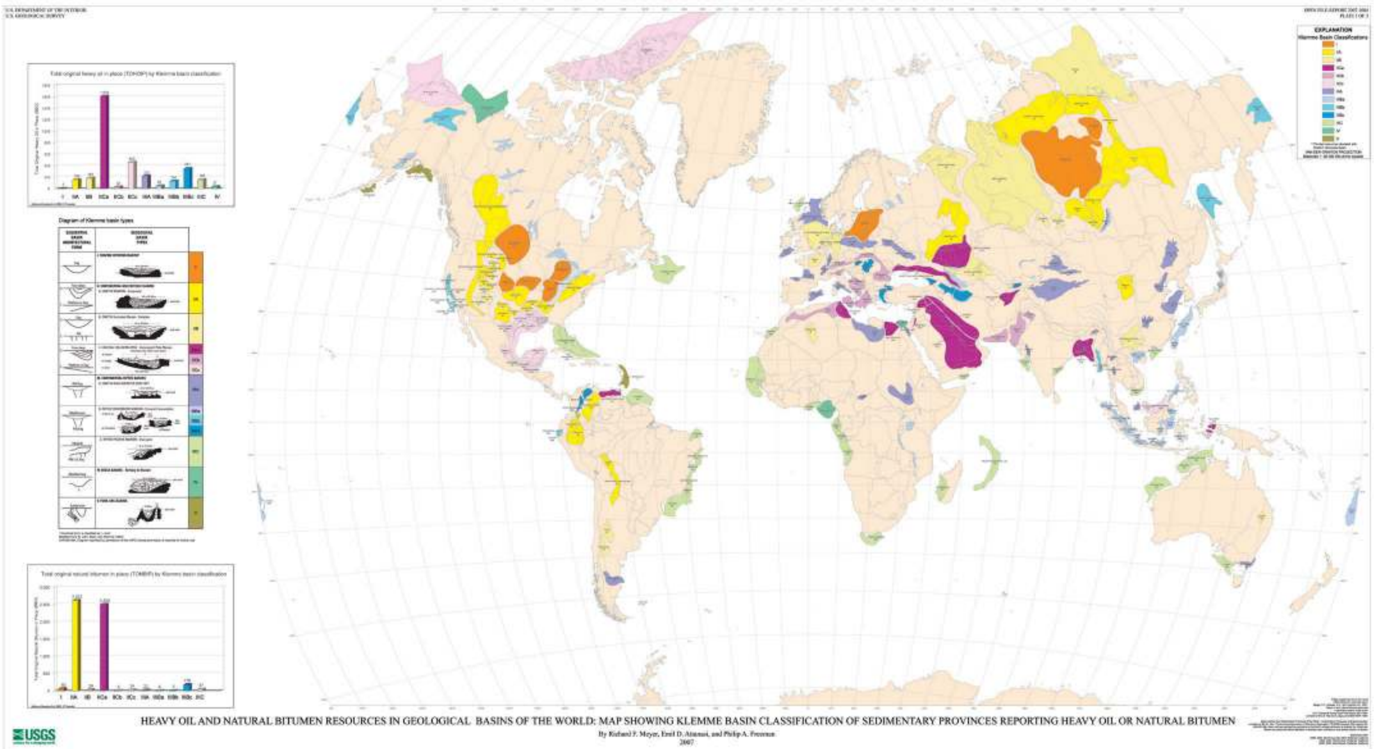
Heavy Oil and Natural Bitumen Resources in Geological Basins of the World



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By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

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Abstract

Heavy oil and natural bitumen are oils set apart by their high viscosity (resistance to flow) and high density (low API gravity). These attributes reflect the invariable presence of up to 50 weight percent asphaltenes, very high molecular weight hydrocarbon molecules incorporating many heteroatoms in their lattices. Almost all heavy oil and natural bitumen are alteration products of conventional oil. Total resources of heavy oil in known accumulations are 3,396 billion barrels of original oil in place, of which 30 billion barrels are included as prospective additional oil. The total natural bitumen resource in known accumulations amounts to 5,505 billion barrels of oil originally in place, which includes 993 billion barrels as prospective additional oil. This resource is distributed in 192 basins containing heavy oil and 89 basins with natural bitumen. Of the nine basic Klemme basin types, some with subdivisions, the most prolific by far for known heavy oil and natural bitumen volumes are continental multicyclic basins, either basins on the craton margin or closed basins along convergent plate margins. The former includes 47 percent of the natural bitumen, the latter 47 percent of the heavy oil and 46 percent of the natural bitumen. Little if any heavy oil occurs in fore-arc basins, and natural bitumen does not occur in either fore-arc or delta basins.

Introduction

Until recent years conventional, light crude oil has been abundantly available and has easily met world demand for this form of energy. By year 2007, however, demand for crude oil worldwide has substantially increased, straining the supply of conventional oil. This has led to consideration of alternative or insufficiently utilized energy sources, among which heavy crude oil and natural bitumen are perhaps the most readily available to supplement short- and long-term needs. Heavy oil has long been exploited as a source of refinery feedstock, but has commanded lower prices because of its lower quality relative to conventional oil. Natural bitumen is a very viscous crude oil that may be immobile in the reservoir. It typically requires upgrading to refinery feedstock grade (quality). When natural bitumen is mobile in the reservoir, it is generally known as extra-heavy oil. As natural asphalt, bitumen has been exploited since antiquity as a source of road paving, caulk, and mortar and is still used for these purposes in some parts of the world. The direct use of mined asphalt for road paving is now almost entirely local, having been replaced by manufactured asphalt, which can be tailored to specific requirements.

This study shows the geological distribution of known heavy oil and natural bitumen volumes by basin type. These data are presented to advance a clearer understanding of the relationship between the occurrence of heavy oil and natural bitumen and the type of geological environment in which these commodities are found. The resource data presented were compiled from a variety of sources. The data should not be considered a survey of timely resource information such as data published annually by government agencies and public reporting services. With the exception of Canada, no such data source on heavy oil and natural bitumen accumulations is available. The amounts of heavy oil yet unexploited in known deposits represent a portion of future supply. To these amounts may be added the heavy oil in presently poorly known and entirely unexploited deposits. Available information indicates cumulative production accounts for less than 3 percent of the discovered heavy oil originally in place and less than 0.4 percent of the natural bitumen originally in place.

Terms Defined for this Report

- Conventional (light) Oil: Oil with API gravity greater than 25°.
- Medium Oil: Oil with API gravity greater than 20°API but less than or equal to 25°API.
- Heavy Oil: Oil with API gravity between 10°API and 20°API inclusive and a viscosity greater than 100 cP.
- Natural Bitumen: Oil whose API gravity is less than 10° and whose viscosity is commonly greater than 10,000 cP. It is not possible to define natural bitumen on the basis of viscosity alone because much of it, defined on the basis of gravity, is less viscous than 10,000 cP. In addition, viscosity is highly temperature-

dependent (fig. 1), so that it must be known whether it is measured in the reservoir or in the stock tank. In dealing with Russian resources the term natural bitumen is taken to include both maltha and asphalt but excludes asphaltite.

- Total Original Oil in Place (TOOIP): Both discovered and prospective additional oil originally in place.
- Original Oil in Place-Discovered (OOIP-Disc.): Discovered original oil in place.
- Reserves (R): Those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, and quantities of petroleum that are anticipated to be technically but not necessarily commercially recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian reserve classes A, B, and C1 are included here (See Grace, Caldwell, and Hether,1993, for an explanation of Russian definitions.)
- Prospective Additional Oil in Place: The amount of resource in an unmeasured section or portion of a known deposit believed to be present as a result of inference from geological and often geophysical study.
- Original Reserves (OR): Reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimately recoverable, particularly in the case of new discoveries.

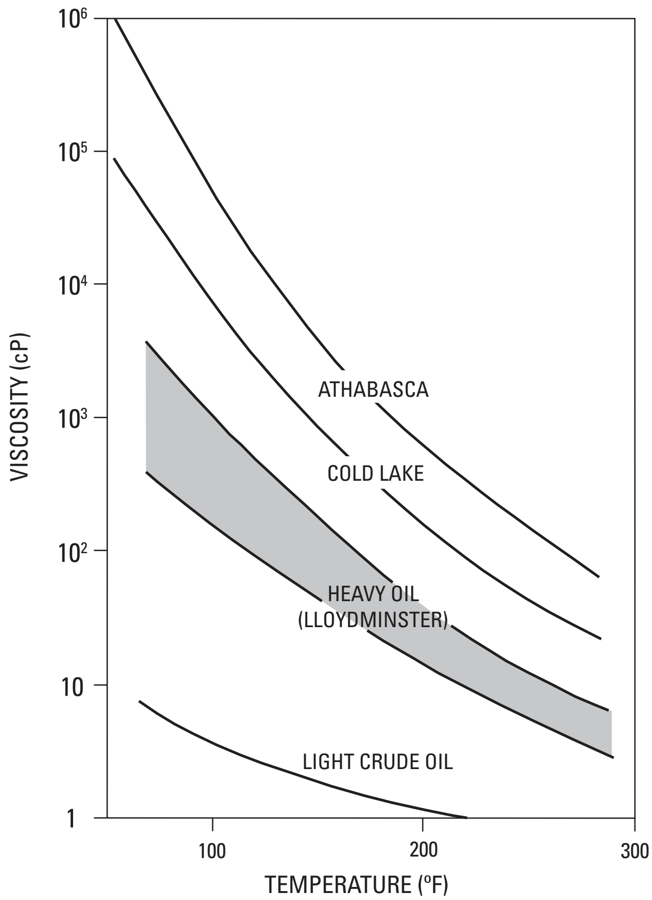

Figure 1. Response of viscosity to change in temperature for some Alberta oils (cP, centipoise), (Raicar and Proctor, 1984).

Chemical and Physical Properties

Fundamental differences exist between natural bitumen, heavy oil, medium oil, and conventional (light) oil, according to the volatilities of the constituent hydrocarbon fractions: paraffinic, naphthenic, and aromatic. When the light fractions are lost through natural processes after evolution from organic source materials, the oil becomes heavy, with a high proportion of asphaltic molecules, and with substitution in the carbon network of heteroatoms such as nitrogen, sulfur, and oxygen. Therefore, heavy oil, regardless of source, always contains the heavy fractions, the asphaltics, which consist of resins, asphaltenes, and preasphaltenes (the carbene-carboids) (Yen, 1984). No known heavy oil fails to incorporate asphaltenes. The large asphaltic molecules define the increase or decrease in the density and viscosity of the oil. Removal or reduction of asphaltene or preasphaltene drastically affects the rheological properties of a given oil and its aromaticity (Yen, 1984). Asphaltenes are defined formally as the crude oil fraction that precipitates upon addition of an n-alkane, usually n-pentane or n-heptane, but remains soluble in toluene or benzene. In the crude oil classification scheme of Tissot and Welte (1978), the aromatic-asphaltics and aromatic-naphthenics characterize the heavy oil and natural bitumen deposits of Canada and Venezuela and are the most important of all crude oil classes with respect to quantity of resources. The aromatic-intermediate class characterizes the deposits of the Middle East (Yen, 1984).

Some of the average chemical and physical properties of conventional, medium, and heavy crude oils and natural bitumen are given in table 1, in order to show their distinguishing characteristics. The data are derived from multiple sources, some old and others adhering to standards employed in different countries. The conversion factors outlined in table 2 were used to convert published data to a uniform standard. Some of the properties in table 1 are important with respect to heavy oil and natural recovery from the ground and other properties in table 1 serve as the basis for decisions for upgrading and refinery technologies. Moving across table 1 from conventional oil to natural bitumen, increases may be seen in density (shown as reductions in API gravity), coke, asphalt, asphaltenes, asphaltenes + resins, residuum yield (percent volume), pour point, dynamic viscosity, and the content of copper, iron, nickel, vanadium among the metals and in nitrogen and sulfur among the non-metals. Values diminish for reservoir depth, gasoline and gas-oil yields, and volatile organic compounds (VOC and BTEX –Benzene, Toluene, Ethylbenzene, and

Xylenes). The significance of these differences is often reflected in the capital and operating expenses required for the recovery, transportation, product processing, and environmental mitigation of the four oil types. The principal sources of analytical data for table 1 are Environmental Technology Centre (2003), Hyden (1961), Oil & Gas Journal Guide to Export Crudes (2006), U.S. Department of Energy, National Energy Technology Laboratory (1995), and various analyses published in technical reports.

The resins and asphaltenes play an important role in the accumulation, recovery, processing, and utilization of petroleum. The resins and asphaltenes are the final form of naphtheno-aromatic molecules. The carbon skeleton appears to comprise three to five polyaromatic sheets, with some heterocyclic (N-S-O) compounds. These crystallites may combine to form high molecular weight aggregates, with the high viscosity of heavy oils related to the size and abundance of the aggregates. Most asphaltenes are generated from kerogen evolution in response to depth and temperature increases in sedimentary basins. Different types of asphaltenes may be derived from the main kerogen types. Asphaltenes are not preferentially mobilized, as are light hydrocarbons during migration from source rocks to reservoir beds, where they are less abundant if the crude oil is not degraded (Tissot, 1981).

Some heavy oil and natural bitumen originates with chemical and physical attributes shown in table 1 as immature oil which has undergone little if any secondary migration. The greatest amount of heavy oil and natural bitumen results from the bacterial degradation under aerobic conditions of originally light crude oils at depths of about 5,000 feet or less and temperatures below 176°F. The consequence of biodegradation is the loss of most of the low molecular weight volatile paraffins and naphthenes, resulting in a crude oil that is very dense, highly viscous, black or dark brown, and asphaltic. An active water supply is required to carry the bacteria, inorganic nutrients, and oxygen to the oil reservoir, and to remove toxic by-products, such as hydrogen sulfide, with low molecular weight hydrocarbons providing the food (Barker, 1979). The low molecular weight components also may be lost through water washing in the reservoir, thermal fractionation, and evaporation when the reservoir is breached at the earth's surface (Barker, 1979). The importance of this process to the exploitation of heavy oil and natural bitumen lies in the increase of NSO (nitrogen-sulfur-oxygen) compounds in bacterially-altered crude oil and the increase in asphaltenes (Kallio, 1984).

Bacterial degradation of crude oil may also take place under anaerobic conditions, thus obviating the need for a fresh water supply at shallow depths (Head, Jones, and Larter, 2003; Larter and others, 2006). This proposal envisions degradation even of light oils at great depths so long as the maximum limiting temperature for bacterial survival is not exceeded. This theory does not account in any obvious way for the high percentage in heavy oil and natural bitumen of polar asphaltics, that is, the resins and asphaltenes.

Oil mass loss entailed in the formation of heavy oil and natural bitumen deposits has been the subject of numerous research studies. Beskrovnyi and others (1975) concluded that three to four times more petroleum was required than the reserves of a natural bitumen for a given deposit. Based upon material balance calculations in the Dead Sea basin, Tannenbaum, Starinsky, and Aizenshtat (1987) found indications that 75% of the original oil constituents in the C15+ range had been removed as a result of alteration processes. By accounting for the lower carbon numbers as well, they estimated that the surface asphalts represented residues of only 10-20% of the original oils. Head, Jones, and Larter (2003) diagram mass loss increasing from essentially zero for conventional oil to something more than 50% for heavy oils, which of themselves are subject to no more than 20% loss. Accompanying the mass loss is a decrease in API gravity from 36° to 5-20°; decrease in gas/oil ratio from 0.17 kg gas/kg oil; decrease in gas liquids from 20% to 2%; increase in sulfur from 0.3wt% to 1.5+wt%; and decrease in C15+ saturates from 75% to 35%. This calculation of mass loss shows: (1) the enormous amount of oil initially generated in heavy oil and natural bitumen basins, especially Western Canada Sedimentary and Eastern Venezuela basins; and (2) the huge economic burden imposed by this mass loss on the production-transportation-processing train of the remaining heavy oil and natural bitumen.

Origins of Heavy Oil and Natural Bitumen

It is possible to form heavy oil and natural bitumen by several processes. First, the oil may be expelled from its source rock as immature oil. There is general agreement that immature oils account for a small percentage of the heavy oil (Larter and others, 2006). Most heavy oil and natural bitumen is thought to be expelled from source rocks as light or medium oil and subsequently migrated to a trap. If the trap is later elevated into an oxidizing zone, several processes can convert the oil to heavy oil. These processes include water washing, bacterial degradation and evaporation. In this case, the biodegradation is aerobic. A third proposal is that biodegradation can also occur at depth in subsurface reservoirs (Head, Jones, and Larter, 2003; Larter and others, 2003; Larter and others, 2006). This explanation permits biodegradation to occur in any reservoir that has a water leg and has not been heated to more than 176° F. The controls on the biodegradation depend on local factors rather than basin-wide factors. Because the purpose of this report is to describe the geologic basin setting of the known heavy oil and natural bitumen deposits, it is beyond the scope of this report to argue the source or genesis of heavy oil and natural bitumen for each basin of the world.

Data Sources

Data for heavy oil resource occurrences and quantities for individual oilfields and reservoirs have been compiled from many published reports and commercial data bases. The most important of these include Demaison (1977), IHS Energy Group (2004), NRG Associates (1997), Parsons (1973), Roadifer (1987), Rühl (1982), and the U.S. Department of Energy, National Energy Technology Laboratory (1983, 2005)

Data for natural bitumen deposits in the United States are summarized in U.S Department of Energy, National Energy Technology Laboratory (1991), but information for Utah is taken from Oblad and others (1987) and Ritzma (1979). Although there is no single data source for deposits outside the United States, there is a rich literature, particularly for Russia and the countries of the Former Soviet Union. For Canada, reliance is placed on reports of the Alberta Energy and Utilities Board (2004) and Saskatchewan Industry and Resources (2003).

Resource Estimates

We consider the total original oil in place (OOIP) to be the most useful parameter for describing the location and volume of heavy oil and natural bitumen resources. Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than define the resource volumes that could someday be of commercial interest. If only a recoverable volume of heavy oil for the accumulation was published, the discovered OOIP was computed according to the protocol set forth in table 3.

Natural bitumen originally in place is often reported in the literature. Where only a recoverable estimate is published, the in-place volumes were calculated according to the protocols given for heavy oil; this is especially the case for bitumen deposits above 4°API gravity, to which we arbitrarily refer as extra-heavy oil.

Poorly known deposits of heavy oil and natural bitumen are included in the category of prospective additional resources, as described in table 3. In no case are values for prospective additional resource volumes calculated as in the case of discovered resources but were taken directly from the published literature.

Table 4 summarizes the resources and essential physical parameters of the heavy oil and natural bitumen contained in each of the basin types. These characteristics affect heavy oil and natural bitumen occurrence and recovery. Recovery can be primary, as in the case of cold production without gravel packing, if the gas to oil ratio is high enough to provide necessary reservoir energy. Otherwise, recovery generally necessitates the application of enhanced recovery methods, such as thermal energy or the injection of solvents.

Recovery Methods

How the reservoir parameters apply to enhanced recovery is summarized from Taber, Martin, and Seright (1997a, 1997b) in table 5, which covers the most commonly used, or at least attempted enhanced oil recovery (EOR) methods. Of these methods, immiscible gas injection, polymer flooding, and *in situ* combustion (fireflood) have met with limited success for heavy oil and natural bitumen. Steam injection (cyclic steam, huff ‘n puff) has been most successful, frequently by use of cyclic steam, followed by steam flooding. Surface mining and cold *in situ* production are usually considered to be primary recovery methods. They can be suited to the extraction of heavy oil and natural bitumen under proper conditions.

Most of the process descriptions which follow are taken from Taber, Martin, and Seright (1997b). Many processes may result in the process agent, such as nitrogen or carbon dioxide, remaining immiscible with the reservoir hydrocarbon or else becoming miscible with it. The miscibility is dependent upon the minimum miscibility pressure (MMP) and determines the way in which the process agent achieves EOR. While this summary discussion shows the breadth of the EOR processes operators have tried and continue to try as experimental projects, thermal EOR methods account for most of the heavy oil that is commercially produced. Data on the frequency of the applications are taken, unless otherwise cited, from the Oil and Gas Journal Historical Review, 1980-2006 (2006), particularly the Oil and Gas Journal 2000 and 2006 EOR Surveys.

Nitrogen gas drive is low in cost and therefore may be used in large amounts. It is commonly used with light oils for miscible recovery. However, it may also be used for an immiscible gas flood. The Oil and Gas Journal 2000 Survey includes one immiscible nitrogen gas drive in a sandstone reservoir with 16˚API oil at 4,600 feet depth. It was reported to be producing 1,000 barrels per day (b/d) of enhanced production. The Journal’s 2006 Survey reports one each heavy oil nitrogen miscible and nitrogen immiscible projects. The miscible project is 19˚API, located in the Bay of Campeche, with 19 wells, but with no report of production capacity. The immiscible project has oil of 16˚API at 4,600 feet in sandstone. For this project total production is reported to be 1,500 b/d of which 1,000 b/d is enhanced by immiscible nitrogen injection.

Of the 77 CO2 projects in the Journal 2000 Survey, 70 are for miscible CO2 and none entails heavy oil. This is true also in the Journal 2006 Survey, where all 86 CO2 projects are devoted to light oil, above 28˚API. In the Journal 2000 Survey, five of the seven immiscible CO2 projects are applied to heavy oil reservoirs, four in clastics and one in limestone. The latter, in the West Raman field in Turkey, involves oil of 13°API, lies at 4,265 feet, and produces 8,000 b/d. The reservoir contains nearly two billion barrels of original oil in place. Recoverable reserves remain low because of the recalcitrance of the reservoir. Steam flooding has been unsuccessful. By the date of the Journal 2006, there are eight immiscible CO2 projects, with five of them entailing heavy oil amounting to 7,174 b/d. The two largest projects are light oil and heavy oil and are each in carbonate reservoirs.

Polymer/chemical flooding includes micellar/polymer, alkaline-surfactant-polymer (ASP), and alkaline fluids (Taber, Martin, and Seright, 1997a, 1997b). Recovery is complex, leading to the lowering of interfacial tension between oil and water, solubilization of oil in some micellar systems, emulsification of oil and water, wettability alteration, and enhancement of mobility. Limitations and costs indicate for these floods the desirability of clean clastic formations. The Journal 2000 Survey shows five heavy oil polymer/chemical floods of 15°API in sandstone reservoirs at about 4,000 feet. They were producing about 366 b/d and the projects were deemed successful or promising. Projects such as these are below the desirable gravity limits and are more viscous than desired at 45 cP.

Polymer floods improve recovery over untreated water flood by increasing the viscosity of the water, decreasing thus the mobility of the water, and contacting a larger volume of the reservoir. The advantages of a polymer flood over a plain water flood are apparent. The Journal 2000 Survey lists 22 polymer flood projects, of which five involve heavy oil. These five are within the range of the polymer screen, although the gravities are marginal, lying from 13.5°API to a bit above 15°API. The five were producing 7,140 b/d, of which 2,120 b/d were attributed to EOR. The Journal 2006 Survey shows 20 polymer floods, with five exploring heavy oil reservoirs. Three of the five are producing 7,140 b/d total oil and 2,120 b/d of enhanced production.

The Journal 2000 Survey shows four hot water floods, one of which is heavy oil with a gravity of 12°API, viscosity of 900 cP, and starting saturation of only 15 percent. Project production was 300 b/d. Two of three hot water floods included in the Journal 2006 Survey are intended to enhance production of heavy oil. The two yield about 1,700 b/d of total oil and 1,700 b/d of enhanced hot water flood oil.

In situ combustion (fire flood) is theoretically simple, setting the reservoir oil on fire and sustaining the burn by the injection of air. Usually, the air is introduced through an injector well and the combustion front moves toward to the production wells. A variant is to include a water flood with the fire, the result being forward combustion with a water flood. Another variant is to begin a fire flood, then convert the initial well to a producer and inject air from adjacent wells. The problem with this reverse combustion is that it doesn't appear to work.

In situ combustion leads to oil recovery by the introduction of heat from the burning front, which leads to reduction in viscosity. Further, the products of steam distillation and thermal cracking of the reservoir oil are carried forward to upgrade the remaining oil. An advantage of the process is that the coke formed by the heat itself burns to supply heat. Lastly, the injected air adds to the reservoir pressure. The burning of the coke sustains the process so that the process would not work with light oil deficient in asphaltic components. The process entails a number of problems, some severe, but the Journal 2000 Survey shows 14 combustion projects, of which five are light oil and the remaining nine are heavy, between 13.5°API and 19°API. Viscosities and starting oil saturations are relatively high. It is notable that the heavy oil projects are in sandstones and the light oil in carbonates. The heavy oil *in situ* combustion projects were producing about 7,000 b/d. The Journal 2006 Survey includes nine heavy oil combustion projects among a total of twenty-one. The heavy oil projects yield about 7,000 b/d of combustion-enhanced oil, which ranges from 13.5˚API to 19˚API.

Steam injection for EOR recovery is done in two ways, either by cyclic steam injection (huff 'n puff) or continuous steam flood. Projects are frequently begun as cyclic steam, whereby a high quality steam is injected and soaks the reservoir for a period, and the oil, with lowered viscosity from the heat, is then produced through the injection well. Such soak cycles may be repeated up to six times, following which a steam flood is initiated. In general, steam projects are best suited to clastic reservoirs at depths no greater than about 4,000 feet, and with reservoir thicknesses greater than 20 feet and oil saturations above 40% of pore volume. For reservoirs of greater depth the steam is lowered in quality through heat loss to the well bore to where the project becomes a hot water flood. Steam is seldom applied to carbonate reservoirs in large part due to heat loss in fractures.

The Journal 2000 Survey lists 172 steam drive projects. Of these, four in Canada give no gravity reading, thirteen are medium oil from 22°API to 25°API, and the rest are heavy oil. The largest of all is at Duri field in Indonesia and this oil is 22°API. For the project list as a whole, the average gravity is 14°API, with a maximum value of 30°API and a minimum of 4°API. The average viscosity is 37,500 cP, with maximum and minimum values of 5,000,000 cP and 6 cP. Oil saturations range from 35% to 90%, the average being 68%. Most importantly, production from the project areas was 1.4 million b/d and of this, 1.3 million b/d was from steam drive EOR.

All but three of the 120 steam projects found in the Journal 2006 Survey entail recovery of heavy oil. The oil averages 12.9˚API, with a low value of 8˚API and a high of 28˚API (one of the three light oil reservoirs). The viscosity averages 58,000 cP, with a high value of 5 million cP and a low of 2 cP. The projects are yielding over 1.3 million b/d, virtually all being steam EOR.

Maps

The geographic distribution of basins reporting heavy oil and natural bitumen, as identified by their Klemme basin types, appears on Plate 1. A diagram of the Klemme basin classification illustrates the architectural form and the geological basin structure by type. This plate also includes histograms of the total original oil in place resource volumes of both heavy oil and natural bitumen. Plates 2 and 3, respectively, depict the worldwide distribution of heavy oil and natural bitumen resources originally in place. Each map classifies basins by the reported volumes of total original oil in place. A table ranks the basins by total original oil in place volumes besides indicating Klemme basin type and reporting discovered original oil in place and prospective additional oil in place. Plates 2 and 3 also include an inset map of the geographic distribution of original heavy oil or natural bitumen by 10 world regions (see table 6 for regional listing of countries reporting heavy oil or natural bitumen.)

Basin outlines of the sedimentary provinces are digitally reproduced from the AAPG base map compiled by St. John (1996). The basin outlines of St. John (1996) are unaltered. However, the reader should note that the basin outlines are considered to be generalizations useful for displaying the resource distributions but are less than reliable as a regional mapping tool. Also, some basin names have been changed to names more commonly used by geologists in the local country. These equivalent names and the original names from Bally (1984) and St. John (1996) are detailed in table 1-1 in Appendix 1. The basin outline for Eastern Venezuela as shown does not include the island of Trinidad where both heavy oil and natural bitumen resources occur. For this report, resources from Trinidad and Tobago are reported in the Eastern Venezuela basin totals. In a few cases a single basin as outlined on the plates is composed of multiple basins to provide more meaningful local information. This is particularly true in the United States, where the AAPG-CSD map was employed (Meyer, Wallace, and Wagner, 1991). In each case, the individual basins retain the same basin type as the basin shown on the map and all such basins are identified in Appendix 1.

Basins having heavy oil or natural bitumen deposits are listed in table 2-1 in Appendix 2 along with the Klemme basin type, countries and U.S. states or Canadian provinces reporting deposits and other names cited in literature. The Klemme basin classification diagram in Plate 1 is reprinted in fig. 3-1 in Appendix 3 for the reader's convenience. The tables from Plates 2 and 3 are reprinted as table 4-1 and table 4-2 for the reader's convenience.

Klemme Basin Classification

Many classifications of petroleum basins have been prepared. In one of the earliest, Kay (1951) outlined the basic architecture of geosynclines, with suggestions as to their origins. Kay's work preceded the later theory of plate tectonics. Klemme (1977, 1980a, 1980b, 1983, 1984) gives a summary description of petroleum basins together with their classification, based upon basin origin and inherent geological characteristics. This classification is simple and readily applicable to the understanding of heavy oil and natural bitumen occurrence. The Klemme basin types assigned to the heavy oil and natural bitumen basins described in this report correspond to the assignments made in St. John, Bally, and Klemme (1984). In some cases of multiple type designations in St. John, Bally, and Klemme (1984) a unique type designation was resolved by reference to Bally (1984) or Bally and Snelson (1980). Only a few of the basins originally designated as multiple types in St. John, Bally and Klemme (1984) appear to contain heavy oil and natural bitumen.

Table 7 summarizes the criteria upon which Klemme based his classification. The general description of the resource endowment associated to the Klemme basin classification is based upon oilfield (and gasfield) data of the world as of 1980 without regard to the density or other chemical attributes of the hydrocarbons they contain (Klemme, 1984). At the time of Klemme's work, the average density U.S. refinery crude oil was about 33.7°API (Swain, 1991). A decline in the average to about 30.6°API by 2003 perhaps signifies the increasing importance of heavy oil in the mix (Swain, 2005).

Generally, basins may be described as large or small and linear or circular in shape. They may also be described by the ratio of surface area to sedimentary volume. The basement profile or basin cross-section, together with the physical description, permits the interpretation of the fundamental basin architecture. The basin can then be placed within the relevant plate tectonic framework and assigned to one of four basin types, of which two have sub-types. A diagram of the Klemme basin types appears on Plate 1, color-coded to the basins on the map.

In the following section we provide descriptions of the basin types from Klemme (1980b, 1983, 1984) followed by discussion of the heavy oil and natural bitumen occurrences within those same basin types, summary data for which are given in table 4. Because most heavy oil and natural bitumen deposits have resulted from the alteration of conventional and medium oil, the factors leading to the initial conventional and medium oil accumulations are relevant to the subsequent occurrence of heavy oil and natural bitumen.

Type I. Interior Craton Basins

The sediment load in these basins is somewhat more clastic than carbonate. Reservoir recoveries are low and few of the basins contain giant fields. Traps are generally related to central arches, such as the Cincinnati arch, treated here as a separate province (Plates 1-3), or the arches of the Siberian platform (see below for further explanation). Traps also are found in smaller basins over the craton, such as the Michigan basin. The origin of these depressions is unclear although most of them began during the Precambrian (Klemme, 1980a, 1980b).

The six Type I basins having heavy oil contain less than 3 billion barrels of oil in place and of this 93% occurs in the Illinois basin alone. Four Type I basins that contain natural bitumen have 60 billion barrels of natural bitumen in place, with nearly 99% in the Tunguska basin in eastern Siberia and the rest in the Illinois basin. The Tunguska basin covers most of the Siberian platform, around the borders of which are found cratonic margin basins of Type IIA. For convenience all the resource is assigned to the Tunguska basin. The prospective additional resource of 52 billion barrels is almost certainly an absolute minimum value for this potentially valuable but difficult to access area (Meyer and Freeman, 2006.)

Type II. Continental Multicyclic Basins

Type IIA. Craton margin (composite)

These basins, formed on continental cratonic margins, are generally linear, asymmetrical in profile, usually beginning as extensional platforms or sags and ending as compressional foredeeps. Therefore they are multicyclic basins featuring a high ratio of sediment volume to surface area. Traps are mainly large arches or block uplifts and may be found in rocks of either the lower (platform) or upper (compression) tectonic cycle. About 14% of conventional oil discovered in the world by 1980 is from marginal cratonic basins (Klemme, 1980a, 1980b).

Type IIA basins are of moderate importance with respect to heavy oil, with about 158 billion barrels of oil in place distributed among 28 basins. Three Type IIA basins, the Western Canada Sedimentary, Putumayo, and Volga-Ural, have combined total heavy oil resource of 123 billion barrels of oil in place, or 78% of the total for Type IIA basins.

In comparison, natural bitumen in 24 Type IIA basins accounts for 2,623 billion barrels of natural bitumen in place, or nearly 48% of the world natural bitumen total. The Western Canada Sedimentary basin accounts for 2,334 billion barrels of natural bitumen in place, or about 89%. Of the Canadian total, 703 billion barrels of natural bitumen in place is prospective additional oil, largely confined to the deeply buried bitumen in the carbonate that underlie the Peace River and part of the Athabasca oil sand deposit in an area known as the Carbonate Triangle. The significance of the Canadian deposits lies in their concentration in a few major deposits: Athabasca, from which the reservoir is exploited at or near the surface and shallow subsurface, and Cold Lake and Peace River, from which the bitumen is extracted from the subsurface. Two other basins contain much less but still significant amounts of natural bitumen, the Volga-Ural basin in Russia (263 billion barrels of natural bitumen in place) and the Uinta basin in the United States (12 billion barrels of natural bitumen in place). The Volga-Ural deposits are numerous, but individually are small and mostly of local interest. The Uinta deposits are much more concentrated aerially, but are found in difficult terrain remote from established transportation and refining facilities.

Type IIB. Craton accreted margin (complex)

These basins are complex continental sags on the accreted margins of cratons. Architecturally, they are similar to Type IIA basins, but begin with rifting rather than sags. About three-quarters of Type IIA and IIB basins have proven productive, and they contain approximately one-fourth of the world's total oil and gas (Klemme, 1980a, 1980b).

The 13 Type IIB basins contain a moderate amount of heavy oil (193 billion barrels of oil in place). The two most significant basins are in Russia, West Siberia and Timan-Pechora. These, together with most of the other Type IIB heavy oil basins, are of far greater importance for their conventional and medium oil resources.

Five Type IIB basins hold 29 billion barrels of natural bitumen in place. Only the Timan-Pechora basin contains significant natural bitumen deposits, about 22 billion barrels of natural bitumen in place. Unfortunately, this resource is distributed among a large number of generally small deposits.

Type IIC. Crustal collision zone (convergent plate margin)

These basins are found at the crustal collision zone along convergent plate margins, where they are downwarped into small ocean basins. Although they are compressional in final form, as elongate and asymmetrical foredeeps, they begin as sags or platforms early in the tectonic cycle. Type IIC downwarp basins encompass only about 18 percent of world basin area, but contain nearly one-half of the world's total oil and gas. These basins are subdivided into three subtypes, depending on their ultimate deformation or lack thereof: Type IICa, closed; Type IICb, trough; and Type IICc, open (Klemme, 1980a, 1980b).

Although basins of this type begin as downwarps that opened into small ocean basins (Type IICc), they may become closed (Type IICa) as a result of the collision of continental plates. Upon closing, a large, linear, asymmetric basin with sources from two sides is formed, resembling a Type IIA basin. Further plate movement appears to destroy much of the closed basin, leaving a narrow, sinuous foredeep, that is, a Type IICb trough. Relatively high hydrocarbon endowments in the open and the closed types may be related to above-normal geothermal gradients, which accentuates hydrocarbon maturation and long-distance ramp migration. Traps are mostly anticlinal, either draping over arches or compressional folds, and are commonly related to salt flowage.

Type IICa basins, with their architectural similarity to Type IIA basins, are the most important of the three Type IIC heavy oil basins. The 15 basins account for 1,610 billion barrels of the heavy oil in place, with the Arabian, Eastern Venezuela, and Zagros basins containing 95% of the total. Of particular interest is the Eastern Venezuela basin which includes large accumulations of conventional and medium oil, while at the same time possessing an immense resource of both heavy oil and natural bitumen.

Type IICa basins also are rich in natural bitumen, with a total of 2,507 billion barrels of natural bitumen in place among the six. About 83% of this occurs in Venezuela, mostly in the southern part of the Eastern Venezuelan basin known as the Orinoco Oil Belt. Here the reservoir rocks impinge upon the

Guyana craton in much the same fashion as the reservoir rocks of the Western Canada Sedimentary basin lap onto the Canadian shield. The only other significant Type IICa accumulation of natural bitumen is found in the North Caspian basin (421 billion barrels of natural bitumen in place).

Fourteen Type IICb basins contain modest amounts of heavy oil (32 billion barrels of oil in place) and even less of natural bitumen (5 billion barrels of natural bitumen in place in seven basins). Much of this resource is found in the Caltanisetta and Durres basins, on either side of the Adriatic Sea. Durres basin resources are aggregated with the South Adriatic and the province is labeled South Adriatic on the plates. Significant amounts of the Caltanisetta resource occurs offshore.

The amount of heavy oil in the 12 Type IICc basins is substantial (460 billion barrels of oil in place). The Campeche, by far the largest, and Tampico basins in Mexico and the North Slope basin in the United States account for 89% of the heavy oil. The Campeche field, which is actually an assemblage of closely associated fields, is found about 65 miles offshore of the Yucatan Peninsula in the Gulf of Mexico. The North Slope basin, on the north coast of Alaska, occurs in an area of harsh climate and permafrost, which makes heavy oil and natural bitumen recovery by the application of thermal (steam) methods difficult both physically and environmentally. The U.S. fields in the East Texas, Gulf Coast, and Mississippi Salt Dome basins account for only 5% of the heavy oil in basins of this type.

Only a small amount of natural bitumen (24 billion barrels) has been discovered in eight Type IICc basins. Two of these, the North Slope and South Texas Salt Dome basins, are significant for possible future development.

Type III. Continental Rifted Basins

Type IIIA. Craton and accreted zone (rift)

These are small, linear continental basins, irregular in profile, which formed by rifting and simultaneous sagging in the craton and along the accreted continental margin. About two-thirds of them are formed along the trend of older deformation belts and one-third are developed upon Precambrian shields. Rifts are extensional and lead to block movements so that traps are typically combinations. Oil migration was often lateral, over short distances. Rift basins are few, about five percent of the world's basins, but half of them are productive. Because of their high recovery factors, Type IIIA basins accounted for 10% of the world's total recoverable oil and gas in 1980 (Klemme, 1980a, 1980b).

Globally, there are 28 Type IIIA heavy oil basins, containing 222 billion barrels of oil in place The Bohai Gulf basin in China accounts for 63% of the heavy oil, with an additional 11% derived from the Gulf of Suez and 10% from the Northern North Sea. Outside of these, most Type IIIA basins contain just a few deposits. The five basins in Type IIIA have almost 22 billion barrels of natural bitumen in place, but half of that is located in the Northern North Sea basin.

Type IIIB. Rifted convergent margin (oceanic consumption)

Type IIIBa basins are classified as back-arc basins on the convergent cratonic side of volcanic arcs. They are small, linear basins with irregular profiles (Klemme, 1980a, 1980b).

Not unlike Type IIIA basins, the volume of heavy oil found in the Type IIIBa basins is small. Seventeen heavy oil basins contain 49 billion barrels of oil in place and 83% of this amount is in Central Sumatra.

Just 4 billion barrels of natural bitumen in place are identified in the Type IIIA basin called Bone Gulf. Small amounts are also known to occur in the Cook Inlet and Tonga basins.

Type IIIBb basins are associated with rifted, convergent cratonic margins where wrench faulting and subduction have destroyed the island arc. They are small, linear, and irregular in profile.

The 14 Type IIIBb basins containing heavy oil account for only 134 billion barrels of oil in place. These basins are only moderately important on a global scale, but have been very important to the California oil industry. The seven such basins of California - Central Coastal, Channel Islands, Los Angeles, Sacramento, San Joaquin, Santa Maria, and Ventura – equal 129 billion barrels of oil in place or 96%.

There are nine Type IIIBb basins that report natural bitumen deposits. They contain 4 billion barrels of natural bitumen in place, about half of which is in the Santa Maria basin.

Types IIIBa and IIIBb basins comprise about seven percent of world basin area, but only one-quarter of the basins are productive for oil of all types. However, the productive ones, which represent only two percent of world basin area, yield about seven percent of total world's oil and gas (Klemme, 1983). Some of these productive basins, particularly those located in California, have high reservoir recovery factors.

Type IIIBc basins are small and elongate, irregular in profile, and occupy a median zone either between an oceanic subduction zone and the craton or in the collision zone between two cratonic plates. They result from median zone wrench faulting and consequent rifts. Such basins make up about three and one-half percent of world basin area and contribute two and one-half percent of total world oil and gas.

Type IIIBc basins are important to the occurrence of heavy oil (351 billion barrels of oil in place). Although there are nine basins of this type, 92% of the heavy oil is concentrated in the Maracaibo basin. The Maracaibo basin also yields 95% of the 178 billion barrels of natural bitumen in place in the five basins containing this type of oil. This makes the Maracaibo basin unique: no other basin type is so completely dominated by a single basin.

Type IIIC. Rifted passive margin (divergence)

These basins, often aptly called pull-apart basins, are extensional, elongate, and asymmetric. Located along major oceanic boundaries of spreading plates, they are divergent and occupy the intermediate zone between thick continental crust and thin oceanic crust. They appear to begin with a rifting stage, making possible the later sedimentary fill from the continent. Type IIIC basins, comprising 18 percent of the world's basin area, are mostly offshore and are often in water as deep as 5,000 feet. For this reason their development has been slow but is accelerating as traditional, easily accessible basins reach full development and world demand for petroleum increases (Klemme, 1980a, 1980b).

Twenty-eight Type IIIC basins yield 158 billion barrels of heavy oil in place, but one, the offshore Campos basin, contains 66% of this heavy oil. These continental margin basins must at some point in their histories have been sufficiently elevated to permit their generated conventional oil to be degraded. It is possible that the heavy oil could be very immature, having undergone only primary migration and later elevation. The geologic history of such basins does not encourage this view. However, the oil could well have been degraded bacterially at depth according to the recently proposed mechanisms suggested by Head, Jones, and Larter (2003) and Larter and others (2006). In a pull-apart basin the sediments would have accumulated rapidly and at depth, the expressed oil then was subject to degradation. The problem with degradation at depth is the loss of mobility unless it can be demonstrated that the oil was never elevated and, in fact, the Campos basin oil is deep, occurring at an average depth of nearly 8,400 feet.

The bitumen resource in Type IIIC basins is small (47 billion barrels of natural bitumen in place in seven basins), as are nearly all bitumen occurrences in comparison with the Western Canada Sedimentary and Eastern Venezuela basins. But the 38.3 billion barrels of natural bitumen in place in the Ghana basin of southwestern Nigeria is exploitable and the amount of the resource may be understated. Like many bitumen deposits it awaits more detailed evaluation.

Type IV. Delta (Tertiary to recent)

Deltas form along continental margins as extensional sags, are circular to elongate, and show an extremely high ratio of sediment fill to surface area. Architecturally, they are modified sags comprised of sediment depocenters and occur along both divergent and convergent cratonic margins. Although by 1980 delta basins provide two and one-half percent of world basin area and perhaps six percent of total oil and gas (Klemme, 1980a, 1980b), they account for more of the conventional resource endowment with the recent successful exploration in frontier deep water areas.

The three Type IV delta basins produce scant heavy oil (37 billion barrels of oil in place) and no natural bitumen. This is related to the extremely high ratio of sediment fill to surface area and that these basins exhibited rapid burial of the source organic matter. Burial is constant and uninterrupted, providing very limited opportunity for degradation of the generated petroleum.

Type V. Fore-Arc Basins

Fore-arc basins are located on the ocean side of volcanic arcs. They result from both extension and compression, are elongate and asymmetrical in profile, and architecturally are the result of subduction. Fore-arc basins are few in number and generally not very productive (Klemme, 1980a, 1980b).

Very small amounts of heavy oil are found in the Barbados basin. Although a natural bitumen deposit is reported in the Shumagin basin, volume estimates are not available.

Essentially no heavy oil or natural bitumen is found in fore-arc basins because these basins do not generate large quantities of petroleum of any type and therefore provide relatively little material to be degraded.

Regional Distribution of Heavy Oil and Natural Bitumen

The preceding discussion has been concerned with the distribution of heavy oil and natural bitumen in the world's geological basins. This is of paramount interest in the exploration for the two commodities and for their exploitation. The chemical and physical attributes of the fluids and the reservoirs which contain them do not respect political boundaries.

At the same time it is necessary to understand the geography of the heavy oil and natural bitumen for both economic and political reasons. These factors will be dealt with in detail in a subsequent report. The bar graphs on Plates 2 and 3 give the regional distribution of total and discovered original oil in-place for heavy oil and natural bitumen, respectively. The distribution of the resources is given in table 8. The western hemisphere accounts for about 52 percent of the world's heavy oil and more than 85 percent of its natural bitumen. The Middle East and South America have the largest in-place volumes of heavy oil, followed by North America. North and South America have, by far, the largest in-place volumes of natural bitumen. Very large resource deposits are also known in eastern Siberia but insufficient data are available to make more than nominal size estimates.

Summary

From the preceding basin discussion, Klemme basin Type IICa is by far the most prolific in terms of heavy oil. For natural bitumen Klemme basin Type IIA and Type IICa are the most prolific. The basin types involved are architecturally analogous, beginning with depositional platforms or sags and ending up as foredeeps. They differ only in their modes of origin. What they have in common is truncation against cratonic masses updip from rich source areas. This situation permitted immense accumulations of conventional oil at shallow depths, with near ideal conditions for oil entrapment and biodegradation resulting in formation of heavy oil and bitumen accumulations. The prospective resources from the prospective additional resource deposits in these basins are larger than the discovered resources of many basin types.

The Klemme basin classification system includes elements of basin development and architecture that control basin type. The observed pattern of the heavy oil and natural bitumen occurrences across basin types is consistent with the formation of heavy oil and natural bitumen through the process of degradation of conventional oil. Only relatively small quantities of heavy oil were found in the Interior Craton (Type I), Deltas (Type IV) and Fore-Arc basins (Type V).

Type IICa basins, including the Arabian, Eastern Venezuela, and Zagros, have the largest endowments of heavy oil and also contain the largest amounts of conventional oil. Large volumes of heavy oil are also found in both Type IICc basins, notably, the Campeche, Tampico, and North Slope basins, and in Type IIIBc basins, primarily Maracaibo basin. For natural bitumen, the Western Canada Sedimentary and Eastern Venezuela basins have similar development histories and basin architectural features. Some basin development patterns promote the formation of greater volumes of heavy oil and natural bitumen than others. This is seen most clearly in present occurrences of heavy oil and natural bitumen in the Type IICa and Type IICc basins, with their rich source areas for oil generation and up-dip migration paths to entrapment against cratons. Conventional oil may easily migrate through the tilted platforms until the platforms are breached at or near surface permitting deveopment of asphaltic seals.

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Tables 1–8

Table 1. Some chemical and physical attributes of crude oils (averages).

[cP, centipoise; wt%, weight percent; mgKOH/g, milligrams of potassium hydroxide per gram of sample; sp gr, specific gravity; vol%, volume percent; ppm, parts per million; Concarbon, Conradson carbon; VOC, volatile organic compounds; BTEX, benzene, toluene, ethylbenzene, and xylenes]

Attribute	Unit	Conventional oil (131 basins, 8148 deposits)	Medium oil (74 basins, 774 deposits)	Heavy oil (127 basins, 1199 deposits)	Natural bitumen (50 basins, 305 deposits)
API gravity	degrees	38.1	22.4	16.3	5.4
Depth	feet	5,139.60	3,280.20	3,250.00	1,223.80
Viscosity (77°F)	cP	13.7	34	100,947.00	1,290,254.10
Viscosity (100°F)	cP	10.1	64.6	641.7	198,061.40
Viscosity (130°F)	cP	15.7	34.8	278.3	2,371.60
Conradson Carbon	wt%	1.8	5.2	8	13.7
Coke	wt%	2.9	8.2	13	23.7
Asphalt	wt%	8.9	25.1	38.8	67
Carbon	wt%	85.3	83.2	85.1	82.1
Hydrogen	wt%	12.1	11.7	11.4	10.3
Nitrogen	wt%	0.1	0.2	0.4	0.6
Oxygen	wt%	1.2		1.6	2.5
Sulfur	wt%	0.4	1.6	2.9	4.4
Reid vapor pressure	psi	5.2	2.6	2.2	
Flash point	°F	17	20.1	70.5	
Acid number	mgKOH/g	0.4	1.2	2	3
Pour point	°F	16.3	8.6	19.7	72.9
C1-C4	vol%	2.8	0.8	0.6	
Gasoline + naphtha	vol%	31.5	11.1	6.8	4.4
Gasoline + naphtha	sp gr	0.76	0.769	0.773	0.798
Residuum	vol%	22.1	39.8	52.8	62.2
Residuum	sp gr	0.944	1.005	1.104	1.079
Asphaltenes	wt%	2.5	6.5	12.7	26.1
Asphaltenes + resins	wt%	10.9	28.5	35.6	49.2
Aluminum	ppm	1.174	1.906	236.021	21,040.03
Copper	ppm	0.439	0.569	3.965	44.884
Iron	ppm	6.443	16.588	371.05	4,292.96
Mercury	ppm	19.312	15	8.74	0.019
Nickel	ppm	8.023	32.912	59.106	89.137
Lead	ppm	0.933	1.548	1.159	4.758
Titanium	ppm	0.289	0.465	8.025	493.129
Vanadium	ppm	16.214	98.433	177.365	334.428
Residue Concarbon	wt%	6.5	11.2	14	19
Residue Nitrogen	wt%	0.174	0.304	0.968	0.75
Residue Nickel	ppm	25.7	43.8	104.3	
Residue Sulfur	ppm	1.5	3.2	3.9	
Residue Vanadium	ppm	43.2	173.7	528.9	532
Residue viscosity (122°F)	cP	1,435.80	4,564.30	23,139.80	
Total BTEX volatiles	ppm	10,011.40	5,014.40	2,708.00	
Total VOC volatiles	ppm	15,996.30	8,209.20	4,891.10	

Table 2. Conversion factors and equivalences applied to standardize data.

Standard unit in this report	Units as reported in literaure	Formula
	API gravity	
°API (degrees)	specific gravity (sp gr), (g/cm^3)	= (141.5/(sp gr))-131.5
	Area	
acre	square mile (mi^2)	= (1/640) mi^2
	square kilometer (km^2)	= 0.00405 km^2
	hectare (ha)	= 0.405 ha
	Asphalt in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 4.9× (CCR)
	Barrels of oil	
barrel (bbl), (petroleum, 1 barrel=42 gal)	cubic meter (m^3)	= 0.159 m^3
	metric tonne (t)	= 0.159× (sp gr) ×t
	Coke in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 1.6× (CCR)
	Gas-oil ratio	
cubic feet gas/barrel oil (ft^3 gas/bbl oil)	cubic meters gas/cubic meter oil (m^3 gas/m^3 oil)	= 0.18× (m^3gas/m^3oil)
	Parts per million	
parts per million (ppm)	gram/metric tonne (g/t)	= g/t
	milligram/kilogram (mg/kg)	= mg/kg
	microgram/gram (µg/g)	= µg/g
	milligram/gram (mg/g)	= 0.001 mg/g
	weight percent (wt%)	= 0.0001 wt%
	Parts per billion	
parts per billion (ppb)	parts per million (ppm)	= 0.001 ppm
	Permeability	
millidarcy (md)	micrometer squared (μm^2)	= 1,000 μm^2
	Pressure	
pound per square inch (psi)	kilopascal (kPa)	= 6.89 kPA
	megapascal (Mpa)	= 0.00689 MPa
	bar	= 0.0689 bar
	kilograms/square centimeter (kg/cm^2)	= 0.0703 kg/cm^2
	Specific gravity (density)	
specific gravity (sp gr), (g/cm^3)	°API (degrees)	= 141.5/(131.5+°API)
	Temperature	
degrees Fahrenheit (°F)	degrees Celsius (°C)	= (1.8×°C)+32
degrees Celsius (°C)	degrees Fahrenheit (°F)	= 0.556×(°F-32)
	Viscosity (absolute or dynamic)	
centipoise (cP)	Pascal second (Pa·s)	= 0.001 Pa·s
	millipascal second (mPa·s)	= mPa·s

Table 2. Conversion factors and equivalences applied to standardize data.—Continued

Standard unit in this report	Units as reported in literaure	Formula
	Viscosity (absolute or dynamic)—Continued	
centipoise (cP)—cont.	kinematic viscosity[1]: centistroke (cSt), (mm²/sec)	= cSt × (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given density	= (SUS /4.632)× (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given °API	= (SUS /4.632)×(141.5/(131.5+°API))
	Weight percent	
weight percent (wt%)	parts per million (ppm)	= 10,000 ppm

[1] Kinematic viscosity is equal to the dynamic viscosity divided by the density of the fluid, so at 10°API the magnitudes of the two viscosities are equal.

Table 3. Total original in place resource calculation protocol when discovered oil in place is unavailable.

Define—

- OOIP-disc.: Original Oil In Place, discovered
- RF: Recovery factor (%)
- R: Reserves, known
- OR: Reserves, original sometimes called, known recovery, ultimate production if so reported
- AP: Production, annual
- CP: Production, cumulative
- PA: Prospective additional oil in place resource
- TOOIP = Total original oil in place

Calculations are based given data, which always receives priority; CP, AP and PA are never calculated and must be from published sources. (Assume CP, AP, PA are given)—

- R = 20×AP. This assumes a 20-year life or production plan for the viscous oil.
- OR = R+CP
- RF = 0.1 for clastic reservoirs or if no lithology is reported
- RF = 0.05 for carbonate reservoirs
- OOIP-disc. = OR/RF
- TOOIP = OOIP-disc. + PA

Table 4. Heavy oil and natural bitumen resources in billions of barrels of oil (BBO) and average characteristics of heavy oil and natural bitumen by basin type. Average values for gravity, viscosity, depth, thickness permeability are weighted by volume of oil in place discovered in each heavy oil or natural bitumen deposit by basin type; except for API gravity of heavy oil Type I, where because of relatively few deposits and several outlier values, a trimmed weighted mean value is shown.

[Volumes may not add to totals due to independent rounding; BBO, billions of barrels of oil; cP, centipoise]

Basin type	Total original oil in place (BBO)	Discovered oil in place (BBO)	API gravity (degrees)	Viscosity (cP @ 100°F)	Depth (feet)	Thickness (feet)	Porosity (percent)	Permeability (millidarcy)	Temperature (°F)
				Heavy oil					
I……….	3	2	15.9	724	1,455	11	15.3	88	122
IIA…….	158	157	16.3	321	4,696	36	22.8	819	102
IIB…….	181	181	17.7	303	3,335	96	27.2	341	82
IICa…...	1,610	1,582	15.5	344	3,286	150	24	242	144
IICb…...	32	32	15.4	318	3,976	161	16.9	2,384	126
IICc…...	460	460	17.8	455	6,472	379	19.6	1,080	159
IIIA……	222	222	16.3	694	4,967	279	24.9	1,316	159
IIIBa…..	49	49	19.2	137	558	838	24.9	2,391	122
IIIBb…..	134	134	15.8	513	2,855	390	31.9	1,180	116
IIIBc…..	351	351	13.5	2,318	4,852	142	20.1	446	145
IIIC……	158	158	17.2	962	7,227	273	25.1	868	159
IV……..	37	37	17.9	-	7,263	1,195	27.9	1,996	155
V………	<1	<1	18	-	1,843	135	30	-	144
All types	3,396	3,366	16	641	4,213	205	23.7	621	134
				Natural bitumen					
I……….	60	8		-	20	317	5.5	100	
IIA…….	2,623	1,908	6.8	185,407	223	53	0.4	611	173
IIB…….	29	26	4.5	-		209	13.1	57	113
IICa…...	2,509	2,319	4.4	31,789	806	156	29.8	973	174
IICb…...	5	5	6.8	-	8,414	1,145	4.7	570	181
IICc…...	24	23	5	1,324	3,880	82	32.4	302	263
IIIA……	22	22	8.7	-	4,667	882	30.3	1,373	85
IIIBa…..	4	4	-	-	-	-	-	-	-
IIIBb…..	3	3	6.7	500,659	3,097	586	28.6	2,211	89
IIIBc…..	178	178	9.5	1,322	8,751	52	34	751	139
IIIC……	47	14	7.3	-	900	103	23.1	2,566	117
IV……..	0	0							
V………	0	0							
All types	5,505	4,512	4.9	198,061	1,345	110	17.3	952	158

Table 5. Enhanced oil recovery (EOR) methods for heavy oil showing primary reservoir threshold criteria.

[modified from Taber, Martin, and Seright (1997a,b); cP, centipoises; PV, pore volume; ft, feet; md, millidarcy; °F, degrees Fahrenheit, wt%, weight percent]

Method	Gravity (°API)	Viscosity (cP)	Oil composition	Oil saturation (%PV)	Lithology	Net thickness (ft)	Average permeability (md)	Depth (ft)	Temperature (°F)
				Immiscible gases					
Immiscible gases[a]	>12	<600	Not critical	>35	Not critical	Not critical	Not critical	>1,800	Not critical
				Enhanced waterflood					
Polymer	>15	<150	Not critical	>50	Sandstone preferred	Not critical	>10[b]	<9,000	>200-140
				Thermal/mechanical					
Combustion	>10	<5,000	Asphaltic components	>50	Highly porous sandstone	>10	>50[c]	<11,500	>100
Steam	>8	<200,000	Not critical	>40	Highly porous sandstone	>20	>200[d]	<4500	Not critical
Surface mining	>7	0 cold flow	Not critical	>8 wt% sand	Mineable oil sand	>10[e]	Not critical	>3:1 overburden: sand ratio	Not critical

[a] Includes immiscible carbon dioxide flood.

[b] >3 md for some carbonate reservoirs if the intent is to sweep only the fracture systems.

[c] Transmissibility > 20md-ft/cP.

[d] Transmissibility > 50md-ft/cP.

[e] See depth.

Table 6. Listing of countries reporting deposits of heavy oil and/or natural bitumen grouped by region. (See inset maps of regional distribution on Plates 2 and 3.)

North America	South America	Europe	Africa	Transcaucasia	Middle East	Russia	South Asia	East Asia	Southeast Asia and Oceania
Canada	Argentina	Albania	Algeria	Azerbaijan	Bahrain	Russia	Bangladesh	China	Australia
Mexico	Barbados	Austria	Angola	Georgia	Iran		India	Japan	Brunei
United States	Bolivia	Belarus	Cameroon	Kazakhstan	Iraq		Pakistan	Taiwan	Indonesia
	Brazil	Bosnia	Chad	Kyrgyzstan	Israel				Malaysia
	Colombia	Bulgaria	Congo (Brazzaville)	Tajikistan	Jordan				Myanmar
	Cuba	Croatia	Democratic Re-public of Congo (Kinshasa)	Turkmenistan	Kuwait				Philippines
	Ecuador	Czech Republic	Egypt	Uzbekistan	Neutral Zone				Thailand
	Guatemala	France	Equatorial Guinea		Oman				Tonga
	Peru	Germany	Gabon		Qatar				Vietnam
	Suriname	Greece	Ghana		Saudi Arabia				
	Trinidad & Tobago	Hungary	Libya		Syria				
	Venezuela	Ireland	Madagascar		Turkey				
		Italy	Morocco		Yemen				
		Malta	Nigeria						
		Moldova	Senegal						
		Netherlands	South Africa						
		Norway	Sudan						
		Poland	Tunsia						
		Romania							
		Serbia							
		Slovakia							
		Spain							
		Sweden							
		Switzerland							
		Ukraine							
		United Kingdom							

Table 7. Attributes of Klemme basin types.

[Sources for attributes 1-15 are Klemme (1980a, 1980b, 1984) and attributes 16 and 17 are from this report]

	Type I	Type IIA	Type IIB	Type IICa
	Craton interior	**Continental multicycle basins, craton margin**	**Continental multicycle basins: craton/acreted zone rift-faulted**	**Continental interior multicycle basins: close collision zone at paleoplate margin**
1. Crustal zone	Continental craton	Continental craton	Contnental craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone
2. Tectonic setting	Continenal crust within interior of craton, near or upon Precambrian sheld areas	Continental crust on exterior margin of craton, basins become multicylic ion Paleozoic or Mesozoic when a second cycle of sediments derived from uplife encroaches	Continental crust, or on margin of craton	Convergent margin along collision zone of paleoplates
3. Regional stress	Extensional	1st cycle: extension, 2nd cycle: compression	(1st) extension with rifting, (2nd) extensional sag	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep
4. Basin size, shape	Large, circular to elongate	Moderate to large, circular to elongate	Large, circular	Large, elongate
5. Basin profile	Symmetrical	Asymmetrical	Irregular to asymmetrical	Asymmetrical
6. Sediment ratio[1]	Low	High	High	High
7. Architectural sequence	Sag	1st cycle: platform or sag, 2nd cycle: foredeep	(1st) rift, (2nd) large circular sag	(1st) platform or sag, (2nd) foredeep
8. Special features	Unconformities, regional arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs
9. Basin lithology[2]	Clastic 60%, carbonate 40%	Clastic 75%, carbonate 25%	Clastic 75%, carbonate 25%	Clastic 35%, carbonate 65%
10. Depth of production[3]	Shallow	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 45%, moderate 30%, deep 25%
11. Geothermal gradient	Low	Low	High	High
12. Temperature	Cool	Cool	Cool	High
13. Age	Paleozoic	Paleozoic, Mesozoic	Paleozoic, Mesozoic	Upper Paleozoic, Mesozoic, Tertiary
14. Oil and gas recovery[4]	Low, few giant fields	Average	Generally average	High
15. Traps	Associated with central arches and stratigraphic traps along basin margins	Basement uplifts, mostly arches or blocks	Basement uplifts, mostly combination of structural stratigraphic	Basement uplifts, arches and fault blocks
16. Propensity for heavy oil	Low	Low	Low	High
17. Propensity for natural bitumen	Low	High	Low	High

[1]Sediment ratio: ratio of sediment volume to basin surface area.

[2]Basin lithology: percentages apply to reservoir rocks, not to the basin fill.

[3]Depth of production: shallow, 0-6000 ft.; medium, 6000-9000 ft.; deep, >9000 ft.

[4]Oil and gas recovery (barrels of oil equivalent per cubic mile of sediment): low, <60,000; average, >=60,000 but <300,000; high, >=300,000.

[5]Does not add to 100% in source, Klemme (1980a,b).

Table 7. Attributes of Klemme basin types.—Continued

	Type IICb	Type IICc	Type IIIA	Type IIIBa
	Continental interior multicycle basins: foredeep portion of collision zone at paleoplate margin	**Continental interior multicycle basins: open collision zone at paleoplate margin**	**Continental rifted basins: craton/accreted zone, rift-faulted, with small linear sag**	**Continental rifted basins: back arc rift-faulted convergent margin**
1. Crustal zone	Ocean crust early stages then continental crust of craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone	Continental craton and accreted zone	Contintental accreted zone with oceanic crust in early stages
2. Tectonic setting	Convergent margin along collision zone of paleoplates, but retain only proximal or foredeep portion of original sediment suite	Convergent margin along collision zone of paleoplates	Continental, on margin of craton. About two-thirds of Type IIIA basins form along trend of older deformation; remainder on Precambrian shields	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages
3. Regional stress	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) extension with local wrench faulting during rifting, (2nd) sag	(1st) extension with local wrench faulting compression, (2nd) extension and compression
4. Basin size, shape	Large, elongate	Large, elongate	Small to moderate, fault controlled, elongate	Small, elongate
5. Basin profile	Asymmetrical	Asymmetrical	Irregular	Irregular
6. Sediment ratio[1]	High	High	High	High but variable
7. Architectural sequence	(1st) platform or sag, (2nd) foredeep	(1st) platform or sag, (2nd) foredeep	(1st) extension with local wrench faulting druing rifting, (2nd) sag	Rift faulting leading to linear sag, may be followd by wrench faulting
8. Special features	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs, unconformities	Large traps, evaporite caps, unconformities, regional source seal	Large traps, and unconformities
9. Basin lithology[2]	Clastic 50%, carbonate 50%	Clastic 35%, carbonate 65%	Clastic 60%, carbonate 40%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 45%, moderate 30%, deep 25%	Shallow 45%, moderate 30%, deep 25%	Moderate 55%, shallow 30%, deep 15%	Shallow 70%, moderate 20%, deep 10%
11. Geothermal gradient	High	High	High	High
12. Temperature	High	High	Normal to high	Normal to high
13. Age	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Paleogene, Neogene	Upper Mesozoic, Paleogene and Neogene
14. Oil and gas recovery[4]	Generally low	High	Generally high	Variable
15. Traps	Basement uplifts, arches and fault blocks	Basement uplifts, arches and fault blocks	Basement uplifts, combination structural/stratigraphic; result in fault block movement	Basement uplifts, fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Moderate	Low
17. Propensity for natural bitumen	Low	Low	Low	Low

Table 7. Attributes of Klemme basin types.—Continued

	Type IIIBb	Type IIIBc	Type IIIC	Type IV	Type V
	Continental rifted basins: transverse rift-faulted convergent margin	**Continental rifted basins: median rift-faulted convengent margin**	**Continental rifted basins: rift-faulted divergent margin, may be subdivided into (a) parallel, or (b) transverse basins**	**Deltas**	**Fore-arc basins**
1. Crustal zone	Contintental accreted zone with oceanic crust in early stages	Contintental accreted zone with oceanic crust in early stages	Ocean crust in early stage, then continental crust of craton and accreted zone	Ocean crust in early stage, then continental crust of craton and accreted zone	Continetal accreted crust and oceanic crust
2. Tectonic setting	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Rift faulting along a divergent, passive or pull-apart continental margin	Almost any location: divergent and convergent margins along open or confined coastal areas	Fore-arc basins located on oceanward side of the volcanic arc in subduction or consumption zone
3. Regional stress	(1st) extension and wrench compression, (2nd) extension and compression	(1st) extension and wrench compression, (2nd) extension and compression	Extension leading to rift or wrench faulting	Extension as sag develops but uncertain as to the initial cause of sag, roots being deeply buried	Compression and extension
4. Basin size, shape	Small, elongate	Small, elongate	Small to moderate, elongate	Moderate, circular to elongate	Small, elongate
5. Basin profile	Irregular	Irregular	Asymmetrical	Depocenter	Asymmetrical
6. Sediment ratio[1]	High but variable	High but variable	High	Extremely high	High
7. Architectural sequence	Rift faulting leading to linear sag, may be followd by wrench faulting	Rift faulting leading to linear sag, may be followd by wrench faulting	Linear sage with irregular profile	Roots of deltas deeply buried; extension leads to half-sag with sedimentary fill thickening seaward.	Small linear troughs
8. Special features	Large traps, and unconformities	Large traps, unconformities, and regional arches	Possible unconformities and regional source seals	None	Large traps, and unconformities
9. Basin lithology[2]	Clastic 90%, carbonate 10%	Clastic 90%, carbonate 10%	Clastic 70%, carbonate 30%	Clastic 100%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 70%, moderate 20%, deep 10%	Shallow 70%, moderate 20%, deep 10%	Deep 60%, moderate 30%, shallow 10%	Deep 65%, moderate 30%, shallow 5%	Shallow 70%, deep 20%, moderate 10%
11. Geothermal gradient	High	Normal to high	Low	Low	High
12. Temperature	Normal to high	Normal to high	Cool	Normal to low	High to normal
13. Age	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Paleogene, Neogene, and Quaternary	Upper Mesozoic, Tertiary
14. Oil and gas recovery[4]	Variable	Variable	Low	High	High but variable
15. Traps	Basement uplifts, fault blocks and combination	Basement uplifts, fault blocks and combination	Fault blocks and combination	Primarily tensional growth (roll-over) anticlines and flowage: basement not involved	Fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Low	Low	Nil
17. Propensity for natural bitumen	Low	Low	Low	Nil	Nil

Table 8. Regional distribution of heavy oil and natural bitumen (billion barrels).

[Volumes may not add to totals due to independent rounding]

Region[1]	Discovered orginal oil in place	Prospective additional	Total original oil in place
		Heavy oil	
North America…………………	650	2	651
South America…………………	1099	28	1127
Europe………………………….	75	0	75
Africa…………………………..	83	0	83
Transcaucasia…………………..	52	0	52
Middle East…………………….	971	0	971
Russia…………………………..	182	0	182
South Asia……………………...	18	0	18
East Asia……………………….	168	0	168
Southeast Asia and Oceania……	68	0	68
Total………………………..	3366	29	3396
		Natural bitumen	
North America…………………	1671	720	2391
South America…………………	2070	190	2260
Europe………………………….	17	0	17
Africa…………………………..	13	33	46
Transcaucasia…………………..	430	0	430
Middle East…………………….	0	0	0
Russia…………………………..	296	51	347
South Asia……………………...	0	0	0
East Asia……………………….	10	0	10
Southeast Asia and Oceania……	4	0	4
Total………………………..	4512	993	5505

[1] See table 6 for a list of countries reporting deposits of heavy oil and/or natural bitumen grouped by regions.

Appendixes 1–4

Appendix 1. Map Basin Name Conventions

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Amu Darya	Tadzhik
Arkla	Louisiana Salt Dome
Baikal	Lake Baikal
Barinas-Apure	Llanos de Casanare
Carnarvon	Dampier
Central Montana Uplift	Crazy Mountains
Central Sumatra	Sumatra, Central
East Java	Java, East
East Texas	East Texas Salt Dome
Eastern Venezuela	Maturin
Forest City	Salina-Forest City
Gulf of Alaska	Alaska, Gulf of
Gulf of Suez	Suez, Gulf of
Guyana	Guiana
Junggar	Zhungeer
Kutei	Mahakam
Mae Fang	Fang
Minusinsk	Minisinsk
North Caspian	Caspian, North
North Caucasus-Mangyshlak	Caucasus, North
North Egypt	Western Desert
North Sakhalin	Sakhalin, North
North Sumatra	Sumatra, North
North Ustyurt	Ust Urt
Northern North Sea	North Sea, Northern
Northwest Argentina	Argentina, Northwest
Northwest German	German, Northwest
Northwest Shelf	Dampier
Ordos	Shanganning
Progreso	Guayaquil
Sacramento	Sacramento/San Joaquin
Salinas	Salinas (Mexico)
San Joaquin	Sacramento/San Joaquin
South Adriatic	Adriatic, South
South Palawan	Palawan, South
South Sumatra	Sumatra, South
Timan-Pechora	Pechora
Turpan	Tulufan

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).—Continued

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Upper Magdalena	Magdalena, Upper
West Java	Java, West, Sunda
West of Shetlands	Shetlands, West
Western Canada Sedimentary	Alberta
Yukon-Kandik	Yukon/Kandik

The following basins listed in bold type are from the digital mapping file of St. John (1996) and require further explanation:

- **Anadarko**: includes provinces more commonly known as the *Anadarko,* Central Kansas Uplift, Chautauqua Platform, *Las Animas Arch,* Nemaha Anticline-Cherokee Basin, *Ozark Uplift,* Sedgwick, and South Oklahoma Folded Belt (provinces in italics report neither heavy oil nor natural bitumen.)

- **Sacramento/San Joaquin**: separated into two distinct provinces, Sacramento and San Joaquin.

- **North Sea, Southern**: : includes both the Anglo-Dutch and Southern North Sea basins.

- **South Adriatic**: includes both the Durres and South Adriatic basins.

Other comments:

Three separate outlines for Marathon, Ouachita, and Eastern Overthrust are shown as a common province Marathon/Ouachita/Eastern Overthrust in the original St John (1996) but only Ouachita Basin had reported volumes of natural bitumen resources.

Deposits reported for Eastern Venezuela basin include deposits on the island of Trinidad, which are a likely extension of the rock formations from the surface expression of the basin outline.

The plates attach the name of Barinas Apure to the polygonal province labeled Llanos de Casanare in St. John (1996). Barinas Apure is the province name commonly used in Venezuela and Llanos de Casanare is the province name commonly used in Colombia for the same geologic province.

Appendix 2. Basins, Basin Type and Location of Basins having Heavy Oil and Natural Bitumen Deposits

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.

Geological province	Klemme basin type	Country	State/Province	Other names
Aegian	IIIBc	Greece		North Aegean Trough (North Aegean Sea Basin)
Akita	IIIBa	Japan		Akita Basin, Japan Accreted Arc/Accreted Terrane
Amu-Darya	IICa	Tajikistan, Uzbekistan		Tadzhik, Surkhan-Vaksh, Badkhyz High (Murgab Basin), Afghan-Tajik
Amur	IIIBc	Georgia		
Ana Maria	IIIBb	Cuba		Zaza Basin, Greater Antilles Deformed Belt
Anabar-Lena	IIA	Russia		
Anadarko	IIA	United States	Kans.	
Anadyr	IIIBb	Russia		
Angara-Lena	IIA	Russia		
Anglo-Dutch	IIB	Netherlands		Central Graben, North Sea, Southern
Appalachian	IIA	United States	Ky., N.Y.	
Aquitaine	IIIA	France		Ales, Aquitaine, Lac Basin, Parentis, Massif Central, Pyrenean Foothills-Ebro Basin
Arabian	IICa	Bahrain, Iran, Iraq, Jordan, Kuwait, Neutral Zone, Oman, Qatar, Saudi Arabia, Syria		Arabian Basin, Rub Al Khali, Aneh Graben, Aljafr Sub-basin, Oman Platform, Mesopotamian Foredeep, Palmyra Zone, Oman Sub-Basin, Euphrates/Mardin, Ghaba Salt Basin, Greater Ghawar Uplift, Haleb, Qatar Arch, South Oman Salt Basin, Widyan Basin
Arkla	IICc	United States	Ark., La.	Louisiana Salt Dome
Arkoma	IIA	United States	Ark., Okla.	
Assam	IICb	India		
Atlas	IICb	Algeria		Moroccan-Algerian-Tunisian Atlas, Hodna-Constantine
Bahia Sul	IIIC	Brazil		J Equitinhonha
Baikal	IIIA	Russia		Lake Baikal
Balearic	IIIA	Spain		Western Mediterranean, Gulf of Valencia, Barcelona Trough (Catalano-Balearic Basin), Iberic Cordillera
Baltic	I	Sweden		
Baluchistan	IICb	Pakistan		Sulaiman-Kirthar
Barbados	V	Barbados		Lesser Antilles, Northeast Caribbean Deformed Belt
Barinas-Apure	IIA	Venezuela, Colombia		Barinas-Apure Basin, Llanos de Casanare
Barito	IIIBa	Indonesia		Barito Basin
Bawean	IIIBa	Indonesia		
Beibu Gulf	IIIBa	China		Beibuwan (Gulf of Tonkin) Basin
Bengal	IICa	Bangladesh, India		Bengal (Surma Sub-basin), Tripura-Cachar, Barisal High (Bengal Basin), Ganges-Brahmaputra Delta
Beni	IIA	Bolivia		Foothill Belt
Big Horn	IIA	United States	Mont., Wyo.	
Black Mesa	IIB	United States	Ariz.	Dry Mesa, Dineh Bi Keyah
Black Warrior	IIA	United States	Ala., Miss.	
Bohai Gulf	IIIA	China		Bohai Wan (Huabei-Bohai) Basin, Huabei, Pohal, Luxi Jiaoliao Uplift

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Bombay	IIIC	India		
Bonaparte Gulf	IIIC	Australia		Berkeley Platform (Bonaparte Basin)
Bone Gulf	IIIBa	Indonesia		Bone
Bresse	IIIA	France		Jura Foldbelt
Browse	IIIC	Australia		
Brunei-Sabah	IICc	Brunei, Malaysia		Baram Delta
Cabinda	IIIC	Angola, Congo (Brazzaville), Democratic Republic of Congo (Kinshasa)		Lower Congo Basin, West-Central Coastal
Caltanisetta	IICb	Italy, Malta		Caltanissetta Basin, Ibleian Platform, Sicilian Depression
Cambay	IIIA	India		Cambay North, Bikaner-Nagam, Bombay (in part)
Campeche	IICc	Mexico		Tabasco-Campeche, Yucatan Boderland and Platform, Tobasco, Campeche-Sigsbee Salt, Villahermosa Uplift
Campos	IIIC	Brazil		Cabo Frio High (Campos Basin)
Cantabrian	IIIA	Spain		Offshore Cantabrian Foldbelt (Cantabrian Zone), Spanish Trough-Cantabrian Zone
Carnarvon	IIIC	Australia		Dampier, Northwest Shelf, Carnarvon Offshore, Barrow-Dampier Sub-Basin
Carpathian	IICb	Austria, Czech Republic, Poland, Ukraine		Carpathian Flysch, Carpathian Foredeep, Bohemia, Carpathian-Balkanian
Celtic	IIIA	Ireland		Celtic Sea Graben System, Ireland-Scotland Platform
Central Coastal	IIIBb	United States	Calif.	Coastal, Santa Cruz, Salinas Valley, Northern Coast Range
Central Kansas Uplift	IIA	United States	Kans.	Anadarko
Central Montana Uplift	IIA	United States	Mont.	Crazy Mountains
Central Sumatra	IIIBa	Indonesia		Central Sumatra Basin
Ceram	IICa	Indonesia		North Seram Basin, Banda Arc
Channel Islands	IIIBb	United States		Southern California Borderlands
Chao Phraya	IIIA	Thailand		Phitsanulok Basin, Thailand Mesozoic Basin Belt
Chautauqua Platform	IIA	United States	Okla.	Anadarko
Cincinnati Arch	I	United States	Ky., Ohio	
Cook Inlet	IIIBa	United States	Alaska	Susitna Lowlands
Cuanza	IIIC	Angola		Kwanza Basin, West-Central Coastal
Cuyo	IIB	Argentina		Alvear Sub-basin (Cuyo Basin), Cuyo-Atuel
Dead Sea	IICa	Israel, Jordan		Syrian -African Arc, Levantine, Jafr-Tabuk, Sinai
Denver	I	United States	Colo., Nebr.	Denver-Julesberg
Diyarbakir	IICa	Syria, Turkey		Bozova-Mardin High (Southeast Turkey Fold Belt), Euphrates/ Mardin, Zagros Fold Belt
Dnieper-Donets	IIIA	Ukraine		Dnepr-Donets Graben
Doba	IIIA	Chad		
Durres	IICb	Albania		Ionian Basin (zone), South Adriatic, Pre-Adriatic
East China	IIIBa	China, Taiwan		Diaoyu Island Depression (East China Sea Basin)
East Java	IIIBa	Indonesia		Bawean Arch (East Java Basin)
East Texas	IICc	United States	Tex.	East Texas Salt Dome, Ouachita Fold Belt
Eastern Venezuela	IICa	Venezuela, Trinidad and Tobago		Maturin, Eastern Venezuela Basin, Orinoco Oil Belt, Guarico Sub-basin, Trinidad-Tabago

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Espirito-Santo	IIIC	Brazil		Abrolhos Bank Sub-Basin (Espirito Santo Basin)
Fergana	IIIBc	Kyrgyzstan, Tajikistan, Uzbekistan		
Florida-Bahama	IIIC	Cuba, United States	Fla.	Almendares-San Juan Zone, Bahia Honda Zone, Llasvvillas Zone, Florida Platform, Greater Antilles Deformed Belt
Forest City	I	United States	Kans., Nebr.	Salina-Forest City, Salina, Chadron Arch
Fort Worth	IIA	United States	Tex.	Bend Arch, Fort Worth Syncline, Llano Uplift, Ouachita Overthrust
Gabon	IIIC	Gabon		Gabon Coastal Basin (Ogooue Delta), West-Central Coastal
Gaziantep	IICa	Syria, Turkey		
Ghana	IIIC	Ghana, Nigeria		Benin-Dahomey, Dahomey Coastal
Gippsland	IIIA	Australia		Gippsland Basin
Green River	IIA	United States	Colo., Wyo.	
Guangxi-Guizou	IIB	China		Bose (Baise) Basin, South China Fold Belt
Gulf Coast	IICc	United States	La., Tex.	Mid-Gulf Coast, Ouachita Folded Belt, Burgos
Gulf of Alaska	V	United States	Alaska	
Gulf of Suez	IIIA	Egypt		Gulf of Suez Basin, Red Sea Basin
Guyana	IIIC	Suriname		Guiana, Bakhuis Horst, Guyana-Suriname
Illinois	I	United States	Ill., Ky.	
Indus	IICb	India		Punjab (Bikaner-Nagaur Sub-basin), West Rajasthan
Ionian	IICb	Greece		Epirus, Peloponesus
Irkutsk	IIA	Russia		
Jeanne d’Arc	IIIC	Canada	N.L.	Labrador-Newfoundland Shelf
Jianghan	IIIA	China		Tung-T’Ing Hu
Junggar	IIIA	China		Zhungeer, Anjihai-Qigu-Yaomashan Anticlinal Zone (Junggar)
Kansk	IIA	Russia		
Krishna	IIIC	India		Krishna-Godavari Basin
Kura	IIIBc	Azerbaijan, Georgia		Kura Basin
Kutei	IIIBa	Indonesia		Mahakam
Kuznets	IIB	Russia		
Laptev	IIB	Russia		
Los Angeles	IIIBb	United States	Calif.	
MacKenzie	IV	Canada	N.W.T.	Beaufort Sea, MacKenzie Delta
Mae Fang	IIIA	Thailand		Fang, Mae Fang Basin, Tenasserim-Shan
Maracaibo	IIIBc	Venezuela, Colombia		Maracaibo Basin, Catatumbo
Mauritius-Seychelles	IIIC	Seychelles		
Mekong	IIIC	Vietnam		Mekong Delta Basin
Michigan	I	United States	Mich.	
Middle Magdalena	IIIBc	Colombia		Middle Magdalena Basin
Minusinsk	IIB	Russia		Minisinsk
Mississippi Salt Dome	IICc	United States	Ala., Miss.	
Moesian	IICb	Bulgaria, Moldova, Romania		Moesian Platform-Lom Basin, Alexandria Rosiori Depression (Moesian Platform), Carpathian-Balkanian, West Black Sea

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Molasse	IICb	Austria, Germany, Italy, Switzerland		Molasse Basin
Morondava	IIIC	Madagascar		
Mukalla	IIIC	Yemen		Sayhut Basin, Masila-Jeza
Natuna	IIIA	Indonesia		
Nemaha Anticline-Cherokee Basin	IIA	United States	Kans., Mo.	Anadarko
Neuquen	IIB	Argentina		Agrio Fold Belt (Neuquen Basin)
Niger Delta	IV	Cameroon, Equatorial Guinea, Nigeria		Abakaliki Uplift (Niger Delta)
Niigata	IIIBa	Japan		Niigata Basin, Yamagata Basin, Japan Volcanic Arc/Accreted Terrane
Nile Delta	IV	Egypt		Nile Delta Basin
North Caspian	IICa	Kazakhstan, Russia		Akatol' Uplift, Alim Basin, Beke-Bashkuduk Swell Pri-Caspian, Kobyskol' Uplift, South Emba, Tyub-Karagan
North Caucasus-Mangyshlak	IICa	Russia		Indolo-Kuban-Azov-Terek-Kuma Sub-basins, North Buzachi Arch, Middle Caspian, North Caucasus
North Egypt	IICa	Egypt		Western Desert, Abu Gharadiq
North Sakhalin	IIIBb	Russia		Sakhalin North
North Slope	IICc	United States	Alaska	Arctic Coastal Plains, Interior Lowlands, Northern Foothills, Southern Foothills, Colville
North Sumatra	IIIBa	Indonesia		North Sumatra Basin
North Ustyurt	IIB	Kazakhstan		Ust-Urt
Northern North Sea	IIIA	Norway, United Kingdom		Viking Graben, North Sea Graben
Northwest Argentina	IIA	Argentina		Carandaitycretaceous Basin
Northwest German	IIB	Germany		Jura Trough, West Holstein
Olenek	I	Russia		
Ordos	IIA	China		Shanganning, Qinling Dabieshan Fold Belt
Oriente	IIA	Peru		Acre, Maranon, Upper Amazon
Otway	IIIC	Australia		
Ouachita Overthrust	IIA	United States	Ark.	
Palo Duro	IIA	United States	N. Mex.	Tucumcari
Pannonian	IIIBc	Bosnia and Herzegovina, Croatia, Hungary, Romania, Serbia		Backa Sub-basin (Pannonian Basin)
Paradox	IIB	United States	Utah	
Paris	IIB	France		Anglo-Paris Basin
Pearl River	IIIC	China		Dongsha Uplift (Pearl River Basin), Pearl River Mouth, South China Continental Slope
Pelagian	IICa	Tunisia, Libya		
Permian	IIA	United States	N. Mex., Tex.	Ouachita Fold Belt, Bend Arch, Delaware, Midland
Peten-Chiapas	IICc	Guatemala		Chapayal (South Peten) Basin, North Peten (Paso Caballos), Sierra De Chiapas-Peten, Yucatan Platform
Piceance	IIA	United States	Colo.	
Po	IICb	Italy		Crema Sub-Basin (Po Basin)
Polish	IIIA	Poland		Danish-Polish Marginal Trough, German-Polish

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Potiguar	IIIC	Brazil		Boa Vista Graben (Potiguar Basin), North-Northeastern Region
Potwar	IICb	Pakistan		Bannu Trough (Potwar Basin), Kohat-Potwar
Powder River	IIA	United States	Mont., Wyo.	
Pripyat	IIIA	Belarus		Pripyat Graben
Progreso	IIIBb	Ecuador		Guayaquil, Gulf Of Gayaquil, Jambeli Sub-basin of Progresso Basin, Santa Elena
Putumayo	IIA	Colombia, Ecuador		Napo, Cuenca Oriente Ecuatoriana
Rhine	IIIA	France, Germany		Upper Rhine Graben
Sacramento	IIIBb	United States	Calif.	Sacramento-San Joaquin
Salawati	IICa	Indonesia		Salawati Basin, Bintuni-Salawati
Salinas	IICc	Mexico		Isthmus Of Tehuantepec, Salinas Sub-basin, Isthmus Saline, Saline Comalcalco
San Joaquin	IIIBb	United States	Calif.	Sacramento-San Joaquin
San Jorge	IIIA	Argentina		Rio Mayo, San Jorge Basin
San Juan	IIB	United States	Ariz., Colo., N. Mex.	
Santa Maria	IIIBb	United States	Calif.	
Santos	IIIC	Brazil		
Sarawak	IICc	Malaysia		Central Luconia Platform
Sedgwick	IIA	United States	Kans.	Anadarko
Senegal	IIIC	Senegal		Bove-Senegal Basins
Sergipe-Alagoas	IIIC	Brazil		Sergipe-Alagoas Basin
Shumagin	V	United States	Alaska	
Sirte	IIIA	Libya		Agedabia Trough (Sirte Basin)
Songliao	IIIA	China		
South Adriatic	IICb	Italy		Adriatic, Marche-Abruzzi Basin (Pede-Apenninic Trough), Plio-Pleist Foredeep, Scaglia
South African	IIIC	South Africa		Agulhas Arch (South African Coastal Basin)
South Burma	IIIBb	Burma		Central Burma Basin, Irrawaddy
South Caspian	IIIBc	Azerbaidjan		South Caspian OGP (Apsheron-Kobystan Region), Emba, Guriy Region
South Oklahoma Folded Belt	IIA	United States	Okla., Tex.	Anadarko
South Palawan	IIIBa	Philippines		China Sea Platform, Palawan Shelf
South Sumatra	IIIBa	Indonesia		Central Palembang Depression (South Sumatra Basin)
South Texas Salt Dome	IICc	United States	Tex.	
South Yellow Sea	IIIA	China		Central Uplift (South Huanghai Basin), Subei Yellow Sea
Southern North Sea	IIB	United Kingdom		Central Graben (North Sea Graben system), Dutsh Bank Basin (East Shetland Platform), Witch Ground Graben
Sudan	IIIA	Sudan		Kosti Sub-Basin (Melut Basin), Muglad Basin, Sudd Basin
Sunda	IIIBa	Indonesia		
Surat	IIB	Australia		
Sverdrup	IICc	Canada	N.W.T.	Mellville
Taiwan	IIIBa	Taiwan		Taihsi Basin

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Talara	IIIBb	Peru		Talara Basin
Tampico	IICc	Mexico		Tampico-Tuxpan Embayment, Chicontepec, Tampico-Misantla
Tarakan	IIIBa	Indonesia		Bera Sub-basin (Tarakan Basin), Pamusian-Tarakan
Taranto	IICb	Italy		Abruzzi Zone (Apennine Range). Marche-Abruzzi Basin (Pede-Apenninic Trough), Latium, Calabrian
Tarfaya	IIIC	Morocco		Aaiun-Tarfaya
Tarim	IIIA	China		
Thrace	IIIBc	Turkey		Thrace-Gallipoli Basin, Zagros Fold Belt
Timan-Pechora	IIB	Russia		Belaya Depression (Ural Foredeep), Brykalan Depression, Pechora-Kozhva Mega-Arch, Varendey-Adz'va
Timimoun	IIB	Algeria		Sbaa
Tonga	IIIBa	Tonga		
Tunguska	I	Russia		Baykit Antecline
Turpan	IIIA	China		Tulufan
Tyrrhenian	IIIA	Italy		
Uinta	IIA	United States	Utah	
Upper Magdalena	IIIBc	Colombia		Upper Magdalena Basin
Ventura	IIIBb	United States	Calif.	Santa Barbara Channel
Veracruz	IIIC	Mexico		
Verkhoyansk	IIA	Russia		
Vienna	IIIBc	Austria, Slovakia		Bohemia
Vilyuy	IIA	Russia		
Volga-Ural	IIA	Russia		Aksubayevo-Nurlaty Structural Zone, Bashkir Arch, Belaya Depression, Melekess Basin, Tatar Arch, Vishnevo-Polyana Terrace
Washakie	IIA	United States	Wyo.	
West Java	IIIBa	Indonesia		Arjuna Sub-Basin (West Java Basin), Northwest Java
West of Shetlands	IIIC	United Kingdom		Faeroe, West of Shetland
West Siberia	IIB	Russia		West Siberia
Western Canada Sedimentary	IIA	Canada, United States	Alta., Mont., Sask.	Alberta, Western Canada Sedimentary, Sweetgrass Arch
Western Overthrust	IIA	United States	Ariz., Mont., Nev., Utah	Central Western Overthrust, Great Basin Province, Southwest Wyoming, South Western Overthrust
Williston	I	Canada, United States	N. Dak., Sask.	Sioux Uplift
Wind River	IIA	United States	Wyo.	
Yari	IIA	Colombia		Yari Basin
Yenisey-Khatanga	IIA	Russia		
Yukon-Kandik	IIIBb	United States	Alaska	Yukon-Koyukuk
Zagros	IICa	Iran, Iraq		Zagros Fold Beltzagros or Iranian Fold Belt, Sinjar Trough, Bozova-Mardin High, Euphrates/Mardin

Appendix 3. Klemme Basin Classificaton Figure from Plate 1

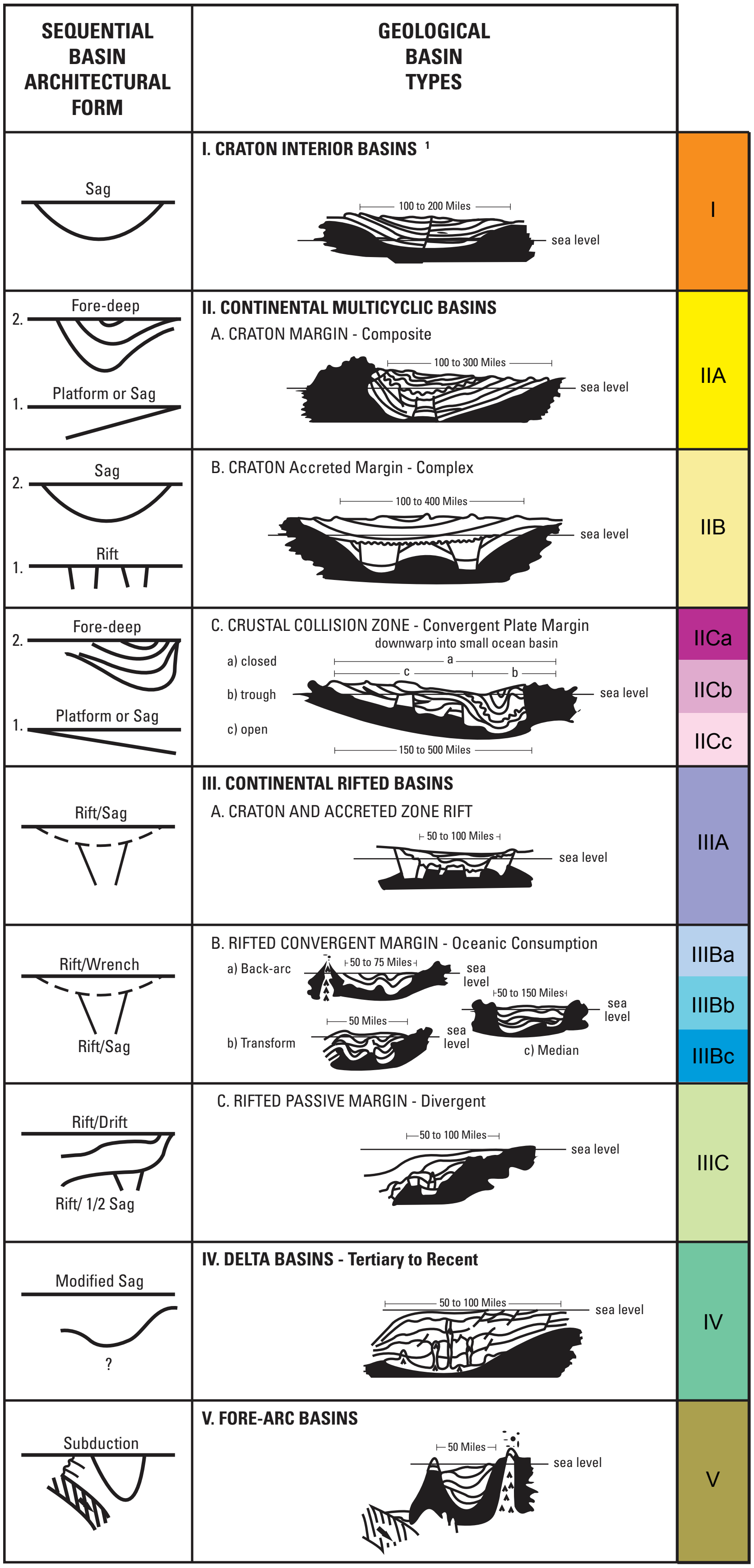

Figure 2-1. Diagram of Klemme basin types from plate 1. Modified from St. John, Bally, and Klemme (1984).

[1] Cincinati Arch is classified as I-Arch

Appendix 4. Tables from the Plates

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Arabian	IICa	842	842				
2	Eastern Venezuela	IICa	593	566	27.7	2,090	1,900	190
3	Maracaibo	IIIBc	322	322		169	169	
4	Campeche	IICc	293	293		0.060	0.060	
5	Bohai Gulf	IIIA	141	141		7.63	7.63	
6	Zagros	IICa	115	115				
7	Campos	IIIC	105	105				
8	West Siberia	IIB	88.4	88.4				
9	Tampico	IICc	65.3	65.3				
10	Western Canada Sedimentary	IIA	54.9	54.9		2,330	1,630	703
11	Timan-Pechora	IIB	54.9	54.9		22.0	22.0	
12	San Joaquin	IIIBb	53.9	53.9		< 0.01	< 0.01	
13	Putumayo	IIA	42.4	42.4		0.919	0.919	
14	Central Sumatra	IIIBa	40.6	40.6				
15	North Slope	IICc	37.0	37.0		19.0	19.0	
16	Niger Delta	IV	36.1	36.1				
17	Los Angeles	IIIBb	33.4	33.4		< 0.01	< 0.01	< 0.01
18	North Caspian	IICa	31.9	31.9		421	421	
19	Volga-Ural	IIA	26.1	26.1		263	263	
20	Ventura	IIIBb	25.2	25.2		0.505	0.505	
21	Gulf of Suez	IIIA	24.7	24.7		0.500	0.500	
22	Northern North Sea	IIIA	22.8	22.8		10.9	10.9	
23	Gulf Coast	IICc	19.7	19.7				
24	Salinas	IICc	16.6	16.6				
25	Middle Magdalena	IIIBc	16.4	16.4				
26	Pearl River	IIIC	15.7	15.7				
27	North Ustyurt	IIB	15.0	15.0				
28	Brunei-Sabah	IICc	14.7	14.7				
29	Diyarbakir	IICa	13.5	13.5				

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.—Continued

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
30	Northwest German	IIB	9.48	9.48				
31	Barinas-Apure	IIA	9.19	9.19		0.38	0.38	
32	North Caucasus-Mangyshlak	IICa	8.60	8.60		0.060	0.060	
33	Cambay	IIIA	8.28	8.28				
34	Santa Maria	IIIBb	8.06	8.06		2.03	2.02	< 0.01
35	Central Coastal	IIIBb	8.01	8.01		0.095	0.025	0.070
36	Big Horn	IIA	7.78	7.78				
37	Arkla	IICc	7.67	7.67				
38	Moesian	IICb	7.39	7.39				
39	Assam	IICb	6.16	6.16				
40	Oriente	IIA	5.92	5.92		0.250	0.250	
41	Molasse	IICb	5.79	5.79		0.010	0.010	
42	Doba	IIIA	5.35	5.35				
43	Morondava	IIIC	4.75	4.75		2.21	2.21	
44	Florida-Bahama	IIIC	4.75	4.75		0.48	0.48	
45	Southern North Sea	IIB	4.71	4.71				
46	Durres	IICb	4.70	4.70		0.37	0.37	
47	Caltanisetta	IICb	4.65	4.65		4.03	4.03	
48	Neuquen	IIB	4.56	4.56				
49	North Sakhalin	IIIBb	4.46	4.46		< 0.01	< 0.01	
50	Cabinda	IIIC	4.43	4.43		0.363	0.363	

Table 4-2. 33 natural bitumen basins ranked by volumes of total original natural bitumen in place (TONBIP). Table repeated from plate 3.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Western Canada Sedimentary	IIA	2,330	1,630	703
2	Eastern Venezuela	IICa	2,090	1,900	190
3	North Caspian	IICa	421	421	
4	Volga-Ural	IIA	263	263	
5	Maracaibo	IIIBc	169	169	
6	Tunguska	I	59.5	8.19	51.3
7	Ghana	IIIC	38.3	5.74	32.6
8	Timan-Pechora	IIB	22.0	22.0	
9	North Slope	IICc	19..0	19.0	
10	Uinta	IIA	11.7	7.08	4.58
11	Northern North Sea	IIIA	10.9	10.9	
12	South Caspian	IIIBc	8.84	8.84	
13	Bohai Gulf	IIIA	7.63	7.63	
14	Paradox	IIB	6.62	4.26	2.36
15	Black Warrior	IIA	6.36	1.76	
16	South Texas Salt Dome	IICc	4.88	3.87	1.01
17	Cuanza	IIIC	4.65	4.65	
18	Bone Gulf	IIIBa	4.46	4.46	
19	Caltanisetta	IICb	4.03	4.03	
20	Nemaha Anticline-Cherokee Basin	IIA	2.95	0.70	2.25
21	Morondava	IIIC	2.21	2.21	
22	Yenisey-Khatanga	IIA	2.21	2.21	
23	Santa Maria	IIIBb	2.03	2.02	<0.01
24	Junggar	IIIA	1.59	1.59	
25	Tarim	IIIA	1.25	1.25	
26	West of Shetlands	IIIC	1.00	1.00	
27	Putumayo	IIA	0.919	0.919	
28	Illinois	I	0.890	0.300	0.590
29	South Oklahoma Folded Belt	IIA	0.885	0.058	0.827
30	South Adriatic	IICb	0.510	0.510	
31	Ventura	IIIBb	0.505	0.505	
32	Gulf of Suez	IIIA	0.500	0.500	
33	Florida-Bahama	IIIC	0.477	0.477	