Chapter PS (Petroleum Systems)

EVALUATION OF HYDROCARBON CHARGE AND TIMING USING THE PETROLEUM SYSTEM

by Leslie B. Magoon[1], Kenneth J. Bird[1], Robert C. Burruss[2], Dan Hayba[2], David W. Houseknecht[3], Margaret A. Keller[1], Paul G. Lillis[4], and Elisabeth L. Rowan[1]

in The Oil and Gas Resource Potential of the 1002 Area, Arctic National Wildlife Refuge, Alaska, by ANWR Assessment Team, U.S. Geological Survey Open-File Report 98-34.

1999

[1] U.S. Geological Survey, MS 969, Menlo Park, CA 94025
[2] U.S. Geological Survey, MS 956, Reston, VA 20192
[3] U.S. Geological Survey, MS 915, Reston, VA 20192
[4] U.S. Geological Survey, MS 977, Denver, CO 80225

This report is preliminary and has not been reviewed for conformity with U.S. Geological Survey editorial standards (or with the North American Stratigraphic Code). Use of trade, product, or firm names is for descriptive purposes only and does not imply endorsement by the U. S. Geological Survey.

Click here or on this symbol in the toolbar to return.

TABLE OF CONTENTS

FIGURES

PLATES

TABLES

PS4. Carbon isotopic values for saturated and aromatic hydrocarbons from tables PS2 and PS3 and plotted on Plate PS1.
PS5. Oil and gas shows in wells adjacent to the 1002 area for the Ellesmerian(!) petroleum system.
PS6. Oil and gas shows in wells adjacent to the 1002 area for Hue-Thomson(!) petroleum system.
PS7. Oil and gas shows in wells adjacent to the 1002 area for the Canning-Sagavanirktok(?) petroleum system.
PS8. Fluid inclusion information by petroleum system.

DIGITAL DATA

Associated with this chapter PS is a digital (spreadsheet) file, "PS1778.xls", located on this cdrom in a data appendix. This file contains laboratory data on outcrop rock and oil samples; these data on individual samples were summarized in Tables 11.3 through 11.7 of Magoon and others (1987) and Table 12.1 of Anders and others (1987).

UNIT ABBREVIATIONS

BBO ....Billions of barrels of oil

bbl ....Barrels

USGS
science for a changing world

ABSTRACT

Three petroleum systems are responsible for the oil and gas occurrences in and adjacent to the 1002 area. Material balance calculations suggest these three systems could have provided a hydrocarbon charge of about 30 billion barrels of oil (BBO) to the 10 plays evaluated in this assessment. The Ellesmerian(!) petroleum system is responsible for the large volumes of oil in the Prudhoe Bay area, the Mikkelsen area, and in some Paleocene Canning turbidites in the Point Thomson-Flaxman Island area. South of the 1002 area, the Triassic Shublik Formation is the source rock that became thermally mature in the interval 75 to 35 Ma. Oil expelled from this source rock has an API gravity of about 25°, sulfur content of 0.9 percent, and a gas-to-oil ratio of 1000 ft^3 /bbl. Calculations suggest that as much as 11 BBO migrated north toward the east plunge of the Barrow arch in the 1002 area. Traps included in the Thomson, Kemik, Undeformed and Deformed Franklinian, and Thin-Skinned and Ellesmerian Thrust-Belt plays are most likely charged by the Ellesmerian(!).

The Hue-Thomson(!) petroleum system is responsible for the oil and gas in the Thomson sand and some Canning turbidites in the Point Thomson-Flaxman Island area. The Cretaceous Hue Shale is the source rock that thermally matured in the interval 52 to 10 Ma as an arcuate front that extended from the Hulahula low around to the south of the 1002 area and moved toward the Point Thomson area as overburden rock was added. Oil expelled from this source rock has an API gravity of about 35°, sulfur content of 0.4 percent, and a gas-to-oil ratio of 6,000 ft^3/bbl. Calculations suggest that as much as 9 BBO migrated from the south and east from the Hulahula low as an arcuate front that impinged on the east end of the Barrow arch. Traps included in the Topset, Turbidite, Wedge, Kemik, Undeformed and Deformed Franklinian, and Thin-Skinned Thrust-Belt plays are most likely charged by the Hue-Thomson(!).

The Canning-Sagavanirktok(?) petroleum system is responsible for the oil and gas in the Hammerhead and Kuvlum fields offshore, oil shows in the Aurora 1 well, the seep at Manning Point, and oil-soaked tundra at Angun Point. Organic-rich shales in the Cretaceous Canning Formation are suspected to be the source rock for the oil and gas that migrated from the offshore toward the 1002 area from 15 Ma to the present day. Oil expelled from this source rock has an API gravity of about 35° or higher, sulfur content of <0.1 percent, and a gas-to-oil ratio of 10,000 ft^3 /bbl. Calculations suggest that about 10 BBO of in-place oil may have been

available to be trapped. Traps included in Topset and Thin-Skinned Thrust-Belt plays are most likely charged by the Canning-Sagavanirktok(?).

INTRODUCTION

The purpose of this paper is to incorporate geological and geochemical data from previous studies to recently acquired results and interpretations included in this Open-File Report to identify, name, and map the petroleum systems in and adjacent to the 1002 area in order to better evaluate the volume of petroleum charge and the time the charge arrived in the areas of the 10 plays. Within and adjacent to the 1002 area, there are indications that commercial accumulations of petroleum could occur, such as oil-stained tundra and sandstones and seep(s) that are proof that oil migrated from deeper accumulations or from active source rocks. Also, Point Thomson-Flaxman Island, Badami, and Sourdough are discovered but undeveloped fields adjacent to the northwest corner of the 1002 area (Bird, Chap. GG).

The geologic setting of the 1002 area is discussed by Bird (Chap. GG). The stratigraphic framework is discussed by Kelley (Chap. BR), DuMoulin (Chap. CC), Schenk and Houseknecht (Chap. TK), and Houseknecht (Chap. BS). Biostratigraphic analysis is provided by Poag (Chap. BI). The tectonic framework is discussed by Cole and others (Chap. SM), Potter and others (Chap. BD), and Grow and others (Chap. NA). The timing of burial and deformation are constrained by fission track analysis by Murphy (Chap. FT). Thermal maturity of source and reservoir rocks using vitrinite reflectance is examined by Bird (Chap. VR). Burial history and modeling exercises are carried out by Hayba and Houseknecht (Chap. TE), Houseknecht and Hayba (Chap. HG), and Rowan (Chap. BE). Organic carbon content of potential source rocks is determined using wireline logs by Keller and others, (Chap. SR). Using fluid inclusions, Burrus (Chap. FI) reconstructs migration paths for oil. Lillis and others (Chap. OA) identifies and characterizes oil types and oil-to-source-rock correlations An assessment overview is by Bird (Chap. AO), and each play is summarized by Houseknecht (Chaps. P1, P2, P3), Schenk (Chaps. P4, P5), Kelley (Chap. P6), Grow (Chaps. P7, P9, P10), and Perry (Chap. P8). This chapter takes the results of these studies and places them in the context of the petroleum system to show how the assessment team evaluated hydrocarbon charge and timing.

PETROLEUM SYSTEM

The petroleum system includes the essential elements and processes as well as all genetically related hydrocarbons that occur in petroleum shows, seeps, and accumulations whose provenance is a single pod of active source rock (Magoon and Dow, 1994b). The petroleum system is the naturally occurring hydrocarbon-fluid system in the geosphere. The petroleum-system concept infers that, by reason of the provenance of genetically related oil and gas accumulations, migration pathways must exist, either now or in the past, connecting the provenance with the accumulations. Using the principles of petroleum geochemistry and geology, this fluid system can be mapped in the geosphere to better understand how and when it could charge undiscovered traps.

In order to properly discuss the petroleum system, it must be named (Magoon and Dow, 1994b). It is a compound name that includes the source rock in the pod of active source rock, the reservoir rock containing the largest volume of petroleum, and the level of certainty of a petroleum system, for example, the Hue-Thomson(!). If the source rock and the major reservoir rock have the same name, then only one name is used, such as the Ellesmerian(!). The level of certainty is the measure of confidence that petroleum from a series of genetically related accumulations originated from a specific pod of active source rock. Three levels used are known (!), hypothetical (.), and speculative (?), depending on the level of geochemical, geological, and geophysical evidence.

Our goal is to map the evolution of three natural fluid systems, or petroleum systems, over time to better evaluate the 10 plays in the 1002 area. Our ability to characterize and map these petroleum systems has improved from the last assessment in 1987 because of new analytical tools and better interpretive skills. Seismic data processing and interpretation; modeling burial history and basin evolution; identifying oil types; mapping source, reservoir, seal, and overburden rocks; and mapping traps have all improved and are discussed in other chapters. However, the petroleum-system process of generation-migration-accumulation is discussed here to show how petroleum occurrence is used in the assessment process.

Thermal Zones of Petroleum Occurrence

The generation-migration-accumulation is one petroleum-system process that includes the generation and movement of petroleum from the pod of active source rock to the petroleum show, seep, or accumulation (Magoon, and Dow, 1994a). Direct physical evidence that a source rock has expelled oil and gas is usually lacking--that is, the source rock fails to become oily. Indirect evidence that a source rock expelled oil and gas is its close stratigraphic proximity to a thermally mature or active source rock and a positive geochemical correlation between the oil and source-rock extract.

Petroleum geochemists agree that the occurrence of petroleum in the subsurface is related to temperature, either to the generation and expulsion of oil and gas from the source rock, or to the accumulation, cracking, and preservation of hydrocarbons in its reservoir rock in a trap. Petroleum geologists recognize that subsurface temperature increases with depth at a rate specified by the geothermal gradient, that the present-day gradient probably differs from the paleogradient, and that vitrinite reflectance measures a maximum temperature along this gradient. The maximum subsurface temperature for any rock unit is assumed to occur at maximum burial depth, past or present, and is the thermal maturity of that source or reservoir rock. Thus, thermal maturity, rather than depth, is the best way to describe petroleum occurrence.

The thermal zones of petroleum occurrence are related to the thermal maturity of the active source rock or reservoir rock (Figure PS1). Four thermal zones are separated by three thresholds of thermal maturity as measured by vitrinite reflectance. Vitrinite reflectance of approximately 0.6% R_o separates the shallower petroleum accumulations from the active source rock, or the provenance of the oil and gas. Reflectance values of approximately 1.0% R_o is the thermal maturity level at which expelled oil in a reservoir rock is starting to crack to lighter oil and wet gas, and 2.0% R_o is the thermal maturity level at which all the light oil has been cracked to dry gas.

Zone of Accumulation. The zone of accumulation occurs where from the pod hydrocarbons, or oil and gas, have been able migrate updip of active source rock to accumulate in a trap at a lower temperature (Figure PS1). This lower temperature insures that thermal cracking of the heavier hydrocarbons cannot occur. However, biodegradation of the oil to a heavier oil frequently occurs if the oil migrates to a trap that is too shallow, or if it migrates to the surface. In addition, as oil that contains dissolved gas migrates to a lower pressure, or shallower depth, gas comes out of solution as its bubble point is reached. The volume of gas expelled with oil determines the depth at which a gas cap forms--that is, the more gas-prone source rocks are responsible for accumulations with higher gas-to-oil ratios (ft^3/bbl) that have a gas cap at a greater depth (Figure PS2).

The process of petroleum migration can determine the fluid type, either gas or oil, in a trap in three ways. First, as petroleum is expelled into a carrier bed from an active source rock, it begins to migrate updip in bulk phase. As the burial depth decreases, the gas phase begins to separate from the oil. If all these fluids migrate to a single trap that is perfectly sealed, the gas-to-oil ratio depends on the quality of the source rock. However, if the petroleum filled downdip traps first and then spilled to updip traps, the fluid phases in these traps would be different.

Second, Gussow (1953) explained the difference in oil and gas content of nearby traps using migration. Levorsen (1954, p. 555-556) summarized and redrew Gussow's figures to show that the deepest trap filled with oil and gas to the spill point. As the volume of migrating oil and gas exceeded the volume of the trap, oil with some dissolved gas spilled updip to the next shallowest trap. This phenomena would continue for the updip traps until the deeper traps are mostly gas and shallower traps are predominantly oil.

Third, fluids can also be separated during migration by poor reservoir or seal rocks. This separation migration is also called dysmigration (Blanc and Connan, 1994). As a mixture of oil and gas migrates, it encounters a seal or reservoir rock that acts as a molecular sieve such that only the lighter hydrocarbons can migrate beyond to the next trap. This places oil nearest to the pod of active source rock and gas in the farthest traps.

Zone of Expulsion. The zone of expulsion is where hydrocarbons, or oil and gas, are expelled (primary migration) from the active source rock (Figure PS1). If the petroleum is expelled into a carrier bed that has lateral continuity, it will migrate updip to the zone of petroleum accumulation. However, if the petroleum is discharged into a reservoir rock that lacks lateral continuity, it will be trapped in this thermal regime. When, or if, this accumulation is subjected to higher temperatures from more burial, it will pass into the next zone of cracking.

Source rock quality is important to the fluid type expelled from a source rock with at least an organic-carbon content of 2.0 wt.% richness. Generally, the higher the hydrogen index (800>HI>300) the more oil-prone is the source rock (Peters and Cassas, 1994, Table 5.2). The gas-to-oil ratio (ft^3/bbl) is less than 1,000, and the volume of petroleum expelled is greatest. As the source rock quality decreases (300>HI>200), the volume of hydrocarbons decreases and the gas-to-oil ratio increases (1,000<GOR<20,000). With further reduction of source-rock quality

(200>HI>50), only gas is generated and then only in small quantities (Figure PS2).

Zone of Cracking. The zone of cracking is where the oil in traps is thermally cracked to lighter oil and wet gas as it is subjected to higher temperatures (Figure PS1). This process continues until all the oil is cracked to dry gas. The API gravity of the oil in this zone ranges from 25-40° and can get as high as 65°. Because thermal cracking of oil increases its API gravity, and API gravity is usually known, gravities above 40° are referred to as light oils. The natural gas in this zone usually has considerable ethane and higher hydrocarbons associated with the methane and is called a wet gas.

Zone of Dry Gas. The zone of dry gas is where mostly methane occurs because it is the only hydrocarbon that is stable at these high temperatures (Figure PS1). Some large dry-gas accumulations originated as oil fields that were subsequently buried to the zone of dry gas preservation. Pyrobitumen or dead oil is evidence that this thermal cracking occurred, and conversely, a dry-gas field that lacks this evidence is usually attributed to a gas-prone source rock.

METHODOLOGY FOR CALCULATING CHARGE

The volume of oil and gas from each petroleum system available to charge the plays within the 1002 area is estimated mathematically. Preferably, it would be best to have the charge volume exceed the trap volume for all plays, assuming that traps formed before the charge arrived. In this case, traps that failed to leak would be full to the spill point. The worst case would be for the trap to form after the charge arrived, the trap leaked, or the timing was correct but the charge was insufficient.

To better understand the volume of charge for each petroleum system, a calculation was made using Schmoker's formula (Schmoker, 1994). The first formula was added to calculate the volume of active source rock of thickness h(cm) and of area A(mi^2). The series of formulas are as follows.

$$V\ (cm^3) = A\ (mi^2) \times 2.59 (km^2/mi^2) \times 10^{10}\ (cm^2/km^2) \times h\ (cm) \qquad (1)$$

$$M\ (gTOC) = [TOC\ (wt\%)/100] \times \rho\ (g/cm^3) \times V\ (cm^3) \qquad (2)$$

$$R\ (mgHC/gTOC) = HIO\ (mgHC/gTOC) - HI\ (mgHC/gTOC) \qquad (3)$$

$$\mathrm{HCG\ (kgHC)} = \mathrm{R\ (mgHC/gTOC)} \times \mathrm{M\ (gTOC)} \times 10^{-6}\ \mathrm{(kg/mg)} \qquad (4)$$

The second equation determines the mass of organic carbon, *M* (gTOC), for the active source rock in the pod. The data needed to calculate *M* (gTOC) are the average TOC (wt%), average formation density, ρ (g/cm^3), and volume, *V* (cm^3), of the active source rock. Multiplication of these three parameters gives the mass of organic carbon in the active source rock. The third equation determines the mass of hydrocarbons generated per unit mass of organic carbon for each active source rock, *R* (mgHC/gTOC). The data needed to calculate *R* are the present-day hydrogen index, HI(mgHC/gTOC), and the original hydrogen index, HIO (mgHC/gTOC), of the source rock prior to any petroleum generation. The difference between these two indices approximates the mass of hydrocarbons generated per gram TOC. The last equation computes the total mass of hydrocarbons generated HCG (kgHC) in each source-rock unit, which is converted to barrels of oil per township using kg/bbl factor for a specific API gravity.

A more specific example shows how the calculations are made for each petroleum system. Since the township is the smallest area used, this example will calculate the volume of in-place oil and gas at the prospect in barrels of oil (bbls) available to all the plays being charged by that petroleum system. The gross thickness of active source rock in the pod is 100 m (300 ft); it has an average organic carbon content (TOC) of 2.0 wt. % and a density of 2.4 g/cm^3. The original hydrogen index (HIO) is 600 mgHC/gTOC, and the present-day spent hydrogen index (HI) is 300 mgHC/gTOC). The calculations are as follows.

$$\begin{aligned} \mathrm{V(cm^3)} &= 36\ \mathrm{(mi^2)} \times 2.59\mathrm{(km^2/mi^2)} \times 10^{10}\ \mathrm{(cm^2/km^2)} \times 10^4\ \mathrm{(cm)} \qquad (1) \\ &= 93.24 \times 10^{14}\ \mathrm{(cm^3)} \end{aligned}$$

$$\begin{aligned} \mathrm{M(gTOC)} &= [2.0\ \mathrm{wt\%})/100] \times 2.4\ \mathrm{(g/cm^3)} \times 93.24 \times 10^{14}\ \mathrm{(cm^3)} \qquad (2) \\ &= 447.6 \times 10^{12}\ \mathrm{(gTOC)} \end{aligned}$$

$$\begin{aligned} \mathrm{R(mgHC/gTOC)} &= 600\mathrm{(mgHC/gTOC)} - 300\mathrm{(mgHC/gTOC)} \qquad (3) \\ &= 3 \times 10^2\ \mathrm{(mgHC/gTOC)} \end{aligned}$$

$$\begin{aligned} \mathrm{HCG(kgHC)} &= 3 \times 10^2\mathrm{(mgHC/gTOC)} \times 447.6 \times 10^{12}\mathrm{(gTOC)} \times 10^{-6}\mathrm{(kg/mg)} \qquad (4) \\ &= 1342.8 \times 10^8\ \mathrm{(kgHC)} / 139.3\ \mathrm{(kg/bbl)} \\ &= 964 \times 10^6\ \text{bbls of } 30^\circ \text{ API oil / township} \end{aligned}$$

Lillis and others (Chap. OA) discuss other equations to make these calculations, but Schmoker's equations are used because of the availability of other comparable calculations (Magoon and Valin, 1994). Schmoker's

(1994) technique requires that the volume of the thermally mature source rock be estimated, and that the richness (TOC) and quality (HI) of the immature and thermally mature source rock be available. This calculation determined the amount of oil generated from the pod of active source rock.

The amount of oil and gas that is expelled and left along the migration path to the trap can be quite high (Magoon and Valin, 1994). For example, only 0.9 of a barrel of oil makes it to the trap for every 100 barrels generated in the Ellesmerian(!) for the entire North Slope (Bird, 1974; Magoon and Valin, 1994). The generation-accumulation efficiency (GAE) is defined as the percentage of the total volume of trapped (in-place) petroleum to the total volume of petroleum generated from the pod of active source rock. Five percent GAE (Magoon and Valin, 1994) is the amount of in-place oil available to the plays in this exercise.

The values used to calculate the volume of oil and gas in all three petroleum systems are shown by area (Table PS1). Results of the calculations are given in Figure PS3. Care must be taken when using the single hydrocarbon charge number reported for each petroleum system because the calculation is oversimplified. Each factor in the equations could vary significantly, but it is felt that overall the numbers are reasonable. For example, to halve or double the TOC of the source rock in the pod will halve or double, respectively, the amount of petroleum available to the plays. However, this exercise provides the volumetric information about hydrocarbon charge that has been missing from previous assessments.

TIME-STRATIGRAPHIC CHART

The stratigraphic occurrence (as evidenced by an accumulation or staining) of oil and gas is evidence that hydrocarbons have used a particular rock unit as a migration path such that its likely migration path from its origin can be deduced. Additional information, such as the geographic proximity and geochemical similarity of oil and gas shows adds to the likelihood of knowing their origin. In order to portray the surface and subsurface stratigraphic occurrences of petroleum on one figure for both the undeformed and deformed area, a time-stratigraphic chart was constructed using the stratigraphic section from Bird and Magoon (1987, Plate 1; location of cross-section is shown on Figure PS4) and the time intervals for the rock units from Rowan (1997; Chap. BE; age and numbering of stratigraphic units is shown in Figure PS5).

The time-stratigraphic cross-section (Figure PS6) uses the time scale from Harland and others (1989), Berggren and others (1995), and Gradstein and others (1994) and the uplift ages from O'Sullivan (1993). The time interval encompassed by unconformities are shown in light grey and include the Early Mississippian unconformity (time interval 2), the Post-Pennsylvanian unconformity or PMU(time interval 5), and the Lower Cretaceous unconformity or LCU (time interval 8). The rock units removed by erosion during these unconformities range from the Endicott Group (3) through the Kingak Shale (7). Rock units from the pebble shale unit (9) through the Paleocene (11) are missing from Paleocene submarine slumping or scouring from the Point Thomson-1 well. The Shublik Formation (6) and the Hue Shale (9) are shown in black because they are oil-prone source rocks in or adjacent to the 1002 area. The Kingak Shale (7) and the pebble shale unit (9) are shown in pink because they are considered gas-prone in the 1002 area.

PREVIOUS WORK ON NORTH SLOPE

Previous work on the origin of oil and gas on the North Slope of Alaska west of the 1002 area is useful because the geologic history is similar. Information acquired about the origin of oil and gas in the Prudhoe Bay and the National Petroleum Reserve in Alaska (NPRA) areas to the west and the Beaufort Sea-Mackenzie delta area to the east can be extrapolated into the 1002 area. Recoverable reserves through 1984 in northern Alaska is 13 billion barrels of oil and more than 37 trillion ft^3 of gas (Bird and Bader, 1987). The Beaufort Sea-Mackenzie Delta area contains recoverable reserves of an estimated 740 million barrels of oil and 10 trillion ft^3 of gas (Bird and Bader, 1987).

Morgridge and Smith (1972) provided information on the richness of potential source rock units in the Prudhoe Bay field area. Jones and Spears (1976) indicated that the oil in the Prudhoe Bay and Kuparuk fields are isotopically similar and therefore originated from the same source rock. Early detailed petroleum geochemical work by Seifert and others (1979) determined that the oil in the Prudhoe Bay field is a mixture that originated from the Triassic Shublik Formation, Jurassic Kingak Shale, and the deep Post-Neocomian shales (pebble shale unit and Hue Shale). Seifert and others (1979) also identified a unique oil that originated from the Kingak Shale. Work by Magoon and Claypool (1981) identified two North Slope oil types, the Barrow-Prudhoe and the Simpson-Umiat oil types. Carman and Hardwick (1983) suggested, based on geochemical similarity and geology, that oil spilled to the Eileen portion of the Prudhoe structure, then to the

Click here or on this symbol in the toolbar to return.

Kuparuk field, then to the Upper Cretaceous fields (West Sak and Ugnu). Source-rock richness across the North Slope and the provenance of these oil types are discussed in Claypool and Magoon (1988), Curiale (1987), Magoon and Bird (1985, 1988, 1994), Magoon and Claypool (1983, 1984, 1985, 1988), and Sedivy and others (1987). Wicks and others (1991), using carbon isotopes and sterane data, indicate that the oils in the Endicott, Prudhoe Bay, Kuparuk, and Eileen West End fields are distinct because of mixing oil from different source rocks.

CHARACTERIZATION OF OIL TYPES

Work for the 1987 Assessment

Oil-stained rocks and oil samples recovered from wells and collected in outcrop were geochemically analyzed for oil-oil and oil-source rock comparisons. The oil-stained samples came from outcrops in the Kavik area, along the Katakturuk and Jago Rivers, and from Manning and Angun Points (Figure PS7; Table PS2). The data and interpretation of these analytical results are discussed in Anders and others (1987). The carbon isotope results for the saturated and aromatic hydrocarbons are reproduced here to show the oil types important to the 1002 area (Figure PS8). The Kingak and Barrow-Prudhoe oil types are only found west of the 1002 area. The Jago oil-type occurs in outcrops on the Katakturuk and Jago Rivers and at Angun Point. Recent analytical work demonstrates that the resampled oil-stained outcrop at Kavik is also a Jago oil-type (Lillis, Chap. OA, Figure OA2). The Manning Point oil type is similar to the Simpson-Umiat oil type.

Based on carbon isotopes of saturated hydrocarbons and C_{19}/C_{23} tricyclic terpanes, the Jago oil type correlated with the Hue Shale (Anders and others, 1987). Using this data, the pebble shale unit and Shublik Formation negatively correlate with either the Jago or Manning oil-types. Bitumen extract from the gas-prone Kingak Shale and Canning Formation marginally correlate with the Jago oil-type. This early work on the oil-source rock correlation of the Hue Shale to the Jago oil type, and the origin of the Prudhoe Bay oil to the west, indicated that there are two petroleum systems in and adjacent to the 1002 area, the Ellesmerian and the Brookian (Magoon and others, 1987).

Work for the 1998 Assessment

During the last 3 years, new geochemical and geological information has been obtained that has improved our understanding of the petroleum systems critical to this oil and gas assessment. The new oil discoveries and exploratory wells drilled offshore from the 1002 area are reviewed by Bird (Chap. GG). USGS field parties, 1995 though 1997, obtained additional samples of oil-stained outcrops (Figure PS9, Table PS3; Schenk and others, Chap. FS). Additional oil samples came from drill-stem tests and solvent extractions of oil-stained cores from the Aurora 1 well, and from wells in the Mikkelsen and Point Thomson areas (Lillis and others, Chap. OA) (Plate PS1).

Classification or differentiation of oil types is done most readily using carbon isotopes of the hydrocarbon fractions. The new analyses of carbon isotopes of the saturated and aromatic hydrocarbon fractions are shown with the old data from Anders and others (1987) (Plate PS1). Based on this new information (Lillis and others, Chap. OA, and Figure OA3), we conclude that there are three oil types within and adjacent to the 1002 area. The Manning oil type includes oil from the Manning Point and Angun seeps and the Aurora 1 well. Based on the carbon isotopes of whole oil, the Hammerhead 1 oil is similar and is therefore also included in this oil type (Curiale, 1995). The Jago oil type from previous work is confirmed with the addition of analyses from oil-soaked core in the Point Thomson and West Mikkelsen wells, and from oil-stained outcrops along the Canning River (Table PS4; Plate PS1). The Kavik oil-stained outcrop was resampled, and the new results place it with the Jago oil type. The Barrow-Prudhoe oil type is indicated by five oil samples from the West Mikkelsen area and two from the Point Thomson area. Based on these oil-oil correlations and previous oil-source rock correlations, we conclude that there are three petroleum systems in and adjacent to the 1002 area--the Ellesmerian(!), Hue-Thomson(!), and Canning-Sagavanirktok(?).

SOURCE ROCKS

For the resource assessment completed in 1987, the data and interpretations on source rocks are reported by Magoon and others (1987, p. 131-143). (Source rock sample locations and laboratory data for each sample are available elsewhere on this cdrom in digital (spreadsheet) format; this data source will be referenced below as file “PS1778.xls” in the data appendix.) The geologic map compiled by Bader and Bird (1986) and the updated geologic map (Bird, chap. GG, plate GG1) shows the location of the oil-stained rocks and seeps in and adjacent to the 1002 area as well as the locations of the exploratory wells. Conclusions from Magoon and others (1987) and Keller and others (Chap. SR) follow.

Shublik Formation

The Triassic Shublik Formation crops out south of the 1002 area and is penetrated by wells just west of the Canning River. Thickness of the Shublik Formation ranges from zero where it is truncated to over 800 ft on the United States-Canadian border (Plate PS2). Everywhere it is sampled near the 1002 area, the Shublik Formation is too thermally mature to determine its original source-rock character. However, farther west along the Barrow arch and in the Colville trough, the Shublik is considered the major source rock for the complex of oil fields in the Prudhoe Bay area (Seifert and others, 1979; Bird, 1994). Robison and others (1996) analyzed core samples of Shublik from the Phoenix 1 well northwest of Prudhoe Bay and found organic carbon contents as high as 10.2 wt. percent and hydrogen indices of 884 mgHC/gOC.

Within and adjacent to the 1002 area, the Shublik Formation is mostly less than 3.0 wt. percent organic carbon content with hydrogen indices less than 100 mgHC/gOC (Magoon and others, 1987, Figure 11.6, Table 11.3). However, these results are based on a limited number of samples from outcrop (see tables in file “PS1778.xls” in the data appendix) and well cuttings, whereas Keller and others (Chap. SR) summarize outcrop data from these and other outcrops and conclude that the average TOC is closer to 2.0 wt. percent, which is what we used for the material balance calculations (Table PS1).

Kingak Shale

The Jurassic Kingak Shale crops out south of the 1002 area, on the Niguanak high, and is penetrated by wells west of the Canning River. The thermal maturity is mostly more than 1.0% R_o, except on the Niguanak high where it is 0.5% R_o. The organic carbon content, which is averaged for each locality or well of the Kingak Shale, ranges from 0.4 to 3.4 wt. percent organic carbon and averages 1.5 wt. percent in four Kavik-area wells and 22 outcrop localities (Magoon and others, 1987, Figure 11.7, Table 11.4; also see tables in file “PS1778.xls” in the data appendix). Keller and others (Chap. SR, Table SR5) determined that the average organic carbon content ranges from 1.0 to 2.2 wt. % in four wells. Based on gas chromatography (Anders and others, 1987), and hydrogen indices of less than 100 mgHC/gOC (Magoon and others, 1987, Table 11.4), the Kingak contains gas-prone organic matter. However, in the Prudhoe Bay area, elemental analyses and C_{15+} hydrocarbons versus organic carbon content plots show that the Kingak Shale is an oil-prone source rock (Magoon and Bird, 1985).

Pebble Shale Unit

The Lower Cretaceous pebble shale unit crops out south of the 1002 area, on the Niguanak high, and is penetrated by wells west of the Canning River. The average organic carbon content for 7 wells and 30 outcrop localities in and adjacent to the ANWR is 2.4 wt. percent and 2.2 wt. percent, respectively (Magoon and others, 1987, Figure 11.9, Table 11.5; also see tables in file “PS1778.xls” in the data appendix). Using eight wells, Keller and others (Chap. SR, Table SR3) determined that the pebble shale unit ranges in thickness from 18 to 245 ft, and the organic carbon content ranges from 1.5 to 3.8 wt. percent in richness. Vitrinite reflectance from outcrop samples indicates that the pebble shale unit in the wells adjacent to the 1002 area is marginally mature in the Point Thomson area and was at peak maturity before uplift in the Kavik area (Bird, Chap. VR). Outcrop information indicates that values increase eastward from 0.8 to 3.1 percent R_o in the Brooks Range and from 0.5 to 0.6 percent R_o in the Niguanak high. Based on Rock-Eval and C_{15+} hydrocarbon content information, the pebble shale unit is a gas-prone source rock in and adjacent to the 1002 area, but the pebble shale unit is oil-prone in the Prudhoe Bay area (Magoon and Bird, 1985; Anders and others, 1987).

Hue Shale

The Upper Cretaceous Hue Shale crops out south of the 1002 area, on the Niguanak high, and is penetrated by wells west of the Canning River. Organic carbon contents averaged at each outcrop range from 1.4 to 12.1 weight percent and average 5.9 wt. percent (Magoon and others, 1987, Figure 11.10, Table 11.6; also see tables in file “PS1778.xls” in the data appendix). Using the “$\Delta \log R$ method” in eight wells, Keller and others (Chap. SR, Table SR2) determined that the gamma ray zone ranged in thickness from 137 to 320 ft, and the total organic carbon content ranged from 1.9 to 3.9 wt. percent. For the section above the gamma ray zone, Keller and others (Chap. SR, Table SR1) indicate thate thickness ranges from 355 to 928 ft and has an organic carbon content of 1.5 to 2.6 wt. percent.

The richest outcrop samples of Hue Shale are from a 150-foot-thick surface section along the Jago River (Palmer and others, 1979) and from scattered outcrops on the Niguanak high (Plate PS3). Here, the organic carbon content from 12 rock samples averages 12 wt. percent (Magoon and others, 1987). The Hue Shale crops out in the Ignek Valley where it is about 300 feet of shale at the base of the section; the shale ranges in organic carbon content from 2 to 6 wt. percent with vitrinite reflectance value of 1.0% R_o (Magoon and others, 1987, Figure 11.8) The TOC value used for the Hue Shale, the only identified oil-prone source rock within the 1002 area, for the material balance calculation is 2.0 wt. percent (Table PS1).

Canning Formation

The Paleocene Canning Formation crops out within and to the south of the 1002 area and is penetrated by wells west of the Canning River. The average organic carbon content for this rock unit increases to the north from 1.0 to 2.0 wt. percent and is interpreted to be buried at considerable depth in the Beaufort Sea. Using the $\Delta \log R$ method on the Mikkelsen Tongue of the Canning Formation in four wells, Keller and others (Chap. SR, Table SR6) indicate that thickness ranges from 1,587 to 1,945 ft, and determined that the average total organic carbon content above 1.0 wt. percent ranges from 1.7 to 3.0 wt. percent. Thermal maturity of the Canning Formation ranges from immature to marginally mature in the undeformed zone and mature to very mature in the deformed zone. Rock-Eval, visual kerogen, and C_{15+} hydrocarbon content all indicate a terrigenous source for the organic matter (Magoon and others, 1987; also see tables in file “PS1778.xls” in the data appendix). Though most of the Canning Formation is a gas-prone source rock, intervals within the Mikkelsen Tongue could be oil-prone and could be the provenance for the Manning oil type. The TOC used for the material balance calculations is 1.0 wt. percent (Table PS1).

ELLESMERIAN(!) PETROLEUM SYSTEM

The Ellesmerian petroleum system was first named by Magoon and others (1987). Based on the oil-source rock correlation work of Seifert and others (1979), the known (!) level of certainty was added to Ellesmerian(!) by Magoon (1988, 1989, and 1992). These workers identified the Shublik Formation, Kingak Shale, and Hue Shale (post-Neocomian shale) as co-sources for the oil in the Prudhoe Bay oil field. Wicks and others (1991), using carbon isotopes and sterane data, indicate that the oils in the Endicott, Prudhoe Bay, Kuparuk, and Eileen West End fields are distinct because of mixing oil from these different source rocks. The Ellesmerian(!) petroleum system is mapped by Bird (1994) as covering most of the entire North Slope petroleum province, offshore and onshore, and includes 26 hydrocarbon accumulations and three source-rock intervals–the Shublik Formation, Kingak Shale, and Hue Shale.

Based on the outcrop belt of thermally mature Shublik Formation (Plate PS2) and Kingak Shale, Bird (1994) mapped the Ellesmerian(!) petroleum system east of the Canning River. Because the Kingak Shale is gas-prone on the Niguanak high and the Hue Shale is included in the Hue-Thomson(!) petroleum system, the Ellesmerian(!) will only include the Shublik source rock in this report.

Pod of Active Source Rock

Because the Jurassic Kingak Shale is considered gas-prone and the Cretaceous Hue Shale is included in the Hue-Thomson(!) petroleum system, the only source rock included in this petroleum system in and adjacent to the 1002 area is the Triassic Shublik Formation (Magoon and others, 1987). The Shublik Formation extends northward to the southern boundary of the 1002 area where it is truncated by the so-called Lower Cretaceous unconformity (Plate PS2). Interpretation of reflection seismic profiles indicate that the Shublik Formation is absent north of this unconformity in the 1002 area. Based on well and seismic information, the Shublik is absent by erosion just north of the Beli Unit-1 well to the Mikkelsen area and in the Point Thomson field. Using the present-day distribution of the Shublik Formation, the pod of active source rock ranges from 150 to 800 feet in thickness and extends from Yukon, Canada, westward and south of the 1002 area to beyond Prudhoe Bay (Figure PS10, Plate PS2).

The richness of the Shublik Formation is reported in Magoon and others (1987, Figure 11.6) and Keller and others (Chap. SR) for the 1002 area, where, on the south edge of the area it is too thermally mature to evaluate for source-rock quality. However, based upon the Phoenix 1 well drilled by Tenneco 50 miles northwest of the Prudhoe Bay field, Robison and others (1996) report data on source-rock quality that can be used to evaluate the Shublik Formation south of the 1002 area. Here, almost 300 feet (from 7,796 to 8,079.5 feet depth) of the Shublik Formation was cored¾ a complete section¾ and evaluated for source rock richness, quality, and thermal maturity. Using Robison and others' (1996) criteria for oil-prone kerogen (minimum of 1 wt.% TOC, S_2 of 6 mgHC/g rock, HI of 400 mgHC/gTOC), there is about 155 net feet of Shublik source rock (283.5 gross feet), or 55 percent oil-prone kerogen. The thermal maturity of this core using vitrinite reflectance is 0.8% Ro.

The iso-reflectance lines contoured at the basal part of the pebble shale unit (Magoon and others, 1987, Figure 11.5) increases from the Prudhoe Bay area, where it is 0.4% R_o, to the east end of the 1002 area where it is 2.0%

Click here or on this symbol in the toolbar to return.

R_o. More recent work by Bird and Keller (Plate PS2) for the Shublik Formation show vitrinite values from less than 0.6% R_o in the Prudhoe Bay area to over 4.0 % R_o in the Yukon, Canada, just east of the 1002 area. A balanced cross section by Cole and others (Chap. SM) shows that the Shublik Formation was buried to its maximum depth at about 47 Ma (Eocene), suggesting that the downdip increase of the contour pattern for vitrinite reflectance shown by Bird and Keller (Plate PS2) should continue south of the 1002 area. This analysis assumes that the vitrinite reflectance values were the result of sedimentary burial rather than imbricated thrust sheets or igneous intrusion. Based on this interpretation, the Shublik Formation first generated and expelled oil and gas at the southern edge of the 1002 area, and possibly as far as east as Yukon, Canada.

Petroleum Occurrence

The oil and gas occurrences attributed to the Ellesmerian(!) petroleum system are west of the Canning River except for two occurrences at the east end of the Sadlerochit Mountains (Figure PS10 and Figure PS11). Based on geochemical analyses, oil samples from the Mikkelsen and Point Thomson areas are attributed to this petroleum system (Plate PS1; Table PS4). Based on stratigraphic position, oil and gas shows in the Kemik, Kavik, and Mikkelsen areas are attributed to the Ellesmerian(!) (Table PS5). Fluid inclusions examined by Burruss (Chap. FI) attributed to this petroleum system are south of the 1002 area and in the Kemik area (Figure PS10 and Table PS8). Oil stains in thin sections of the Lisburne Group in the Sadlerochit Mountains are reported by Armstrong and Mamet (1977) and illustrated in Bird and others (1987). Oil-stained sandstone reported by geologists from the State of Alaska is located at the east end of the Sadlerochit Mountains (Magoon and others, 1987, p. 183). Based on stratigraphic occurrence, these oil stains are included in this petroleum system.

The gas in the Kemik and Kavik fields is included in the Ellesmerian(!) because the gas occurs in Sag River Sandstone, fractured Shublik and Sadlerochit reservoir rocks, (Plate PS4; Chap. WL). Fluid inclusion work by Burruss (Chap. FI) suggests that the traps first held oil that was replaced by "gas-rich, volatile oil or the reservoir was charged with gas and the oil displaced up-dip. Late gas charge could cause de-asphaltening of the oil and formation of the pyrobitumen now present in the pore space." Values of vitrinite reflectance somewhat in excess of 1.0% R_o are too low to thermally crack oil to gas in place (Plate PS4; Canning River cross-section (~45 Ma) on Plate GG3B). Other interpretations for the origin of the gas in these two fields are possible: it could originate from gas-prone source rock within the pebble shale unit or the Canning Formation.

Other gas accumulations on the North Slope in the Ellesmerian(!), such as South Barrow, East Barrow, and Walakpa, contain thermogenic gas (approximately –40 ‰) whose reservoir rocks are thermally immature, or less than 0.6% R_o (Magoon and Bird, 1988). These small gas fields must have been charged from downdip, where the source rock is thermally mature. In contrast, the Kemik and Kavik reservoir rocks have been buried to great depths. Documented paleostructures in the area of these small gas fields are lacking, which argues for the gas coming from gas-prone source rocks rather than thermally cracked oil as is postulated for the Kemik and Kavik fields.

Oil in the Mikkelsen and Point Thomson areas extracted from cores or recovered from drill-stem tests (Table PS3; Plate PS5) was characterized by Lillis and others (Chap. OA). All five oil samples from the Mikkelsen area are Ellesmerian(!) oil or mixtures, whereas four of the 11 oil samples are Ellesmerian(!) in the Point Thomson area (Plate PS5). In these two areas, Ellesmerian(!) has charged the Lisburne Group, the Hue Shale where it is fractured, and the Canning Formation.

Geographic Extent of Petroleum System

The geographic extent of a petroleum system is mapped to include all discovered occurrences of hydrocarbons in accumulations, shows, and seeps and the pod of active source rock that provided these hydrocarbons (Magoon and Dow, 1994). The northern truncation edge of the Shublik Formation is the boundary for the pod of active source rock (Figure PS10). Except for the Point Thomson and Mikkelsen areas, the known petroleum occurrences are all within the area of the pod of active source rock.

Known hydrocarbon occurrences from this petroleum system are lacking within the 1002 area. However, based on the accumulations in the Point Thomson area, on the easterly dip of the Lower Cretaceous unconformity and overlying rock units of the coastal cross-section (Bird, Chap. GG, Plate GG2B), and the fluid inclusion information south of the 1002 area, there is a good possibility that Ellesmerian(!) oil and gas migrated across the 1002 area.

Events Chart

The Ellesmerian(!) events chart provides an overview of the kinematic evolution of this petroleum system (Figure PS12). The Shublik Formation (black portion of rock unit 6) is the source rock. The reservoir and seal rocks within or adjacent to the 1002 area (excluding the Mikkelsen area) include basement rocks (1), Lisburne Group (4), Sadlerochit Group (6), Sag River Sandstone (6), Kingak Shale (7), and Canning Formation (10) (Figure PS12). South of the 1002 area, the Sag River Sandstone through Paleocene rocks overlie the Shublik source rock.

The generation-migration-accumulation of oil and gas from the Shublik Formation started in the south and ended in the north (Rowan, Chap. BE; Figure PS3). In Late Cretaceous time (75 Ma), the Shublik Formation is judged to have entered into the zone of petroleum expulsion far south of the 1002 boundary such that oil and gas were generated and expelled into an adjacent carrier bed, the underlying Sadlerochit Group or the overlying Sag River Sandstone. The expelled oil migrated updip to the north until it arrived at the shallower truncation edge created by the so-called Lower Cretaceous unconformity (LCU). Here the petroleum could migrate either northwestward to the Prudhoe Bay area within the same carrier beds or continue north beyond the truncation edge in carrier beds that might include lag deposits just above the LCU or in porous and permeable rocks beneath the LCU. The existence of continuous carrier beds either above or below the LCU is unknown. The API gravity of oil in the system is approximately 25°, the gas-to-oil ratio is about 1,000, and the sulfur content is 0.9% or higher.

As the Shublik source rock passed through peak generation (0.9% Ro) for oil and gas, it became depleted (1.1% Ro). The incremental northward thickening of the overburden rock, the result of filling of the foreland basin ahead of the advancing Brooks Range deformation, buried the Shublik Formation so that it provided a steady stream of petroleum that migrated north, sort of a northward-moving "front." This process continued until about the end of the Eocene (35 Ma) when the northernmost Shublik reached maximum burial. Since the late Eocene, no oil and gas was generated because of uplift, thrusting, and erosion of the pod of active source rock. The critical moment at about 47 Ma is around the time when most of the oil and gas migrated and accumulated and the Shublik was at maximum burial (Cole and others, Chap. SM, Figure SM6a).

Volume of Petroleum Charge

To better understand the volume of charge for the Ellesmerian(!) petroleum system, a calculation was made using Schmoker's formula (Schmoker, 1994) and the isopach of the Shublik Formation (Plate PS2). The Shublik Formation was divided up into five 1-degree areas (A through E in Plate PS2) that run from the truncation edge of the unit to 69° north latitude. Each area represents about 32 townships (36 square miles/township). The Shublik Formation was assumed to have a total organic carbon of about 2.0 wt. percent, and to lose about 300 hydrogen index units (mgHC/gTOC) as it generated petroleum. The average Shublik thickness for each area ranges from 300 to 600 feet. Using a generation-to-accumulation efficiency (GAE) of 5 percent (Magoon and Valin, 1994), the amount of in-place oil and gas available to the plays was determined (Table PS1). The total in-place volume available to charge the plays from all five areas is about 11 billion barrels of in-place oil.

This volume of 11 billion barrels of in-place oil may have migrated before, during, or after trap development (Figure PS3). Trap formation for the Thin-Skinned Thrust-Belt, and Ellesmerian Thrust-Belt plays occurred after the hydrocarbon charge arrived. The time of trap formation is unclear for the Thomson, Kemik, and Undeformed Franklinian plays.

HUE-THOMSON(!) PETROLEUM SYSTEM

The Hue-Thomson(!) petroleum system covers much of the 1002 area. It was originally named the Brookian petroleum system (Magoon and others, 1987), later revised to Hue-Sagavanirktok/Canning(!) (Magoon, 1988), then to Hue-Sagavanirktok(!) (Magoon, 1989), based on the occurrence of hydrocarbons. Because the petroleum system name utilizes the name of the major reservoir rock and because analyses of oil samples from the Thomson sand indicate that the Hue Shale is its source rock, the petroleum system name was changed to Hue-Thomson(!). It is a known system because there is a positive oil-source rock correlation.

Pod of Active Source Rock

The source rock for this petroleum system in and adjacent to the 1002 area is the Cretaceous Hue Shale (Anders and Magoon, 1986; Anders and others, 1987; Magoon and others, 1987; Keller, Chap. SR; and Lillis, Chap. OA). The Hue Shale crops out in a band that runs from southwest of the Ignek Valley to the north flank of the Sadlerochit Mountains, on the Jago River, and on the Niguanak high (Bader and Bird, 1986; Plate PS3). The Hue Shale is the age and lithologic equivalent of the Boundary Creek and Smoking Hills Formation in the Mackenzie Delta region (Figures 44 and 45, Dixon, 1996). To the west of the 1002 area, the Hue Shale is penetrated by wells in the Kavik area, in the Point Thomson area, and to the east, rocks equivalent in age to part of the Hue Shale are present in the Aurora 1 well (Figure PS13). Northwest of the Marsh Creek anticline, seismic information indicates that over much of the area the Hue Shale is present (Houseknecht and Hayba, Chap. HG). Southeast of the Marsh Creek anticline, the seismic data is unclear; however, the Hue Shale is assumed to be present because it crops out on the Jago River, on the Niguanak high, and is penetrated in the Aurora 1 well (Keller and others, Chap. SR; Nelson and others, Chap. WL).

The thickness of the richest portion of the Hue Shale at the base of the section is based on outcrop and well information. The Hue Shale in the Ignek Valley section is thermally mature (1.0% R_o) and contains source rocks whose TOC exceeds 4 wt. percent in the lower 300 feet of measured section (Magoon and others, 1987). The high gamma-ray values are included in this Ignek Valley section. The faulted section along the Jago River was measured by Palmer and others (1979) to be 150 feet thick, thermally immature (0.5 % R_o), and up to 12 wt. percent TOC. Later, Molenaar (Appendix CM) determined that this Jago River section also included the high gamma-ray zone. Similarly, the Hue Shale in the wells west of the Canning River is richest near its base, where organic carbon contents calculated by the "$\Delta \log R$ method" are as high as 10.0 wt. percent and average between 3.0 and 4.0 wt. percent TOC for the lower 300 ft (Keller and others, Plate SR13).

The Hue Shale is thermally mature over most of the 1002 area southeast of Marsh Creek anticline where overburden from foreland basin sedimentary rocks provided sufficient burial (Cole and others, Chap. SM). In the area of Point Thomson, the Hue Shale is marginally mature (0.6% R_o) but becomes more mature to the southeast where it undoubtedly has generated petroleum (Magoon and others, 1987, Figure 11.5; Rowan, Chap. BE; Houseknecht and Hayba, Chap. HG). The pod of active source rock covers much of the 1002 area (Figure PS13).

Petroleum Occurrence

The oil and gas occurrences attributed to the Hue-Thomson(!) petroleum system are found in outcrop and in the subsurface, most notably in the Thomson sand (Plate PS5). Many of the oil-stained sandstones within the

Click here or on this symbol in the toolbar to return.

1002 area are included in this petroleum system (Figure PS13 and Figure PS14). The geochemical analyses of oils from certain rock units are identified by area and rock unit (Table PS4 and Plate PS2). An in-depth discussion of the geochemical results of these oil samples is in Lillis and others (Chap. OA). These analyses indicate that the hydrocarbon from the oil-stained rock on the Jago River (A), Katakturuk River (B,C), Canning River (D), and the Kavik area (E) are all from the Hue Shale (Figure PS13 and Figure PS14). Five oil samples extracted from cores in the Point Thomson area are from the Thomson sand are judged from geochemical analyses to have originated from the Hue Shale (Plate PS5).

The oil and gas shows in wells were acquired from American Stratigraphic logs and other well logs (Table PS6) and fluid inclusion information is from Burrus (Chap. FI; Table PS8). Petroleum geochemical analyses are lacking for most of these shows so the evidence for them being in this petroleum system are geographic and stratigraphic, that is, they are close to identified Hue Shale oils or easily could have migrated from active Hue Shale into the designated rock unit. Shows attributed to this system occur in the basement complex, Kemik/Thomson reservoir rocks, Hue Shale, Canning Formation, and basal part of the Sagavanirktok Formation.

Geographic Extent of Petroleum System

The geographic extent of the Hue-Thomson(!) petroleum system is determined by the distribution of the Hue Shale in the pod of mature source rock and the closely associated oil that is judged to have come from the Hue Shale. The southern boundary, just south of the 1002 area, is determined by the present-day outcrop truncation edge of the Hue Shale and west of the Canning River by the distribution of oil occurrences assigned to this system, which occur in fluid inclusions, drilling shows, and oil-stained sandstones (Figure PS13). The eastern boundary is mapped from the Jago River oil and the presence of Hue Shale in the Aurora 1 well. The northern boundary follows the coastline because information is lacking as to the northern extent of the Hue Shale; oil is also lacking from the Hue Shale in offshore wells. The boundary hugs the northern limit of the Point Thomson field because the Thomson sand contains oil from the Hue Shale and, beyond that, the Hue is missing due to submarine scouring (Figure PS14). The western boundary extends beyond the map area of Figure PS13 to at least the Sagwon Bluffs, where oil-stained outcrop contains oil from the Hue Shale (Table PS4; Lillis and others, Chap. OA).

Events Chart

The Hue-Thomson(!) events chart provides an overview of the kinematic evolution of this petroleum system (Figure PS15). The Hue Shale (rock unit 9) is the source rock. The reservoir and seal rocks within and adjacent to the 1002 area include the organic-lean but relatively thick succession of mudstone in the upper part of the Hue Shale that also includes tuffs and bentonite, the Lower Canning(10), Paleocene(11), Eocene(12), and Post-Eocene(13). The overburden rock includes all of these rock units.

The generation-migration-accumulation of oil and gas from the Hue Shale started around 52 Ma as an arcuate pattern in the vicinity of the Hulahula low and ended around 10 Ma in a similar arcuate pattern around the eastern nose of the Point Thomson area (Houseknecht and Hayba, Chap. HG; Rowan, Chap. BE). The high thermal maturity of the Hue Shale in outcrop along the southern boundary of the 1002 area suggests that the maturity "front" moved from south to north, whereas the maturity "front" moved from east to west in the western half of the 1002 area. Here, the progradation of the mostly Tertiary overburden rock from southeast to northwest caused the thermal maturity level to increase to the southeast in the 1002 area (Houseknecht and Hayba, Chap. HG). This front of maturing source rock should have continuously provided petroleum to the Point Thomson area from 52 to 10 Ma. This time of charge is shown in Figure PS3 for plays 1 through 6.

Volume of Petroleum Charge

The volume of petroleum charge from the Hue-Thomson(!) available to the plays within the 1002 area is as much as 10 billion barrels. The thickness of the Hue Shale in the pod of active source rock capable of generating oil is estimated to be about 300 feet thick, having a total organic carbon content of about 4 wt. percent and a hydrogen index (HI) reduction from maturity of 400 units. The source rock density is 2.4 g/cm^3 and the generation-accumulation efficiency (GAE) used is 5 percent.

The area of active Hue Shale that could charge the plays within the 1002 is divided up into three areas, F through H (Plate PS3). Area F contains 27 townships and goes as far south as the outcrops in Ignek Valley, almost to the Canning River on the west, along the state-Federal 3-mile limit on the north, and southwest along the Marsh Creek anticline. Calculations indicated that this area provided 2.8 BBO to the plays (Table PS1). Area G, which contains 26 townships, is contiguous with area F and goes as far east as the axis of the Hulahula low. Calculations indicate that another 2.7 BBO are available to the plays. Petroleum drainage from this area could have charged the Topset, Turbidite, Wedge, Thomson, Kemik, and Undeformed Franklinian plays. Area H, which is 38 townships large, lies in the eastern third of the 1002 and would be responsible for charging the Thin-Skinned Thrust-Belt play and possibly the Niguanak-Aurora play. This charge area could provide 9 BBO of in-place petroleum to these plays.

This volume of 9 BBO of in-place oil may have migrated before, during, or after trap development (Figure PS3). Traps formed before the charge arrived for the Turbidite play. Traps formed as the hydrocarbon charge arrived for the Topset, Wedge, and Thin-Skinned Thrust-Belt plays. The time of trap formation is unclear for the Thomson, Kemik, and Undeformed Franklinian plays.

CANNING-SAGAVANIRKTOK(?) PETROLEUM SYSTEM

The Canning-Sagavanirktok(?) petroleum system is based on the distinctive Manning oil type, which includes oil from the Manning Point seep, Hammerhead accumulation, Angun Point seep, and Aurora 1 well. The similarity of the oil in the Canning-Sagavanirktok(?) to the oil from Tertiary rocks in the MacKenzie Delta to the east is striking (McCaffrey and others, 1994). This is a speculative system because the identity of the source rock is uncertain.

Pod of Active Source Rock

The source rock for this petroleum system is suspected to be organic-rich shale in the Mikkelsen Tongue of the Canning Formation in the offshore, or where it may be deeply buried in the Hulahula low (Figure PS16). The primary basis for the pod of mature source rock being located offshore is that the hydrocarbon occurrences are near the north shoreline of the 1002 area and are in Eocene or younger sedimentary rocks. Vitrinite reflectance profiles in Point Thomson area wells, Aurora 1, and Belcher 1 all indicate a 0.6% Ro at 10,000 to 12,000 ft depth (Bird, Chap. VR). Thus, anywhere the Mikkelsen Tongue of the Canning Formation is buried this deep, it is generating petroleum. In addition, the Hammerhead and Kuvlum fields are associated with listric faults that sole out to the north, further suggesting that the hydrocarbons migrated from north to south (Scherr, 1991, Plate 18).

Source rock richness and quality data for the Canning Formation indicate a gas-prone source rock (Magoon and others, 1987). New information acquired from wireline logs indicate that the average TOC of this possible source rock unit is 1.0 wt. percent (Keller and others, Chap. SR).

Petroleum Occurrence

The oil and gas occurrences attributed to the Canning-Sagavanirktok(?) are along the northern coastline (Figure PS16 and Figure PS17; Table PS7 and Table PS8). Oil shows from wells logged by American Stratigraphic Company and from other well information are attributed to this petroleum system on the basis of location and stratigraphic interval. Hammerhead, Manning Point, and Angun Point seeps and the oil-stained core in the Aurora 1 well are geochemically similar (Plate PS1; Lillis and others, Chap. OA). The oil in the Kuvlum field is attributed to this petroleum system based on its close proximity to the Hammerhead field and the fact that the reservoir rock overlies the source rock.

Geographic Extent of Petroleum System

The geographic extent of this petroleum system is mapped on the southern edge of oil occurrences that were most likely charged from the north or immediately below these fields and seeps. In order to calculate a volume of petroleum that could charge the onshore plays, three offshore areas, I through K, represent the pod of active source rock. Each area covers 25 townships (Figure PS16).

Events Chart

The Canning-Sagavanirktok(?) events chart provides a mechanism to examine the time when the essential elements were deposited and the timing relative to trap formation and generation-migration-accumulation of hydrocarbons. The suspected source rock is the Mikkelsen Tongue of the Eocene Canning Formation because of the unique geochemical characteristics of the oil found in this petroleum system. In addition, there is a high degree of confidence that either the lower part of the Hue Shale and the Shublik Formation can be eliminated as the source rock because the oil from these source rocks are so different. Therefore, the Mikkelsen Tongue is the suspected source rock. The reservoir and seal rocks are mostly in the Oligocene units. The overburden rock includes Oligocene and Miocene units.

The generation-migration-accumulation of the oil and gas from the Canning Formation is estimated to have started at about 15 Ma in the offshore (Figure

PS18). The burial front of the source rock migrated north while the migrating front of hydrocarbons migrated south, toward the onshore 1002 area. The API gravity of this oil is suspected to be 35-40° with a gas-to-oil ratio of 15,000-30,000, and a very low sulfur content (<0.5%).

Volume of Petroleum Charge

The volume of petroleum charge available to plays within the 1002 area is uncertain. Assumptions are made about the source-rock thickness, richness and quality—for example, 4,500 ft (1,500 m) thick, a total organic carbon content average of 1 weight percent, and a difference of HI of 100 during hydrocarbon generation. Further, we assume that the active source-rock pod covers 75 townships and that 5 percent of the oil expelled is available to be trapped. The amount of oil available for the plays in the 1002 area is 11 BBO in-place less the oil in Hammerhead and Kuvlum fields (approximately 1 BBO)—this gives 10 BBO in-place (Table PS1; Figure PS3).

REFERENCES CITED

Anders, D.E. , and Magoon, L.B., 1986, Oil-source correlation study in northeastern Alaska, *in* Leythaeuser, D., and Rullkotter, J., eds., Advances in organic geochemistry 1985, Part I, Petroleum Geochemistry: Organic Geochemistry, v. 10, nos. 1-3, p. 407-415.

Anders, D.E., Magoon, L.B., and Lubeck, S.C., 1987, Geochemistry of surface oil shows and potential source rocks, *in* Bird, K.J. and Magoon, L.B., eds., Petroleum geology of the northern part of the Arctic National Wildlife Refuge, Northeastern Alaska: U.S. Geological Survey Bulletin 1778, p. 181-198.

Armstrong, A.K., and Mamet, B.L., 1977, Carboniferous microfacies, microfossils, and corals, Lisburne Group, Arctic Alaska: U.S. Geological Survey Professional Paper 849, 144 p.

Bader, J.W. and Bird, K.J., 1986, Geologic Map of the Demarcation Point, Mt. Michelson, Flaxman Island, and Barter Island Quadrangles, Northeastern Alaska: U.S. Geological Survey Miscellaneous Investigations Series Map I-1791, scale 1:250,000.

Banet, A.C., 1990, Petroleum geology and geochemistry of the Arctic National Wildlife Refuge 1002 area: Anchorage, BLM-Alaska Technical Report 12, 26 p.

Banet, A.C., 1994, A comparison of crude oil chemistry on America's North Slope: Chukchi Sea-Mackenzie Delta: Anchorage, BLM-Alaska Technical Report 17, 20 p.

Berggren, W.A., Kent, D.V., Swisher, C.C. III, and Aubry, M.P., 1995, A revised Cenozoic geochronology and chronostratigraphy: Geochronology Time Scales and Global Stratigraphic Correlation, SEPM (Society for Sedimentary Geology), p. 129-212.

Bird, K.J., 1994, Ellesmerian(!) petroleum system, North Slope of Alaska, U.S.A., *in* Magoon, L.B. and Dow, W.G., eds., The petroleum system—From source to trap: American Association of Petroleum Geologists Memoir 60, p. 339-358.

Bird, K.J., and Bader, J.W., 1987, Regional geologic setting and history of petroleum exploration, *in* Bird, K.J. and Magoon, L.B., eds., Petroleum geology of the northern part of the Arctic National Wildlife Refuge, Northeastern Alaska: U.S. Geological Survey Bulletin 1778, p. 17-25.

Bird, K.J., Griscom, S.B., Bartsch-Winkler, S., and Giovannetti, D.M., 1987, Petroleum reservoir rocks, *in* Bird, K.J. and Magoon, L.B., eds., Petroleum geology of the northern part of the Arctic National Wildlife Refuge, Northeastern Alaska: U.S. Geological Survey Bulletin 1778, p. 79-99.

Blanc, Philippe, and Connan, Jacques, 1954, Preservation, degradation, and destruction of trapped oil, *in* Magoon, L.B. and Dow, W.G., eds., The petroleum system—From source to trap: American Association of Petroleum Geologists Memoir 60, p. 237-247.

Carman, G.J. and Hardwick, P., 1983, Geology and regional setting of Kuparuk oil field, Alaska: American Association of Petroleum Geologist Bulletin, v. 67, p. 1014-1031.

Claypool, G. E., and Magoon, L. B., 1988, Oil and gas source rocks in the National Petroleum Reserve in Alaska, *in* Gryc, George, ed., Geology and exploration of the National Petroleum Reserve in Alaska, 1974 to 1982: U.S. Geological Survey Professional Paper 1399, p. 451-482.

Curiale, J.A., 1987, Crude oil chemistry and classification, Alaska North Slope, *in* Tailleur, Irv and Weimer, Paul, eds., Alaskan North Slope Geology: The Pacific Section, Society of Economic Paleontologists and Mineralogists, and The Alaska Geological Society, p. 161-167.

Curiale, J.A., 1995, Saturated and olefinic terrigenous triterpenoid hydrocarbons in a biodegraded tertiary oil of northeastern Alaska: Organic Geochemistry, v. 23, no. 2, pp. 177-182.

Dixon, J., 1996, Geologic atlas of the Beaufort-Mackenzie area: Geologic Survey of Canada Miscellaneous Report 59, 173 p.

Gradstein, F.M., Agterberg, F.P., Ogg, J.G. Hardenbol, J., van Veen, P., Thierry, J., and Huang, Z., 1994, A Mesozoic time scale: Journal of Geophysical Research, v. 99, no. B12, p. 24,051-24,074.

Gussow, W.C., 1953, Differential trapping of hydrocarbons: Alberta Society of Petroleum Geologists, v. 1, pp. 4-5.

Harland, W.B., Armstrong, R.L., Cox, A.V., Craig, L.E., Smith, A.G., and Smith, D.G., 1989, A geologic time scale 1989: Cambridge University Press, Cambridge, 163 p.

Jones, H.P. and Spears, R.G., 1976, Permo-Triassic reservoirs of Prudhoe Bay field, North Slope, Alaska, *in* J. Braunstein, ed., North American Oil and Gas Fields: American Association of Petroleum Geologists Memoir 24, p. 23-50.

Levorsen, A.I., 1954, Geology of petroleum: W.H. Freeman and Company, San Francisco, 703 p.

Magoon, L.B., 1988, The petroleum system--A classification scheme for research, exploration, and resource assessment, *in* Magoon, L.B. ed., Petroleum systems of the United States: U.S. Geological Survey Bulletin 1870, p. 2-15.

Magoon, L.B., 1989, Identified Petroleum Systems within the United States--1990, *in* Magoon, L.B. ed., Petroleum systems of the United States: U.S. Geological Survey Bulletin 1912, p. 2-9.

Magoon, L.B., 1992, Identified Petroleum Systems within the United States--1992, *in* Magoon, L.B. ed., Petroleum systems of the United States: U.S. Geological Survey Bulletin 2007, p. 2-11.

Magoon, L.B., and Bird, K.J., 1985, Alaskan North Slope petroleum geochemistry for the Shublik Formation, Kingak Shale, pebble shale unit, and Torok Formation, *in* Magoon, L.B. and Claypool, G.E., eds., Alaska North Slope oil/rock correlation study: American Association of Petroleum Geologists Special Studies in Geology No. 20, p. 31-48.

Magoon, L.B., and Bird, K.J., 1988, Evaluation of petroleum source rocks in the National Petroleum Reserve in Alaska using organic carbon, hydrocarbon content, visual kerogen, and vitrinite reflectance, *in* Gryc, George, ed., Geology and exploration of the National Petroleum Reserve in Alaska, 1974 to 1982: U.S. Geological Survey Professional Paper 1399, p. 381-450.

Magoon , L.B., and Claypool, G.E., 1981, Two oil types on the North Slope of Alaska--Implications for exploration: American Association of Petroleum Geologists Bulletin, v. 65, no. 4, p. 644-652.

Click here or on this symbol in the toolbar to return.

Magoon, L.B., and Claypool, G.E., 1983, Petroleum geology of the North Slope of Alaska--Time and degree of thermal maturity, *in* Bjoroy, Malvin, ed., Proceedings of Tenth International Meeting on Organic Geochemistry: Advances in Organic Geochemistry, 1981, p. 28-38.

Magoon, L.B, and Claypool, G.E., 1984, The Kingak Shale of northern Alaska--Regional variations in organic geochemical properties and petroleum source-rock quality: Organic Geochemistry, v. 6, p. 533-542.

Magoon, L.B., and Claypool, G.E., eds., 1985, Alaska North Slope oil/rock correlation study: American Association of Petroleum Geologists Special Studies in Geology No. 20, 682 p.

Magoon, L.B., and Claypool, G.E., 1988, Geochemistry of oil occurrences, National Petroleum Reserve in Alaska, *in* Gryc, George, ed., Geology and exploration of the National Petroleum Reserve in Alaska, 1974-1982: U.S. Geological Survey Professional Paper 1399, p. 519-550.

Magoon, L.B., and Dow, W.G., eds., 1994a, The petroleum system—From source to trap: American Association of Petroleum Geologists Memoir 60, 655 p.

Magoon, L.B., and Dow, W.G., 1994b, The Petroleum System, *in* Magoon, L.B. and Dow, W.G., eds., The petroleum system—From source to trap: American Association of Petroleum Geologists Memoir 60, p. 3-24.

Magoon, L.B., and Schmoker, J.W., 1991, A mass balance calculation to compare hydrocarbons generated to hydrocarbons accumulated for the Tuxedni-Hemlock petroleum system, Cook Inlet, Alaska, *in* Manning, D., ed., Organic geochemistry—Advances and applications in the natural environment: Manchester, Manchester University Press, p. 73-76.

Magoon, L.B., Woodward, P.V., Banet, A.C., Griscom, S.B., Daws, T.A., 1987, Thermal maturity, richness, and type of organic matter of source-rock units, *in* Bird, K.J. and Magoon, L.B., eds., Petroleum geology of the northern part of the Arctic National Wildlife Refuge, Northeastern Alaska: U.S. Geological Survey Bulletin 1778, p. 127-179.

Magoon, L.B., and Valin, Z.C., 1994, Overview of petroleum system case studies, *in* Magoon, L.B. and Dow, W.G., eds., The petroleum system—From source to trap: American Association of Petroleum Geologists Memoir 60, p. 329-338.

Click here or on this symbol in the toolbar to return.

McCaffrey, M.A., Dahl, J.E., Sundararaman, P., Moldowan, J.M., and Schoell, M., 1994, Source rock quality determination from oil biomarkers II--A case study using Teriary-reservoired Beaufort Sea oil: American Association of Petroleum Geologists, v. 78, p. 1527-1540.

Morgridge, D.L., and Smith, W.B., 1972, Geology and discovery of Prudhoe Bay field, eastern Arctic Slope, Alaska, *in* R.E. King, ed., Stratigraphic oil and gas fields: American Association of Petroleum Geologists Memoir 16, p. 489-501.

O'Sullivan, P.B., 1993, 1993, Late Cretaceous and Tertiary thermal and uplift history of the North Slope foreland basin of northern Alaska and northwestern Canada, Ph.D. thesis, La Trobe Univ., Bundoora, Victoria, Australia, 419 p.

Palmer, I.F., Bolm, J.R., Maxey, L.R., and Lyle, W.M., 1979, Petroleum source rock and reservoir quality data from outcrop samples, onshore North Slope of Alaska east of Prudhoe Bay: U.S. Geological Survey Open-File Report 79-1634, 52 p.

Robison, V.D., Liro, L.M., Robison, C.R., Dawson, W.C., and Russo, J.W., 1996, Integrated geochemistry, organic petrology, and sequence stratigraphy of the Triassic Shublik Formation, Tenneco Phoenix #1 well, North Slope, Alaska, U.S.A.: Organic Geochemistry, v. 24, no. 2, p. 257-272.

Rowan, E.L., 1997, Basin evolution, and the timing and extent of oil generation, Canning River region, North Slope, Alaska: Preliminary Basin2 calculations assuming a conductive thermal history: U.S. Geological Survey Open-File Report 97-711, 62 p.

Scherr, J., Banet, S.M., and Bascle, B.J., 1991, Correlation study of selected exploration wells from the North Slope and Beaufort Sea, Alaska: Minerals Management Service OCS Report MMS 91-0076, 29 p.

Schmoker, J.W., 1994, Volumetric calculation of hydrocarbons generated, *in* Magoon, L.B. and Dow, W.G., eds., The petroleum system—From source to trap: American Association of Petroleum Geologists Memoir 60, p. 323-326.

Sedivy, R.A., Penfield, I.E., Halpern, H.I., Drozd, R.J., Cole, G.A., and Burwood, R., 1987, Investigation of source rock-crude oil relationships in the northern Alaska hydrocarbon habitat, *in* Tailleur, I. and Weimer, P., eds.,

Click here or on this symbol
in the toolbar to return.

Alaskan North Slope Geology: The Pacific Section, Society of Economic Paleontologists and Mineralogists, and The Alaska Geological Society, p. 169-179.

Seifert, W.K., Moldowan, J.M., and Jones, J.W., 1979, Application of biological marker chemistry to petroleum exploration: Proceedings of the 10th World Petroleum Congress, p. 425-440.

State of Alaska, 1992, Kavik field, *in* 1992 Annual Report: Alaska Oil and Gas Conservation Commission, p. 128.

State of Alaska, 1995, Kemik field, *in* 1995 Annual Report, Alaska Oil and Gas Conservation Commission, p. 187-188.

Wicks, J.L., Buckingham, M.L., and Dupree, J.H., 1991, Endicott Field—U.S.A. North slope basin, Alaska, *in* Foster, N.H. and Beaumont, E.A., compilers, Structural Traps V, Treatise of Petroleum Geology Atlas of Oil and Gas fields: American Association of Petroleum Geologists, Structural Traps V, p. 1-25.

Click here or on this symbol
in the toolbar to return.

Click here or on this symbol
in the toolbar to return.

Thermal maturity	Zone of Petroleum Occurrence	Product	Location	Comments
	Zone of Accumulation	Hydrocarbon, Petroleum, or Oil and gas	(in reservoir rock at trap)	Petroleum able to migrate to a lower temperature
~0.6%R_o				
	Zone of Expulsion	Hydrocarbon, Petroleum, or Oil and gas	(from pod of active source rock to reservoir rock in trap)	
~1.0%R_o				
	Zone of Cracking	Light oil and Wet gas	(in reservoir rock at trap)	Petroleum unable to migrate to a lower temperature
~2.0%R_o				
	Zone of Dry Gas	Dry gas and Pyrobitumen	(in reservoir rock at trap)	

Figure PS1. Four zones of petroleum occurrence based on thermal maturity. Hydrocarbon, petroleum, and oil and gas are all synonyms, for example the shallowest level is the zone of petroleum accumulation.

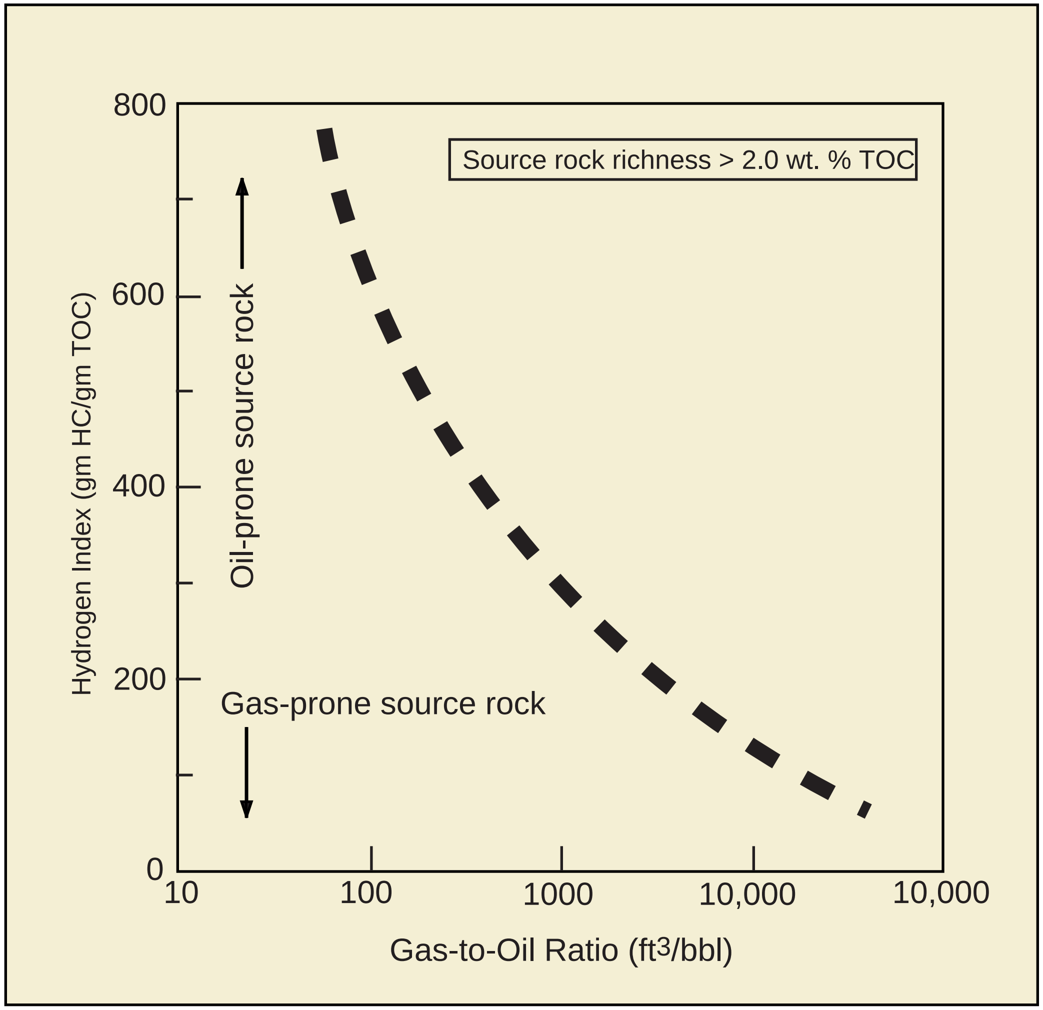
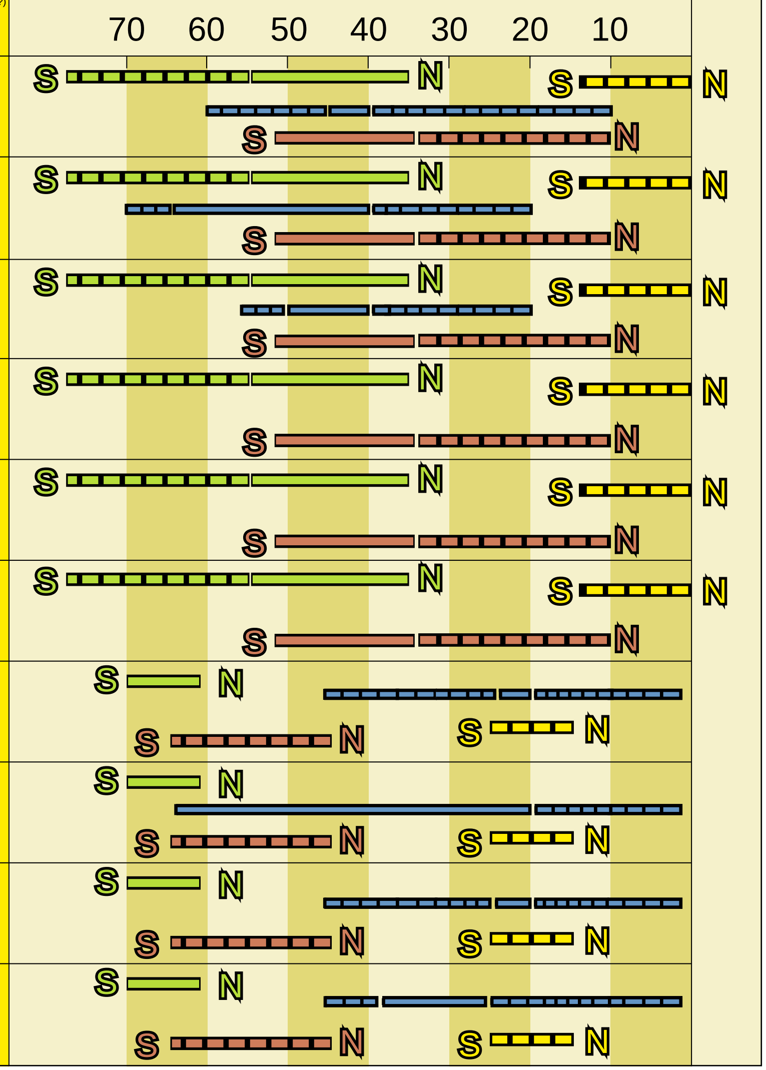


Figure PS2. Graphs showing the increase of gas-to-oil ratio (GOR) with decreasing hydrogen index (HI) in a source rock with at least 2 wt. % total organic carbon (TOC). The volume of petroleum expelled also decreases with decreasing HI.

Click here or on this symbol
in the toolbar to return.

TRAP / Play	HYDROCARBON CHARGE — Petroleum System: Ellesmerian(!) Petroleum System 11 bbls	Hue-Thomson(!) Petroleum System 9 bbls	Canning-Sagavanirktok(?) Petroleum System 10 bbls
#1 Topset Play	5-25[1]	50-75	75-95
#2 Turbidite Play	5-25	>95	25-50
#3 Wedge Play	5-25	>95	25-50
#4 Thomson Play	>95	>95	<5
#5 Kemik Play	>95	>95	<5
#6 Undeformed Franklinian Play	>95	>95	<5
#7 Deformed Franklinian Play	>95	>95	<5
#8 Thin-Skinned Thrust-Belt Play	>95(W) 5-25(E)	>95	>95
#9 Ellesmerian Thrust-Belt Play	>95	5-25	<5
#10 Niguanak-Aurora Play	5-25	25-50	5-25

TIME OF CHARGE AND TRAP DEVELOPMENT (Ma)



[1] Scale used in evaluation: <5; 5-25; 25-50; 50-75; 75-95; >95; Scale used on play assessment form: 0.05, 0.15; 0.35; 0.65, 0.85, 0.95.

Evaluation team: Ken Bird, Fran Cole, Curt Huffman, Margaret Keller, Les Magoon, Tom Moore, Elisabeth Rowan, and Paul Lillis on April 23-25, 1997 at USGS in Menlo Park, CA.

Revised: Elizabeth Rowan and Les Magoon in September, 1997 at USGS in Menlo Park, CA.

Revised by Evaluation team: Ken Bird, Bob Burruss, Kevin Evans, John Grow, Dan Hayba, Margaret Keller, Naresh Kumar, Paul Lillis, Les Magoon, Tom Moore, and John Murphy on December 16-17, 1997 at the USGS in Menlo Park, CA.

EXPLANATION

- Modeled duration of charge from Ellesmerian(!) petroleum system
- Interpreted duration of charge from Ellesmerian(!) petroleum system
- S South, time pod of active source rock expelled oil and gas in the south
- N North, time pod of active source rock ceased expelling oil and gas (on south to north migration front)
- Trap formation most likely to have occurred
- Trap formation could have occurred

Figure PS3. Probability and timing of hydrocarbon charge for three petroleum systems. The top row of the table gives the volume of petroleum, in billions of in-place barrels of oil (BBO), estimated to reach the traps in a play area for each petroleum system. Other rows in the table give the probability that a particular petroleum system charged the traps in a given play. The bar chart shows the time over which the hydrocarbon charge was available to charge a trap in the play, provided the trap was available to charge. The time over which the trap developed is also shown.

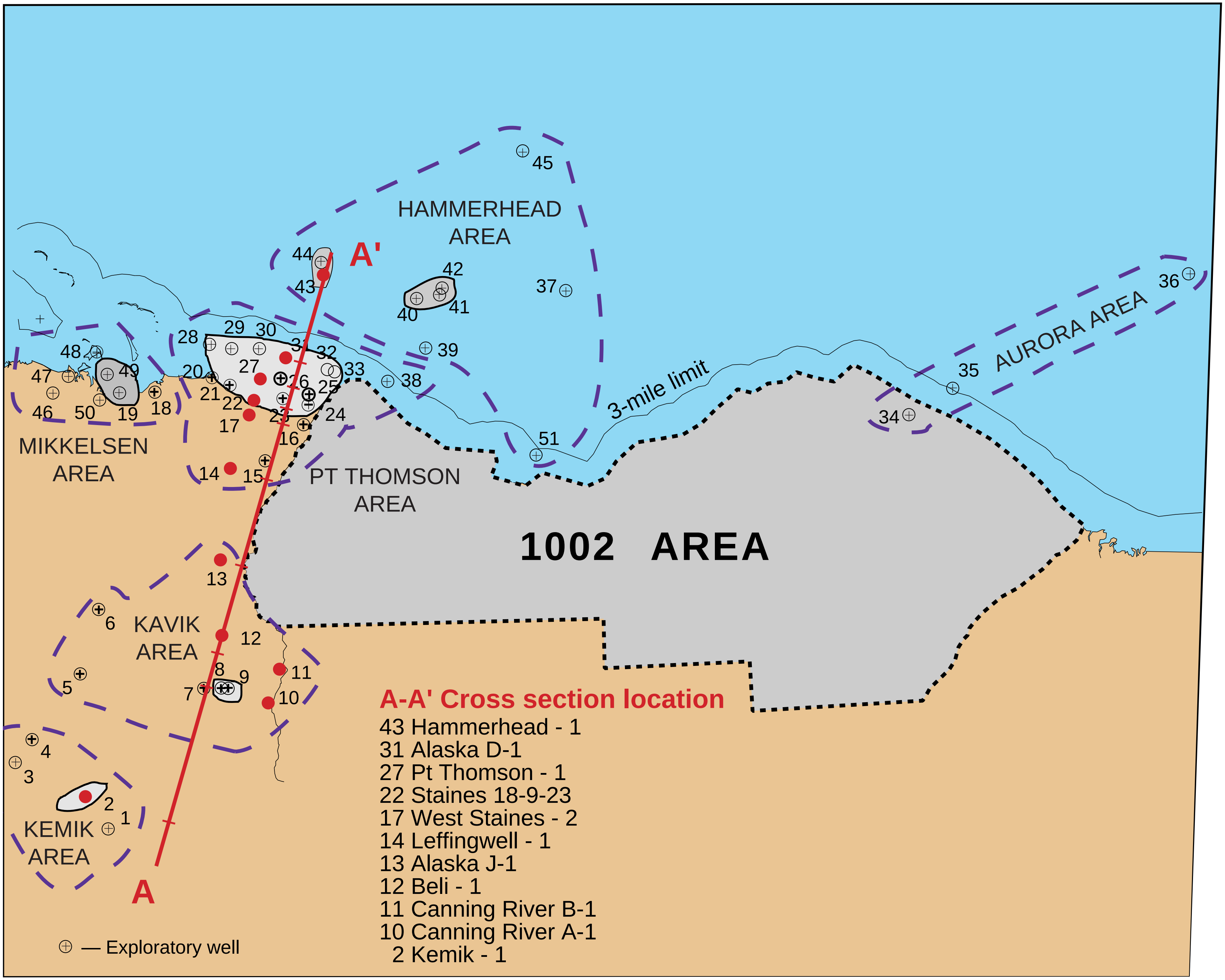


Figure PS4. Map of 1002 and adjacent area showing the location of time-stratigraphic cross section A-A'. A complete list of well names and numbers is given in tables PS5, PS6, or PS7.

The Oil and Gas Resource Potential of the
Arctic National Wildlife Refuge 1002 Area, Alaska
Open File Report 98-34

Click here or on this symbol
in the toolbar to return.

Stratigraphic Units

Ma	Strat No.	Description
-1.5 to 0	15	Pleistocene + Holocene
-1.8 to -1.5	14	Early Pleistocene unconformity
-34 to -1.8	13	Post-Eocene
-55 to -34	12	Eocene
-65 to -55	11	Staines Unit; Paleocene
-74 to -65	10	Lower Canning, Latest Cretaceous
-141 to -74	9	Kemik Ss.(135)+Pebble shale(124.5)+ Hue Shale(74); Early Cretaceous
-146 to -141	8	Lower Cretaceous unconformity (LCU)
-208 to -146	7	Kingak Shale, Jurassic
-269 to -208	6	Sadlerochit Gp.(241)+Shublik Fm.(209.5) +Sag Rv. Ss.(208); Triassic
-290 to -269	5	Post-Pennsylvanian unconformity (PMU)
-323 to -290	4	Lisburne Gp., Pennsylvanian
-345 to -323	3	Endicott Gp., Mississippian
-362.5 to -345	2	Early Mississippian unconformity
< -362.5	1	Pre-Mississippian basement complex

Revised 2/97

Compiled by LBM and LER

Figure PS5. The ages of the stratigraphic units used in the time-stratigraphic section.

Click here or on this symbol
in the toolbar to return.

Time-Stratigraphic Cross Section
West of Arctic National Wildlife Refuge

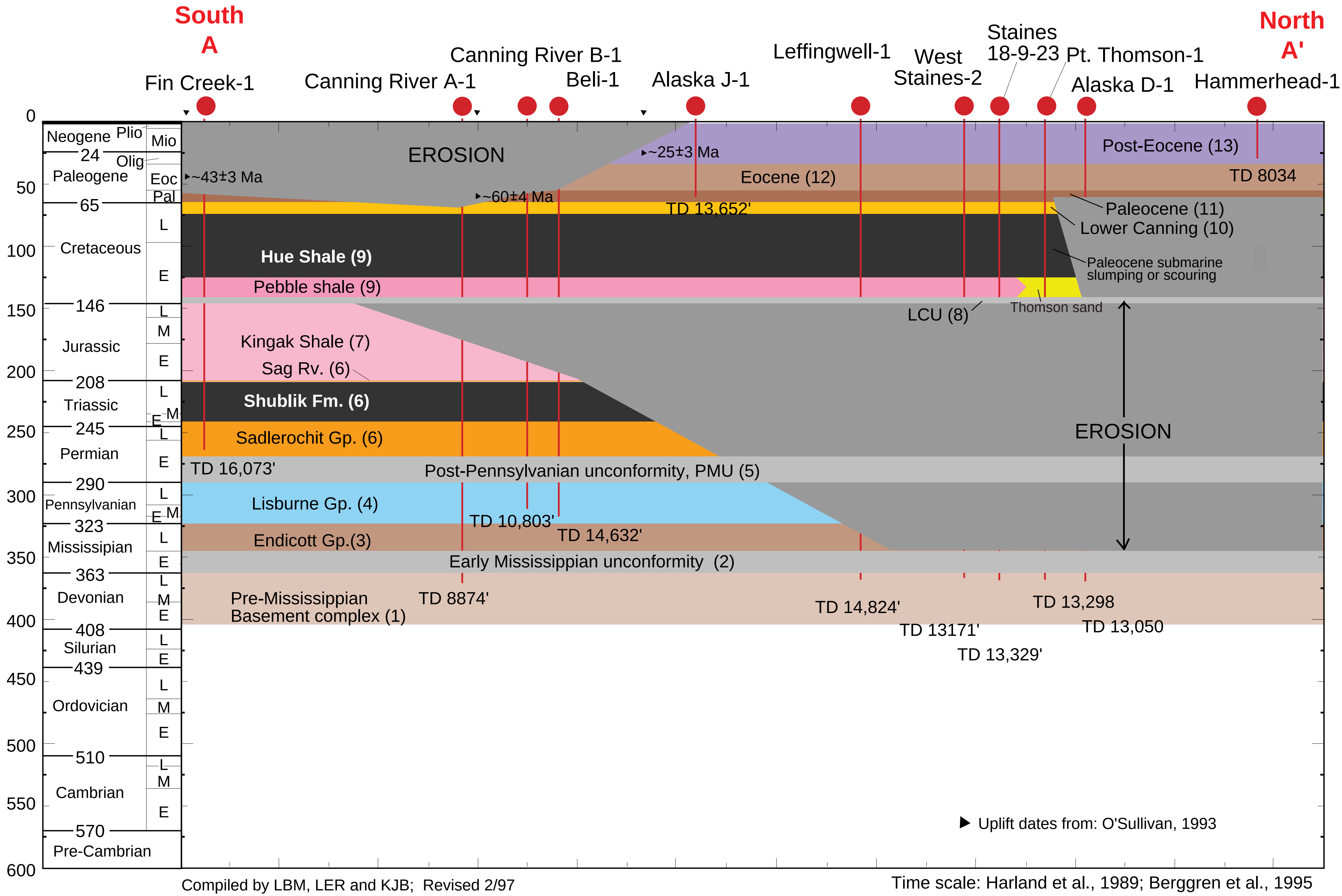


Figure PS6. Time-stratigraphic cross section west of the 1002 area of the Arctic National Wildlife Refuge.

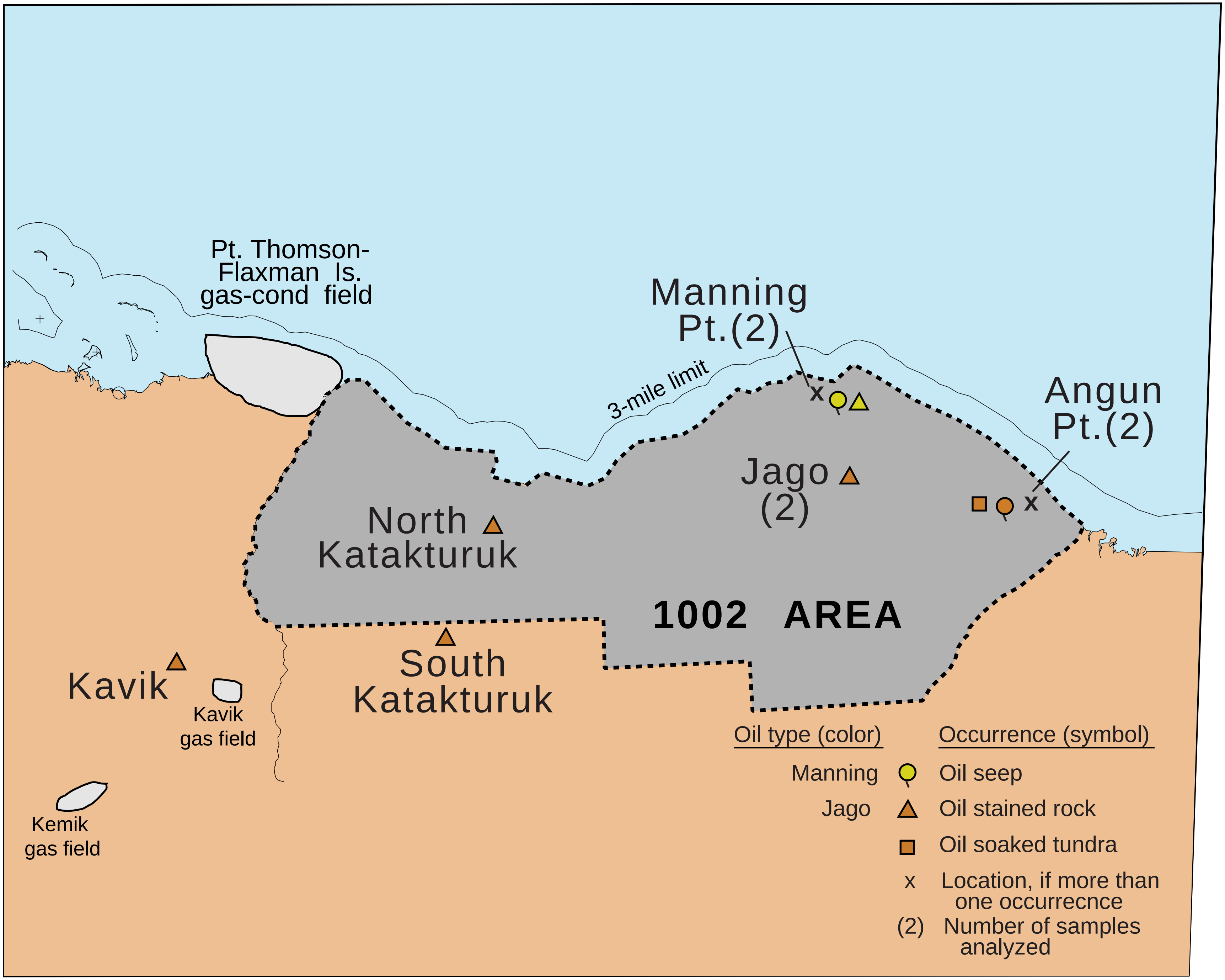


Figure PS7. Map of 1002 and adjacent area showing the location of oil samples for analyses reported by Anders and others (1987).

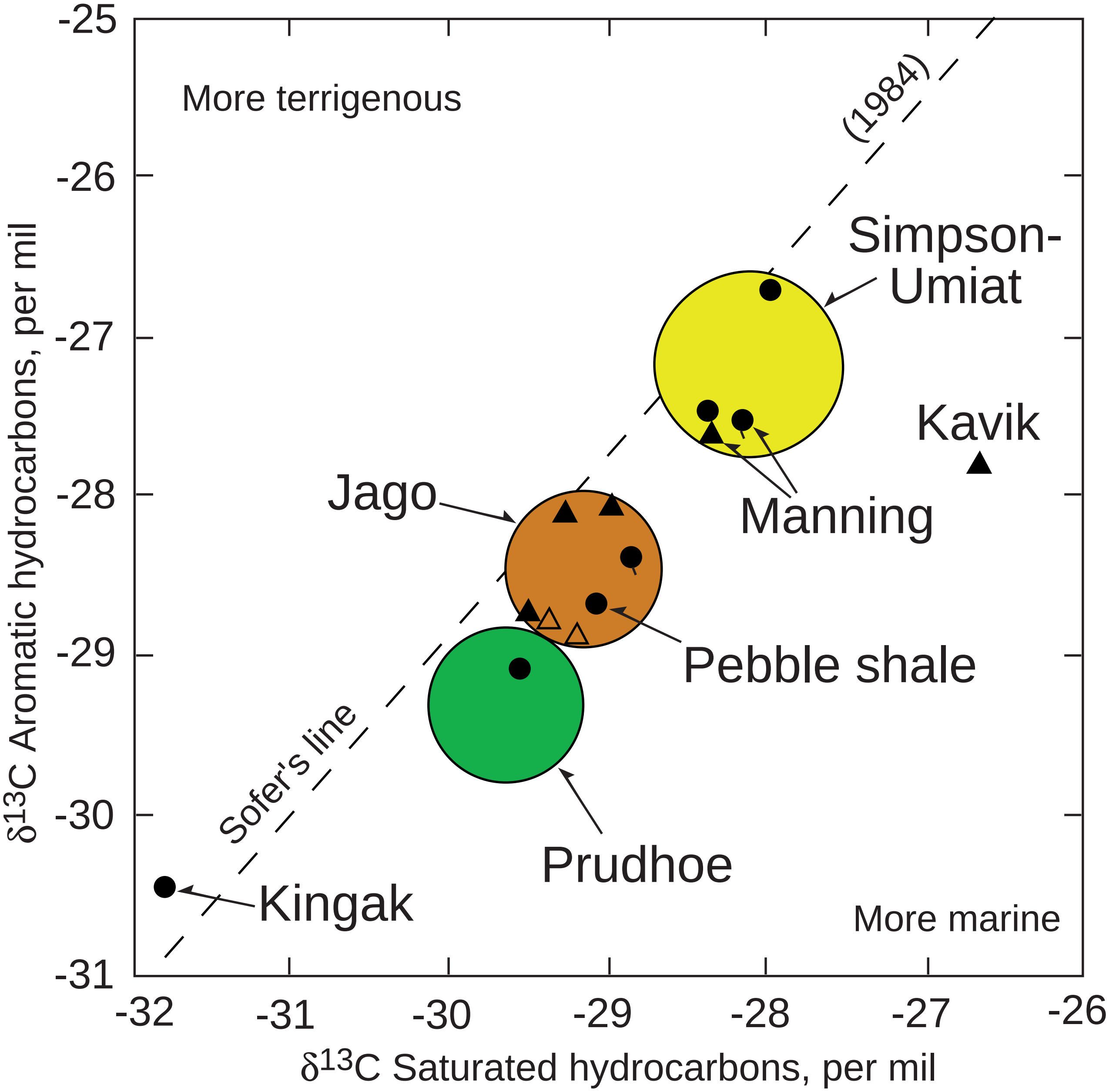


Figure PS8. Graph of carbon isotopic composition of saturated and aromatic hydrocarbons samples for analyses reported by Anders and others (1987).

USGS
science for a changing world

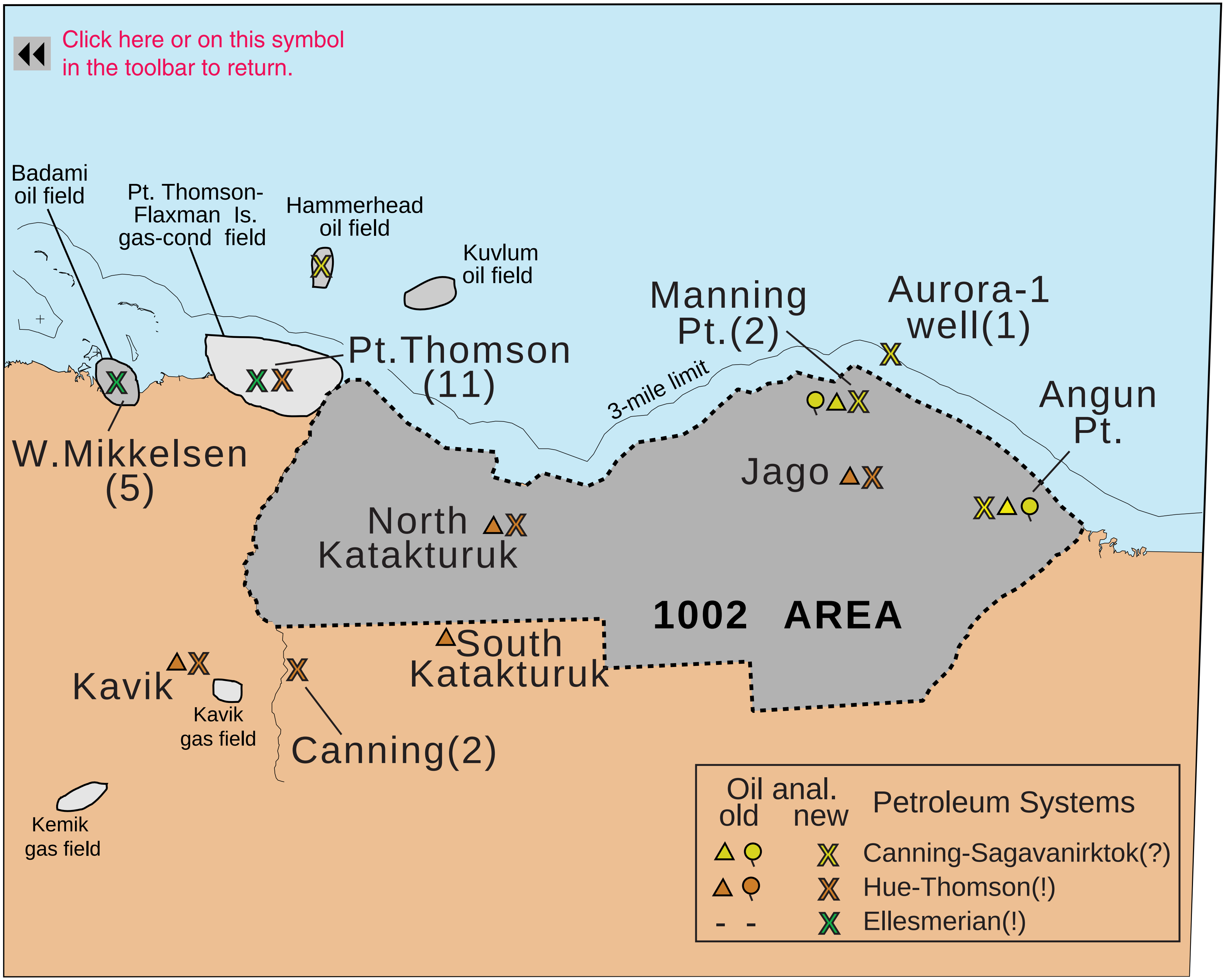


Figure PS9. Map of 1002 and adjacent area showing the location of oil samples for analyses reported by Anders and others (1987).

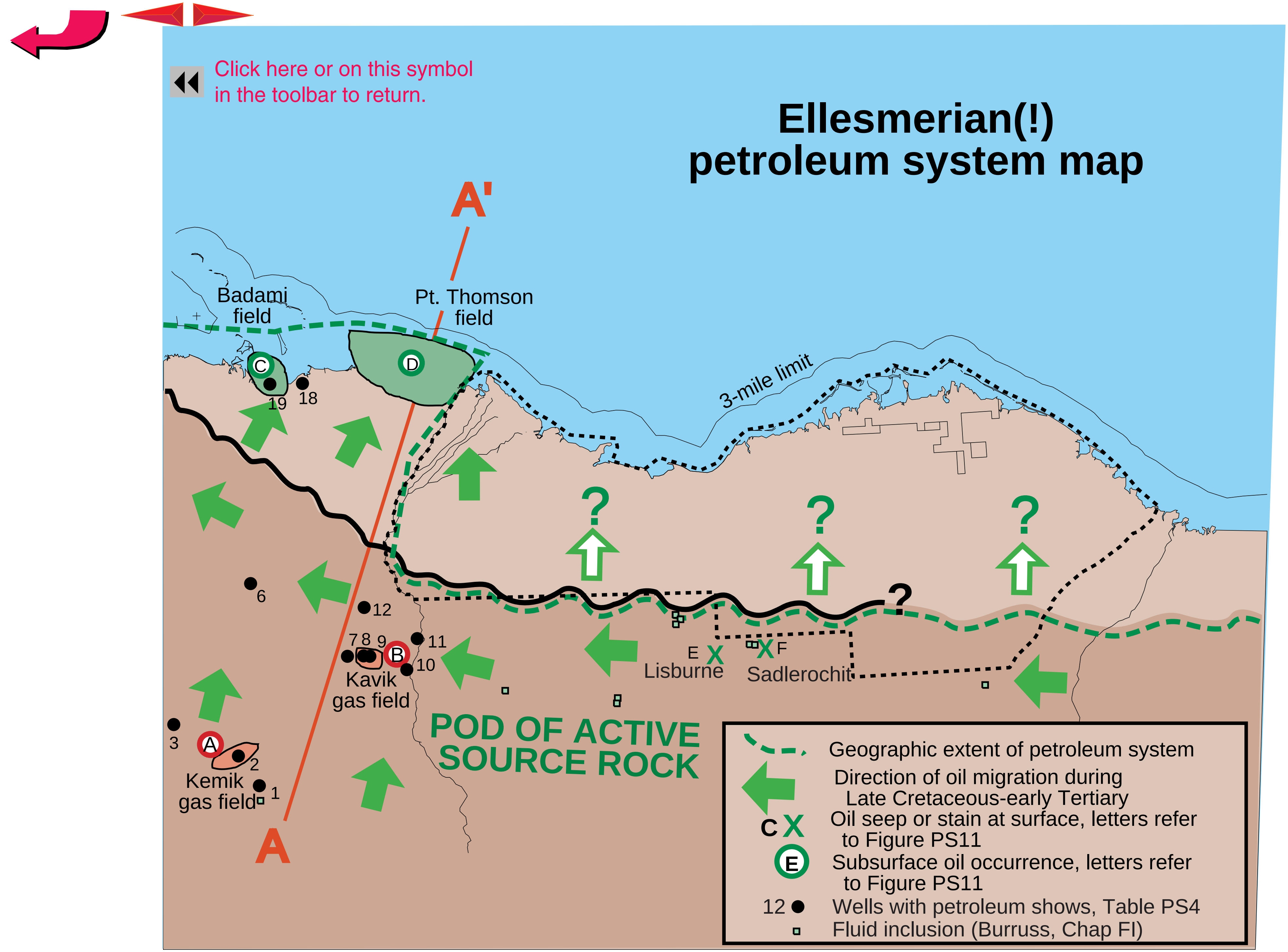


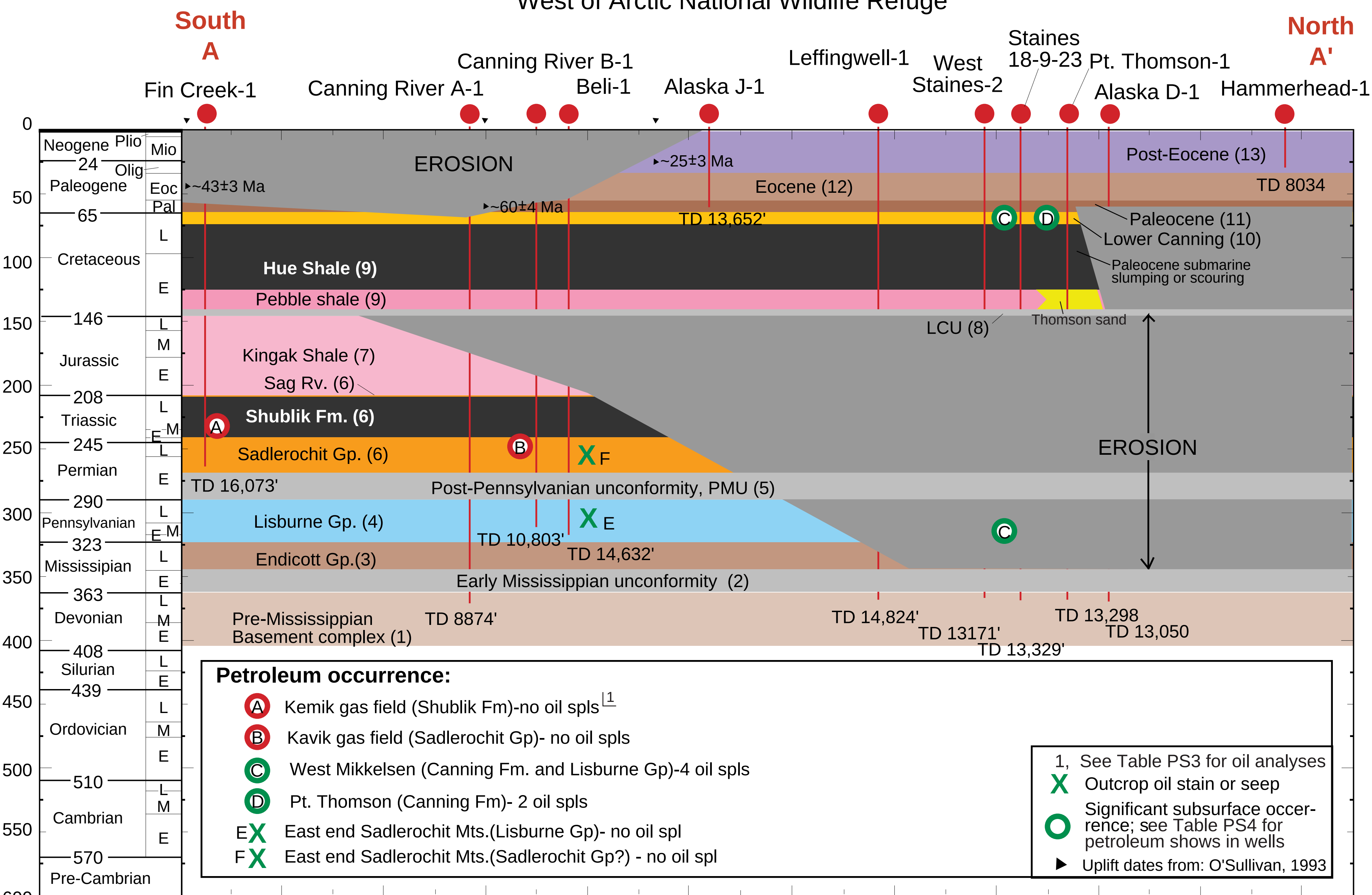
Figure PS10. Map of the Ellesmerian(!) petroleum system showing the pod of active source rock, oil and gas occurrences, geographic extent, and possible migration direction for petroleum.

Click here or on this symbol in the toolbar to return.

Petroleum Occurrence in Ellesmerian(!)

Time-Stratigraphic Chart

West of Arctic National Wildlife Refuge



Compiled by LBM, LER and KJB; Revised 2/97

Time scale: Harland et al., 1989; Berggren et al., 1995

Figure PS11. Petrolum occurrences in the Ellesmerian(!) petroleum system shown on the time-stratigraphic section.

Click here or on this symbol
in the toolbar to return.

Ellesmerian(!) Events Chart

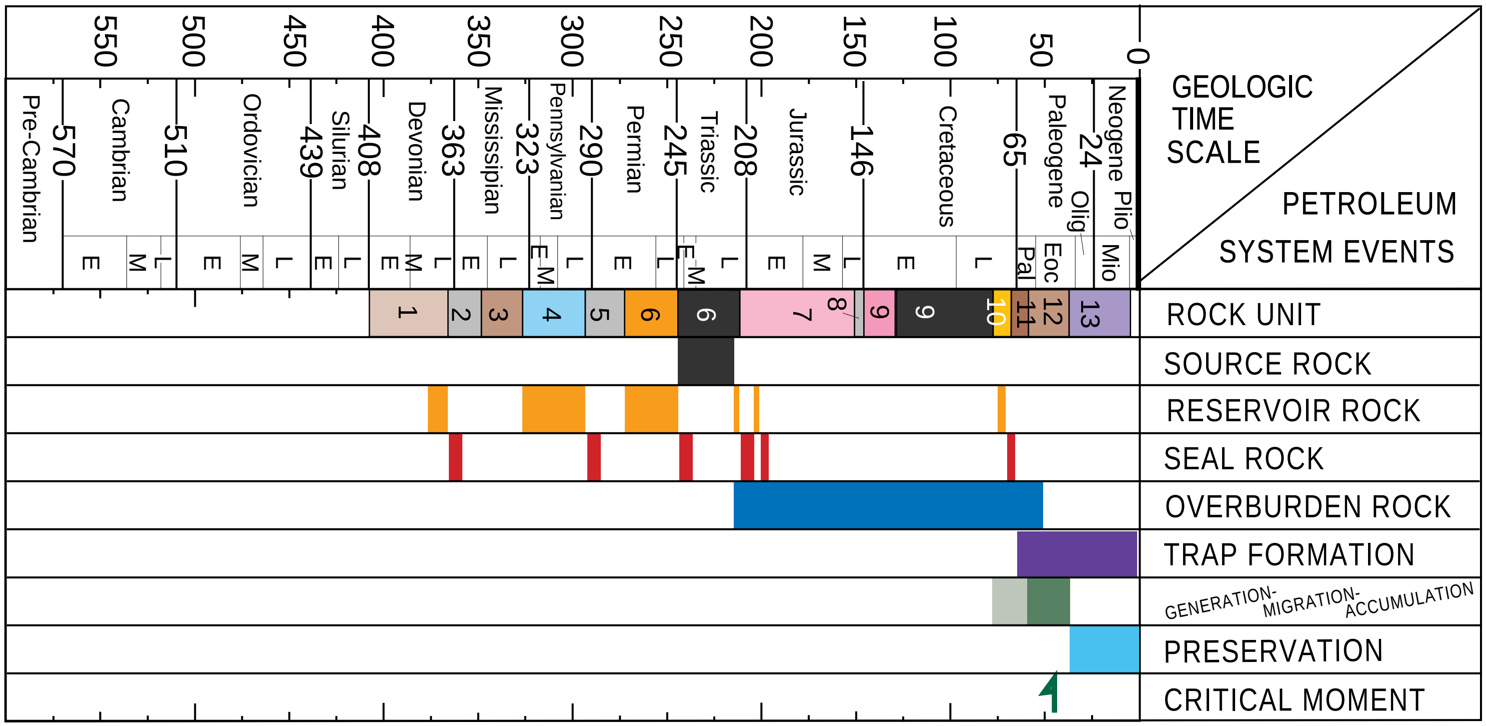


Figure PS12. Events Chart for the Ellesmerian(!) petroleum system.

Click here or on this symbol
in the toolbar to return.

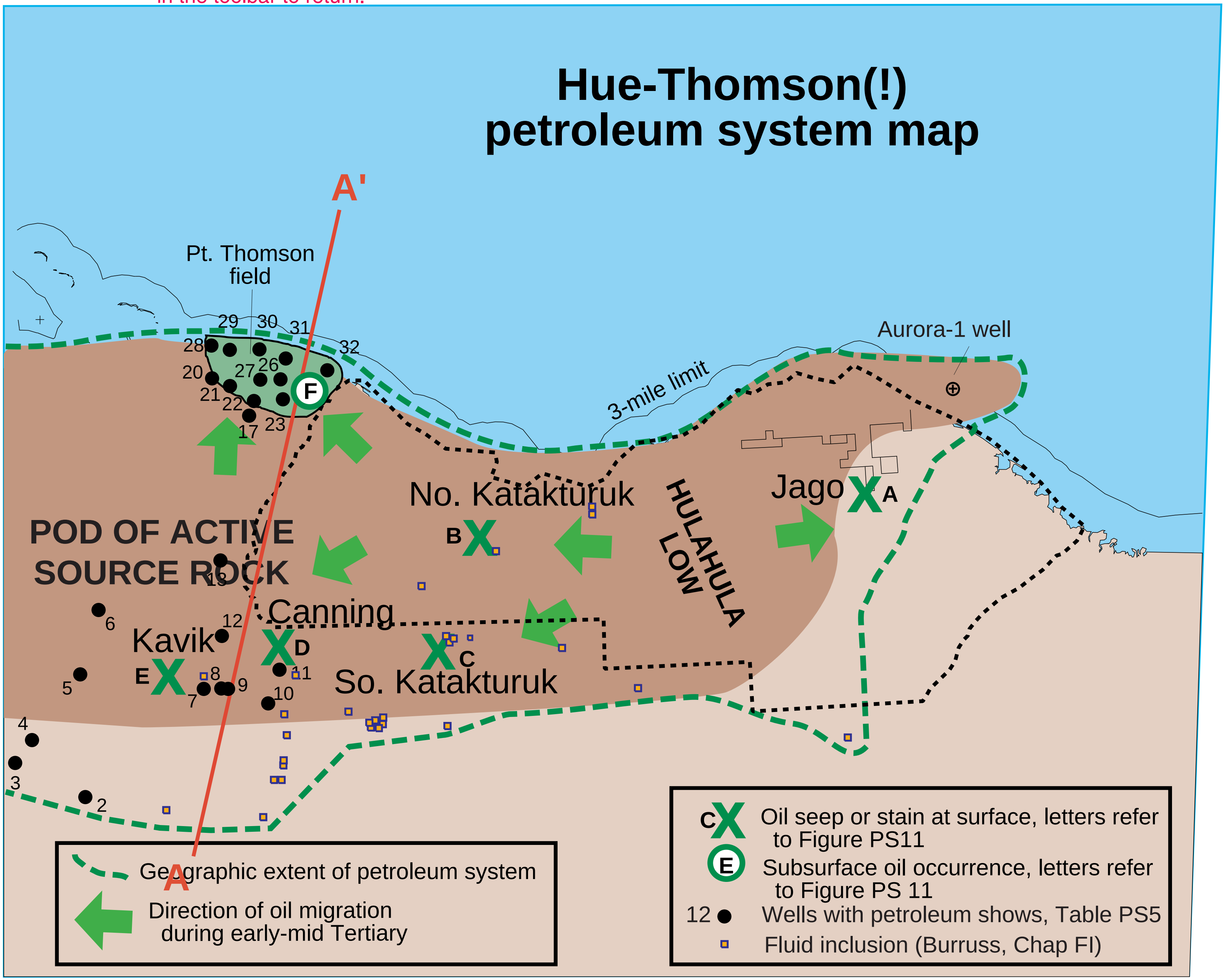


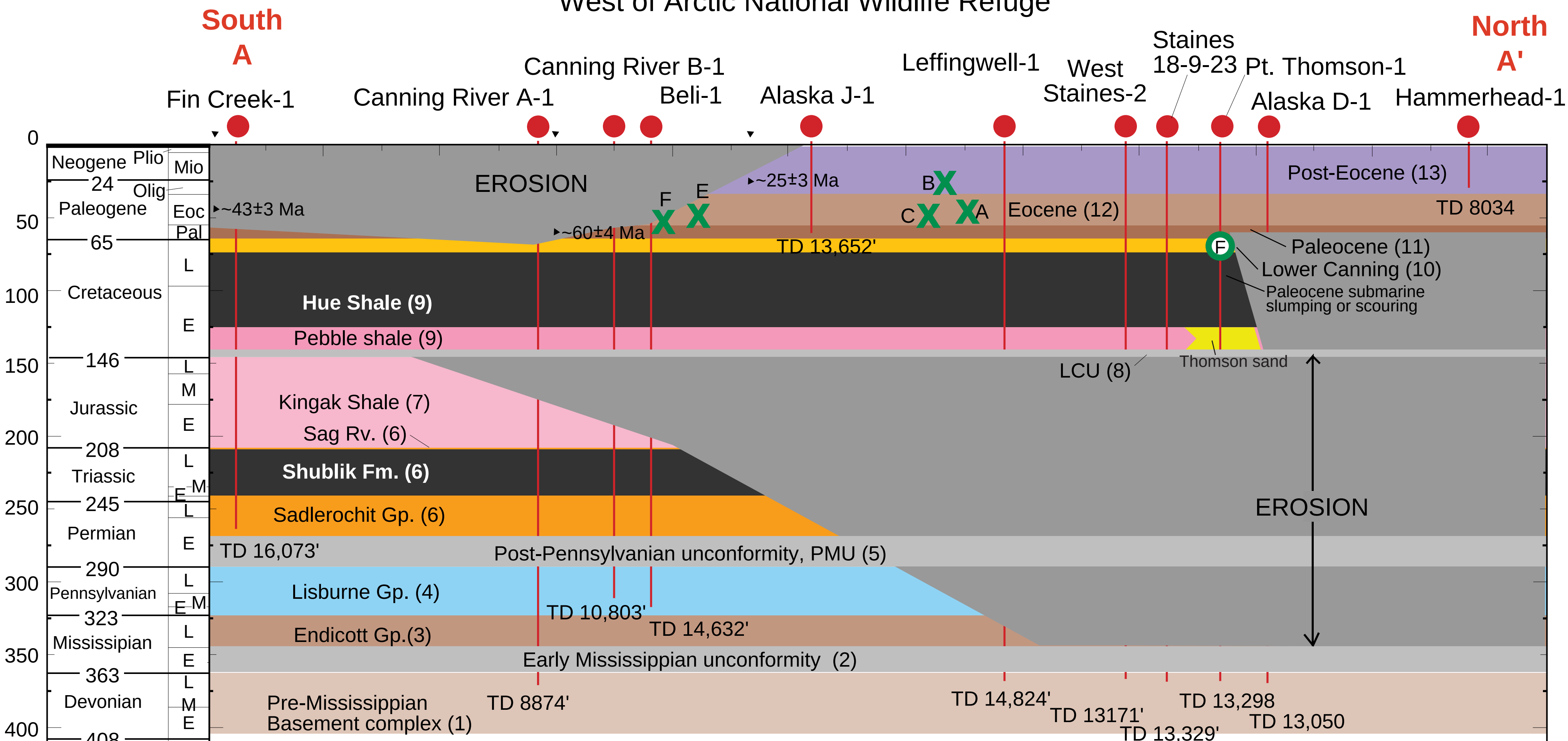
Figure PS13. Map of the Hue-Thomson(!) petroleum system showing the pod of active source rock, oil and gas occurrences, geographic extent, and possible migration direction for petroleum.

Click here or on this symbol in the toolbar to return.

Petroleum Occurrence in Hue-Thomson(!)

Time-Stratigraphic Chart

West of Arctic National Wildlife Refuge



Petroleum occurrence:

- X A Jago River oil-stained shale (Sagavanirktok Fm)- 3 oil spls [1]
- X B North Katakturuk River (Sagavanirktok Fm)- 2 oil spls
- X C South Katakturuk River (Canning Fm)- 1 oil spl
- X D Canning River (Sagavanirktok Fm)- 2 oil spls
- X E Kavik area (Sagavanirktok Fm)- 2 oil spls
- F Point Thomson field (Canning Fm and Thomson sand)- 2 oil spls

1, See Table PS3 for oil analyses

X Outcrop oil stain or seep

O Significant subsurface occurrence; see Table PS4 for petroleum shows in wells

▶ Uplift dates from: O'Sullivan, 1993

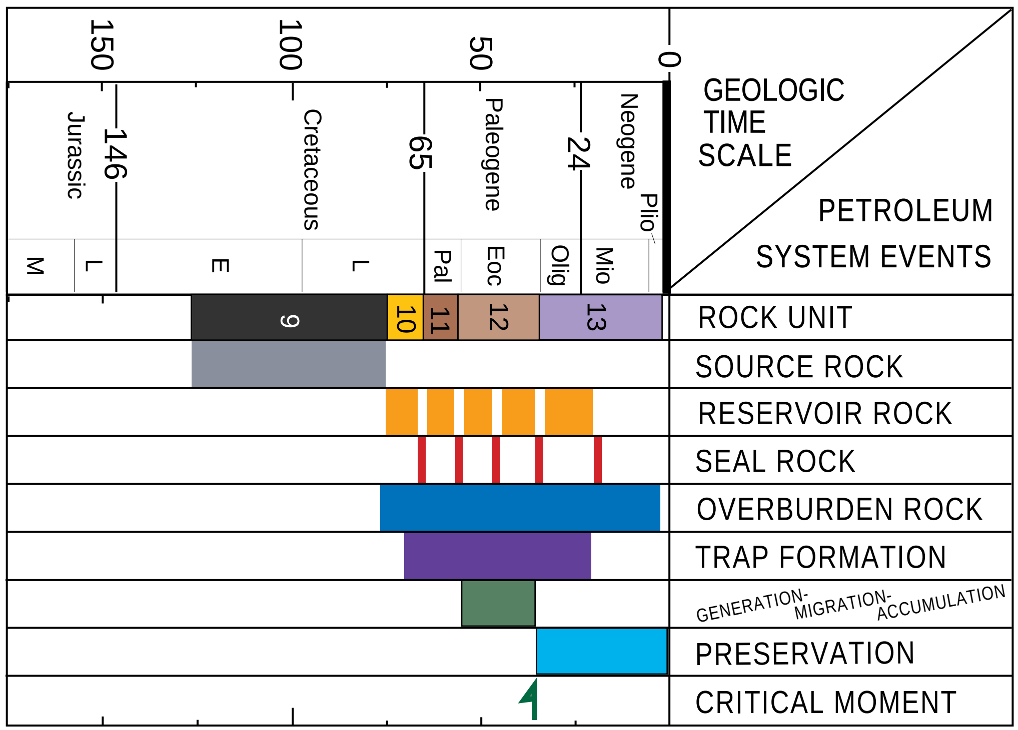
Compiled by LBM, LER and KJB; Revised 4/97

Time scale: Harland et al., 1989; Berggren et al., 1995

Figure PS14. Petrolum occurrences in the Hue-Thomson(!) petroleum system shown on the time-stratigraphic section.

Click here or on this symbol
in the toolbar to return.

Hue-Thomson(!) Events Chart



Time scale: Harland et al., 1989; Berggren et al., 1995

Figure PS15. Events Chart for the Hue-Thomson(!) petroleum system.

Click here or on this symbol
in the toolbar to return.

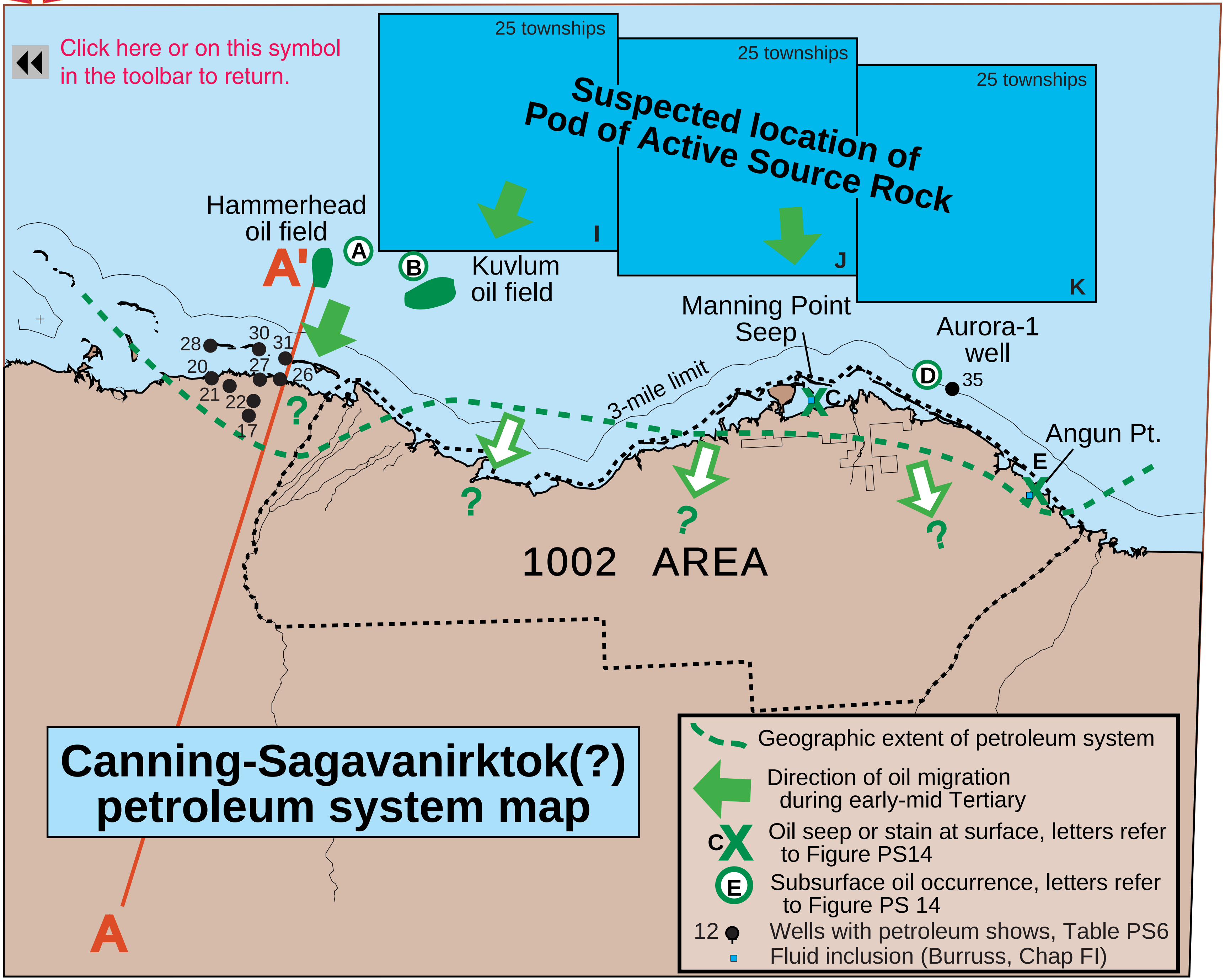


Figure PS16. Map of the Canning-Sagavanirktok(?) petroleum system showing the oil and gas occurrences, geographic extent of sourthern-most boundary, and possible migration direction for petroleum.

Click here or on this symbol in the toolbar to return.

Petroleum Occurrence in Canning-Sagavanirktok(?)

Time-Stratigraphic Chart

West of Arctic National Wildlife Refuge

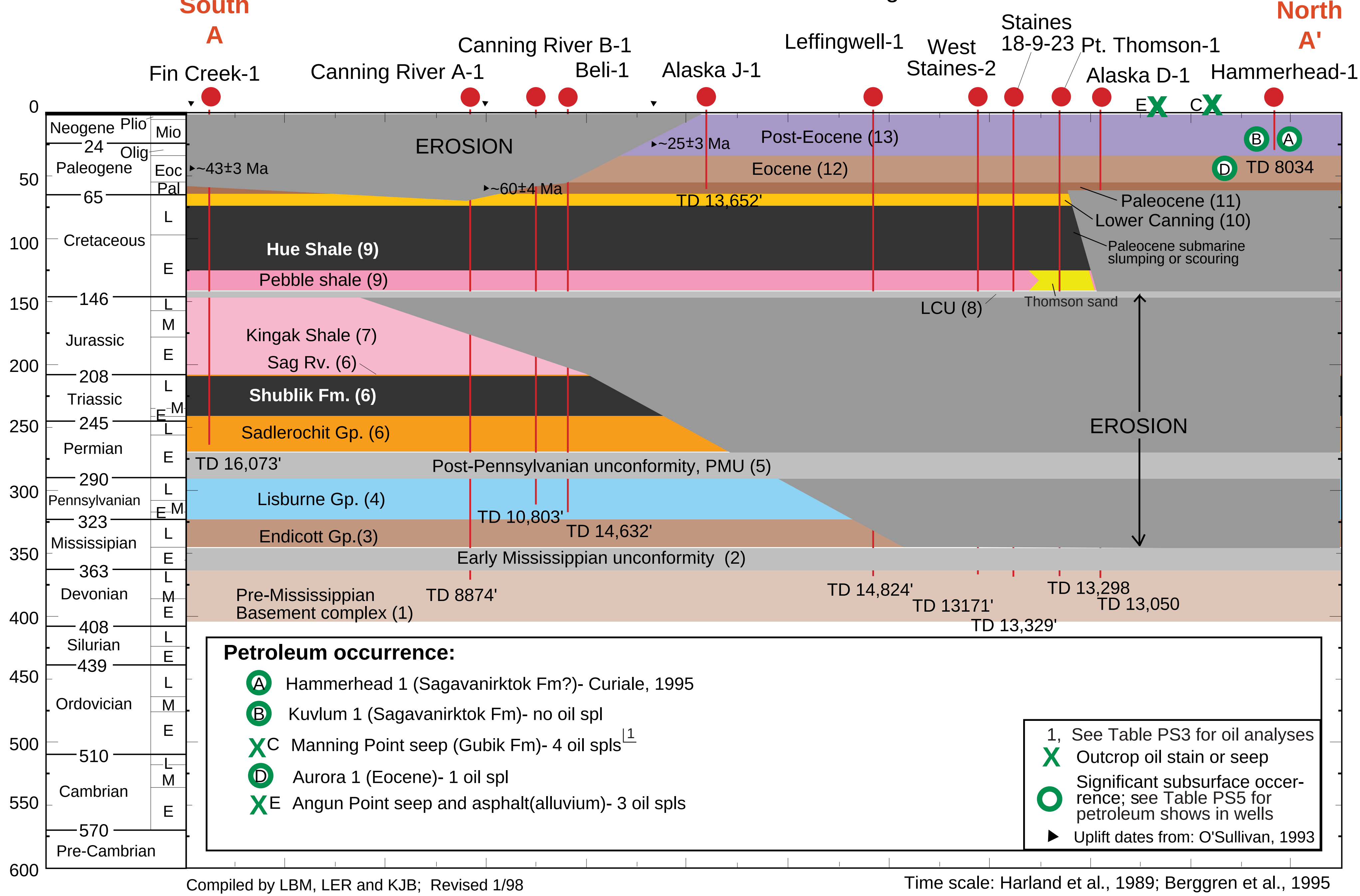


Figure PS17. Petroleum occurrences in the Canning-Sagavanirktok(?) petroleum system shown on the time-stratigraphic section.

Canning-Sagavanirktok(?) Events Chart

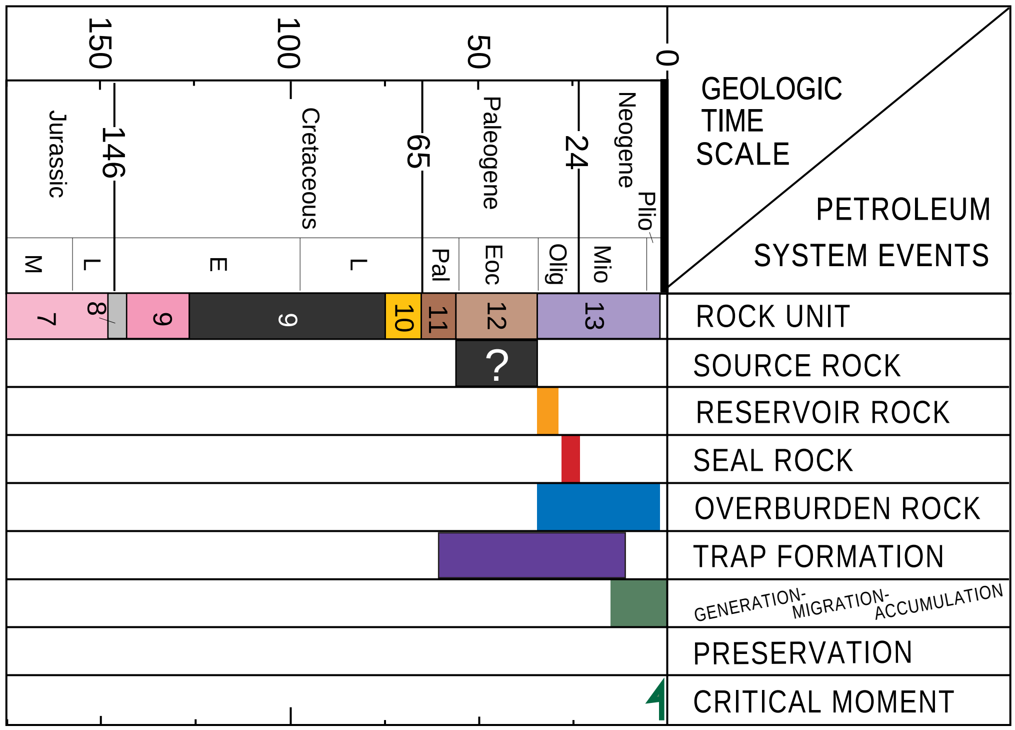
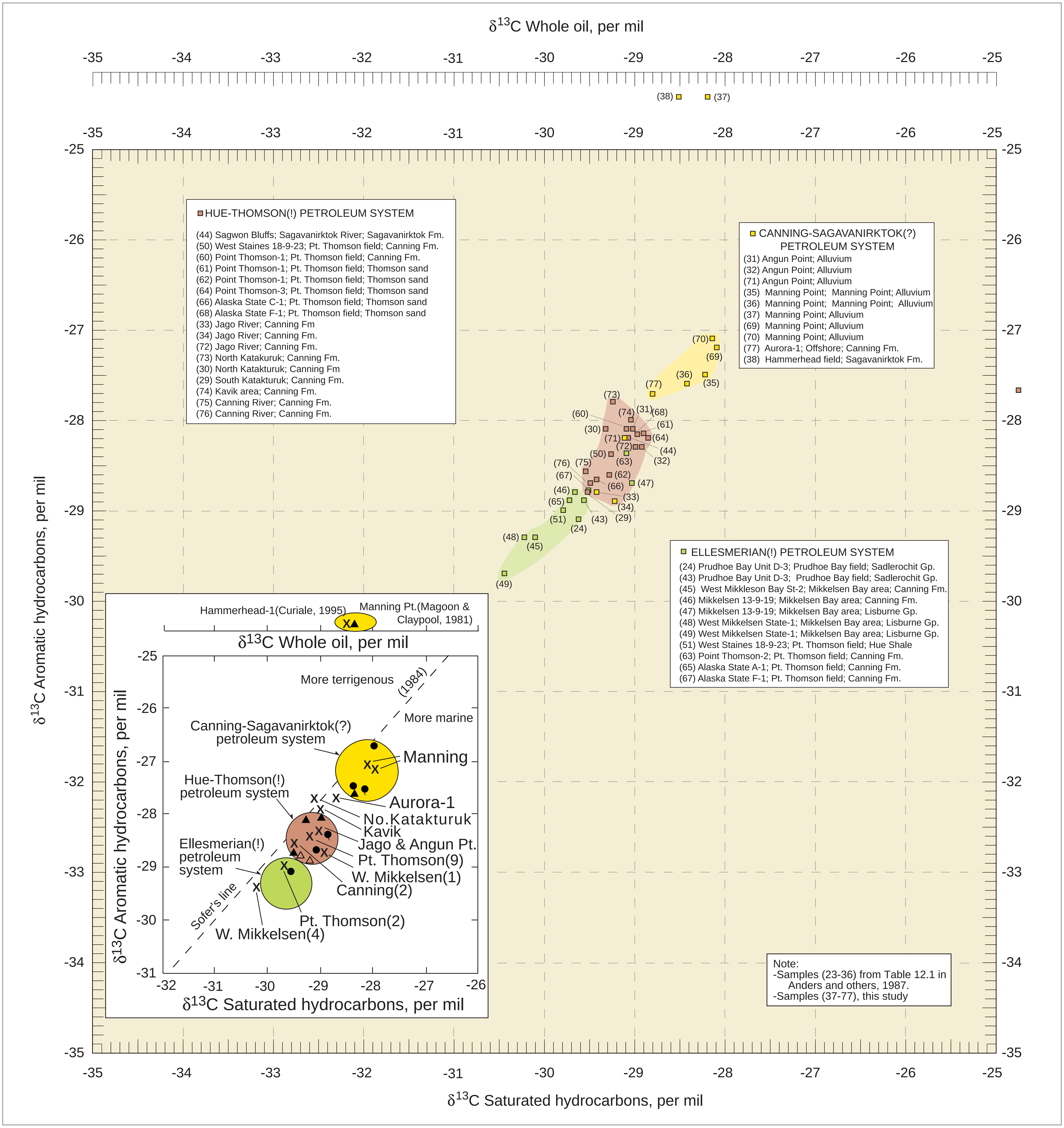


Figure PS18. Events Chart for the Canning-Sagavanirktok(?) petroleum system. Time scale from Harland and others, 1989 and Berggren and others, 1995.

Click here or on this symbol in the toolbar to return.

U.S. DEPARTMENT OF THE INTERIOR
U.S. GEOLOGICAL SURVEY

OPEN-FILE REPORT 98-34
PLATE PS1



δ13C±ISOTOPIC COMPOSITION OF OILS FROM THE ELLEMERIAN(!), HUE-THOMSON(!), AND CANNING-SAGAVANIRKTOK (?) PETROLEUM SYSTEMS

By
Leslie B. Magoon
1998

Click here or on this symbol
in the toolbar to return.

U.S. DEPARTMENT OF THE INTERIOR
U.S. GEOLOGICAL SURVEY

OPEN-FILE REPORT 98-34
PLATE PS2

SHUBLIK FORMATION ISOPACH AND THERMAL MATURITY MAP

By

Kenneth J. Bird and Margaret A. Keller

1998

U.S. DEPARTMENT OF THE INTERIOR
U.S. GEOLOGICAL SURVEY

OPEN-FILE REPORT 98-34
PLATE PS3

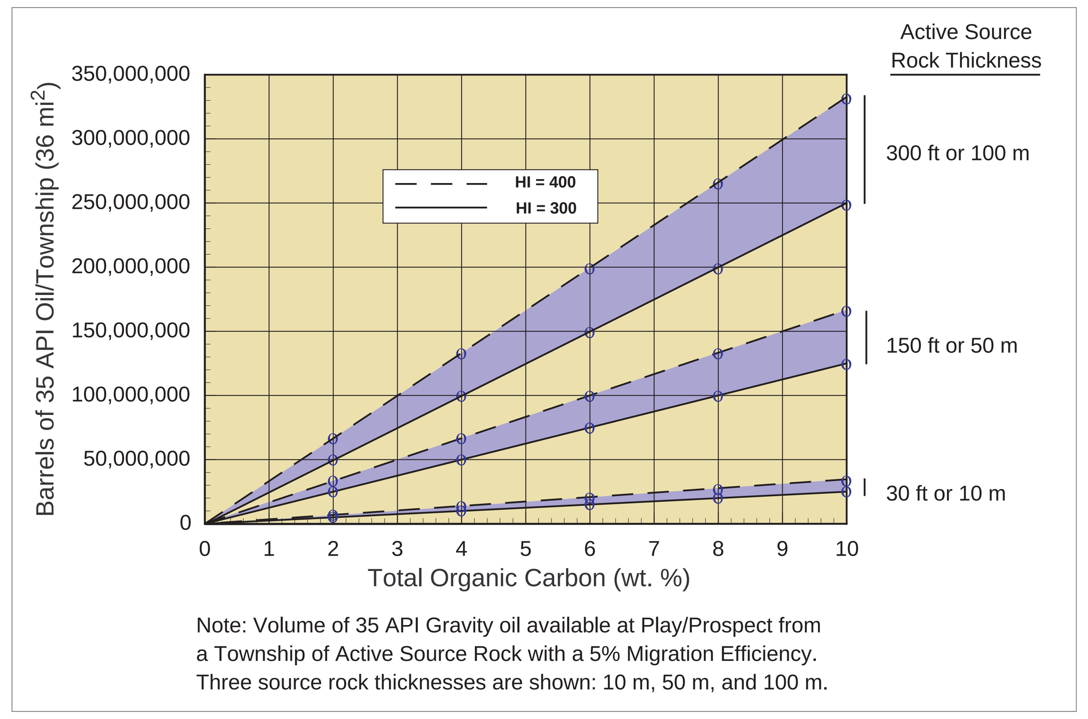


Figure 1. Hydrocarbon Charge for Hue-Thomson(!) Petroleum System

Table 1. All data for Hue Shale (sample areas A-J)

Sampled Area	T_{max}	$\%R_o$ mean		OC	S_2	HI
A	428	0.41	Immature	0.79	5.31	672
A	454	0.	mature	3.35	11.2	334
B	481		mature	3.75	1.4	37
C	421		Immature	3.23	9.85	304
D	431		Immature	2.84	1.78	62
E	447		mature	3.12	2.24	71
E	453	0.93	mature	6.08	3.22	53
E	468	0.96	mature	2.82	0.66	24
E	461	-0-	mature	2.54	0.61	24
E	437	1.03	mature	2.51	0.58	23
E	437	1.11	mature	1.94	1.06	55
E	447	-0-	mature	3.12	2.12	68
E	445	1.15	mature	4.97	3.36	68
E	416	0.96	mature	3.12	0.91	29
E	447	-0-	mature	4.31	1.63	38
E	430	1.06	mature	4.62	0.69	15
E	-0-	0.75	mature			
F	-0-	1.07	mature			
G	-0-	0.85	mature			
G	-0-	0.76	mature			
H	-0-	0.66	Immature?			
H	-0-	0.63	Immature?			
H	399	0.63	Immature	5.53	9.05	163
H	402	-0-	Immature	5.21	16.87	323
H	406	0.	Immature	14.22	64.97	456
H	401	-0-	Immature	7.45	22.26	298
H	409	0.5	Immature	5.91	19.16	324
H	402	-0-	Immature	5.96	11.59	194
H	-0-	0.31	Immature			
H	-0-	0.34	Immature			
H	-0-	0.26	Immature			
H	-0-	0.28	Immature			
H	-0-	0.38	Immature			
H	-0-	0.43	Immature			
H	-0-	0.49	Immature			
J	408	0.	Immature	18.26	86.13	471
J	407	-0-	Immature	10.72	30.44	283
J	405	0.99	Immature?	11.86	49.22	415
J	403	-0-	Immature	6.56	23.21	353
J	409	0.	Immature	10.75	49.41	459
J	405	-0-	Immature	6.55	27.87	425
J	404	0.	Immature	15.56	78.58	505
J	406	0.75	Immature?	1.93	1.06	54

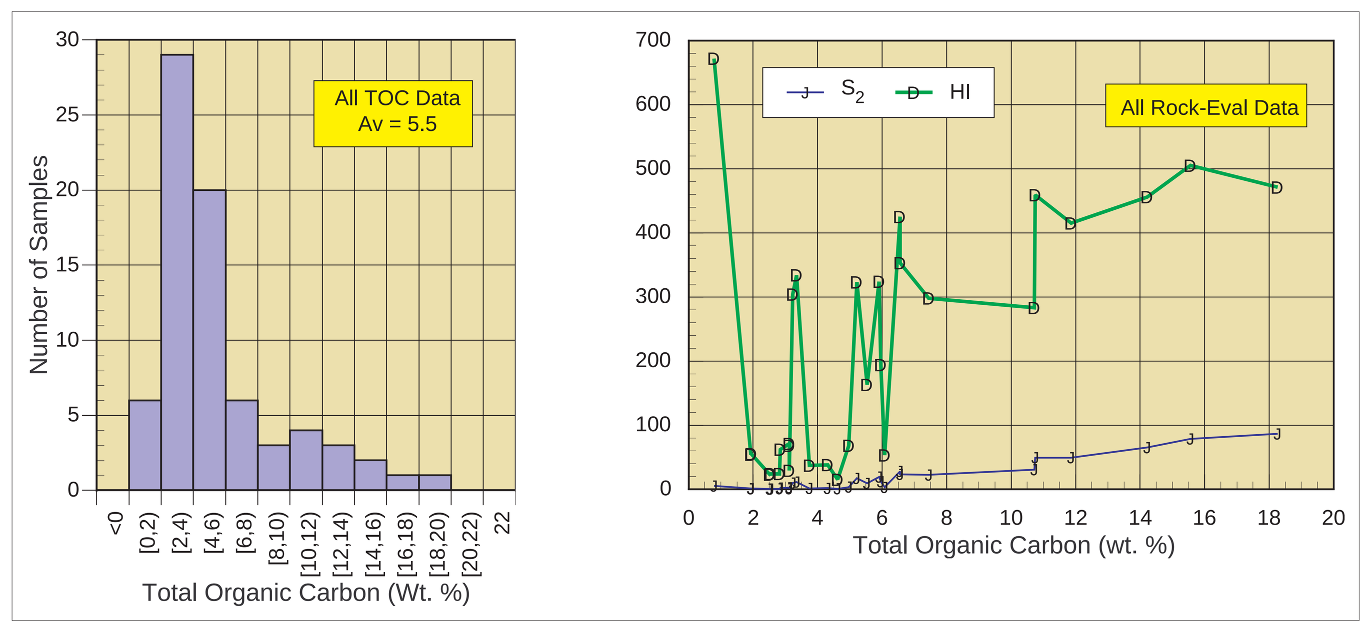
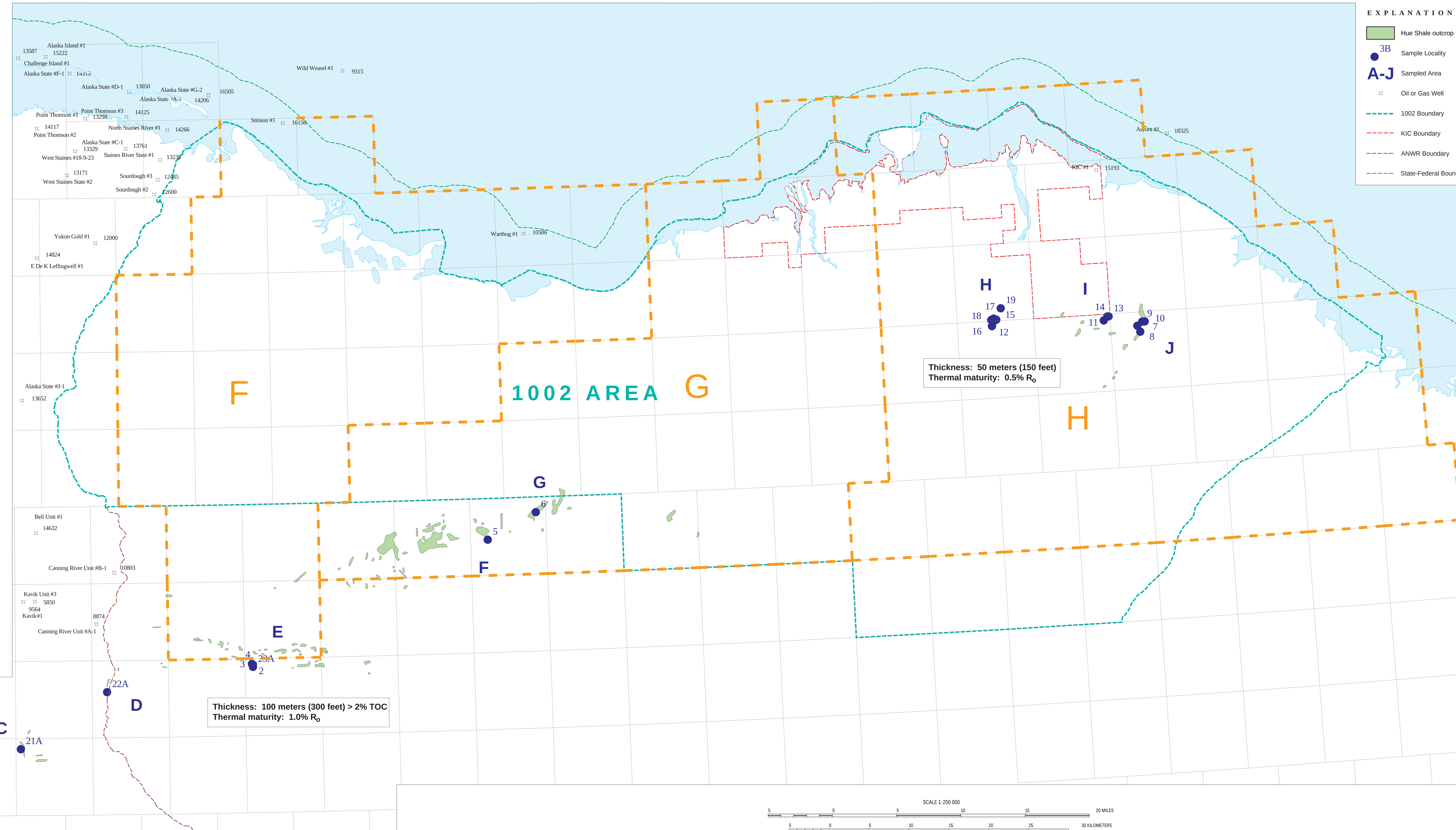


Figure 2. All data for Hue Shale (sample areas A-J)



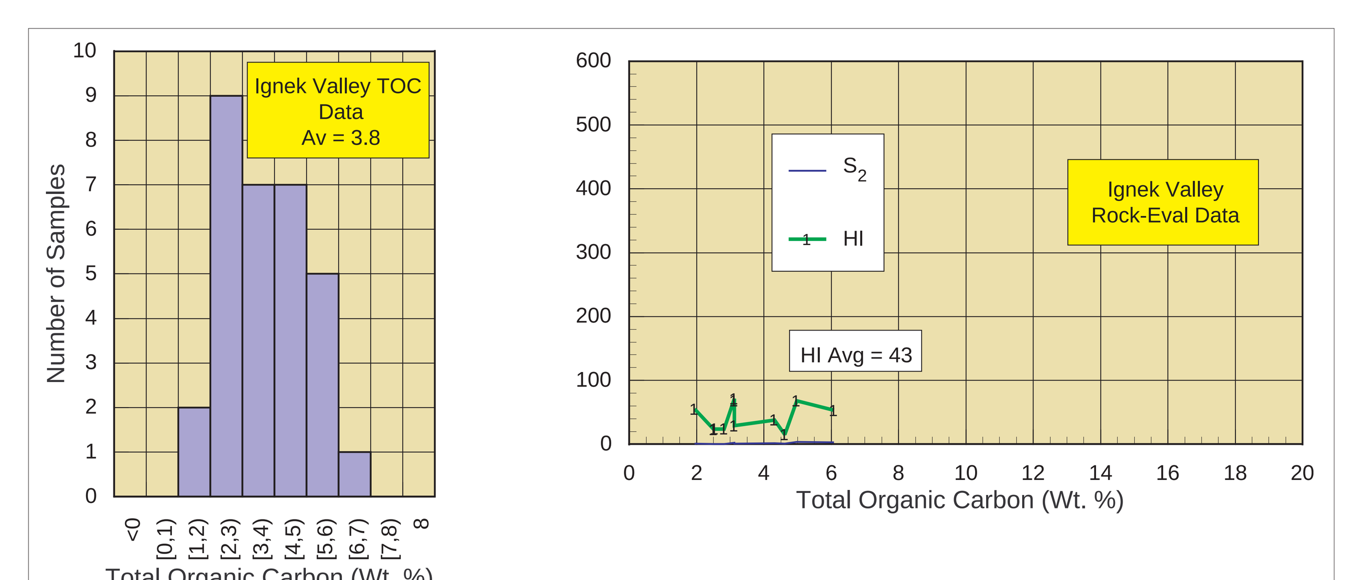


Figure 3. Data for Hue Shale-Ignek Valley Section (sample area E)

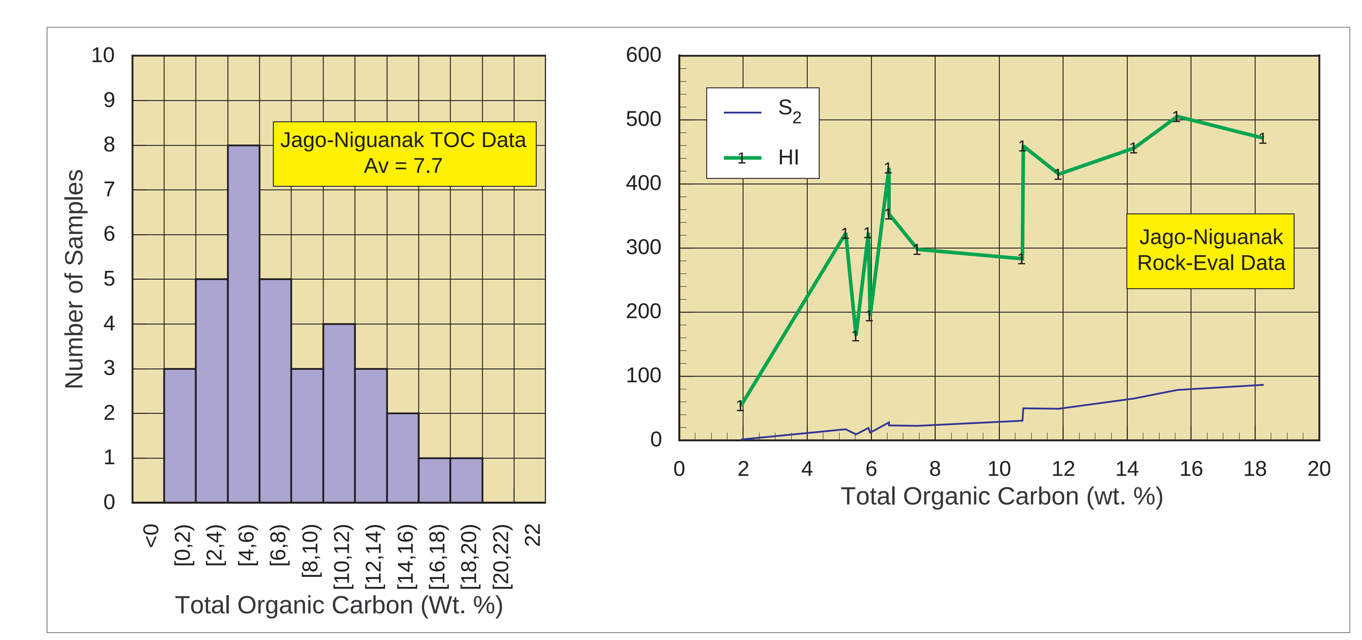


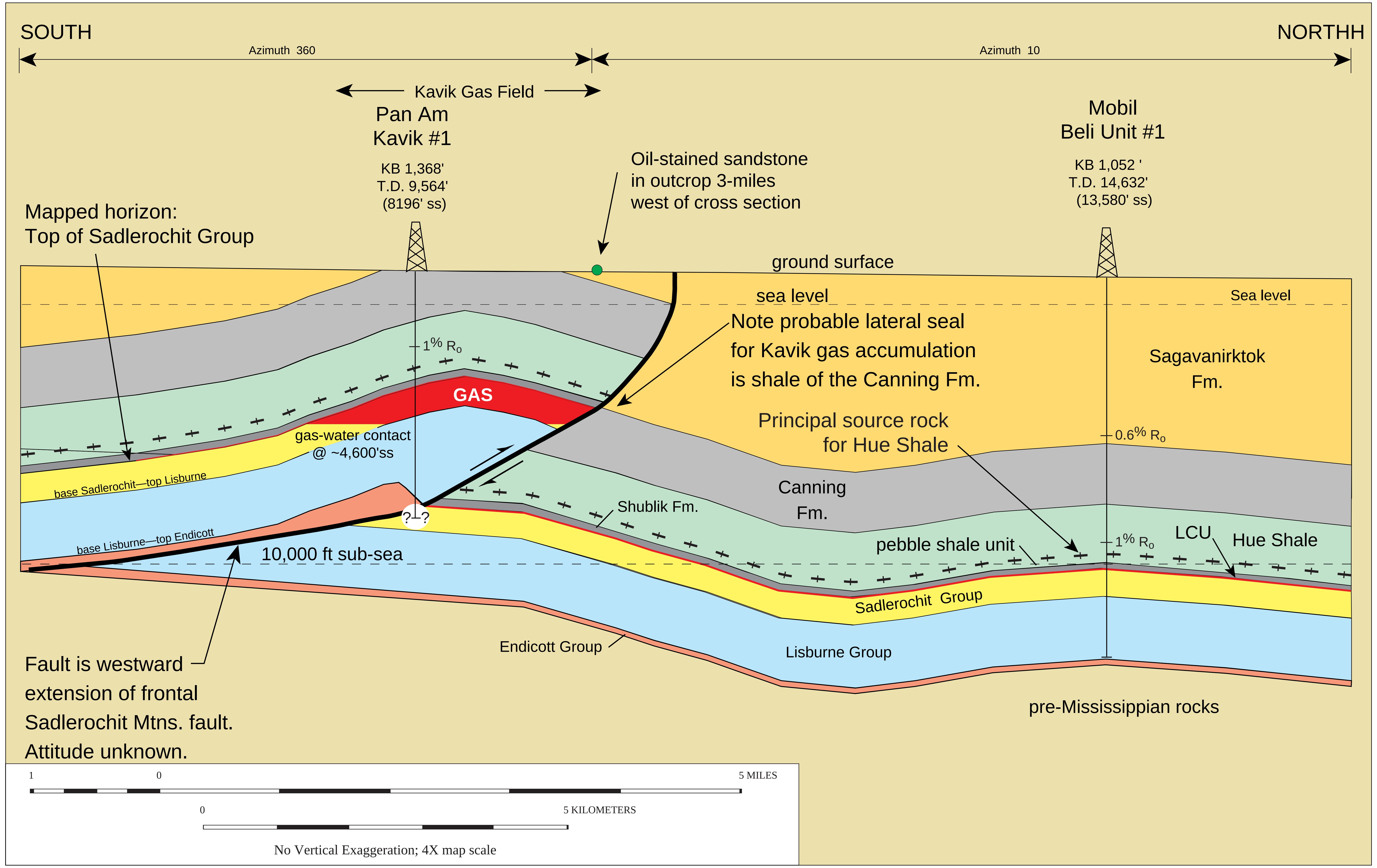
Figure 4. Data for Hue Shale-Jago/Niguanak Areas (sample areas H-J)

ORGANIC GEOCHEMISTRY OF THE CRETACEOUS HUE SHALE IN THE 1002 AREA, NORTH SLOPE, ALASKA

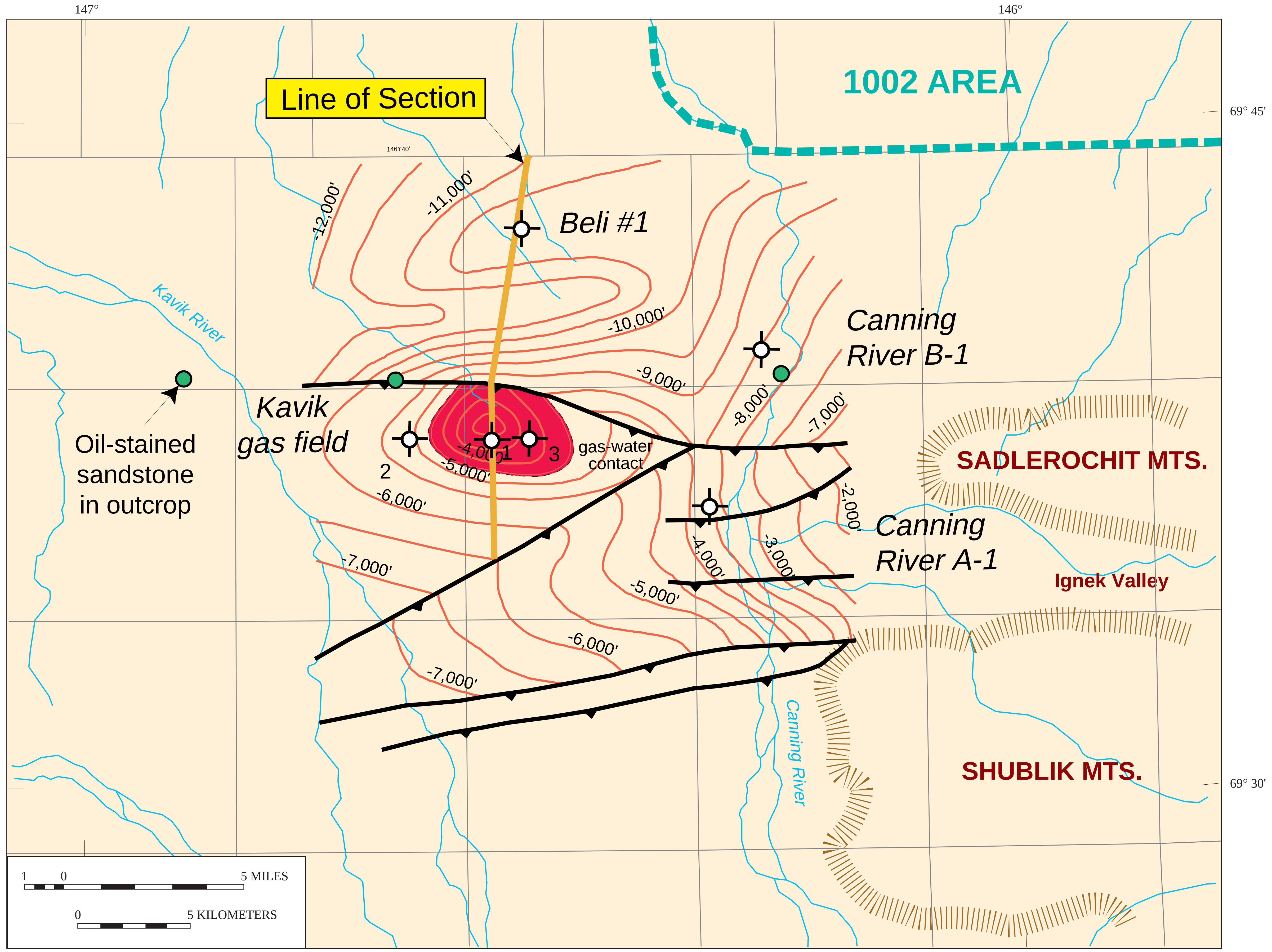
By
Leslie B. Magoon and Michael S. Sinor

1998

Click here or on this symbol in the toolbar to return.



Cross-section based on structure contour map of top of Sadlerochit Group by ARCO in Kavik gas-field area with stratigraphy extrapolated from the wells. Stratigraphy shown is based on that in each well and projected horizontally with no change in thicknesses to the nearest fault.



Location of cross-section and structure contour map on top of Sadlerochit Group in the Kavik gas field area as mapped by Arco (from *State of Alaska 1992 Oil and Gas Statistical Report*, p. 128).

STRUCTURE CONTOUR MAP AND CROSS-SECTION OF KAVIK GAS FIELD

By

Kenneth J. Bird

1998

USGS
science for a changing world

Click here or on this symbol in the toolbar to return.

PLATE PS5 (INSET). Map showing location of diagramatic cross-section of oil types in the Mikkelsen Bay-Point Thomson Area, North Slope, Alaska.

EXPLANATION

(green bar)	Drill-stem tested interval	62	Oil from Hue Shale
(red bar)	Cored interval	45	Oil from Shublik Formation
<---11,624'	Oil sample extracted from core at this depth.	MD	Measured Depth
11,870' / 12,200'	Oil sample from drill-stem test conducted over interval shown.	TVDss	True Vertical Depth (sub-sea)

OIL TYPES IN THE MIKKELSEN BAYÐPOINT THOMSON AREA

By

Kenneth J. Bird, Kevin R. Evans, Leslie B. Magoon, and Paul G. Lillis

1998

Click here or on this symbol
in the toolbar to return.

Table PS1. Values and results, by area, used to calculate hydrocarbon charge from each petroleum system for all plays.

[Areas A-E are shown on plate PS2, areas F-H on plate PS3, areas I-K on fig. PS16. TOC, total organic carbon; HIO, original hydrogen index; HC, hydrocarbon; HI, hydrogen index; R, hydrocarbons generated per gram of total organic carbon; HCG, generated hydrocarbons; bbl, barrel(s); API: American Petroleum Institute. Numbers labeled "total" may not be exact sum of numbers in column above due to rounding]

Area	Townships (miles^2)	Thickness ($\infty 10^2$cm)	Thickness (ft)	Volume ($\infty 10^{12}$cm^3)	Density (g/cm^3)	Average TOC (wt. %)	Mass TOC ($\infty 10^{10}$g)	HIO (mgHC/ gTOC)	HI (mgHC/ gTOC)	R (mgHC/ gTOC)	HCG/area ($\infty 10^4$ kgHC)	°API oil (kg/bbl)**	Bbl/area ($\infty 10^4$ bbl)	In-place oil* ($\infty 10^6$ bbl)
							ELLESMERIAN(!)							
A	32	100	300	298,368	2.4	2.0	1,432,166	600	300	300	429,649,920	139.30	3,084,350	1,542
B	32	133	400	396,829	2.4	2.0	1,904,781	600	300	300	571,434,394	139.30	4,102,185	2,051
C	32	133	400	396,829	2.4	2.0	1,904,781	600	300	300	571,434,394	139.30	4,102,185	2,051
D	32	150	450	447,552	2.4	2.0	2,148,250	600	300	300	644,474,880	139.30	4,626,525	2,313
E	32	200	600	596,736	2.4	2.0	2,864,333	600	300	300	859,299,840	139.30	6,168,699	3,084
													TOTAL	11,042
							HUE-THOMSON(!)							
F	27	100	300	251,748	2.4	4.0	2,416,781	400	100	300	725,034,240	131.15	5,528,282	2,764
G	26	100	300	242,424	2.4	4.0	2,327,270	400	100	300	698,181,120	131.15	5,323,531	2,662
H	38	100	300	354,312	2.4	4.0	3,401,395	400	100	300	1,020,418,560	131.15	7,780,546	3,890
													TOTAL	9,316
							CANNING-SAGAVANIRKTOK(?)							
I	25	1,500	4,500	3,496,500	2.4	1.0	8,391,600	300	200	100	839,160,000	131.15	6,398,475	3,199
J	25	1,500	4,500	3,496,500	2.4	1.0	8,391,600	300	200	100	839,160,000	131.15	6,398,475	3,199
K	25	1,500	4,500	3,496,500	2.4	1.0	8,391,600	300	200	100	839,160,000	131.15	6,398,475	3,199
													TOTAL	9,598

*Migration efficiency of 5 percent.
**139.30 kg/bbl = 30°API oil; 131.15 kg/bbl = 40° API oil.

Table PS2. Petroleum geochemical results reported in U.S. Geological Survey Bulletin 1778.

[TOC, total organic carbon; Bit., bitumen; NHC, non-hydrocarbon; HC, hydrocarbon; S, saturated hydrocarbons; A, aromatic hydrocarbons; $\delta^{13}C$ sat., carbon isotopic ratio of saturated hydrocarbons; $\delta^{13}C$ arom., carbon isotopic ratio of aromatic hydrocarbons. Leaders (--) indicate no data]

Sample no.	Rock unit, well, or outcrop	TOC (wt. %)	Bit. (ppm)	Bit./TOC (%)	NHC (ppm)	HC (ppm)	HC/TOC (%)	S/A	$\delta^{13}C$ sat. (per mill)	$\delta^{13}C$ arom. (per mill)
Oils from the Prudhoe Bay area and the National Petroleum Reserve in Alaska										
23	Kavearak Point 32-25	--	--	--	8.2	91.8	--	3.8	–31.8	–30.5
24	Prudhoe Bay Unit D-3	--	--	--	20.2	79.8	--	1.4	–29.6	–29.1
25	Umiat-4	--	--	--	1.2	98.8	--	4	–28.0	–26.7
26	Simpson Shot-Hole	--	--	--	5.7	94.3	--	4.1	–28.4	–27.5
27	So. Barrow-20	--	--	--	12	88	--	3.1	–29.1	–28.7
Oil-stained outcrops and surface seeps from the Arctic National Wildlife Refuge										
28	Kavik outcrop	2.8	26,400	94.3	80.9	19.1	18	3.8	–26.7	–27.8
29	So. Katakturuk outcrop	0.5	4,240	84.8	9.3	90.7	76.9	5.2	–29.5	–28.8
30	No. Katakturuk outcrop	2.3	20,240	88	73.8	26.2	23.1	2.6	–29.3	–28.1
31	Angun Point outcrop	7.9	69,520	88	77.9	22.1	19.4	3	–29.0	–28.1
32	Angun Point seep	--	--	--	73.6	24.4	--	2.9	–28.9	–28.3
33	Jago River outcrop	1.9	8,500	44.7	19.9	80.1	35.8	2.5	–29.4	–28.8
34	Jago River outcrop	2.7	20,500	75.9	12.9	87.1	66.1	2.2	–29.2	–28.9
35	Manning Point seep	--	--	--	26.8	73.2	--	5.2	–28.2	–27.5
36	Manning Point outcrop	11	96,400	87.6	11.7	88.3	77.4	5.4	–28.4	–27.6

Click here or on this symbol
in the toolbar to return.

Table PS3. Geochemical data from oil-stained outcrops and surface seeps in ANWR and oil-stained cores from wells adjacent to 1002 area.

[Seq., sequence; API, API gravity of oil; GOR, gas-to-oil ratio; Sulfur, sulfur concentration in weight percent; $\delta^{13}C$ sat., carbon isotopic ratio of saturated hydrocarbons; $\delta^{13}C$ arom., carbon isotopic ratio of aromatic hydrocarbons; oil-st. otcrp., oil-stained outcrop; oil-st. core, oil-stained core; oil-st. alluv., oil-stained alluvium; oil-st. ss., oil-stained sandstone; oil-st. slty. sh., oil-stained silty shale; oil ext., oil extract; bbl, barrels; DST, drill-stem test; BOPD, barrels of oil per day; MCFD, thousands of cubic feet of gas per day. Leaders (--) indicate no data]

Sample no.	Job no.	Seq. no.	Sample ID	Location	Rock unit	Lithology	Sample type	Fluid type	Depth	API	GOR	Recovery	Sulfur	$\delta^{13}C$ sat.	$\delta^{13}C$ arom.
41	97010	027	Shot-Hole B19 57-80	Simpson Peninsula	Nanushuk Gp.	Sandstone	oil	oil	--	24	--	--	0.2	-28.72	-27.65
42	97010	028	Kavearak Point 32-25	Milne Point field	Kingak Shale	Sandstone	oil	oil	7,702-7,710	34	--	--	0.2	-31.80	-30.59
43	97010	026	Prudhoe Bay D-3	Prudhoe Bay field	Sadlerochit Gp.	Sandstone	oil	oil	10,417-10,535	26	--	--	0.9	-29.54	-28.89
44	97037	002	Sagwon Bluffs	Sagavanirktok River	Sagavanirktok Fm.	Sandstone	oil-st. otcrp.	oil	Outcrop	--	--	--	--	-28.98	-28.16
45	96074	006	W Mikkelsen Unit 2	West Mikkelsen Unit	Canning Fm	Sandstone	oil-st. core	oil ext.	10,501.7	none	none	14 bbl of heavy oil	--	-30.08	-29.25
46	97016	002	13-9-19 Mikkelsen	Mikkelsen Bay field	Canning Fm.	Sandstone	oil	oil	10,468-10,550	30	none	DST 7	0.8	-29.64	-28.78
47	97016	003	13-9-19 Mikkelsen	Mikkelsen Bay field	Lisburne Gp.	Limestone	oil	oil	11,870-12,200	19.5	none	DST 4	1.1	-29.01	-28.69
48	96074	001	W Mikkelsen State 1	West Mikkelsen Unit	Lisburne Gp.	Limestone	oil-st. core	oil ext.	11,705.5	none	none	none	--	-30.20	-29.31
49	96074	002	W Mikkelsen State 1	West Mikkelsen Unit	Lisburne Gp.	Limestone	oil-st. core	oil ext.	11,359.9	none	none	none	--	-30.42	-29.65
50	97012	001	West Staines 18-9-23	Pt. Thomson field	Canning Fm.	Sandstone	oil-st. core	oil ext.	11,672	27	none	210 BOPD and gas	--	-29.24	-28.38
51	97016	001	West Staines 18-9-23	Pt. Thomson field	Hue Shale	Sandstone	oil	oil	12,512-12,795	29	none	DST 8	0.8	-29.77	-29.01
60	97012	002	Point Thomson Unit 1	Pt. Thomson field	Canning Fm.	Sandstone	oil-st. core	oil ext.	11,424	44	17,045	2,250 MCFD; 132 BOPD	--	-29.07	-28.10
61	97012	003	Point Thomson Unit 1	Pt. Thomson field	Thomson sand	Sandstone	oil-st. core	oil ext.	12,848	45	22,705	3,860 MCFD; 170 BOPD	--	-28.88	-28.15
62	97012	004	Point Thomson Unit 1	Pt. Thomson field	Thomson sand	Sandstone	oil-st. core	oil ext.	13,013	18	5,826	13,307 MCFD; 2,283 BOPD	--	-29.26	-28.61
63	97012	005	Point Thomson Unit 2	Pt. Thomson field	Canning Fm.	Sandstone	oil-st. core	oil ext.	11,624	21	500	124 MCFD; 248 BOPD	--	-29.07	-28.37
64	97012	006	Point Thomson Unit 3	Pt. Thomson field	Thomson sand	Sandstone	oil-st. core	oil ext.	13,872	38	13,336	6,348 MCFD; 476 BOPD	--	-28.83	-28.20
65	97012	007	Alaska State A-1	Pt. Thomson field	Canning Fm.	Sandstone	oil-st. core	oil ext.	12,575	23	864	2,200 MCFD; 2,500 BOPD	--	-29.70	-28.89
66	97012	008	Alaska State C-1	Pt. Thomson field	Thomson sand	Sandstone	oil-st. core	oil ext.	13,612.2	37	3,890	3,400 MCFD;875 BOPD	--	-29.40	-28.66
67	97012	009	Alaska State F-1	Pt. Thomson field	Canning Fm.	Sandstone	oil-st. core	oil ext.	12,066	22	1,040	116 MCFD; BOPD	--	-29.49	-28.78
68	97012	010	Alaska State F-1	Pt. Thomson field	Thomson sand	Sandstone	oil-st. core	oil ext.	13,818	35	14,912	4,235 MCFD; 284 BOPD	--	-28.95	-28.16
69	95069	003	95DLG-MP1	Manning Point	Alluvium	Sand	oil-st. alluv.	oil ext.	outcrop	--	--	--	--	-28.07	-27.16
70	95069	007	95DLG-MP2	Manning Point	Alluvium	Sand	oil-st. alluv.	oil ext.	outcrop	--	--	--	--	-28.12	-27.08
71	97035	001	97CRB17	Angun Point	Alluvium	(Tundra)	oil-st. alluv.	oil ext.	outcrop	--	--	--	--	-28.60	-27.77
72	95069	002	95DLG-6A	Jago River	Canning Fm	Sandstone	oil-st. ss.	oil ext.	outcrop	--	--	--	--	-28.97	-28.29
73	95069	001	95DLG-2A1	North Katakuruk	Canning Fm.	Sandstone	oil-st. ss.	oil ext.	outcrop	--	--	--	--	-29.22	-27.80
74	96074	008	96RCB2	Kavik area	Canning Fm	Sandstone	oil-st. ss.	oil ext.	outcrop	--	--	--	--	-29.02	-27.99
75	96074	009	96RCB14B	Canning River	Canning Fm.	Sandstone	oil-st. ss.	oil ext.	outcrop	--	--	--	--	-29.52	-28.57
76	97037	001	97DH38	Canning River	Canning Fm.	Sandstone	oil-st. ss.	oil ext.	outcrop	--	--	--	--	-29.30	-28.55
77	97056	001	Aurora 1	Offshore	Canning Fm.	Silty shale	oil-st. slty. sh.	oil ext.	9,700	--	--	--	--	-28.80	-27.71

Table PS4. Carbon isotopic values for saturated and aromatic hydrocarbons from tables PS2 and PS3 by petroleum system.

[δ^{13}C sat., carbon isotopic ratio of saturated hydrocarbons; δ^{13}C arom., carbon isotopic ratio of aromatic hydrocarbons. Leaders (--) indicate no data]

Petroleum system	Sample no.	Job no.	Seq. no.	Sample designation	Field or outcrop name	δ^{13}C sat. (per mill)	δ^{13}C arom. (per mill)	Reference
Canning-Sagavanirktok(?)	31	--	--	--	Angun Point outcrop	-29	-28.1	USGS Bulletin 1778
Canning-Sagavanirktok(?)	32	--	--	--	Angun Point seep	-28.9	-28.3	USGS Bulletin 1778
Canning-Sagavanirktok(?)	35	--	--	--	Manning Point seep	-28.2	-27.5	USGS Bulletin 1778
Canning-Sagavanirktok(?)	36	--	--	--	Manning Point outcrop	-28.4	-27.6	USGS Bulletin 1778
Canning-Sagavanirktok(?)	69	95069	003	95DLG-MP1	Manning Point	-28.07	-27.16	This study
Canning-Sagavanirktok(?)	70	95069	007	95DLG-MP2	Manning Point	-28.12	-27.08	This study
Canning-Sagavanirktok(?)	71	97035	001	97CRB17	Angun Point	-28.6	-27.77	This study
Canning-Sagavanirktok(?)	77	97056	001	Aurora 1	Offshore	-28.8	-27.71	This study
Hue-Thomson(!)	30	--	--	--	No. Katakturuk outcrop	-29.3	-28.1	USGS Bulletin 1778
Hue-Thomson(!)	33	--	--	--	Jago River outcrop	-29.4	-28.8	USGS Bulletin 1778
Hue-Thomson(!)	34	--	--	--	Jago River outcrop	-29.2	-28.9	USGS Bulletin 1778
Hue-Thomson(!)	44	97037	002	Sagwon Bluffs	Sagavanirktok River	-28.98	-28.16	This study
Hue-Thomson(!)	50	97012	001	West Staines 18-9-23	Pt. Thomson field	-29.24	-28.38	This study
Hue-Thomson(!)	60	97012	002	Point Thomson Unit 1	Pt. Thomson field	-29.07	-28.1	This study
Hue-Thomson(!)	61	97012	003	Point Thomson Unit 1	Pt. Thomson field	-28.88	-28.15	This study
Hue-Thomson(!)	64	97012	006	Point Thomson Unit 3	Pt. Thomson field	-28.83	-28.2	This study
Hue-Thomson(!)	68	97012	010	Alaska State F-1	Pt. Thomson field	-28.95	-28.16	This study
Hue-Thomson(!)	72	95069	002	95DLG-6A	Jago River	-28.97	-28.29	This study
Hue-Thomson(!)	73	95069	001	95DLG-2A1	North Katakuruk	-29.22	-27.8	This study
Hue-Thomson(!)*	29	--	--	--	So. Katakturuk outcrop	-29.5	-28.8	USGS Bulletin 1778
Hue-Thomson(!)*	62	97012	004	Point Thomson Unit 1	Pt. Thomson field	-29.26	-28.61	This study
Hue-Thomson(!)*	66	97012	008	Alaska State C-1	Pt. Thomson field	-29.4	-28.66	This study
Hue-Thomson(!)*	74	96074	008	96RCB2	Kavik area	-29.02	-27.99	This study
Hue-Thomson(!)*	75	96074	009	96RCB14B	Canning River	-29.52	-28.57	This study
Hue-Thomson(!)*	76	97037	001	97DH38	Canning River	-29.3	-28.55	This study
Ellesmerian(!)	24	--	--	Prudhoe Bay Unit D-3	Prudhoe Bay field	-29.6	-29.1	USGS Bulletin 1778
Ellesmerian(!)	43	97010	026	Prudhoe Bay Unit D-3	Prudhoe Bay field	-29.54	-28.89	This study
Ellesmerian(!)	45	96074	006	W Mikkelsen Unit 2	West Mikkelsen Unit	-30.08	-29.25	This study
Ellesmerian(!)	46	97016	002	13-9-19 Mikkelsen	Mikkelsen Bay field	-29.64	-28.78	This study
Ellesmerian(!)	47	97016	003	13-9-19 Mikkelsen	Mikkelsen Bay field	-29.01	-28.69	This study
Ellesmerian(!)	48	96074	001	W Mikkelsen State 1	West Mikkelsen Unit	-30.2	-29.31	This study
Ellesmerian(!)	49	96074	002	W Mikkelsen State 1	West Mikkelsen Unit	-30.42	-29.65	This study
Ellesmerian(!)	51	97016	001	West Staines 18-9-23	Pt. Thomson field	-29.77	-29.01	This study
Ellesmerian(!)	65	97012	007	Alaska State A-1	Pt. Thomson field	-29.7	-28.89	This study
Ellesmerian(!)	67	97012	009	Alaska State F-1	Pt. Thomson field	-29.49	-28.78	This study
Ellesmerian(!)*	63	97012	005	Point Thomson Unit 2	Pt. Thomson field	-29.07	-28.37	This study

* Mixed oil types (fig. OA3).

Click here or on this symbol
in the toolbar to return.

Table PS5. Oil and gas shows in wells adjacent to the 1002 area for the Ellesmerian(!) petroleum system.

[Am Strat, American Stratigraphic Co. Leaders (--) indicate no data]

Well no.	Well name	Shows	See plate	Stratigraphic units: Sagavanirktok	Canning	Hue Shale	Pebble shale	Kemik/Thomson	Kingak	Sag River	Shubkik	Sadlerochit	Lisburne	Basement
KEMIK AREA														
1	Kemik Unit 2	Am Strat	WL27	--	--	--	--	--	1,770-1,780	--	--	--	--	--
2	Kemik Unit 1	Am Strat	WL26	--	--	--	--	--	5,670-5,680	--	--	8,870-10,970	13,340-14,310	--
3	Fin Creek Unit 1	Am Strat	WL17	--	--	--	--	--	10,540-10,570	--	--	--	--	--
4	Shaviovik Unit 1	Am Strat	No data	--	--	--	--	--	--	--	--	--	--	--
KAVIK AREA														
5	Gyr 1	Mud log	WL19	--	--	--	--	--	--	--	--	--	--	--
6	West Kavik 1	Am Strat	WL25	--	--	--	--	--	--	--	--	13,690-13,700	14,603-16,600	--
7	Kavik Unit 2	Am Strat	WL23	--	--	--	--	--	--	--	--	6,200-6,230	--	--
8	Kavik 1	Am Strat	WL22	--	--	--	--	--	--	--	--	4,750-4,970	5,670-7,570	9,340-9,350
9	Kavik Unit 3	Am Strat	WL24	--	--	--	--	--	--	--	--	5,330-5,550	--	--
10	Canning River Unit A-1	Am Strat	WL13	--	--	--	--	--	--	--	--	4,490-4,830	6,250-6,450	8,200-8,830
11	Canning River Unit B-1	Am Strat	WL14	--	--	--	--	--	--	--	--	8,820-8,860	--	--
12	Beli Unit 1	Am Strat	WL12	--	--	--	--	--	10,920-10,930	11,150-11,190	--	11,400-12,190	--	--
13	Alaska State J-1	Mud log	WL7	--	--	--	--	--	--	--	--	--	--	--
MIKKELSEN AREA														
18	E Mikkelsen Bay State 1	Am Strat	WL32	8,110-8,120	9,310-11,750	--	--	12,300-12,320	--	--	--	--	--	--
19	Badami 1	Mud log	WL9	--	9,335-10,635	12,080-12,245	--	--	--	--	--	--	--	12,555-12,825
46	Alpenglow State 1	Confidential	WL1	--	--	--	--	--	--	--	--	--	--	--
47	W Mikkelsen State 1	No data	WL30	--	--	--	--	--	--	--	--	--	--	--
48	W Mikkelsen Unit 2	No data	WL31	--	--	--	--	--	--	--	--	--	--	--
49	Badami 2	No data	WL10	--	--	--	--	--	--	--	--	--	--	--
50	Mikkelsen Bay State 1	No data	WL29	--	--	--	--	--	--	--	--	--	--	--
PT. THOMSON AREA														
14	E De K Leffingwell 1	No data	WL28	--	--	--	--	--	--	--	--	--	--	--
15	Yukon Gold 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
16	Sourdough 2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
17	West Staines State 2	Am Strat	WL37	--	--	--	--	--	--	--	--	--	--	--
20	Point Thomson Unit 4	Am Strat	WL36	--	--	--	--	--	--	--	--	--	--	--
21	Point Thomson Unit 2	Am Strat	WL34	--	--	--	--	--	--	--	--	--	--	--
22	West Staines 18-9-23	Am Strat	WL38	--	--	--	--	--	--	--	--	--	--	--
23	Alaska State C-1	Am Strat	WL4	--	--	--	--	--	--	--	--	--	--	--
24	Staines River State 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
25	North Staines River 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
26	Point Thomson Unit 3	Am Strat	WL35	--	--	--	--	--	--	--	--	--	--	--
27	Point Thomson Unit 1	Am Strat	WL33	--	--	--	--	--	--	--	--	--	--	--
28	Challenge Island 1	Am Strat	WL15	--	--	--	--	--	--	--	--	--	--	--
29	Alaska Island 1	Am Strat	WL2	--	--	--	--	--	--	--	--	--	--	--
30	Alaska State F-1	Am Strat	WL6	--	--	--	--	--	--	--	--	--	--	--
31	Alaska State D-1	Am Strat	WL5	--	--	--	--	--	--	--	--	--	--	--
32	Alaska State A-1	Am Strat	WL3	--	--	--	--	--	--	--	--	--	--	--
33	Alaska State G-2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
38	Stinson 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
HAMMERHEAD AREA														
37	Corona 1	Confidential	WL16	--	--	--	--	--	--	--	--	--	--	--
39	Wild Weasel	Confidential	WL39	--	--	--	--	--	--	--	--	--	--	--
40	Kuvlum 2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
41	Kuvlum 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
42	Kuvlum 3	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
43	Hammerhead 1	No data	WL20	--	--	--	--	--	--	--	--	--	--	--
44	Hammerhead 2	No data	WL21	--	--	--	--	--	--	--	--	--	--	--
45	Galahad 1	Confidential	WL18	--	--	--	--	--	--	--	--	--	--	--
51	Warthog 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
AURORA AREA														
34	Jago River 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
35	Aurora 1	Mud log	WL8	--	--	--	--	--	--	--	--	--	--	--
36	Belcher 1	Amoco log	WL11	--	--	--	--	--	--	--	--	--	--	--

Click here or on this symbol in the toolbar to return.

ANWR CDTable PS6. Oil and gas shows in wells adjacent to the 1002 area for the Hue-Thomson(!) petroleum system.
[Am Strat, American Stratigraphic Co. Leaders (--) indicate no data]

Well no.	Well name	Shows	See plate	Stratigraphic units										
				Sagavanirktok	Canning	Hue Shale	Pebble shale	Kemik/Thomson	Kingak	Sag River	Shubkik	Sadlerochit	Lisburne	Basement
	KEMIK AREA													
1	Kemik Unit 2	Am Strat	WL27	--	--	--	--	--	--	--	--	--	--	--
2	Kemik Unit 1	Am Strat	WL26	--	--	2,340-2,620	--	--	--	--	--	--	--	--
3	Fin Creek Unit 1	Am Strat	WL17	--	4,040-7,150	--	--	--	--	--	--	--	--	--
4	Shaviovik Unit 1	Am Strat	No data	1,420-4,230	--	--	--	--	--	--	--	--	--	--
	KAVIK AREA													
5	Gyr 1	Mud log	WL19	--	7,740-7,800	--	--	--	--	--	--	--	--	--
6	West Kavik 1	Am Strat	WL25	--	11,100-11,110	--	--	--	--	--	--	--	--	--
7	Kavik Unit 2	Am Strat	WL23	--	390-2,840	4,180-4,200	--	--	--	--	--	--	--	--
8	Kavik 1	Am Strat	WL22	--	--	3,080-3,090	--	--	--	--	--	--	--	--
9	Kavik Unit 3	Am Strat	WL24	--	1,630-1,690	--	--	--	--	--	--	--	--	--
10	Canning River Unit A-1	Am Strat	WL13	--	--	--	--	3,080-3,250	--	--	--	--	--	--
11	Canning River Unit B-1	Am Strat	WL14	3,050-5,510	--	--	--	8,030-8,070	--	--	--	--	--	--
12	Beli Unit 1	Am Strat	WL12	1,010-4,340	5,220-9,830	10,650-10,720	--	10,800-10,850	--	--	--	--	--	--
13	Alaska State J-1	Mud log	WL7	8,860-13,350	--	--	--	--	--	--	--	--	--	--
	MIKKELSEN AREA													
18	E Mikkelsen Bay State 1	Am Strat	WL32	--	--	--	--	--	--	--	--	--	--	--
19	Badami 1	Mud log	WL9	--	--	--	--	--	--	--	--	--	--	--
46	Alpenglow State 1	Confidential	WL1	--	--	--	--	--	--	--	--	--	--	--
47	W Mikkelsen State 1	No data	WL30	--	--	--	--	--	--	--	--	--	--	--
48	W Mikkelsen Unit 2	No data	WL31	--	--	--	--	--	--	--	--	--	--	--
49	Badami 2	No data	WL10	--	--	--	--	--	--	--	--	--	--	--
50	Mikkelsen Bay State 1	No data	WL29	--	--	--	--	--	--	--	--	--	--	--
	PT. THOMSON AREA													
14	E De K Leffingwell 1	No data	WL28	--	--	--	--	--	--	--	--	--	--	--
15	Yukon Gold 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
16	Sourdough 2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
17	West Staines State 2	Am Strat	WL37	--	9,260-11,770	--	--	--	--	--	--	--	--	--
20	Point Thomson Unit 4	Am Strat	WL36	--	10,240-14,280	14,450-14,800	--	14,800-14,970	--	--	--	--	--	14,990-15,000
21	Point Thomson Unit 2	Am Strat	WL34	--	9,010-11,680	12,490-12,670	--	--	--	--	--	--	--	--
22	West Staines 18-9-23	Am Strat	WL38	--	6,150-12,010		--	--	--	--	--	--	--	--
23	Alaska State C-1	Am Strat	WL4	--	9,470-12,940	13,060-13,210	--	13,420-13,710	--	--	--	--	--	--
24	Staines River State 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
25	North Staines River 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
26	Point Thomson Unit 3	Am Strat	WL35	--	9,890-12,970	--	--	13,000-13,920	--	--	--	--	--	13,940-14,010
27	Point Thomson Unit 1	Am Strat	WL33	10,720-12,170	--	12,580-12,820	--	12,820-13,160	--	--	--	--	--	--
28	Challenge Island 1	Am Strat	WL15	--	10,860-13,180	13,230-13,420	--	13,430-13,480	--	--	--	--	--	13,490-13,520
29	Alaska Island 1	Am Strat	WL2	12,210-15,000	--	--	--	--	--	--	--	--	--	15,000-15,130
30	Alaska State F-1	Am Strat	WL6	--	8,830-13,680	--	--	13,790-14,320	--	--	--	--	--	--
31	Alaska State D-1	Am Strat	WL5	--	8,200-12,730	--	--	--	--	--	--	--	--	12,870-12,880
32	Alaska State A-1	Am Strat	WL3	--	10,650-12,900	--	--	--	--	--	--	--	--	12,940-13,510
33	Alaska State G-2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
38	Stinson 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
	HAMMERHEAD AREA													
37	Corona 1	Confidential	WL16	--	--	--	--	--	--	--	--	--	--	--
39	Wild Weasel	Confidential	WL39	--	--	--	--	--	--	--	--	--	--	--
40	Kuvlum 2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
41	Kuvlum 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
42	Kuvlum 3	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
43	Hammerhead 1	No data	WL20	--	--	--	--	--	--	--	--	--	--	--
44	Hammerhead 2	No data	WL21	--	--	--	--	--	--	--	--	--	--	--
45	Galahad 1	Confidential	WL18	--	--	--	--	--	--	--	--	--	--	--
51	Warthog 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
	AURORA AREA													
34	Jago River 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
35	Aurora 1	Mud log	WL8	--	--	--	--	--	--	--	--	--	--	--
36	Belcher 1	Amoco log	WL11	--	--	--	--	--	--	--	--	--	--	--

Click here or on this symbol in the toolbar to return.

Table PS7. Oil and gas shows in wells adjacent to the 1002 area for the Canning-Sagavanirktok(!) petroleum system. [Am Strat, American Stratigraphic Co. Leaders (--) indicate no data]

Well no.	Well name	Shows	See plate	Stratigraphic units										
				Sagavanirktok	Canning	Hue Shale	Pebble shale	Kemik/Thomson	Kingak	Sag River	Shubkik	Sadlerochit	Lisburne	Basement
KEMIK AREA														
1	Kemik Unit 2	Am Strat	WL27	--	--	--	--	--	--	--	--	--	--	--
2	Kemik Unit 1	Am Strat	WL26	--	--	--	--	--	--	--	--	--	--	--
3	Fin Creek Unit 1	Am Strat	WL17	--	--	--	--	--	--	--	--	--	--	--
4	Shaviovik Unit 1	Am Strat	No data	--	--	--	--	--	--	--	--	--	--	--
KAVIK AREA														
5	Gyr 1	Mud log	WL19	--	--	--	--	--	--	--	--	--	--	--
6	West Kavik 1	Am Strat	WL25	--	--	--	--	--	--	--	--	--	--	--
7	Kavik Unit 2	Am Strat	WL23	--	--	--	--	--	--	--	--	--	--	--
8	Kavik 1	Am Strat	WL22	--	--	--	--	--	--	--	--	--	--	--
9	Kavik Unit 3	Am Strat	WL24	--	--	--	--	--	--	--	--	--	--	--
10	Canning River Unit A-1	Am Strat	WL13	--	--	--	--	--	--	--	--	--	--	--
11	Canning River Unit B-1	Am Strat	WL14	--	--	--	--	--	--	--	--	--	--	--
12	Beli Unit 1	Am Strat	WL12	--	--	--	--	--	--	--	--	--	--	--
13	Alaska State J-1	Mud log	WL7	--	--	--	--	--	--	--	--	--	--	--
MIKKELSEN AREA														
18	E Mikkelsen Bay State 1	Am Strat	WL32	--	--	--	--	--	--	--	--	--	--	--
19	Badami 1	Mud log	WL9	--	--	--	--	--	--	--	--	--	--	--
46	Alpenglow State 1	Confidential	WL1	--	--	--	--	--	--	--	--	--	--	--
47	W Mikkelsen State 1	No data	WL30	--	--	--	--	--	--	--	--	--	--	--
48	W Mikkelsen Unit 2	No data	WL31	--	--	--	--	--	--	--	--	--	--	--
49	Badami 2	No data	WL10	--	--	--	--	--	--	--	--	--	--	--
50	Mikkelsen Bay State 1	No data	WL29	--	--	--	--	--	--	--	--	--	--	--
PT. THOMSON AREA														
14	E De K Leffingwell 1	No data	WL28	--	--	--	--	--	--	--	--	--	--	--
15	Yukon Gold 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
16	Sourdough 2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
17	West Staines State 2	Am Strat	WL37	5,380-8,390	--	--	--	--	--	--	--	--	--	--
20	Point Thomson Unit 4	Am Strat	WL36	6,810-9,990	--	--	--	--	--	--	--	--	--	--
21	Point Thomson Unit 2	Am Strat	WL34	5,860-8,380	6,250-7,840	--	--	--	--	--	--	--	--	--
22	West Staines 18-9-23	Am Strat	WL38	5,700-8,550	--	--	--	--	--	--	--	--	--	--
23	Alaska State C-1	Am Strat	WL4	--	--	--	--	--	--	--	--	--	--	--
24	Staines River State 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
25	North Staines River 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
26	Point Thomson Unit 3	Am Strat	WL35	6,720-7,310	8,090-8,240	--	--	--	--	--	--	--	--	--
27	Point Thomson Unit 1	Am Strat	WL33	4,430-9,080	7,050-7,150	--	--	--	--	--	--	--	--	--
28	Challenge Island 1	Am Strat	WL15	3,050-6,180	7,860-8,220	--	--	--	--	--	--	--	--	--
29	Alaska Island 1	Am Strat	WL2	--	--	--	--	--	--	--	--	--	--	--
30	Alaska State F-1	Am Strat	WL6	--	7,310-7,320	--	--	--	--	--	--	--	--	--
31	Alaska State D-1	Am Strat	WL5	2,830-3,570	--	--	--	--	--	--	--	--	--	--
32	Alaska State A-1	Am Strat	WL3	--	--	--	--	--	--	--	--	--	--	--
33	Alaska State G-2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
38	Stinson 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
HAMMERHEAD AREA														
37	Corona 1	Confidential	WL16	--	--	--	--	--	--	--	--	--	--	--
39	Wild Weasel	Confidential	WL39	--	--	--	--	--	--	--	--	--	--	--
40	Kuvlum 2	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
41	Kuvlum 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
42	Kuvlum 3	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
43	Hammerhead 1	No data	WL20	--	--	--	--	--	--	--	--	--	--	--
44	Hammerhead 2	No data	WL21	--	--	--	--	--	--	--	--	--	--	--
45	Galahad 1	Confidential	WL18	--	--	--	--	--	--	--	--	--	--	--
51	Warthog 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
AURORA AREA														
34	Jago River 1	Confidential	No data	--	--	--	--	--	--	--	--	--	--	--
35	Aurora 1	Mud log	WL8	--	9,634-9,674	--	--	--	--	--	--	--	--	--
36	Belcher 1	Amoco log	WL11	--	--	--	--	--	--	--	--	--	--	--

Click here or on this symbol
in the toolbar to return.

Table PS8. Fluid inclusion information from Burruss (chap. FI), listed by petroleum system.

[G, geochemical evidence; S, stratigraphic occurrence; T, on or north of Lower Cretaceous unconformity; Sag, Sagavanirktok; Fm, Formation; ph, phase; fl, flourescent; incl, inclusion; Cret, Cretaceous; Paleoc, Paleocene; turb(s), turbidite(s); grn, grain(s); UK(?), Upper Cretaceous(?); Kp, Cretaceous pebble shale unit; qtz, quartz; frac, fracture(s). Leaders (--) indicate no data]

Petroleum system	Basis	Formation	Sample ID	Locality	Petroleum indications	Latitude	Longitude
CANNING-SAGAVANIRKTOK(?)							
Canning-Sagavanirktok(?)	G	Quaternary	95DLG-MP1	Manning Point oil seep	Oil saturated unconsolidated sand	70.11666	-143.51666
Canning-Sagavanirktok(?)	G	Quaternary	97RCB17	Angun Point oil seep	Oil saturated unconsolidated sand	69.918	-142.395
HUE-THOMSON(!)							
Hue-Thomson(!)	G	Sagavanirktok	96RCB14B	Canning River, Ken Bird oil stain locality	Oil stain, no fluorescent inclusions	69.65367	-146.2425
Hue-Thomson(!)	S	Sagavanirktok	83AMK-1	Sag Fm, E side of Tamiariak River	2-ph yellow fl incl, 1-ph blue fl incl	69.81117	-145.57567
Hue-Thomson(!)	G?	Sagavanirktok	95DLG-2C	Fluvial Sagavanirktok Fm, bluff on east side of Katakturuk River	2-phase yellow fluorescent inclusions	69.871	-145.17933
Hue-Thomson(!)	G	Sagavanirktok?	96RCB2	Kavik oil stained ss	Oil stain and no fluorescent inclusions	69.65317	-146.72067
Hue-Thomson(!)	G	Sagavanirktok?	96DH122	Marsh Creek anticline (MCA3)	Rare yellow fluorescent inclusions	69.94567	-144.66433
Hue-Thomson(!)	S	Canning	96RCB10	Hue Creek	Rare blue fluorescent inclusions	69.5695	-145.81217
Hue-Thomson(!)	S	Canning	96RCB13	Katakturuk River south	Blue fluorescent incl	69.71583	-145.43333
Hue-Thomson(!)	S	Canning	95DH44	Hue Creek	Dead oil and 2 grains with yellow fl incl	69.5695	-145.81217
Hue-Thomson(!)	G	Canning	96DH121	Marsh Creek anticline (MCA2)	A few grains with yellow fluorescent inclusions	69.93167	-144.66517
Hue-Thomson(!)	?	Canning	96DH146	Katakturuk 1	Yellow fluorescent inclusions	69.71467	-145.43583
Hue-Thomson(!)	?	Canning	96DH149	Katakturuk 2	One grain with 2-phase yellow fl incl	69.71533	-145.32783
Hue-Thomson(!)	S	Canning?	80AMK-26	Brookian turbidites, Ignek Valley	One grain with blue fluorescent 2-phase inclusions	69.571	-145.8
Hue-Thomson(!)	S	Canning?	80AMK-41D	Cret-Paleoc turb section along Katakturuk River north of Sadlerochit Mtns	Yellow fl 1- +2-ph incl, 1-ph blue fl incl	69.715	-145.43333
Hue-Thomson(!)	S	Canning?	82AMK-20	Paleocene turbidites, W bank of Canning River	One grn 2-ph yellow fl incl	69.58317	-146.30333
Hue-Thomson(!)	G	Canning?	82AMK-78	Oil-stained UK(?) turbs, W side Canning River	Abundant 2-ph yellow fl incl	69.545	-146.29167
Hue-Thomson(!)	S	Arctic Creek	97RCB13	Ridge west of Okerokovik River, Arctic Creek facies	1-phase gas inclusions	69.505	-143.3883
Hue-Thomson(!)	S	Kemik	95FC-01C	Kavik River south	Yellow, white, blue fluorescent inclusions	69.39683	-146.418
Hue-Thomson(!)	?	Kemik	95FC-14B	Hue Creek	Blue and yellow fluorescent inclusions	69.55555	-145.83333
Hue-Thomson(!)	?	Kemik	96RCB12	Hue Creek	Blue fluorescent inclusions	69.55667	-145.835
Hue-Thomson(!)	?	Kemik	96RCB5	Marsh Creek at Kelleys footwall cutoff	Yellow and blue fl inclusions, possible 1-phase gas	69.69167	-144.85
Hue-Thomson(!)	S	Kemik	96RCB15B	Canning River, Kemik duplexes	Rare blue fluorescent inclusions	69.46417	-146.34083
Hue-Thomson(!)	S	Kemik	96RCB15D	Canning River, Kemik duplexes	Yellow and blue fluorescent inclusions	69.46417	-146.34083
Hue-Thomson(!)	S	Kemik	96DH34	Horseshoe, Ignek Valley	Dead oil	69.5565	-145.45767
Hue-Thomson(!)	S	Kemik	96DH35	Horseshoe, Ignek Valley	Dead oil in clasts as detrital component	69.5565	-145.45767
Hue-Thomson(!)	S	Kemik	96DH37	Horseshoe, Ignek Valley	Dead oil	69.5565	-145.45767
Hue-Thomson(!)	S	Kemik	96DH39	Horseshoe, Ignek Valley	Trace dead oil	69.5565	-145.45767
Hue-Thomson(!)	S	Kemik	96DH42	Horseshoe, Ignek Valley	Dead oil	69.5565	-145.45767
Hue-Thomson(!)	S	Kemik	96DH84	Sadlerochit 2 section	Possible dead oil	69.6135	-144.4625
Hue-Thomson(!)	G?	Kemik	80AMK-18H	120' Kemik Ss section, W bank Canning River	Blue fluorescent inclusions	69.49733	-146.31133
Hue-Thomson(!)	S	Kemik	80AMK-23A	117' Kemik Ss section, Fin Creek	1- and 2-phase blue fluorescent inclusions	69.4105	-146.91667
Hue-Thomson(!)	S	Kemik	82AMK-55C	Kemik Ss–Kp, Ignek Creek section	Dead oil	69.58617	-145.97
Hue-Thomson(!)	S	Kemik	95DLG-7A	Repeated Kemik Ss, Canning River	1 grain with blue fl 2-ph incl, possible dead oil	69.4995	-146.30933
Hue-Thomson(!)	S	Kemik	95FC-17	Kemik Ss, Hue Creek, Ignek Valley	Blue-white fl 2-ph in matrix and pebbles, dead oil	69.55833	-145.83333
ELLESMERIAN(!)							
Ellesmerian(!)	T	Kemik	96DH18	Last Creek	Gas inclusions in quartz + calcite cement in breccia	69.632	-144.44817
Ellesmerian(!)	T	Kemik	80AMK-49B	Kemik Ss, Last Creek, E end of Sadlerochit Mtns	Dead oil?	69.63067	-144.42817
Ellesmerian(!)	T	Kemik	83AMK-40D	Kemik Ss, E fork Marsh Creek	Dead oil	69.69567	-144.85983
Ellesmerian(!)	T	Kemik	83AMK-40F	Kemik Ss, E fork Marsh Creek	Dead oil	69.69567	-144.85983
Ellesmerian(!)	S	Kingak	97RCB11	Aichilik River section, deformed Kingak	1-phase gas inclusions	69.53	-143.0695
Ellesmerian(!)	S	Kingak?	95DH-14	Marsh Creek	1-phase methane-rich gas	69.68658	-144.84267
Ellesmerian(!)	S	Kingak?	96DH81	Peregrine Nest	1-phase methane-rich gas	69.34267	-147.20933
Ellesmerian(!)	S	Shublik	95DH-34	Fire Creek, Shublik Mtns	Secondary aqueous and 1-phase methane-rich incl	69.53583	-145.20167
Ellesmerian(!)	S	Shublik	95FC-15B	Hue Creek	Possible 1-phase methane-rich inclusions	69.55555	-145.83333
Ellesmerian(!)	S	Shublik	Kemik Unit 1	Kemik gas field, sample from core at 8,669'	Water and CH_4-rich gas in quartz (qtz-calcite frac)	--	--
Ellesmerian(!)	S	Sag River/Shublik	Kavik Unit 3	Kavik gas field, core samples 4,946.2', 5,035.7', and 5,069.3'	Water and blue fluorescent oil in quartz (qtz-calcite)	--	--
Ellesmerian(!)	S	Fire Creek	95DH-29	Fire Creek, Shublik Mtns	Secondary, 1-phase methane-rich gas inclusions	69.53219	-145.20667
Ellesmerian(!)	S	Lisburne	CarlsonMS	Marsh Creek measured section	2-phase yellow fluorescent inclusions and dead oil	69.6803	-144.85