Chapter OP

ASSESSMENT OPERATIONAL PROCEDURES

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INTRODUCTION

Geologic, exploration-history, and production data were synthesized by assessment geologists to provide estimates of the number and sizes of undiscovered oil and gas fields in assessment units. Petroleum coproduct ratios for undiscovered fields, selected ancillary data, and resource allocations to countries and provinces and to the onshore/offshore areas of countries and provinces were also estimated. These initial estimates by the assessment geologist (assessor) were recorded on an input data form. The initial estimates were then reviewed and revised as deemed necessary by a panel of U.S. Geological Survey (USGS) geologists (Assessment Meeting Team) and the assessor during a formal assessment meeting. After review and upon reaching consensus on the estimates, undiscovered resources were calculated using these revised estimates. Figure OP-1 shows a flow diagram of the assessment procedure for the World Petroleum Assessment 2000.

INPUT DATA

Input data were recorded on the Seventh Approximation New Millennium World Petroleum Assessment Data Form for Conventional Assessment Units (described in chapter AM and shown as fig. OP-2) and include the following: identification information about the assessment unit; characteristics of the assessment unit; estimates of the number and sizes of undiscovered fields; estimates of the average coproduct ratios for undiscovered fields; selected ancillary data for undiscovered fields; and allocation of undiscovered resources to countries, other land parcels, and offshore areas.

Identification Information

Identification information includes the date of the assessment meeting; the assessor's name; and the names and codes of the region, province, total petroleum system (TPS), and assessment unit (AU). In addition, the growth function that was applied to the known field-size data and information regarding analogs used to aid the assessment, as well as other pertinent (but brief) information, were recorded as Notes from Assessor.

Characteristics of Assessment Unit

The input data for the Characteristics of the AU section classifies the AU and provides some historical data. The primary commodity type in the AU is based on the gas to oil ratio (GOR) of the petroleum endowment, which includes both the discovered and undiscovered petroleum. Like individual fields, an AU is characterized as being oil prone if the GOR is less than 20,000 cubic feet of gas per barrel of oil (CFG/BO); otherwise, it is gas prone.

The minimum field size, which relates in part to the forecast span of 30 years, was chosen for each AU. Resources in fields smaller than the minimum size are excluded from the assessment. The minimum field size was in no case less than 1 million barrels of oil equivalent (MMBOE) or greater than 20 MMBOE.

The most common minimum field size for a given AU was 1 MMBOE. Sometimes, a minimum undiscovered field size larger than 1 MMBOE was estimated to avoid accounting for large numbers of volumetrically insignificant fields, especially for AUs in which the record of discovered fields contained few small fields. The minimum gas-field size is the equivalent size used for oil fields where 1 barrel of oil equals 6,000 cubic feet of gas. In the 30-year forecast span, volumes of oil and gas from very small fields are unlikely to contribute significantly to the total undiscovered resources.

Assessment-unit maturity is classified as established if more than 13 fields exceeding minimum size have been discovered, frontier if 1 to 13 fields exceeding minimum size have been discovered, or hypothetical if no fields exceeding minimum size have been discovered. Established AUs have a sufficient number of discovered fields for historic field-level data to be of help in estimating properties of undiscovered fields.

At the other extreme, properties of undiscovered fields in hypothetical AUs, for which the TPS containing the AU has not been adequate for commercial petroleum production and for which no historic field-level data exist, must be estimated primarily on the basis of geologic analogs. Hypothetical AUs carry higher inherent assessment uncertainty than established and frontier AUs.

Discovery-history segments are the first-, second-, and third-thirds (or first- and second-halves) of the number of existing oil or gas fields in an AU ranked according to date of discovery (see chapter DS). The median field sizes of discovery-history segments are recorded for informational purposes on the input-data form. Changes of median field sizes of discovered fields through time are considered when estimating the sizes of undiscovered fields. This section may be left blank if data are not available, or if only one field constitutes the median for a given discovery segment (in order not to release proprietary database information).

Assessment-unit probabilities are estimated for each AU. All four risking elements (charge, rocks, timing, and accessibility (access)) are similar in application. They address the question of whether at least one field of minimum size, somewhere in the AU, has the potential to be added to reserves in the next 30 years. Each risk element thus applies to the AU as a whole, and does not equate to the percentage of the AU that might be unfavorable in terms of charge, rocks, timing, or access. Because of the large areas of the AUs and the constraints on minimum field size (from 1 to 20 MMBOE), most AUs, even hypothetical ones, had a virtual guarantee of at least one field of minimum size or larger.

The risking structure described in the previous paragraph is based on the assumption that AUs are reasonably homogeneous in terms of charge, rocks, and timing. For example, favorable charge should not occur only in the western half of an AU and favorable rocks only in the eastern half. Such a situation would suggest that the AU is too large and should be modified.

If nothing is known about a risking element at the assessment-unit level, the default probability of occurrence (P) should reflect a world-average probability. This default value is not necessarily P=0.50. Guidelines for assigning probability of occurrence to the risking elements of charge, rocks, timing, and access are given in table OP-1.

Undiscovered Fields

The number and grown sizes of undiscovered fields were recorded in the next section of the input-data form. Grown field sizes are defined as known field sizes that were adjusted upward to account for estimated future reserve growth (described in chapter DS). Three fractiles for the number and grown sizes of undiscovered oil fields and undiscovered gas fields were estimated for each AU. For some AUs in Canada, these estimates were made for pools rather than fields because of data availability. The three fractiles represent the minimum (F_{100}), median (F_{50}), and maximum (F_0) values of probability distributions. The particular type of probability distribution need not be specified in order to estimate these three fractiles.

Average Ratios for Undiscovered Fields, to Assess Coproducts

Coproduct ratios are required in order to assess the coproducts of gas and natural gas liquids (NGL) in oil fields and liquids (crude oil plus NGL) in gas fields. The gas to oil ratio (GOR) in undiscovered oil fields, NGL to gas ratio in undiscovered oil fields, and total liquids to gas ratio (LGR) in undiscovered gas fields were each estimated and recorded as three fractiles (F_{100}, F_{50}, and F_0) in recognition of the uncertainty inherent in estimating average properties of undiscovered fields. Oil to gas ratios in gas fields were not estimated in World Petroleum Assessment 2000.

The coproduct ratios are based on available field-level data for the AU or an analog area, and are projected for the undiscovered fields. If adequate data were not available, default coproduct ratios based on world averages were recorded (table OP-2).

Selected Ancillary Data for Undiscovered Fields

The input data recorded on the Seventh Approximation form (fig. OP-2) include a modest set of ancillary data useful for economic analyses of assessment results. These data do not contribute directly to undiscovered-resource calculations. The ancillary data for undiscovered oil fields include estimates of the API gravity of oil, sulfur content of oil, drilling depth (from rig to bit), and water depth, if offshore.

Natural gas, as defined in this assessment, is a mixture of hydrocarbon gases, mainly methane, and nonhydrocarbon gases such as carbon dioxide, hydrogen sulfide, and nitrogen. Estimated undiscovered gas volumes are for natural gas, as opposed to hydrocarbon gases. The ancillary data for undiscovered gas fields provide guidelines as to the percentages of these nonhydrocarbon gases. The ancillary data for undiscovered gas fields include estimates of the inert gas content, carbon dioxide content, and hydrogen sulfide content, as well as drilling depth and water depth, if offshore.

Estimates of ancillary data are based on available historical information but have been projected for the undiscovered fields in order to reflect changing exploration patterns. Ancillary data are recorded as three fractiles (F_{100}, F_{50}, and F_0) in recognition of the variation in these properties in an AU.

Allocation of Undiscovered Resources in the Assessment Unit to Countries or Other Land Parcels

Information necessary to allocate undiscovered resources in the AU to various countries or other land parcels, and their offshore portions, is recorded. The volume percent of assessed resources allocated to an entity does not necessarily match the areal percent of that entity.

Although the input-data form allows for allocation percentages to be entered as three fractiles (F_{100}, F_{50}, and F_0), this option was not used in the World Petroleum

Assessment 2000. Instead, volume percents were recorded as point estimates, to more easily satisfy the requirement that allocated resources must sum to the AU total.

QUANTIFICATION OF GEOLOGIC UNDERSTANDING

The transfer of geologic understanding into numbers for the Seventh Approximation form cannot be done and described in "cookbook" fashion. This section, then, cannot give a complete explanation of step-by-step thought processes that took place in the assessment. It does, however, address many of the considerations that repeatedly arose during discussions by the Assessment Meeting Team while coming to consensus about input values. The quantification of geologic understanding for purposes of developing a petroleum-resource assessment can follow many approaches (Charpentier and others, 1995).

Estimates of the number and sizes of undiscovered fields were obtained by a variety of methods. Typically, a combination of geologic knowledge of the AU, the analysis of exploration and discovery history, and the broad knowledge and experience of the assessor and the Assessment Meeting Team were used to make the final estimates.

The number of undiscovered fields in an AU is generally dependent on the geologic elements and fundamental processes of generation, migration, entrapment, and preservation of petroleum of the TPS, together with the exploration maturity of the AU. Where information was available, prospect counting and analysis of accumulation density were used to refine the estimates of the number of undiscovered fields. Where parts of the AU were unexplored or less explored, the reasons for exploration heterogeneity were examined. Exploration heterogeneity may result from not only poor exploration results, but also political and physical constraints on exploration, such as extreme water depths or large sand dunes. In addition, incomplete databases can give the impression of exploration heterogeneity.

Varying degrees of exploration of different stratigraphic horizons or different trap types within a single AU were also taken into consideration during the assessment process.

The sizes of undiscovered fields in an AU can be estimated using both geologic knowledge and trends observed in discovery-history segments. Distributions of both the number and sizes of undiscovered fields change through time as an AU is explored. The largest fields are generally found early in the exploration history. Unless a new exploration concept is developed, discovered field sizes tend to decrease through time. Large fields can be discovered later in the exploration history, however, if new areas are opened to exploration, or if new exploration concepts are developed. The possibility for new exploration trends, which would not be imbedded in the past discovery history, was considered by the Assessment Meeting Team.

In cases where an AU had little or no discovered-field information, other assessed areas that were assumed to be similar in terms of petroleum geology were used as partial analogs. No two AUs are exactly alike, but what is learned about the basic controls on petroleum occurrence in one area can be applied elsewhere. The use of analogs, explicit or implicit, is fundamental to the process of undiscovered resource assessment. The wide range of professional experience of the Assessment Meeting Team was an important factor in the selection of analogs.

ASSESSMENT MEETINGS

Seventh Approximation data forms completed by the assessor were reviewed in formal assessment meetings by the Assessment Meeting Team. The team was made up of senior petroleum geoscientists having years of experience, doctoral degrees, and specialization in various disciplines of geology, including sedimentology, structural geology and tectonism, geophysics, mathematical geology, paleontology, sedimentary petrology, and geochemistry. The Assessment Meeting Team reviewed the input data for each AU to maintain the accuracy and consistency of the assessment procedure.

The assessment meetings were conducted over a time period of more than one year. During this period, the core membership of the Assessment Meeting Team did not change. The in-depth discussions related to an AU commonly lasted for several hours. The team could rarely complete more than three or four AUs in one day. Assessment meetings were not superficial or complacent reviews of the input-data form.

At each assessment meeting, the assessor first presented a description of the AU geology, including regional setting, structural evolution, source-rock properties, and depositional history. Each of the estimates by the assessor on the initial input form was systematically addressed. As the meeting progressed, a digital version of the final input form was constructed. Commonly, revisions were made to the initial input data upon analysis of the geologic, exploration, and discovery-history data. Preliminary calculations of undiscovered resources were performed as part of the review process. Upon final consensus of the Assessment Methodology Team and the assessor, the digital input form was saved, printed, and initialed by each of the team members.

The assessment meetings were open to only USGS employees directly involved in the scheduled assessment. Persons from outside the USGS, including USGS-paid contractors, could not attend these meetings. These rather unusual steps were taken to ensure that the World Petroleum Assessment 2000 remained fair, honest, and objective. The assessment served no particular agenda, within or outside of government, and was not influenced by special interest groups.

CALCULATIONS OF UNDISCOVERED PETROLEUM RESOURCES

Undiscovered petroleum resources were calculated by a Monte Carlo simulation model from probability distributions based on the data recorded on the input form. The program that performs the simulation is called Emc2 and is described in chapter MC.

Probability Distributions

Triangular distributions, calculated from the input fractiles of F_{100}, F_{50}, and F_0, were used to represent the number of undiscovered fields and the coproduct ratios. A triangular distribution is uniquely determined by these fractiles and it is not necessary to specify a mode for the distribution. The number of undiscovered fields and the average coproduct ratios have distributions that represent the uncertainty of a single value and the triangular distributions show the assessor's uncertainty of that value. Triangular distributions allow moderate ranges of skewness. Skewness exceeding that allowed for triangular distributions was taken as an indication that the population was not sufficiently homogeneous. Mathematical checks were implemented to ensure that the median input value (F_{50}) was consistent with a triangular probability distribution.

Lognormal distributions were used to represent the sizes of undiscovered fields. Field-size distributions exhibit very high skewness that cannot be represented by triangular distributions. The lognormal distributions were calculated from the input fractiles of F_{100}, F_{50}, and F_0 with the maximum value used to truncate the lognormal distribution at the 0.1 percent fractile ($F_{0.1}$). The origins of the lognormal distributions were shifted along the horizontal (field-size) axis to the minimum field size. This modified distribution is called a shifted, truncated lognormal distribution. Shifting the lognormal distribution to the minimum field size rather than truncating the distribution at the minimum field size maintained the median undiscovered field size, as defined by the assessment geologist. Also, truncating these highly skewed distributions at the $F_{0.1}$ did not shift the median value appreciably.

The field-size distributions show not only the uncertainty of the value but also the range of values in the population of fields. The shifted, truncated lognormal distributions were extremely skewed in accordance with comparisons to analog field-size distributions of mature U.S. plays in which virtually all fields exceeding minimum size have been discovered.

Calculation Procedure

Monte Carlo simulation was used to calculate probability distributions for undiscovered oil, gas, and NGL volumes from the probability distributions that represent the geologically based assessment input parameters and the AU probabilities (MC). Input distributions were assumed to be independent of one another (correlation of zero).

At each iteration, a value for a number of undiscovered fields (n) was randomly selected from the number-of-fields distribution. Then, n random selections were taken from the undiscovered field-size distribution. The sizes of these n selections were added together to provide one value of a probability distribution for undiscovered oil or gas volume. Oil in oil fields was calculated separately from gas in gas fields. This procedure was repeated 50,000 times to provide the undiscovered-volume distributions (see chapter MC, fig.OP-1). Additionally, each of the 50,000 values of the undiscovered-volume distribution was multiplied by randomly selected values of the coproduct ratios (GOR, NGL to gas ratio, and LGR) to provide values for distributions of the volumes of total liquids in undiscovered gas fields, gas in undiscovered oil fields, and NGL in undiscovered oil fields.
The Monte Carlo method gave additional information about the largest undiscovered field. During the course of a simulation, the largest field size that was randomly selected in each iteration was used to generate a probability distribution

for the size of the largest undiscovered field. The mean of this distribution is reported in various tables on this multi-CD-ROM set as the expected largest undiscovered field size. The expected largest field size, which is smaller than the largest possible field size (F_0), is an assessment result of particular value to economic planning and risk evaluation.

Experiments were performed that compared the results of Monte Carlo simulations with those calculated using equations of distribution parameters. The experiments showed that, except for the case of very low numbers of undiscovered fields, the resultant distributions of both methods were similar and very close in shape to a lognormal distribution.

Probability distributions for undiscovered resource volumes were multiplied by point estimates for the various land-parcel percentages and offshore percentages to obtain allocated undiscovered resource volumes, such as undiscovered resources by country or province.

Undiscovered resource volumes were calculated, by Monte Carlo simulation, at the AU level. Aggregations of results to higher levels (TPS, province, and region) were done with the assumption of perfect positive dependency. In aggregating the eight region-level sets of estimates to the world level, a positive correlation of 0.5 was assumed. Allocation and aggregation procedures are described in chapter AA.

Undiscovered Field-Size Distributions

Binned undiscovered oil and gas frequency-size distributions show the expected (mean) number of undiscovered fields by size category (bin) for each AU. These distributions were generated to aid in the future construction of economic models. Undiscovered field size is based on quantity of the primary commodity assessed. Size categories are specified in millions of barrels of oil (MMBO) for oil fields and billions of cubic feet of gas (BCFG) for gas fields. Field-size classes were chosen to be consistent with previous USGS assessments of petroleum resources.

The frequency-size distributions were calculated using data from the Seventh Approximation input-data form. In particular, undiscovered field size is characterized by the shifted, truncated lognormal distribution, and the number of undiscovered fields (at least as large as the minimum size) is modeled with the triangular distribution. Field size and the number of undiscovered fields are assumed to be independent. Parameters of the shifted, truncated lognormal distribution for undiscovered fields were estimated using the F_{100}, F_{50}, and F_0 field sizes. The maximum field size was set equal to the upper tail truncation point at 0.999 probability.

Size-class probabilities were calculated using the estimated truncated, shifted lognormal distribution. The mean number of undiscovered fields was calculated from the triangular distribution and was risked by the geologic probability of the AU (that is, the product of the probabilities of the geologic attributes of charge, rocks, and timing). Of the 246 AUs that were quantitatively assessed, 31 AUs had at least one geologic attribute with probability of less than 1. Access probability was not used for this calculation, but only two of the 246 AUs had access probability less than one.

Expected frequency-size distributions at the AU level were combined into province-level distributions using the allocation percentages provided by the assessment geologist on the input-data form. The AU frequency-size distributions are mean values, so they may be arithmetically summed to compute the province-level expected frequency-size distribution.

Details of the calculations for undiscovered field-size distributions are provided in Appendix 1.

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APPENDIX 1

COMPUTATION OF THE FIELD-SIZE FREQUENCY DISTRIBUTIONS

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The field-size frequency distributions characterize the population of undiscovered fields (occurring in discrete accumulations) that contain the assessed oil and gas resources. Undiscovered field size is classified on the basis of the quantity of the primary commodity assessed. Oil fields have size categories specified in millions of barrels of oil (MMBO) and gas fields in billions of cubic feet of gas (BCFG). The field-size frequency distributions were calculated with assessment data from the Seventh Approximation data-input form, and used in the probabilistic model explained in this chapter and chapter AM.

The number of undiscovered fields, at least as large as the minimum size specified on the input form, is characterized by a triangular distribution. A properly selected combination of minimum, maximum, and median (50th fractile) numbers of undiscovered fields was estimated and recorded on the input form. These values uniquely define a mode (most likely value) for the triangular distribution. The expected or mean value for number of undiscovered fields depicted by the triangular distribution is computed as 1/3 the sum of the minimum, modal, and maximum values. The unconditional expected values shown in the histograms are computed as a product of the mean number of undiscovered fields calculated from the triangular distribution and the geologic probability (that is, the product of the probabilities of the geologic attributes of charge, reservoir, and timing). Of the 246 AUs quantitatively assessed, 31 AUs have at least one geologic attribute with probability of less than 1. In only two of the 246 AUs is the access probability less than 1.

The shifted, right-truncated lognormal distribution is used to model undiscovered field sizes, which are represented by the random variable *Y*. The density function for this distribution is given as

$$f_T(y) = \frac{1}{F(T)s_X\sqrt{2p}\,(y-g)}\exp\left[-\frac{1}{2}\left(\frac{\ln(y-g)-m_X}{s_X}\right)^2\right], \quad g \le y \le T$$

where *F(T)* is the cumulative probability evaluated at the truncation point. The random variable $X = ln(Y - g)$ is normally distributed. Following Johnson and Kotz (1970, p. 112-117), then $m_X = \ln(f50 - g)$, where *f*50 is the median of the field size distribution and $s_X = (\ln(f001 - g) - m_X)/F^{-1}(0.999)$, where *f*001 is the maximum size specified by the assessment geologist, the shift parameter, *g*, is the minimum field-size specified by the geologist, and $F^{-1}(0.999)$ is the inverse normal probability function. It is assumed that $1 - F^{-1}(f001) =$ 0.001. The mean and variance of the shifted truncated lognormally distributed random variable

Y can be obtained by numerical integration. Three values, namely *f*100, *f*50, and the maximum as *f*001, specify this distribution.

Size-class probabilities were calculated using the estimated parameters in the cumulative distribution function. The expected number of fields by size class was found by multiplying the (unconditional) mean estimate of the number of fields at least as large as the minimum size by each size class probability. All computations were carried out in double precision. The accuracy of the numerical integration algorithm was verified by comparing results of selected cases with results obtained using the Maple V (Waterloo Maple, 1998) mathematical analysis software package. Computations in Maple V are carried out in integer arithmetic, presumably minimizing round-off and truncation error.

Table OP-1. Guidelines for assigning probability of occurrence to the risking elements of charge, rocks, timing, and access. A lack of knowledge and data does not necessarily result in a default value of 0.50.

P=0.0	The element is so unfavorable that no chance whatsoever exists for a field.
P=0.10	The element is extremely unfavorable, but the chance that it is good enough for a field cannot be absolutely ruled out.
P=0.25	The element could be described in terms of "poor", or "unpromising"; in terms of exploration, the quality of the element leaves much to be desired.
P=0.50	The element is characterized by words such as "marginal", "barely adequate", or similar lukewarm terms.
P=0.75	The quality of the element is "decent", or "adequate"; however, a problem of some sort does exist.
P=0.90	The element is extremely favorable, but the chance for an unpleasant surprise cannot be completely ruled out.
P=1.0	The element is so favorable that, as far as this one element is concerned, a field is absolutely certain.

Table OP-2. Default values for coproduct ratios. Median values are arithmetic means calculated from ultimate recoverable volumes reported by Petroconsultants (1996). Minimum and maximum values are ±50 percent of the median value.

[NGL is natural gas liquids; CFG/BO is cubic feet of gas per barrel of oil; BNGL/MMCFG is barrels of NGL per million cubic feet of gas; BL/MMCFG is barrels of total liquids per million cubic feet of gas. Oil fields are defined as having a gas to oil ratio of less than 20,000 CFG/BO whereas gas fields contain 20,000 CFG/BO or greater. Ratios were calculated for individual fields and averaged. Gas to oil ratios were calculated only if both gas and oil volumes were reported. NGL to gas ratios were calculated only if both gas and NGL volumes were reported. Total liquids (NGL plus oil) to gas ratios were calculated if gas and either oil or NGL were reported. The median total liquids to gas ratio and NGL to gas ratio of this table may therefore reflect a volume of NGL that is greater than the norm, because liquid volumes may only be reported for those fields from which oil or NGL are produced.]

	Minimum	Median	Maximum
OIL FIELDS:			
Gas to Oil ratio (CFG/BO)	1,100	2,200	3,300
NGL to Gas Ratio (BNGL/MMCFG)	30	60	90
GAS FIELDS:			
(NGL + Oil) to Gas Ratio (BL/MMCFG)	22	44	66

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Assessment Procedure for World Petroleum Assessment 2000

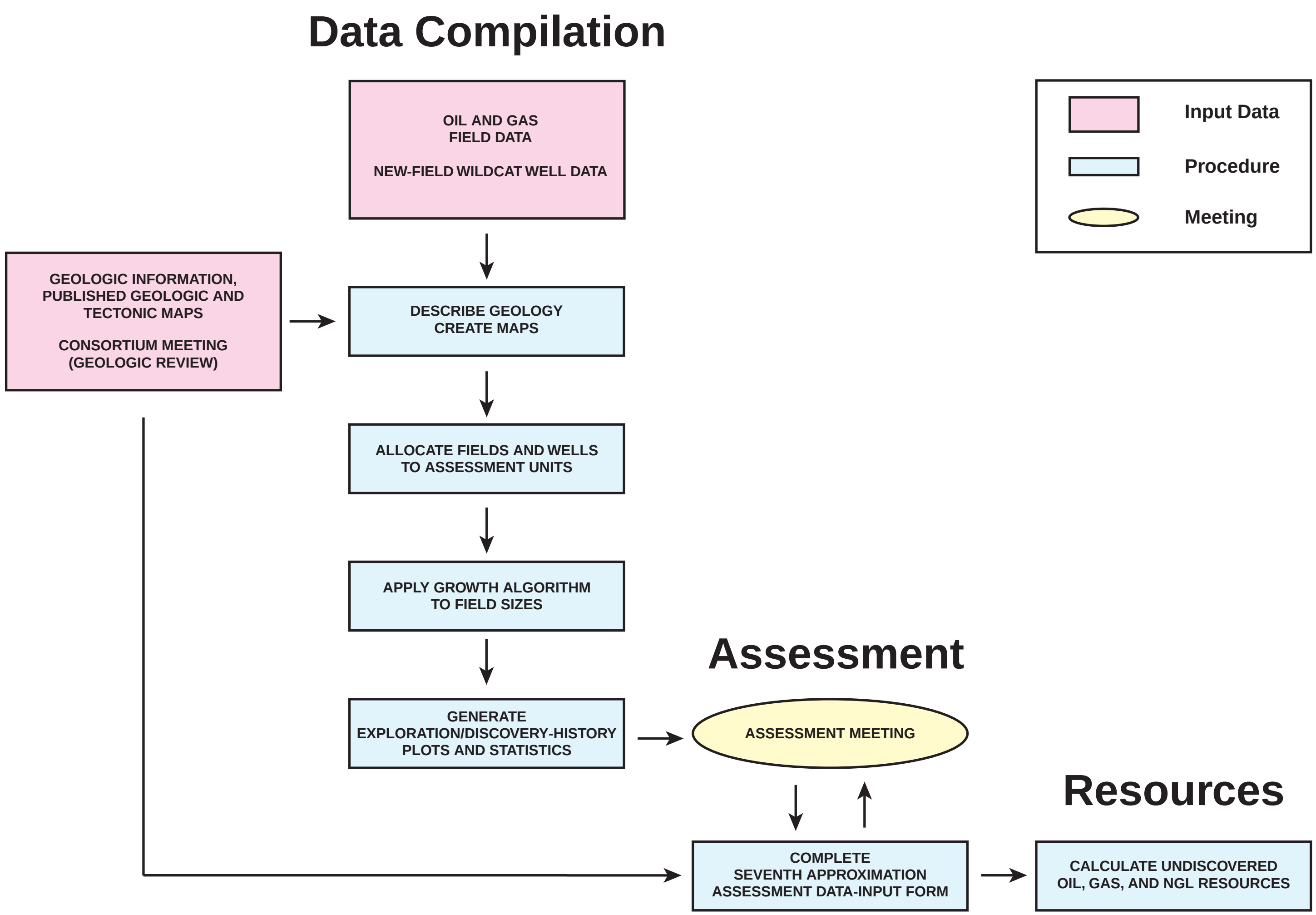

Figure OP-1. Simplified flow diagram of the assessment procedure.

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

SEVENTH APPROXIMATION
NEW MILLENNIUM WORLD PETROLEUM ASSESSMENT
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS

Date:………………………….. ______________________________
Assessment Geologist:…….. ______________________________
Region:……………………….. ______________________________ Number: ________
Province:……………………… ______________________________ Number: ________
Priority or Boutique………… ______________________________
Total Petroleum System:…… ______________________________ Number: ________
Assessment Unit:…………… ______________________________ Number: ________
* Notes from Assessor:……. ______________________________

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall):… ________

What is the minimum field size?………. ________ mmboe grown (≥1mmboe)
(the smallest field that has potential to be added to reserves in the next 30 years)

Number of discovered fields exceeding minimum size:………… Oil: ________ Gas: ________
Established (>13 fields) ________ Frontier (1-13 fields) ________ Hypothetical (no fields) ________

Median size (grown) of discovered oil fields (mmboe):
1st 3rd ________ 2nd 3rd ________ 3rd 3rd ________
Median size (grown) of discovered gas fields (bcfg):
1st 3rd ________ 2nd 3rd ________ 3rd 3rd ________

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered field ≥ minimum size………………	________
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered field ≥ minimum size……	________
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered field ≥ minimum size	________

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……..……....….. ________

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered field ≥ minimum size………………………………………………….…………………..………..……… ________

UNDISCOVERED FIELDS

Number of Undiscovered Fields: How many undiscovered fields exist that are ≥ minimum size?:
(uncertainty of fixed but unknown values)

Oil fields:………………………………… min. no. (>0) ________ median no. ________ max no. ________
Gas fields:……………………………… min. no. (>0) ________ median no. ________ max no. ________

Size of Undiscovered Fields: What are the anticipated sizes (**grown**) of the above fields?:
(variations in the sizes of undiscovered fields)

Oil in oil fields (mmbo)………………..…… min. size ________ median size ________ max. size ________
Gas in gas fields (bcfg):…………………… min. size ________ median size ________ max. size ________

Figure OP-2. Basic input-data form for the Seventh Approximation.

Assessment Unit (name, no.) ______________________________

AVERAGE RATIOS FOR UNDISCOVERED FIELDS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Fields:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………...………	______	______	______
NGL/gas ratio (bngl/mmcfg)……………………...….	______	______	______

Gas fields:	minimum	median	maximum
Liquids/gas ratio (bngl/mmcfg)……………….…….	______	______	______
Oil/gas ratio (bo/mmcfg)…………………………….	______	______	______

SELECTED ANCILLARY DATA FOR UNDISCOVERED FIELDS
(variations in the properties of undiscovered fields)

Oil Fields:	minimum	median	maximum
API gravity (degrees)…………………….…………	______	______	______
Sulfur content of oil (%)………………………..…..	______	______	______
Drilling Depth (m) ……………...………………….	______	______	______
Depth (m) of water (if applicable)……………..…..	______	______	______

Gas Fields:	minimum	median	maximum
Inert gas content (%)………………………....……	______	______	______
CO_2 content (%)……………………………….....…	______	______	______
Hydrogen-sulfide content (%)……………….……..	______	______	______
Drilling Depth (m)……………………………………	______	______	______
Depth (m) of water (if applicable)………………….	______	______	______

Figure 2. Continued. Basic input-data form for the Seventh Approximation.

Assessment Unit (name, no.) ______________________________

ALLOCATION OF UNDISCOVERED RESOURCES IN THE ASSESSMENT UNIT
TO COUNTRIES OR OTHER LAND PARCELS (uncertainty of fixed but unknown values)

1. ______________________________ represents ________ areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	________	________	________
Volume % in parcel (areal % x richness factor):…	________	________	________
Portion of volume % that is offshore (0-100%)……	________	________	________

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	________	________	________
Volume % in parcel (areal % x richness factor):…	________	________	________
Portion of volume % that is offshore (0-100%)……	________	________	________

2. ______________________________ represents ________ areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	________	________	________
Volume % in parcel (areal % x richness factor):…	________	________	________
Portion of volume % that is offshore (0-100%)……	________	________	________

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	________	________	________
Volume % in parcel (areal % x richness factor):…	________	________	________
Portion of volume % that is offshore (0-100%)……	________	________	________

3. ______________________________ represents ________ areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	________	________	________
Volume % in parcel (areal % x richness factor):…	________	________	________
Portion of volume % that is offshore (0-100%)……	________	________	________

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	________	________	________
Volume % in parcel (areal % x richness factor):…	________	________	________
Portion of volume % that is offshore (0-100%)……	________	________	________

Figure 2. Continued. Basic input-data form for the Seventh Approximation.