World Petroleum Council

Petroleum Resources Management System

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Petroleum Resources Management System

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

This document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information, and specific chapters are referenced herein. Appendix A is a consolidated glossary of terms used in resources evaluations and replaces those published in 2005.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

This SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, including its Appendix, may be referred to by the abbreviated term "SPE-PRMS" with the caveat that the full title, including clear recognition of the co-sponsoring organizations, has been initially stated.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

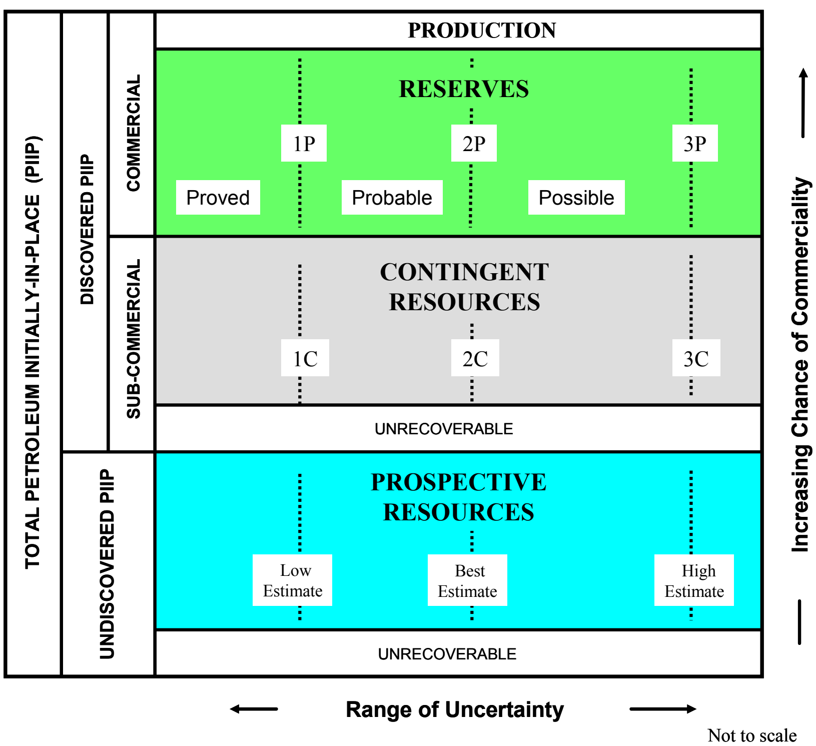

Figure 1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

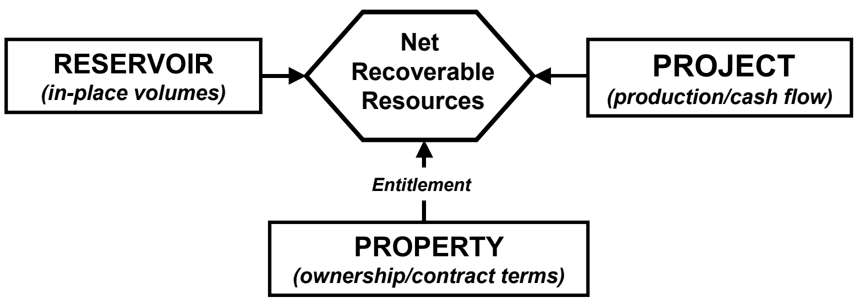

Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system as shown in Figure 1-1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality (the vertical axis) and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification vs. categorization varies with individual projects and is often an iterative analysis process leading to a final report. "Report," as used herein, refers to the presentation of evaluation results within the business entity conducting the assessment and should not be construed as replacing guidelines for public disclosures under guidelines established by regulatory and/or other government agencies.

Additional background information on resources classification issues can be found in Chapter 2 of the 2001 SPE/WPC/AAPG publication: "Guidelines for the Evaluation of Petroleum Reserves and Resources," hereafter referred to as the "2001 Supplemental Guidelines."

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.1.3 Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative).

As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

2.1.3.1 <u>Project Maturity Sub-Classes</u>

As illustrated in Figure 2-1, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

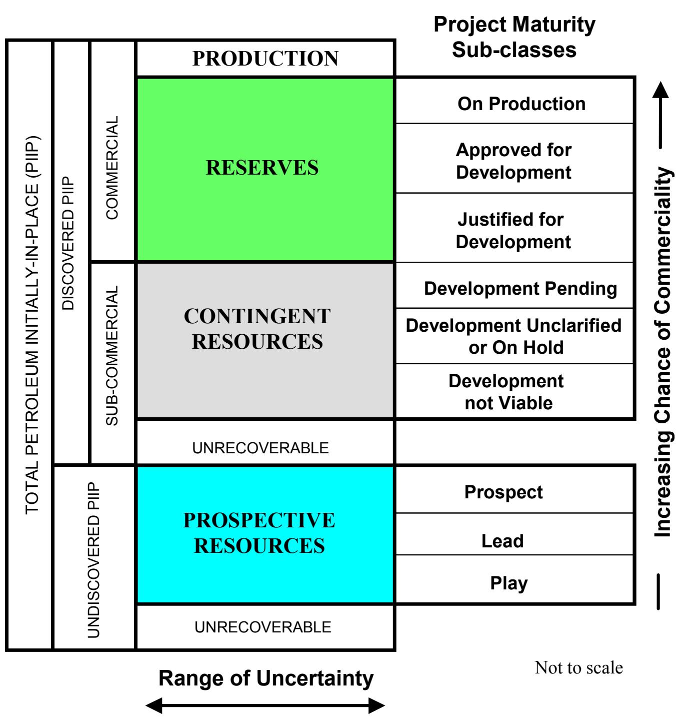

Figure 2-1: Sub-classes based on Project Maturity.

Project Maturity terminology and definitions have been modified from the example provided in the 2001 Supplemental Guidelines, Chapter 2. Detailed definitions and guidelines for each Project Maturity sub-class are provided in Table I. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as "decision gates."

Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies, that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling.

Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

2.1.3.2 Reserves Status

Once projects satisfy commercial risk criteria, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (detailed definitions and guidelines are provided in Table 2):

- Developed Reserves are expected quantities to be recovered from existing wells and facilities.
    - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
    - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.
- Undeveloped Reserves are quantities expected to be recovered through future investments**.**

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Determination of Commerciality, section 2.1.2) is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

2.1.3.3 Economic Status

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions (see Commercial Evaluations, section 3.1). Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is "undetermined." Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates (see also Reference Point, section 3.2.1). Those discovered in-place volumes for which a feasible development project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Table III presents category definitions and provides guidelines designed to promote consistency in resource assessments. The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

- Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

- Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

2.3 Incremental Projects

The initial resource assessment is based on application of a defined initial development project. Incremental projects are designed to increase recovery efficiency and/or to accelerate production through making changes to wells or facilities, infill drilling, or improved recovery. Such projects should be classified according to the same criteria as initial projects. Related incremental quantities are similarly categorized on certainty of recovery. The projected increased recovery can be included in estimated Reserves if the degree of commitment is such that the project will be developed and placed on production within a reasonable timeframe.

Circumstances where development will be significantly delayed should be clearly documented. If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources (see Determination of Commerciality, section 2.1.2).

2.3.1 Workovers, Treatments, and Changes of Equipment

Incremental recovery associated with future workover, treatment (including hydraulic fracturing), re-treatment, changes of equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed or Undeveloped Reserves depending on the magnitude of associated costs required (see Reserves Status, section 2.1.3.2).

2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in Reserves estimates. If the eventual installation of compression was planned and approved as part of the original development plan, incremental recovery is included in Undeveloped Reserves. However, if the cost to implement compression is not significant (relative to the cost of a new well), the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the spacing beyond that utilized within the initial development plan, subject to government regulations (if such approvals are required). Infill drilling may have the combined effect of increasing recovery efficiency and accelerating production. Only the incremental recovery can be considered as additional Reserves; this additional recovery may need to be reallocated to individual wells with different interest ownerships.

2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir performance. It includes waterflooding, secondary or tertiary recovery processes, and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified).

The judgment on commerciality is based on pilot testing within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

2.4 Unconventional Resources

Two types of petroleum resources have been defined that may require different approaches for their evaluations:

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.

3.0 Evaluation and Reporting Guidelines

The following guidelines are provided to promote consistency in project evaluations and reporting. "Reporting" refers to the presentation of evaluation results within the business entity conducting the evaluation and should not be construed as replacing guidelines for subsequent public disclosures under guidelines established by regulatory and/or other government agencies, or any current or future associated accounting standards.

3.1 Commercial Evaluations

Investment decisions are based on the entity's view of future commercial conditions that may impact the development feasibility (commitment to develop) and production/cash flow schedule of oil and gas projects. Commercial conditions include, but are not limited to, assumptions of financial conditions (costs, prices, fiscal terms, taxes), marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., historical costs, comparative market values); the guidelines herein apply only to evaluations based on cash flow analysis. Moreover, modifying factors such contractual or political risks that may additionally influence investment decisions are not addressed. (Additional detail on commercial issues can be found in the "2001 Supplemental Guidelines," Chapter 4.)

3.1.1 Cash-Flow-Based Resources Evaluations

Resources evaluations are based on estimates of future production and the associated cash flow schedules for each development project. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project. The calculation shall reflect:

- The expected quantities of production projected over identified time periods.
- The estimated costs associated with the project to develop, recover, and produce the quantities of production at its Reference Point (see section 3.2.1), including environmental, abandonment, and reclamation costs charged to the project, based on the evaluator's view of the costs expected to apply in future periods.
- The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods including that portion of the costs and revenues accruing to the entity.
- Future projected production and revenue related taxes and royalties expected to be paid by the entity.
- A project life that is limited to the period of entitlement or reasonable expectation thereof.
- The application of an appropriate discount rate that reasonably reflects the weighted average cost of capital or the minimum acceptable rate of return applicable to the entity at the time of the evaluation.

While each organization may define specific investment criteria, a project is generally considered to be "economic" if its "best estimate" case has a positive net present value under the organization's standard discount rate, or if at least has a positive undiscounted cash flow.

3.1.2 Economic Criteria

Evaluators must clearly identify the assumptions on commercial conditions utilized in the evaluation and must document the basis for these assumptions.

The economic evaluation underlying the investment decision is based on the entity's reasonable forecast of future conditions, including costs and prices, which will exist during the life of the project (forecast case). Such forecasts are based on projected changes to current conditions; SPE defines current conditions as the average of those existing during the previous 12 months.

Alternative economic scenarios are considered in the decision process and, in some cases, to supplement reporting requirements. Evaluators may examine a case in which current conditions are held constant (no inflation or deflation) throughout the project life (constant case).

Evaluations may be modified to accommodate criteria imposed by regulatory agencies regarding external disclosures. For example, these criteria may include a specific requirement that, if the recovery were confined to the technically Proved Reserves estimate, the constant case should still generate a positive cash flow. External reporting requirements may also specify alternative guidance on current conditions (for example, year-end costs and prices).

There may be circumstances in which the project meets criteria to be classified as Reserves using the forecast case but does not meet the external criteria for Proved Reserves. In these specific circumstances, the entity may record 2P and 3P estimates without separately recording Proved. As costs are incurred and development proceeds, the low estimate may eventually satisfy external requirements, and Proved Reserves can then be assigned.

While SPE guidelines do not require that project financing be confirmed prior to classifying projects as Reserves, this may be another external requirement. In many cases, loans are conditional upon the same criteria as above; that is, the project must be economic based on Proved Reserves only. In general, if there is not a reasonable expectation that loans or other forms of financing (e.g., farm-outs) can be arranged such that the development will be initiated within a reasonable timeframe, then the project should be classified as Contingent Resources. If financing is reasonably expected but not yet confirmed, the project may be classified as Reserves, but no Proved Reserves may be reported as above.

3.1.3 Economic Limit

Economic limit is defined as the production rate beyond which the net operating cash flows from a project, which may be an individual well, lease, or entire field, are negative, a point in time that defines the project's economic life. Operating costs should be based on the same type of projections as used in price forecasting. Operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those cash costs that will actually be eliminated if project production ceases should be considered in the calculation of economic limit). Operating costs should include fixed property-specific overhead charges if these are actual incremental costs attributable to the project and any production and property taxes but, for purposes of calculating economic limit, should exclude depreciation, abandonment and reclamation costs, and income tax, as well as any overhead above that required to operate the subject property itself. Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated non-hydrocarbons (see Associated Non-Hydrocarbon Components, section 3.2.4).

Interim negative project net cash flows may be accommodated in short periods of low product prices or major operational problems, provided that the longer-term forecasts must still indicate positive economics.

3.2 Production Measurement

In general, the marketable product, as measured according to delivery specifications at a defined Reference Point, provides the basis for production quantities and resources estimates. The following operational issues should be considered in defining and measuring production. While referenced specifically to Reserves, the same logic would be applied to projects forecast to develop Contingent and Prospective Resources conditional on discovery and development. (Additional detail on operational issues that impact resources estimation can be found in the "2001 Supplemental Guidelines," Chapter 3.)

3.2.1 Reference Point

Reference Point is a defined location(s) in the production chain where the produced quantities are measured or assessed. The Reference Point is typically the point of sale to third parties or where custody is transferred to the entity's downstream operations. Sales production and estimated Reserves are normally measured and reported in terms of quantities crossing this point over the period of interest.

The Reference Point may be defined by relevant accounting regulations in order to ensure that the Reference Point is the same for both the measurement of reported sales quantities and for the accounting treatment of sales revenues. This ensures that sales quantities are stated according to their delivery specifications at a defined price. In integrated projects, the appropriate price at the Reference Point may need to be determined using a netback calculation.

Sales quantities are equal to raw production less non-sales quantities, being those quantities produced at the wellhead but not available for sales at the Reference Point. Non-sales quantities include petroleum consumed as fuel, flared, or lost in processing, plus non-hydrocarbons that must be removed prior to sale; each of these may be allocated using separate Reference Points but when combined with sales, should sum to raw production. Sales quantities may need to be adjusted to exclude components added in processing but not derived from raw production. Raw production measurements are necessary and form the basis of engineering calculations (e.g., production performance analysis) based on total reservoir voidage.

3.2.2 Lease Fuel

Lease fuel is that portion of produced natural gas, crude oil, or condensate consumed as fuel in production and lease plant operations.

For consistency, lease fuel should be treated as shrinkage and is not included in sales quantities or resource estimates. However, some regulatory guidelines may allow lease fuel to be included in Reserves estimates where it replaces alternative sources of fuel and/or power that would be purchased in their absence. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense. Flared gas and oil and other losses are always treated as shrinkage and are not included in either product sales or Reserves.

3.2.3 Wet or Dry Natural Gas

The Reserves for wet or dry natural gas should be considered in the context of the specifications of the gas at the agreed Reference Point. Thus, for gas that is sold as wet gas, the volume of the wet gas would be reported, and there would be no associated or extracted hydrocarbon liquids reported separately. It would be expected that the corresponding enhanced value of the wet gas would be reflected in the sales price achieved for such gas.

When liquids are extracted from the gas prior to sale and the gas is sold in dry condition, then the dry gas volume and the extracted liquid volumes, whether condensate and/or natural gas liquids, should be accounted for separately in resource assessments. Any hydrocarbon liquids separated from the wet gas subsequent to the agreed Reference Point would not be reported as Reserves.

3.2.4 Associated Non-Hydrocarbon Components

In the event that non-hydrocarbon components are associated with production, the reported quantities should reflect the agreed specifications of the petroleum product at the Reference Point. Correspondingly, the accounts will reflect the value of the petroleum product at the Reference Point. If it is required to remove all or a portion of non-hydrocarbons prior to delivery, the Reserves and production should reflect only the residual hydrocarbon product.

Even if the associated non-hydrocarbon component (e.g., helium, sulfur) that is removed prior to the Reference Point is subsequently and separately marketed, these quantities are not included in petroleum production or Reserves. The revenue generated by the sale of non-hydrocarbon products may be included in the economic evaluation of a project.

3.2.5 Natural Gas Re-Injection

Natural gas production can be re-injected into a reservoir for a number of reasons and under a variety of conditions. It can be re-injected into the same reservoir or into other reservoirs located on the same property for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In such cases, assuming that the gas will eventually be produced and sold, the gas volume estimated as eventually recoverable can be included as Reserves.

If gas volumes are to be included as Reserves, they must meet the normal criteria laid down in the definitions including the existence of a viable development, transportation, and sales marketing plan. Gas volumes should be reduced for losses associated with the re-injection and subsequent recovery process. Gas volumes injected into a reservoir for gas disposal with no committed plan for recovery are not classified as Reserves. Gas volumes purchased for injection and later recovered are not classified as Reserves.

3.2.6 Underground Natural Gas Storage

Natural gas injected into a gas storage reservoir to be recovered at a later period (e.g., to meet peak market demand periods) should not be included as Reserves.

The gas placed in the storage reservoir may be purchased or may originate from prior production. It is important to distinguish injected gas from any remaining native recoverable volumes in the reservoir. On commencing gas production, its allocation between native gas and injected gas may be subject to local regulatory and accounting rulings. Native gas production would be drawn against the original field Reserves. The uncertainty with respect to original field volumes remains with the native reservoir gas and not the injected gas.

There may be occasions, such as gas acquired through a production payment, in which gas is transferred from one lease or field to another without a sale or custody transfer occurring. In such cases, the re-injected gas could be included with the native reservoir gas as Reserves. The same principles regarding separation of native resources from injected quantities would apply to underground oil storage.

3.2.7 Production Balancing

Reserves estimates must be adjusted for production withdrawals. This may be a complex accounting process when the allocation of production among project participants is not aligned with their entitlement to Reserves. Production overlift or underlift can occur in oil production records because of the necessity for participants to lift their production in parcel sizes or cargo volumes to suit available shipping schedules as agreed among the parties. Similarly, an imbalance in gas deliveries can result from the participants having different operating or marketing arrangements that prevent gas volumes sold from being equal to entitlement share within a given time period.

Based on production matching the internal accounts, annual production should generally be equal to the liftings actually made by the participant and not on the production entitlement for the year. However, actual production and entitlements must be reconciled in Reserves assessments. Resulting imbalances must be monitored over time and eventually resolved before project abandonment.

3.3 Resources Entitlement and Recognition

While assessments are conducted to establish estimates of the total Petroleum Initially-in-Place and that portion recovered by defined projects, the allocation of sales quantities, costs, and revenues impacts the project economics and commerciality. This allocation is governed by the applicable contracts between the mineral owners (lessors) and contractors (lessees) and is generally referred to as "entitlement." For publicly traded companies, securities regulators may set criteria regarding the classes and categories that can be "recognized" in external disclosures.

Entitlements must ensure that the recoverable resources claimed/reported by individual stakeholders sum to the total recoverable resources; that is, there are none missing or duplicated in the allocation process. (The "2001 Supplemental Guidelines," Chapter 9, addresses issues of Reserves recognition under production-sharing and non-traditional agreements.)

3.3.1 Royalty

Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs by the producer (lessee/contractor) having access to the petroleum resources.

Many agreements allow for the lessee/contractor to lift the royalty volumes and sell them on behalf of, and pay the proceeds to, the royalty owner/lessor. Some agreements provide for the royalty to be taken only in-kind by the royalty owner. In either case, royalty volumes must be deducted from the lessee's entitlement to resources. In some agreements, royalties owned by the host government are actually treated as taxes to be paid in cash. In such cases, the equivalent royalty volumes are controlled by the contractor who may (subject to regulatory guidance) elect to report these volumes as Reserves and/or Contingent Resources with appropriate offsets (increase in operating expense) to recognize the financial liability of the royalty obligation.

Conversely, if a company owns a royalty or equivalent interest of any type in a project, the related quantities can be included in Resources entitlements.

3.3.2 Production-Sharing Contract Reserves

Production-Sharing Contracts (PSCs) of various types replace conventional tax-royalty systems in many countries. Under the PSC terms, the producers have an entitlement to a portion of the production. This entitlement, often referred to as "net entitlement" or "net economic interest," is estimated using a formula based on the contract terms incorporating project costs (cost oil) and project profits (profit oil).

Although ownership of the production invariably remains with the government authority up to the export point of the project, the producers may take title to their share of the net entitlement at that point and may claim that share as their Reserves.

Risked-Service Contracts (RSCs) are similar to PSCs, but in this case, the producers are paid in cash rather than in production. As with PSCs, the Reserves claimed are based on the parties' net economic interest. Care needs to be taken to distinguish between an RSC and a "Pure Service Contract." Reserves can be claimed in an RSC on the basis that the producers are exposed to capital at risk, whereas no Reserves can be claimed for Pure Service Contracts because there are no market risks and the producers act as contractors.

Unlike traditional royalty-lease agreements, the cost recovery system in production-sharing, risk-service, and other related contracts typically reduce the production share and hence Reserves obtained by a contractor in periods of high price and increase volumes in periods of low price. While this ensures cost recovery, it introduces a significant price-related volatility in annual Reserves estimates under cases using "current" economic conditions. Under a defined "forecast conditions case," the future relationship of price to Reserves entitlement is known.

The treatment of taxes and the accounting procedures used can also have a significant impact on the Reserves recognized and production reported from these contracts.

3.3.3 Contract Extensions or Renewals

As production-sharing or other types of agreements approach maturity, they can be extended by negotiation for contract extensions, by the exercise of options to extend, or by other means.

Reserves should not be claimed for those volumes that will be produced beyond the ending date of the current agreement unless there is reasonable expectation that an extension, a renewal, or a new contract will be granted. Such reasonable expectation may be based on the historical treatment of similar agreements by the license-issuing jurisdiction. Otherwise, forecast production beyond the contract term should be classified as Contingent Resources with an associated reduced chance of commercialization. Moreover, it may not be reasonable to assume that the fiscal terms in a negotiated extension will be similar to existing terms.

Similar logic should be applied where gas sales agreements are required to ensure adequate markets. Reserves should not be claimed for those quantities that will be produced beyond those specified in the current agreement or reasonably forecast to be included in future agreements.

In either of the above cases, where the risk of cessation of rights to produce or inability to secure gas contracts is not considered significant, evaluators may choose to incorporate the uncertainty by categorizing quantities to be recovered beyond the current contract as Probable or Possible Reserves.

4.0 Estimating Recoverable Quantities

Assuming that projects have been classified according to their project maturity, the estimation of associated recoverable quantities under a defined project and their assignment to uncertainty categories may be based on one or a combination of analytical procedures. Such procedures may be applied using an incremental (risk-based) and/or scenario approach; moreover, the method of assessing relative uncertainty in these estimates of recoverable quantities may employ both deterministic and probabilistic methods.

4.1 Analytical Procedures

The analytical procedures for estimating recoverable quantities fall into three broad categories: (a) analogy, (b) volumetric estimates, and (c) performance-based estimates, which include material balance, production decline, and other production performance analyses. Reservoir simulation may be used in either volumetric or performance-based analyses. Pre- and early post-discovery assessments are typically made with analog field/project data and volumetric estimation. After production commences and production rates and pressure information become available, performance-based methods can be applied. Generally, the range of EUR estimates is expected to decrease as more information becomes available, but this is not always the case.

In each procedural method, results are not a single quantity of remaining recoverable petroleum, but rather a range that reflects the underlying uncertainties in both the in-place volumes and the recovery efficiency of the applied development project. By applying consistent guidelines (see Resources Categorization, section 2.2.), evaluators can define remaining recoverable quantities using either the incremental or cumulative scenario approach. The confidence in assessment results generally increases when the estimates are supported by more than one analytical procedure.

4.1.1 Analogs

Analogs are widely used in resources estimation, particularly in the exploration and early development stages, when direct measurement information is limited. The methodology is based on the assumption that the analogous reservoir is comparable to the subject reservoir regarding reservoir and fluid properties that control ultimate recovery of petroleum. By selecting appropriate analogs, where performance data based on comparable development plans (including well type, well spacing and stimulation) are available, a similar production profile may be forecast.

Analogous reservoirs are defined by features and characteristics including, but not limited to, approximate depth, pressure, temperature, reservoir drive mechanism, original fluid content, reservoir fluid gravity, reservoir size, gross thickness, pay thickness, net-to-gross ratio, lithology, heterogeneity, porosity, permeability, and development plan. Analogous reservoirs are formed by the same, or very similar, processes with regard to sedimentation, diagenesis, pressure, temperature, chemical and mechanical history, and structural deformation.

Comparison to several analogs may improve the range of uncertainty in estimated recoverable quantities from the subject reservoir. While reservoirs in the same geographic area and of the same age typically provide better analogs, such proximity alone may not be the primary consideration. In all cases, evaluators should document the similarities and differences between the analog and the subject reservoir/project. Review of analog reservoir performance is useful in quality assurance of resource assessments at all stages of development.

4.1.2 Volumetric Estimate

This procedure uses reservoir rock and fluid properties to calculate hydrocarbons in-place and then estimate that portion that will be recovered by a specific development project(s). Key uncertainties affecting in-place volumes include:

- Reservoir geometry and trap limits that impact gross rock volume.
- Geological characteristics that define pore volume and permeability distribution.
- Elevation of fluid contacts.
- Combinations of reservoir quality, fluid types, and contacts that control fluid saturations.

The gross rock volume of interest is that for the total reservoir. While spatial distribution and reservoir quality impact recovery efficiency, the calculation of in-place petroleum often uses average net-to-gross ratio, porosity, and fluid saturations. In more heterogeneous reservoirs, increased well density may be required to confidently assess and categorize resources.

Given estimates of the in-place petroleum, that portion that can be recovered by a defined set of wells and operating conditions must then be estimated based on analog field performance and/or simulation studies using available reservoir information. Key assumptions must be made regarding reservoir drive mechanisms.

The estimates of recoverable quantities must reflect uncertainties not only in the petroleum in-place but also in the recovery efficiency of the development project(s) applied to the specific reservoir being studied.

Additionally, geostatistical methods can be used to preserve spatial distribution information and incorporate it in subsequent reservoir simulation applications. Such processes may yield improved estimates of the range of recoverable quantities. Incorporation of seismic analyses typically improves the underlying reservoir models and yields more reliable resource estimates. [Refer to the "2001 SPE Supplemental Guidelines" for more detailed discussion of geostatistics (Chapter 7) and seismic applications (Chapter 8)].

4.1.3 Material Balance

Material balance methods to estimate recoverable quantities involve the analysis of pressure behavior as reservoir fluids are withdrawn. In ideal situations, such as depletion-drive gas reservoirs in homogeneous, high-permeability reservoir rocks and where sufficient and high quality pressure data is available, estimation based on material balance may provide very reliable estimates of ultimate recovery at various abandonment pressures. In complex situations, such as those involving water influx, compartmentalization, multiphase behavior, and multilayered or low-permeability reservoirs, material balance estimates alone may provide erroneous results. Evaluators should take care to accommodate the complexity of the reservoir and its pressure response to depletion in developing uncertainty profiles for the applied recovery project.

Computer reservoir modeling or reservoir simulation can be considered a sophisticated form of material balance analysis. While such modeling can be a reliable predictor of reservoir behavior under a defined development program, the reliability of input rock properties, reservoir geometry, relative permeability functions, and fluid properties are critical. Predictive models are most reliable in estimating recoverable quantities when there is sufficient production history to validate the model through history matching.

4.1.4 Production Performance Analysis

Analysis of the change in production rates and production fluids ratios vs. time and vs. cumulative production as reservoir fluids are withdrawn provides valuable information to predict ultimate recoverable quantities. In some cases, before decline in production rates is apparent, trends in performance indicators such as gas/oil ratio (GOR), water/oil ratio (WOR), condensate/gas ratio (CGR), and bottomhole or flowing pressures can be extrapolated to an economic limit condition to estimate reserves.

Reliable results require a sufficient period of stable operating conditions after wells in a reservoir have established drainage areas. In estimating recoverable quantities, evaluators must consider complicating factors affecting production performance behavior, such as variable reservoir and fluid properties, transient vs. stabilized flow, changes in operating conditions, interference effects, and depletion mechanisms. In early stages of depletion, there may be significant uncertainty in both the ultimate performance profile and the commercial factors that impact abandonment rate. Such uncertainties should be reflected in the resources categorization. For very mature reservoirs, the future production forecast may be sufficiently well defined that the remaining uncertainty in the technical profile is not significant; in such cases, the "best estimate" 2P scenario may also be used for the 1P and 3P production forecasts. However, there may still be commercial uncertainties that will impact the abandonment rate, and these should be accommodated in the resources categorization.

4.2 Deterministic and Probabilistic Methods

Regardless of the analytical procedure used, resource estimates may be prepared using either deterministic or probabilistic methods. A deterministic estimate is a single discrete scenario within a range of outcomes that could be derived by probabilistic analysis.

In the deterministic method, a discrete value or array of values for each parameter is selected based on the estimator's choice of the values that are most appropriate for the corresponding resource category. A single outcome of recoverable quantities is derived for each deterministic increment or scenario.

In the probabilistic method, the estimator defines a distribution representing the full range of possible values for each input parameter. These distributions may be randomly sampled (typically using Monte Carlo simulation software) to compute a full range and distribution of potential outcome of results of recoverable quantities (see "2001 Supplemental Guidelines," Chapter 5, for more detailed discussion of probabilistic reserves estimation procedures). This approach is most often applied to volumetric resource calculations in the early phases of an exploitation and development projects. The Resources Categorization guidelines include criteria that provide specific limits to parameters associated with each category. Moreover, the resource analysis must consider commercial uncertainties. Accordingly, when probabilistic methods are used, constraints on parameters may be required to ensure that results are not outside the range imposed by the category deterministic guidelines and commercial uncertainties.

Deterministic volumes are estimated for discrete increments and defined scenarios. While deterministic estimates may have broadly inferred confidence levels, they do not have associated quantitatively defined probabilities. Nevertheless, the ranges of the probability guidelines established for the probabilistic method (see Range of Uncertainty, section 2.2.1) influence the amount of uncertainty generally inferred in the estimate derived from the deterministic method.

Both deterministic and probabilistic methods may be used in combination to ensure that results of either method are reasonable.

4.2.1 Aggregation Methods

Oil and gas quantities are generally estimated and categorized according to certainty of recovery within individual reservoirs or portions of reservoirs; this is referred to as the "reservoir level" assessment. These estimates are summed to arrive at estimates for fields, properties, and projects. Further summation is applied to yield totals for areas, countries, and companies; these are generally referred to as "resource reporting levels." The uncertainty distribution of the individual estimates at each of these levels may differ widely, depending on the geological settings and the maturity of the resources. This cumulative summation process is generally referred to as "aggregation."

Two general methods of aggregation may be applied: arithmetic summation of estimates by category and statistical aggregation of uncertainty distributions. There is typically significant divergence in results from applying these alternative methods. In statistical aggregation, except in the rare situation when all the reservoirs being aggregated are totally dependent, the P90 (high degree of certainty) quantities from the aggregate are always greater than the arithmetic sum of the reservoir level P90 quantities, and the P10 (low degree of certainty) of the aggregate is always less than the arithmetic sum P10 quantities assessed at the reservoir level. This "portfolio effect" is the result of the central limit theorem in statistical analysis. Note that the mean (arithmetic average) of the sums is equal to the sum of the means; that is, there is no portfolio effect in aggregating mean values.

In practice, there is likely to be a large degree of dependence between reservoirs in the same field, and such dependencies must be incorporated in the probabilistic calculation. When dependency is present and not accounted for, probabilistic aggregation will overestimate the low estimate result and underestimate the high estimate result. (Aggregation of Reserves is discussed in Chapter 6 of the "2001 Supplemental Guidelines.")

The aggregation methods utilized depends on the business purpose. It is recommended that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. Results reporting beyond this level should use arithmetic summation by category but should caution that the aggregate Proved may be a very conservative estimate and aggregate 3P may be very optimistic depending on the number of items in the aggregate. Aggregates of 2P results typically have less portfolio effect that may not be significant in mature properties where the statistical median approaches the mean of the resulting distribution.

Various techniques are available to aggregate deterministic and/or probabilistic field, property, or project assessment results for detailed business unit or corporate portfolio analyses where the results incorporate the benefits of portfolio size and diversification. Again, aggregation should incorporate degree of dependency. Where the underlying analyses are available, comparison of arithmetic and statistical aggregation results may be valuable in assessing impact of the portfolio effect. Whether deterministic or probabilistic methods are used, care should be taken to avoid systematic bias in the estimation process.

It is recognized that the monetary value associated with these recoveries is dependent on the production and cash flow schedules for each project; thus, aggregate distributions of recoverable quantities may not be a direct indication of corresponding uncertainty distributions of aggregate value.

4.2.1.1 Aggregating Resources Classes

Petroleum quantities classified as Reserves, Contingent Resources, or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources and/ or Prospective Resources will not achieve commercial production.

Where the associated discovery and commerciality risks have been quantitatively defined, statistical techniques may be applied to incorporate individual project risk estimates in portfolio analysis of volume and value.

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Class/Sub-Class	**Definition**	**Guidelines**
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/Sub-Class	**Definition**	**Guidelines**
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Appendix A: Glossary of Terms Used in Resources Evaluations

Originally published in January 2005, the SPE/WPC/AAPG Glossary has herein been revised to align with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System document. The glossary provides high-level definitions of terms use in resource evaluations. Where appropriate, sections and/or chapters within the 2007 and/or 2001 documents are referenced to best show the use of selected terms in context.

TERM	Reference	DEFINITION
1C	2007 - 2.2.2	Denotes low estimate scenario of Contingent Resources.
2C	2007 - 2.2.2	Denotes best estimate scenario of Contingent Resources.
3C	2007 - 2.2.2	Denotes high estimate scenario of Contingent Resources.
1P	2007 - 2.2.2	Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves.
2P	2007 - 2.2.2	Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves.
3P	2007 - 2.2.2	Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves.
Accumulation	2001 - 2.3	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	2007 - 3.5.1 2001 - 6	The process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Approved for Development	2007 - Table I	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway.
Analogous Reservoir	2007 - 3.4.1	Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.
Assessment	2007 - 1.2	See Evaluation.
Associated Gas		Associated Gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Barrels of Oil Equivalent (BOE)	2001 - 3.7	See Crude Oil Equivalent.
Basin-Centered Gas	2007 - 2.4	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas saturated reservoirs and lack of a down-dip water leg.

Behind-Pipe Reserves	2007 - 2.1.3.1	Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Best Estimate	2007 - 2.2.2 2001 - 2.5	With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
Bitumen	2007 - 2.4	See Natural Bitumen.
Buy Back Agreement		An agreement between a host government and a contractor under which the host pays the contractor an agreed price for all volumes of hydrocarbons produced by the contractor. Pricing mechanisms typically provide the contractor with an opportunity to recover investment at an agreed level of profit.
Carried Interest	2001 - 9.6.7	A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a license in which both own a portion of the working interest.
Chance	2007 - 1.1	Chance is 1- Risk. (See Risk)
Coalbed Methane (CBM)	2007 - 2.4	Natural gas contained in coal deposits, whether or not stored in gaseous phase. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. (Also termed Coal Seam Gas, CSG, or Natural Gas from Coal, NGC)
Commercial	2007 - 2.1.2 and Table 1	When a project is commercial, this implies that the essential social, environmental and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.
Committed Project	2007 - 2.1.2 and Table 1	Projects are committed only when it can be demonstrated that there is a firm intention to develop them and bring them to production. Intention may be demonstrated with funding/financial plans and declaration of commerciality based on realistic expectations of regulatory approvals and reasonable satisfaction of other conditions that would otherwise prevent the project from being developed and brought to production.

Completion		Completion of a well. The process by which a well is brought to its final classification—basically dry hole, producer, injector, or monitor well. A dry hole is normally plugged and abandoned. A well deemed to be producible of petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir. Various methods are utilized to establish this connection, but they commonly involve the installation of some combination of borehole equipment, casing and tubing, and surface injection or production facilities.
Completion Interval		The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	2001 - 9.6.1	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an enterprise. The enterprise is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned.
Condensate	2001 - 3.2	Condensates are a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from natural gas liquids (NGL) on two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensate.
Conditions	2007 - 3.1	The economic, marketing, legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated (also termed Contingencies).
Constant Case	2007 - 3.1.1	Modifier applied to project resources estimates and associated cash flows when such estimates are based on those conditions (including costs and product prices) that are fixed at a defined point in time (or period average) and are applied unchanged throughout the project life, other than those permitted contractually. In other words, no inflation or deflation adjustments are made to costs or revenues over the evaluation period.
Contingency	2007 - 3.1 and Table 1	See Conditions.
Contingent Project	2007 - 2.1.2	Development and production of recoverable quantities has not been committed due to conditions that may or may not be fulfilled.
Contingent Resources	2007 - 1.1 and Table 1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.
Continuous-Type Deposit	2007 - 2.4 2001 - 2.3	A petroleum accumulation that is pervasive throughout a large area and which is not significantly affected by hydrodynamic influences. Such accumulations are included in Unconventional Resources. Examples of such deposits include "basin-centered" gas, shale gas, gas hydrates, natural bitumen and oil shale accumulations.

Conventional Crude Oil	2007 - 2.4	Crude oil flowing naturally or capable of being pumped without further processing or dilution (see Crude Oil).
Conventional Gas	2007 - 2.4	Conventional Gas is a natural gas occurring in a normal porous and permeable reservoir rock, either in the gaseous phase or dissolved in crude oil, and which technically can be produced by normal production practices.
Conventional Resources	2007 - 2.4	Conventional resources exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Conveyance	2001 - 9.6.9	Certain transactions that are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings and may not qualify for the recognition and reporting of oil and gas reserves.
Cost Recovery	2001 - 9.6.2, 9.7.2	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the gross production stream. The contractor normally receives payment in oil production and is exposed to both technical and market risks.
Crude Oil	2001 - 3.1	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Crude Oil Equivalent	2001 - 3.7	Converting gas volumes to the oil equivalent is customarily done on the basis of the nominal heating content or calorific value of the fuel. There are a number of methodologies in common use. Before aggregating, the gas volumes first must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1 barrel of oil equivalent (BOE) = 5,600 standard cubic feet (scf) of gas to 1 BOE = 6,000 scf. (Many operators use 1 BOE = 5,620 scf derived from the metric unit equivalent 1 m^3 crude oil = 1,000 m^3 natural gas). (Also termed Barrels of Oil Equivalent.)
Cumulative Production	2007 - 1.1	The sum of production of oil and gas to date (see also Production).
Current Economic Conditions	2007 - 3.1.1	Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve a defined averaging period. The SPE guidelines recommend that a 1-year historical average of costs and prices should be used as the default basis of "constant case" resources estimates and associated project cash flows.
Cushion Gas Volume		With respect to underground natural gas storage, Cushion Gas Volume (CGV) is the gas volume required in a storage field for reservoir management purposes and to maintain adequate minimum storage pressure for meeting working gas volume delivery with the required withdrawal profile. In caverns, the cushion gas volume is also required for stability reasons. The cushion gas volume may consist of recoverable and non-recoverable in-situ gas volumes and injected gas volumes.
Deposit	2007 - 2.4	Material laid down by a natural process. In resource evaluations, it identifies an accumulation of hydrocarbons in a reservoir (see Accumulation).

Deterministic Estimate	2007 - 3.5	The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data.
Developed Reserves	2007 - 2.1.3.2 and Table 2	Developed Reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered "developed" only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	2007 - 2.1.3.2 and Table 2	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	2007 - 2.1.3.2 and Table 2	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are also those expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Development Not Viable	2007 - 2.1.3.1 and Table 1	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. A project maturity sub-class that reflects the actions required to move a project towards commercial production.
Development Pending	2007 - 2.1.3.1 and Table 1	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class that reflects the actions required to move a project towards commercial production.
Development Plan	2007 - 1.2	The design specifications, timing and cost estimates of the development project including, but not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation and marketing. (See also Project.)
Development Unclarified or On Hold	2007 - 2.1.3.1 and Table 1	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Discovered	2007 - 2.1.1	A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. (See also Known Accumulations.)

Discovered Petroleum Initially-in-Place	2007 - 1.1	Discovered Petroleum Initially-in-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered Petroleum Initially-in-Place may be subdivided into Commercial, Sub-Commercial, and Unrecoverable, with the estimated commercially recoverable portion being classified as Reserves and the estimated sub-commercial recoverable portion being classified as Contingent Resources.
Dry Gas	2001 - 3.2	Dry Gas is a natural gas remaining after hydrocarbon liquids have been removed prior to the reference point. The dry gas and removed hydrocarbon liquids are accounted for separately in resource assessments. It should be recognized that this is a resource assessment definition and not a phase behavior definition. (Also called Lean Gas.)
Dry Hole	2001 - 2.5	A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Economic	2007 - 3.1.2 2001 - 4.3	In relation to petroleum Reserves and Resources, economic refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation.
Economic Interest	2001 - 9.4.1	An Economic Interest is possessed in every case in which an investor has acquired any Interest in mineral in place and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return of his capital.
Economic Limit	2007 - 3.1.2 2001 - 4.3	Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative.
Entitlement	2007 - 3.3	That portion of future production (and thus resources) legally accruing to a lessee or contractor under the terms of the development and production contract with a lessor.
Entity	2007 - 3.0	Entity is a legal construct capable of bearing legal rights and obligations. In resources evaluations this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Estimated Ultimate Recovery (EUR)	2007 - 1.1	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.
Evaluation	2007- 3.0	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. Projects are classified and estimates of derived quantities are categorized according to applicable guidelines. (Also termed Assessment.)

Evaluator	2007 - 1.2, 2.1.2	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including Reserves and Resources and attributed value estimates.
Exploration		Prospecting for undiscovered petroleum.
Field	2001 - 2.3	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities.
Flare Gas	2007 - 3.2.2 2001 - 3.1	Total volume of gas vented or burned as part of production and processing operations.
Flow Test	2007 - 2.1.1	An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test).
Fluid Contacts	2007 - 2.2.2	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	2007 - 3.1.1	Modifier applied to project resources estimates and associated cash flow when such estimates are based on those conditions (including costs and product price schedules) forecast by the evaluator to reasonably exist throughout the life of the project. Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Forward Sales	2001 - 9.6.6	There are a variety of forms of transactions that involve the advance of funds to the owner of an interest in an oil and gas property in exchange for the right to receive the cash proceeds of production, or the production itself, arising from the future operation of the property. In such transactions, the owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Determination as to whether the transaction represents a sale or financing rests on the particular circumstances of each case.
Fuel Gas	2007 - 3.2.2	See Lease Fuel.
Gas Balance	2007 - 3.2.7 2001 - 3.10	In gas production operations involving multiple working interest owners, an imbalance in gas deliveries can occur. These imbalances must be monitored over time and eventually balanced in accordance with accepted accounting procedures.

Gas Cap Gas	2001 - 6.2.2	Gas Cap Gas is a free natural gas which overlies and is in contact with crude oil in the reservoir. It is a subset of Associated Gas.
Gas Hydrates	2007 - 2.4	Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure, or clathrate. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Because of this large gas-storage capacity, gas hydrates are thought to represent an important future source of natural gas. Gas hydrates are included in unconventional resources, but the technology to support commercial production has yet to be developed.
Gas Inventory		With respect to underground natural gas storage, "gas inventory" is the sum of Working Gas Volume and Cushion Gas Volume.
Gas/Oil Ratio	2007 - 3.4.4	Gas to oil ratio in an oil field, calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil , symbol R_s; produced gas/oil ratio, symbol R_p; or another suitably defined ratio of gas production to oil production.
Gas Plant Products		Gas Plant Products are natural gas liquids (or components) recovered from natural gas in gas processing plants and, in some situations, from field facilities. Gas Plant Products include ethane, propane, butanes, butanes/propane mixtures, natural gasoline and plant condensates, sulfur, carbon dioxide, nitrogen, and helium.
Gas-to-Liquids (GTL) Projects		Gas-to-Liquids projects use specialized processing (e.g., Fischer-Tropsch synthesis) to convert natural gas into liquid petroleum products. Typically, these projects are applied to large gas accumulations where lack of adequate infrastructure or local markets would make conventional natural gas development projects uneconomic.
Geostatistical Methods	2001 - 7.1	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of masses of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates, including the definition of (all) well and reservoir parameters in 1, 2, and 3 dimensions and the resultant modeling and potential prediction of various aspects of performance.
High Estimate	2007 - 2.2.2 2001 - 2.5	With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrocarbons	2007 - 1.1	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon.

Improved Recovery (IR)	2007 - 2.3.4	Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.)
Injection	2001 - 3.5 2007 - 3.2.5	The forcing, pumping, or free flow under vacuum, of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
Justified for Development	2007 - 2.1.3.1 and Table 1	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Kerogen		The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	2007 - 2.1.1 2001 - 2.2	An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as "known," and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons.
Lead	2007 - 2.1.3.1 and Table 1	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Lease Condensate		Lease Condensate is condensate recovered from produced natural gas in gas/liquid separators or field facilities.
Lease Fuel	2007 - 3.2.2	Oil and/or gas used for field and processing plant operations. For consistency, quantities consumed as lease fuel should be treated as shrinkage. However, regulatory guidelines may allow lease fuel to be included in Reserves estimates. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense.
Lease Plant		A general term referring to processing facilities that are dedicated to one or more development projects and the petroleum is processed without prior custody transfer from the owners of the extraction project (for gas projects, also termed "Local Gas Plant").
Liquefied Natural Gas (LNG) Project		Liquefied Natural Gas projects use specialized cryogenic processing to convert natural gas into liquid form for tanker transport. LNG is about 1/614 the volume of natural gas at standard temperature and pressure.
Loan Agreement	2001 - 9.6.5	A loan agreement is typically used by a bank, other investor, or partner to finance all or part of an oil and gas project. Compensation for funds advanced is limited to a specified interest rate.

Low/Best/High Estimates	2007 - 2.2.1, 2.2.2	The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project.
Low Estimate	2007 - 2.2.2 2001 - 2.5	With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons	2007 - 2.2.2.	The deepest occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, or core data.
Marginal Contingent Resources	2007 - 2.1.3.3	Known (discovered) accumulations for which a development project(s) has been evaluated as economic or reasonably expected to become economic but commitment is withheld because of one or more contingencies (e.g., lack of market and/or infrastructure).
Measurement	2007 - 3.0	The process of establishing quantity (volume or mass) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Interest	2001 - 9.3	Mineral Interests in properties including (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	2001 - 5 2007 - 3.5	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum volumes).
Natural Bitumen	2007 - 2.4	Natural Bitumen is the portion of petroleum that exists in the semisolid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Natural Bitumen has a viscosity greater than 10,000 milliPascals per second (mPa.s) (or centipoises) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural Bitumen generally requires upgrading prior to normal refining. (Also called Crude Bitumen.)
Natural Gas	2007 - 3.2.3 2001 - 6.6, 9.4.4	Natural Gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include some amount of non-hydrocarbons.

Natural Gas Inventory		With respect to underground natural gas storage operations "inventory" is the total of working and cushion gas volumes.
Natural Gas Liquids	2007 - A13 2001 - 3.2, 9.4.4	Natural Gas Liquids (NGL) are a mixture of light hydrocarbons that exist in the gaseous phase and are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensates.
Natural Gas Liquids to Gas Ratio		Natural gas liquids to gas ratio in an oil or gas field, calculated using measured natural gas liquids and gas volumes at stated conditions.
Net-Back	2007 - 3.2.1	Linkage of input resource to the market price of the refined products.
Net Profits Interest	2001 - 9.4.4	An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid.
Net Working Interest	2001 - 9.6.1	A company's working interest reduced by royalties or share of production owing to others under applicable lease and fiscal terms. (Also called Net Revenue Interest.)
Non-Hydrocarbon Gas	2007 - 3.2.4 2001 - 3.3	Natural occurring associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium. If non-hydrocarbon gases are present, the reported volumes should reflect the condition of the gas at the point of sale. Correspondingly, the accounts will reflect the value of the gas product at the point of sale.
Non-Associated Gas		Non-Associated Gas is a natural gas found in a natural reservoir that does not contain crude oil.
Normal Production Practices		Production practices that involve flow of fluids through wells to surface facilities that involve only physical separation of fluids and, if necessary, solids. Wells can be stimulated, using techniques including, but not limited to, hydraulic fracturing, acidization, various other chemical treatments, and thermal methods, and they can be artificially lifted (e.g., with pumps or gas lift). Transportation methods can include mixing with diluents to enable flow, as well as conventional methods of compression or pumping. Practices that involve chemical reforming of molecules of the produced fluids are considered manufacturing processes.
Oil Sands		Sand deposits highly saturated with natural bitumen. Also called "Tar Sands." Note that in deposits such as the western Canada "oil sands," significant quantities of natural bitumen may be hosted in a range of lithologies including siltstones and carbonates.
Oil Shales	2007 - 2.4	Shale, siltstone and marl deposits highly saturated with kerogen. Whether extracted by mining or in situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil).
Offset Well Location		Potential drill location adjacent to an existing well. The offset distance may be governed by well spacing regulations. In the absence of well spacing regulations, technical analysis of drainage areas may be used to define the spacing. For Proved volumes to be assigned to an offset well location there must be conclusive, unambiguous technical data which supports the reasonable certainty of production of hydrocarbon volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the lowest known hydrocarbon.

On Production	2007 - 2.1.3.1 and Table 1	The development project is currently producing and selling petroleum to market. A project status/maturity sub-class that reflects the actions required to move a project toward commercial production.
Operator		The company or individual responsible for managing an exploration, development, or production operation.
Overlift/Underlift	2007 - 3.2.7 2001 - 3.9	Production overlift or underlift can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed among the parties. At any given financial year-end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year, and not on the production entitlement for the year.
Penetration	2007 - 1.2	The intersection of a wellbore with a reservoir.
Petroleum	2007 - 1.0	Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.
Petroleum Initially-in-Place	2007 - 1.1	Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-place, Natural Gas-in-place and Natural Bitumen-in-place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment.)
Pilot Project	2007 - 2.3.4, 2.4	A small-scale test or trial operation that is used to assess the suitability of a method for commercial application.
Play	2007 - 2.1.3.1 and Table 1	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Pool		An individual and separate accumulation of petroleum in a reservoir.
Possible Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery		Primary recovery is the extraction of petroleum from reservoirs utilizing only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	2007 - 2.2.1	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. SPE convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)

Probabilistic Estimate	2007 - 3.5	The method of estimation of Resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	2007 - 1.1	Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and non-sales, including non-hydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations.
Production-Sharing Contract	2007 - 3.3.2 2001 - 9.6.2	In a production-sharing contract between a contractor and a host government, the contractor typically bears all risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced.
Profit Split	2001 - 9.6.2	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor is entitled to a share of the remaining profit oil or gas. The contractor receives payment in oil or gas production and is exposed to both technical and market risks.
Project	2007 - 1.2 2001 - 2.3	Represents the link between the petroleum accumulation and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	2007 - 1.2 2001 - 9.4	A volume of the Earth's crust wherein a corporate entity or individual has contractual rights to extract, process, and market a defined portion of specified in-place minerals (including petroleum). Defined in general as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prorationing		The allocation of production among reservoirs and wells or allocation of pipeline capacity among shippers, etc.
Prospect	2007 - 2.1.3.1 and Table 1	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class that reflects the actions required to move a project toward commercial production.

Prospective Resources	2007 - 1.1 and Table 1	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Proved Economic	2007 - 3.1.1	In many cases, external regulatory reporting and/or financing requires that, even if only the Proved Reserves estimate for the project is actually recovered, the project will still meet minimum economic criteria; the project is then termed as "Proved Economic."
Proved Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven."
Purchase Contracts	2001 - 9.6.8	A contract to purchase oil and gas provides the right to purchase a specified volume of production at an agreed price for a defined term.
Pure-Service Contract	2001 - 9.7.5	A pure-service contract is an agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific period of time. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the terms of the contract with little exposure to either project performance or market factors.
Range of Uncertainty	2007 - 2.2 2001 - 2.5	The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. (See Resource Uncertainty Categories.)
Raw Natural Gas	2007 - 3.2.1	Raw Natural Gas is natural gas as it is produced from the reservoir. It includes water vapor and varying amounts of the heavier hydrocarbons that may liquefy in lease facilities or gas plants and may also contain sulfur compounds such as hydrogen sulfide and other non-hydrocarbon gases such as carbon dioxide, nitrogen, or helium, but which, nevertheless, is exploitable for its hydrocarbon content. Raw Natural Gas is often not suitable for direct utilization by most types of consumers.
Reasonable Certainty	2007 - 2.2.2	If deterministic methods for estimating recoverable resource quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered.
Reasonable Expectation	2007 - 2.1.2	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur.
Reasonable Forecast	2007 - 3.1.2	Indicates a high degree of confidence in predictions of future events and commercial conditions. The basis of such forecasts includes, but is not limited to, analysis of historical records and published global economic models.
Recoverable Resources	2007 - 1.2	Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations.

Recovery Efficiency	2007 - 2.2	A numeric expression of that portion of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage.
Reference Point	2007 - 3.2.1	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions prior to custody transfer (or consumption). Also called Point of Sale or Custody Transfer Point.
Reserves	2007 - 1.1	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	2001 - 2.3	A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system.
Resources	2007 - 1.1	The term “resources” as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional” (see Total Petroleum Initially-in-Place). (In basin potential studies, it may be referred to as Total Resource Base or Hydrocarbon Endowment.)
Resources Categories	2007 - 2.2 and Table 3	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes)
Resources Classes	2007 - 1.1, 2.1 and Table 1	Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project’s estimated chance of reaching producing status.
Revenue-Sharing Contract	2001 - 9.6.3	Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor payment. With these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Reversionary Interest		The right of future possession of an interest in a property when a specified condition has been met.
Risk	2001 - 2.5	The probability of loss or failure. As “risk” is generally associated with the negative outcome, the term “chance” is preferred for general usage to describe the probability of a discrete event occurring.

Risk and Reward	2001 - 9.4	Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues due to technical and economic risks. Technical risk affects a company's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risked-Service Contract	2007 - 3.3.2 2001 - 9.7.4	These agreements are very similar to the production-sharing agreements with the exception of contractor payment, but risk is borne by the contractor. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	2007 - 3.3.1 2001 - 3.8	Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner.
Sales	2007 - 3.2	The quantity of petroleum product delivered at the custody transfer (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities. All recoverable resources are estimated in terms of the product sales quantity measurements.
Shut-in Reserves	2007 - 2.1.3.2 and Table 2	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing; (2) wells which were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons.
Solution Gas		Solution Gas is a natural gas which is dissolved in crude oil in the reservoir at the prevailing reservoir conditions of pressure and temperature. It is a subset of Associated Gas.
Sour Natural Gas	2001 - 3.4	Sour Natural Gas is a natural gas that contains sulfur, sulfur compounds, and/or carbon dioxide in quantities that may require removal for sales or effective use.
Stochastic	2001 - 5	Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation.
Sub-Commercial	2007 - 2.1.2	A project is Sub-Commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. Discovered sub-commercial projects are classified as Contingent Resources.
Sub-Marginal Contingent Resources	2007 - 2.1.3.3	Known (discovered) accumulations for which evaluation of development project(s) indicated they would not meet economic criteria, even considering reasonably expected improvements in conditions.
Sweet Natural Gas	2001 - 3.3	Sweet Natural Gas is a natural gas that contains no sulfur or sulfur compounds at all, or in such small quantities that no processing is necessary for their removal in order that the gas may be sold.

Synthetic Crude Oil (SCO)	2001 - A12, A13	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. SCO may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
Taxes	2001 - 9.4.2	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Uncertainty	2007 - 2.2	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Total Petroleum Initially-in-Place	2007 - 1.1	Total Petroleum Initially-in-Place is generally accepted to be all those estimated quantities of petroleum contained in the subsurface, as well as those quantities already produced. This was defined previously by the WPC as "Petroleum-in-place" and has been termed "Resource Base" by others. Also termed "Original-in-Place" or "Hydrocarbon Endowment."
Uncertainty	2007 - 2.2 2001 - 2.5	The range of possible outcomes in a series of estimates. For recoverable resource assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional Resources	2007 - 2.4,	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders). (Also termed "Non-Conventional" Resources and "Continuous Deposits.")
Undeveloped Reserves	2001 - 2.1.3.1 and Table 2	Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
Unitization		Process whereby owners group adjoining properties and divide reserves, production, costs, and other factors according to their respective entitlement to petroleum quantities to be recovered from the shared reservoir(s).
Unproved Reserves	2001 - 5.1.1	Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.
Unrecoverable Resources	2007 - 1.1	That portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

Upgrader	2007 - 2.4	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil (SCO). While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Well Abandonment		The permanent plugging of a dry hole, an injection well, an exploration well, or a well that no longer produces petroleum or is no longer capable of producing petroleum profitably. Several steps are involved in the abandonment of a well: permission for abandonment and procedural requirements are secured from official agencies; the casing is removed and salvaged if possible; and one or more cement plugs and/or mud are placed in the borehole to prevent migration of fluids between the different formations penetrated by the borehole. In some cases, wells may be temporarily abandoned where operations are suspended for extended periods pending future conversions to other applications such as reservoir monitoring, enhanced recovery, etc.
Wet Gas	2001 - 3.2 2007 - 3.2.3	Wet (Rich) Gas is natural gas from which no liquids have been removed prior to the reference point. The wet gas is accounted for in resource assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resource assessment definition and not a phase behavior definition.
Working Gas Volume		With respect to underground natural gas storage, Working Gas Volume (WGV) is the volume of gas in storage above the designed level of cushion gas which can be withdrawn/injected with the installed subsurface and surface facilities (wells, flowlines, etc.) subject to legal and technical limitations (pressures, velocities, etc.). Depending on local site conditions (injection/withdrawal rates, utilization hours, etc.), the working gas volume may be cycled more than once a year.
Working Interest	2001 - 9	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.