Planning Area are illustrated in a schematic cross section in figure 31a. For the main part of the North Aleutian basin, traps are hypothesized to be charged by gas, condensate, and oil originating from deeply buried, gas-prone source rocks of Tertiary age. For the southwest part of the Planning Area, which is underlain by possibly oil-prone Mesozoic rocks, traps in Mesozoic sandstones are hypothesized to be charged by original oil migration from Mesozoic oil source rocks. Traps in Tertiary sandstones overlying oil-prone Mesozoic rocks are hypothesized to be charged by re-migration of oil out of disrupted Mesozoic reservoirs.

The hypothetical petroleum system responsible for the majority of potential undiscovered oil and gas resources in the Planning Area is illustrated on the right side of figure 31a. Sandstone reservoirs (Bear Lake-Stepovak play sequence) within the domes draped over basement uplifts are charged by petroleum generated in Tertiary rocks (Tolstoi play sequence) deeply buried in grabens flanking the uplifts. A regional shale seal (lower part of Stepovak Fm.; fig. 10 and pl. 3) floors the Bear Lake-Stepovak reservoir sequence and is pierced by horst-bounding faults that extend upward into the shallow level of the basin fill above seismic horizon "D". These faults may provide the critical pathways for petroleum migration between the deep oil and gas generation centers ("GAS/COND KITCHEN" in fig. 31a) flanking basement uplifts and the shallow traps that overlie the uplifts. Gas and oil migrating out of Tertiary rocks in the deep grabens may also fill Tolstoi reservoir sandstones in traps ringing the faulted flanks of basement uplifts.

The hypothetical petroleum system responsible for a minority fraction of undiscovered oil resources in the Planning Area is illustrated on the left side of figure 31a. Mesozoic rocks beneath the Black Hills uplift reached thermal maturity sufficient for oil generation prior to Eocene time and may contain oil pools that formed in Mesozoic (probably Cretaceous?) time. Cenozoic-age faulting may have disrupted some of these oil pools and provided avenues for re-migration into traps in overlying Oligocene-Miocene reservoir sandstones of the Bear Lake-Stepovak play sequence. Traps in Tertiary reservoirs on the Black Hills uplift may also be charged by gas and condensate migrating out of deeply buried Tertiary strata in North Aleutian basin. However, this would requires 50+ miles of lateral migration through the highly faulted southwest part of the North Aleutian basin, with great risk of diversion of migrating petroleum up faults and loss to surface seeps.

Play Definition

Plays were separated first on the basis of reservoir characteristics, for which the stratigraphic sequence serves as proxy. Further separations were made on the basis of structural setting and hydrocarbon charge models (source type [oil vs. gas] and access [length and integrity of migration path]).

The Bear Lake-Stepovak sequence was defined so as to capture the main reservoir package between seismic horizons "A" and "C" (fig. 9 and pl. 2), which is characterized by abundant, thick, porous, and permeable sandstones. The Bear Lake-Stepovak sequence is draped over basement uplifts in the southwest part of the North Aleutian basin and forms the key exploration play in the basin. The Bear Lake-Stepovak play sequence can be traced to the Black Hills uplift, where it is also draped over basement uplifts. But the Black Hills uplift is treated as a separate play because it has access to hypothetical oil-prone sources in the underlying Mesozoic assemblage. The Black Hills uplift has limited access (large distances across highly faulted areas) to the deeply buried gas-prone Tertiary age sources that are hypothesized to charge the main Bear Lake-Stepovak play. The Tolstoi play sequence hosts poor-quality reservoir sandstones (thin and impermeable) and is involved in flank traps against basement uplifts. The Tolstoi sequence is thus set apart into a third play.

A fourth play identifies low-pressure biogenic gas resources in shallow Plio-Pleistocene strata of glacial and marine origins.

The substrate of Mesozoic rocks beneath the North Aleutian basin in divided into a southern province of deformed sedimentary rocks (play 5) and a northern province of volcano-plutonic rocks (play 6). The Mesozoic deformed sedimentary rocks on the south include rocks correlative to regional oil sources and are primarily an oil play. The volcano-plutonic Mesozoic assemblage on the north forms the cores of basement uplifts and if properly fractured, might form a reservoir for hydrocarbons. The schematic structural cross section in figure 31b illustrates the organization of the six plays and associated trap types. The 6 plays are described in detail below.

Play Descriptions, North Aleutian Basin, Alaska

Play 1: Bear Lake-Stepovak (Oligocene-Miocene)

Play Area: 14,820 square miles
Play Water Depth Range: 15-300 feet
Play Depth Range: 2,000-10,000 feet
Reservoir Thermal Maturity: 0.25%-0.48% vitrinite reflectance
Risked, Mean, Undiscovered, Technically Recoverable Resources:
271 Mmb (oil) + 136 Mmb (gas-condensate) = 406 Mmb liquids (rounding sums to 406)
5.473 Tcf (gas) + 0.113 Tcf (solution gas) = 5.586 Tcf gas
Pool Rank 1 Mean Conditional Resource: 827 Mmboe (4.65 Tcfge)
Play Exploration Chance: 0.1872

Play 1, the "Bear Lake-Stepovak" play, is the dominant play in the North Aleutian Basin OCS Planning Area, with 61% (1,400 Mmboe) of the Planning Area energy endowment (2,287 Mmboe). Oil and gas-condensate liquids form 29% of the hydrocarbon energy endowment of play 1.

The Bear Lake-Stepovak play sequence corresponds in the North Aleutian Shelf COST 1 well to the lower part of the Milky River Formation, all of the Bear Lake Formation, and the upper (sandy) part of the Stepovak Formation. The play sequence ranges in age from late Oligocene through early Pliocene (fig. 9 and pl. 2). In onshore areas, rocks correlative to play 1 were penetrated by 9 wells (David River 1/1A, Hoodoo Lake 1, Hoodoo Lake 2, Sandy River 1, Port Heiden 1, Ugashik 1, Becharof Lake 1, Great Basins 1, and Great Basins 2 wells). Offshore, in eastern St. George basin, correlative rocks were penetrated by the St. George Basin COST 2, Monkshood 1, and Bertha 1 wells. The principal point of offshore control is the North Aleutian Shelf COST 1 stratigraphic information test well that was drilled by an industry consortium in 1983. The area of play 1 is shown in figure 32.

No pools of oil or gas were encountered in any wells penetrating the Bear Lake-Stepovak sequence in the North Aleutian basin. Minor gas shows are associated with coals in the Bear Lake-Stepovak sequence in the North Aleutian Shelf COST 1 well and in most wells onshore. In the Becharof Lake 1 well, cuttings headspace gas carbon isotopes (AOGCC, 1985) for the Bear Lake and Stepovak Formations range from -19.5 to -65.4 ($\delta^{13}C$ [PDB]), indicating mixed thermogenic and biogenic gas (fig. 24). No shows of oil were noted within the Bear Lake-Stepovak play sequence in the North Aleutian Shelf COST 1 well. Oil shows were noted in the play sequence in the Becharof Lake 1, Sandy River 1, and David River 1/1A wells. Flow tests in the Bear Lake-Stepovak sequence in the Sandy River 1 well recovered gas-cut drilling mud and formation waters.

Most of the oil and gas resources of play 1 are associated with Oligocene- to Miocene-age sandstones in simple domes draped over basement uplifts, as illustrated schematically in figure 31b (and in the seismic panel in fig. 6 and pl. 1). Mapped domes range up to 93,000 acres in closure areas. Thick (maximum = 277 ft), highly porous reservoir sandstones sum to 3,305 feet in the North Aleutian Shelf COST 1 well—comprising 61 percent of the 5,390 ft-thick Bear Lake-Stepovak play sequence (figs. 11-16). No oil source formation has been identified in the North Aleutian basin but coals and shales with Type III (coal-like) organic matter are abundant and could form sources for both biogenic and thermogenic gas, condensate, and perhaps minor oil (fig. 21). For this reason, play 1 is modeled as gas-prone. Oil shows were encountered in the interval from 15,300 to 16,800 feet (corresponds to 0.78% to 1.04% Ro) in the North Aleutian Shelf COST 1 well. Carbon isotopes on extracts from the show interval correlate to extracts and oils from Tertiary-age rocks in northern Cook Inlet as opposed to extracts and oils from known Mesozoic-age oil source rocks on the Alaska Peninsula and beneath Cook Inlet (fig. 27). These data suggest that Mesozoic oil source beds do not underlie North Aleutian basin in the area of play 1. This interpretation is supported by magnetic intensity data (fig. 7) that suggest that play 1 is underlain by a substrate of Mesozoic volcano-plutonic rocks. The hypothesized petroleum system for play 1 assumes that gas and minor liquids migrate out of Tertiary rocks in the deep parts of North Aleutian basin and rise along faults bounding basement uplifts to charge shallow reservoir beds draped over uplifts.

Three major risk factors for play 1 relate to: **1) seal** (reservoir sequence is very sand-rich and is not capped by a regional seal); **2) source adequacy** (no attractive source formation in known Tertiary-age rocks; Mesozoic rocks beneath play 1 are pervasively invaded by plutons and cannot form a source for petroleum); and **3) petroleum migration to reservoirs** (a major seal sequence—bentonitic shales of the lower Stepovak Formation—floors the reservoir sequence and is only sparsely pierced by faults).

Play 2: Tolstoi (Eocene-Oligocene)

Play Area: *10,890 square miles*
Play Water Depth Range: *15-300 feet*
Play Depth Range: *4,000-20,000 feet*
Reservoir Thermal Maturity: *0.3%-1.65% vitrinite reflectance*
Risked, Mean, Undiscovered, Technically Recoverable Resources:
62 Mmb (oil) + 61 Mmb (gas-condensate) =

123 Mmb liquids
2.476 Tcf (gas) + 0.025 Tcf (solution gas) = 2.501 Tcf gas
Pool Rank 1 Mean Conditional Resource: 208 Mmboe (1.17 Tcfge)
Play Exploration Chance: 0.1404

Play 2, the "Tolstoi" play, is the second most important play in the North Aleutian Basin OCS Planning Area, with 25% (568 Mmboe) of the Planning Area energy endowment (2,287 Mmboe). Oil and gas-condensate liquids form 22 percent of the hydrocarbon energy endowment of play 2.

The Tolstoi play sequence corresponds in the North Aleutian Shelf COST 1 well to the lower part of the Stepovak Formation and the entire Tolstoi Formation. The play sequence ranges in age from early Eocene to early Oligocene (fig. 9 and pl. 2). In onshore areas, rocks correlative to play 2 were penetrated by 5 wells (Becharof Lake 1, Great Basins 1, Great Basins 2, Hoodoo Lake 2, and David River 1/1A wells). Offshore, in eastern St. George Basin, correlative rocks were penetrated by the St. George Basin COST 2 well. The North Aleutian Shelf COST 1 well is the most important point of control for the Tolstoi play sequence in the North Aleutian basin. The area of play 2 is shown in figure 33.

Gas is pooled in several Tolstoi Formation intervals in the Becharof Lake 1 well, where flow tests of separate intervals recovered gas at rates ranging from 10 to 50 mcfg/d, or a total of 90 mcfg/d for all three zones. In the Becharof Lake 1 well, cuttings headspace gas carbon isotopes (AOGCC, 1985) for the Tolstoi Formation range from -32.8 to -43.9 ($\delta^{13}C$ [PDB]), indicating thermogenic gas (fig. 24). Gas was recovered in flow tests from two intervals in the Tolstoi Formation at rates of 5 to 10 Mcfgpd (with 300-400 bwpd) in the David River 1/1A well. Gas shows were associated with Tolstoi Formation coals in the North Aleutian Shelf COST 1 well as well as in the 5 Tolstoi penetrations onshore. Oil shows were noted in the Tolstoi Formation in the North Aleutian Shelf COST 1, Becharof Lake 1, Hoodoo Lake 2, and David River 1/1A wells).

Most of the oil and gas resources of play 2 are associated with simple anticlines draped over basement uplifts, or, in truncation traps (against faults and unconformities) on the flanks of basement uplifts, as illustrated in figure 31. Mapped traps range up to 53,000 acres in closure area. The upper part of the Tolstoi play sequence (lower part of Stepovak Formation) passes over the crests of basement uplifts. In the North Aleutian Shelf COST 1 well, the upper part of the Tolstoi play sequence contains porous and permeable sandstones that are sparse (236 feet net, or 10% of interval) and thin (maximum = 43 feet) (figs. 11-16). A regional shale seal in the lower part of the Stepovak Formation is prominent within the upper part of the Tolstoi play sequence (fig. 9 and pl. 2). The lower part of the Tolstoi play sequence is involved in fault- and stratigraphic-truncation traps on the flanks of basement uplifts. Sandstones are abundant in the lower Tolstoi play sequence (1,910 feet net, 30% of sequence) in the North Aleutian Shelf COST 1 well, but are thin-bedded (maximum = 57 feet) and impermeable (diagenesis of volcanic particles has resulted in collapse of framework grains; 84% of core samples have <10 md permeability) (figs. 11-16). No oil source rock formation has been identified in the North Aleutian basin but coals and shales with Type III (coal-like) organic matter are abundant and could form sources for both biogenic and thermogenic gas, condensate, and minor oil (fig. 21). For this reason, play 2 is modeled as gas-prone. Oil shows were encountered in the interval from 15,300 to 16,800 feet (corresponds to 0.78% to 1.04% Ro) in the North Aleutian Shelf COST 1 well. Carbon isotopes on extracts from the show interval correlate to extracts and oils from Tertiary-age rocks in northern Cook Inlet as opposed to extracts and oils from Mesozoic-age source rocks on the Alaska Peninsula and beneath Cook Inlet (fig. 27). These data suggest that Mesozoic oil source beds do not underlie North Aleutian basin in the area of play 2. The hypothetical petroleum system for play 2 assumes that gas and minor liquids migrating out of Tertiary rocks in the deep parts of North Aleutian basin rise along faults bounding basement uplifts to charge shallow reservoir beds draped over uplifts or truncated on uplift flanks.

The major risk factors for play 2 relate to: **1) reservoir** (thin sandstones are porous in the upper Tolstoi play sequence but are impermeable in the lower Tolstoi play sequence); and **2) source adequacy** (no attractive source formation in known Tertiary-age rocks; Mesozoic rocks beneath play 2 are pervasively invaded by plutons and cannot form a source for petroleum).

Play 3: Black Hills Uplift-Amak Basin (Eocene-Miocene)

Play Area: 6,990 square miles
Play Water Depth Range: 15-700 feet
Play Depth Range: 2,000-20,000 feet (mostly 2,000-5,000 feet)
Reservoir Thermal Maturity: 0.23%-2.00% (mostly 0.23%-0.31%) vitrinite reflectance
Risked, Mean, Undiscovered, Technically Recoverable Resources:
149 Mmb (oil) + 6 Mmb (gas-condensate) = 155 Mmb liquids
0.249 Tcf (gas) + 0.063 Tcf (solution gas) = 0.312 Tcf gas
Pool Rank 1 Mean Conditional Resource: 378 Mmboe (2.12 Tcfge)
Play Exploration Chance: 0.105

Play 3, the "Black Hills Uplift-Amak Basin" play, is a subordinate play in the North Aleutian Basin OCS Planning Area, with 9% (210 Mmboe) of the Planning Area energy endowment (2,287 Mmboe). Oil and gas-condensate liquids form 74% of the energy endowment of play 3.

The Black Hills uplift is a regional arch that extends west from the Alaska Peninsula to join the shelf-edge uplift that forms the west boundary of St. George basin. The Black Hills uplift is onlapped by the Tertiary-age sedimentary fill of both the North Aleutian and Amak basins, but only rocks correlative to the Bear Lake-Stepovak sequence of play 1 crest the top of the uplift. Over the crest, the Bear Lake-Stepovak-equivalent sequence (fig. 9 and pl. 1) ranges up to 5,000 feet thick and directly overlies moderately deformed Mesozoic sedimentary rocks. Rocks of the lower part of the Stepovak Formation and the Tolstoi Formation are truncated at faults and unconformities on the north and south flanks of the uplift. No wells have penetrated the Tolstoi-equivalent strata in the Amak basin south of the Black Hills uplift. In onshore areas, rocks correlative to the Bear Lake-Stepovak play sequence were penetrated by 9 wells (David River 1/1A, Hoodoo Lake 1, Hoodoo Lake 2, Sandy River 1, Port Heiden 1, Ugashik 1, Becharof Lake 1, Great Basins 1, and Great Basins 2 wells). Offshore, correlative rocks were penetrated at the North Aleutian Shelf COST 1 well (North Aleutian basin) and at the St. George Basin COST 2, Monkshood 1, and Bertha 1 wells (St. George basin). The closest point of offshore control is the Bertha 1 well, located on the crest of the Black Hills uplift. The Bear Lake-Stepovak-equivalent sequence at the Bertha 1 well is mostly marine and non-coal-bearing, and is a more distal facies than the correlative coal-bearing (nonmarine to inner neritic; fig. 9 and pl. 2) sequences penetrated onshore and at the North Aleutian Shelf COST 1 well. The area of play 3 is shown in figure 34.

No pools of oil or gas have been discovered in the Bear Lake-Stepovak play sequence or correlative rocks of plays 1 and 3. Gas shows are widely associated with coals in the Bear Lake and Stepovak Formations and oil shows have been noted in these formations in 3 wells onshore (Becharof Lake 1, Sandy River 1, and David River 1/1A wells). Flow tests recovered gas from the Tolstoi Formation in the Becharof Lake 1 well and oil shows were noted in 4 Tolstoi penetrations (North Aleutian Shelf COST 1, Becharof Lake 1, Hoodoo Lake 2, and David River 1/1A wells). No oil or gas shows are associated with the Bear Lake-Stepovak sequence in the Bertha 1 well, located on the Black Hills uplift near the west boundary of play 3.

Most of the oil and gas resources of play 3 are associated with broad, low-amplitude anticlines draped over culminations on the Black Hills uplift, as illustrated in figure 31. Mapped traps have closure areas ranging up to 133,000 acres. Thick (maximum = 220 feet), highly porous, and plentiful (sum to 1,706 feet net, or 59% of sequence) reservoir sandstones are present in the Bear Lake-Stepovak-equivalent sequence in the Bertha 1 well. No regional seal caps the abundant sandstones in the Bear Lake-Stepovak-equivalent sequence at the Bertha 1 well.

No oil source rocks have been identified in the Tertiary sedimentary fill of either the North Aleutian or Amak basins. In the North Aleutian basin (and presumably the Amak basin), coals and shales with Type III (coal-like) organic matter are abundant and could form sources for both biogenic and thermogenic gas, condensate, and minor oil. In the southwest part of the North Aleutian basin, thousands of feet of Tertiary rocks are thermally mature and could generate oil and gas, given appropriate organic compositions (fig. 19). However, the Amak basin fill reaches a maximum thickness of only 12,500 feet. The depth to the 0.6% vitrinite reflectance isograd at the North Aleutian Shelf COST 1 well is 12,312 feet subsea (figs. 9 and 17). If the depth for this isograd at the COST well is extrapolated to Amak basin, only about 200 feet of rocks at the floor of the Amak basin are forecast to be thermally mature and capable of generating petroleum (figs. 18 and 19). It is therefore unlikely that Amak basin forms a source for significant quantities of petroleum. In any case, gas and condensate generated in the deep parts of either Amak or North Aleutian basins must migrate laterally tens of miles through areas highly dissected by very young strike-slip faults (that follow the margins of the Black Hills uplift). Because of the risks of losses through long-distance lateral migration and diversion at faults, it is unlikely that significant quantities of gas and condensate generated in the Amak or North Aleutian basins would reach traps on the Black Hills uplift.

The Black Hills uplift is underlain by an assemblage of folded Mesozoic sedimentary rocks that include strata age-equivalent to known regional oil source beds of Middle Jurassic (Kialagvik Fm. or Tuxedni Gp.) and Late Triassic (Kamishak Fm.) ages. The Middle Jurassic Tuxedni Group is the source for 1.6 billion barrels of original oil reserves in northern Cook Inlet (AKDO&G, 2002), most of which is pooled in Tertiary-age rocks that overlie the Tuxedni Group. The Tuxedni-correlative sequence—the Kialagvik Formation—is present in the Cathedral River 1 well onshore and equivocal geochemical anomalies may suggest a past role as an oil source (fig. 20). In the Cathedral River 1 well, oil shows were widely observed in the rocks overlying the Kialagvik Formation. The Kialagvik Formation is thermally overmature (TAI = 3.0 to 3.8) and post oil-generative in the Cathedral River 1 well (fig. 20). It is probable that Mesozoic oil sources in this area generated and expelled the oil in a past (pre-Tertiary) cycle of deep burial, long before the deposition of the Tertiary-age rocks flanking or overlapping the Black Hills arch. Oil-charging of the Tertiary-age rocks in play 3 must therefore rely upon capturing oil remobilized out of Mesozoic reservoirs where it was sequestered perhaps 30 million years earlier during Mesozoic (Late Cretaceous?) burial and oil generation. The hypothetical Mesozoic oil pools within the Black Hills uplift must first survive uplift, deep erosion, and re-burial beneath Oligocene and younger strata. The Mesozoic oil pools must remain intact during creation of the drape anticlines in Tertiary rocks over culminations on the Black Hills uplift. Once the drape anticlines had formed, fault disruption of the Mesozoic pools must then trigger the release of the oil sequestered in Mesozoic reservoirs. The released oil then migrates upward in some (necessarily) focused or non-dispersive pattern en route to Tertiary-age reservoir sandstones in the drape anticlines. The charge model for play 3 prospects is dependent upon a long chain of critical events and therefore seems likely to fail.

Two major risk factors for play 3 relate to: **1) migration** (must re-migrate oil from underlying disrupted Mesozoic pools or gas from distant generation centers in North Aleutian or Amak basins, crossing numerous young faults); and **2) seal** (the reservoir sequence over the crest of the Black Hills uplift is very sand-rich and is not capped by a regional seal).

Play 4: Milky River Biogenic Gas (Plio-Pleistocene)

Play Area: 50,710 square miles
Play Water Depth Range: 15-700 feet
Play Depth Range: 500-3,000 feet
Reservoir Thermal Maturity: 0.20%-0.26% vitrinite reflectance
Risked, Mean, Undiscovered, Technically Recoverable Resources:
Biogenic gas in negligible recoverable quantities
Play Exploration Chance: 0.000

Play 4, the “Milky River Biogenic Gas” play, is the most extensive yet least prospective play in the North Aleutian Basin OCS Planning Area. Play 4 probably contains sizable in-place quantities of biogenic gas simply because of the vast area embraced by the play. However, very little of this gas is likely to be recoverable by conventional means, and the technically recoverable resource endowment is assessed as negligible.

The Milky River play sequence corresponds in the North Aleutian Shelf COST 1 well to the upper part of the Milky River Formation and overlying, unnamed Quaternary deposits. The play sequence ranges in age from early Pliocene to Holocene (fig. 9 and pl. 2). In onshore areas, rocks correlative to play 4 were penetrated by 9 wells (David River 1/1A, Hoodoo Lake 1, Hoodoo Lake 2, Sandy River 1, Port Heiden 1, Ugashik 1, Becharof Lake 1, Great Basins 1, and Great Basins 2 wells). Offshore, in eastern St. George basin, correlative rocks were penetrated by the St. George Basin COST 2, Monkshood 1, and Bertha 1 wells. The principal point of offshore control is the North Aleutian Shelf COST 1 well that was drilled by an industry consortium in 1983. The area of play 4 is shown in figure 35.

No pools of oil or gas were encountered in any wells penetrating the Milky River play sequence in the North Aleutian basin.

Minor biogenic gas shows are associated with the Milky River sequence in the North Aleutian Shelf COST 1 well (Robertson Research, 1983, p. 1), several wells onshore, and in the Bertha 1 well in the St. George basin. In the Becharof Lake 1 well, cuttings headspace gas carbon isotopes (AOGCC, 1985) for the Milky River Formation range from -67.9 to -80.2 ($\delta^{13}C$ [PDB]), clearly indicating gas of largely biogenic origin (fig. 24). Biogenic gas is primarily a product of bacterial fermentation of the organic matter buried within sediments (Hunt, 1979, p. 154).

In offshore areas, biogenic gas may be pooled in features emplaced by large alpine glaciers that invaded Bristol Bay from the south (Alaska Peninsula) and northeast (Alaska Range) during the Pleistocene epoch and then retreated during the last 10,000 years. The legacy of glaciation may include drumlins, eskers, and recessional moraines. These elevated landforms are gravelly, porous features that were later drowned in rising sea waters and are now draped and perhaps sealed by unconsolidated pelagic mud. Such features might pool biogenic gas, at least in southern parts of North Aleutian basin. Thick shelfal sandstone sequences of Pliocene age, presumably representing large-scale current-molded bedforms, also form candidates for stratigraphic traps for biogenic gas, as illustrated in figure 31. Pools of biogenic gas in play 4 would be characterized by very low pressure (no more than 1,300 psi) and would not yield significant fractions of the in-place gas to conventional development wells. The biogenic gas may occur in low saturations or be dissolved in formation waters. In either case, gas production might be accompanied by abundant formation water, a typical experience in biogenic gas production (Hunt, 1979, p. 155; Shurr and Ridgley, 2002).

We note that most Cook Inlet gas fields are largely of biogenic origin with basin-wide original recoverable gas reserves of 8.6 Tcf (AKDO&G, 2002). Cook Inlet clearly offers a successful example of a commercial biogenic gas province. However, the Cook Inlet gas fields occur in fold structures (often overlying oil fields) that gathered the gas from surrounding extensive areas of gas biogenesis. Cook Inlet gas field reference depths range from 1,935 feet to 10,000 feet (average, 5,790 feet) and are normally-pressured to over-pressured (AOGCC, 2001). The Cook Inlet gas field sandstone reservoirs (Miocene and Pliocene) are overlain by compacted shales that form competent seals. The Cook Inlet gas fields, though filled with biogenic gas, do not provide a useful analog for play 4. Because of similarities in trap type, burial depths, and reservoir and seal lithologies, the Cook Inlet biogenic gas fields are most analogous to the drape-anticline prospects of North Aleutian basin plays 1 and 2, which range in depth from 2,500 to 10,000 ft. However, the latter are expected to be charged with mostly thermogenic gas and condensate.

Areas of significant risk to play 4 include: **1) gas recoverability** (low reservoir pressure and high formation water production); **2) poor seal** (poor integrity of the unconsolidated pelagic mud that may seal glacial features); **3) reservoir** (poor reservoir continuity); and **4) charge** (lack of aquifer structure that would concentrate and convey biogenic gas to stratigraphic traps). Play 4 is assessed to have an exploration chance of zero and negligible undiscovered technically recoverable oil and gas resources.

Play 5: Mesozoic Deformed Sedimentary Rocks (Triassic-Cretaceous)

Play Area: 5,040 square miles
Play Water Depth Range: 15-700 feet
Play Depth Range: 2,000-15,000 feet
Reservoir Thermal Maturity: 0.60%-1.30% vitrinite reflectance
Risked, Mean, Undiscovered, Technically Recoverable Resources:
38 Mmb (oil) + 0 Mmb (gas-condensate) = 38 Mmb liquids
0.000 Tcf (gas) + 0.017 Tcf (solution gas) = 0.017 Tcf gas
Pool Rank 1 Mean Conditional Resource: 63 Mmboe
Play Exploration Chance: 0.09216

Play 5, the "Mesozoic Deformed Sedimentary Rocks" play, contributes a mere 1.8% (41 Mmboe) of the energy endowment (2,287 Mmboe) of the North Aleutian Basin OCS Planning Area. Oil forms 93% of the energy endowment of play 5.

Folded and thrust-faulted Mesozoic sedimentary rocks are widely exposed on the south side of the Alaska Peninsula (figs. 5, 8). Exploration drilling on the Alaska Peninsula began in 1903 with drilling on oil seeps along the axes of anticlines near the east end of Becharof Lake (fig. 5). Oil seep drilling continued through 1940 and ultimately 10 wells were drilled (tbl. 1). Five modern (1961-1981) wells (Canoe Bay 1, Big River 1, Koniag 1, Painter Creek 1, and Wide Bay 1) also tested exposed fold structures along the south flank of the Alaska Peninsula (Molenaar, 1996b, tbl. 1). On the north flank of the Alaska Peninsula and along the southern edge of North Aleutian basin, Mesozoic sedimentary rocks were penetrated by 3 wells (Cathedral River 1, David River 1/1A, and Hoodoo Lake 2 wells). To the west, five wells in St. George basin (St. George COST 2, Rat 1, Segula 1, Tustamena 1 [Y-0530], and Tustamena 2 [Y-0527] wells) reached total depth in Jurassic rocks. The North Aleutian Shelf COST 1 well did not penetrate Mesozoic rocks (fig. 9 and pl. 2). The principal point of well information for the Mesozoic rocks of play 5 is the Cathedral River 1 well atop the onshore extension of the Black Hills uplift. The Cathedral River 1 well penetrated a relatively complete Mesozoic sequence 13,911 feet thick and ranging in age from Late Triassic (Kamishak Fm.) to Late Jurassic (Naknek Fm.) (fig. 20). The area of play 5 is shown in figure 36.

No significant pools of oil or gas were encountered in any of the wells testing Mesozoic rocks on the Alaska Peninsula or in St. George basin. The Humble Bear Creek 1 well near Becharof Lake (fig. 2) recovered 450 Mcf/d of gas and large amounts (5,800 feet in drill pipe) of salt water (AOGCC, 1959) from a 120-foot interval of the uppermost part of the Talkeetna Formation (Detterman, 1990). Elsewhere, several wells encountered sparse oil and gas shows in Mesozoic rocks correlative to the play 5 sequence. Oil shows generally consist of white to yellow sample fluorescence and weak to streaming white, blue, or yellow cut fluorescence from isolated pores or fractures in impermeable sandstones and siltstones. In the Cathedral River 1 well, oil shows were encountered as shallow as 390 feet and were commonly observed down to 7,500 feet. At 7,500 feet, a petroleum-based mud additive (Soltex©) was introduced to the drilling mud, casting suspicion on the authenticity of the widespread hydrocarbon shows observed at greater depths. Flow tests in the Shelikof and Kialagvik Formations (Middle Jurassic) and the Talkeetna Formation (Lower Jurassic) in the Cathedral River 1 well recovered gassy drilling mud with traces of oil. In northern Cook Inlet, some oil production (<300,000 barrels) has occurred from fractured Talkeetna Formation beneath the principal accumulation (in Tertiary rocks) in the McArthur River field (AOGCC, 2001, p. 171).

Across the eastern Alaska Peninsula and western Alaska Range, the Bruin Bay fault forms the contact between a Mesozoic volcano-plutonic arc terrane on the north and a Mesozoic sedimentary basin on the south. The Bruin Bay fault is extrapolated offshore beneath the North Aleutian basin as the boundary between a northern area of high-frequency, high-amplitude magnetic anomalies and a southern area of low-frequency, low-amplitude magnetic anomalies (fig. 7). We speculate that the magnetic anomaly field north of the projected Bruin Bay fault corresponds to the volcano-plutonic arc terrane exposed north of the Bruin Bay fault onshore. These rocks were penetrated beneath Tertiary strata in three wells (Great Basins 1, Great Basins 2, and Becharof Lake 1 wells) in the northeast part of North Aleutian basin. The magnetic anomaly field south of the projected Bruin Bay fault represents an offshore extension of the deformed Mesozoic sedimentary rocks of the Alaska Peninsula, as demonstrated by penetrations of Mesozoic rocks at several wells to the west in St. George basin and at the Cathedral River 1, David River 1/1A, and Hoodoo Lake 2 wells on the Alaska Peninsula. The area of play 5 corresponds to the area of the low-frequency, low-amplitude magnetic field south of the offshore extension of the Bruin Bay fault, and underlies the Amak basin and the Black Hills uplift (fig. 7).

Most of the oil and gas resources of play 5 are associated with hypothetical pools of oil captured in anticlines or fault traps like those exposed on the Alaska Peninsula, as illustrated in figure 31. We have not mapped such structures within the Mesozoic complex offshore, but fold, thrust-fault, and wrench-fault structures are observed in available seismic data. The surface anticlines outlined by geologic mapping near Becharof Lake range from 7,000 to 147,000 acres in gross map area and the ranges of sizes of these anticlines were used to model hypothetical prospect areas in play 5. Potential reservoir formations in play 5 include the Lower Jurassic Talkeetna Formation, the Upper Jurassic Naknek Formation, the Lower Cretaceous Staniukovich and Herendeen Formations, and the Upper Cretaceous Chignik and/or Hoodoo Formations (stratigraphic column in fig. 8). In outcrop and well penetrations, most of these sandstones and conglomerates are highly zeolitized and preserve negligible porosity (Franks and Hite, 1980). The Staniukovich and Naknek Formations generally have the smallest fractions of volcaniclastic detritus (Burk, 1965, fig. 10), and, as the younger (or shallower) reservoir formations in the Mesozoic assemblage, have a burial history that is less severe than that of Middle Jurassic and older units.

The principal resource in play 5 is predicted to be oil with no accumulations of free gas. Play 5 was modeled as an oil play because it is assumed to be charged by Middle Jurassic oil sources like those that charged the undersaturated (relative to gas) oil fields of northern Cook Inlet. Play 5 includes strata that are age-equivalent to known regional oil source beds of Middle Jurassic (Kialagvik Fm. or Tuxedni Gp.) and Late Triassic (Kamishak Fm.) ages. The Middle Jurassic Tuxedni Group is the source for 1.6 billion barrels of original oil reserves in northern Cook Inlet (AKDO&G, 2002), most of which are pooled in Tertiary-age rocks that overlie the Tuxedni Group. The Tuxedni-correlative sequence on the Alaska Peninsula—the Kialagvik Formation—is present in the Cathedral River 1 well onshore. Geochemical anomalies associated with the Kialagvik Formation in the

Cathedral River 1 well may suggest a past role as an oil source (fig. 20). In the Cathedral River 1 well, oil shows were widely observed in the rocks overlying the Kialagvik Formation, which is thermally overmature (TAI = 3.0 to 3.8) and post oil-generative (fig. 20). It is probable that Mesozoic oil sources in this area generated and expelled the oil in a past (pre-Tertiary) cycle of deep burial and thermal transformation of organic matter. The existence of viable oil accumulations in play 5 requires that the generation of oil out of these source rocks predate zeolitization of pore systems in Mesozoic sandstone reservoirs. Unfortunately, the general case appears to be that oil generation and migration followed reservoir zeolitization. Oil, though commonly observed in Mesozoic rocks in wells and outcrops, is only observed in trace quantities in fractures or in isolated pores that survived zeolitization.

Four major risk factors for play 5 relate to: **1) reservoir** (early zeolitization and porosity destruction in chemically reactive volcaniclastic sandstones); **2) timing** (oil generation and migration must occur early [Late Jurassic or Early Cretaceous] to protect reservoir pore systems, but traps probably did not form until Late Cretaceous or early Cenozoic time); **3) trap integrity** (breaching of traps at Miocene and older Cenozoic unconformities or trap disruption by faults may have destroyed Mesozoic petroleum accumulations); and **4) preservation** (exhumation to shallow burial depths and invasion of meteoric waters may have promoted biological degradation of oil in Mesozoic-age accumulations to asphaltic materials).

Play 6: Mesozoic Buried Granitic Hills (Jurassic-Cretaceous Magmatic Rocks)

Play Area: 46,810 square miles
Play Water Depth Range: 15-400 feet
Play Depth Range: 6,000-12,000 feet
Reservoir Thermal Maturity: 0.34%-0.60% vitrinite reflectance (projected from burial depth but irrelevant because reservoirs are fractured plutonic and volcanic rocks)
Risked, Mean, Undiscovered, Technically Recoverable Resources:
26 Mmb (oil) + 5 Mmb (gas-condensate) = 30 Mmb liquids (rounding sums to 31)
0.195 Tcf (gas) + 0.010 Tcf (solution gas) = 0.206 Tcf gas (rounding sums to 0.205)
Pool Rank 1 Mean Conditional Resource: 148 Mmboe (0.83 Tcfge)
Play Exploration Chance: 0.04095

Play 6, the "Mesozoic Buried Granitic Hill" play, is a subordinate play in the North Aleutian Basin OCS Planning Area, with 3% (67 Mmboe) of the Planning Area energy endowment (2,287 Mmboe). Oil and gas-condensate liquids form 45% of the hydrocarbon energy endowment of play 6.

The rocks comprising the Mesozoic Buried Granitic Hill play correspond to the Mesozoic plutonic complex exposed in the Alaska Range to the northeast of the North Aleutian basin. The latter rocks are the roots of a volcanic arc system of Jurassic and Cretaceous age. The volcanic arc system is long-lived and remains active today as the chain of large, active volcanoes along the backbone of the Alaska Peninsula. The area of play 6 is shown in figure 37.

Jurassic and Cretaceous plutonic rocks are overlain unconformably by Tertiary strata in wells in the northeastern parts of the North Aleutian basin. This plutonic complex was penetrated by 3 wells (Great Basins 1, Great Basins 2, and Becharof Lake 1 wells) at depths ranging from 8,780 to 10,860 feet. Plutonic rocks (quartz diorite) in the lowermost 15 ft of the Port Heiden 1 well have been assigned to the Middle Jurassic by Detterman (1990), although Brockway et al. (1975) included these rocks with the overlying Eocene-Oligocene Meshik volcanics. Radiometric dating of some of these plutonic rocks by the K-Ar method (Geochron, 1969; original reported dates--not recalculated using modern constants; Brockway et al., 1975) has yielded ages of 96.3 Ma (Great Basins 2 well), 120 Ma, and 177 Ma (Great Basins 1 well), or, ranging from mid-Cretaceous to Middle Jurassic in equivalent stratigraphic age.

No pools of oil or gas were encountered in any of the well penetrations of the Mesozoic magmatic arc complex. A gas seep at "Gas Rocks" along the southwest shore of Becharof Lake (located in fig. 23 [spl. 149]) is located along the projected trace of the Bruin Bay fault. This gas seep consists mostly of carbon dioxide and nitrogen.

On the eastern Alaska Peninsula and western Alaska Range, the Bruin Bay fault forms the contact between a Mesozoic volcano-plutonic arc terrane on the north and a Mesozoic sedimentary basin on the south. The Bruin Bay fault is extrapolated offshore as the boundary between a northern area of high-frequency, high-amplitude magnetic anomalies and a southern area of low-frequency, low-amplitude magnetic anomalies (fig. 7). We speculate that the magnetic anomaly field north of the projected Bruin Bay fault corresponds to the volcano-plutonic arc terrane exposed north of the Bruin Bay fault onshore. These rocks were penetrated beneath Tertiary strata in three wells (Great Basins 1, Great Basins 2, and Becharof Lake 1 wells) in the northeast part of North Aleutian basin. The magnetic anomaly field south of the projected Bruin Bay fault represents an offshore extension of the deformed Mesozoic sedimentary rocks of the Alaska Peninsula, as demonstrated by well penetrations of Mesozoic rocks at several wells to the west in St. George basin and at the Cathedral River 1, David River 1/1A, and Hoodoo Lake 2 wells on the Alaska Peninsula. The area of play 6 corresponds to the area of the high-frequency, high-amplitude magnetic anomaly field north of the offshore extension of the Bruin Bay fault. This magnetic anomaly field is interpreted to mark a substrate of Mesozoic volcano-plutonic rocks that underlies the northern ninety-two percent of the North Aleutian Basin OCS Planning Area.

The Mesozoic basement rocks penetrated at the Great Basins 1 well are described from cores as polymictic conglomerates[31] passing

[31] *The stratigraphic assignment of these conglomerates in the Great Basins 1 well has been used to make a case for association with the very different terranes that lie north and south of the Bruin Bay fault. Hite (2004, p. 17) has argued that the assignment of these conglomerates to the Naknek Formation (after Detterman, 1990) indicates that the well penetrated the Mesozoic sedimentary (Chignik) terrane south of the Bruin Bay fault. (Regional mapping published by Magoon et al [1976] confines the Upper Jurassic Naknek Formation to the terrane south of the Bruin Bay fault.) However, the Hite interpretation also requires that the Bruin Bay fault curve abruptly westward from the southwest shore of Becharof Lake so as to pass north of the Great Basins 1 well. We note that views differ on the correct assignment for the conglomerates in the depth interval 10,516-10,850 ft md in the Great Basins 1 well. Brockway et al. (1975) assigned these conglomerates to the Oligocene Stepovak Formation and as such they would have no bearing on the interpretation of position relative to the terranes separated by the Bruin Bay fault. The conglomerates at the Great Basins 1 well pass downward into granitic gneiss and lamprophyre that, in our view, are most sensibly associated with the volcano-plutonic arc (Iliamna) terrane north of the Bruin Bay fault. Shales interbedded with the conglomerates are described as "baked" (AOGCC, 1959b, p. 11) and the deeper granitic rocks have been K-Ar dated at 120 and 177 Ma (Early Cretaceous and earliest Middle Jurassic, respectively; Geochron, 1969; Brockway et al., 1975). Contact metamorphism of*

downward into granitic gneiss (with large orthoclase porphyroblasts) and lamprophyre (rich in dark minerals and transitional to gabbros). The Great Basins 2 well penetrated diorite and granite, brecciated and seamed with calcite veins. The Mesozoic rocks penetrated at the Becharof Lake 1 well are described as metamorphic green schist, meta-gabbro, and meta-diorite, highly fractured and veined by feldspar and quartz.

All of the undiscovered potential oil and gas resources of play 6 are associated with hypothetical pools lodged in fractured "granitic"[32] rocks that core basement uplifts of Tertiary age, as illustrated in figure 31. These granite-cored uplifts were repeatedly exposed to weathering and erosion through early Tertiary (perhaps also Late Cretaceous) time. We hypothesize that fractures in the granites provided avenues for deep invasion by meteoric waters during times of surface exposure. The meteoric waters may have enlarged fractures through dissolution and created a bulk porosity that was later occupied by petroleum (following deep reburial). In addition to an abundance of fractures, fractures must be lengthy and sufficiently diverse in orientations and depth of penetration in the granitic body to establish effective connectivity across pool areas of thousands of acres. The granite-cored basement uplifts were eventually (in Late Eocene time, approx. 40 Ma) sealed beneath a regional shale within the lower part of the Stepovak Formation. We hypothesize that gas and oil arising from Type III and coaly source rocks of Tertiary age in deep areas of the North Aleutian basin that surround the basement uplifts migrated up the bounding faults and invaded the fractured and weathered granites at the crest of the basement uplifts.

Features similar to the North Aleutian basin buried hills form important exploration targets in the Bohai (North China) basin (Guangming and Quanheng, 1982) and offshore Vietnam (Areshev et al., 1992). Buried hills form an important play concept for exploration of the Mesozoic assemblage in ultra-deep waters of the U.S. Gulf of Mexico (Post et al., 2001). In the productive analog from Vietnam, the granitic rocks range in age from 97 to 178 Ma (mid-Cretaceous to Middle Jurassic) and feature bulk porosity values ranging from up to 25.0%. Effective porosity averages between 2.5% and 3.8% and is roughly distributed in halves as "fracture porosity" and as "caverns" or "microcaverns", the latter the legacy of dissolution of fracture surfaces by both hydrothermal and meteoric fluids. Vietnam's largest field (Bach Ho) is lodged in a fractured granitic reservoir and produces approximately 280,000 bbl/day (Brown, 2005, p. 8). Paul Post (pers. comm., August 2003) of the Minerals Management Service has compiled data on the buried hill oil and gas fields of China and Vietnam. Pool volumes can exceed 1 billion barrels of oil and 2 trillions of cubic feet of gas. Productive columns can range up to 3,300 feet (P'An, 1982, tbl. 1; O&GJ, 2003). Initial production rates can exceed 18,000 barrels of oil per day. Oil recovery factors can range up to 900 bbl/acre-foot (F50 = 158 bbl/acre-foot). The variability in these fractured reservoirs is such that the upper parts of the reservoir can be sparsely

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shales interbedded with the conglomerates by Middle Jurassic intrusives suggests to us that the conglomerates might more logically be assigned to the Lower Jurassic Talkeetna Formation, which is widely mapped and commonly intruded by plutons in the volcano-plutonic arc (Iliamna) terrane north of the Bruin Bay fault (Magoon et al., 1976). We conclude that the conglomerates and magmatic rocks penetrated below 10,516 ft md in the Great Basins 1 well probably represent the volcano-plutonic terrane north of the Bruin Bay fault.

[32] *Here referring to any felsic pluton or massive felsic volcanic flow.*

fractured while better fracture systems exist deeper in the buried hill. Many hydrocarbon accumulations in Vietnam and China (and elsewhere) may have been missed because exploration wells stopped drilling as soon as granitic rocks were encountered in the belief that it was economic basement and no hydrocarbons could be housed there (Sladen, 1997). The data compiled and analyzed by Paul Post for analog features in China and Vietnam formed the basis for the pay thickness and oil and gas yields used in the play 6 resource model (prospect areas are based on MMS seismic mapping).

Three major risk factors for play 6 relate to: **1) reservoir** (requires extensive fractures, enhanced by weathering, and of sufficient vertical and horizontal lengths and diversity of orientation to achieve connectivity across an area of tens of thousands of acres); **2) adequate source** (no attractive source formation in known Tertiary-age rocks); and **3) migration** (hydrocarbons generated in deep basin areas surrounding basement uplifts must first migrate vertically up bounding faults to reach the horsts, but then must encounter sealing levels on the same faults that act to divert hydrocarbons into the crests of uplifts; there is some risk that these faults will instead allow the hydrocarbons to escape upwards into overlying Tertiary sedimentary rocks).

GEOLOGIC ASSESSMENT MODEL

The creation of the geologic model used in the computer simulation for the undiscovered oil and gas resources of the North Aleutian Basin OCS Planning Area drew data from MMS seismic mapping, exploratory wells, producing fields in analogous reservoirs in the northern Cook Inlet basin, and published literature. Tabulations of the geologic input data used to assess the 6 plays identified in the North Aleutian Basin OCS Planning Area are given in tables 3, 4, 5, 6, 7, and 8.

Prospect Areas and Volumes

This oil and gas assessment relies upon the seismic mapping conducted prior to 1988 by the Alaska (Region) office of the Minerals Management Service. This mapping identified 74 prospects in the North Aleutian Basin OCS Planning Area. This mapping was the basis for construction of probability distributions for the aerial sizes of prospects and probability distributions for the numbers of prospects. These are the most influential variables within the geologic model used to compute the undiscovered oil and gas potential and it is important that they are grounded in direct information.

Mapped prospects were grouped by play and the prospect areas (maximum closure within spill point) were tabulated and entered into the *BESTFIT* module within @*RISK* for approximation by a log-normal probability distribution. The closure areas of mapped prospects in the North Aleutian Basin OCS Planning Area range from 2,600 to 133,000 acres. Independent probability distributions for prospect areas were created for each play. These are the distributions reported as "Prospect Area (acres)-Model Input" in tables 3 through 8.

The prospect area distribution was then aggregated (in *@RISK*) with a probability distribution for fill fraction (described below) to obtain the probability distribution for pool area. The *@RISK* aggregation reports back an "as-sampled" prospect area distribution, which is reported as the "Prospect Area (acres)-Model Output" in tables 3 through 8.

The pool area distribution reported from the *@RISK* aggregation was then aggregated with a probability distribution for pay thickness (described below) in order to calculate a probability distribution for pool volume (in acre-feet) in the *POOLS* module within *GRASP*. The pool volume distribution and the pool numbers distribution (described below) were then aggregated to calculate the volumes (acre-feet) of discrete hypothetical pools in the *PSRK* module. The *PSUM* module completed the analysis by charging the discrete hypothetical pools with a specified mix of petroleum fluids and then calculating resources for the individual pools and the play as a whole.

The construction of probability distributions for trap fill fractions relied upon subjective analysis of each of the key elements controlling trap fill. We first considered the charge potential for the play, that is, the extent to which hydrocarbons were made available to fill traps within the play. In plays understood to have easy access to abundant hydrocarbons migrating from areas of prolific oil and gas generation, trap fill fractions were permitted to rise to a maximum of 1.0 (100%). Generally, these are plays with prospects amidst a hydrocarbon generation center. In plays perceived to have limited access to migrating hydrocarbons were modeled with prospects incompletely filled. For plays requiring migration from distant generation areas, trap fill fractions were reduced in recognition of the risks of high losses and diversions (up faults to surface seeps) incurred by long-distance migration.

Given access to some significant source of hydrocarbons for the play, attention was then turned to trap size, trap amplitude, trap type, and seal integrity. Trap size is an issue where limited hydrocarbons are available to fill high-volume traps. Trap amplitude becomes a factor when the vertical relief is very large, so large that differential pressures across seals[33] at the crests could rupture the seals and allow the hydrocarbons to escape. Trap integrity is also a function of trap type. A trap sealed by one or more faults is probably at more risk for leakage than a simple anticline sealed by a single, continuous shale formation. Seal integrity is generally controlled by lithology and thickness. Even high-amplitude prospects could reasonably be allowed to be completely filled if sealed by thick, well-consolidated, clay-rich shales. Shales that can be shown to be geopressured also offer greater seal integrity and more complete filling of traps might be anticipated where such geopressured shales form the seals.

Prospect Numbers

As noted above, MMS seismic mapping identified a total of 74 prospects[34] in the

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[33] *created by contrasts between hydrostatic pressures in rocks saturated by relatively high-density water and excess pressures ("buoyant pressures") developed in columns of relatively low-density hydrocarbons*

[34] *In plays 1, 2, 3, and 6. No prospects are mapped in play 5. There, the minimum (F99) number of prospects (and areas) were estimated from the density and sizes of surface anticlines exposed on the Alaska Peninsula from Becharof Lake to Chignik Bay.*

North Aleutian Basin OCS Planning Area. Some prospects represent closures at different depth levels (separate play sequences) on a single structure, so the total number of identified discrete prospective structures in the Planning Area is somewhat less than 74.

In assessment work, we generally concede that large numbers of prospects could remain unidentified, some even in the most thoroughly mapped areas. "Unidentified" prospects exist for a variety of reasons. Some prospects remain unidentified because some areas lack seismic data. Some smaller prospects may have been missed because they fall within spaces in the seismic grid. Other prospects may be missed because of lack of detail in stratigraphic analysis. Lastly, many prospects may remain unidentified because they are subtle or impossible to detect in seismic data. It is generally acknowledged that unidentified prospects exist in all basins and plays, that some fraction of the unidentified prospects probably contain petroleum, and that some of the unidentified prospects will ultimately be tested and discovered to contain pooled oil or gas, perhaps in commercial quantities. Therefore, unidentified prospects must be given account in the assessment of undiscovered oil and gas potential.

For the exploration plays identified in the North Aleutian Basin OCS Planning Area we supplemented the numbers of known prospects with some estimate of the numbers of prospects that might remain unidentified. The estimation process focused on the completeness of seismic information and the level of geological complexity. In thoroughly-mapped plays with simple geology and large structures, like play 1, relatively few prospects are expected to remain unidentified. Conversely, in plays with complex geology, deficient analysis (sparse seismic data, or rudimentary seismic-stratigraphic analysis), or predominantly small prospects, like play 2, very large numbers of prospects might reasonably be expected to remain unidentified.

We constructed prospect numbers probability distributions for each play using a graphical approach. Our practice was to first post the number of mapped prospects at F99 (99% probability of equaling or exceeding the associated value) on log-probability graph paper. To the number of mapped prospects we add our estimate for the number of unidentified prospects; this sum is then posted at the extreme right (at ~F00) on the same log-probability plot. A line connecting these two data points then defines the probability distribution for prospect numbers for a particular play.

We estimated that as many as 285 hypothetical prospects might remain unidentified in the 5 assessed exploration plays (play 4 was not quantitatively assessed). When added to the 74 mapped prospects (and the 11 prospects at minimum inferred for play 5), we have a maximum estimated endowment of 370 prospects. When aggregated with the play risk models in the *MPRO* module of *GRASP*, we obtained a maximum endowment of 119 hypothetical pools[35] that contributed to the overall undiscovered oil and gas potential of the North Aleutian Basin OCS Planning Area.

Pay Thickness Model

Cook Inlet oil fields (data reported by AOGCC, 2001) were used as an analog for

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[35] *sum of maximum numbers of pools found for 5 plays, as reported in tables 3, 4, 5, 6, 7, and 8*

developing probability distributions for pay thickness for the prospects in North Aleutian basin. The North Aleutian Shelf COST 1 well encountered abundant thick sandstones (aggregate exceeding 3,000 feet) in the Bear Lake-Stepovak play (1) sequence. Given the thin and discontinuous shale seals within and above the Bear Lake-Stepovak sequence, and, the unknown charge capacity for basin petroleum sources, it seems unlikely that all sandstones in this sequence would form "pay" across any given prospect. The nonmarine to inner neritic sandstones of the Bear Lake-Stepovak sequence are broadly analogous to the nonmarine to inner neritic (estuarine) Tertiary basin fill of Cook Inlet basin (Kenai Gp., Beluga Fm., and Sterling Fm.) as described by Hite (1976) and Hayes et al. (1976). Pay thickness data for the oil and gas fields of northern Cook Inlet are presented in figure 38. The statistical fit to these data was used to model pay thickness for analogous plays (1 and 3) in the North Aleutian Basin OCS Planning Area. Figure 11 shows that there is clearly adequate sandstone in this sequence to accommodate the most generous pay thickness model—certainly the modest pay thickness model developed from Cook Inlet oil and gas fields in figure 38. (We note that the amplitudes of mapped prospects in the North Aleutian basin range from 46 to 584 feet [mean = 227 feet], adequate at maximum amplitudes to accommodate the full pay column [456 feet] modeled in figure 38.) Pay thicknesses for play 2 were reduced to reflect the observed (in core data) poor reservoir qualities in the sandstones of the Tolstoi play sequence.

Construction of Probability Distributions With Limited Data

The input parameters required by the computer models for plays are listed in the data forms shown in table 3 through table 13. There has been little or no exploratory drilling and very little data are directly available for most of these input parameters. However, in many cases, one can forecast the extreme ranges for any particular input parameter using regional well data or data from analogous basins. For example, in the calculation of gas recovery factors, the reservoir temperature is an important variable that is controlled by burial depth and geothermal gradient. The latter information is available from seismic mapping (depths) and well data (geothermal gradient), or thermal models from analogous basins. Our approach to constructing a probability distribution for reservoir temperature is to estimate the temperature extremes – the temperatures of the shallowest (coolest) and deepest (hottest) prospects in the play. Then, we post the minimum temperature at the 99.99 (effectively 100.0) percent probability and the maximum temperature at the 0.01 (effectively 0) percent probability in a "normal" (Gaussian) probability plot. (One might also use a log-normal probability plot to conduct this exercise. We assumed a normal distribution for play reservoir temperature.) A straight line drawn connecting the two points (invoking a normal distribution) then defines a probability distribution for reservoir temperature for the play. An example plot is shown in figure 39. Newendorp (1975, p. 383) termed such constructions "force-fit" distributions. Many input probability distributions in the geologic computer models for plays in this assessment were created using this method.

Computation of Oil and Gas Recovery Factors

The *GRASP* computer model requires entries for recoverable petroleum per unit volume of petroleum-saturated reservoir. The data forms in table 3 through table 13 list these entries as "Oil Recovery Factor" (barrels of oil recoverable per acre-foot of reservoir pool) and "Gas Recovery Factor" (thousands of cubic feet of gas recoverable per acre-foot of reservoir pool). In the absence of local production experience, predicting these values for undiscovered pools is difficult because they are the product of complex interactions of several variables. Analogous reservoirs in comparable plays or geologic settings can form a source for such data. However, establishing credible analogs and finding published data for them are both difficult tasks. In the North Aleutian Basin OCS Planning Area, we chose to use a computer model to calculate the oil and gas recovery factors using basic information that is often available from regional studies or local well data.

The data required to compute oil and gas recovery factors are essentially the variables in the yield equations for oil and gas. These are listed in the data forms of tables 9, 10, 11, and 12 and are noted in the yield equations below:

Oil Recovery Factor:

- ***a***. Porosity (decimal fraction)
- ***b***. Water Saturation (decimal fraction)
- ***c***. Oil Recovery Efficiency (decimal fraction)
- ***d***. Oil Volume Factor (as 1/FVF [where FVF = Formation Volume Factor = Reservoir Barrels Per Stock Tank Barrels])

Barrels Oil Recoverable per Acre-Foot of Pool Reservoir (BO)
= 7758.38 Bbl/acre-ft (a·(1-b)·c·d)

Gas Recovery Factor:

- ***a***. Porosity (decimal fraction)
- ***b***. Water Saturation (decimal fraction)
- ***c***. Reservoir Pressure (pounds per in^2)
- ***d***. Gas FVF (as 1/Z [Z = Gas Deviation[36] Factor])
- ***e***. Gas Recovery Efficiency (decimal fraction)
- ***f***. Gas Shrinkage Factor (decimal fraction)
- ***g***. Reservoir Temperature (in °Rankine= °F+460)

Thousands of Cubic Feet of Gas Recoverable per Acre-Foot of Pool Reservoir (MCFG)*
= [43,560 ft^3/acre-ft] [a·(1-b)] [(60°+460°)·d·e] [c/14.73] [(1-f)/g [1/1,000]

* (at standard surface conditions of 60 °F (520°R) and 14.73 pounds per in^2 [1 atmosphere])[37]

or, rearranging for simplification:

Thousands of Cubic Feet of Gas Recoverable per Acre-Foot of Pool Reservoir (MCFG)*

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[36] *Also known as the compressibility factor, a measure of deviation from ideal gas behavior. The "Z" factor can be defined as the ratio between the volume actually occupied by a gas at a certain pressure and temperature and the volume that the gas would occupy, if it behaved like an ideal gas, at the same pressure and temperature (McCain, 1973, p. 95-109). For ideal gases, the "Z" value is 1.0. "Z" factors can range from 0.2 to 2.0, but in most North Aleutian prospects, estimated "Z" values range from 0.65 to 1.04 (tbls. 9 to 11).*

[37] *The value of 14.73 psi/atm was inherited from earlier MMS assessment work. The conventional value is 14.70 psi/atm, although the legal base in many States is 14.65 psi/atm, and in New Mexico and Louisiana it is 15.025 psi/atm (Craft and Hawkins, 1959, p. 11).*

= 1537.8 (a·(1-b)·c·d·e) (1-f)/g

Many of these variables, such as temperature, pressure, and porosity, are depth-dependent and can be predicted over the depth ranges of plays if geothermal, geopressure, and porosity-decline gradients, respectively, are known. These latter data are available from exploratory wells and can often be extrapolated with some confidence over large areas. In this case, geothermal and geopressure data were obtained from the North Aleutian Shelf COST 1 well. Likewise, porosity data were extracted from the abundant core porosity data obtained by the COST well and incorporated directly into oil and gas yields after statistical approximation by normal and log-normal distributions (figs. 12, 13, 14, and 15).

If reservoir texture can be estimated, irreducible water saturations can be predicted from porosity determinations by reference to a series of general tables and charts. We began by estimating the lithology and grain size of potential reservoirs and using these data to estimate bulk volume water using a published table (Asquith and Gibson, 1982, p. 98, tbl. 8). The value for bulk volume water was taken as equivalent to the "φS_{wi}" (porosity · irreducible water saturation) curves in a porosity-saturation cross plot published by Schlumberger (1991, p. 158, chart K-3). By pairing minimum and maximum porosity values with extreme "φS_{wi} " values (from textural considerations and the Asquith table)[38], estimates for irreducible water saturations can be read from the Schlumberger chart. In this way, minimum and maximum values for water saturations were determined for the play and used to construct "force-fit" log-normal probability distributions for entry to the computer model. Averaged "initial water saturation" data for Cook Inlet oil and gas fields (AOGCC, 2001) were used to calibrate the medians of the probability distributions for water saturation in the North Aleutian plays.

When oil is produced, it shrinks in volume because gases dissolved in the oil at reservoir pressures are released at surface pressures. This volume change is represented by the "Oil Formation Volume Factor" or "FVF" (reservoir barrels per stock tank barrels) and it is dictated by the quantity of dissolved solution gas (gas-oil ratio, or GOR), which is in turn controlled by reservoir pressure, temperature and petroleum composition(s). A single distribution was used for all North Aleutian plays. The probability distribution for Formation Volume Factor was estimated from a statistical fit to 14 FVF values reported for Cook Inlet producing oil fields (AOGCC, 2001). These data were inverted and entered as the "Oil Volume Factor (1/FVF)" for purposes of oil yield calculations (tbls. 9, 10, 11, and 12).

Ranges in oil and gas recovery efficiencies were estimated from recovery data for various combinations of reservoirs and drive mechanisms as published by White (1989, p. 3-29 to 3-31) and Arps (1967).

The gas "Z" factor, or "deviation" factor, was determined using charts published by Standings and Katz (1942; republished by Anderson [1975, p. 155-156] and McCain [1973, p. 95-109]) and using estimates for gas gravities, reservoir temperatures, and reservoir pressures. Gas gravities were obtained from data for producing fields in Cook Inlet (AOGCC, 2001).

[38]*minimum porosity (10%) paired with a poorly-sorted, very- fine-grained sandstone; maximum observed porosity paired with a well-sorted example of the coarsest-grained clastic rock expected to occur within the play sequence*

Probability distributions for all of the variables in the yield equations, and appropriate unit conversion constants, were entered into the @*RISK* computer program and aggregated with dependencies to calculate probability distributions for oil and gas recovery factors. The input variables and the dependency models are shown in tables 9, 10, 11, and 12. Probability distributions for oil and gas recovery factors for play 6 (listed in tbl. 8) were taken from MMS data compilations by Paul Post (pers. Comm.., August, 2003).

Risk Assessment

Analyses of play risk were carried out along the lines suggested by White (1993). First, risk was assessed at the play level, where the absence of a critical element could hazard the success of the entire play. Second, risk was assessed at the prospect level, where a critical element might be absent at some sites and cause some fraction of the prospects in a successful play to be barren of hydrocarbons.

Chances for success at the prospect level are analogous to drilling success rates in commercially successful plays in productive basins (some specific examples provided by Clifford, 1986, p. 370). Our subjective estimates for prospect level chances of success are conditioned upon success (i.e., success is assumed) at the play level. The play chance for an unproven play is typically less than 1.0. The prospect chance is ultimately multiplied against the play chance to obtain an "exploration" chance. The exploration chance is in turn used with the (probability distribution for) numbers of prospects to determine the (probability distribution for) numbers of pools[39].

Success of a play or prospect can be defined in different ways. Commercial success in oil prospecting is contingent upon finding sufficient reserves to permit the accumulation to be developed at a profit. However, some (or most) oil or gas pools, particularly in the Arctic, are too small to warrant commercial development. Nevertheless, these small pools represent "geologic" successes, proving that petroleum must have been generated somewhere and was able to migrate to traps bearing porous media. The small pools, by their existence, prove that all components of the play petroleum system are working properly.

In this assessment of the North Aleutian Basin OCS Planning Area, the condition for "geologic" success for a play was a single occurrence of conventionally pooled hydrocarbons capable of flowing to a well-bore. Any play known to host such an occurrence was assigned a play level chance of success of 1.0. For example, based on small gas flows in tests from the Tolstoi Formation at the Becharof Lake 1 and the David River 1/1A wells, play 2 (Tolstoi) was assigned a play chance of 1.0. The play chances for all other plays are less than 1.0 because no pooled hydrocarbons have been identified in these plays. No attempt was made to formalize a specific minimum field size as part of the condition of "geologic" success. Although similar definitions for play success, in which no minimum pool sizes are specified, are advocated by some experts, (Capen, 1992; Rose, 1992), the practice has been criticized by prominent experts such as White (1993, p. 2050).

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[39] *performed in a mathematically complex process by the MPRO module of the GRASP computer program, as described by Bennett (1994)*

The construction of risk models required a subjective appraisal of the factors underlying play and prospect success. Our subjective risk analysis focused upon each of the main elements required for successful creation and preservation of oil or gas accumulations, including: 1) trap definition and integrity; 2), reservoir presence and quality; 3) charge or source success; and 4) preservation success. Exploration chances for the 6 plays identified in the North Aleutian Basin OCS Planning Area range from 0.0 (play 4) to 0.1872 (play 1). The key risk factors for each of the 6 plays identified in the North Aleutian Basin OCS Planning Area are listed in tables 3, 4, 5, 6, 7, and 8.

Assessment Results for North Aleutian Basin

Table 14 shows the results of the 2006 oil and gas assessment of the North Aleutian Basin OCS Planning Area, including results for total technically recoverable hydrocarbon energy (in barrels of oil-equivalent) and four individual commodities (oil, condensate from gas, free gas ("non-associated"[40] and solution gas) for individual plays. Planning Area totals by individual commodity are also listed.

<u>**Play 1: Bear Lake-Stepovak (Oligocene-Miocene)**</u>

Play 1 is the dominant play in the North Aleutian Basin OCS Planning Area, with 61% (1,400 Mmboe) of the Planning Area hydrocarbon energy endowment (2,287 Mmboe) at mean risked values. The play hydrocarbon energy endowment (risked, recoverable) ranges from 0 Mmboe (F95) to 3,749 Mmboe (F05), as shown in figure 40A. Gas ("non-associated" [free] gas and solution gas) forms 71% of the hydrocarbon energy endowment of play 1.

In the computer simulation for play 1, each of the 7,198 successful trials is comprised of one or more "pools" (or "hits", in assessment vernacular), for a total of 73,007 pools sampled for size (tbl. 15). These pools can be grouped and displayed as size classes, as shown in the histogram of figure 40B. Pool size class 12 contains the largest share (15,882, or 22%) of pools "discovered" among the 10,000 trials[41] conducted by the computer simulation for play 1. Pool size class 12 ranges from 64 to 128 Mmboe. Pool count statistics for the play 1 simulation are shown in table 15. The largest pool among the 73,007 pools or "hits" in the computer simulation for play 1 falls within pool size class 19, which ranges in size from 8,192 to 16,384 Mmboe (or 46

[40] *The term "non-associated gas" as used in GRASP output reports refers to both free gas occurring as pools of gas unaccompanied by oil and free gas occurring in gas caps directly overlying oil accumulations. The industry convention is to describe the free gas in caps overlying oil accumulations as "associated" gas.*

[41] *The model simulates the drilling of all pools in the play by comparing computer-generated random numbers (ranging from 0.0 to 1.0) to the user-input play risk factors (play risk = 1.0 – play chance). When the random number exceeds the risk, then the trial is declared "successful," indicating a discovery (i.e., hydrocarbons exist in the pool), or pool. Most successful trials contain several pools.*

to 92 Tcfge; tbl. 15 and fig. 40B). The computer simulation therefore indicates some potential for very large hydrocarbon pools in play 1.

A maximum of 34 hypothetical pools is forecast by the aggregation of the risk model and the prospect numbers model (tbl. 3) for play 1, as shown in figure 40C. These 34 pools range in mean conditional (un-risked) recoverable volumes from 6 Mmboe (pool rank 34) to 827 Mmboe (pool rank 1). Pool rank 1 (fig. 40C) ranges in possible conditional recoverable volumes from 187 Mmboe (F95) to 2,495 Mmboe (F05), or in a gas case from 1.05 Tcfge (F95) to 14.02 Tcfge (F05). Data for the size ranges of play 1 pools are given in table 16. As noted above, at low probabilities we observe some potential for very large hydrocarbon pools in play 1. The high-side potential recognizes the combination of large, simple traps and thick, high-quality reservoir formations that form the best exploration opportunities in both play 1 and the entire North Aleutian Basin OCS Planning Area. Overall, play 1 and most of the North Aleutian basin are hypothesized to be charged by sources within the Tertiary basin fill and are modeled as gas prone. Therefore, the largest pool in play 1 (and in the Planning Area) is most likely to be charged by gas.

Play 2: Tolstoi (Eocene-Oligocene)

Play 2 is the second most important play in the North Aleutian Basin OCS Planning Area, with 25% (568 Mmboe) of the Planning Area hydrocarbon energy endowment (2,287 Mmboe) at mean risked values. The play 2 hydrocarbon energy endowment (risked, recoverable) ranges from 91 Mmboe (F95) to 1,293 Mmboe (F05), as shown in figure 41A. Gas ("non-associated" [free] gas and solution gas) forms 78% of the hydrocarbon energy endowment of play 2.

In the computer simulation for play 2, each of the 9,905 successful trials is comprised of one or more pools (or "hits"), for a total of 61,326 pools sampled for size (tbl. 17). These pools can be grouped and displayed as size classes, as shown in the histogram of figure 41B. Pool size class 12 contains the largest share (18,963, or 31%) of pools "discovered" among the 10,000 trials conducted by the computer simulation for play 2. Pool size class 12 ranges from 64 to 128 Mmboe. Pool count statistics for the play 2 simulation are shown in table 17. The 5 largest pools among the 61,326 pools or "hits" in the computer simulation for play 2 fall within pool size class 16, which ranges in size from 1,024 to 2,048 Mmboe (or 5.8 to 11.5 Tcfge; fig. 41B). The computer simulation therefore indicates some low-probability potential for large hydrocarbon pools in play 2.

A maximum of 44 hypothetical pools is forecast by the integration of the risk model and the prospect numbers model (tbl. 4) for play 2, as shown in figure 41C. These 44 pools range in mean conditional (un-risked) recoverable volumes from 7 Mmboe (pool rank 44) to 208 Mmboe (pool rank 1). Pool rank 1 (fig. 41C) ranges in possible conditional recoverable volumes from 61 Mmboe (F95) to 467 Mmboe (F05), or, in the gas case, from 0.34 Tcfge (F95) to 2.62 Tcfge (F05). Data for the size ranges of the play 2 pools are given in table 18. The modest high-side potential recognizes the thin, typically impermeable reservoir formations that characterize play 2. Overall, play 2 is Tertiary-sourced and is modeled as gas-prone, so the largest pool is most likely to be charged by gas.

Play 3: Black Hills Uplift-Amak Basin (Eocene-Miocene)

Play 3 is a subordinate play in the North Aleutian Basin OCS Planning Area, with 9% (210 Mmboe) of the Planning Area hydrocarbon energy endowment (2,287 Mmboe). The play 3 hydrocarbon energy endowment (risked, recoverable) ranges from 0 Mmboe (F95) to 1,077 Mmboe (F05), as shown in figure 42A. Gas ("non-associated" [free] gas and solution gas) forms 26% of the hydrocarbon energy endowment of play 3.

In the computer simulation for play 3, each of the 4,127 successful trials is comprised of one or more pools (or "hits"), for a total of 15,323 pools sampled for size (tbl. 19). These pools can be grouped and displayed as size classes, as shown in the histogram of figure 42B. Pool size class 11 contains the largest share (2,521, or 16%) of pools "discovered" among the 10,000 trials conducted by the computer simulation for play 3. Pool size class 11 ranges from 32 to 64 Mmboe. Pool count statistics for the play 3 simulation are shown in table 19. The largest pool among the 15,323 pools or "hits" in the computer simulation for play 3 falls within pool size class 19, which ranges in size from 8,192 to 16,384 Mmboe (fig. 42B). The computer simulation therefore indicates a low-probability potential for very large hydrocarbon pools in play 3.

A maximum of 13 hypothetical pools is forecast by the aggregation of the risk model and the prospect numbers model (tbl. 5) for play 3, as shown in figure 42C. These pools range in mean conditional (un-risked) recoverable volumes from 4 Mmboe (pool rank 13) to 378 Mmboe (pool rank 1). Pool rank 1 (fig. 42C) ranges in possible conditional recoverable volumes from 20 Mmboe (F95) to 1,302 Mmboe (F05), or, in the gas case, from 0.11 Tcfge (F95) to 7.32 Tcfge (F05). Data for the size ranges of the play 3 pools are given in table 20. As noted above, at very low probabilities, we observe some potential for large pools of hydrocarbons in play 3. This high-side potential recognizes the small number of very large closures in play 3 that have been identified by seismic mapping. Because of the potential for oil sourced from underlying Mesozoic sedimentary rocks and the great distance to Tertiary gas sources, play 3 is predominately an oil play. The largest pool in play 3 is most likely to contain oil.

Play 4: Milky River Biogenic Gas (Plio-Pleistocene)

Play 4 is the most regionally extensive yet least prospective play in the North Aleutian Basin OCS Planning Area. Play 4 probably contains sizeable in-place quantities of biogenic gas. However, all hypothetical prospects (none are identified) are related to stratigraphic isolation of sandstone or glacial-moraine bodies within unconsolidated marine mud. Any gas production might be accompanied by high water production because of low gas saturations, a common experience in biogenic gas production. Formation pressures are low owing to shallow burial depths and recovery efficiencies will accordingly be quite low. The recoverable biogenic gas endowment of play 4 is therefore assessed as negligible, as shown in table 6 and figure 43.

Play 5: Mesozoic Deformed Sedimentary Rocks (Triassic-Cretaceous)

Play 5 contributes 1.8% (41 Mmboe) to the hydrocarbon energy endowment (2,287 Mmboe) of the North Aleutian Basin OCS

Planning Area. The play hydrocarbon energy endowment (risked, recoverable) ranges from 0 Mmboe (F95) to 197 Mmboe (F05), as shown in figure 44A. Gas (solution gas only) forms 7% of the hydrocarbon energy endowment of play 5.

In the computer simulation for play 5, each of the 3,923 successful trials is comprised of one or more pools (or "hits"), for a total of 14,327 pools sampled for size (tbl. 21). These pools can be grouped and displayed as size classes, as shown in the histogram of figure 44B. Pool size class 10 contains the largest share (3,088, or 22%) of pools "discovered" among the 10,000 trials conducted by the computer simulation for play 5. Pool size class 10 ranges from 16 to 32 Mmboe. Pool count statistics for the play 5 simulation are shown in table 21. The largest pool among the 14,327 pools or "hits" in the computer simulation for play 5 falls within pool size class 16, which ranges in size from 1,024 to 2,048 Mmboe (tbl. 21 and fig. 44B). The computer simulation therefore indicates an extremely low-probability potential for modest to large (sub-multi-billion barrel) hydrocarbon pools in play 5.

A maximum of 13 hypothetical pools is forecast by the aggregation of the risk model and the prospect numbers model (tbl. 7) for play 5, as shown in figure 44C. These pools range in mean conditional (un-risked) recoverable volumes from 2 Mmboe (pool rank 13) to 63 Mmboe (pool rank 1). Pool rank 1 (fig. 44C) ranges in possible conditional recoverable volumes from 8 Mmboe (F95) to 176 Mmboe (F05), or, in the case of gas, from 0.04 Tcfge (F95) to 0.99 Tcfge (F05). Data for the size ranges of the play 5 pools are given in table 22. Overall, it seems unlikely that any sizeable pools of hydrocarbons will be found in play 5—mostly because of the poor reservoir capacities forecast by the observed regional zeolitization and wholesale pore occlusion in Mesozoic sandstones. The Mesozoic assemblage of play 5 includes rocks that are age-equivalent to established regional oil sources. Although the age-equivalent rocks in play 5 have not been securely demonstrated to be significant sources for oil in the area of the North Aleutian basin, it is most likely that if any pools exist in play 5, they will consist of oil.

Play 6: Mesozoic Buried Granitic Hills (Jurassic-Cretaceous Magmatic Rocks)

Play 6 is a subordinate play in the North Aleutian Basin OCS Planning Area with 3% (67 Mmboe) of the Planning Area hydrocarbon energy endowment (2,287 Mmboe). The play hydrocarbon energy endowment (risked, recoverable) ranges from 0 Mmboe (F95) to 330 Mmboe (F05), as shown in figure 45A. Gas ("non-associated" [free] gas and solution gas) forms 55% of the hydrocarbon energy endowment of play 6.

In the computer simulation for play 6, each of the 3,427 successful trials is comprised of one or more pools (or "hits"), for a total of 13,089 pools sampled for size (tbl. 23). These pools can be grouped and displayed as size classes, as shown in the histogram of figure 45B. Pool size class 10 contains the largest share (2,483, or 19%) of pools "discovered" among the 10,000 trials conducted by the computer simulation for play 6. Pool size class 10 ranges from 16 to 32 Mmboe. Pool count statistics for the play 6 simulation are shown in table 23. The 4 largest pools among the 13,089 pools or "hits" in the computer simulation for play 6 falls within pool size class 18, which ranges in size from 4,096 to 8,192 Mmboe. The computer simulation therefore indicates a low probability (effectively zero) for very large hydrocarbon pools in play 6.

A maximum of 15 hypothetical pools is forecast by the aggregation of the risk model and the prospect numbers model (tbl. 8) for play 6, as shown in figure 45C. These pools range in mean conditional (un-risked) recoverable volumes from 2 Mmboe (pool rank 15) to 148 Mmboe (pool rank 1). Pool rank 1 (fig. 45C) ranges in possible conditional recoverable volumes from 9 Mmboe (F95) to 469 Mmboe (F05), or, in the gas case, from 0.05 Tcfge (F95) to 2.64 Tcfge (F05). Data for the size ranges of the play 6 pools are given in table 24. At low probabilities, we observe some potential for modest-size pools of hydrocarbons in play 6—their modest sizes owing mostly to the doubtful capacity of the fractured granites that are conjectured to form the reservoirs for play 6 pools. Play 6 is Tertiary-sourced and is modeled as gas prone, so the largest pool is most likely to be charged by gas.

Overall Results for Oil and Gas Endowments of North Aleutian Basin

Graphical summaries for overall basin hydrocarbon endowments (risked, recoverable) are shown in figure 46. Total Planning Area technically recoverable hydrocarbon resources range from 91 Mmboe (F95) to 6,647 Mmboe (F05), with a mean outcome of 2,287 Mmboe (fig. 46A). At mean values, 67% of the hydrocarbon energy endowment is gas ("non-associated" [free] gas and solution gas from oil) and 33% is liquid petroleum (free oil and condensate from gas). The North Aleutian Basin OCS Planning Area is overall a gas-prone province, although some subordinate plays are primarily oil plays.

Technically recoverable gas resources for the North Aleutian Basin OCS Planning Area range from 0.404 Tcfg (F95) to 23.278 Tcfg (F05), with a mean outcome of 8.622 Tcfg (fig. 46B). Table 14 separates gas commodities and shows that at mean values, 97% (8.393 Tcfg) of the gas endowment exists as "non-associated" [free] gas, with the remaining 3% (0.229 Tcfg) dissolved as solution gas in free oil.

Technically recoverable liquid petroleum resources for the North Aleutian Basin OCS Planning Area range from 19 Mmbo (F95) to 2,505 Mmbo (F05), with a mean outcome of 751 Mmbo (fig. 46C). Table 14 separates liquid petroleum commodities and shows that at mean values, 72% (545 Mmbo) of the liquid petroleum exists as free oil, with the remaining 28% (208 Mmbo) dissolved as condensate in free gas.

A comparative plot for cumulative probability distributions for liquid petroleum (oil and condensate), total petroleum energy (BOE, all gas and liquids), and total gas (free gas and solution gas) is shown in figure 46D.

Large Individual Gas Fields Are Possible

Play 1, the *Bear Lake-Stepovak play*, captures most of the large prospects in the central part of the North Aleutian basin. The *mean conditional* (un-risked) size of the largest hypothetical pool in play 1 (and the North Aleutian basin overall) is 4.65 trillions of cubic feet of natural gas (or 827 millions of barrels [oil-energy-equivalent]). As shown in the pool rank plot in figure 47, the largest hypothetical pool is nearly twice the size of the largest gas field in Cook Inlet (Kenai gas field, 2.427 Tcfg EUR). At *maximum* (F05) size, the largest pool in play 1 could contain 14.02 trillions of cubic feet of natural gas (or 2.495 billions of barrels [oil-energy-equivalent]).

Economic Potential of North Aleutian Basin

The hypothetical infrastructure model for the 2006 MMS economic assessment is illustrated in the map of figure 48. Our infrastructure model, although a likely scenario, was constructed only for the purpose of conducting economic tests and is not necessarily a predictor of actual future installations. The model assumes that several prospects that were leased in 1988 (since relinquished untested back to the U.S. Government) are found to contain commercial gas reserves. Development platforms (with some subsea completions over field margins) send production to an offshore hub that is centrally located over the prospect that garnered the highest bids in the 1988 lease sale. Trunk pipelines (gas and oil) link the offshore hub to gas conditioning facilities and a liquefied-natural-gas (LNG) plant at a port in Balboa Bay on the Pacific (south) coast of the Alaska Peninsula (fig. 48). At the LNG plant, the natural gas is chilled to a liquid state (-260°F) preparatory to loading into tankers. The LNG tankers then convey the gas to receiving and re-gasification terminals either at Nikiski in Cook Inlet (550 mi. tanker sailing) or on the U.S. West Coast (assumed 2,600 mi. tanker sailing). Minimum transportation tariffs in the economic model represent a Cook Inlet destination while the maximum tariffs represent a U.S. West Coast destination.

The Cook Inlet market is isolated and small, typically consuming a little over 200 Bcfg/yr (Sherwood and Craig, 2001, tbl. 5). It is unlikely that the entire North Aleutian basin production stream (estimated at 150 Bcfg/yr) could be absorbed by the Cook Inlet market. Most North Aleutian basin gas would likely be marketed to the U.S. West Coast, Hawaii, or perhaps even the Asian Pacific Rim. However, the Cook Inlet would form a logical and accessible alternative destination for some fraction of the production from North Aleutian basin.

Condensate and oil are assumed to be loaded at Balboa Bay and tankered to Cook Inlet or perhaps to the oil loading terminal for the Trans-Alaska oil pipeline system (TAPS) at Valdez, Alaska (located in figs. 1, 4).

A summary of the results of the economic modeling for the North Aleutian basin are shown in table 25. Economic modeling yields first positive economic results at prices of $14/barrel of oil and $2.12/Mcf of associated solution gas. Non-associated gas pools yield first positive economic results at a gas price of $3.63/Mcf (tbl. 25). In any case, these “threshold” prices correspond to very small risked volumes of gas, condensate, and oil. Meaningful volumes of gas (>1 Tcfg) are not economically recoverable until prices exceed $4.54/Mcfg (tbl. 25).

A minimum developable gas reserve of 5 Tcf will probably be required to justify a grassroots LNG export system in the remote frontier area of the North Aleutian basin. The 5 Tcf of gas will presumably be supplied by several fields. Our economic analysis indicates that economic recovery of 5 Tcf of gas will require prices of $6.50/Mcf and $43/barrel (2005$) landed at the U.S. West Coast. Current gas prices do exceed $6.50/Mcf by a wide margin (recent gas prices at the Los Angeles city gate exceed $13.00/Mcf; Natural Gas Week, 19 December 2005). If market prices can be sustained at the current level or higher, a large fraction of the North Aleutian basin gas endowment could ultimately be economically recoverable.

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Table 1: North Aleutian Basin and Alaska Peninsula Exploration Wells, 1903-1983

Operator and Well Name	Year Completed	Location	Kelly Bushing Elevation; Age and Name, Surface Formation	Total Depth; Fm., Age and Name, Formation at Total Depth
Pacific Oil and Commercial Pacific Oil No. 1	1903	NW/4 Sec. 3, T29S, R40W	Ground level(?); M. Jurassic, Shelikof Fm.	1421 feet; M. Jurassic, Shelikof Fm.
J.H. Costello Costello No. 1	1903	NW/4 Sec. 10,T29S, R40W	Ground level(?); M. Jurassic, Shelikof Fm.	728 feet;M. Jurassic, Shelikof Fm.
Pacific Oil and Commercial Pacific Oil No. 2	1904	SE/4 Sec. 3, T29S, R40W	Ground level(?);M. Jurassic, Shelikof Fm.	1542 feet;M. Jurassic, Shelikof Fm.
J.H. Costello Costello No. 2	1904	SE/4 Sec. 10, T29S, R40W	Ground level(?);M. Jurassic, Shelikof Fm.	TD Unknown;M. Jurassic, Shelikof? Fm.
Standard Lathrop No. 1	1923	SE/4 Sec. 17, T29S, R43W	Ground level(?); U. Jurassic, Naknek Fm.	500 feet; U. Jurassic, Naknek Fm.
Tidewater Associated Finnegan No. 1	1923	NE/4 Sec. 30, T29S, R43W	Ground level(?); U. Jurassic, Naknek Fm.	560 feet; U. Jurassic, Naknek Fm.
Standard Oil McNally No. 1	1925	NW/4 Sec. 29, T29S, R43W	Ground level(?); U. Jurassic Naknek Fm.	510 feet; U. Jurassic, Naknek Fm.
Tidewater Associated Alaska No.1	1925	SW/4 Sec.20, T29S, R43W	Ground level, 694 ft; U. Jurassic, Naknek Fm.	3033 feet; M. Jurassic, Shelikof Fm.
Standard Lee No. 1	1926	SW/4 Sec.20, T29S, R43W	Ground level, 764 ft; U. Jurassic, Naknek Fm.	5053 feet; M. Jurassic, Shelikof Fm.
Standard, et. al. Grammer No. 1	1940	Sec. 10, T30S, R41W	375 feet; M. Jurassic, Shelikof Fm.	7596 feet; Lower Jurassic, Talkeetna Fm.?
Humble-Shell Bear Creek Unit No. 1	1959	Sec 36, T29S, R41W	927 feet; M. Jurassic, Shelikof Fm.	14,374 feet; Triassic, Kamishak Fm.
General Petroleum Great Basins No. 1	1959	Sec. 2, T27S, R48W	231 feet; Quaternary, Un-named Alluvium	11,080 feet; Mesozoic Granitic Basement
General Petroleum Great Basins No. 2	1959	Sec. 35, T25S, R50W	105 feet; Quaternary, Un-named Alluvium	8865 feet; Mesozoic Granitic Basement
Pure Canoe Bay No. 1	1961	Sec. 8, T54S, R78W	1221 feet; U. Cretaceous, Hoodoo Fm.	6642 feet; U. Jurassic, Naknek Fm.
Richfield Wide Bay Unit No. 1	1963	Sec. 5, T33S, R44W	54 feet; M. Jurassic, Kialagvik Fm.	12,568 feet; Triassic, Kamishak Fm.
Gulf Sandy River Federal No. 1	1963	Sec. 10, T46S, R70W	235 feet; Quaternary, Un-named Alluvium	13,068 feet; Oligocene, Stepovak Fm.
Great Basins Ugashik No. 1	1966	Sec. 8, T32S, R52W	142 feet; Quaternary, Un-named Alluvium	9476 feet; Oligocene, Meshik Fm.
Cities Service Painter Creek No. 1	1967	Sec. 14, T35S, R51W	394 feet; Pliocene, Milky River Fm.	7912 feet; U. Jurassic, Naknek Fm.
Pan American David River No. 1 & No. 1-A	1969	Sec. 12, T50S, R80W	70 feet; Pliocene, Milky River Fm.	13,769 feet; (U. Cretaceous, Chignik Fm.?)
Pan American Hoodo Lake No. 1	1970	Sec. 21, T50S, R76W	141 feet; Pliocene, Milky River Fm.	8048 feet; Oligocene, Stepovak Fm.
Pan American Hoodoo Lake No. 2	1970	Sec. 35, T50S, R76W	345 feet; Pliocene, Milky River Fm.	11,234 feet; U.Jurassic, Naknek Fm.
Gulf Port Heiden Unit No. 1	1972	Sec. 20, T37S, R59W	36 feet; Quaternary, Un-named Alluvium	15,015 feet; Oligocene, Meshik Fm.
Amoco Cathedral River No. 1	1974	Sec. 29, T51S, R83W	178 feet; U. Jurassic, Naknek Fm.	14,301 feet; Triassic, Kamishak Fm.
Phillips Big River No. A-1	1977	Sec 15, T49S, R68W	281 feet; Oligocene, Stepovak Fm.	11,371 feet; U. Jurassic, Naknek Fm.
Chevron Koniag No. 1	1981	Sec. 2, T38S, R49W	62 feet; U. Jurassic, Naknek Fm.	10,905 feet; Triassic, Kamishak Fm.
Amoco Becharof No. 1	1985	Sec. 15, T28S, R48W	220 feet; Quaternary, Un-named Alluvium	9022 feet; Mesozoic Granitic Basement
Offshore Wells				
Arco North Aleutian Basin COST No. 1	1983	56.724° N. Lat., 171.976° W. Long.	74 feet; Quaternary-Pleistocene, Marine Mud	17,155 feet; Eocene - Tolstoi

Table adapted from Molenaar (1996b, tbl. 1)

Table 2: Summary of Selected Extract Data, North Aleutian Shelf COST 1 Well

North Aleutian Shelf COST 1 Extract Data: Oil Show Interval 15,300-16,800 ft bkb										
Spl. No.	**Spl. Type**	**Depth/ Interval**	**SAT %**	**ARO %**	**NSO + ASPH %**	**Del^{13}C SAT**	**Del^{13}C ARO**	**Pristane/ Phytane**	**Pristane/ n-C17**	**Phytane/ n-C18**
MMSAK2003-1	Core	16006-16029 & 16701.2-16720	6.82	1.16	92.02	-28.5	-27.3	2.65	0.45	0.19
MMSAK2003-2	Cuttings	15700-16800	56.21	9.26	34.53	-28.0	-26.9	3.75	0.83	0.23
RR-1	Core	15354.6	2.6	43.9	53.5	NA	NA	9.30	1.31	0.15
RR-2	Core	15368.5	9.9	37.3	52.8	NA	NA	6.54	1.26	0.19
RR-3	Core	16009.3	19.1	33.7	47.2	NA	NA	5.00	0.71	0.15
RR-4	Core	16029	31.3	32	36.7	NA	NA	3.85	0.73	0.20
RR-5	Core	16703.7	21.4	57.4	21.2	NA	NA	2.78	0.47	0.17
RR-6	Core	16714.6	14.8	25	60.2	NA	NA	2.14	0.48	0.22
RR-7	Core	16719.6	37.4	21.6	41	NA	NA	2.27	0.36	0.16

MMSAK: Baseline-DGSI for Minerals Management Service, 2003

RR: Roberston Research for ARCO and COST Well Consortium, 1983

Thermal maturity of show interval = 0.78% to 1.04% vitrinite reflectance

Table 3: Play 1, *GRASP* Play Data Form (Minerals Management Service-Alaska Regional Office)

Basin: North Aleutian Basin
Play Number: 1
Play UAI Number: AAAAA HAB
Assessor(s): K.W. Sherwood, D. Comer, J. Larson
Play Name: Bear Lake-Stepovak (Oligocene-Miocene)
Date: December 2004

Play Area: 14,820mi^2 (9.5 million acres)
Reservoir Thermal Maturity: 0.25%-0.48% Ro
Play Depth Range: 2,000-10,000 feet (mean = 6,000 ft)
Expected Oil Gravity: 35^O API
Play Water Depth Range: 15-300 feet (mean = 250 ft)

POOLS Module (Volumes of Pools, Acre-Feet)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Prospect Area (acres)-Model Input*	3227		4249		10661	13794/11325			26750				92660
Prospect Area (acres)-Model Output**	989	3408	4394	6710	10825	13560/10075	17299	22441	26058	33526	40000	44000	88280
Fill Fraction (Fraction of Area Filled)	0.17	0.28	0.3	0.34	0.4	0.41/0.10	0.48	0.51	0.53	0.6	0.65	0.69	1
Productive Area of Pool (acres)	247	1310	1706	2638	4299	5742/4972	7173	9421	11081	14063	17500	21000	51718
Pay Thickness (feet)	3	21	29	52	98	151/180***	184	258	324	340	375	400	550

* model fit to prospect area data in *BESTFIT*
** output from *@RISK* after aggregation with fill fraction
*** original fit to Cook Inlet data

MPRO Module (Numbers of Pools)

Input Play Level Chance	0.72
Output Play Level Chance	0.72

Prospect Level Chance	0.26

Exploration Chance	0.1872

Risk Model

Play Chance	Petroleum System Factors	Prospect Chance
0.8	Seal (no regional seal over reservoir sequence)	0.5
0.9	Source (mainly Tertiary coals and Type III shales)	0.65
	Migration (regional shale seal between source & reservoir)	0.8

Fractile	F99	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Numbers of Prospects in Play	24	28	30	32	38	39/7.95	43	46	49	52	56	60	80
Numbers of Pools in Play					8	7.30/5.40	11	13	14	15	17	19	34

Zero Pools at F72.00

Minimum Number of Pools	4 (F70)
Mean Number of Pools	7.3
Maximum Number of Pools	34

POOLS/PSRK/PSUM Modules (Play Resources)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Oil Recovery Factor (bbl/acre-foot)	89	212	247	319	424	465/209	564	657	728	848	1008	1130	1516
Gas Recovery Factor (Mcfg/acre-foot)	279	578	657	812	1029	1093/399	1304	1480	1613	1832	2114	2327	2584
Gas Oil Ratio (Sol'n Gas)(cf/bbl)	56	162	195	267	376	426/220	531	638	723	871	1073	1100	1110
Condensate Yield ((bbl/Mmcfg)	1	14	17	21	25	25/7	29	32	34	35	37	39	50

Pool Size Distribution Statistics from *POOLS* (1,000 BOE): μ (mu)= 11.439 σ^2 (sigma squared)= 1.628

Random Number Generator Seed= 297,150

BOE Conversion Factor (cf/bbl)	5620
Probability Any Pool is 100% Oil	0.1
Probability Any Pool is 100% Gas	0.8

Probability Any Pool Contains Both Oil and Free Gas (Gas Cap)	0.1
Fraction of Pool Volume Gas-Bearing in Oil Pools with Gas Cap	0.9

Table 4: Play 2, *GRASP* Play Data Form (Minerals Management Service-Alaska Regional Office)

Basin: North Aleutian Basin
Play Number: 2
Play UAI Number: AAAAA HAC

Assessor(s): K.W. Sherwood, D. Comer, J. Larson
Play Name: Tolstoi (Eocene-Oligocene)

Date: December 2004

Play Area: 10,890 mi^2 (7 million acres)
Reservoir Thermal Maturity: 0.30%-1.65% Ro

Play Depth Range: 4,000 to 20,000 feet (mean = 12,000 ft)
Expected Oil Gravity: 35^{O} API
Play Water Depth Range: 15-300 feet (mean = 250 ft)

POOLS Module (Volumes of Pools, Acre-Feet)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01
Prospect Area (acres)- Model Input*	6787 (act)		6567 (fit)		11169	15925/9790			28028			
Prospect Area (acres)- Model Output**	1518	5490	6647	9321	13549	15555/8547	19702	23776	27111	33179	36000	38000
Fill Fraction (Fraction of Area Filled)	0.16	0.28	0.3	0.34	0.4	0.41/0.10	0.48	0.51	0.53	0.6	0.65	0.69
Productive Area of Pool (acres)	455	2031	2509	3631	5447	6442/3960	8173	10082	11572	14470	16000	17000
Pay Thickness (feet)	31	49	53	60	69	71/17	80	86	91	98	107	113

* model fit to prospect area data in *BESTFIT*
** output from *@RISK* after aggregation with fill fraction

MPRO Module (Numbers of Pools)

Input Play Level Chance	1
Output Play Level Chance	0.9906

Prospect Level Chance	0.1404

Exploration Chance	0.1404

Risk Model	Play Chance	Petroleum System Factors	Prospect Chance
		Minor gas pools tested (90 Mcfg/d) in Becharof Lake 1 well	
		Reservoir (impermeable through most of sequence)	0.216
		Source (mainly Tertiary coals and Type III shales)	0.65

Fractile	F99	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01
Numbers of Prospects in Play	16	20	23	30	40	43.65/19.72	51	60	65	75	90	100
Numbers of Pools in Play	1	2	2	4	6	6.13/3.60	8	9	11	12	15	18

Zero Pools at F99.06

Minimum Number of Pools	1 (F99.00)

Mean Number of Pools	6.13

Maximum Number of Pools	44

POOLS/PSRK/PSUM Modules (Play Resources)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01
Oil Recovery Factor (bbl/acre-foot)	25	57	75	113	178	203/118	266	322	364	430	480	510
Gas Recovery Factor (Mcfg/acre-foot)	18	351	433	630	921	997/497	1285	1509	1657	1933	2100	2300
Gas Oil Ratio (Sol'n Gas)(cf/bbl)	56	162	195	267	376	426/220	531	638	723	871	1073	1100
Condensate Yield ((bbl/Mmcfg)	1	14	17	21	25	25/17	29	32	34	35	37	39

Pool Size Distribution Statistics from *POOLS* (1,000 BOE): **μ (mu)=** 11.079 **σ^2 (sigma squared)=** 0.828

Random Number Generator Seed= 668,076

BOE Conversion Factor (cf/bbl)	5620
Probability Any Pool is 100% Oil	0.1
Probability Any Pool is 100% Gas	0.8

Probability Any Pool Contains Both Oil and Free Gas (Gas Cap)	0.1
Fraction of Pool Volume Gas-Bearing in Oil Pools with Gas Cap	0.9

Table 5: Play 3, *GRASP* Play Data Form (Minerals Management Service-Alaska Regional Office)

Basin: North Aleutian Basin
Play Number: 3
Play UAI Number: AAAAA HAD

Assessor(s): K.W. Sherwood, D. Comer, J. Larson
Play Name: Black Hills Uplift - Amak Basin (Eocene-Miocene)

Date: December 2004

Play Area: 6,990 mi2 (4.5 million acres)
Reservoir Thermal Maturity: 0.23%-2.00% Ro (mostly 0.23%-0.31% Ro)

Play Depth Range: 2,000-12,500 feet (mostly 2,000-5,000 feet)
Expected Oil Gravity: 35^{O} API
Play Water Depth Range: 15-700 feet (mean = 350 ft)

POOLS Module (Volumes of Pools, Acre-Feet)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Prospect Area (acres)-Model Input*	2667 (act)		2350 (fit)		5916	25230/48696			57316				133385
Prospect Area (acres)-Model Output**	509	1643	2471	4869	11201	19995/23424	25426	38733	49245	70155	78000	82000	133124
Fill Fraction (Fraction of Area Filled)	0.02	0.07	0.08	0.12	0.15	0.17/0.08	0.2	0.26	0.28	0.33	0.4	0.45	1
Productive Area of Pool (acres)	42	226	343	706	1734	3554/5194	4054	6211	8543	12700	17000	20000	56488
Pay Thickness (feet)	3	21	29	52	98	151/180*	184	258	324	340	375	400	550

* model fit to prospect area data in *BESTFIT*
** output from *@RISK* after aggregation with fill fraction
*** original fit to Cook Inlet data

MPRO Module (Numbers of Pools)

Input Play Level Chance	0.42
Output Play Level Chance	0.4128

Prospect Level Chance	0.25

Exploration Chance	0.105

Risk Model

Play Chance	Petroleum System Factors	Prospect Chance
0.6	Migration (lengthy, highly-faulted path from Tertiary source)	0.5
0.7	Seal (no regional seal over reservoir)	0.5

Fractile	F99	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Numbers of Prospects in Play	10	11	12	13	14	14.61/1.83	15	16	17	17.5	17.7	18	20
Numbers of Pools in Play						1.53/2.12	3	4	5	6	7	7	13

Zero Pools at F41.28

Minimum Number of Pools	1 (F40.00)	Mean Number of Pools	1.53	Maximum Number of Pools	13

POOLS/PSRK/PSUM Modules (Play Resources)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Oil Recovery Factor (bbl/acre-foot)	42	129	158	221	311	343/177	427	500	558	644	800	960	1300
Gas Recovery Factor (Mcfg/acre-foot)	8	441	531	686	873	888/302	1074	1194	1271	1389	1450	1550	1963
Gas Oil Ratio (Sol'n Gas)(cf/bbl)	56	162	195	267	376	426/220	531	638	723	871	1073	1100	1110
Condensate Yield ((bbl/Mmcfg)	1	14	17	21	25	25/7	29	32	34	35	37	39	50

Pool Size Distribution Statistics from *POOLS* (1,000 BOE): μ (mu)= 10.662 σ^2 (sigma squared)= 2.666

Random Number Generator Seed= 354,412

BOE Conversion Factor (cf/bbl)	5620
Probability Any Pool is 100% Oil	0.4
Probability Any Pool is 100% Gas	0.2

Probability Any Pool Contains Both Oil and Free Gas (Gas Cap)	0.4
Fraction of Pool Volume Gas-Bearing in Oil Pools with Gas Cap	0.5

Table 6: Play 4, *GRASP* Play Data Form (Minerals Management Service-Alaska Regional Office)

Basin: North Aleutian Basin
Play Number: 4
Play UAI Number: AAAAA HAE

Assessor(s): K.W. Sherwood, D. Comer, J. Larson
Play Name: Milky River Biogenic Gas (Plio-Pleistocene)

Date: December 2004

Play Area: 50,706 mi2 (32.45 million acres)
Reservoir Thermal Maturity: 0.20%-0.26% Ro

Play Depth Range: 500-3,000 feet
Expected Oil Gravity: 35^{O} API
Play Water Depth Range: 15-700 feet

POOLS Module (Volumes of Pools, Acre-Feet)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Prospect Area (acres)	Play 4 Not Quantified; Assessed to Have Negligible Undiscovered Technically Recoverable Biogenic Gas Resources												
Fill Fraction (Fraction of Area Filled)													
Productive Area of Pool (acres)													
Pay Thickness (feet)													

MPRO Module (Numbers of Pools)

Input Play Level Chance	0
Output Play Level Chance	

Prospect Level Chance	0

Exploration Chance	0

Risk Model	Play Chance	Petroleum System Factors	Prospect Chance
	0	Gas recoverability (low pressure; water production)	0
	0	Seal (unconsolidated mud)	0
	0	Reservoir (poor continuity)	0
		Charge (No Structured Fetch to Potential Traps)	

Fractile	F99	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Numbers of Prospects in Play	No Identified Prospects												
Numbers of Pools in Play													

Minimum Number of Pools	0	Mean Number of Pools	0	Maximum Number of Pools	0

POOLS/PSRK/PSUM Modules (Play Resources)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Oil Recovery Factor (bbl/acre-foot)	Play 4 Not Quantified; Assessed to Have Negligible Undiscovered Technically Recoverable Biogenic Gas Resources												
Gas Recovery Factor (Mcfg/acre-foot)													
Gas Oil Ratio (Sol'n Gas)(cf/bbl)													
Condensate Yield ((bbl/Mmcfg)													

Pool Size Distribution Statistics from *POOLS* (1,000 BOE): μ (mu)= NA σ^2 (sigma squared)= NA

Random Number Generator Seed= 255,476

BOE Conversion Factor (cf/bbl)	5620
Probability Any Pool is 100% Oil	0
Probability Any Pool is 100% Gas	1

Probability Any Pool Contains Both Oil and Free Gas (Gas Cap)	0
Fraction of Pool Volume Gas-Bearing in Oil Pools with Gas Cap	NA

Table 7: Play 5, *GRASP* Play Data Form (Minerals Management Service-Alaska Regional Office)

Basin: North Aleutian Basin
Play Number: 5
Play UAI Number: AAAAA HAF

Assessor(s): K.W. Sherwood, D. Comer, J. Larson
Play Name: Mesozoic Deformed Sedimentary Rocks (Triassic-Cretaceous)

Date: December 2004

Play Area: 5,040 mi^2 (3.2 million acres)
Reservoir Thermal Maturity: 0.6% to 2.0% Ro

Play Depth Range: 2,000 to 15,000 feet (mean = 8,000 ft)
Expected Oil Gravity: 35^O API
Play Water Depth Range: 15-700 feet (mean = 350 ft)

POOLS Module (Volumes of Pools, Acre-Feet)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Prospect Area (acres)-Model Input*	7000		10415		39621	68223/95634			150718				147000
Prospect Area (acres)-Model Output**	1024	6793	9768	18402	35028	44767/33824	63167	82991	97444	116497	120000	125000	146550
Fill Fraction (Fraction of Area Filled)	0.03	0.05	0.06	0.08	0.1	0.11/0.05	0.13	0.16	0.17	0.2	0.23	0.25	0.5
Productive Area of Pool (acres)	93	595	902	1736	3478	5004/4766	6596	9087	10687	13683	17000	19000	43443
Pay Thickness (feet)	18	47	55	73	100	113/60	137	162	182	215	260	295	564

* model fit to prospect area data in *BESTFIT*
** output from @*RISK* after aggregation with fill fraction

MPRO Module (Numbers of Pools)

Input Play Level Chance	0.4
Output Play Level Chance	0.3925

Prospect Level Chance	0.2304

Exploration Chance	0.09216

Risk Model	Play Chance	Petroleum System Factors	Prospect Chance
	0.5	Reservoir (widespread early zeolitization)	0.6
	0.8	Timing of migration (if early, no traps; if late, no porosity)	0.6
		Trap integrity (erosional breaching and fault disruption)	0.8
		Preservation (denudation to shallow depths/biodegradation of petroleum accumulations in Mesozoic rocks)	0.8

Fractile	F99	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Numbers of Prospects in Play	11	12	13	14	15	15.56/1.76	16	17	17.5	18	18.5	19	22
Numbers of Pools in Play						1.43/2.06	3	4	5	6	7	7	13

Zero Pools at F39.25

Minimum Number of Pools	2 (F35)	Mean Number of Pools	1.43	Maximum Number of Pools	13

POOLS/PSRK/PSUM Modules (Play Resources)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Oil Recovery Factor (bbl/acre-foot)	1	17	21	30	43	47/25	59	69	77	89	105	120	218
Gas Recovery Factor (Mcfg/acre-foot)	No Free Gas												
Gas Oil Ratio (Sol'n Gas)(cf/bbl)	56	162	195	267	376	426/220	531	638	723	871	1073	1100	1110
Condensate Yield ((bbl/Mmcfg)	No Free Gas												

Pool Size Distribution Statistics from *POOLS* (1,000 BOE): μ (mu)= 9.564 σ^2 (sigma squared)= 1.609

Random Number Generator Seed= 458,844

BOE Conversion Factor (cf/bbl)	5620
Probability Any Pool is 100% Oil	1
Probability Any Pool is 100% Gas	0

Probability Any Pool Contains Both Oil and Free Gas (Gas Cap)	0
Fraction of Pool Volume Gas-Bearing in Oil Pools with Gas Cap	0

Table 8: Play 6, *GRASP* Play Data Form (Minerals Management Service-Alaska Regional Office)

Basin: North Aleutian Basin
Play Number: 6
Play UAI Number: AAAAA HAG

Assessor(s): K.W. Sherwood, D. Comer, J. Larson
Play Name: Mesozoic Buried Granitic Hills (Jurassic-Cretaceous Magmatic Rocks)
Date: December 2004

Play Area: 46,810 mi^2 (30 million acres)
Reservoir Thermal Maturity: Fractured Granite Reservoir (0.34%-0.60% Ro projected from depth range)

Play Depth Range: 6,000-12,000 feet (mean = 9,000 ft)
Expected Oil Gravity: 35° API
Play Water Depth Range: 15-400 feet (mean = 300 ft)

POOLS Module (Volumes of Pools, Acre-Feet)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Prospect Area (acres)-Model Input*	4000		5537		13119	16454/12456			31082				92660
Prospect Area (acres)-Model Output**	1281	4235	5538	8339	13240	16493/11905	21097	27029	31445	39296	46000	50000	90285
Fill Fraction (Fraction of Area Filled)	0.02	0.07	0.08	0.12	0.15	0.17/0.08	0.2	0.25	0.28	0.33	0.4	0.45	1
Productive Area of Pool (acres)	108	523	696	1157	2008	2838/2846	3473	4615	5690	7550	9600	12000	30768
Pay Thickness (feet)	88	115	142	184	254	276/116	351	405	435	505	547	561	575

* model fit to prospect area data in *BESTFIT*
** output from *@RISK* after aggregation with fill fraction

MPRO Module (Numbers of Pools)

Input Play Level Chance	0.35
Output Play Level Chance	0.3428

Prospect Level Chance	0.117

Exploration Chance	0.04095

Risk Model	Play Chance	Petroleum System Factors	Prospect Chance
	0.35	Reservoir (granites fractured with weathering enhancement)	0.3
		Source (mainly Tertiary coals and Type III shales)	0.65
		Migration (fault migration paths must both transmit [deep] and seal [shallow])	0.6

Fractile	F99	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Numbers of Prospects in Play	24	26	27	29	32	31.99/3.62	33	34	36	38	40	42	48
Numbers of Pools in Play						1.31/2.10	3	4	5	6	7	8	15

Zero Pools at F34.28

Minimum Number of Pools	2 (F30)
Mean Number of Pools	1.31
Maximum Number of Pools	15

POOLS/PSRK/PSUM Modules (Play Resources)

Fractile	F100	F95	F90	F75	F50	Mean/Std. Dev.	F25	F15	F10	F05	F02	F01	F00
Oil Recovery Factor (bbl/acre-foot)	5	31	43	81	158	228/191	310	444	580	610	680	710	1000
Gas Recovery Factor (Mcfg/acre-foot)	3	27	38	73	146	218/193	290	420	541	620	695	730	1200
Gas Oil Ratio (Sol'n Gas)(cf/bbl)	56	162	195	267	376	426/220	531	638	723	871	1073	1100	1110
Condensate Yield ((bbl/Mmcfg)	1	14	17	21	25	25/7	29	32	34	35	37	39	50

Pool Size Distribution Statistics from *POOLS* (1,000 BOE): μ (mu)= 9.814 σ^2 (sigma squared)= 2.170

Random Number Generator Seed= 599,626

BOE Conversion Factor (cf/bbl)	5620
Probability Any Pool is 100% Oil	0.1
Probability Any Pool is 100% Gas	0.8

Probability Any Pool Contains Both Oil and Free Gas (Gas Cap)	0.1
Fraction of Pool Volume Gas-Bearing in Oil Pools with Gas Cap	0.9

Table 9: DATA SHEET FOR @*RISK* MODELS FOR OIL AND GAS RECOVERY FACTORS FOR PLAY 1

Assessment Area: North Aleutian Basin **Date: December 2003**
Play: 1 - Bear Lake-Stepovak (Oligocene-Miocene)
Assessors: K.W. Sherwood, D. Comer, J. Larson

Oil Recovery Factor (barrels recoverable per acre-foot)

Input Constant and @RISK Equation: "=7758.38*a2*(1-b2)*c2*d2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	**Porosity**	0.314705	0.053704	0.010	0.414	***T-Normal***
b	**Water Saturation**	0.343750	0.059615	0.030	0.700	***T-L-Normal***
c	**Oil Recovery Efficiency**	0.346810	0.057227	0.050	0.650	***T-L-Normal***
d	**Oil Volume Factor [1/FVF]**	0.793075	0.094369	0.500	1.000	***T-Normal***

Dependency or Correlation Matrix for Oil Recovery Factor Calculation

		Porosity	Water Saturation	Oil Recovery Efficiency	Oil Volume Factor [1/FVF]
a	**Porosity**	1	-0.9	0.9	0
b	**Water Saturation**	-0.9	1	-0.8	0
c	**Oil Recovery Efficiency**	0.9	-0.8	1	0
d	**Oil Volume Factor [1/FVF]**	0	0	0	1

Gas Recovery Factor (mcfg recoverable per acre-foot)

Input Constant and @RISK Equation: "=1537.8*a2*(1-b2)*c2*d2*e2*(1-f2)/g2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	**Porosity**	0.314705	0.053704	0.100	0.414	***T-Normal***
b	**Water Saturation**	0.343750	0.059615	0.030	0.700	***T-L-Normal***
c	**Pressure (psi)**	2609.400000	438.190000	878.000	4390.000	***T-Normal***
d	**Gas FVF (1/Z)**	1.079112	0.028545	0.960	1.200	***T-Normal***
e	**Gas Recovery Efficiency**	0.797408	0.038362	0.650	0.950	***T-Normal***
f	**Gas Shrinkage Factor***	0.126230	0.161910	0.000	1.000	***T-L-Normal***
g	**Temperature (ºRankine)**	594.101000	18.089000	525.000	664.000	***T-Normal***

Dependency or Correlation Matrix for Gas Recovery Factor Calculation

		Porosity	Water Saturation	Pressure (psi)	Gas FVF (1/Z)	Gas Recovery Efficiency	Gas Shrinkage Factor*	Temperature (ºRankine)
a	**Porosity**	1	-0.9	0	0	0.8	0	0
b	**Water Saturation**	-0.9	1	0	0	-0.6	0	0
c	**Pressure (psi)**	0	0	1	0	0	0	0.95
d	**Gas FVF (1/Z)**	0	0	0	1	0	0	0
e	**Gas Recovery Efficiency**	0.8	-0.6	0	0	1	0	0
f	**Gas Shrinkage Factor***	0	0	0	0	0	1	0
g	**Temperature (ºRankine)**	0	0	0.95	0	0	0	1

** Includes gas volume lost to condensate drop-out and content of inert gases (Nitrogen, Oxygen, Argon, Hydrogen Sulfide, Carbon Dioxide, and Helium)*

Table 10: DATA SHEET FOR @*RISK* MODELS FOR OIL AND GAS RECOVERY FACTORS FOR PLAY 2

Assessment Area: North Aleutian Basin **Date: December 2003**
Play: 2 - Tolstoi (Eocene-Oligocene)
Assessors: K.W. Sherwood, D. Comer, J. Larson

Oil Recovery Factor (barrels recoverable per acre-foot)

Input Constant and @RISK Equation: "=7758.38*a2*(1-b2)*c2*d2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity	0.213296	0.080897	0.100	0.335	*T-Normal*
b	Water Saturation	0.452190	0.051720	0.060	0.700	*T-L-Normal*
c	Oil Recovery Efficiency	0.254150	0.060354	0.050	0.650	*T-L-Normal*
d	Oil Volume Factor [1/FVF]	0.793075	0.094369	0.500	1.000	*T-Normal*

Dependency or Correlation Matrix for Oil Recovery Factor Calculation

		Porosity	Water Saturation	Oil Recovery Efficiency	Oil Volume Factor [1/FVF]
a	Porosity	1	-0.9	0.9	0
b	Water Saturation	-0.9	1	-0.8	0
c	Oil Recovery Efficiency	0.9	-0.8	1	0
d	Oil Volume Factor [1/FVF]	0	0	0	1

Gas Recovery Factor (mcfg recoverable per acre-foot)

Input Constant and @RISK Equation: "=1537.8*a2*(1-b2)*c2*d2*e2*(1-f2)/g2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity	0.213296	0.080897	0.100	0.335	*T-Normal*
b	Water Saturation	0.452190	0.051720	0.060	0.700	*T-L-Normal*
c	Pressure (psi)	7432.000000	1388.500000	1756.000	13000.000	*T-Normal*
d	Gas FVF (1/Z)	0.935260	0.107430	0.500	1.360	*T-Normal*
e	Gas Recovery Efficiency	0.603219	0.051470	0.400	0.800	*T-Normal*
f	Gas Shrinkage Factor*	0.126230	0.161910	0.000	1.000	*T-L-Normal*
g	Temperature (ºRankine)	700.150000	32.112000	563.000	834.000	*T-Normal*

Dependency or Correlation Matrix for Gas Recovery Factor Calculation

		Porosity	Water Saturation	Pressure (psi)	Gas FVF (1/Z)	Gas Recovery Efficiency	Gas Shrinkage Factor*	Temperature (ºRankine)
a	Porosity	1	-0.9	0	0	0.8	0	0
b	Water Saturation	-0.9	1	0	0	-0.6	0	0
c	Pressure (psi)	0	0	1	0	0	0	0.95
d	Gas FVF (1/Z)	0	0	0	1	0	0	0
e	Gas Recovery Efficiency	0.8	-0.6	0	0	1	0	0
f	Gas Shrinkage Factor*	0	0	0	0	0	1	0
g	Temperature (ºRankine)	0	0	0.95	0	0	0	1

** Includes gas volume lost to condensate drop-out and content of inert gases (Nitrogen, Oxygen, Argon, Hydrogen Sulfide, Carbon Dioxide, and Helium)*

Table 11: DATA SHEET FOR @*RISK* MODELS FOR OIL AND GAS RECOVERY FACTORS FOR PLAY 3

Assessment Area: North Aleutian Basin **Date: December 2003**
Play: 3 - Black Hills Uplift - Amak Basin (Eocene-Miocene)
Assessors: K.W. Sherwood, D. Comer, J. Larson

Oil Recovery Factor (barrels recoverable per acre-foot)

Input Constant and @RISK Equation: "=7758.38*a2*(1-b2)*c2*d2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity	0.314705	0.053704	0.100	0.414	*T-Normal*
b	Water Saturation	0.343750	0.059615	0.030	0.700	*T-L-Normal*
c	Oil Recovery Efficiency	0.254150	0.060354	0.050	0.650	*T-L-Normal*
d	Oil Volume Factor [1/FVF]	0.793075	0.094369	0.500	1.000	*T-Normal*

Dependency or Correlation Matrix for Oil Recovery Factor Calculation

		Porosity	Water Saturation	Oil Recovery Efficiency	Oil Volume Factor [1/FVF]
a	Porosity	1	-0.9	0.9	0
b	Water Saturation	-0.9	1	-0.8	0
c	Oil Recovery Efficiency	0.9	-0.8	1	0
d	Oil Volume Factor [1/FVF]	0	0	0	1

Gas Recovery Factor (mcfg recoverable per acre-foot)

Input Constant and @RISK Equation: "=1537.8*a2*(1-b2)*c2*d2*e2*(1-f2)/g2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity	0.314709	0.053704	0.100	0.414	*T-Normal*
b	Water Saturation	0.343750	0.059615	0.030	0.700	*T-L-Normal*
c	Pressure (psi)	1502.800000	155.320000	878.000	2195.000	*T-Normal*
d	Gas FVF (1/Z)	1.450000	0.015716	1.370	1.520	*T-Normal*
e	Gas Recovery Efficiency	0.797408	0.038362	0.650	0.950	*T-Normal*
f	Gas Shrinkage Factor*	0.126230	0.161910	0.000	1.000	*T-L-Normal*
g	Temperature (ºRankine)	552.479700	6.622400	525.000	581.000	*T-Normal*

Dependency or Correlation Matrix for Gas Recovery Factor Calculation

		Porosity	Water Saturation	Pressure (psi)	Gas FVF (1/Z)	Gas Recovery Efficiency	Gas Shrinkage Factor*	Temperature (ºRankine)
a	Porosity	1	-0.9	0	0	0.8	0	0
b	Water Saturation	-0.9	1	0	0	-0.6	0	0
c	Pressure (psi)	0	0	1	0	0	0	0.95
d	Gas FVF (1/Z)	0	0	0	1	0	0	0
e	Gas Recovery Efficiency	0.8	-0.6	0	0	1	0	0
f	Gas Shrinkage Factor*	0	0	0	0	0	1	0
g	Temperature (ºRankine)	0	0	0.95	0	0	0	1

** Includes gas volume lost to condensate drop-out and content of inert gases (Nitrogen, Oxygen, Argon, Hydrogen Sulfide, Carbon Dioxide, and Helium)*

Table 12: DATA SHEET FOR @*RISK* MODELS FOR OIL AND GAS RECOVERY FACTORS FOR PLAY 5

Assessment Area: North Aleutian Basin **Date: December 2003**
Play: 5 - Mesozoic Deformed Sedimentary Rocks (Triassic-Cretaceous)
Assessors: K.W. Sherwood, D. Comer, J. Larson

Oil Recovery Factor (barrels recoverable per acre-foot)

Input Constant and @RISK Equation: "=7758.38*a2*(1-b2)*c2*d2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity	0.075664	0.019040	0.000	0.150	*T-Normal*
b	Water Saturation	0.531180	0.042925	0.400	0.700	*T-L-Normal*
c	Oil Recovery Efficiency	0.206220	0.033169	0.100	0.400	*T-L-Normal*
d	Oil Volume Factor [1/FVF]	0.793075	0.094367	0.556	0.901	*T-Normal*

Dependency or Correlation Matrix for Oil Recovery Factor Calculation

		Porosity	Water Saturation	Oil Recovery Efficiency	Oil Volume Factor [1/FVF]
a	Porosity	1	-0.9	0.9	0
b	Water Saturation	-0.9	1	-0.8	0
c	Oil Recovery Efficiency	0.9	-0.8	1	0
d	Oil Volume Factor [1/FVF]	0	0	0	1

Gas Recovery Factor (mcfg recoverable per acre-foot)

Input Constant and @RISK Equation: "=1537.8*a2*(1-b2)*c2*d2*e2*(1-f2)/g2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity					*T-Normal*
b	Water Saturation					*T-L-Normal*
c	Pressure (psi)					*T-Normal*
d	Gas FVF (1/Z)		No Free Gas			*T-Normal*
e	Gas Recovery Efficiency					*T-Normal*
f	Gas Shrinkage Factor*					*T-L-Normal*
g	Temperature (ºRankine)					*T-Normal*

Dependency or Correlation Matrix for Gas Recovery Factor Calculation

		Porosity	Water Saturation	Pressure (psi)	Gas FVF (1/Z)	Gas Recovery Efficiency	Gas Shrinkage Factor*	Temperature (ºRankine)
a	Porosity	1	-0.9	0	0	0.8	0	0
b	Water Saturation	-0.9	1	0	0	-0.6	0	0
c	Pressure (psi)	0	0	1	0	0	0	0.95
d	Gas FVF (1/Z)	0	0	0	1	0	0	0
e	Gas Recovery Efficiency	0.8	-0.6	0	0	1	0	0
f	Gas Shrinkage Factor*	0	0	0	0	0	1	0
g	Temperature (ºRankine)	0	0	0.95	0	0	0	1

** Includes gas volume lost to condensate drop-out and content of inert gases (Nitrogen, Oxygen, Argon, Hydrogen Sulfide, Carbon Dioxide, and Helium)*

Table 13: DATA SHEET FOR @RISK MODELS FOR OIL AND GAS RECOVERY FACTORS FOR PLAY 6

Assessment Area: North Aleutian Basin **Date: December 2003**
Play: 6 - Mesozoic Buried Granitic Hills (Jurassic-Cretaceous Magmatic Rocks)
Assessors: K.W. Sherwood, D. Comer, J. Larson

Oil Recovery Factor (barrels recoverable per acre-foot)

Input Constant and @RISK Equation: "=7758.38*a2*(1-b2)*c2*d2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity	Oil and Gas Yields From Literature Compilation and Analysis by Paul Post and Jesse Hunt of U.S. Minerals Management Service, Gulf of Mexico OCS Region				*T-Normal*
b	Water Saturation					*T-L-Normal*
c	Oil Recovery Efficiency					*T-L-Normal*
d	Oil Volume Factor [1/FVF]					*T-Normal*

Dependency or Correlation Matrix for Oil Recovery Factor Calculation

		Porosity	Water Saturation	Oil Recovery Efficiency	Oil Volume Factor [1/FVF]
a	Porosity	1	-0.9	0.9	0
b	Water Saturation	-0.9	1	-0.8	0
c	Oil Recovery Efficiency	0.9	-0.8	1	0
d	Oil Volume Factor [1/FVF]	0	0	0	1

Gas Recovery Factor (mcfg recoverable per acre-foot)

Input Constant and @RISK Equation: "=1537.8*a2*(1-b2)*c2*d2*e2*(1-f2)/g2"

		Mean	Standard Deviation	Minimum	Maximum	f(x) Type
a	Porosity	Oil and Gas Yields From Literature Compilation and Analysis by Paul Post and Jesse Hunt of U.S. Minerals Management Service, Gulf of Mexico OCS Region				*T-Normal*
b	Water Saturation					*T-L-Normal*
c	Pressure (psi)					*T-Normal*
d	Gas FVF (1/Z)					*T-Normal*
e	Gas Recovery Efficiency					*T-Normal*
f	Gas Shrinkage Factor*					*T-L-Normal*
g	Temperature (ºRankine)					*T-Normal*

Dependency or Correlation Matrix for Gas Recovery Factor Calculation

		Porosity	Water Saturation	Pressure (psi)	Gas FVF (1/Z)	Gas Recovery Efficiency	Gas Shrinkage Factor*	Temperature (ºRankine)
a	Porosity	1	-0.9	0	0	0.8	0	0
b	Water Saturation	-0.9	1	0	0	-0.6	0	0
c	Pressure (psi)	0	0	1	0	0	0	0.95
d	Gas FVF (1/Z)	0	0	0	1	0	0	0
e	Gas Recovery Efficiency	0.8	-0.6	0	0	1	0	0
f	Gas Shrinkage Factor*	0	0	0	0	0	1	0
g	Temperature (ºRankine)	0	0	0.95	0	0	0	1

** Includes gas volume lost to condensate drop-out and content of inert gases (Nitrogen, Oxygen, Argon, Hydrogen Sulfide, Carbon Dioxide, and Helium)*

Table 14: 2006 Assessment Results for North Aleutian Basin OCS Planning Area

Risked, Undiscovered, Technically Recoverable Oil and Gas Resources

		BOE Resources (Mmboe)			Oil Resources (Mmbo)			Gas-Condensate Liquid Resources (Mmbo)			Nonassociated* Gas Resources (Tcfg)			Solution Gas Resources (Tcfg)			Total Liquid Resources (Mmbo)			Total Gas Resources (Tcfg)			Ratio of Gas to Oil ***
Play Number	**Play Name**	**F95**	**Mean**	**F05**	**F95**	**Mean**	**F05**	**F95**	**Mean**	**F05**	**F95**	**Mean**	**F05**	**F95**	**Mean**	**F05**	**F95**	**Mean**	**F05**	**F95**	**Mean**	**F05**	
1	**Bear Lake-Stepovak** (Oligocene-Miocene)	0	1400	3749	0	271	828	0	136	349	0.000	5.473	14.131	0.000	0.113	0.330	0	406	1176	0.000	5.586	14.461	71/29
2	**Tolstoi** (Eocene-Oligocene)	91	568	1293	9	62	139	10	61	141	0.401	2.476	5.640	0.003	0.025	0.053	19	123	280	0.404	2.501	5.693	78/22
3	**Black Hills Uplift-Amak Basin** (Eocene-Miocene)	0	210	1077	0	149	706	0	6	38	0.000	0.249	1.588	0.000	0.063	0.289	0	155	743	0.000	0.312	1.877	26/74
4	**Milky River Biogenic Gas** (Plio-Pleistocene)	Play 4 Assessed with Negligible Resources																					
5	**Mesozoic Deformed Sedimentary Rocks** (Triassic-Cretaceous)	0	41	197	0	38	183	0	0	0	0.000	0.000	0.000	0.000	0.017	0.079	0	38	183	0.000	0.017	0.079	07/93
6	**Mesozoic Buried Granitic Hills** (Jurassic-Cretaceous Magmatic Rocks)	0	67	330	0	26	93	0	5	29	0.000	0.195	1.128	0.000	0.010	0.041	0	30	122	0.000	0.206	1.169	55/45
Sum of All Plays**		**91**	**2287**	**6647**	**9**	**545**	**1948**	**10**	**208**	**556**	**0.401**	**8.393**	**22.487**	**0.003**	**0.229**	**0.791**	**19**	**753**	**2505**	**0.404**	**8.622**	**23.278**	**67/33**

* Free gas, occurring as gas caps associated with oil and as oil-free gas pools.

** Values as reported out of *Basin Level Analysis-Geologic Scenario* aggregation module in *GRASP*, *"Volume Ordered"* aggregation option. Total liquids and total gas values were obtained by summing resource values for means and fractiles of component commodities. Play resource values are rounded and may not sum to totals reported from basin aggregation.

*** Calculated as the ratio of total gas to total liquids at mean values (1 barrel of liquids = 5,620 cubic feet of gas at standard conditions). Given as ratio between fractions summing to 100.

BOE, total energy, in millions of barrels (5,620 cubic feet of gas per barrel of oil, energy-equivalent); Mmbo, millions of barrels of oil or liquids; Tcfg, trillions of cubic feet of natural gas

Table 15: Conditional (Unrisked) Recoverable Pool Size Results for Play 1 - Bear Lake-Stepovak (Oligocene-Miocene)

Classification and Size			Pool Count Statistics				Pool Type Counts		
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Pool Count	Percentage	Trial Average	Trials with Pool Average	Mixed Pool Count	Oil Pool Count	Gas Pool Count
1	0.0312	0.0625	0	0	0	0	0	0	0
2	0.0625	0.125	0	0	0	0	0	0	0
3	0.125	0.25	4	0.005479	0.0004	0.000556	0	0	4
4	0.25	0.5	8	0.010958	0.0008	0.001111	0	0	8
5	0.5	1	53	0.072596	0.0053	0.007363	4	5	44
6	1	2	207	0.283534	0.0207	0.028758	11	5	191
7	2	4	604	0.827318	0.0604	0.083912	49	24	531
8	4	8	1630	2.232663	0.163	0.226452	146	73	1411
9	8	16	3893	5.332366	0.3893	0.540845	378	173	3342
10	16	32	7896	10.815401	0.7896	1.096971	741	442	6713
11	32	64	12596	17.253139	1.2596	1.749931	1231	754	10611
12	64	128	15882	21.754078	1.5882	2.206446	1584	1249	13049
13	128	256	14566	19.951511	1.4566	2.023618	1497	1508	11561
14	256	512	9798	13.42063	0.9798	1.361211	1094	1476	7228
15	512	1024	4321	5.918611	0.4321	0.600306	434	902	2985
16	1024	2048	1282	1.755996	0.1282	0.178105	101	448	733
17	2048	4096	238	0.325996	0.0238	0.033065	23	98	117
18	4096	8192	28	0.038352	0.0028	0.00389	1	20	7
19	8192	16384	1	0.00137	0.0001	0.000139	0	1	0
20	16384	32768	0	0	0	0	0	0	0
21	32768	65536	0	0	0	0	0	0	0
22	65536	131072	0	0	0	0	0	0	0
23	131072	262144	0	0	0	0	0	0	0
24	262144	524288	0	0	0	0	0	0	0
25	524288	1048576	0	0	0	0	0	0	0
Not Classified			0	0	0	0	0	0	0
		Totals =	73007	100.000000	7.3007	10.142679	7294	7178	58535

Number of Pools Not Classified = 0
Number of Trials with Pools = 7198
Number of Pools Below Class 1 = 0
Number of Pools Above Class 25 = 0

Table 16: Conditional (Unrisked) Recoverable Sizes of Ranked Pools for Play 1 - Bear Lake-Stepovak (Oligocene-Miocene)

Pool Size in Millions of Barrels of Oil, Energy-Equivalent							
Pool Rank	F95	F75	F50	Mean	F25	F05	F01
1	187	370	591	827	899	2495	3464
2	106	211	321	378	475	816	1255
3	65	139	214	245	317	542	738
4	41	97	153	174	227	382	543
5	26	69	113	130	172	290	404
6	17	50	86	99	133	227	319
7	12	38	67	78	106	184	260
8	9	29	53	63	86	153	215
9	7	23	44	53	72	129	182
10	6	19	36	44	61	110	157
11	5	16	31	38	53	96	138
12	4	14	27	34	46	85	123
13	4	13	24	30	41	76	111
14	4	12	22	27	37	69	101
15	3	11	20	25	34	64	93
16	3	10	18	23	31	59	125
17	3	9	17	22	29	56	81
18	3	9	16	21	28	53	77
19	2	8	16	20	27	50	72
20	2	8	15	19	25	48	69
21	2	8	15	18	25	46	65
22	2	8	14	17	24	43	61
23	2	7	14	17	23	41	58
24	2	7	13	16	21	39	55
25	2	7	12	15	20	37	51
26	2	6	12	14	19	34	48
27	2	6	11	13	18	32	45
28	1	6	10	12	17	30	42
29	1	5	10	12	16	28	39
30	1	5	9	11	15	26	36
31	1	5	9	10	14	24	33
32	1	4	8	9	13	22	29
33	1	4	7	8	11	19	26
34	1	3	5	6	9	15	22

Maximum Number of Pools = 34

Table 17: Conditional (Unrisked) Recoverable Pool Size Results for Play 2 - Tolstoi (Eocene-Oligocene)

Classification and Size			Pool Count Statistics				Pool Type Counts		
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Pool Count	Percentage	Trial Average	Trials with Pool Average	Mixed Pool Count	Oil Pool Count	Gas Pool Count
1	0.0312	0.0625	0	0	0	0	0	0	0
2	0.0625	0.125	0	0	0	0	0	0	0
3	0.125	0.25	2	0.003261	0.0002	0.000202	0	0	2
4	0.25	0.5	3	0.004892	0.0003	0.000303	0	0	3
5	0.5	1	34	0.055441	0.0034	0.003433	1	0	33
6	1	2	105	0.171216	0.0105	0.010601	2	3	100
7	2	4	310	0.505495	0.031	0.031297	12	13	285
8	4	8	944	1.539315	0.0944	0.095305	68	80	796
9	8	16	2646	4.314646	0.2646	0.267138	225	333	2088
10	16	32	8004	13.05156	0.8004	0.808077	780	819	6405
11	32	64	16546	26.9804	1.6546	1.670469	1662	1633	13251
12	64	128	18963	30.921633	1.8963	1.914488	1920	1780	15263
13	128	256	10866	17.718422	1.0866	1.097022	1033	1123	8710
14	256	512	2633	4.293448	0.2633	0.265825	252	352	2029
15	512	1024	265	0.432117	0.0265	0.026754	23	39	203
16	1024	2048	5	0.008153	0.0005	0.000505	0	1	4
17	2048	4096	0	0	0	0	0	0	0
18	4096	8192	0	0	0	0	0	0	0
19	8192	16384	0	0	0	0	0	0	0
20	16384	32768	0	0	0	0	0	0	0
21	32768	65536	0	0	0	0	0	0	0
22	65536	131072	0	0	0	0	0	0	0
23	131072	262144	0	0	0	0	0	0	0
24	262144	524288	0	0	0	0	0	0	0
25	524288	1048576	0	0	0	0	0	0	0
Not Classified			0	0	0	0	0	0	0
		Totals =	61326	100	6.1326	6.191419	5978	6176	49172

Number of Pools Not Classified = 0
Number of Trials with Pools = 9905
Number of Pools Below Class 1 = 0
Number of Pools Above Class 25 = 0

Table 18: Conditional (Unrisked) Recoverable Sizes of Ranked Pools for Play 2 - Tolstoi (Eocene-Oligocene)

Pool Size in Millions of Barrels of Oil, Energy-Equivalent *							
Pool Rank	F95	F75	F50	Mean	F25	F05	F01
1	61	122	181	208	258	467	686
2	34	75	113	124	159	248	330
3	22	54	83	90	117	182	241
4	16	41	65	71	94	146	191
5	13	34	54	59	78	122	161
6	11	29	46	51	68	107	142
7	9	25	41	45	60	96	129
8	8	22	37	41	54	88	119
9	7	21	34	38	50	82	112
10	6	19	31	35	47	79	107
11	6	18	30	34	45	76	104
12	6	17	29	33	44	75	100
13	5	16	28	32	43	74	97
14	5	16	28	32	44	74	94
15	5	16	28	32	45	73	92
16	5	17	29	33	46	71	89
17	6	17	30	33	46	69	85
18	6	18	31	33	46	67	82
19	6	18	31	32	45	64	78
20	6	19	30	32	43	62	75
21	6	18	29	30	41	59	72
22	6	17	28	29	39	56	68
23	6	16	26	27	37	53	65
24	5	15	25	26	35	51	62
25	5	14	24	25	33	48	59
26	5	14	22	23	31	46	56
27	4	13	21	22	30	44	54
28	4	12	20	21	28	42	52
29	3	11	19	20	27	40	49
30	3	11	18	19	26	38	47
31	3	10	17	18	25	37	45
32	3	9	16	17	23	35	53
33	2	9	15	16	22	34	42
34	2	8	14	16	22	32	40
35	2	8	14	15	21	31	39
36	2	8	13	14	20	30	37
37	2	7	13	14	19	28	35
38	2	7	12	13	18	27	34
39	2	7	12	12	17	26	32
40	1	6	11	12	16	24	30
41	1	6	10	11	15	23	28
42	1	5	9	10	14	21	26
43	1	5	8	9	12	19	24
44	1	3	6	7	10	16	21
Maximum Number of Pools = 44							

** ranked as reported in PSRK module of GRASP*

Table 19: Conditional (Unrisked) Recoverable Pool Size Results for Play 3 - Black Hills Uplift-Amak Basin (Eocene-Miocene)

Classification and Size			Pool Count Statistics				Pool Type Counts		
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Pool Count	Percentage	Trial Average	Trials with Pool Average	Mixed Pool Count	Oil Pool Count	Gas Pool Count
1	0.0312	0.0625	3	0.019578	0.0003	0.000727	2	1	0
2	0.0625	0.125	4	0.026105	0.0004	0.000969	1	2	1
3	0.125	0.25	18	0.11747	0.0018	0.004362	5	4	9
4	0.25	0.5	60	0.391568	0.006	0.014538	25	16	19
5	0.5	1	140	0.913659	0.014	0.033923	51	49	40
6	1	2	320	2.088364	0.032	0.077538	126	104	90
7	2	4	624	4.072309	0.0624	0.151199	226	194	204
8	4	8	1139	7.43327	0.1139	0.275987	464	373	302
9	8	16	1744	11.381583	0.1744	0.422583	695	647	402
10	16	32	2362	15.414736	0.2362	0.572329	937	906	519
11	32	64	2521	16.452393	0.2521	0.610855	1026	999	496
12	64	128	2440	15.923775	0.244	0.591228	973	1017	450
13	128	256	1889	12.327873	0.1889	0.457717	787	811	291
14	256	512	1182	7.713894	0.1182	0.286407	464	571	147
15	512	1024	569	3.713372	0.0569	0.137873	226	305	38
16	1024	2048	242	1.579325	0.0242	0.058638	82	141	19
17	2048	4096	58	0.378516	0.0058	0.014054	16	40	2
18	4096	8192	6	0.039157	0.0006	0.001454	1	5	0
19	8192	16384	1	0.006526	0.0001	0.000242	0	1	0
20	16384	32768	0	0	0	0	0	0	0
21	32768	65536	0	0	0	0	0	0	0
22	65536	131072	0	0	0	0	0	0	0
23	131072	262144	0	0	0	0	0	0	0
24	262144	524288	0	0	0	0	0	0	0
25	524288	1048576	0	0	0	0	0	0	0
Not Classified			1	0.006526	0.0001	0.000242	0	0	1
		Totals =	15323	99.999992	1.5323	3.712866	6107	6186	3029

Number of Pools Not Classified = 1
Number of Trials with Pools = 4127
Number of Pools Below Class 1 =1
Number of Pools Above Class 25 = 0

Table 20: Conditional (Unrisked) Recoverable Sizes of Ranked Pools for Play 3 - Black Hills Uplift-Amak Basin (Eocene-Miocene)

Pool Size in Millions of Barrels of Oil, Energy-Equivalent							
Pool Rank	F95	F75	F50	Mean	F25	F05	F01
1	19.7	83	195	378	444	1302	3328
2	5.8	27	64	110	136	365	667
3	2.7	13	31	52	65	169	312
4	1.7	7	18	30	38	98	176
5	1.2	5	12	20	25	64	114
6	1.0	4	9	14	18	45	80
7	0.8	3	7	11	14	34	60
8	0.7	3	6	9	11	27	47
9	0.6	2	5	7	9	22	38
10	0.5	2	4	6	8	19	32
11	0.4	2	4	5	7	16	27
12	0.4	2	3	5	6	14	23
13	0.3	1	3	4	5	11	19

Maximum Number of Pools = 13

Table 21: Conditional (Unrisked) Recoverable Pool Size Results for Play 5 - Mesozoic Deformed Sedimentary Rocks (Triassic-Cretaceous)

Classification and Size			Pool Count Statistics				Pool Type Counts		
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Pool Count	Percentage	Trial Average	Trials with Pool Average	Mixed Pool Count	Oil Pool Count	Gas Pool Count
1	0.0312	0.0625	5	0.034899	0.0005	0.001275	0	5	0
2	0.0625	0.125	7	0.048859	0.0007	0.001784	0	7	0
3	0.125	0.25	32	0.223355	0.0032	0.008157	0	32	0
4	0.25	0.5	101	0.704963	0.0101	0.025746	0	101	0
5	0.5	1	278	1.940392	0.0278	0.070864	0	278	0
6	1	2	570	3.978502	0.057	0.145297	0	570	0
7	2	4	1201	8.382773	0.1201	0.306143	0	1201	0
8	4	8	2164	15.104348	0.2164	0.551619	0	2164	0
9	8	16	2948	20.576534	0.2948	0.751466	0	2948	0
10	16	32	3088	21.553709	0.3088	0.787153	0	3088	0
11	32	64	2387	16.660851	0.2387	0.608463	0	2387	0
12	64	128	1166	8.13848	0.1166	0.297222	0	1166	0
13	128	256	304	2.121868	0.0304	0.077492	0	304	0
14	256	512	66	0.460669	0.0066	0.016824	0	66	0
15	512	1024	8	0.055839	0.0008	0.002039	0	8	0
16	1024	2048	1	0.00698	0.0001	0.000255	0	1	0
17	2048	4096	0	0	0	0	0	0	0
18	4096	8192	0	0	0	0	0	0	0
19	8192	16384	0	0	0	0	0	0	0
20	16384	32768	0	0	0	0	0	0	0
21	32768	65536	0	0	0	0	0	0	0
22	65536	131072	0	0	0	0	0	0	0
23	131072	262144	0	0	0	0	0	0	0
24	262144	524288	0	0	0	0	0	0	0
25	524288	1048576	0	0	0	0	0	0	0
Not Classified			1	0.00698	0.0001	0.000255	0	1	0
		Totals =	14327	100	1.4327	3.652052	0	14327	0

Number of Pools Not Classified = 1
Number of Trials with Pools = 3923
Number of Pools Below Class 1 = 1
Number of Pools Above Class 25 = 0

Table 22: Conditional (Unrisked) Recoverable Sizes of Ranked Pools for Play 5 - Mesozoic Deformed Sedimentary Rocks (Triassic-Cretaceous)

Pool Size in Millions of Barrels of Oil, Energy-Equivalent							
Pool Rank	F95	F75	F50	Mean	F25	F05	F01
1	8	24	45	63	80	176	387
2	3	10	20	26	35	70	107
3	2	6	11	15	20	41	63
4	1	4	8	10	14	27	42
5	1	3	5	7	10	20	31
6	1	2	4	6	8	15	24
7	1	2	4	5	6	13	19
8	0.4	1	3	4	5	11	16
9	0.4	1	3	3	5	9	14
10	0.3	1	2	3	4	8	12
11	0.3	1	2	3	4	7	11
12	0.2	1	2	2	3	6	9
13	0.2	1	2	2	3	5	8

Maximum Number of Pools = 13

Table 23: Conditional (Unrisked) Recoverable Pool Size Results for Play 6 - Mesozoic Granitic Buried Hills (Jurassic-Cretaceous)

Classification and Size			Pool Count Statistics				Pool Type Counts		
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Pool Count	Percentage	Trial Average	Trials with Pool Average	Mixed Pool Count	Oil Pool Count	Gas Pool Count
1	0.0312	0.0625	2	0.01528	0.0002	0.000584	0	0	2
2	0.0625	0.125	10	0.0764	0.001	0.002918	0	0	10
3	0.125	0.25	35	0.2674	0.0035	0.010213	0	0	35
4	0.25	0.5	102	0.77928	0.0102	0.029764	0	0	102
5	0.5	1	250	1.910001	0.025	0.07295	11	1	238
6	1	2	498	3.804722	0.0498	0.145317	12	3	483
7	2	4	1030	7.869203	0.103	0.300554	61	16	953
8	4	8	1709	13.056766	0.1709	0.498687	146	44	1519
9	8	16	2302	17.587288	0.2302	0.671725	233	88	1981
10	16	32	2483	18.970127	0.2483	0.72454	271	149	2063
11	32	64	2173	16.601727	0.2173	0.634082	297	238	1638
12	64	128	1397	10.673084	0.1397	0.407645	167	260	970
13	128	256	733	5.600122	0.0733	0.21389	74	249	410
14	256	512	247	1.887081	0.0247	0.072075	13	144	90
15	512	1024	86	0.65704	0.0086	0.025095	5	66	15
16	1024	2048	22	0.16808	0.0022	0.00642	0	19	3
17	2048	4096	5	0.0382	0.0005	0.001459	0	5	0
18	4096	8192	4	0.03056	0.0004	0.001167	0	4	0
19	8192	16384	0	0	0	0	0	0	0
20	16384	32768	0	0	0	0	0	0	0
21	32768	65536	0	0	0	0	0	0	0
22	65536	131072	0	0	0	0	0	0	0
23	131072	262144	0	0	0	0	0	0	0
24	262144	524288	0	0	0	0	0	0	0
25	524288	1048576	0	0	0	0	0	0	0
Not Classified			1	0.00764	0.0001	0.000292	0	0	1
		Totals =	13089	100.000008	1.3089	3.819376	1290	1286	10513

Number of Pools Not Classified = 1
Number of Trials with Pools = 3427
Number of Pools Below Class 1 = 1
Number of Pools Above Class 25 = 0

Table 24: Conditional (Unrisked) Recoverable Sizes of Ranked Pools for Play 6 - Mesozoic Granitic Buried Hills (Jurassic-Cretaceous)

Pool Size in Millions of Barrels of Oil, Energy-Equivalent							
Pool Rank	F95	F75	F50	Mean	F25	F05	F01
1	9	33	71	148	154	469	1416
2	3	13	27	42	52	131	234
3	2	7	14	21	28	64	112
4	1	4	9	13	18	40	68
5	1	3	6	9	12	28	46
6	1	2	5	7	9	21	34
7	1	2	4	6	8	16	27
8	0.5	2	3	5	6	13	22
9	0.4	1	3	4	5	11	18
10	0.3	1	3	4	5	10	16
11	0.3	1	2	3	4	9	14
12	0.3	1	2	3	4	8	12
13	0.2	1	2	3	3	7	11
14	0.2	1	2	2	3	6	9
15	0.2	1	1	2	2	5	8

Maxiumum Number of Pools = 15

Table 25: 2006 Economic Assessment Results for North Aleutian Basin OCS Planning Area

Risked, Undiscovered, Technically and Economically Recoverable Oil and Gas Resources

SCENARIO	OIL AND CONDENSATE (Mmbo)			FREE GAS AND SOLUTION GAS (Tcfg)			BOE (Mmboe)			MPhc
	F95	Mean	F05	F95	Mean	F05	F95	Mean	F05	
Technically Recoverable (Petroleum Endowment)	19	753	2505	0.404	8.622	23.278	91	2287	6647	1.00
Threshold or "Marginal" Prices ($2005, Mean Resource Case) Required for First Positive Economic Results = $14/barrel of oil and $2.12/Mcf of Solution Gas. The Threshold Price for Economic Non-Associated Gas = $3.63/Mcf.										
Economically Recoverable at $18/Bbl (Oil) and $2.72/Mcf (Gas)	0	45	200	0.000	0.017	0.053	0	48	209	0.05
Economically Recoverable at $30/Bbl (Oil) and $4.54/Mcf (Gas)	2	378	1371	0.001	0.909	2.780	3	539	1865	0.54
Economically Recoverable at $46/Bbl (Oil) and $6.96/Mcf (Gas)	11	631	2180	0.132	5.852	16.548	34	1672	5125	0.90
Economically Recoverable at $80/Bbl (Oil) and $12.10/Mcf (Gas)	19	738	2468	0.392	8.396	22.767	89	2232	6519	0.99

ECONOMIC ASSUMPTIONS *: 2005 base year; oil price is Alaska North Slope crude landed at U.S. West Coast; gas price is LNG delivered to U.S. West Coast; 0.8488 is gas value discountrelative to oil on a BOE basis; flat real prices and costs; 3% inflation; 12% discount rate; 35% Federal tax.*
TERMINOLOGY *:* ***Mmbo*** *, millions of barrels of oil and condensate;* ***Tcfg*** *, trillions of cubic feet, gas;* ***Mmboe*** *, total oil and gas in millions of energy-equivalent barrels;* ***Mean*** *, resource quantities at the mean in cumulative probability distributions;* ***F95*** *, the resource quantity having a 95-percent probability of being met or exceeded;* ***F05*** *, the resource quantity having a 5-percent probability of being met or exceeded; The* ***MPhc*** *for technically recoverable resources is the probability that the assessment area contains at least one accumulation. The* ***MPhc*** *for the economic cases is the probability that the area contains at least one economic accumulation under the given economic conditions. For example, if the $30 case shows a MPhc of 0.22, then 2,200 out of 10,000 trials have at least one prospect with economically recoverable resources (oil or gas) at the given starting prices and other economic conditions. Resource quantities are risked (product of multiplying the conditional resources and MPhc).*

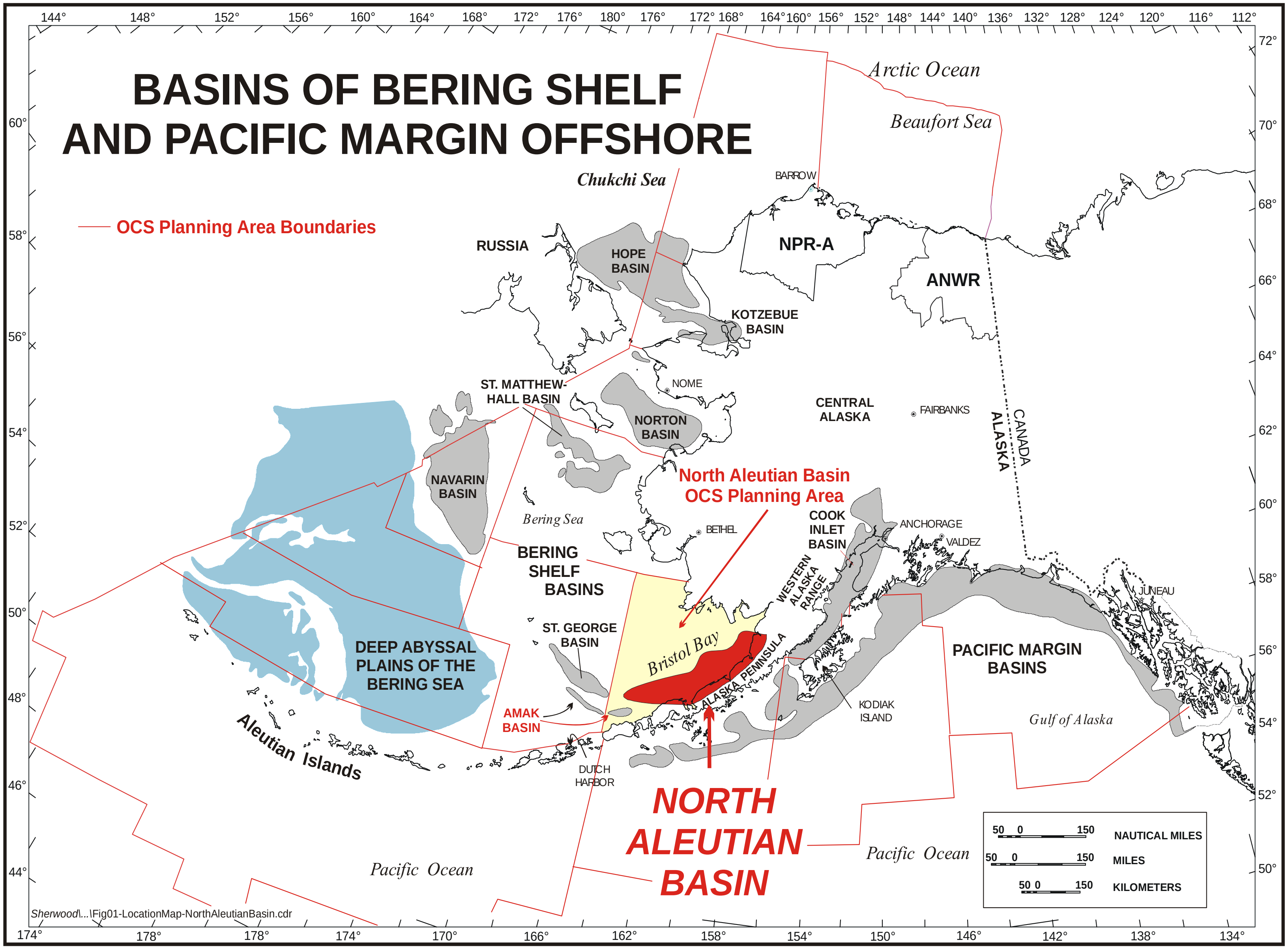


Figure 1: Location map for North Aleutian basin and other Tertiary-age basins of the Bering shelf, Pacific margin, and southern Chukchi Sea.

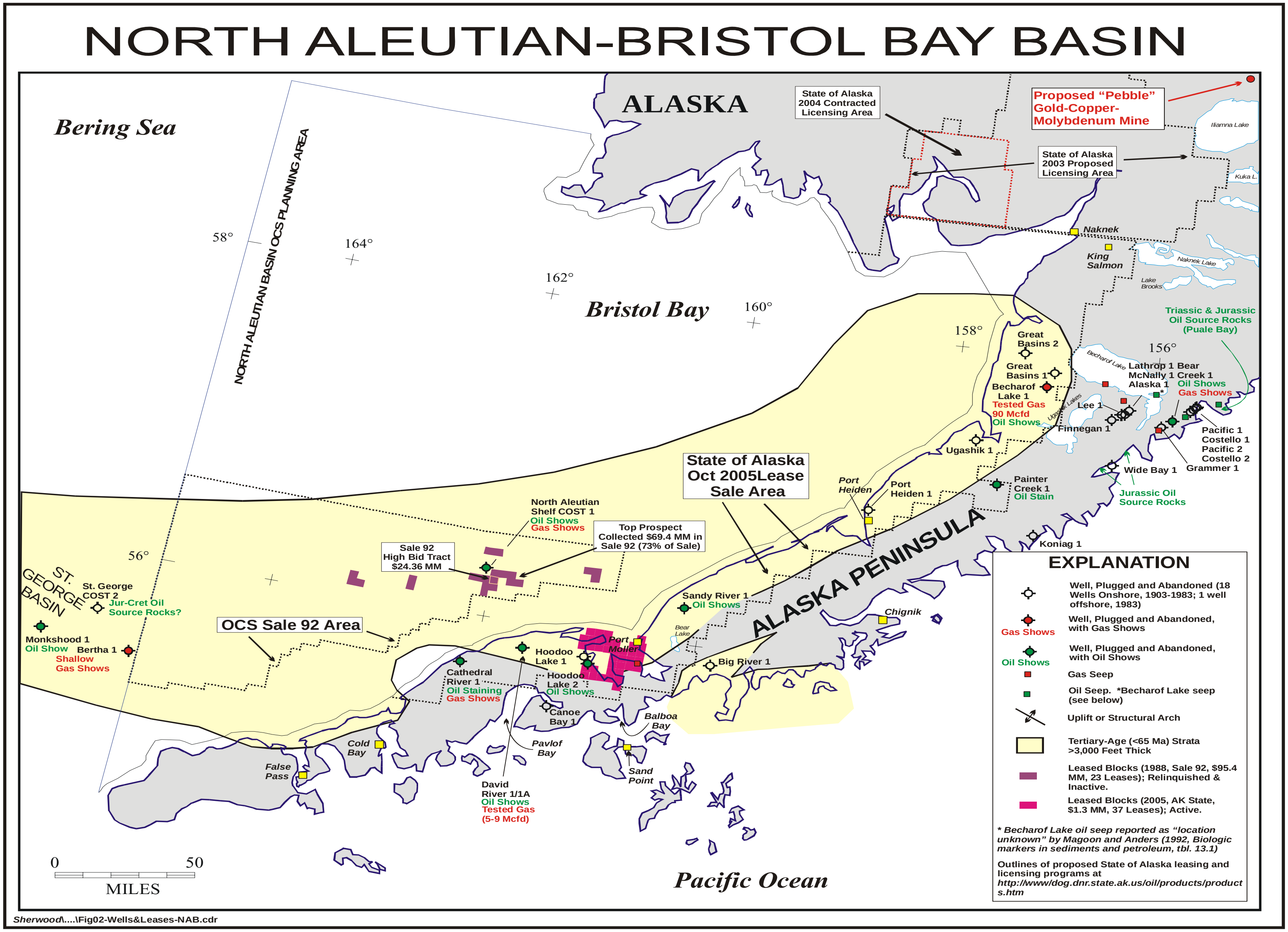


Figure 2: Regional map for North Aleutian basin, with well control, Sale 92 (1988) leases (now relinquished and inactive), and regional distribution of Tertiary-age sedimentary rocks.

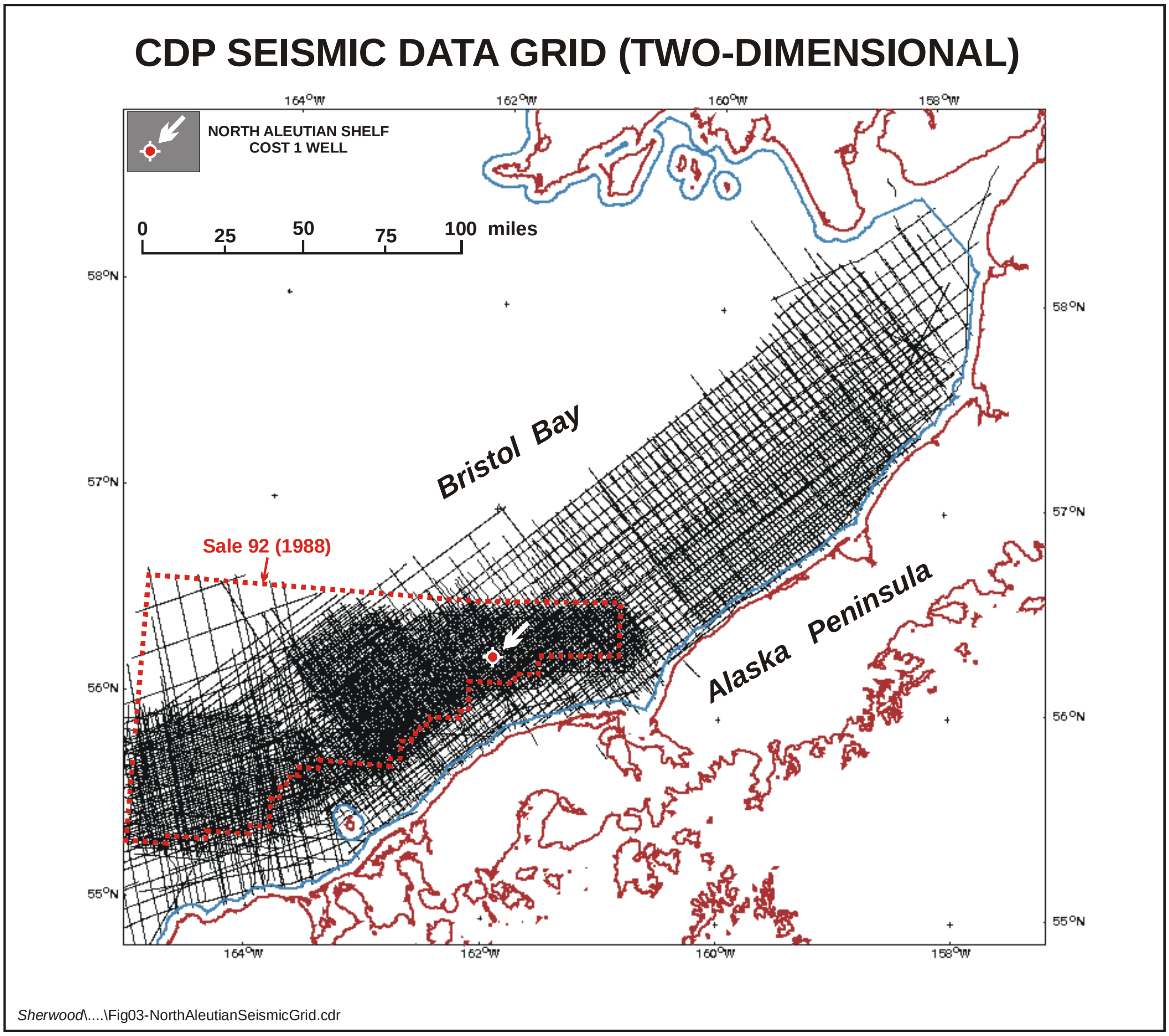


Figure 3: CDP (common-depth-point) seismic data (two-dimensional) for the North Aleutian Basin OCS Planning Area. Most data was acquired prior to 1988. Seismic data gathered to date within the North Aleutian Basin OCS Planning Area consists of 64,672 combined line miles of conventional, two-dimensional, common-depth-point (CDP) and shallow-penetrating, high-resolution (HRD) data. Of the seismic data held by MMS, 95% is CDP and 5% is HRD. Airborne magnetic data in the area covers 9,596 line miles. Approximately 6,400 miles of airborne gravity data have also been gathered in the Planning Area.

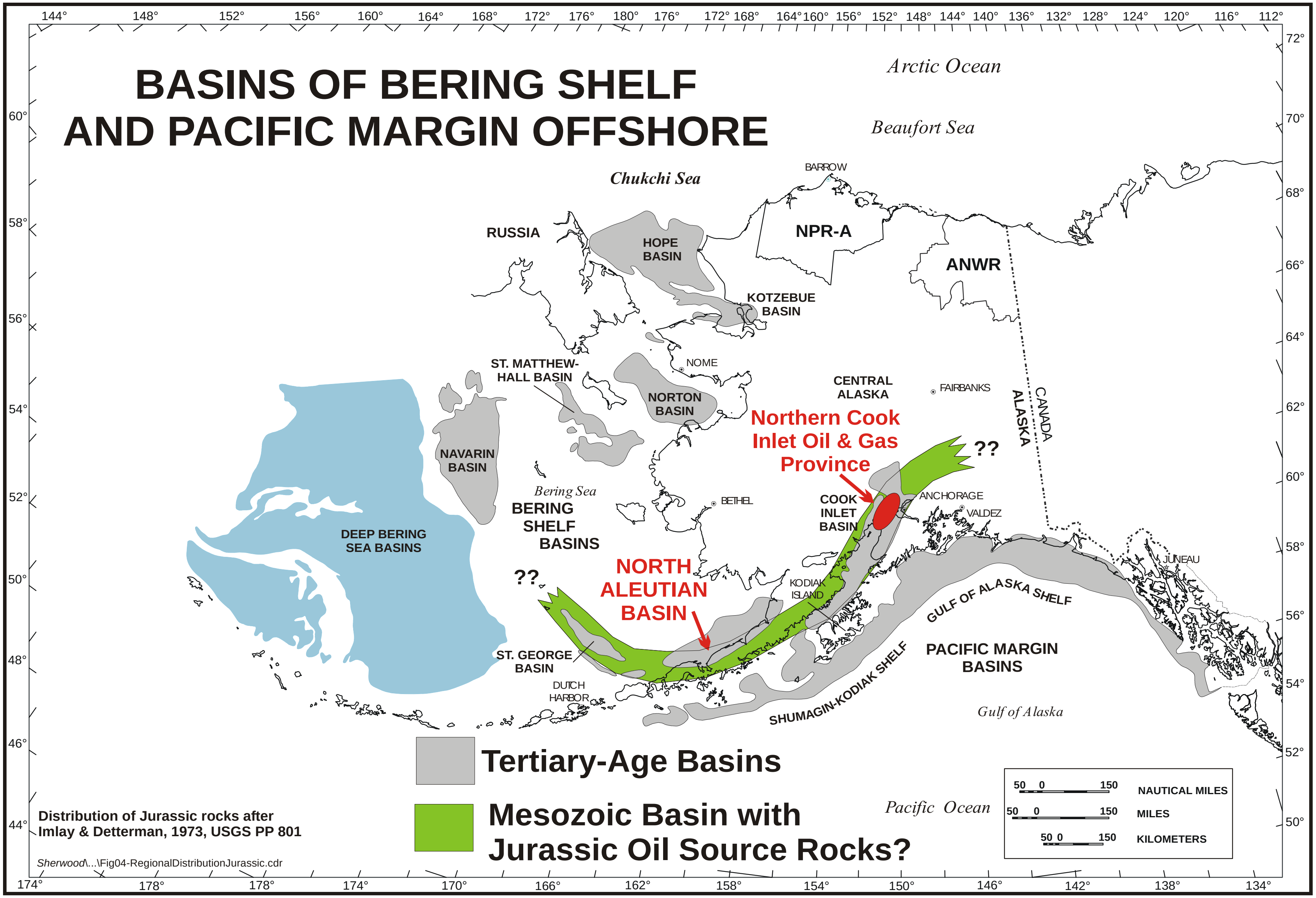


Figure 4: Regional distribution of Mesozoic sedimentary basin containing strata correlative to Middle Jurassic oil source rocks that generated 1.4 billion barrels of oil reserves in the oil fields of northern Cook Inlet basin. Distribution of Jurassic rocks after Imlay and Detterman (1973) and Worrall (1991).

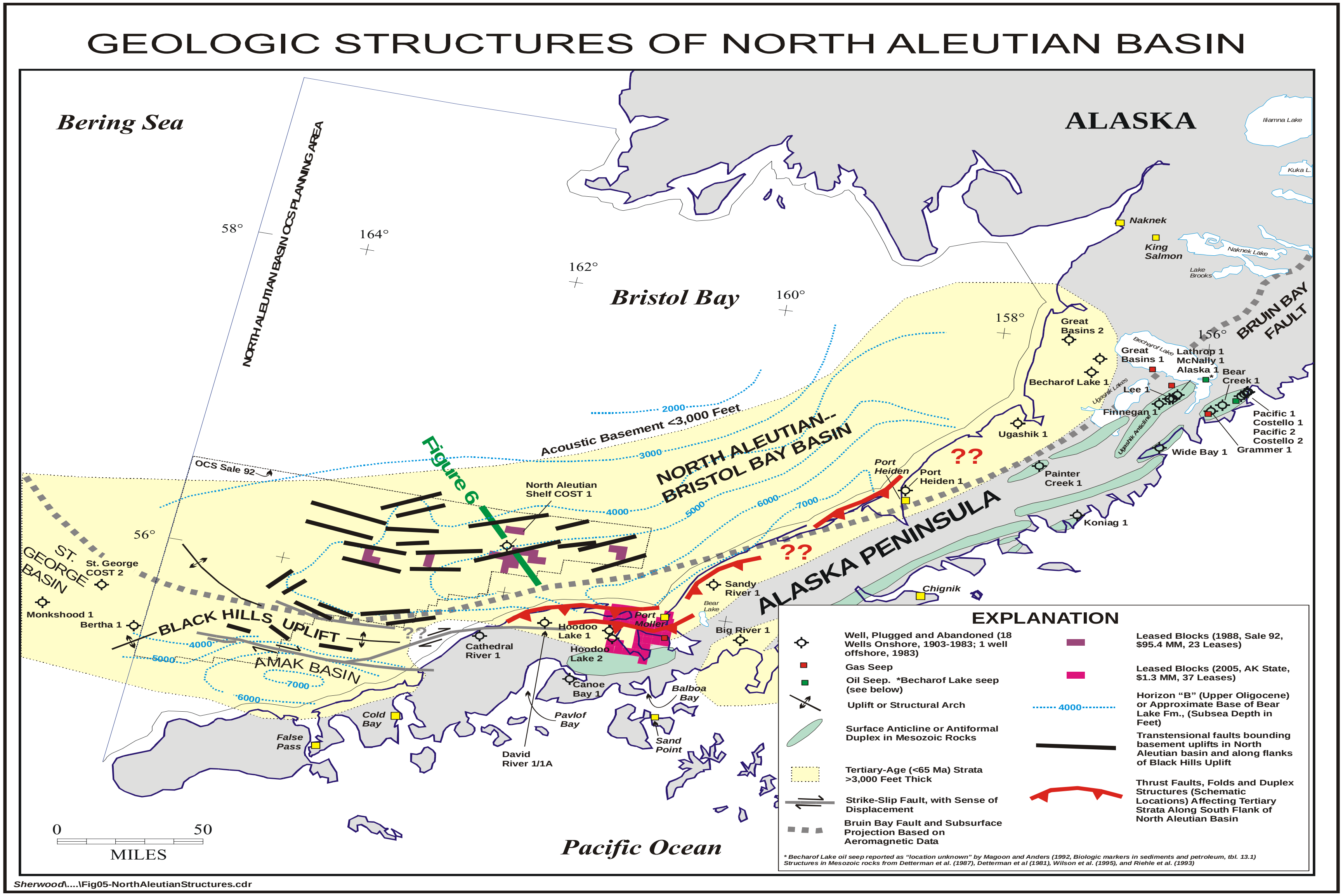


Figure 5: Principal geologic structures of the North Aleutian basin and contiguous areas, including: 1) transtensional faults and basement uplifts in western parts of the basin; 2) wrench-fault structures along the Black Hills uplift; and 3) fold/thrust belts along the southeast margin of the basin. The fold/thrust structures do not appear to extend into the Federal offshore (>3 miles).

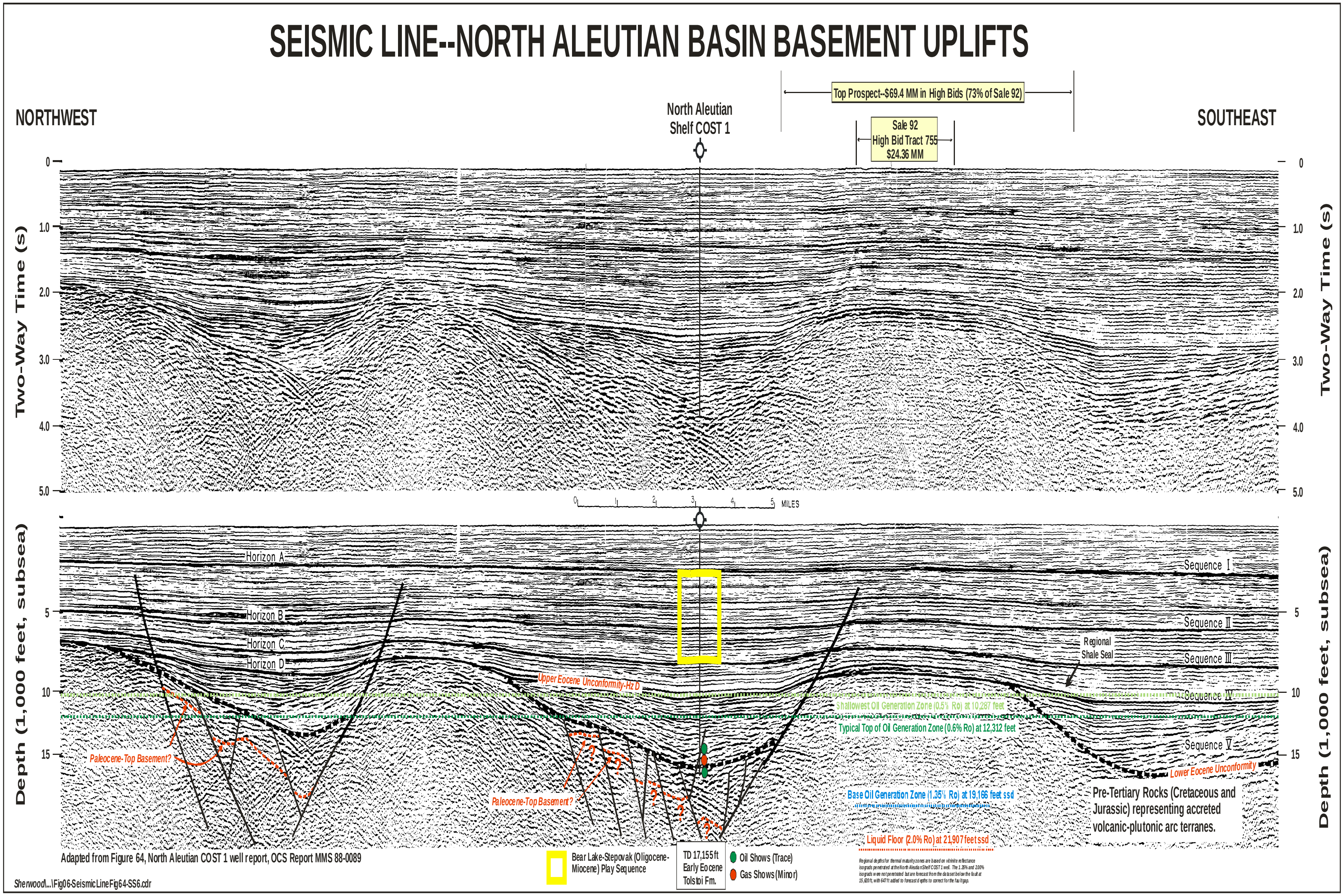


Figure 6: Seismic profile through basement uplifts in western North Aleutian basin, showing Tertiary sedimentary sequences and basin structures. Profiles adapted from Turner et al. (1988, fig. 64). The location of the profile is shown in figure 5. A full-scale version of figure 6 is also available as plate 1.

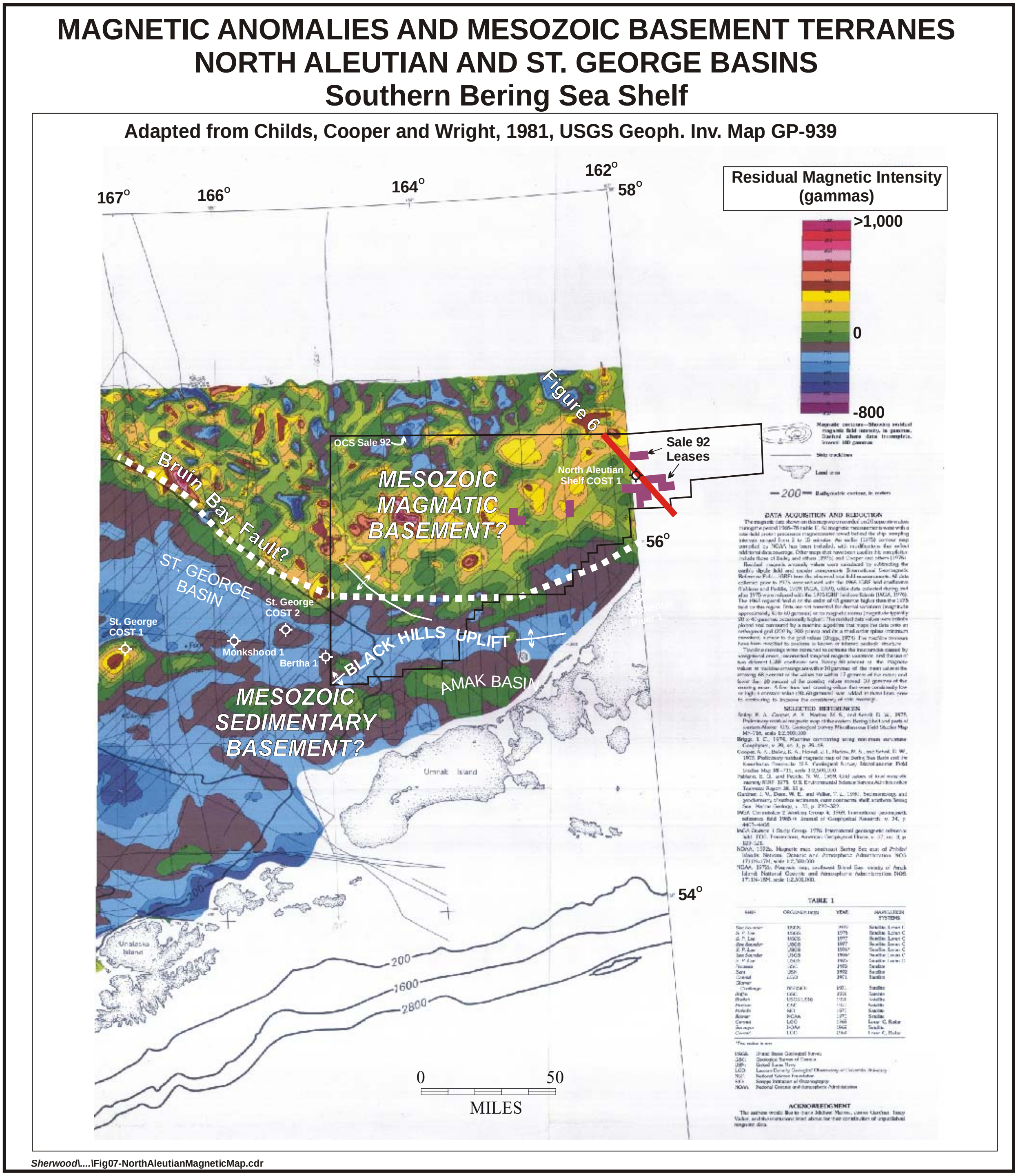


Figure 7: Magnetic intensity map with offshore speculative extrapolation of the Bruin Bay fault. Adapted from Childs et al. (1981).

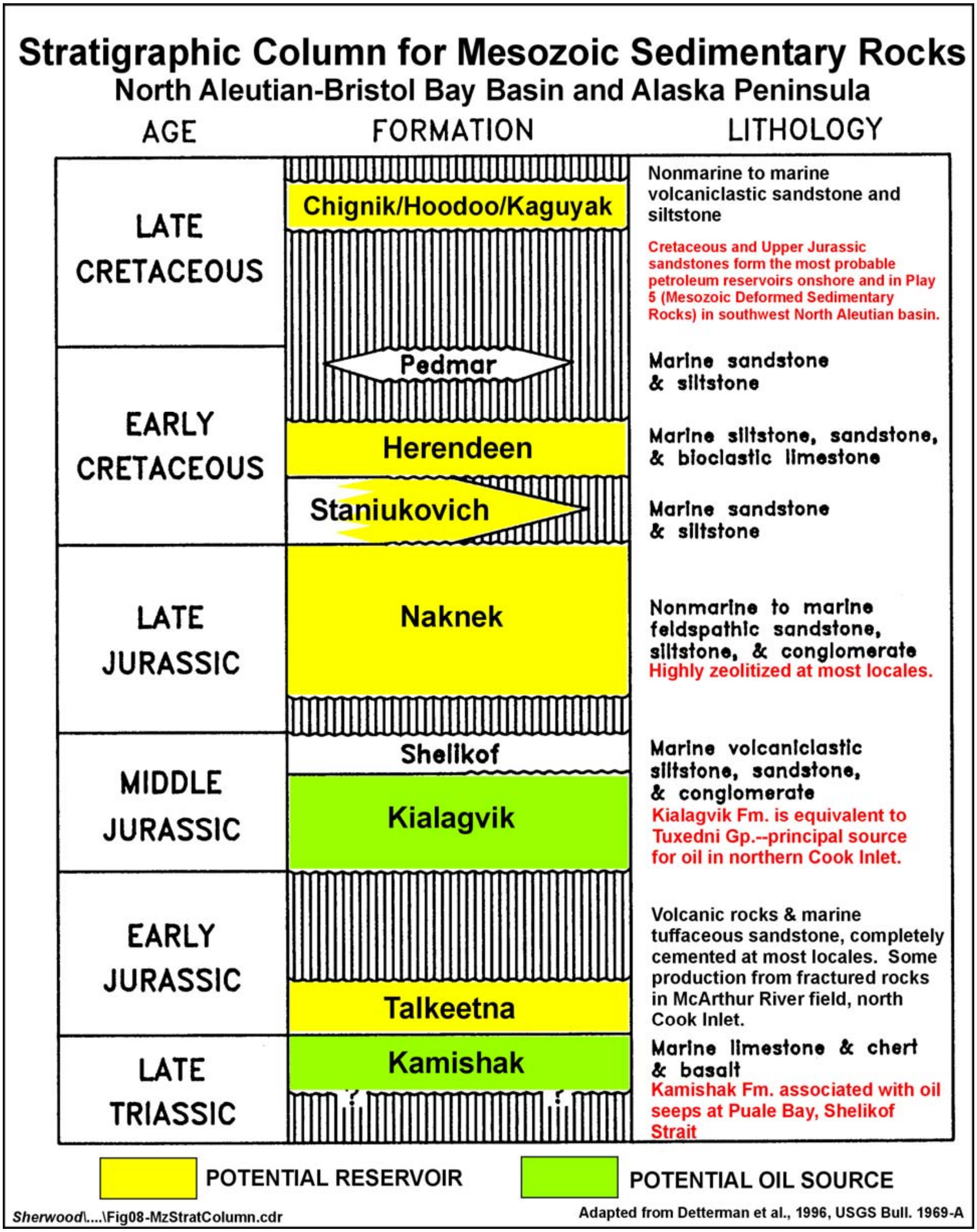


Figure 8: Mesozoic stratigraphy, Alaska Peninsula and substrate beneath southwest part of North Aleutian basin.

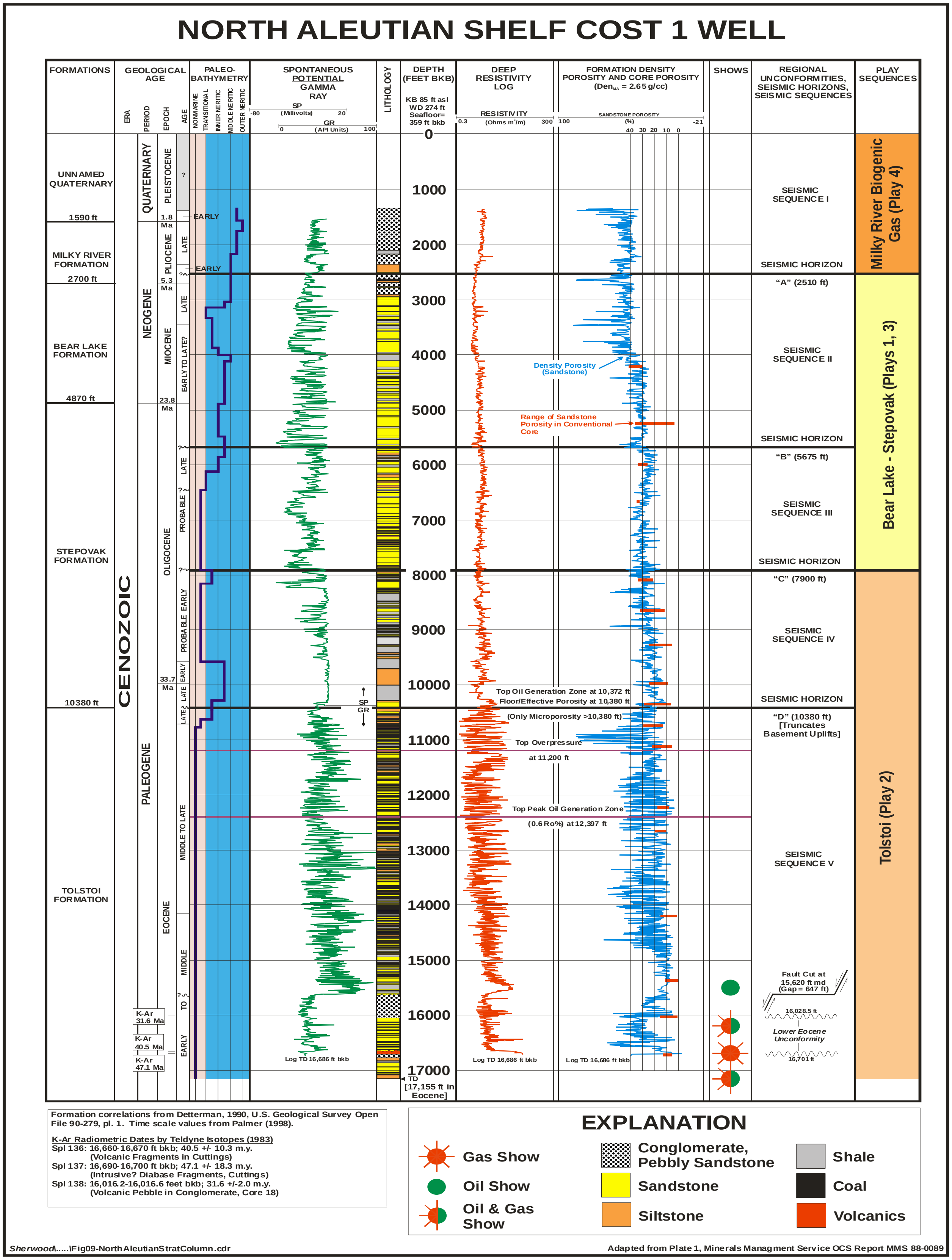


Figure 9: Wellbore stratigraphy, North Aleutian Shelf COST 1 stratigraphic test well, drilled by an industry consortium in 1983. A full-scale version of figure 9 is available as plate 2.

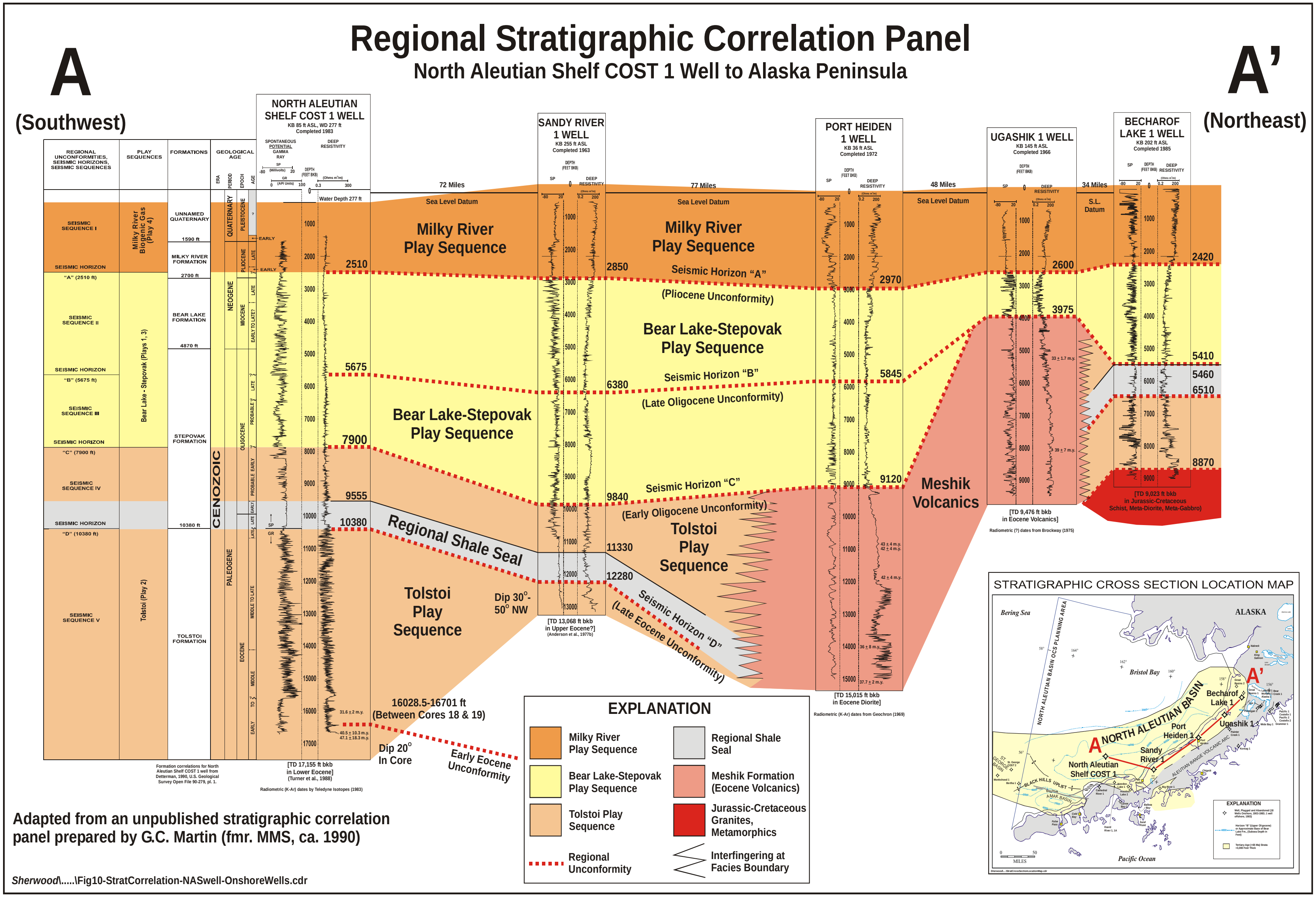


Figure 10: Regional stratigraphic correlation panel for Tertiary sequence in North Aleutian Shelf COST 1, Sandy River 1, Port Heiden 1, Ugashik 1, and Becharof Lake 1 wells, North Aleutian basin and Alaska Peninsula. A full-scale version of figure 10 is available as plate 3.

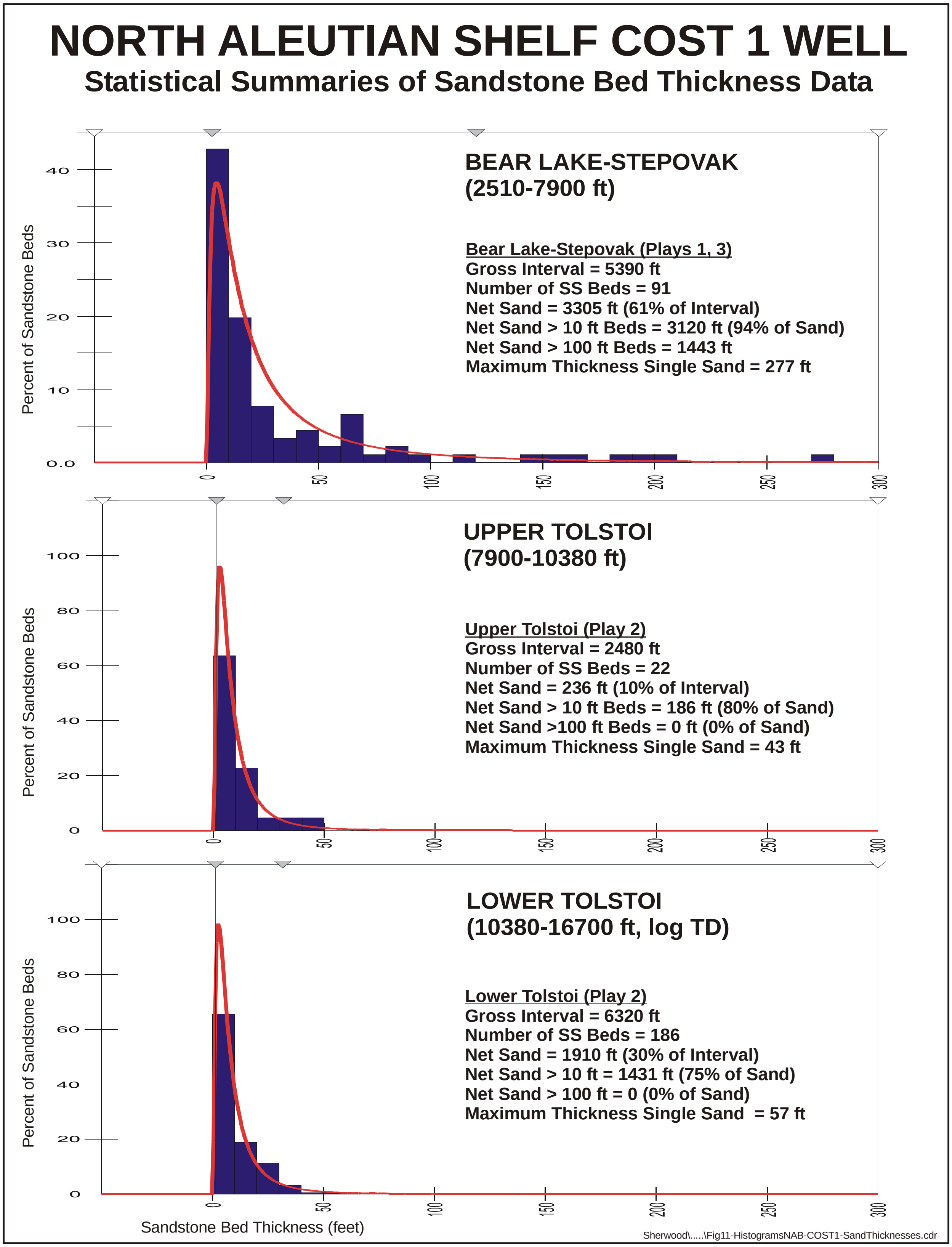


Figure 11: Statistical summaries for sandstone bed thicknesses for North Aleutian basin play sequences. The Tolstoi sequence is treated in two parts because virtually all sandstones below 10,380 feet bkb are impermeable owing to diagenesis of volcanic framework grains and implosion of the pore system.

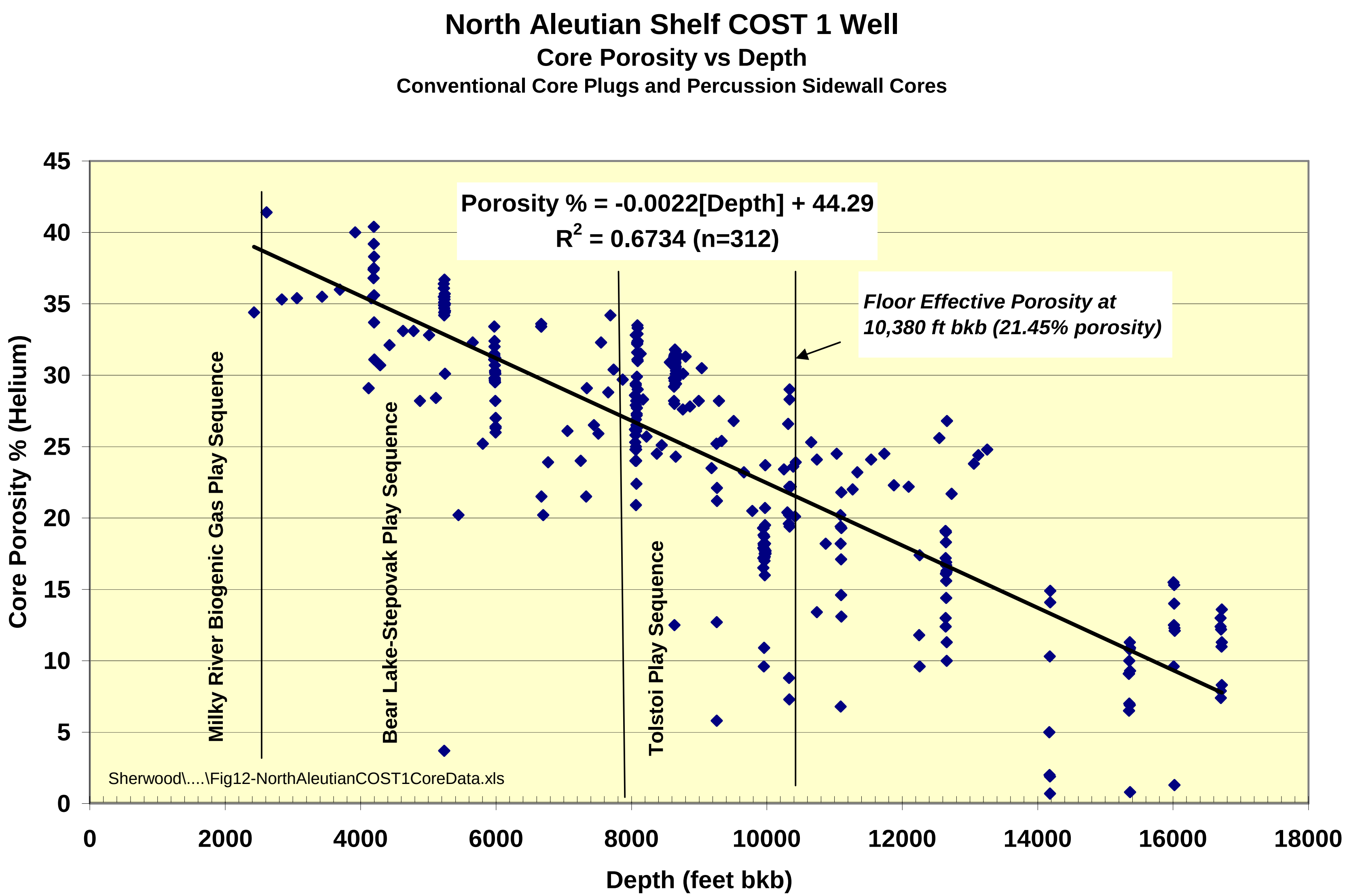


Figure 12: Core porosity versus depth in the North Aleutian Shelf COST 1 well, with linear regression function for porosity decline with depth. All data from Core Laboratories (1983).

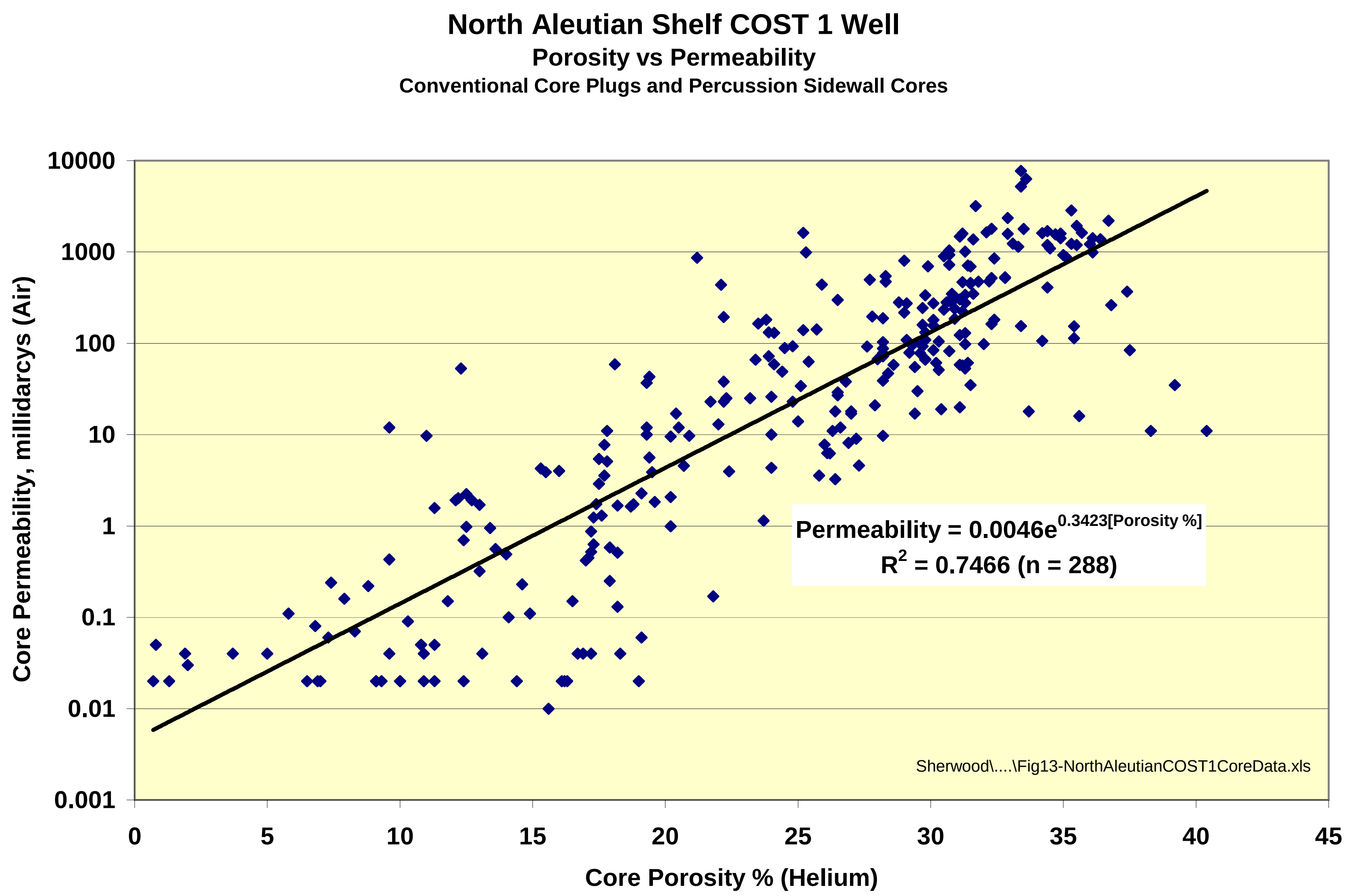


Figure 13: Core porosity versus permeability for sandstones, North Aleutian Shelf COST 1 well, with correlation. All data from Core Laboratories (1983).

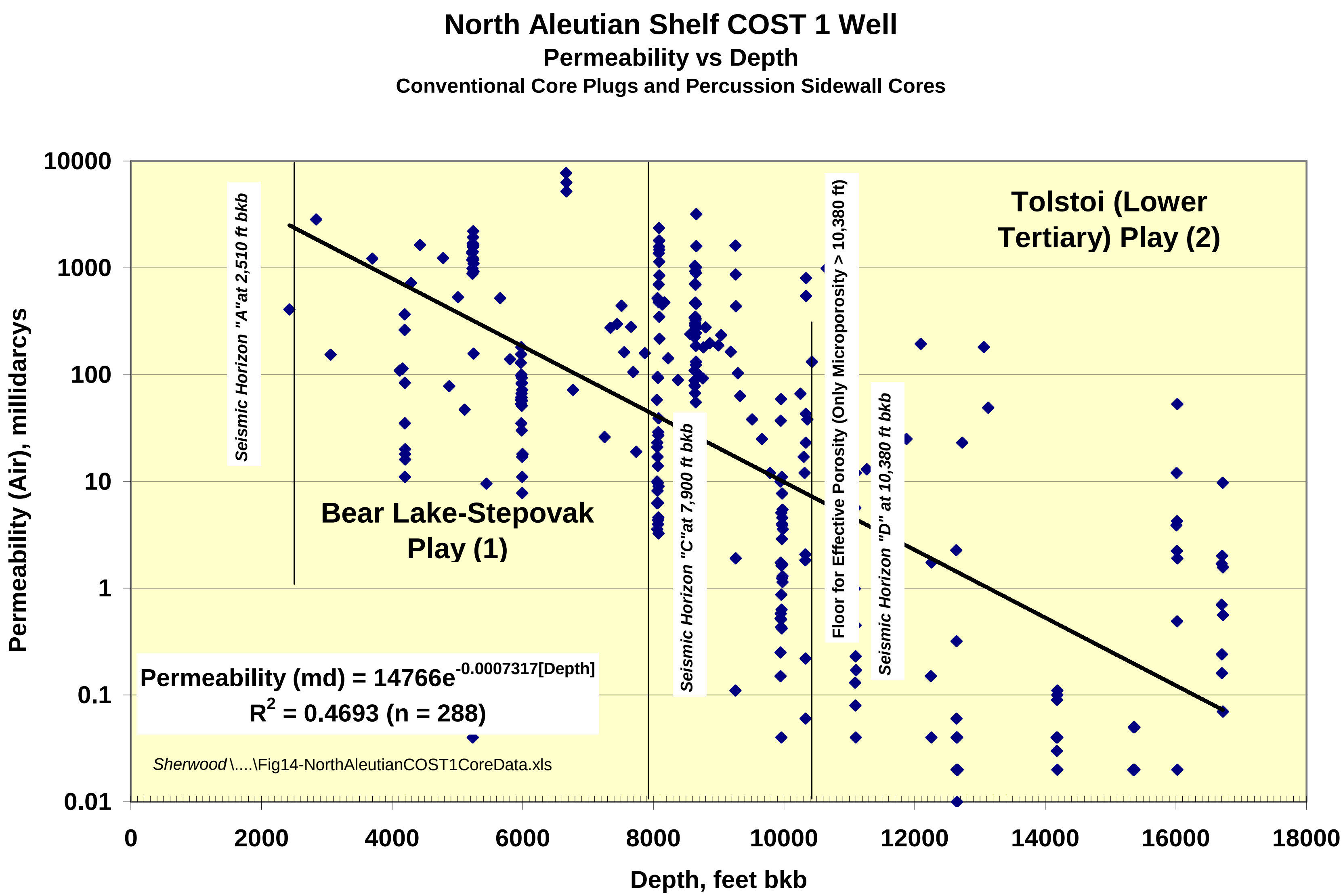


Figure 14: Core permeability versus depth for sandstones, North Aleutian Shelf COST 1 well, with function for permeability decline with depth. All data from Core Laboratories (1983).

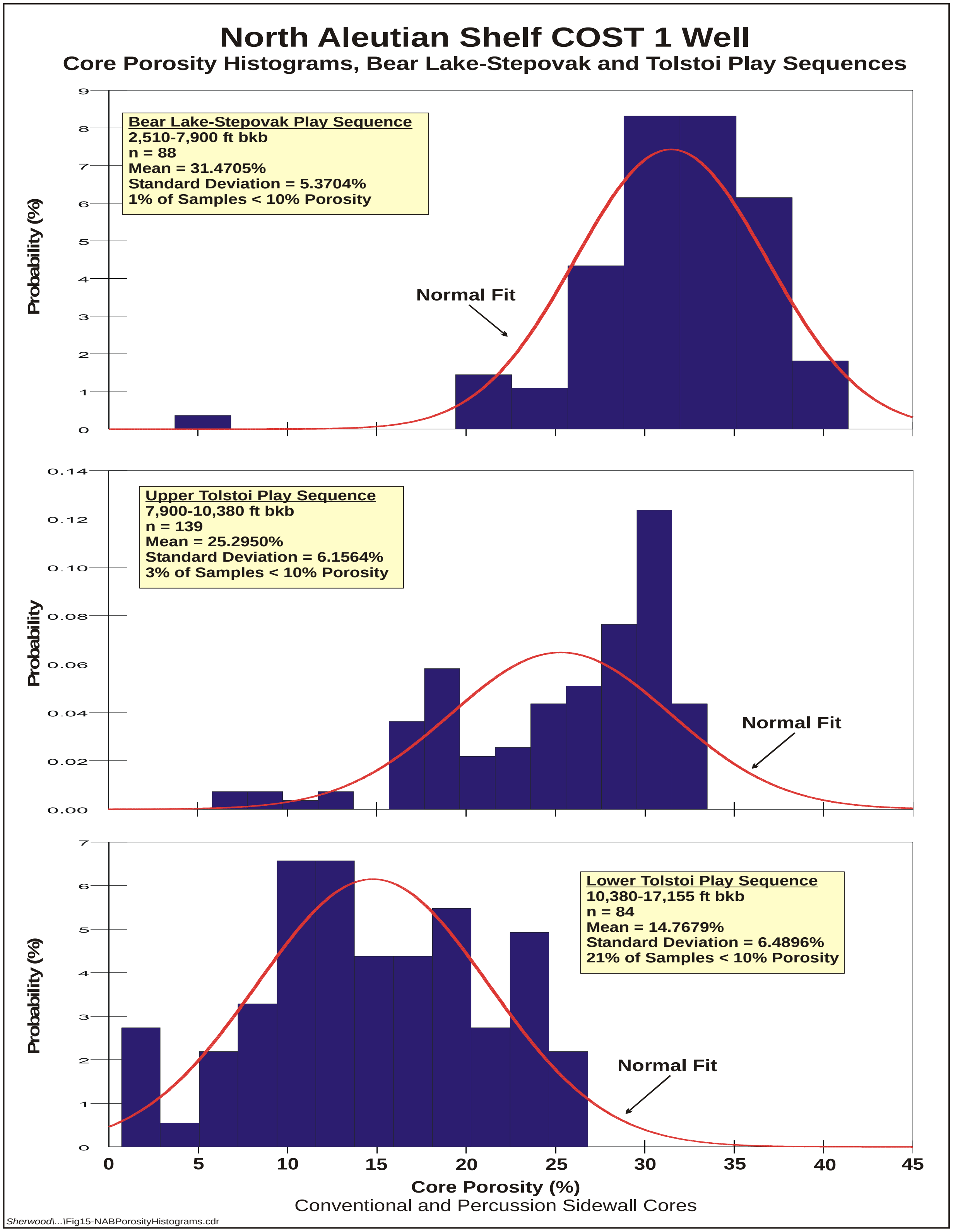


Figure 15: Porosity histograms for Bear Lake-Stepovak, Upper Tolstoi, and Lower Tolstoi play sequences from 311 conventional and sidewall core samples. Tolstoi sandstones below 10,380 feet bkb are essentially impermeable because of diagenesis of volcanic framework grains and collapse of the pore system. All data from Core Laboratories (1983).

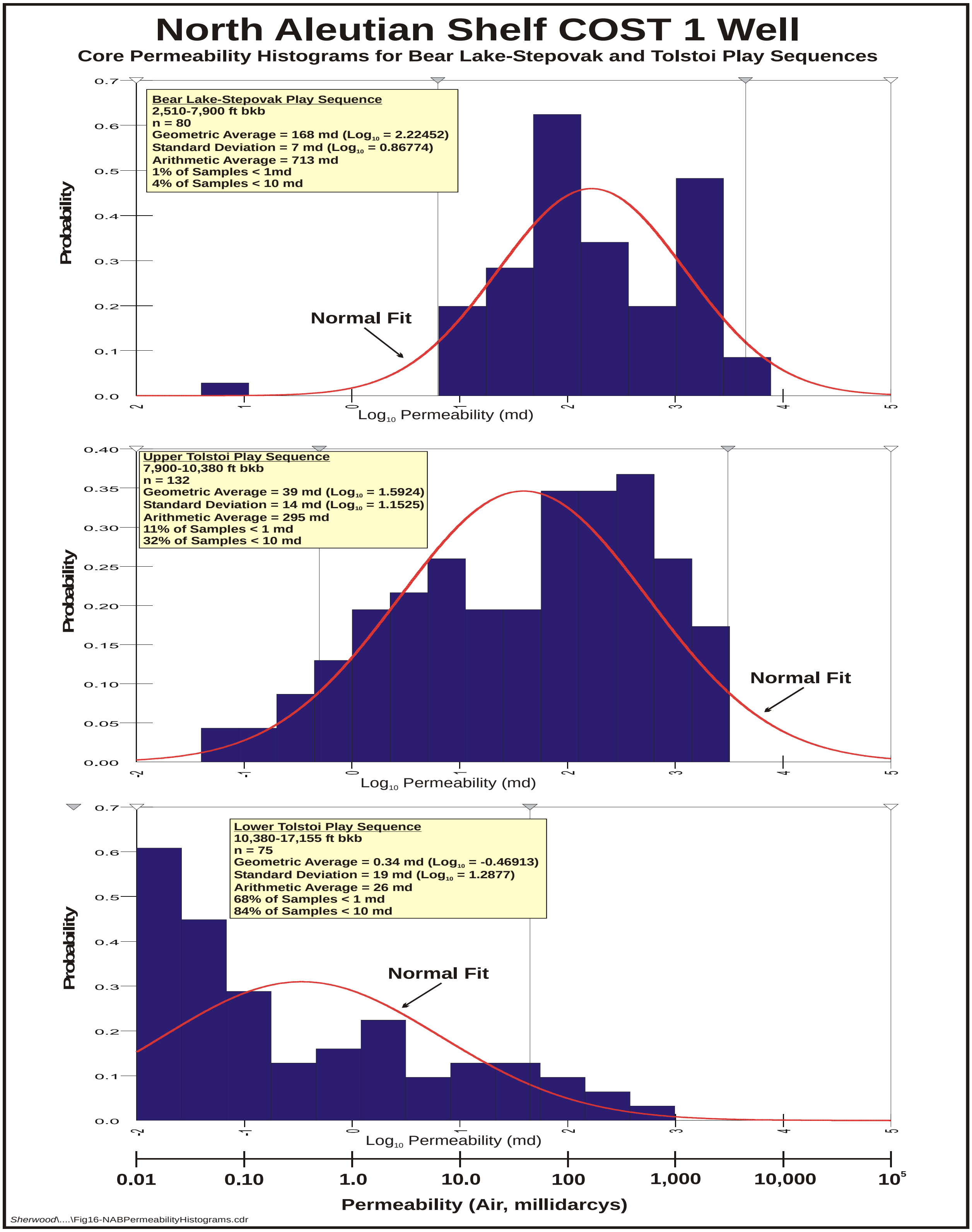


Figure 16: Permeability histograms for Bear Lake-Stepovak, Upper Tolstoi, and Lower Tolstoi play sequences from 287 conventional and percussion sidewall core samples. Tolstoi sandstones below 10,380 feet bkb are essentially impermeable because of cementation, diagenesis of volcanic framework grains, and collapse of the pore system. All data from Core Laboratories (1983).

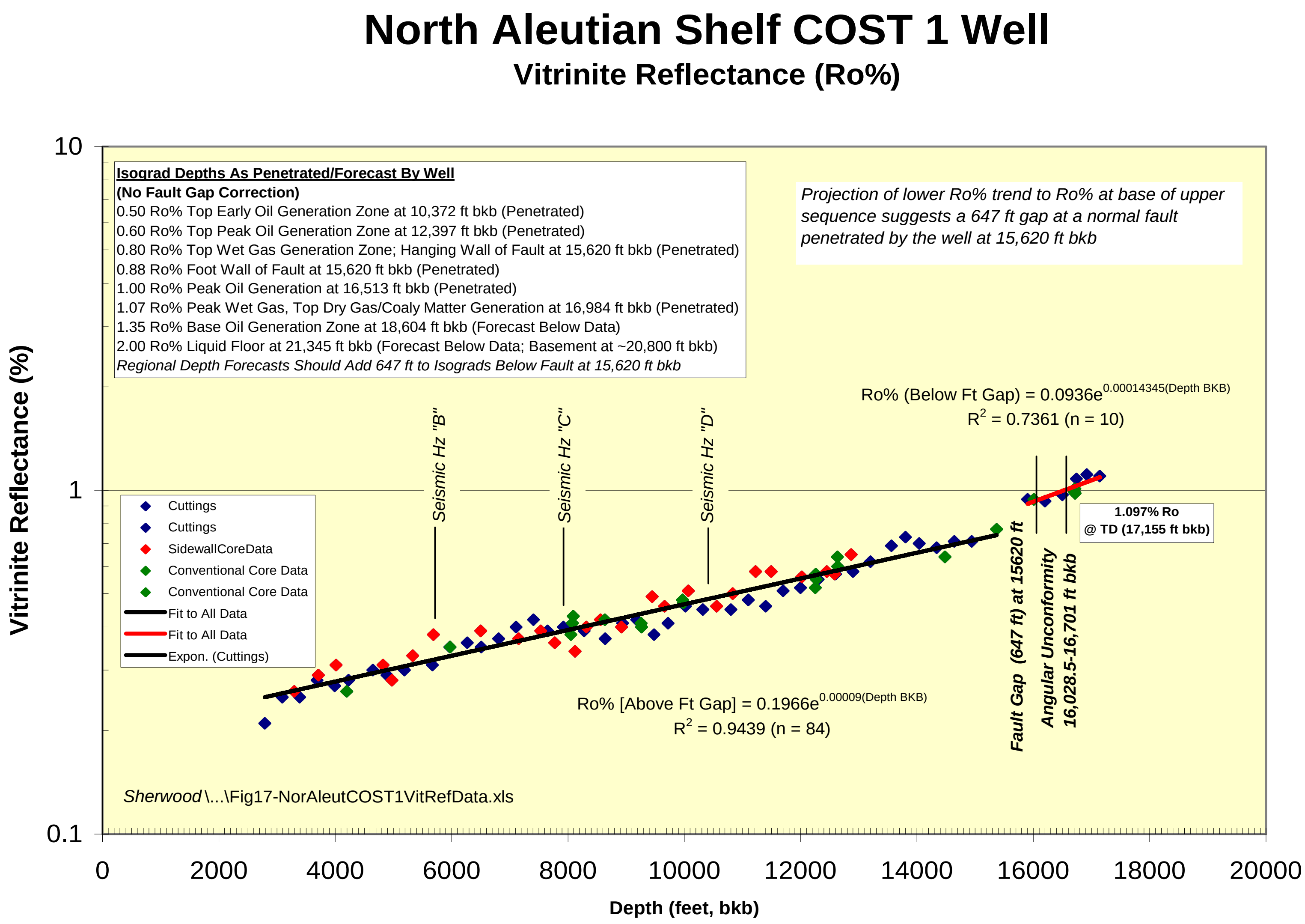


Figure 17: Vitrinite reflectance data for 94 samples of cuttings, conventional cores, and percussion sidewall cores in the North Aleutian Shelf COST 1 well, with statistical fits and forecasts for depths of important isograds. All analyses prepared by Robertson Research (1983). Critical isograd values from Dow (1977a, fig. 3) and Waples (1980).

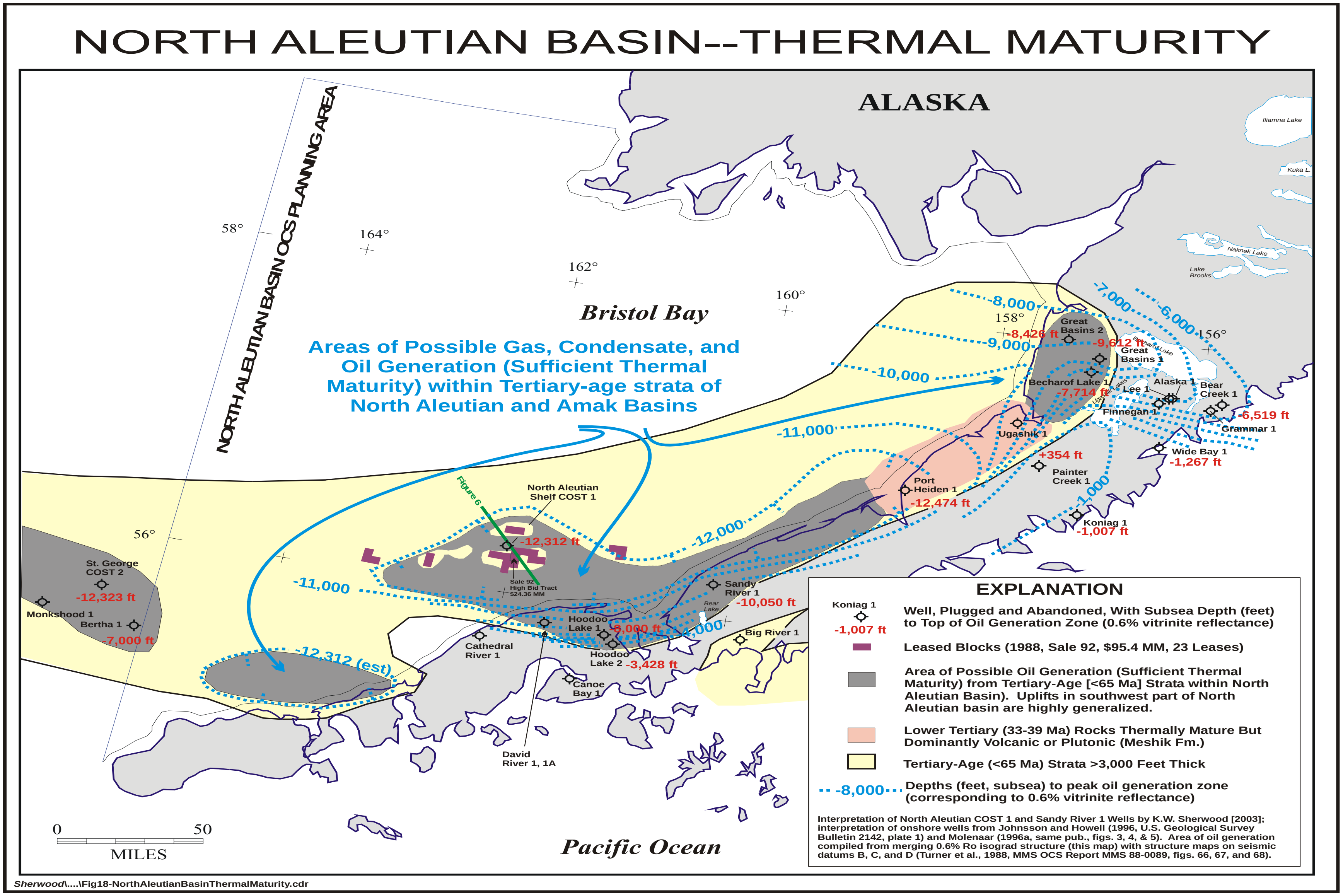


Figure 18: Depth to top of oil generation zone (0.6% vitrinite reflectance) with probable areas of thermal maturity of Tertiary rocks sufficient for oil generation in and beneath the North Aleutian basin. The North Aleutian basin is segmented by a 33-39 Ma volcanic center that invaded the basin in the area of the Port Heiden 1 and Ugashik 1 wells, producing the volcanic flows and volcaniclastics of the Meshik Formation (age-equivalent to the Stepovak Formation).

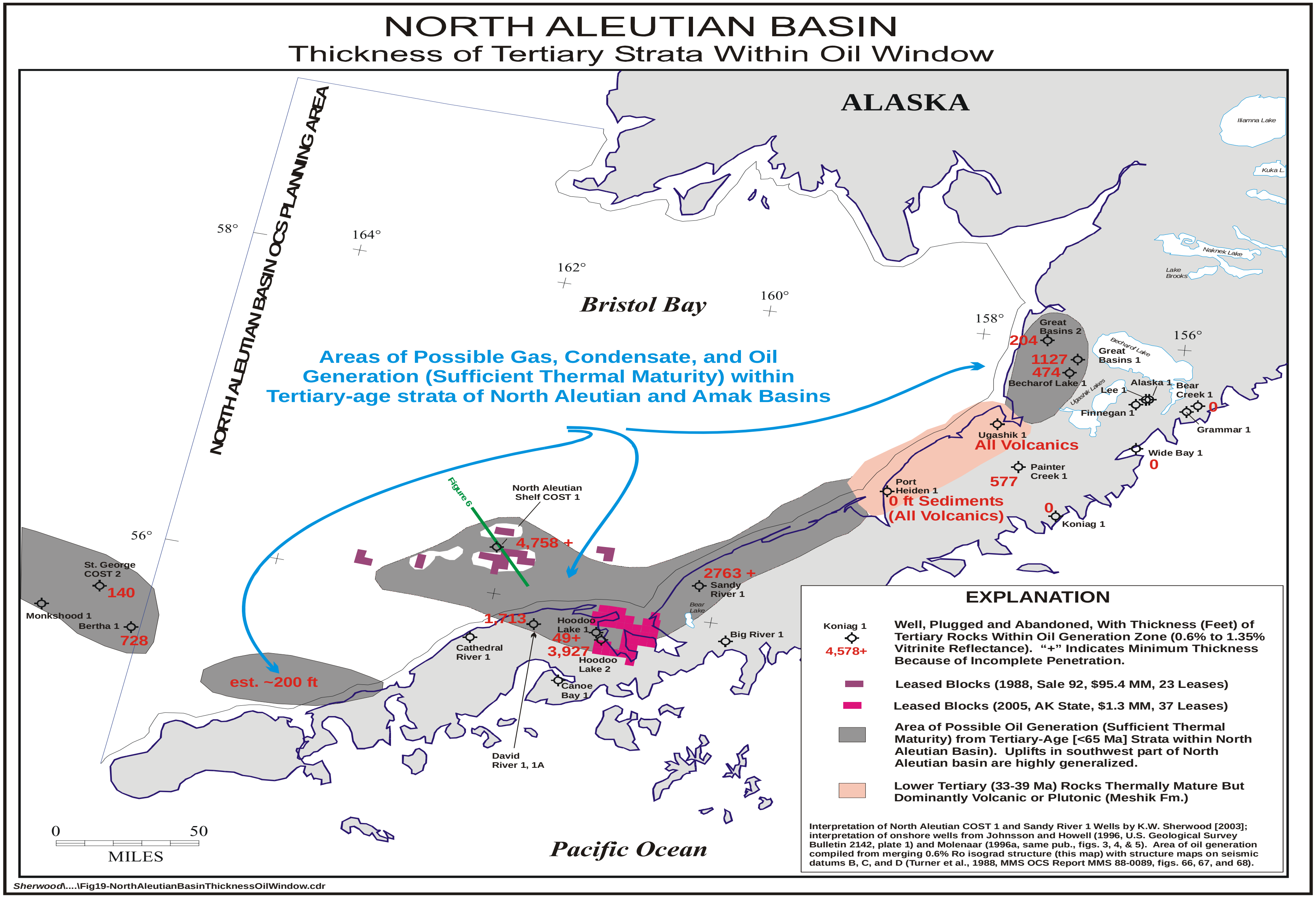


Figure 19: Isopach map for thickness of Tertiary-age rocks within oil generation zone (0.6% to 1.35% vitrinite reflectance) with probable areas of thermal maturity sufficient for oil generation within and beneath North Aleutian basin.

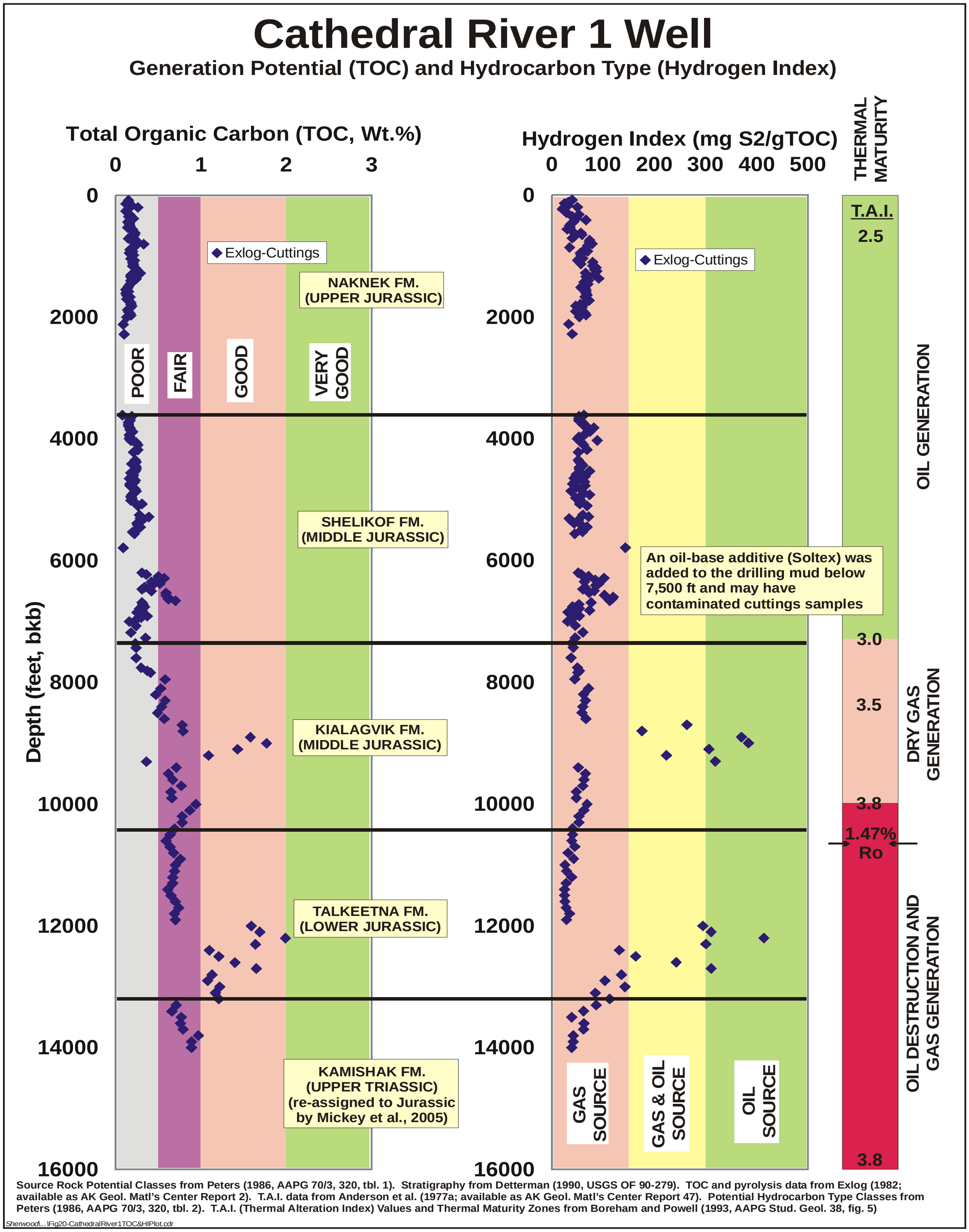


Figure 20: Generation potential (total organic carbon) and hydrocarbon type (hydrogen index) indicators for Mesozoic rocks in the Cathedral River 1 well. Analyses conducted and reported by Exlog (1982). T.A.I. (thermal alteration index) data from Anderson et al. (1977a). Vitrinite reflectance data point at 10,650 feet bkb from Robertson Research (1982).

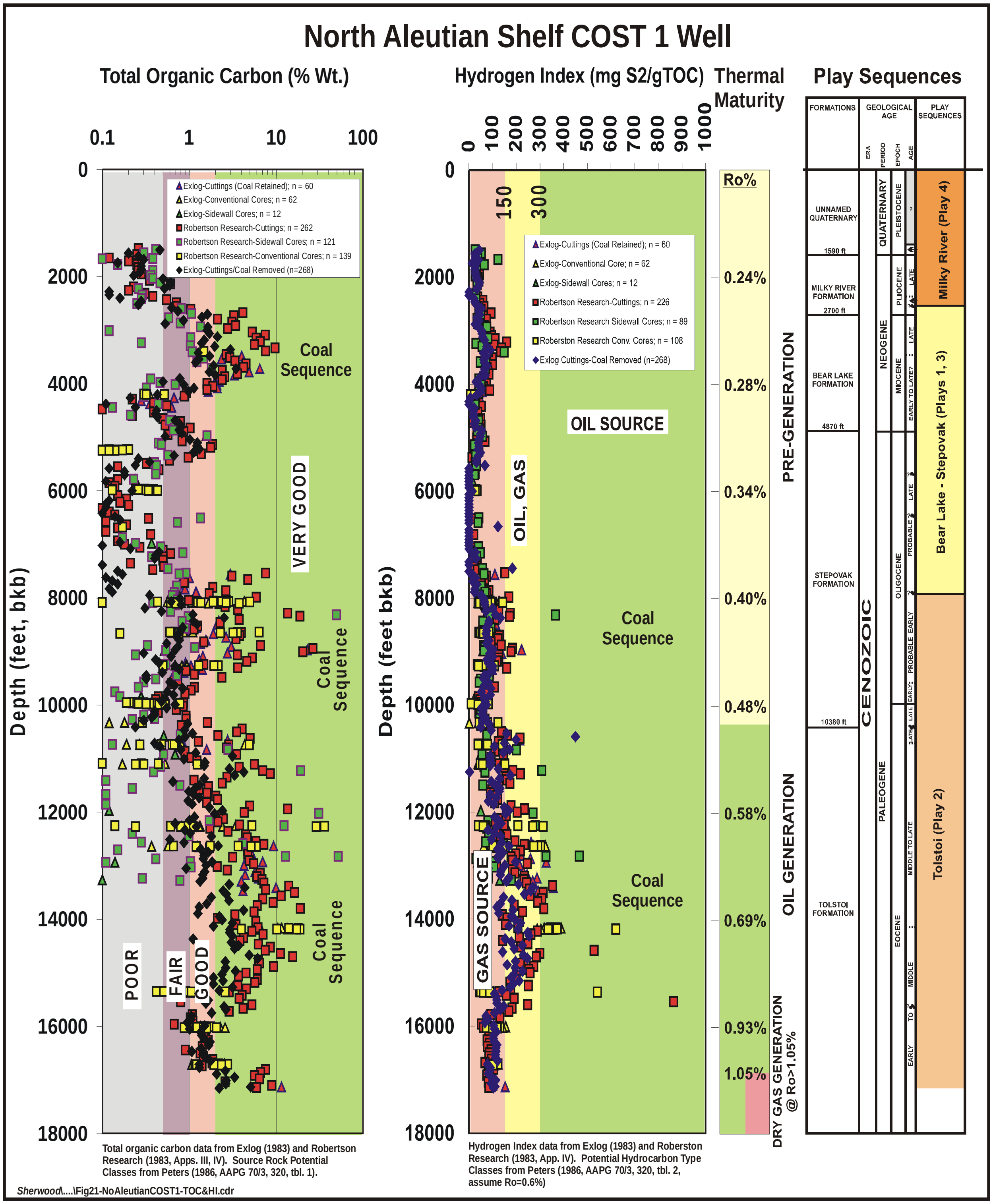


Figure 21: Generation potential (total organic carbon) and hydrocarbon type (hydrogen index) indicators for Tertiary rocks in the North Aleutian Shelf COST 1 well. Analyses from Exlog (1983) and Robertson Research (1983). Posted vitrinite reflectance values are from data fits in figure 17.

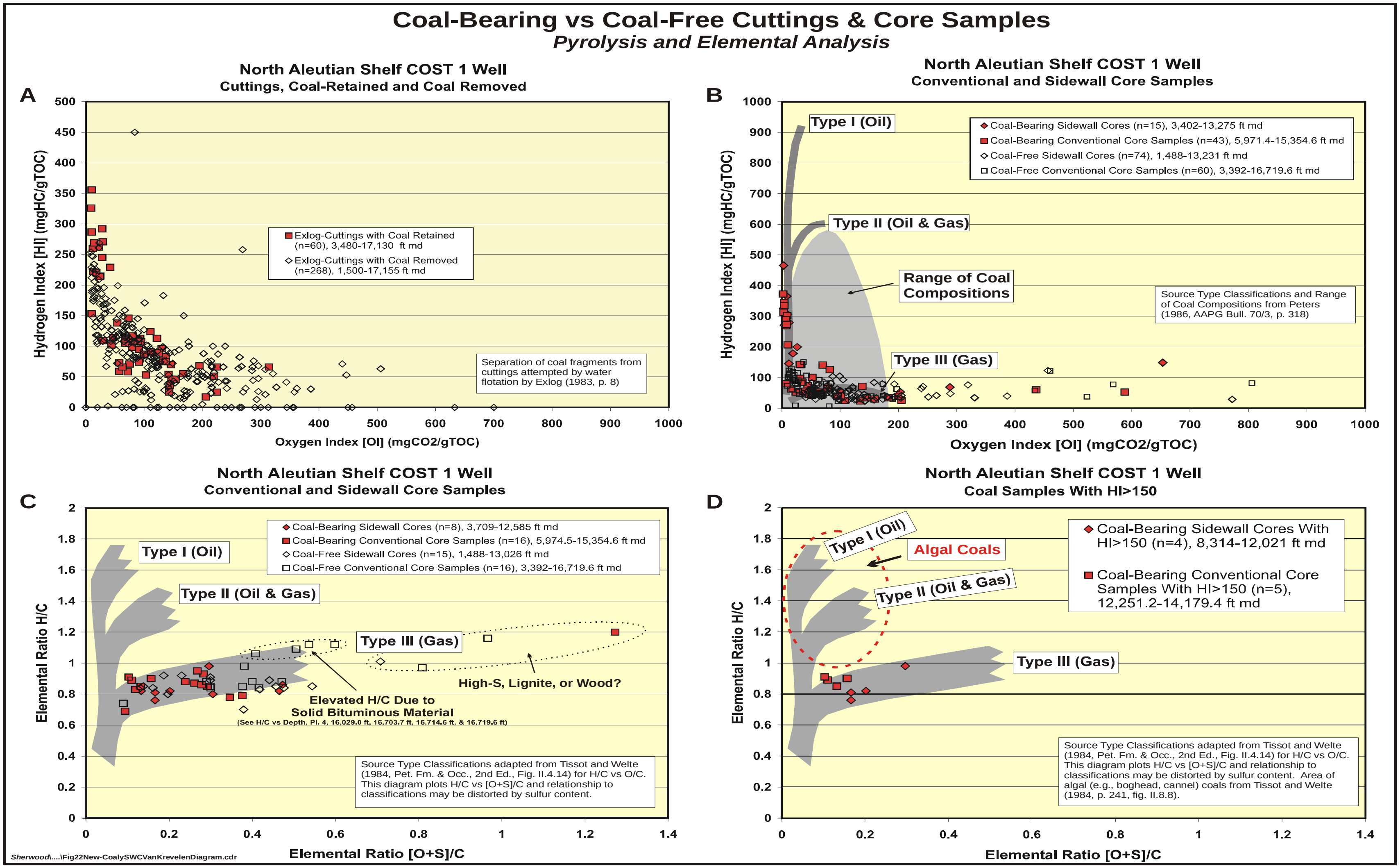
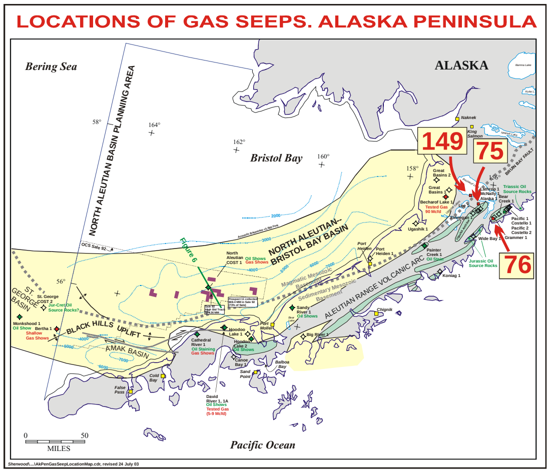
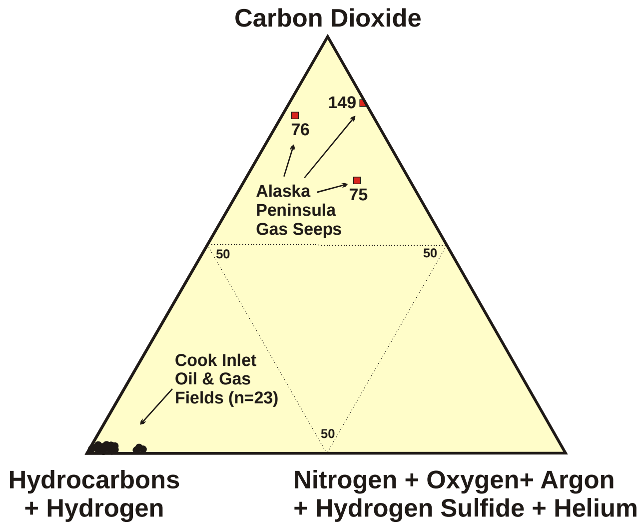


Figure 22: (A) Modified Van Krevelen plot comparing Exlog (1983) pyrolysis data for cuttings with coal partly removed (by flotation in water) and cuttings with coal content retained. The fields of the two data sets essentially overlap; (B) Sidewall and conventional core samples, with coal-bearing and coal-free samples plotted separately-all samples with HI>151 are described as coal-bearing; (C) Van Krevelen-type plot showing elemental data for sidewall and conventional core samples, with coal-bearing and coal-free samples plotted separately; (D) Van Krevelen-type plot with elemental analyses for all coal-bearing samples with HI>150 (shows that these samples are dominated by Type III kerogens). Tertiary rocks penetrated by the North Aleutian Shelf COST 1 well are all gas-prone and offer little potential for generation of oil. All core data from Robertson Research (1983, Apps. IV, VII).

GAS SEEPS, ALASKA PENINSULA





Alaska Peninsula Gas Seeps

Geog. Loc.	Ugashik Crater, SE Rim	Salmon Creek	Becharof Lk-Gas Rocks
BOM Index	75	76	149
BOM Sample	14033	14047	14051
Location	Sec.2, T29S, R44W (SM)	Sec. 11, T30S, R41W (SM)	Sec. 9, T27S, R44W (SM)
Sample Date	24-Jun-74	6-Jul-74	6-Jul-74
Methane (%)	10.70	15.70	0.10
Ethane (%)	0.40	0.20	0.00
Propane (%)	0.10	tr	tr
N-Butane (%)	0.00	0.00	0.00
IsoButane (%)	0.00	0.00	0.00
N-Pentane (%)	0.00	0.00	0.00
IsoPentane (%)	0.00	0.00	0.00
CycloPentane (%)	0.00	0.00	0.00
Hexanes Plus (%)	0.00	0.00	0.00
Nitrogen (%)	23.20	2.50	12.30
Oxygen (%)	tr	0.30	3.00
Argon (%)	0.40	tr	0.20
Hydrogen (%)	0.00	tr	0.00
Hydrogen Sulfide (%)	0.00	0.00	0.00
Carbon Dioxide (%)	65.30	81.30	84.50
Helium (%)	0.01	0.01	tr
Heating Value (Btu/ft^3)	118	163	1
Specific Gravity (Air=1.0)	1.293	1.360	1.447
HC:CO2:N+Inerts (normalized)	11.2:65.2:23.6	15.9:81.3:2.8	0.1:84.5:15.4

Data for seeps from Moore and Sigler, 1987, U.S. Bureau of Mines Information Circular 9129, p. 15-21

Sherwood\....\Fig23-GasSeeps&DataAkPen.cdr

Figure 23: Analyses of gas compositions from Alaska Peninsula seeps and oil and gas fields in northern Cook Inlet basin. Alaska Peninsula gas seeps are mostly carbon dioxide and probably reflect magmatic intrusion and decarbonation of limestones in the subsurface. All data are from Moore and Sigler (1987, p. 15-21).

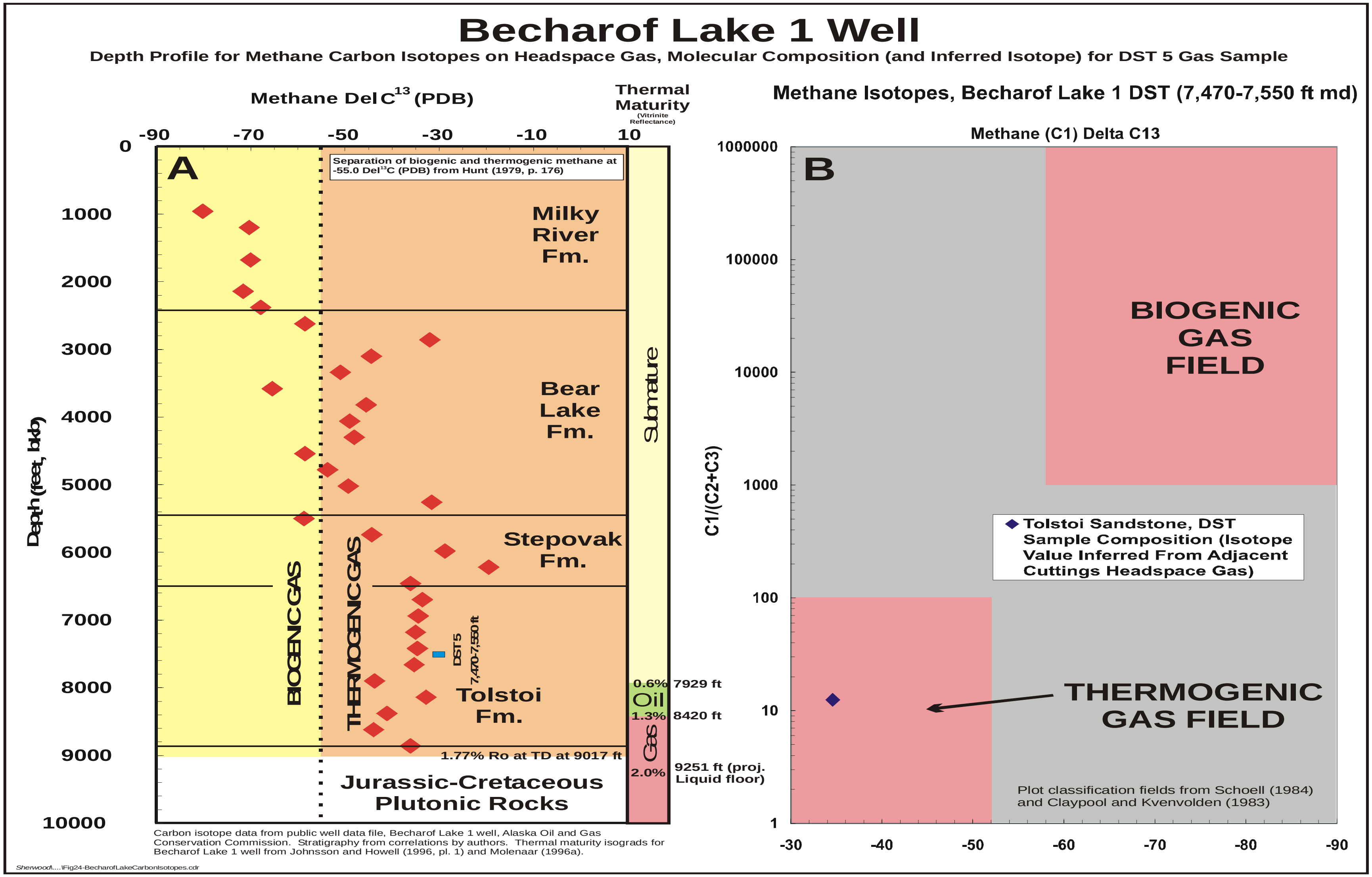


Figure 24: A) Methane carbon isotope data for Amoco Becharof Lake 1 well. Gas is biogenic above 3,000 feet, and thermogenic below 5,500 feet. Both types of gas are mixed in the intermediate interval from 3,000 to 5,500 feet. Data from AOGCC (1985, Carbon Isotope Ratios). B) Gas recovered from a flow test of the interval 7,470 to 7,550 feet consists of 87.5% methane, 4.7% ethane, 2.3% propane, 0.8% butane, 1.0% hydrogen, and 3.7% "other" (AOGCC, 1985, DST data) and classifies as thermogenic in cross-plot of Schoell (1984) and Claypool and Kvenvolden (1983).

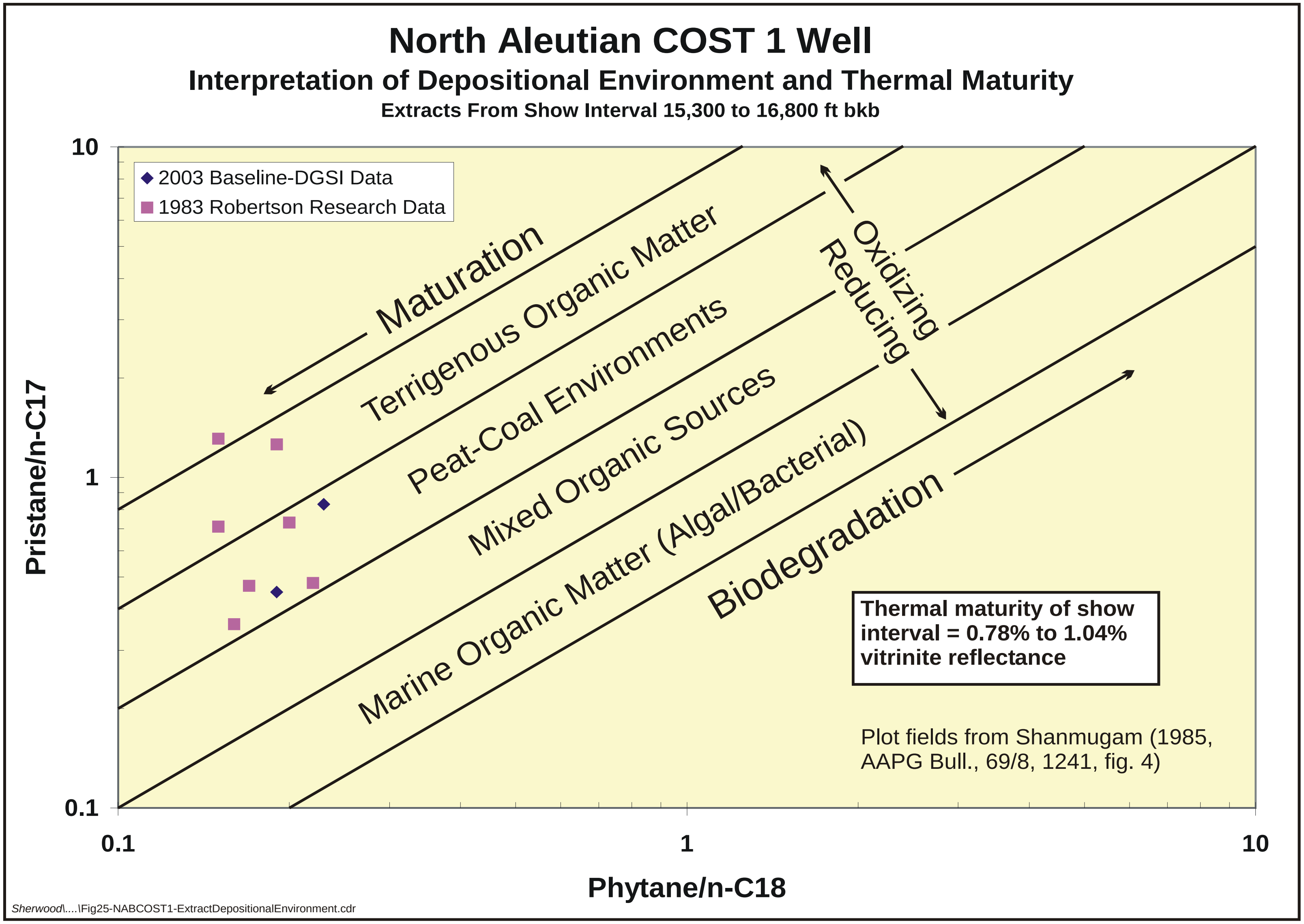


Figure 25: Cross plot for Pristane/n-C17 versus Phytane/n-C18 ratios for rock extracts from the oil show interval in nonmarine Eocene Tolstoi Formation from 15,300 to 16,800 feet bkb in the North Aleutian Shelf COST 1 well. A terrigenous, coal-bearing depositional environment is indicated, consistent with a source within Tertiary nonmarine rocks. All data from Baseline DGSI (2003) and Robertson Research (1983).

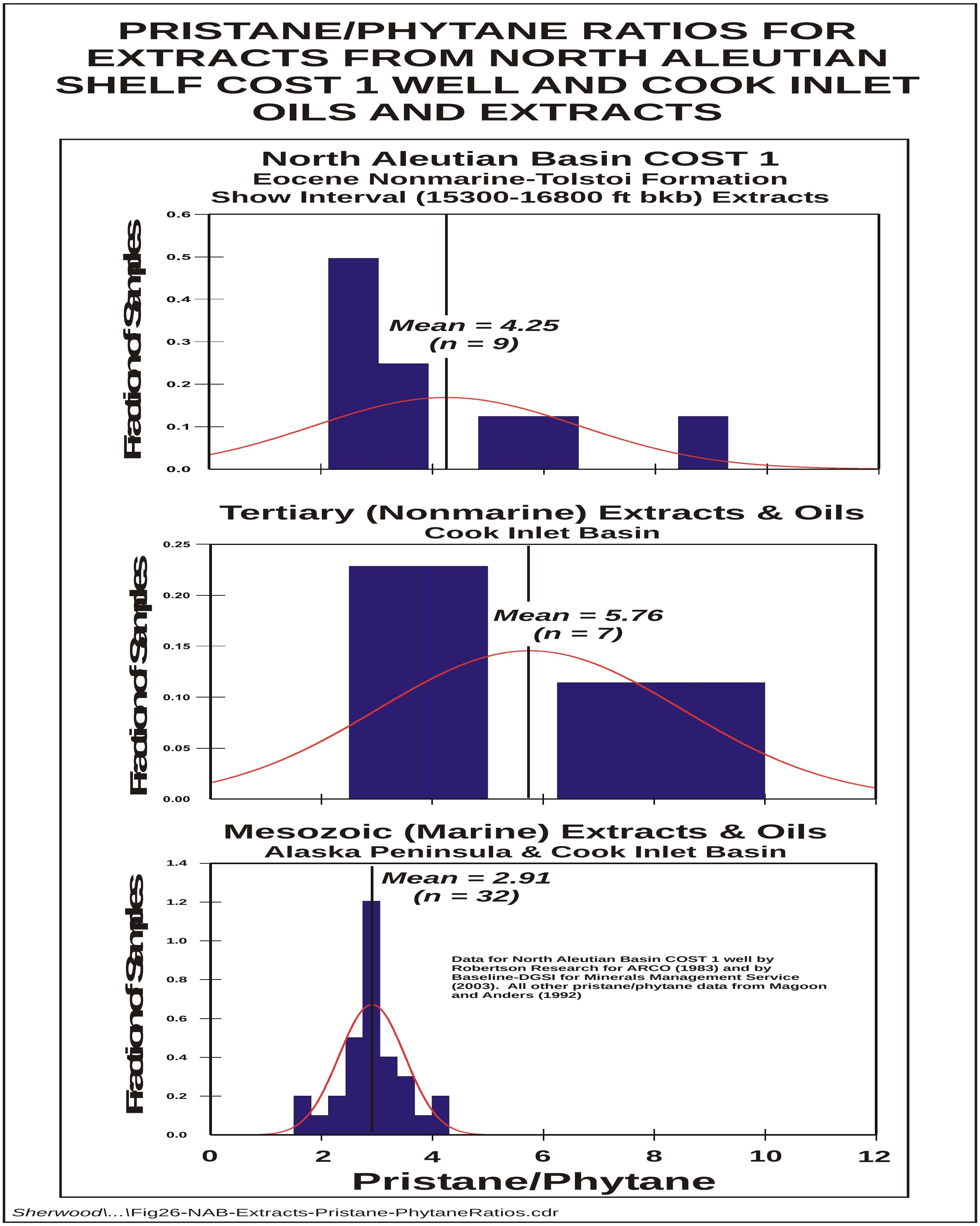


Figure 26: Histograms for Pristane/Phytane ratios of North Aleutian Shelf COST 1 well extracts, Tertiary (nonmarine) extracts and oils, and Mesozoic (marine) extracts and oils. The thermal maturity of the oil show interval in the North Aleutian Shelf COST 1 well ranges from 0.78% to 1.04% vitrinite reflectance. These data suggest that oil shows in the North Aleutian Shelf COST 1 well originated from Tertiary nonmarine sources. All data from Baseline DGSI (2003), Robertson Research (1983), and Magoon and Anders (1992).

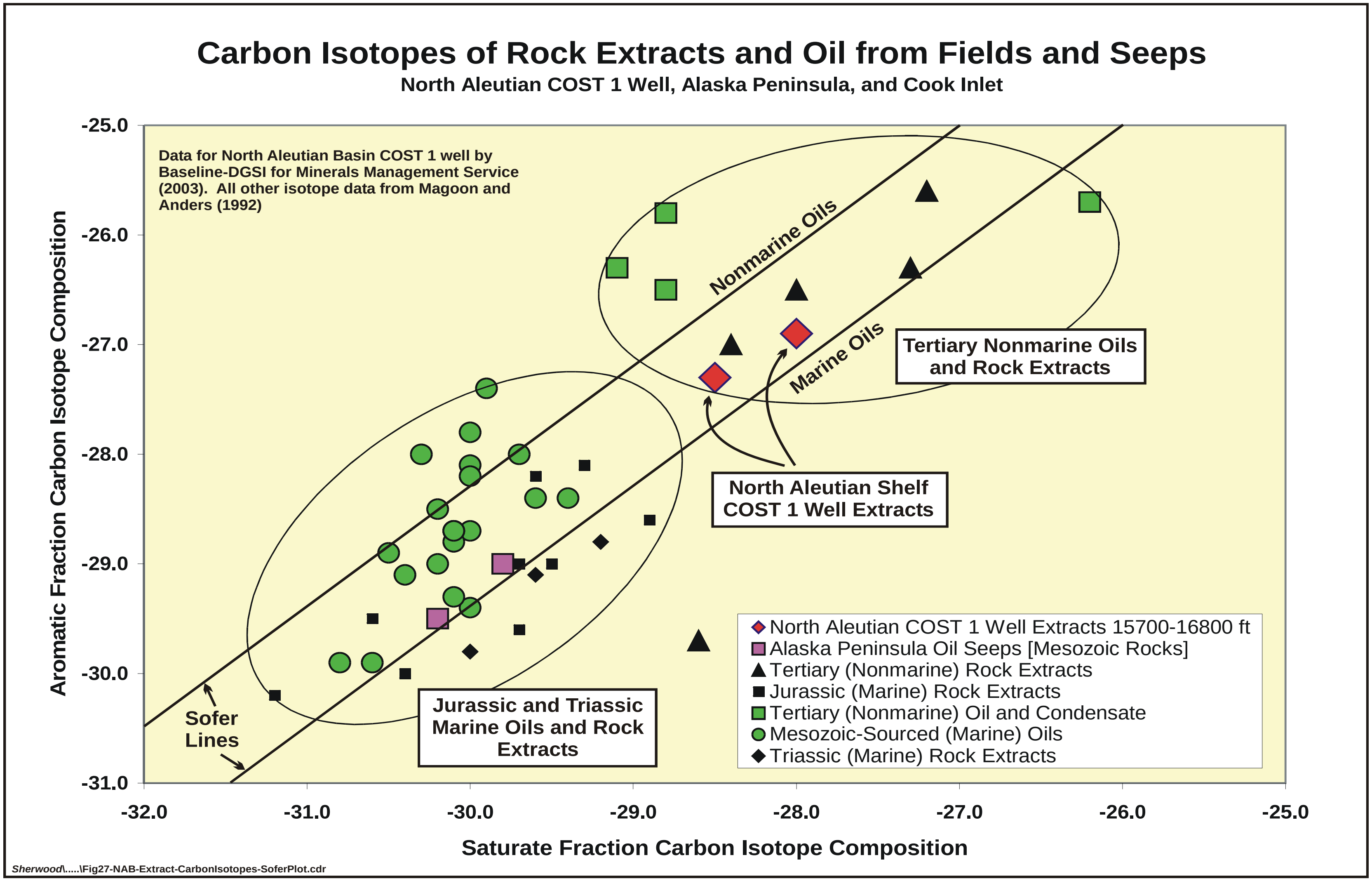


Figure 27: Sofer cross plot for carbon isotopes for aromatics and saturates, comparing North Aleutian Shelf COST 1 well extracts, Tertiary (nonmarine) extracts and oils, and Mesozoic (marine) extracts and oils. The thermal maturity of the oil show interval in the North Aleutian Shelf COST 1 well ranges from 0.78% to 1.04% vitrinite reflectance. These data suggest that oil shows in the North Aleutian Shelf COST 1 well originated from Tertiary nonmarine sources. All data from Baseline DGSI (2003), Robertson Research (1983), and Magoon and Anders (1992).

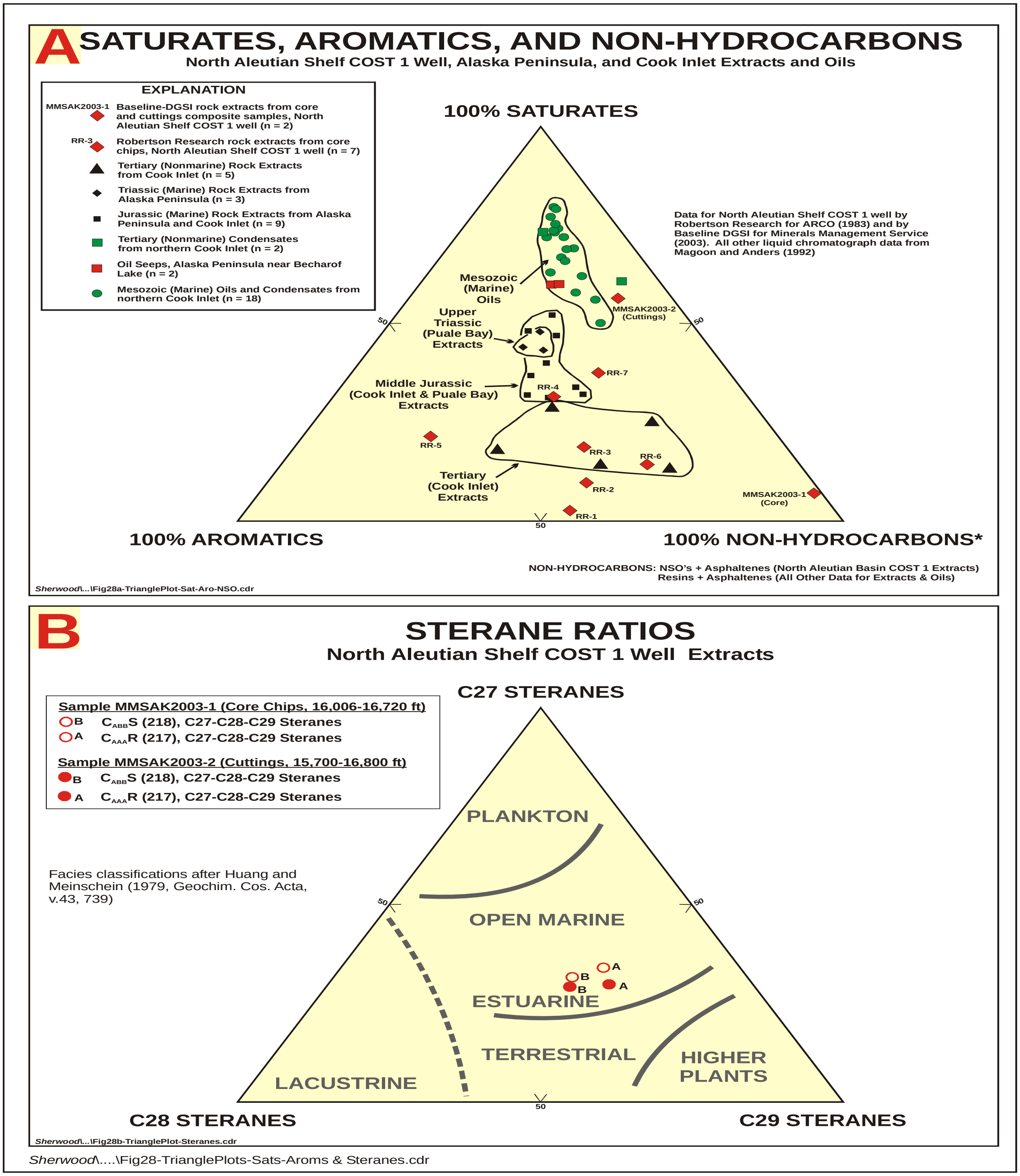


Figure 28: **A)** Triangular plot for saturates versus aromatics versus non-hydrocarbons, North Aleutian Shelf COST 1 well extracts, Tertiary (nonmarine) extracts and oils, and Mesozoic (marine) extracts and oils. The thermal maturity of the oil show interval in the North Aleutian Shelf COST 1 well ranges from 0.78% to 1.04% vitrinite reflectance. These data suggest that oil shows in the North Aleutian Shelf COST 1 well originated from Tertiary nonmarine sources. All data from Baseline DGSI (2003), Robertson Research (1983), and Magoon and Anders (1992). **B)** Triangular plot for C27-C28-C29 steranes for 2 extracts from interval 15,700 to 16,800 ft bkb in the North Aleutian Shelf COST 1 well. Data from Baseline DGSI (2003 and Appendix 3 of this report). C29 steranes are dominant but ratios suggest mixing of marine and nonmarine environments. Facies classifications after Huang and Meinschein (1979) and Shanmugam (1985, fig. 5)

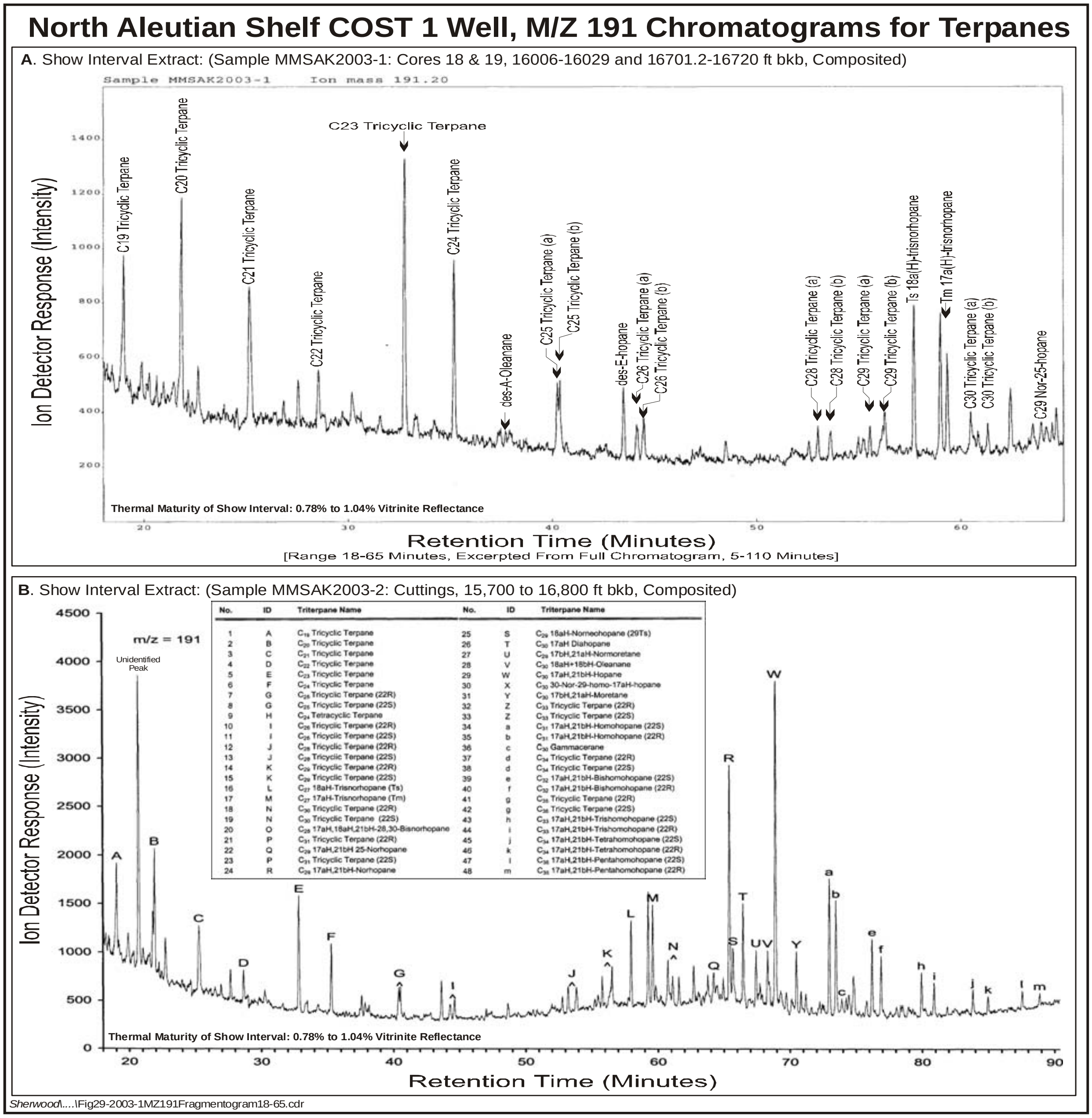
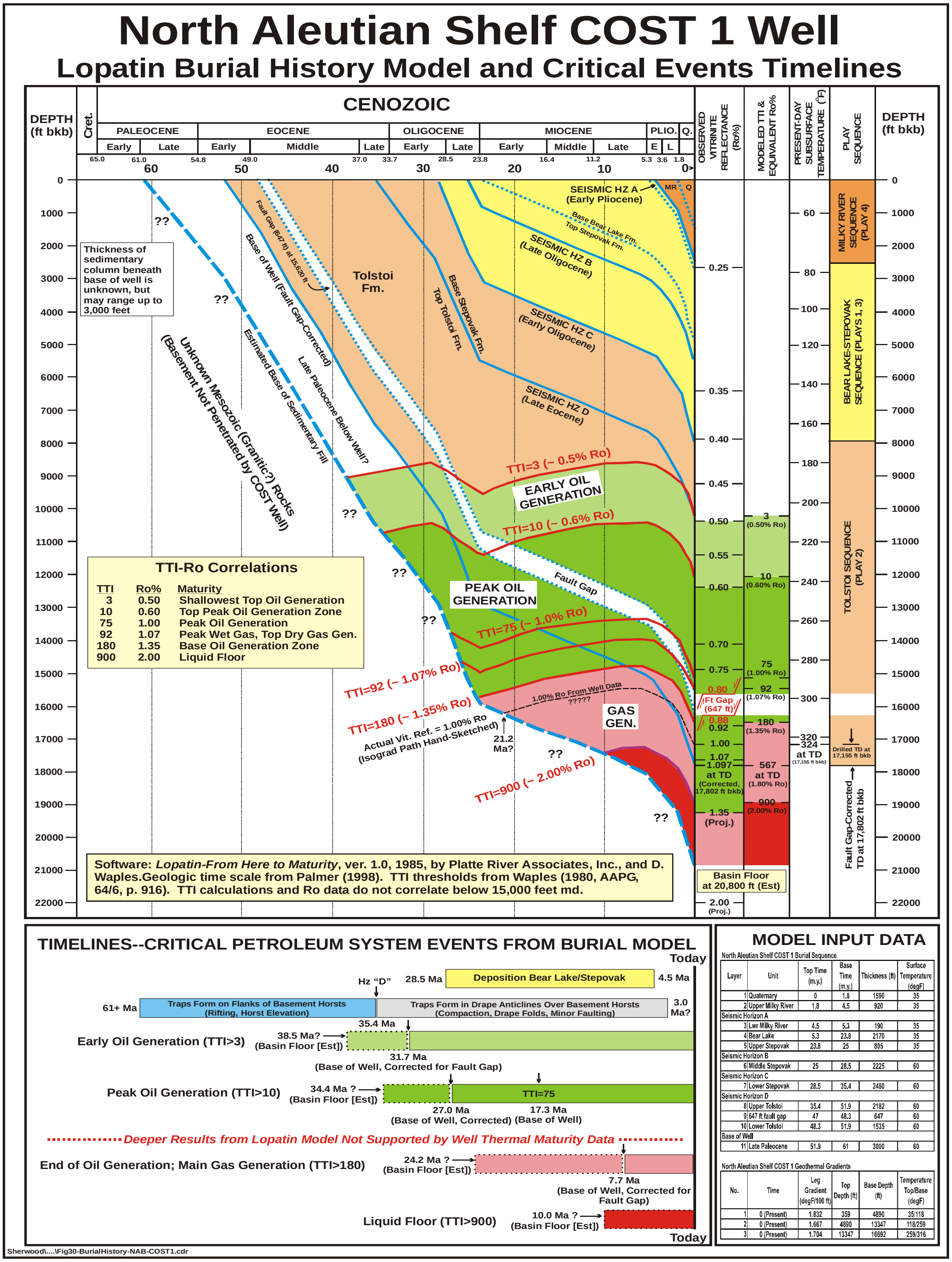


Figure 29: (A) Excerpt from M/Z 191 chromatogram by Baseline DGSI (2003) for an extract from sample MMSAK2003-1, composited from cores 18 and 19, 16,006-16,720 ft bkb, North Aleutian Shelf COST 1 well. (B) Entire M/Z 191 chromatogram by Baseline DGSI (2003) for an extract from sample MMSAK2003-2 composited from cuttings, 15,700-16,800 ft bkb. (When the interval from 15,700-16,800 ft was drilled, the well was uncased below 9-5/8 inch casing at 13,287 ft bkb (Turner et al., 1988, p. 7) and subject to contamination by cave.) Both chromatograms show abundant C19 to C30 tricyclic terpanes, with C23 + C24 peak areas dominant in both samples (C19-tri/C23-tri = 0.43 to 0.75). In the lower chromatogram (for the cuttings extract), a prominent unidentified terpane between peak A (C19-tri) and peak B (C20-tri) is not present in the core extract. This unidentified peak is prominent among condensates of nonmarine (Tertiary) origin in the northern Cook Inlet (Magoon and Anders, 1992, fig. 13.9, spl. 18, and p. 264) but absent from other Cook Inlet samples. Magoon and Anders (1992) and Magoon (1994) have noted that abundant tricyclic terpanes characterize extracts from Upper Triassic rocks at Puale Bay (located in fig. 2) and some oils in southern Cook Inlet basin. However, several other parameters (figs. 25, 26, 27, and 28) suggest that the extracts from the "oil show interval" in the North Aleutian Shelf COST 1 well probably originated from Tertiary nonmarine rocks.



North Aleutian Shelf COST 1 Burial Sequence

Layer	Unit	Top Time (m.y.)	Base Time (m.y.)	Thickness (ft)	Surface Temperature (degF)
1	Quaternary	0	1.8	1590	35
2	Upper Milky River	1.8	4.5	920	35
Seismic Horizon A					
3	Lwr Milky River	4.5	5.3	190	35
4	Bear Lake	5.3	23.8	2170	35
5	Upper Stepovak	23.8	25	805	35
Seismic Horizon B					
6	Middle Stepovak	25	28.5	2225	60
Seismic Horizon C					
7	Lower Stepovak	28.5	35.4	2480	60
Seismic Horizon D					
8	Upper Tolstoi	35.4	51.9	2182	60
9	647 ft fault gap	47	48.3	647	60
10	Lower Tolstoi	48.3	51.9	1535	60
Base of Well					
11	Late Paleocene	51.9	61	3000	60

North Aleutian Shelf COST 1 Geothermal Gradients

No.	Time	Leg Gradient (degF/100 ft)	Top Depth (ft)	Base Depth (ft)	Temperature Top/Base (degF)
1	0 (Present)	1.832	359	4890	35/118
2	0 (Present)	1.667	4890	13347	118/259
3	0 (Present)	1.704	13347	16692	259/316

Figure 30: Burial history plot for North Aleutian Shelf COST 1 well, with timelines for critical petroleum system events.

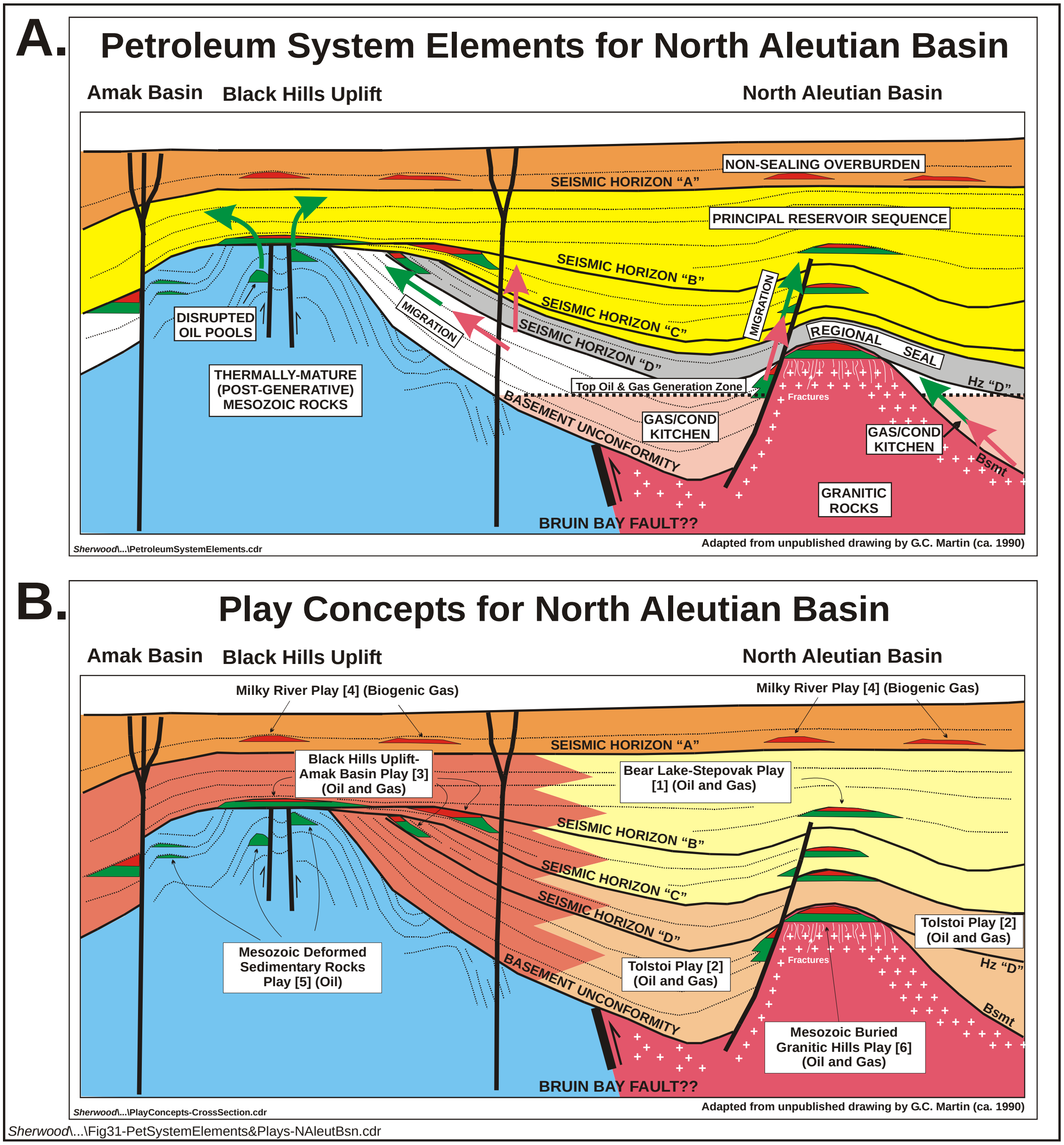


Figure 31: Schematic cross sections illustrating petroleum system elements and play concepts for North Aleutian Basin OCS Planning Area.

A) Petroleum system elements, including regional reservoir sequence floored by a regional seal and underlain by deep gas/condensate "kitchens" in grabens flanking uplifts. Petroleum generated in "kitchens" migrates to traps in shallow reservoir formations draped over basement uplifts via faults that pierce the regional seal. The Black Hills uplift may be reached by long-distance lateral migration of petroleum across highly faulted areas. Fault disruption of Mesozoic oil pools beneath the Black Hills uplift may release oil into overlying strata. Arrows show hypothetical migration paths for gas (red) and oil (green).

B) Six oil and gas plays defined for North Aleutian Basin OCS Planning Area, separated on the basis of reservoir character, structural style, and access to petroleum sources.

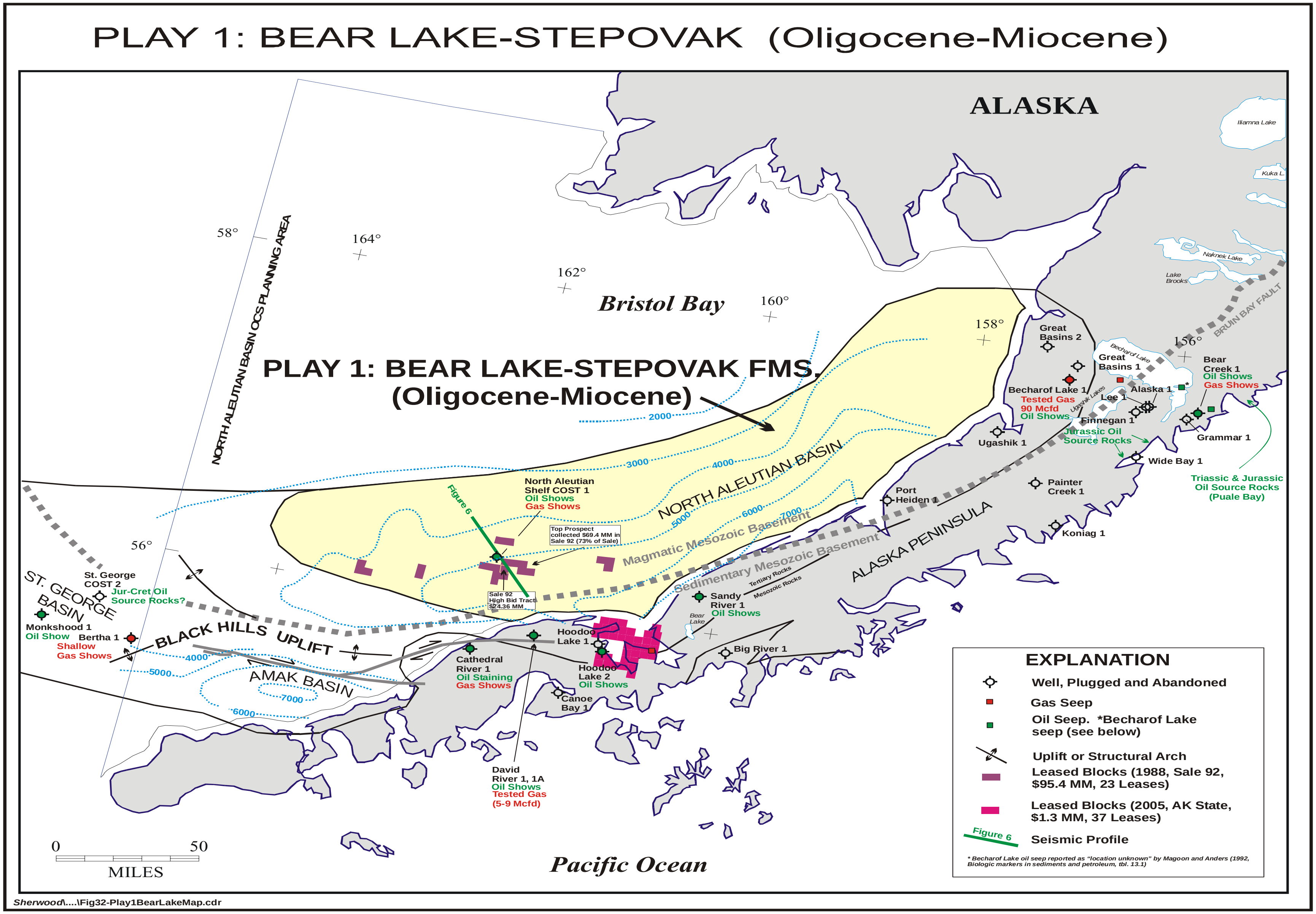


Figure 32: Area of play 1, Bear Lake-Stepovak play, North Aleutian Basin OCS Planning Area, Alaska.

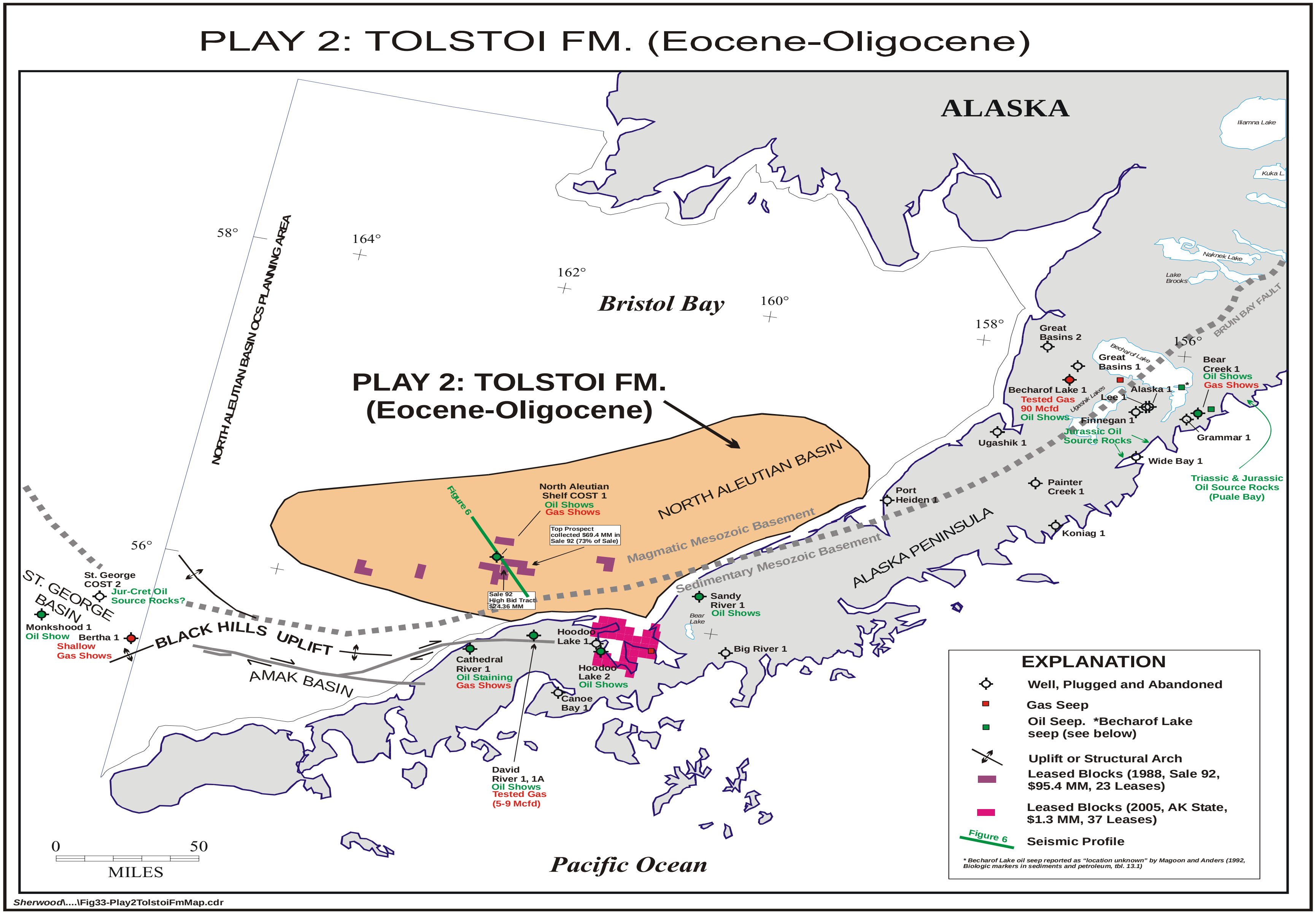


Figure 33: Area of play 2, Tolstoi play, North Aleutian Basin OCS Planning Area, Alaska.

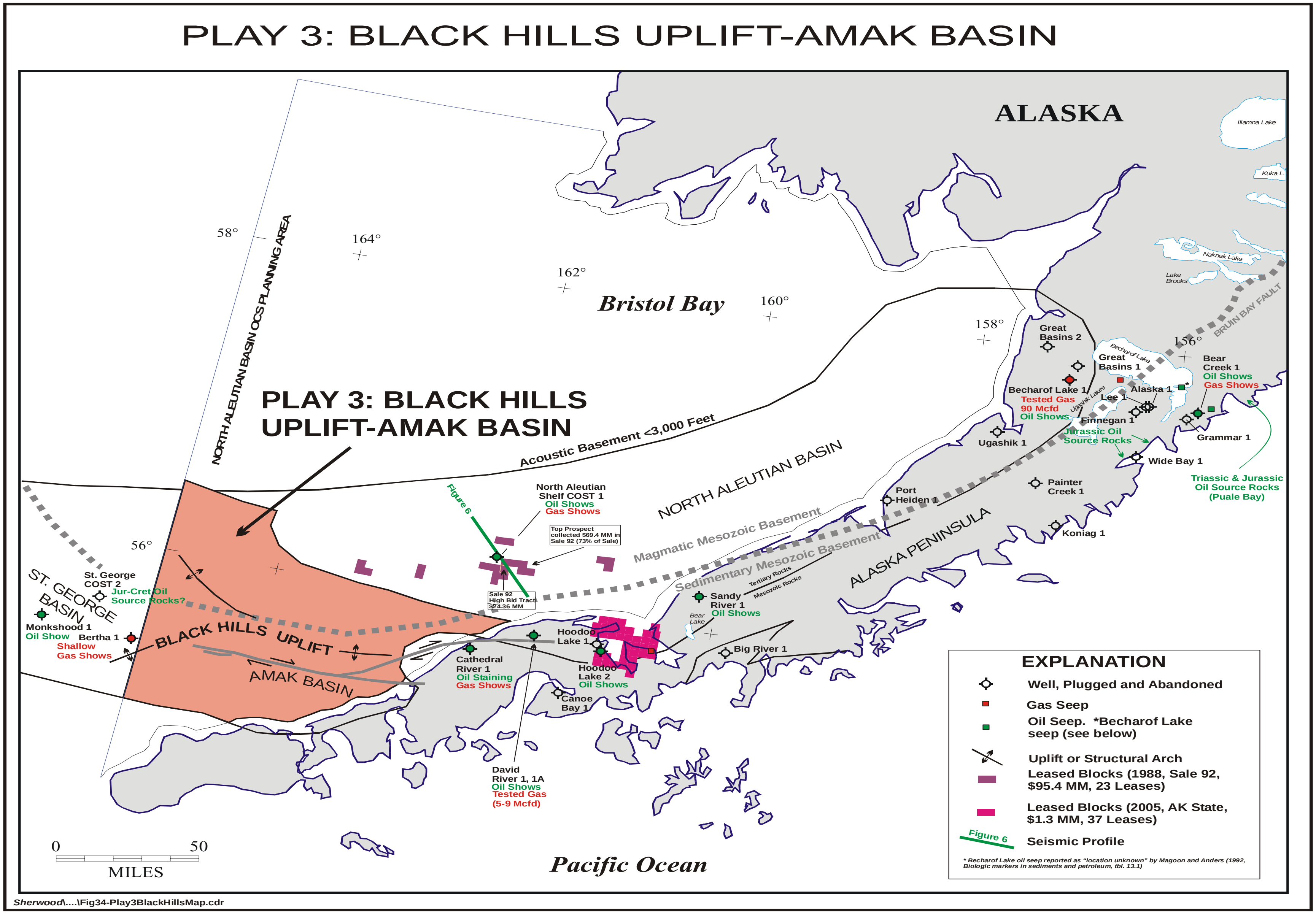


Figure 34: Area of play 3, Black Hills Uplift-Amak Basin, North Aleutian Basin OCS Planning Area, Alaska.

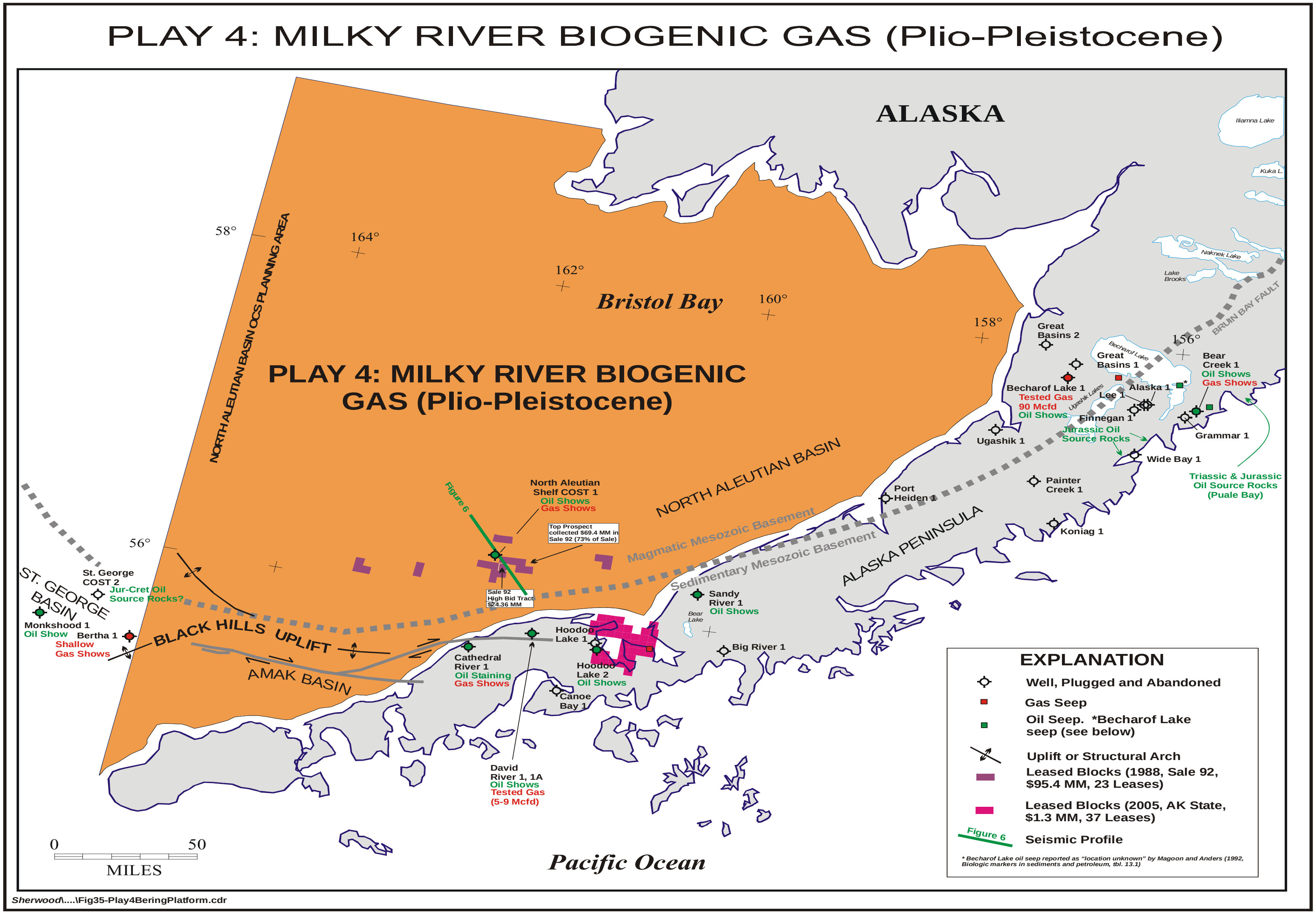


Figure 35: Area of play 4, Milky River Biogenic Gas play, North Aleutian Basin OCS Planning Area, Alaska.

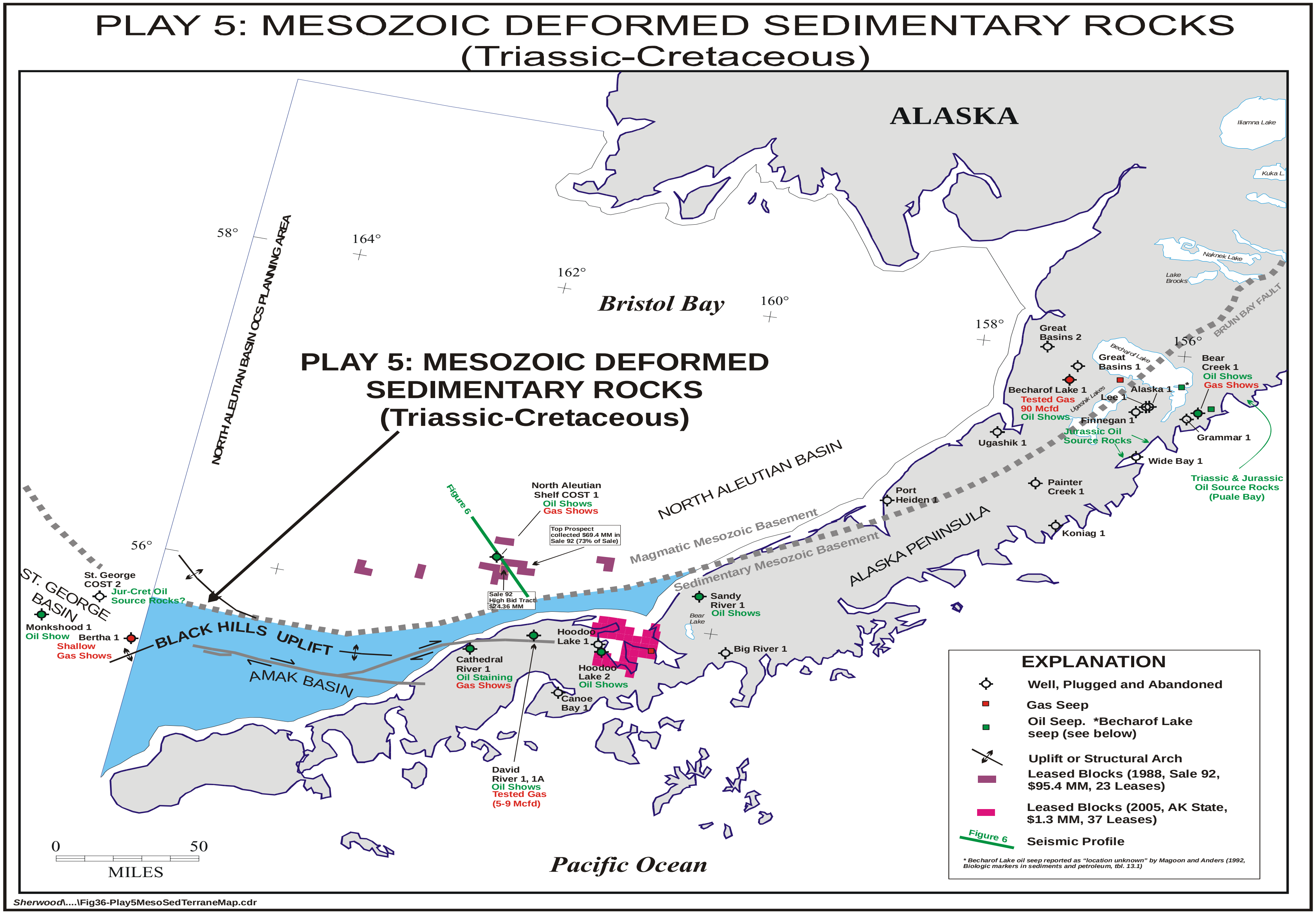


Figure 36: Area of play 5, Mesozoic Deformed Sedimentary Rocks play, North Aleutian Basin OCS Planning Area, Alaska.

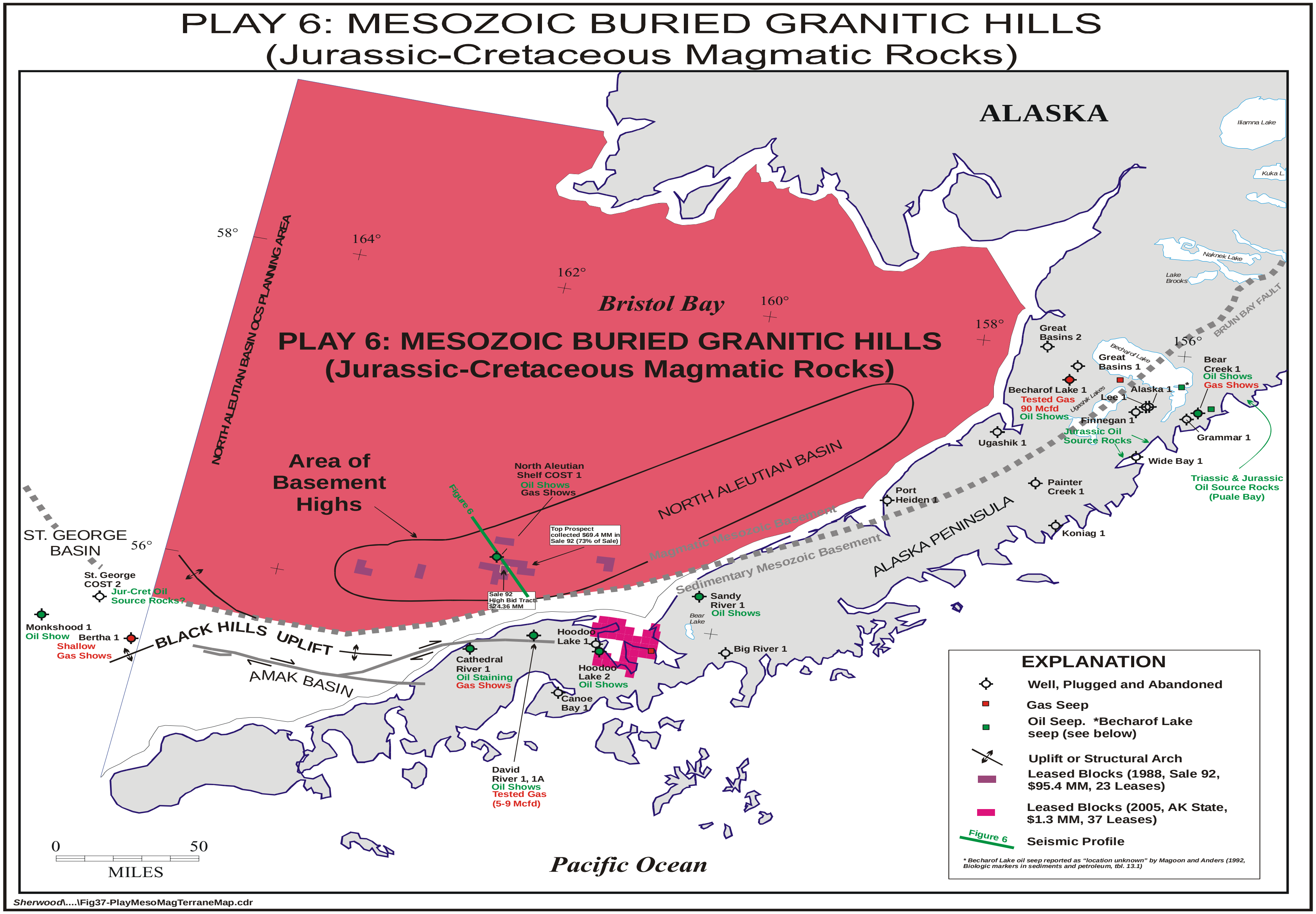


Figure 37: Area of play 6, Mesozoic Buried Granitic Hills play, North Aleutian Basin OCS Planning Area, Alaska.

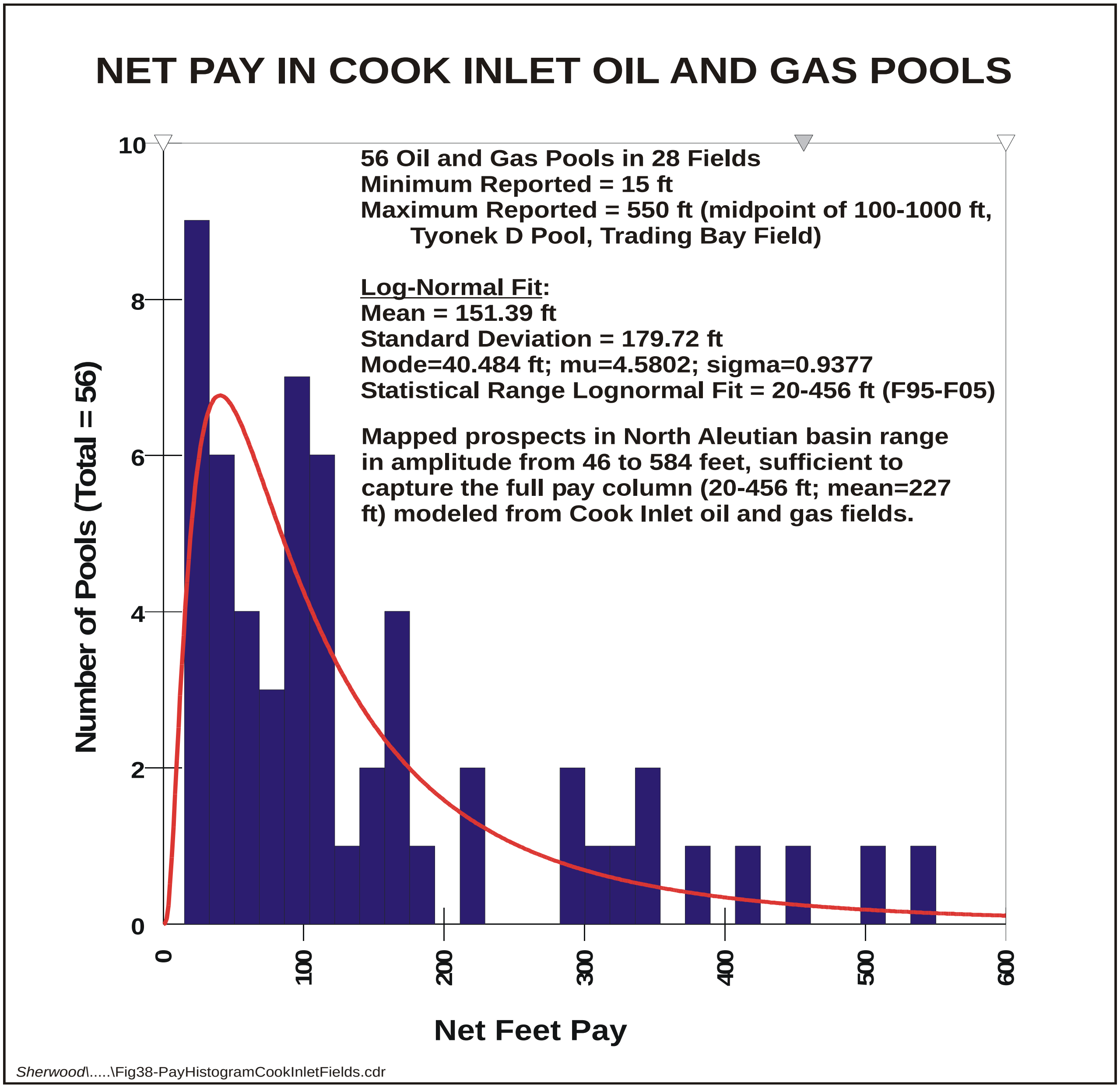


Figure 38: Histogram for pay thickness in Tertiary reservoirs in oil and gas fields of Cook Inlet. The log-normal fit to these data was the basis for the pay thickness model for plays 1 and 3 in the North Aleutian basin. A modified (reduced to reflect lower permeability) version of this distribution formed the pay thickness model for play 2. Data from AOGCC (2001).

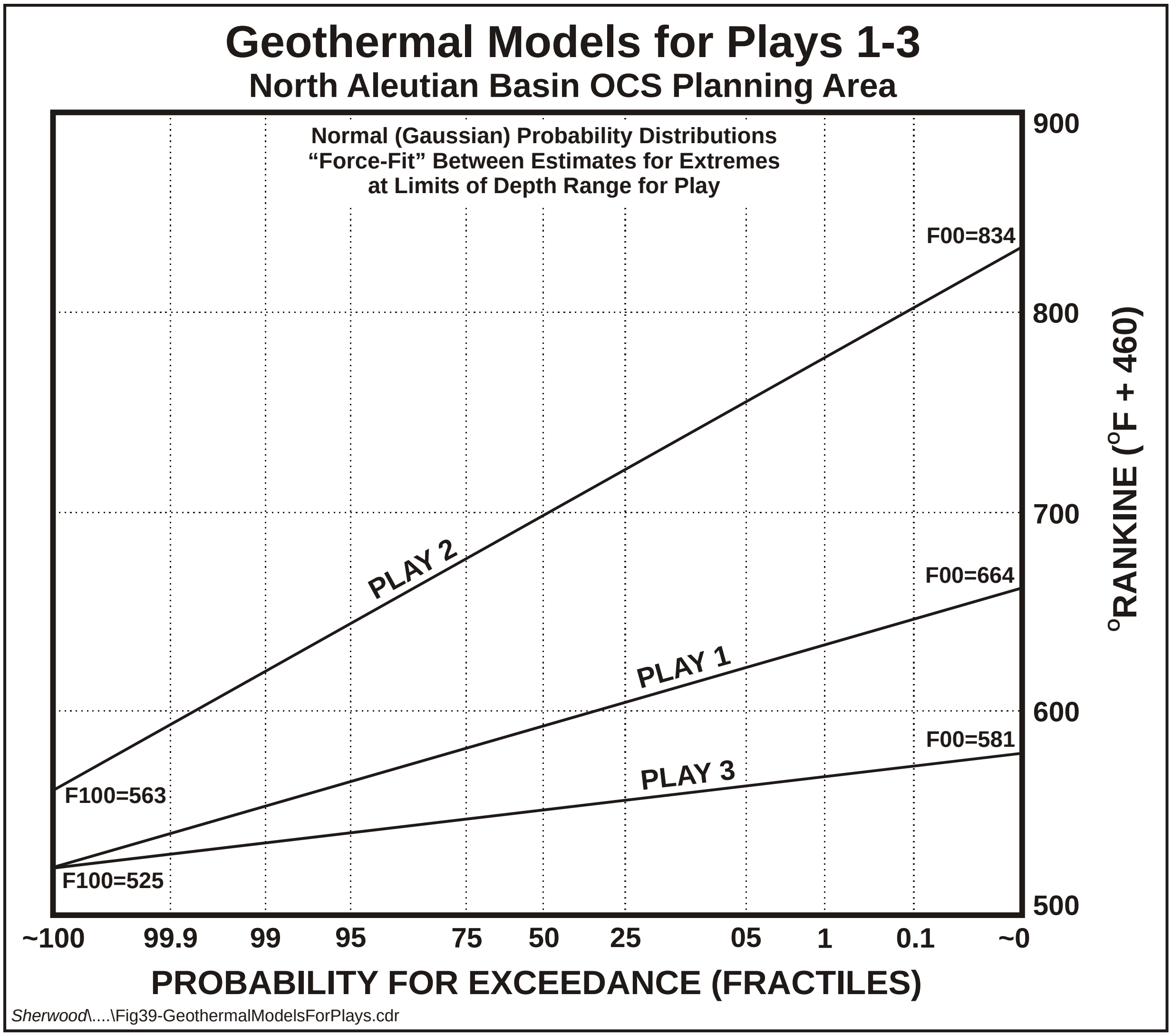
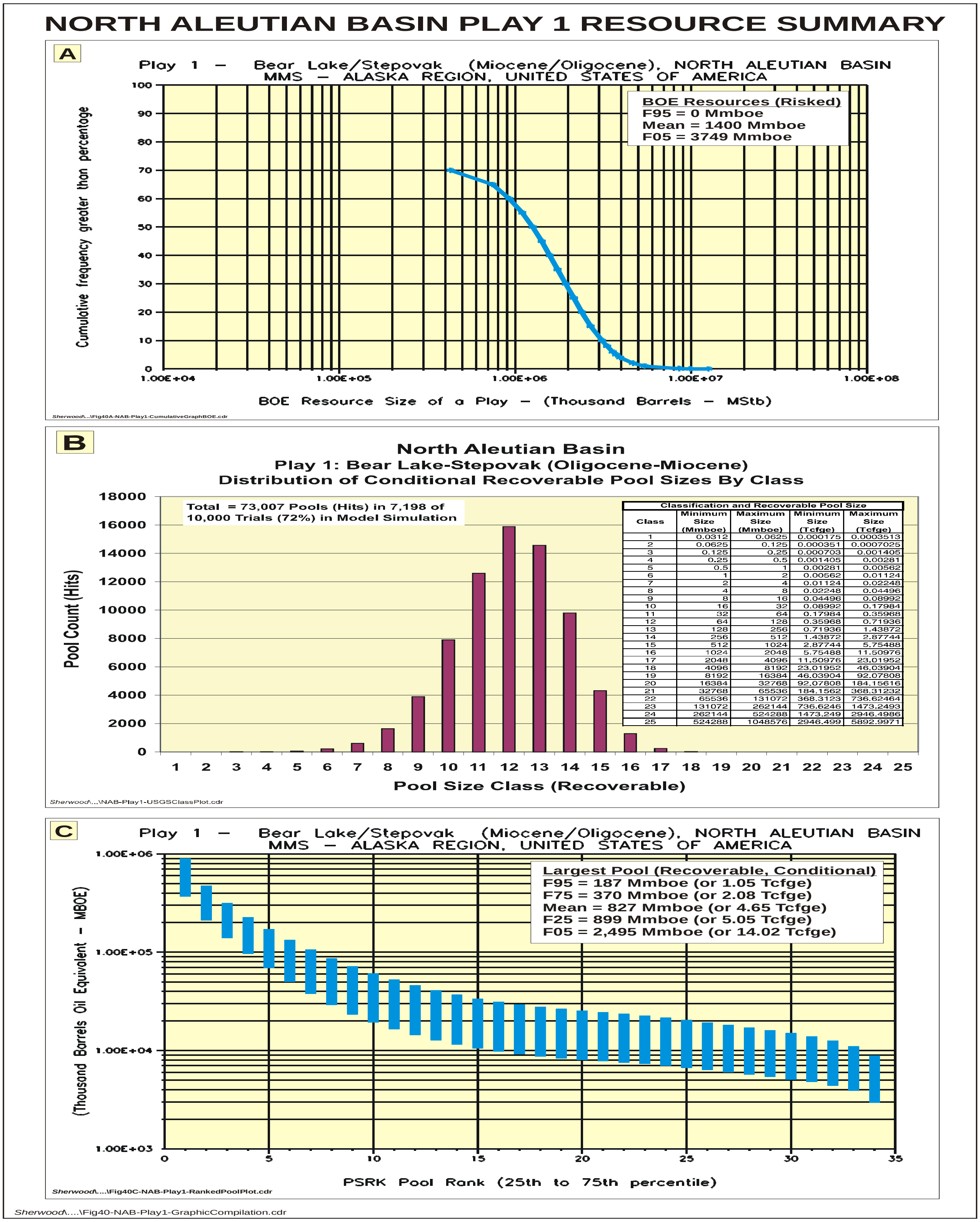
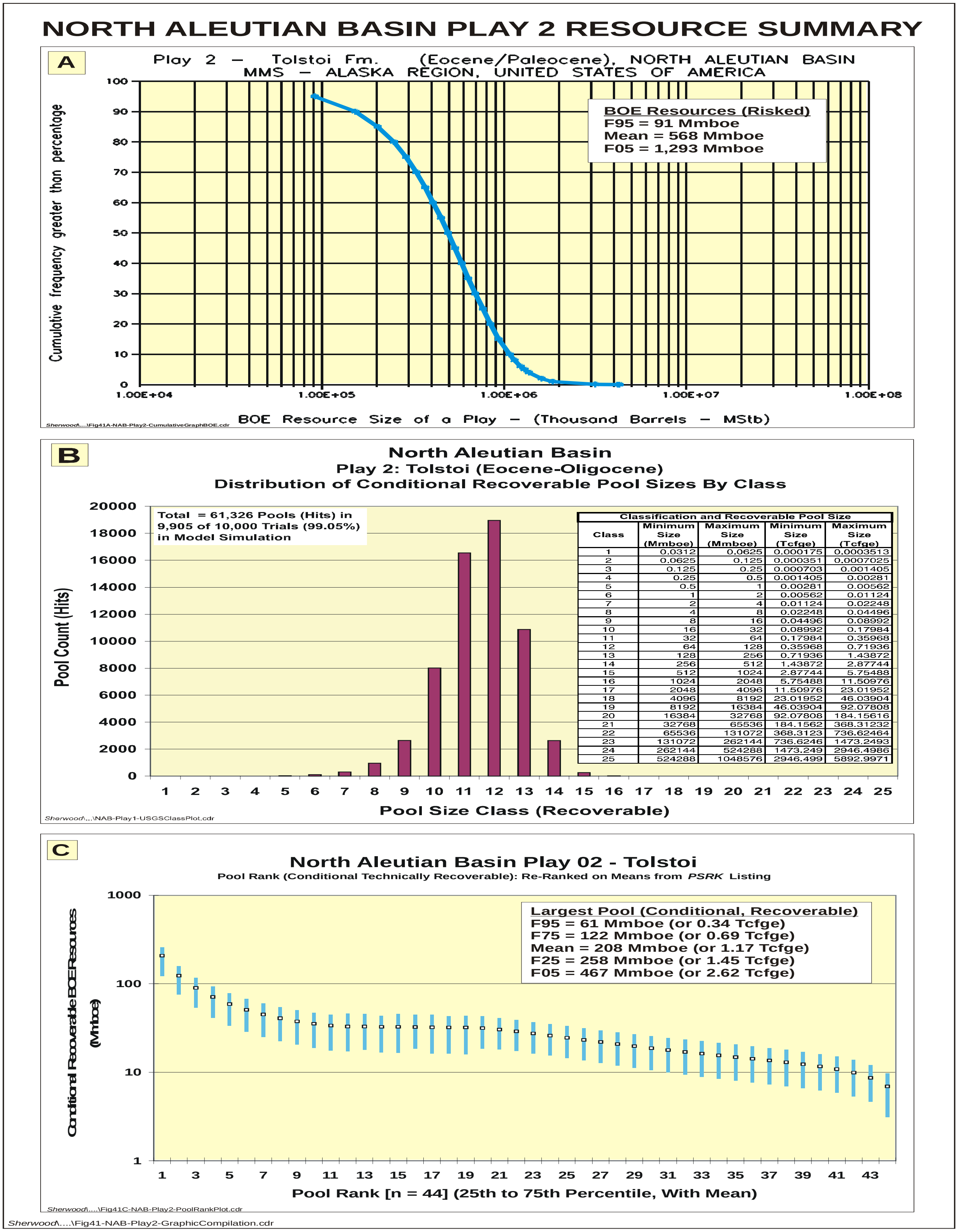


Figure 39: Examples of "force-fit" probability distributions constructed between estimates for extreme values. These geothermal models for North Aleutian plays 1, 2, and 3 are based on depth ranges of plays and a geothermal gradient of 17ºF/1,000 ft at the North Aleutian Shelf COST 1 well (Turner et al., 1988, fig. 92, p. 182).



Classification and Recoverable Pool Size				
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Minimum Size (Tcfge)	Maximum Size (Tcfge)
1	0.0312	0.0625	0.000175	0.0003513
2	0.0625	0.125	0.000351	0.0007025
3	0.125	0.25	0.000703	0.001405
4	0.25	0.5	0.001405	0.00281
5	0.5	1	0.00281	0.00562
6	1	2	0.00562	0.01124
7	2	4	0.01124	0.02248
8	4	8	0.02248	0.04496
9	8	16	0.04496	0.08992
10	16	32	0.08992	0.17984
11	32	64	0.17984	0.35968
12	64	128	0.35968	0.71936
13	128	256	0.71936	1.43872
14	256	512	1.43872	2.87744
15	512	1024	2.87744	5.75488
16	1024	2048	5.75488	11.50976
17	2048	4096	11.50976	23.01952
18	4096	8192	23.01952	46.03904
19	8192	16384	46.03904	92.07808
20	16384	32768	92.07808	184.15616
21	32768	65536	184.1562	368.31232
22	65536	131072	368.3123	736.62464
23	131072	262144	736.6246	1473.2493
24	262144	524288	1473.249	2946.4986
25	524288	1048576	2946.499	5892.9971

Figure 40: Assessment results for North Aleutian Basin OCS Planning Area play 1 (Bear Lake-Stepovak play). (A), cumulative probability plot for total risked recoverable BOE resources (barrels of oil-equivalent); (B), pool class size histogram, conditional recoverable BOE volumes; (C), pool rank plot, conditional recoverable BOE volumes.



Classification and Recoverable Pool Size				
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Minimum Size (Tcfge)	Maximum Size (Tcfge)
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3	0.125	0.25	0.000703	0.001405
4	0.25	0.5	0.001405	0.00281
5	0.5	1	0.00281	0.00562
6	1	2	0.00562	0.01124
7	2	4	0.01124	0.02248
8	4	8	0.02248	0.04496
9	8	16	0.04496	0.08992
10	16	32	0.08992	0.17984
11	32	64	0.17984	0.35968
12	64	128	0.35968	0.71936
13	128	256	0.71936	1.43872
14	256	512	1.43872	2.87744
15	512	1024	2.87744	5.75488
16	1024	2048	5.75488	11.50976
17	2048	4096	11.50976	23.01952
18	4096	8192	23.01952	46.03904
19	8192	16384	46.03904	92.07808
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21	32768	65536	184.1562	368.31232
22	65536	131072	368.3123	736.62464
23	131072	262144	736.6246	1473.2493
24	262144	524288	1473.249	2946.4986
25	524288	1048576	2946.499	5892.9971

Figure 41: Assessment results for North Aleutian Basin OCS Planning Area play 2 (Tolstoi play). (A), cumulative probability plot for total risked recoverable BOE resources (barrels of oil-equivalent); (B), pool class size histogram, conditional recoverable BOE volumes; (C), pool rank plot, conditional recoverable BOE volumes.

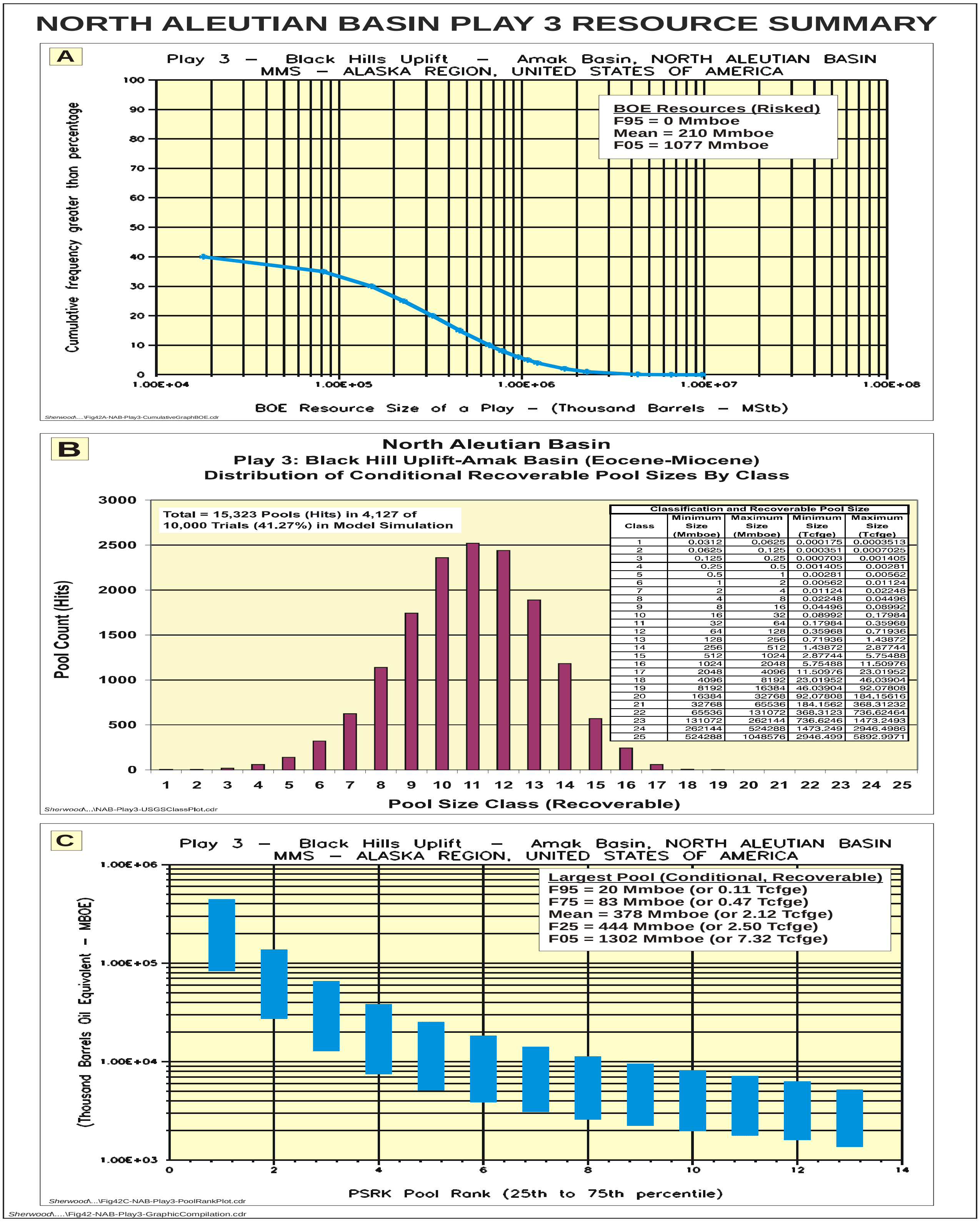

Figure 42: Assessment results for North Aleutian Basin OCS Planning Area play 3 (Black Hills Uplift-Amak Basin play). (A), cumulative probability plot for total risked recoverable BOE resources (barrels of oil-equivalent); (B), pool class size histogram, conditional recoverable BOE volumes; (C), pool rank plot, conditional recoverable BOE volumes.

NORTH ALEUTIAN BASIN PLAY 4 RESOURCE SUMMARY

The Milky River Biogenic Gas play (play 4) is assessed with negligible recoverable gas resources.

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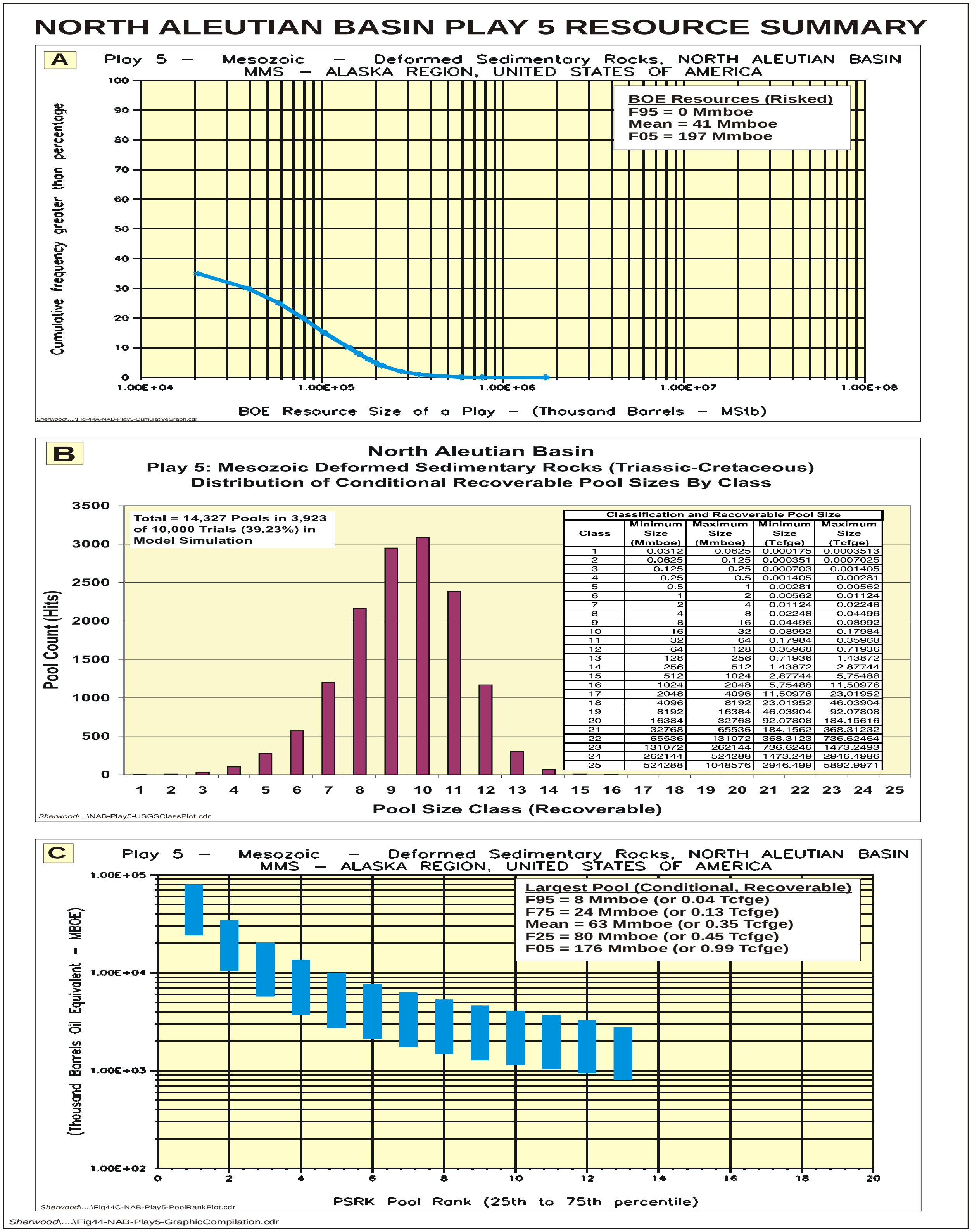
Figure 43: Assessment results for North Aleutian Basin OCS Planning Area play 4 (Milky River Biogenic Gas play).



Classification and Recoverable Pool Size

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3	0.125	0.25	0.000703	0.001405
4	0.25	0.5	0.001405	0.00281
5	0.5	1	0.00281	0.00562
6	1	2	0.00562	0.01124
7	2	4	0.01124	0.02248
8	4	8	0.02248	0.04496
9	8	16	0.04496	0.08992
10	16	32	0.08992	0.17984
11	32	64	0.17984	0.35968
12	64	128	0.35968	0.71936
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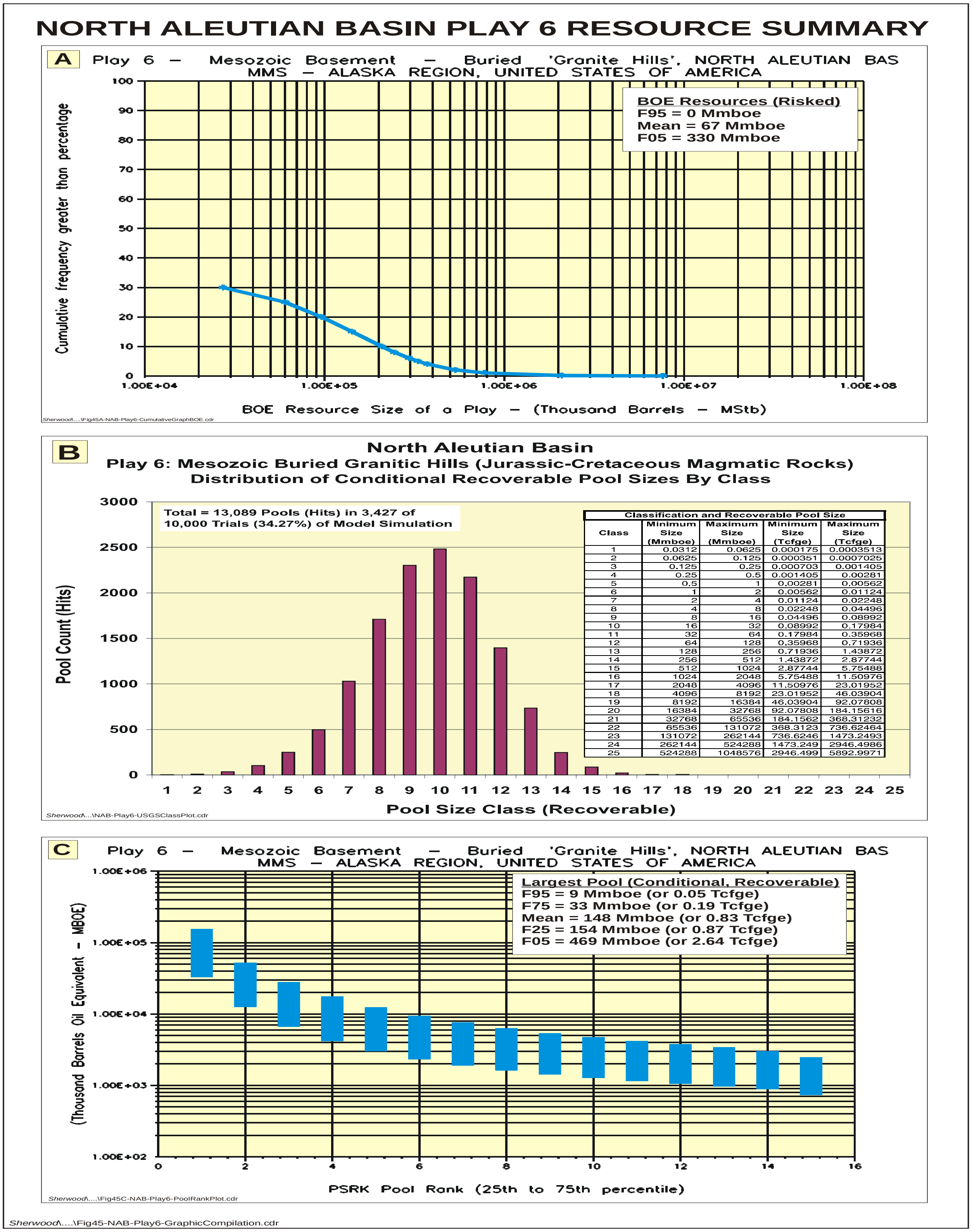
21	32768	65536	184.1562	368.31232
22	65536	131072	368.3123	736.62464
23	131072	262144	736.6246	1473.2493
24	262144	524288	1473.249	2946.4986
25	524288	1048576	2946.499	5892.9971

Figure 44: Assessment results for North Aleutian Basin OCS Planning Area play 5 (Mesozoic Deformed Sedimentary Rocks play). (A), cumulative probability plot for total risked recoverable BOE resources (barrels of oil-equivalent); (B), pool class size histogram, conditional recoverable BOE volumes; (C), pool rank plot, conditional recoverable BOE volumes.



Classification and Recoverable Pool Size				
Class	Minimum Size (Mmboe)	Maximum Size (Mmboe)	Minimum Size (Tcfge)	Maximum Size (Tcfge)
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2	0.0625	0.125	0.000351	0.0007025
3	0.125	0.25	0.000703	0.001405
4	0.25	0.5	0.001405	0.00281
5	0.5	1	0.00281	0.00562
6	1	2	0.00562	0.01124
7	2	4	0.01124	0.02248
8	4	8	0.02248	0.04496
9	8	16	0.04496	0.08992
10	16	32	0.08992	0.17984
11	32	64	0.17984	0.35968
12	64	128	0.35968	0.71936
13	128	256	0.71936	1.43872
14	256	512	1.43872	2.87744
15	512	1024	2.87744	5.75488
16	1024	2048	5.75488	11.50976
17	2048	4096	11.50976	23.01952
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20	16384	32768	92.07808	184.15616
21	32768	65536	184.1562	368.31232
22	65536	131072	368.3123	736.62464
23	131072	262144	736.6246	1473.2493
24	262144	524288	1473.249	2946.4986
25	524288	1048576	2946.499	5892.9971

Figure 45: Assessment results for North Aleutian Basin OCS Planning Area play 6 (Mesozoic Buried Granitic Hills play). (A), cumulative probability plot for total risked recoverable BOE resources (barrels of oil-equivalent); (B), pool class size histogram, conditional recoverable BOE volumes; (C), pool rank plot, conditional recoverable BOE volumes.

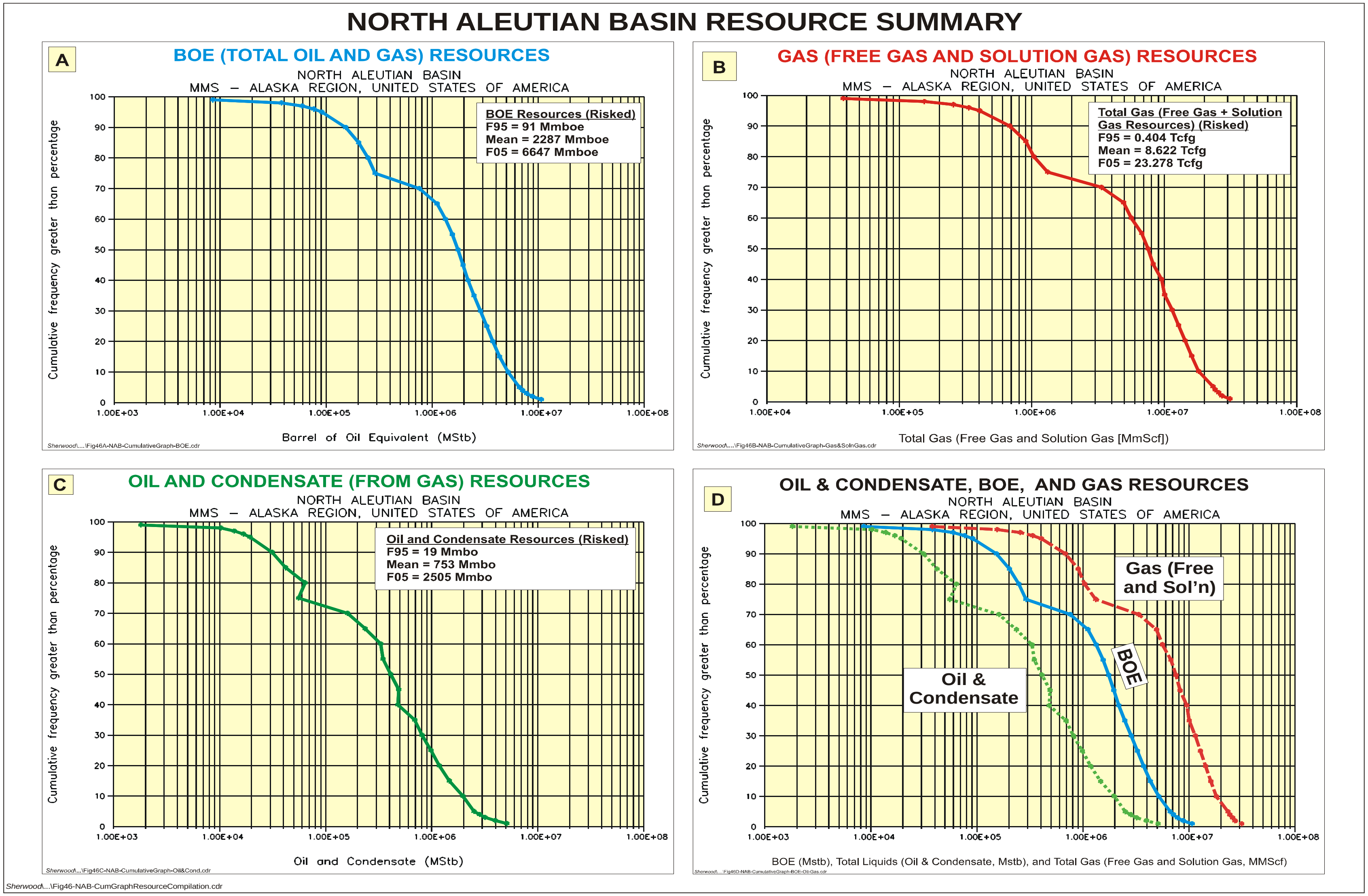

Figure 46: Assessment results for North Aleutian Basin OCS Planning Area. (A), cumulative probability plot for total risked recoverable BOE resources (oil and gas in barrels of oil-equivalent); (B), cumulative probability plot for total risked recoverable liquid (oil + condensate from gas) resources; (C), cumulative probability plot for total risked recoverable gas (free gas and solution gas) resources; (D), comparative cumulative probability plot for oil & condensate, BOE, and gas (free gas and solution gas).

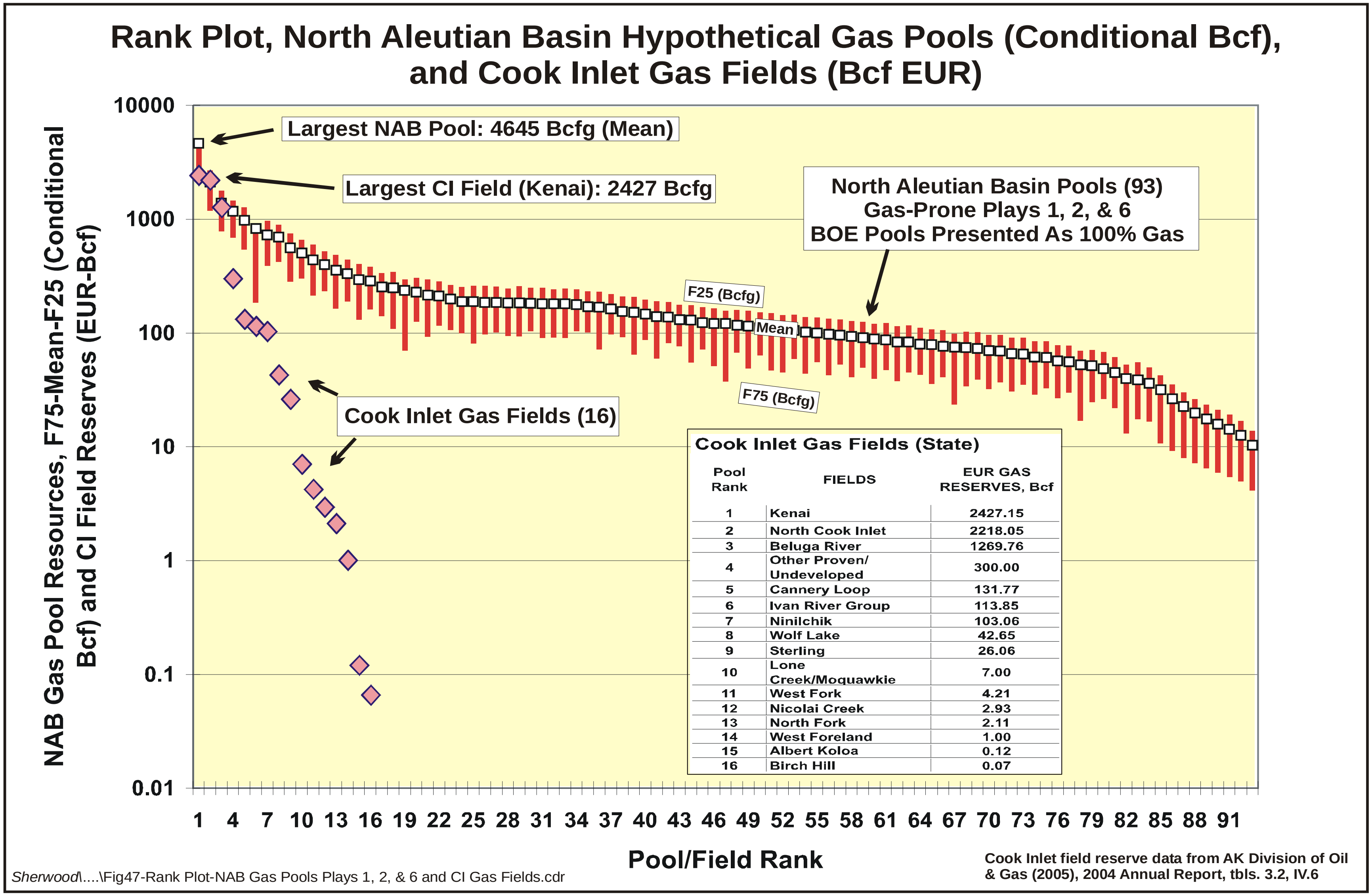

Figure 47: Hypothetical gas pools in gas-prone plays (1, 2, and 6) of North Aleutian basin are comparable in size to the gas fields of Cook Inlet basin. The largest hypothetical pool in North Aleutian basin could be almost twice the size of the Kenai gas field in Cook Inlet. Total Cook Inlet EUR = 11.6 Tcf gas. The North Aleutian Basin OCS Planning Area is estimated to contain 8.6 Tcf gas (mean, risked, technically-recoverable).

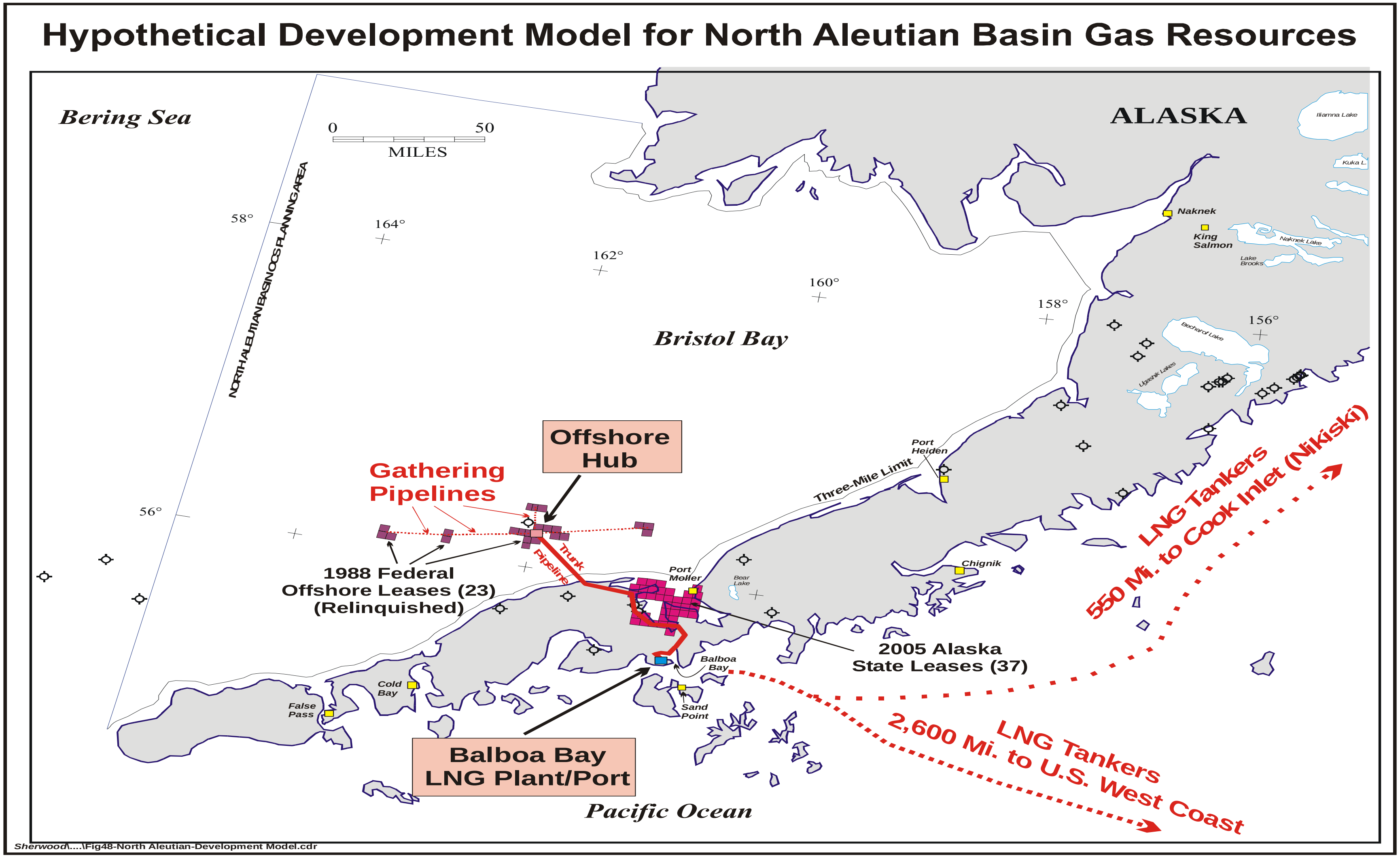

Figure 48: Hypothetical development model for North Aleutian basin gas resources. Platforms and subsea completions at offshore gas fields direct the gas into gathering pipelines that carry the gas to an offshore hub. A 75-mile pipeline (25 miles subsea, 50 miles overland) then carries the gas to a hypothetical liquefied natural gas (LNG) plant at Balboa Bay (site in southwest arm identified in 1980 study by Dames & Moore). At the LNG plant the gas is refrigerated to a liquid state (-260ºF) preparatory to shipping via LNG tankers to hypothetical receiving and re-gasification facilities in Cook Inlet or along the U.S. (or Canada or Mexico) West Coast.