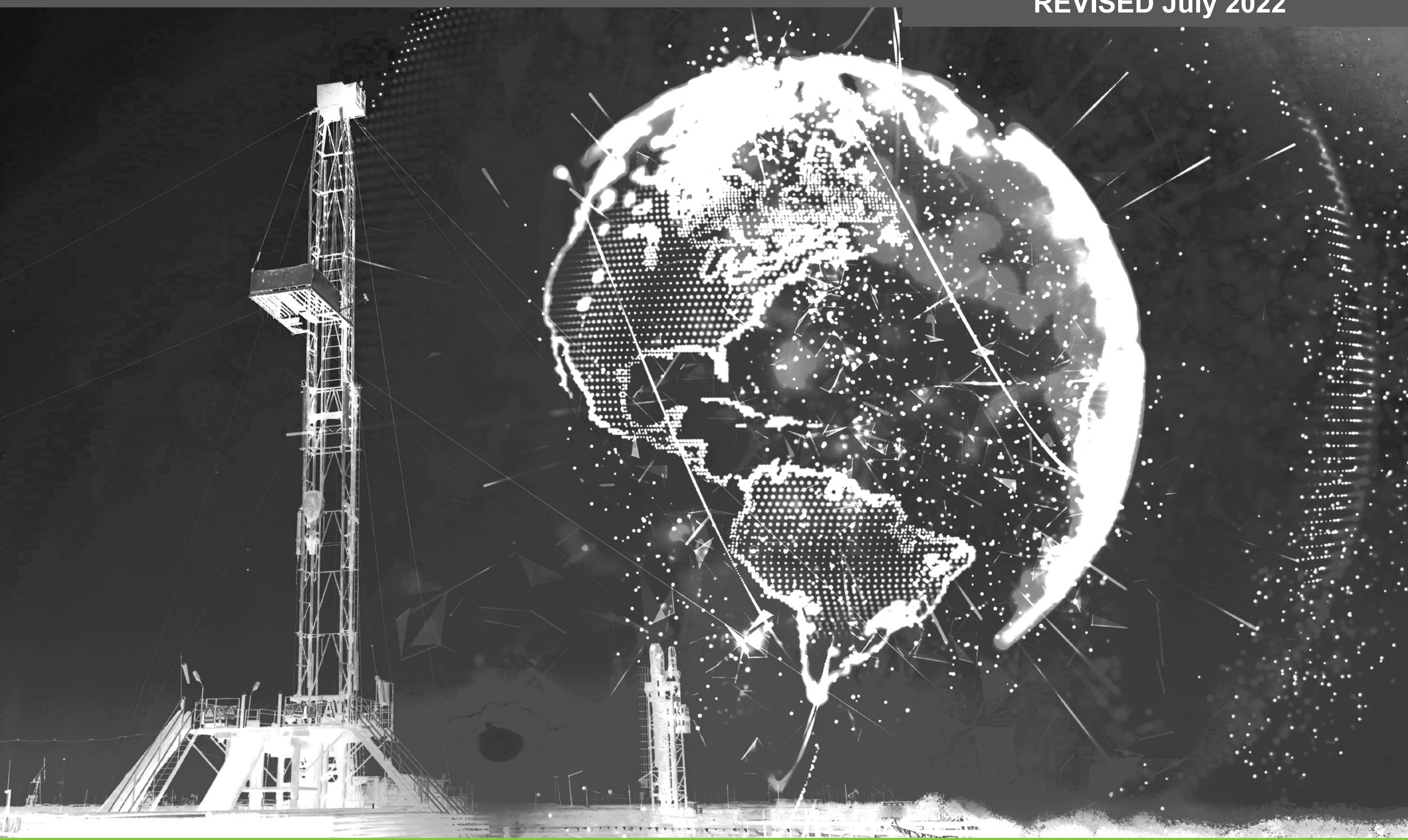
PRMS
Guidelines

Guidelines for Application of the Petroleum Resources Management System

REVISED July 2022



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Guidelines for Application of the
Petroleum Resources Management System

Sponsored by:

Society of Petroleum Engineers (SPE)
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Foreword

Charles Vanorsdale

This document, *Guidelines for Application of the PRMS*, or “AG,” represents an update to the 2011 version of the same-named document. It is a companion volume to the Petroleum Resources Management System, or “PRMS,” which was updated in 2018. The AG is not intended to replace any principles within the PRMS but rather to provide further clarity on the PRMS guidelines by way of textual detail and example situations. In the event of any conflict between specific principles in the AG and the PRMS, the PRMS principles will take precedence.

Note that sections within the two documents are referenced differently herein. When the AG, in any of its individual chapters, refers to a section with the symbol “§,” this will indicate a specific passage within the PRMS. Any other reference to a section, such as “Section” or “Sec.,” indicates a specific passage within the current chapter of the AG.

The individual chapters of the AG contain numerous example applications of PRMS guidelines. As with all resource assessment processes, the examples are based on the particular situations and data as spelled out in the chapter, and the results from the examples are not intended to be universally true for all situations and/or data.

Finally, the AG is based on and aligned with the PRMS, and it is not intended to be utilized in conjunction with any other resources guidelines or regulatory reporting requirements.

Contents

Chapter 1

Introduction

Charles Vanorsdale

1.1 Rationale for the Applications Guidelines Revision

The *Guidelines for Application of the PRMS* (or Application Guidelines, AG), as the name suggests, is the companion document to the Petroleum Resources Management System (PRMS), with the intended purpose of providing the PRMS user with a more detailed understanding of the principles involved therein for consistent practice in petroleum reserves and resources evaluation. Industry feedback through professional conferences, workshops, and public comment since the 2007 publication of the PRMS reinforced the need to issue further clarification and amplification of the PRMS and its guidelines. Consequently, to address these concerns, the original AG document was published in November 2011 (*Guidelines for Application of the Petroleum Resources Management System* 2011).

In 2014, an effort began to update the PRMS (2007) with the formation of several small teams within the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee. The Oil and Gas Reserves Committee called upon representatives from the five sponsoring professional organizations that had created the 2007 PRMS (SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, and Society of Exploration Geophysicists) with the addition of two further organizations (Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers) in the endeavor to collaboratively issue the updated PRMS. The clarification process culminated in the release of PRMS (2018) in June of that year, retaining the founding principles embodied in PRMS 2007. With that revision, an update to the 2011 AG was necessary, and it was planned to be co-released by the seven sponsoring organizations.

The 2011 AG itself was a significant update of the prior *Guidelines for the Evaluation of Petroleum Reserves and Resources* released in 2001. The 2011 AG was likewise a four-year undertaking that drew upon the resources of the five original sponsors and resulted in the inclusion of two additional major topic chapters, “Assessment of Petroleum Reserves Using Deterministic Procedures” and “Unconventional Resources.” Example applications were inserted in several chapters for the first time.

With that same professional collaborative vision, steered by the Oil and Gas Reserves Committee, the seven organizations devoted considerable resources toward this new AG. As with the PRMS, the AG update involved worldwide representation and a broad spectrum of industry participants from major producers, national oil companies, service companies, the banking and financial community, petroleum consulting firms, and universities. Tens of thousands of hours were dedicated by highly qualified individuals volunteering their time toward these efforts.

The ever-changing petroleum industry has necessitated a reevaluation of material in the AG 2011. The AG 2011 was the starting point for this work and has been augmented considerably by subject matter experts incorporating industry feedback and the inclusion of several illustrative examples in each chapter. These examples were created for the express purpose of conveying principles and concepts that users of the previous AG noted were not clearly articulated by the text alone. Further, the chapter on "Unconventional Resources" has been revised to reflect the advances in interpretation and assessment methods since 2011. Two new chapters have been added in this AG, namely:

- *Petrophysics* (Chapter 5) and
- *Reservoir Simulation* (Chapter 6).

These chapters have been added due to the continued integration of multidisciplinary technical activities associated with petroleum resources evaluation. PRMS 2018 introduced, for the first time, a definition of "net pay," a term used frequently in the industry, but one that actually carries different connotations between different disciplines. The term obviously impacts petrophysics, as well as reservoir simulation and several other chapters.

In fact, a mission of this updated AG was to view the content not as separate, standalone chapters but rather from a holistic standpoint. The editorial teams for each chapter were responsible not only for the review of their assigned chapter, but also the review of all chapters, in an attempt to ensure a common and consistent language for the concepts and principles throughout. A concern noted by several authors of this AG has been that the broader perspective of reserves and resources assessment has been supplanted by reliance on the opinion of subject matter experts, without independent scrutiny on the part of the evaluator. Ultimately, the evaluator is accountable not only for the end product (typically a reserves/resources assessment report), but also for the multidisciplinary input used to generate that report.

A list of Reference Terms used in resources evaluations is included at the end of the AG document. The list does not replace the PRMS Glossary but refers the user to the chapters and sections where the terms are used in the AG.

Finally, as with the PRMS 2018, material updates to this AG revision will be uploaded using version control on the SPE website.

Ron Harrell

1.2 History of Petroleum Reserves and Resources Definitions

The initial efforts at establishing oil reserves definitions in the US were led by the American Petroleum Institute. At the beginning of World War I, the US government formed the National Petroleum War Service Committee to ensure adequate oil supplies for the war effort. At the close of World War I, the National Petroleum War Service Committee was reborn as the American Petroleum Institute. In 1937, American Petroleum Institute created definitions for Proved oil reserves that they followed in their annual estimates of US oil reserves. Little attention was paid to natural gas reserves until after 1946, when the American Gas Association created similar definitions for Proved gas reserves.

SPE's initial involvement in establishing petroleum reserves definitions began in 1962 following a plea from US banks and other investors for a consistent set of reserves definitions that could be both understood and relied upon by the industry in financial transactions where petroleum reserves served as collateral. Individual lenders and oil producers had their own "in-house" definitions, but these varied widely in content and purpose. In 1962, the SPE Board of Directors appointed a 12-person committee of well-recognized and respected individuals. They were known as the Special Committee on Definitions of Proved Reserves for Property Evaluation. The group was composed of two oil producers, one pipeline company, one university professor, two banks, two insurance companies (lenders), and four petroleum consultants.

This group collaborated over a period of three years, debating the exact wording and terms of their assignment before submitting their single-page work product to the SPE board in 1965. The SPE board adopted the committee's recommendation by a vote of seven in favor, three dissenting, and two abstaining. The American Petroleum Institute observer was supportive; the American Gas Association observer opposed the result.

In 1981, SPE released updated Proved oil and gas definitions that contained only minor revisions of the initial 1965 version.

The 1987 SPE petroleum reserves definitions were the result of an effort initiated by the Society of Petroleum Evaluation Engineers, but ultimately developed and sponsored by SPE. These definitions, issued for the first time by a large professional organization, included recognition of the unproved categories of Probable and Possible Reserves. Much discussion centered around the use of probabilistic assessment techniques as a supplement or alternative to more-traditional deterministic methods. Following the receipt of comments from members worldwide, and in particular members from North America, the SPE board did not approve the inclusion of any discussion about probabilistic methods of reserves evaluation in the 1987 definitions. As a consequence, these definitions failed to garner widespread international acceptance and adoption.

The 1997 SPE/World Petroleum Council reserves definitions grew out of a cooperative agreement between the World Petroleum Council and SPE and appropriately embraced the recognition of probabilistic assessment methods. The American Association of Petroleum Geologists became a sponsor of and an integral contributor to the 2000 SPE/World Petroleum Council/American Association of Petroleum Geologists definitions and provided invaluable contributions toward the implementation of resources definitions. In 2007, the Society of Petroleum Evaluation Engineers became the fourth sponsoring society, followed by the Society of Exploration Geophysicists joining as an adopting sponsor shortly thereafter.

This recitation is not intended to omit or minimize the creative influence of numerous other individuals, organizations, or countries who have made valuable contributions over time to the derivation of petroleum resources definitions out of an initial mining perspective. Users of this information are encouraged, however, to recognize that the foregoing history of relevant industry-adopted reserves and resources definitions and evaluation practices has been entirely created by competent industry professionals tirelessly volunteering their time over many years—several decades for some—to create the controlling standards and guidance in reserves and resources management practices worldwide.

Further, the PRMS/AG sponsors recognize that the reserves and resources definitions must remain relevant and up-to-date and will remain diligent in working toward periodic updates and improvements.

1.3 References

Guidelines for Application of the Petroleum Resources Management System. 2011. Richardson, Texas, USA: Society of Petroleum Engineers, and London, UK: World Petroleum Council.

Petroleum Resources Management System. 2007. Richardson, Texas, USA: Society of Petroleum Engineers.

Petroleum Resources Management System, Version 1.01. 2018. Richardson, Texas, USA: Society of Petroleum Engineers.

Chapter 2

Petroleum Resources Definitions, Classification, and Categorization Guidelines

Rich DuCharme (Chair)
Dan Olds and Xavier Troussaut

2.1 Introduction

The Petroleum Resources Management System (2018), termed PRMS herein, is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources. Although the system encompasses the entire in-place petroleum resource and characterizes projects at various levels of technical and commercial maturity, its widest application has been for estimating commercially recoverable quantities using a globally recognized system. Because no petroleum quantities can be commercially recovered without the installation of (or access to) the appropriate production, processing, and transportation facilities, application of the PRMS focuses on the development project that has been (or will be) implemented to recover petroleum from one or more accumulations. Further, the PRMS provides an explicit distinction between the chance of commerciality of that project, which defines its maturity (Classification), and the range of uncertainty in the petroleum quantities forecast to be potentially recovered and marketed in the future from that project (Categorization). This two-axis system is illustrated in **Fig. 2.1.**

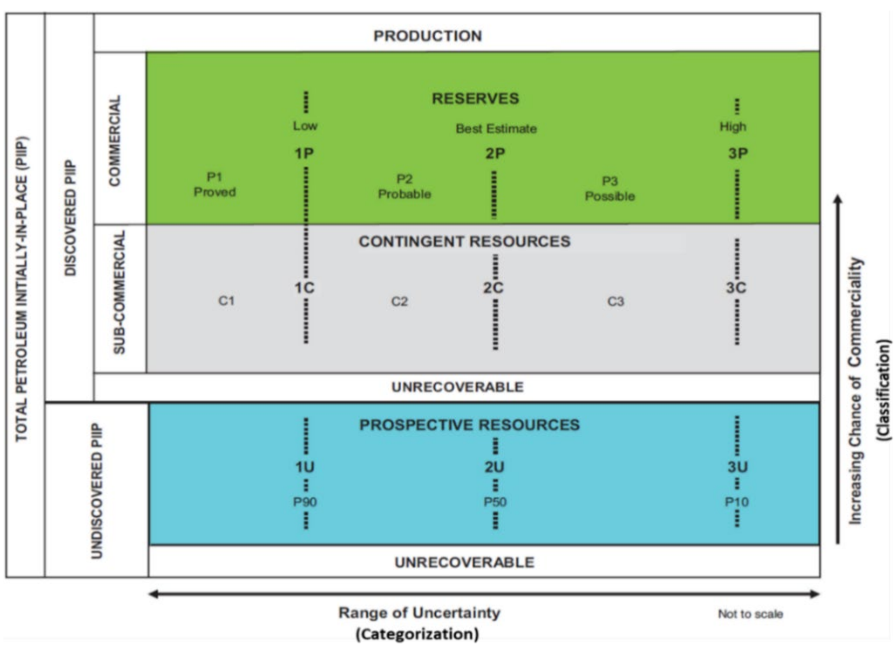


Fig. 2.1—Resources classification framework.

Each project is classified according to its maturity or status using three main classes, with the option to subdivide further using sub-classes. The three classes are Reserves, Contingent Resources, and Prospective Resources, which reflect the remaining estimated recoverable quantities at the time of the evaluation. These estimates of remaining recoverable quantities exclude previously produced volumes as well as unrecoverable quantities that may become recoverable in the future as new technology is developed or economic conditions improve. Separately, the range of uncertainty in the estimated recoverable and marketable quantities from that specific project is categorized based on the principle of identifying three estimates (Low, Best, and High) of the potential outcome.

For projects that satisfy the requirements for commerciality (PRMS § 2.1.2), Reserves may be assigned to the project, and the three estimates of the recoverable commercial quantities would be designated as 1P (Proved: equivalent to low estimate or at least P90 if probabilistic methods are used), 2P (Proved plus Probable: equivalent to best estimate or at least P50 if probabilistic methods are used), and 3P (Proved plus Probable plus Possible: equivalent to high estimate or at least P10 if probabilistic methods are used) Reserves. The equivalent categories for sub-commercial projects with Contingent Resources are 1C, 2C, and 3C, while equivalent categories for Prospective Resources are 1U, 2U, and 3U.

The PRMS also accommodates the ability to categorize and report Reserve quantities incrementally as Proved (P1), Probable (P2), and Possible (P3), rather than using the realizable scenarios of 1P, 2P, and 3P. Likewise, the incremental quantities of Contingent Resources can be reported as C1, C2, and C3 rather than using the scenarios of 1C, 2C, and 3C. Because of the undiscovered nature of Prospective Resources and the likely application of probabilistic approaches, recognition of incremental quantities for Prospective Resources implies more precision than is warranted and, therefore, they are not differentiated incrementally in the PRMS.

2.1.1 Project-Based Classification System. The PRMS is a project-based system, where a project is "a defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g., compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project" (PRMS 2018, Appendix A, 47).

There are actually three elements that constitute an evaluation of net recoverable resources. The Project definition is one element. In addition, we have the Reservoir (which contains the petroleum accumulation) and the Property (which defines the unique associated contractual rights and obligations, including the fiscal terms, of the lease or license area) elements. As discussed in more detail in PRMS § 1.2, these elements are related as shown in **Fig. 2.2.**

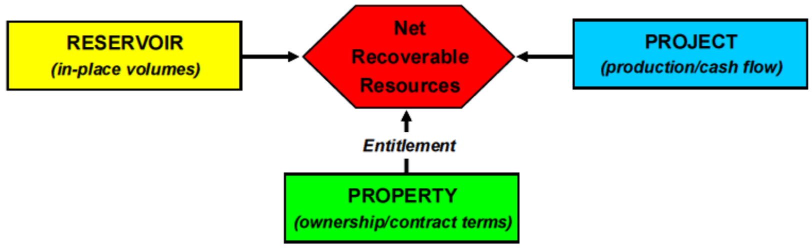


Fig. 2.2—Key elements of a resources evaluation.

The scope of this chapter relates to the Project and the associated definitions, classification, and categorization of the recoverable petroleum resources. Aspects concerning the related cash flow and commerciality considerations of the Project are detailed in Chapter 9—*Evaluation of Petroleum Reserves and Resources* of this document. The technical assessments of the in-place volumes and their recoverable quantities are discussed from a deterministic approach in Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* and from a probabilistic approach in Chapter 7—*Probabilistic Resources Estimation*. Ownership and entitlement are the focus of Chapter 12—*Resources Entitlement and Recognition*.

2.2 Defining a Project

Each project is considered as an investment opportunity, and a decision must be made to proceed, reassess, postpone, or exit the project. An entity's decisions reflect the selection or rejection of investment opportunities from a portfolio based on consideration of the funds available, the cost of the specific project, and the expected outcome (in terms of value) of that investment. The critical point in the PRMS is the linkage between the decision to proceed with a project and the estimated future recoverable quantities associated with that project. It is worth noting that the rigor of the assessment used to estimate the recoverable quantities (Low, Best, High) for the project will tend to align with the maturity of the project (i.e., more mature projects will require more detailed development plans and more rigorous analysis) (see PRMS § 1.2.0.9).

Defining the term "project" unambiguously can be difficult because its nature will vary with the level of maturity. For example, a mature project may be defined in great detail by a comprehensive development plan, which may be prepared and submitted to the partners, host government, or relevant regulatory authority for approval to proceed with development, or a development plan may contain multiple projects at different maturity levels. The development plan may be revised over time as updated results are obtained or as less mature projects in the development plan increase their commercial maturity and likelihood of occurrence. These development plans may include full details of all the planned development wells and their locations, specifications for surface processing and export facilities, discussion of environmental considerations, staffing requirements, market assessment, estimated capital, operating and site rehabilitation costs, etc. In contrast, the drilling of an exploration prospect represents a less mature project that could become a commercial development if the well is successful. The assessment of the economic viability of the exploration project will still require a view of the likely development scheme, although the development plan may be outlined in broad conceptual terms based on analogs.

In all cases, the decision to proceed with a project not only requires an estimate of future product prices, but also an assessment of future costs, based on an evaluation of the development scope (e.g., wells, facilities) and operation, to support the economic evaluation of that investment. In this context, the development facilities include all the necessary production, processing, and transportation facilities to enable delivery of petroleum from the accumulation(s) to a product sales point (or to an internal transfer point between upstream operations and midstream/downstream operations); for more detail, please see Chapter 11—*Production Measurement & Operational Issues* of this document. This development scope and cost define the project because the planned investment of the capital costs is the basis for the economic evaluation of the investment and, hence, the decision to proceed (or not) with the project. Evaluation of the estimated recoverable sales quantities and the range of uncertainty in that estimate will also be key inputs to the economic evaluation, and these are based on a defined development project.

A project may involve the development of a single petroleum accumulation (e.g., a reservoir or field), or a group of accumulations, or there may be more than one project implemented on a single accumulation. The following are some examples of projects:

- When a detailed development plan is prepared for partner and/or government approval, then the plan itself defines the project. If the plan included optional wells that had received capital commitment with project and government approval, these would not constitute a separate project, but would form part of the assessment of the range of uncertainty in potentially recoverable quantities from the project.
- When a development project is defined to produce oil from an accumulation that also contains a significant gas cap, and the gas cap development is not an integral part of the oil development, then a separate gas development project may also be defined for a future project decision, even if there is currently no gas market (i.e., Contingent Resources).
- When a development plan is based on primary recovery only, and a secondary recovery process is envisioned but will be subject to a separate capital commitment decision and/or approval process at the appropriate time, then it is considered as two separate projects.
- When decision making is entirely on an individual, well-by-well basis, then each well constitutes a separate project.
- When late-life installation of gas-compression facilities is included in the original approved development plan, then it is part of a single gas development project. When compression was not part of the approved development plan, yet it is technically feasible and will require economic justification and a capital commitment decision and/or approval before installation, then the installation of gas-compression facilities represents a separate project (PRMS § 2.3.2).
- In the assessment of an undrilled prospect, an economic evaluation will be made to underpin the decision to drill. This evaluation includes consideration of a conceptual development plan in order to estimate costs and recoverable quantities (Prospective Resources) assuming a positive outcome from the exploration well. The project is defined by the exploration well and a conceptual development plan that will have less detail than more mature opportunities (e.g., often relying on analog developments and reasonable assumptions).
- In some cases, an investment decision may involve multiple projects of exploration, appraisal, and/or development activities. Because the PRMS subdivides resource quantities on the basis of three classes that reflect the distinction between these activities (i.e., Reserves, Contingent Resources, and Prospective Resources), it is appropriate to consider that the investment decision is based on implementing a group of projects, whereby each project is uniquely placed in one of the three classes (by identifying separate projects, the evaluator avoids the problem of split classification).

- When a developed field's reserves are constrained by a license or contract expiry, then those quantities that may be produced beyond the expiration date of the current contract will be attributed to a separate project associated with renegotiated contract extension and fiscal terms and extended field life. This project is typically assigned to Contingent Resources with a reduced chance of commercialization, unless there is reasonable expectation that an extension, renewal, or new contract will be granted, which, in this case, may allow for these quantities to be assigned to Reserves (PRMS § 3.3.3.2). A reasonable expectation of extension and fiscal terms may be based on existing contract extension terms, negotiations, or historical treatment of similar agreements. If the evaluator is unable to support reasonable expectations, then the recoverable quantities associated with the potential extension should be retained in Contingent Resources and may only be assigned to Reserves when reasonable expectation of proceeding with the extension has been achieved. Note that this separate project associated with pursuing an extension will be assigned to a single sub-class and, therefore, is not considered split classification (PRMS § 2.2.0.4).

Projects may change in character over time and can aggregate or subdivide. For example, an exploration project may initially be defined on the basis of drilling a well; yet, if a discovery is made, a subsequent project decision to develop the accumulation will be considered as a separate standalone project. However, if the discovery is smaller than expected and perhaps is unable to support an export pipeline on its own, then the project might be placed in the appropriate contingent sub-class (see Section 2.7) and delayed until another discovery is made nearby, and the two discoveries could then be developed as a single project that is able to justify the cost of the pipeline. The investment decision following the second successful exploration well is then based on proceeding with the development of the two accumulations simultaneously using shared facilities (the pipeline), and the combined development plan then constitutes the project. Again, the key is that the project is defined by the basis on which the investment decision is made.

Similarly, a discovered accumulation, following successful exploration, may initially be assessed as a single development opportunity, but upon further evaluation, it may then be split into two or more (i.e., exploratory/appraisal and development) distinct projects. For example, the level of uncertainty (e.g., in reservoir performance) may be such that it is considered more prudent to implement a pilot project first. The initial concept of a single field development project then becomes two separate projects: the pilot project and the subsequent development of the remainder of the field, with the latter project contingent on the successful outcome of the first project.

A key strength of using a project-based system such as PRMS is that it encourages the consideration of all possible technically feasible opportunities to maximize project outcomes, even though some projects may not be economically viable when initially evaluated. These projects are still part of the portfolio, and identifying and classifying them ensures that they remain visible as potential opportunities for the future.

The quantities that are classified as Unrecoverable should be limited to those that are currently not technically recoverable by a defined project based on established technology or technology under development (see Section 2.3). A portion of these Unrecoverable quantities may become recoverable in the future if new technology is developed, commercial circumstances change, or additional data is acquired.

2.3 Project Classification

Under the PRMS, projects must be classified individually so that the estimated recoverable quantities associated with the project can be correctly assigned to one of the three main classes (see Fig. 2.1). The distinction between the three classes is based on the definitions of discovery and commerciality, as documented in PRMS § 2.1.1 and § 2.1.2, respectively. The evaluation of a discovery begins at the level of the well-penetrated accumulation (including adjacent reservoirs interpreted with reasonable confidence to be in communication with the well-penetrated reservoir) and determines whether there is confidence in the presence of significant hydrocarbons. A discovery should be significant enough to merit assessment as a potential commercial development in order to estimate discovered petroleum initially in place. It is the existence of "significant hydrocarbons" that justifies the application of a project (detailed or conceptual) to further differentiate the recoverable from the unrecoverable resources. (Note: "Unrecoverable" is a subset within the petroleum initially in place and a part of the resource base, but it is not part of Prospective or Contingent Resources; see Fig. 2.1.) The project is then evaluated to determine its maturity (commercial or sub-commercial) and classification of the project's recoverable resource quantity.

The definition of "discovery" requires evidence (testing, sampling, seismic and/or logging data) from at least one well penetration in the accumulation (or group of penetrated accumulations) to have demonstrated a "significant quantity of potentially recoverable hydrocarbons" (PRMS § 2.1.1.1). In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs. In this context, "significant quantity" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and evaluating the potential for commercial recovery.

Estimated recoverable quantities from a discovery are classified as Contingent Resources until such time that a defined project can be shown to have satisfied all the criteria necessary to reclassify some or all of the quantities as Reserves (i.e., commerciality is achieved). In cases where the discovery is, for example, adjacent to existing infrastructure with sufficient excess capacity, and a commercially viable development project is immediately evident (e.g., by connecting the discovery well into the available infrastructure) with firm intent by the entity to proceed with development, then the estimated recoverable quantities may be classified as Reserves. More commonly, the estimated recoverable quantities for a discovery will be classified as Contingent Resources while further appraisal and/or evaluation is carried out.

Discovered accumulations may contain in-place quantities that are not considered viable to recover using established technology or technology under development; such quantities may be classified as Discovered Unrecoverable (i.e., no Contingent Resources). Future technological advances or improvements in commercial circumstances may move those Unrecoverable quantities to Contingent Resources or Reserves (PRMS § 2.1.1.2).

The criteria for commerciality (and hence assigning Reserves to a project) are set out in the PRMS § 2.1.2.1 and should be considered carefully. While estimates of Reserve quantities may change with time, including during the period before production startup, it should be a rare event for a project that had been assigned to the Reserves class to be reclassified to Contingent Resources. Such a reclassification should occur only as the consequence of an unforeseeable event that is beyond the control of the entity, such as an unexpected political, legal, or market (including pricing) change that, for example, causes development activities to be delayed beyond a reasonable time frame, which is typically considered to be five years, unless a longer time frame is justifiable (PRMS § 2.1.2.3). Even so, if there are any identifiable areas of concern regarding receipt of all the necessary approvals/contracts for a new development, it is recommended that the project remain in the Contingent Resources class until such time that the specific concern has been addressed.

For projects not yet deemed commercial, Contingent Resources may be assigned if the recoverable quantity is dependent on either "established technology" or "technology under development." The following guidelines should be used to distinguish these Contingent Resources from those significant quantities that should be classified as Discovered Unrecoverable:

- The technology has been demonstrated to be commercially viable in analogous reservoirs; in this case, the Discovered Recoverable quantities may be classified as Contingent Resources.
- The technology has been demonstrated to be commercially viable in other reservoirs that are *not* analogous, and a pilot project will be necessary to demonstrate commerciality for this reservoir.
    - If a pilot project is conducted and deemed technically successful, then Discovered Recoverable quantities from the full project may be classified as Contingent Resources.
    - If a pilot project is conducted and deemed technically unsuccessful, then all quantities should be classified as Discovered Unrecoverable.
- The technology has *not* been demonstrated to be commercially viable but is currently under active development, and there is sufficient direct evidence (e.g., from a test project in an analogous reservoir) to indicate that it may reasonably be expected to be available for commercial application. In this case, Discovered Recoverable quantities from the full project may be classified as Contingent Resources.
- The technology has *not* been demonstrated to be viable and is *not* currently under active development; in this case, all quantities should be classified as Discovered Unrecoverable.

2.4 Range of Uncertainty Categorization

The "range of uncertainty" (see Fig. 2.1 horizontal axis) reflects a range of estimated quantities potentially recoverable from an accumulation (or group of accumulations) by a specific, defined project. Because all potentially recoverable quantities are estimates that are based on assumptions regarding future reservoir performance (among other things), there will always be some uncertainty in the estimate of the recoverable quantity resulting from the implementation of a specific project. There will be uncertainty in both the estimated in-place quantities and in the recovery efficiency, and there may also be project-specific commercial uncertainties. Where performance-based estimates are used (e.g., based on decline curve analysis), there will be some uncertainty. However, for very mature projects or constrained market access, the level of technical uncertainty may be relatively minor; in such cases, the best estimate scenario may be justifiable to also use for the Low and High estimate scenarios (PRMS § 4.1.4.3).

In the PRMS, once the project has been classified as Prospective Resources, Contingent Resources, or Reserves based on the project's level of commercial maturity (see Fig. 2.1 vertical axis), the range of uncertainty then determines the categorization of the estimated recoverable quantities, and it is characterized by three specific outcomes reflecting Low, Best, and High (or P90, P50, and P10 if probabilistic methods are used) estimates from the project. For example, if the project satisfies all the criteria for Reserves, and the Low, Best, and High estimates are economically viable, then these estimates will be designated as Proved (1P), Proved plus Probable (2P), and Proved plus Probable plus Possible (3P), respectively.

The three estimates (Low, Best, and High) may be based on deterministic or probabilistic methods, as discussed in Section 2.5, and they will reflect the range of uncertainty of project outcomes. While estimates may be made using deterministic or probabilistic methods (or, for that matter, using multiscenario methods), the underlying principles must be the same if comparable results are to be achieved. It is useful, therefore, to keep in mind certain characteristics of the probabilistic method when applying a deterministic approach:

- The range of uncertainty relates to the uncertainty in the estimate of recoverable quantities for a specific project. The full range of uncertainty extends from a minimum estimated recoverable quantity for the project through all potential outcomes up to a maximum recoverable quantity. Because the minimum and maximum outcomes are the extreme cases, it is considered more practical to use Low and High estimates as a reasonable representation of the range of uncertainty in the estimate of recoverable quantities. Where probabilistic methods are used, the P90 and P10 outcomes are typically selected for the Low and High estimates, respectively, although the official requirement is that the selected case should have at least a 90% probability that the quantities actually recovered will equal or exceed the Low estimate and at least a 10% probability that the quantities actually recovered will equal or exceed the High estimate (see PRMS § 2.2.1.2).
- In the probabilistic method, probabilities actually correspond to ranges of outcomes, rather than to a specific scenario. The P90 estimate, for example, corresponds to the situation wherein there is an estimated 90% probability that the quantities actually recovered will lie somewhere between the P90 and the P0 (maximum) outcomes. Obviously, there is a corresponding 10% probability that the quantities recovered will lie between the P90 and the P100 (minimum) outcomes, assuming of course that the evaluation of the full range of uncertainty is valid. In a deterministic context, "a high degree of confidence that the quantities will be recovered" (PRMS § 2.2.2.8) does not mean that there is a high probability that the exact quantity designated as Proved will be the actual quantity recovered; it means there is a high degree of confidence that the actual quantity recovered will equal or exceed the Proved amount.
- In this uncertainty-based approach, a deterministic estimate is a single discrete scenario that should lie within the range that would be generated by a probabilistic analysis. The range of uncertainty reflects our inability to estimate the actual recoverable quantities for a project exactly, and the Low, Best, and High estimates are simply single discrete scenarios that are representative of the range of uncertainty in estimating the remaining recoverable quantities.

As noted earlier, for very mature producing projects or projects with ample supply but market or license off-take constraints (e.g., the high confidence recoverable quantity exceeds the off-take constraint), it may be concluded that there is such a small range of uncertainty in estimated remaining recoverable quantities that 1P, 2P, and 3P Reserves can be assumed to be equal, and the incremental P2 (Probable) and P3 (Possible) quantities are approximately equal to zero. Often, this approach is used when a producing well has sufficient long-term production history such that a forecast based on decline curve analysis is considered to be subject to relatively little uncertainty (see PRMS § 4.1.4.3). In reality, of course, the range of uncertainty is never zero (especially when considered in the context of remaining quantities), and any assumption that the uncertainty is not material to the estimate should be carefully considered, and the basis for the assumption should be documented.

Typically, there always will be a range of uncertainty and, therefore, Low, Best, and High estimates of recoverable quantities (or a full probabilistic distribution) that characterize the range, whether for Reserves, Contingent Resources, or Prospective Resources. However, there are specific circumstances that can lead to having 2P and 3P Reserves, but zero 1P Reserves. For example, an undeveloped project may satisfy the criteria to be classified as Reserves based on the Best estimate, but the Low estimate is not economic and therefore fails to qualify as 1P Reserves. In this circumstance, the entity may record 2P and 3P Reserves for the development project, but no 1P Reserves (PRMS § 3.1.2.8 and the first sentence of § 2.1.3.7.4). Moreover, in this example, the Low estimate cannot be reported as a different classification (e.g., the entity cannot report 1C, 2P, and 3P), since this would result in split classification, which is not allowed (PRMS § 2.2.0.4).

2.5 Methods for Estimating the Range of Uncertainty in Recoverable Quantities

There are several different methods commonly used to estimate the range of uncertainty in recoverable quantities for a project. While the objective of the exercise is to estimate at least three outcomes (Low, Best, and High estimates of recoverable quantities) that reflect the range of uncertainty, it is important to recognize that the underlying philosophy must be the same, regardless of the approach used. In this context "deterministic" methods rely on a single set of discrete parameters (gross rock volume, average porosity, etc.) that represent a physically realizable and realistic combination in order to derive a single, specific estimate of recoverable quantities (e.g., a combination of parameters represents a specific scenario).

Evaluators may choose to apply more than one method to a specific project, especially for more complex developments. For example, three deterministic scenarios may be selected after reviewing a Monte Carlo analysis of the same project. The following terminology is recommended for the primary methods in current use. These methods are discussed in more detail in subsequent chapters of this document (see Chapter 4—*Assessment of Petroleum Resources Using Deterministic Procedures*, and Chapter 7—*Probabilistic Reserves Estimation*).

2.5.1 Deterministic "Scenario" Method. In this method, three discrete scenarios are developed that reflect the Low, Best, and High estimates of recoverable quantities. These scenarios must reflect realistic combinations of parameters with particular care required to ensure that a reasonable range of values is used for each reservoir property, and one set of input parameters is selected that best represents the corresponding confidence category for each estimated recoverable quantity. It is generally not appropriate to combine the Low estimate for each input parameter to determine a Low case outcome, as this would not represent a realistic Low case scenario (it would be closer to the absolute minimum possible outcome).

2.5.2 Deterministic "Incremental" Method. This method is often used in mature, spatially extensive onshore environments. Typically, this approach defines discrete areal (and sometimes vertical) segments of the accumulation as High, Best, and Low confidence based on considerations of well spacing and/or geological knowledge (i.e., the different degrees of confidence are governed by distance from known data) in determining estimates of recoverable quantities under the defined development plan. For example, Proved Developed Reserves are assigned within the immediate drilled area, and Proved Undeveloped Reserves are assigned to adjacent, high-confidence drilling locations based on continuity of the delineated productive reservoir. Probable and Possible Reserves are assigned to less confident locations, often at a further distance from Proved well locations; beyond these locations, there may exist Contingent Resources, if they are part of the same discovered accumulation. These additional quantities (e.g., Probable Reserves) are estimated discretely as opposed to defining a Proved plus Probable Reserves scenario. In such cases, particular care is required to define the project correctly (e.g., distinguishing between wells that are planned and committed as opposed to those that are still contingent, whether individual wells or area development patterns comprise the project) and to ensure that all uncertainties, including recovery efficiency, are appropriately addressed.

2.5.3 Geostatistical Method. This approach may be used to more reliably describe the spatial distribution of geoscience and reservoir engineering data, thereby better describing the variability and uncertainties within an accumulation. By preserving spatial distribution of data, which can be represented in a static reservoir model and incorporated in a reservoir simulation, these techniques can provide improved estimates of the range of recoverable quantities. For example, incorporating seismic analyses can improve the understanding, mapping, and modeling of the static geological framework and the geostatistical variability of reservoir properties beyond limited well control, thereby enhancing the resource estimation.

2.5.4 Probabilistic Method. This method examines the probabilistic distribution of the input parameters and the resource or reserves subsequently estimated. It is commonly implemented using Monte Carlo simulation or stochastic modelling. The evaluator defines the probability distributions of the input parameters and the relationships (correlations) between them, and the model derives an output distribution based on a combination of those input assumptions. Each iteration of the model is a single, discrete deterministic scenario; yet, in this case, the simulation model, rather than the evaluator, determines the combination of parameters for each iteration, and it runs many different possible combinations (often several thousand) in order to develop a full probability distribution of the range of possible outcomes, from which three representative outcomes are selected (i.e., P90, P50, and P10).

2.5.5 Integrated Method. Resource assessments can integrate several methods, including deterministic, geostatistical, and probabilistic, in combination to better define uncertainty and ensure that the results of the methods are reasonable. An example is the multiscenario method, which is a combination of the deterministic (scenario) method and the probabilistic method. In this case, significant numbers of discrete deterministic scenarios are developed by the evaluator (perhaps 100 or more), and probabilities are assigned to each possible discrete input assumption. For instance, three depth conversion models may be considered possible, and each one is assigned a probability based on the evaluator's assessment of the relative likelihood of each of the models. Each scenario leads to a single deterministic outcome, and the probabilities for each of the input parameters are combined to give a probability for that scenario/outcome. Given a sufficient number of scenarios, it is possible to develop a full probability distribution, from which three specific deterministic scenarios that are closest to P90, P50, and P10 may be selected.

2.6 Chance of Commerciality

The "chance of commerciality" (see Fig. 2.1 vertical axis) reflects the chance that a project will be committed for development and reach commercial producing status. As a project moves to a higher level of commercial maturity, there is typically an increasing chance that the accumulation will be commercially developed and the project's recoverable quantities will be moved to Reserves.

An evaluator has the option to express commercial risk qualitatively by allocation to classes and sub-classes (see Section 2.7 on Project Maturity sub-classes) and/or quantitatively as the chance of commerciality (P_c), which, for undiscovered resources, is defined as the product of two risk components (PRMS § 2.1.3.2):

- Chance of geologic discovery (P_g): The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, and
- Chance of development (P_d): Once discovered, the chance that the known accumulation will be commercially developed.

For a Prospective Resource, P_c is the product of P_g and P_d ($P_c = P_g \times P_d$), reflecting the risk of discovery as well as the risk of commercial development. Yet, once a discovery is made (i.e., P_g = 100%), then the chance of commerciality becomes equivalent to the chance of development ($P_c = P_d$) for Reserves and Contingent Resources, because these classifications are attributable only to discovered accumulations. Furthermore, for a project to be classified as Reserves, there should be a very high probability that it will proceed to commercial development (i.e., very little, if any, commercial risk). Consequently, commercial risk is generally ignored in the estimation and reporting of Reserves, although some Reserves may still carry minor commercial risk if final approvals or contracts (items outside the entity's control) have not yet been obtained, but they are deemed, at the time of the Reserve classification, to be reasonably certain to obtain (see Section 2.7 discussion of Justified for Development). However, for projects with Contingent or Prospective Resources, the commercial risk may be quite significant and should be carefully considered.

Consider first the approach for estimating Prospective Resources. The chance of geologic discovery (P_g) is assessed based on the probability that all the components necessary for an accumulation to form (hydrocarbon source, reservoir, trap, migration, etc.) are present. Separately, an evaluation of the potential size of the discovery is undertaken. Often, this is performed probabilistically and leads to a "full distribution" of the range of uncertainty in potentially recoverable quantities, given that a discovery is made. This "full distribution" of potential outcomes provides the basis for the Low, Best, and High estimates for the full range of recoverable quantities for Prospective Resources, and it is consistent with the use of the full range of recoverable quantities in assessing Reserves and Contingent Resources as described in Section 2.4 and below. Because this range may include outcomes that are below the economic threshold for a commercially viable project, the probability of being above the economic threshold is used to define the chance of development (P_d), and hence the chance of commerciality (P_c) is obtained by multiplying P_d by the chance of geologic discovery (P_g).

An alternative approach for estimating Prospective Resources is to include only the commercially successful portion of the full distribution (i.e., the "success case" portion rather than the "full distribution"). In this case, the range would exclude outcomes that are below the economic threshold for a commercially viable project; therefore, the probability of achieving this "success case" portion of the range with a discovery well is lower, which must be incorporated into the chance of development (P_d) when using the "success case" as the Prospective Resource range (i.e., "full distribution" P_d > "success case" P_d).

In both approaches for determining Prospective Resource ranges ("full distribution" vs. "success case"), the risked mean Prospective Resource will be the same. That is, achieving the higher "success case" distribution is riskier than achieving the "full distribution," which also includes the uneconomic outcomes; therefore, the risked mean of the two cases will be equal (i.e., the higher risk/lower probability applied to the "success case" mean will be equal to the product of the lower risk/higher probability applied to the "full distribution" mean). The key for the evaluator is to clearly document the basis and assumptions used to estimate the Prospective Resources and assess the underlying risks related to commercialization (i.e., chance of geologic discovery, chance of development).

Once a discovery has been made, and a range of technically recoverable quantities has been assessed for a known accumulation from the "full distribution" of outcomes, these estimated recoverable quantities (Low, Best, and High) will be assigned as Contingent Resources if there are any contingencies that currently preclude the project from being classified as commercial (i.e., prevent recognition as Reserves). If the contingency is purely nontechnical (such as lack of environmental approval, for example), the uncertainty in the estimated recoverable quantities generally will not be impacted by the removal of the contingency. The Contingent Resource quantities (1C, 2C, and 3C) should then theoretically move directly to 1P, 2P, and 3P Reserves (PRMS § 2.2.2.6) once this nontechnical contingency is removed, provided of course that the same economic criteria are applied, all other criteria for assigning Reserves have been satisfied, and the planned recovery project has not changed in any way. In this example, the chance of commerciality is the probability that the necessary permits will be obtained.

However, another possible contingency precluding a development decision could be that the estimated 1C quantities are considered to be too small to commit to the project, even though the 2C level is commercially viable. It is not uncommon, for example, for an entity first to test that the 2C estimate satisfies all their corporate hurdles and then, as a project robustness test, to require that the Low (1C) outcome at least reaches a break-even economic threshold. If the project fails this latter test, and development remains contingent on satisfying this break-even test, further data acquisition (potentially appraisal drilling) would be required to reduce the range of uncertainty. In such a case, the chance of commerciality is the probability that the appraisal efforts will increase the Low (1C) estimate above the break-even level, which is not the same as the probability (assessed before the additional appraisal) that the actual recoverable quantity will exceed the break-even level.

When reporting Contingent Resource estimates, the commercial risk associated with such projects can vary widely, with some having a high chance of proceeding to development, while others might have a much lower chance of being developed. If Contingent Resources are reported externally, the commercial risk can be communicated to users (e.g., stakeholders) by various means, including: describing the specific contingencies associated with individual projects; reporting a quantitative chance of commerciality for each project; and/or assigning each project to one of the Project Maturity sub-classes (see Section 2.7).

Aggregation of quantities that are subject to commercial risk raises further complications and is discussed in more detail in Chapter 8—*Aggregation of Reserves and Resources* in this document.

2.7 Project Maturity Sub-Classes

Under the PRMS, identified recoverable petroleum-initially-in-place must always be assigned to one of the three classes: Reserves, Contingent Resources, or Prospective Resources. Further subdivision is optional, and three options are provided in PRMS that can be used together or separately to identify particular characteristics of the project and its associated recoverable quantities. These options are Project Maturity sub-classes as described below, Reserves Status (see Section 2.8), and Economic Status (see Section 2.9).

As illustrated in **Fig. 2.3,** development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (e.g., business decisions, data acquisition, evaluation) required to move a project toward commercial production.

This approach supports management of portfolios of opportunities at various stages of exploration, appraisal, and development and may be supplemented by associated quantitative estimates of chance of commerciality, as discussed in Section 2.6. The boundaries between different levels of project maturity may align with internal (entity-specific) project "decision gates," thus providing a direct link between the decision-making process within an entity and characterization of its portfolio through resource classification. This link can also act to facilitate the consistent assignment of appropriate quantified risk factors for the chance of commerciality.

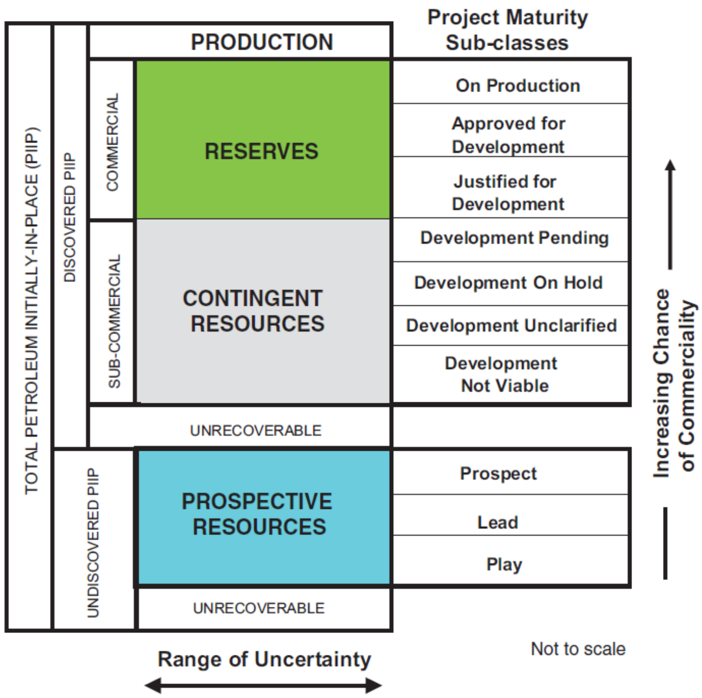


Fig. 2.3—Sub-classes based on project maturity.

Evaluators may adopt alternative sub-classes and project maturity modifiers to align with their own decision-making process, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management. Note that, in quantitative terms, the "chance of commerciality" axis shown in Figs. 2.1 and 2.3 is not intended to represent a linear scale, nor is it necessarily wholly sequential in the sense that a Contingent Resource project that is classified as "Development Not Viable" could have a lower chance of commerciality than a low-risk Prospect, for example. In general, however, quantitative estimates of the chance of commerciality will increase as a project moves "up the ladder" from an exploration concept to a field that is producing.

If the sub-classes in Fig. 2.3 are adopted, the following general guidelines should be considered in addition to those documented in Table 1 of the PRMS:

- **On Production** refers to a development project that is producing or is capable of producing and selling petroleum to the market at the effective date of the evaluation. Implementation of the project may not be 100% complete at that date, and so some of the reserves may still be Undeveloped (see Section 2.8). In some cases, the project may have advanced past the Approved for Development phase and is capable of production, but production has not yet commenced due to short-term circumstances outside of the project. In these cases, the project is still considered On Production. Likewise, in situations where production is temporarily interrupted (i.e., shut-in) and requires minor costs to restart, the project would still be considered On Production. Alternatively, if the interruption requires significant additional capital investment or the time frame to resume production is not certain to occur, then the project no longer has Proved Developed Reserves and should be reclassified to the appropriate sub-class.

- **Approved for Development** requires technical maturity of the project and all elements of commerciality to be in place (i.e., approvals are obtained, capital funds are committed). Construction and installation of project facilities should be under way or due to start imminently. Only a completely unforeseeable change in circumstances that is beyond the control of the developers would be an acceptable reason for failure of the project to be developed within a reasonable time frame.
- **Justified for Development** essentially covers the period when the operator and its partners have agreed that the defined project is commercially viable, and they have decided to proceed with development on the basis of an agreed development plan (i.e., there is a "firm intent"), but before the project has reached the Approved for Development sub-class, when all necessary approvals are in place (e.g., regulatory approval of the development plan) and a "final investment decision" has been made by the partners to commit the necessary capital funds. "Firm intent," in this context, is supported by evidence of alignment to proceed by all participating entities, with no known contingencies that would preclude development from proceeding at the appropriate time and within a reasonable time frame. In the PRMS, the recommended benchmark is that development would be expected to be initiated within five years of assignment as Reserves to this sub-class, unless a longer time frame is justified; for example, a remote development location, late-life compression installation, plateau extension, or infrastructure capacity constraint drives a longer time frame. In all cases, the justification for longer duration should be critically reviewed and documented (PRMS § 2.1.2.3 and § 2.1.3.6.4). It is worth noting that most projects progress directly from Development Pending into Approved for Development once all approvals and funds are secured.
- **Development Pending** is limited to those projects that are actively subject to project-specific activities, such as appraisal drilling or detailed evaluation, that are designed to confirm commerciality and/or to determine the optimum development scenario. In addition, it may include projects that have nontechnical contingencies, provided these contingencies are currently being actively pursued by the developers and are expected to be resolved positively within a reasonable time frame. Such projects would be expected to have a high probability of becoming a commercial development (i.e., a high chance of commerciality).
- **Development On Hold** is typified when a development plan has been identified, and the project is considered to have at least a reasonable chance of commerciality, but there are contingencies that need to be resolved before the project can move toward development. The contingencies may be either internal or external (examples: lack of funding, uncertainty of obtaining necessary permits). The primary difference between Development Pending and Development On Hold is that in the former case, the remaining contingencies are being addressed (e.g., data collection, negotiations) and are reasonably expected to be resolved within a reasonable time frame, whereas in the latter case, resolution of the primary contingencies may be seen less favorably and be subject to a significant time delay (e.g., technology advancement, market development, regulatory

policy progression). Any change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to a Development Not Viable sub-class.

- **Development Unclarified** is for discovered accumulations where additional data and analysis are required to define a development plan, and appraisal activities are ongoing to clarify the potential for development (e.g., a recent discovery). Contingencies have yet to be fully defined, and the chance of commerciality may be difficult to assess with any confidence.
- **Development Not Viable** is assigned when a technically viable project has been assessed as being of insufficient potential to warrant development, acquiring additional data, or any further efforts to remove contingencies. However, the estimated recoverable quantities are recorded so that the potential development opportunity will be recognized in the event of a major change in technology and/or commercial conditions. Projects in this sub-class would be expected to have a low chance of commerciality.

It is important to note that while the aim is always to move projects to the Reserves class with higher levels of maturity, and eventually to production, a change in circumstances (disappointing well results, change in fiscal regime, etc.) can lead to projects being reclassified to a lower sub-class. Further, projects may not necessarily pass sequentially through each sub-class as they move up or down the *y*-axis of commerciality.

One area of possible confusion is the distinction between Development Not Viable and Discovered Unrecoverable. A key goal of portfolio management should be to identify potential incremental development options for a reservoir, so it is strongly recommended that all technically feasible projects (i.e., based on established technology or technology under development) that could be applied to a reservoir are identified even though some may not be economically viable at the time. Such an approach highlights the extent to which identified incremental development projects would achieve a level of recovery efficiency that is at least comparable to analogous reservoirs. Looking at it from the other direction, if analogous reservoirs are achieving levels of recovery efficiency significantly better than the reservoir under consideration, it is possible that there are development options that have been overlooked.

Quantities should be classified as Discovered Unrecoverable only if no technically feasible projects have been identified that could lead to the recovery of any of these quantities (PRMS § 2.1.1.2). A portion of Unrecoverable quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Section 2.11 herein presents example applications of the Project Maturity sub-classes.

2.8 Reserves Status

Estimated recoverable quantities associated with projects that fully satisfy the requirements for Reserves may be subdivided according to their operational and funding status.

Under the PRMS, subdivision by Reserves Status is optional and includes the following status levels: Developed Producing, Developed Non-Producing, and Undeveloped. These subdivisions may be applied to all categories of Reserves (i.e., Proved, Probable, and Possible).

Reserves Status has long been used as a subdivision of Reserves in certain environments, and it is obligatory under some reporting regulations to subdivide Proved Reserves into Proved Developed and Proved Undeveloped. In many other areas, subdivision by Reserves Status is not required by relevant reporting regulations and is not widely used by evaluators. Unless mandated by regulation, it is up to the evaluator to determine the usefulness of these, or any of the other, subdivisions in any particular situation.

Subdivision by Reserves Status or by Project Maturity sub-class is optional, and, because they are to some degree independent of each other, both can be applied together. Such an approach requires some care, because it is possible to confuse the fact that Project Maturity sub-classes are linked to the status of the project as a whole, whereas Reserves Status considers the level of implementation of the project, essentially on a well-by-well basis. Therefore, unless each well constitutes a separate project, Reserves Status is a subdivision of Reserves within a project.

The relationship between the two optional classification approaches may be best understood by considering all the possible combinations, as illustrated below. **Table 2.1** shows that a project that is On Production could have Reserves in all three Reserves Status subdivisions, but it is the only sub-class with Developed Producing status, whereas all project Reserves must be Undeveloped if the project is classified as Justified for Development.

Project Maturity Sub-Class	Reserves Status		
	Developed Producing Reserves	Developed Non-Producing Reserves	Undeveloped Reserves
On Production	☐	☐	☐
Approved for Development	☐	☐	☐
Justified for Development	☐	☐	☐

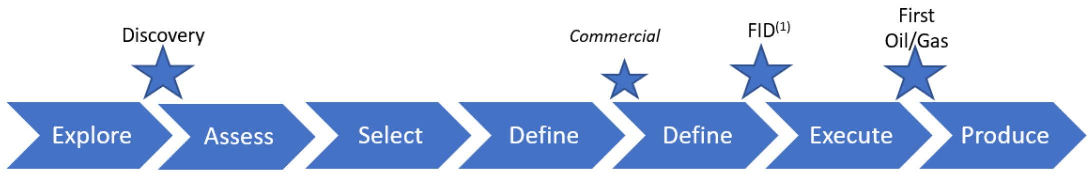
Table 2.1—Project Maturity sub-class relative to Reserves Status sub-class.

Applying Reserves Status in the absence of Project Maturity sub-classes can lead to the mixing of different types of Undeveloped Reserves and may hide the fact that they are subject to different levels of project maturity. By using Project Maturity sub-classes, a clear distinction can be made among:

- Those Reserves from "On Production" projects that remain Undeveloped because, although production has begun or is capable of producing from completed wells, some of the project wells have yet to be drilled at the date of the evaluation;
- Those Reserves from Approved for Development projects that remain Undeveloped because implementation of the approved, committed, and budgeted development project is ongoing, and drilling of the production wells, for example, is still in progress at the date of the evaluation; and
- Those Reserves from Justified for Development projects that remain Undeveloped while awaiting final approvals or contracts to be obtained before proceeding with development on the basis of an agreed development plan (i.e., there is a "firm intent" with no known contingencies that will preclude development from proceeding at the appropriate time and within a reasonable time frame).

For portfolio analysis and decision-making purposes, it is clearly important to be able to distinguish between these three types of Undeveloped Reserves with different levels of project maturity.

Fig. 2.4 illustrates how a typical project stage gate process can be related to the PRMS (e.g., status, classification, chance of development).



Also known as		Appraisal	Concept select	Pre-FEED, FEED[2]			
Discovery status	Undiscovered	Discovered	Discovered	Discovered	Discovered	Discovered	Discovered
Class	Prospective	Contingent	Contingent	Contingent	Reserves	Reserves	Reserves
Sub-class	Prospective	Unclarified	Pending	Pending	Justified for Development	Approved for development	On production
Reserves status	Not applicable	Not applicable	Not applicable	Not applicable	Undeveloped	Undeveloped or Developed non-producing	Undeveloped or Developed non-producing or Developed Producing
Chance of Development	Reasonable	Reasonable	Likely	High	Reasonably certain	Certain	Certain

[1] FID: Final Investment Decision; [2] FEED: Front-End Engineering Design

Fig. 2.4—Project stage gate sub-classes based on project maturity.

2.9 Economic Status

A third option for classification purposes is to subdivide Contingent Resource projects on the basis of economic status into Economically Viable or Economically Not Viable Contingent Resources; these sub-classes are based on assumed reasonable forecast conditions. In addition, the PRMS indicates that, where evaluations are incomplete, such that it is premature to clearly assess the project economics, it is acceptable to note that the project economic status is "undetermined" (PRMS § 2.1.3.7.6). As with the classification options for Reserves that are based on Reserves Status, this is an optional subdivision that may be used alone or in combination with Project Maturity sub-classes.

Broadly speaking, one might expect the following approximate (not necessarily equivalent) relationships between the two optional approaches **(Table 2.2):**

Project Maturity Sub-Class	Economic Status Sub-Class
Development Pending	Economically Viable Contingent Resources
Development On Hold	
Development Unclarified	Undetermined
Development Not Viable	Economically Not Viable Contingent Resources

Table 2.2—Approximate Project Maturity sub-class relative to Economic Status sub-class.

2.10 Estimated Ultimate Recovery and Technically Recoverable Resources

The PRMS (2018) has introduced "Estimated Ultimate Recovery" and "Technically Recoverable Resources" (EUR and TRR, respectively), commonly used terms in the industry, in its Glossary in an effort to avoid confusion with prior PRMS terminology (PRMS § 1.1.0.8).

EUR is an estimate of recoverable quantities of petroleum (including quantities already produced) from an accumulation(s), whether discovered or undiscovered. It is not a Reserve or Resource category or class, but rather a way to simply describe the quantity estimated to be recoverable based on defined conditions (for clarity, EUR must reference the associated technical and commercial conditions applied; e.g., proved EUR is Proved Reserves plus prior production). Care must be taken to ensure that consistent measurement (e.g., raw, marketable, sales quantities) between cumulative and forecast quantities is used for EUR.

TRR, on the other hand, are the estimated remaining technically recoverable quantity from an accumulation(s), whether discovered or undiscovered, and it is based on the volumes expected to be recovered from the project(s) being implemented or planned. TRR is not constrained by commercial conditions and does not include previously produced quantities (e.g., it is a forward-looking estimate of remaining technically recoverable quantities). The term "TRR" appears to have originated in governmental and geological assessments that were designed to reflect a nation's ability to marshal its hydrocarbon endowment in the event of a crisis. Therefore, TRR is an estimate of future technically recoverable quantities and does not include historical cumulative production.

For an EUR, there may be a "technical recovery" estimate, which could differ from a TRR estimate. This may happen, for example, when the technology applied in the EUR estimate is established technology, while the TRR estimate also relies on technology under development. "Technology under development" and "established technology" are considered currently available technology for TRR and can both be used to estimate technically recoverable Contingent and Prospective Resources. In all cases, any statement of EUR and TRR requires the conditions associated with their usage to be clearly noted and documented.

The following simple example illustrates some of the concepts associated with developing an EUR or TRR estimate. In **Fig. 2.5,** a well's historical production rates have been fitted with a hyperbolic decline forecast extrapolated to the technical limit (considering factors such as water handling, lift capacity, etc.). On the right-side axis, cumulative production is recorded. At the technical limit, the corresponding cumulative recovery is shown as the "Technical EUR" or, as denoted on the cumulative production line, "EUR_{tech}." However, the economic limit of production is reached before the technical limit, and we have a "Commercial EUR" or "EUR_{com}."

Notice that the "Cumulative Production" line starts at the left-side origin ("Initial Production") and represents a running total recovery from the beginning; i.e., the EUR figure will include the production prior to the "Evaluation Date" shown on the *x*-axis.

The area under the production forecast curve between the Evaluation Date and the Economic Limit Date has been highlighted and designated as "Reserves." (The quantity has satisfied the economic criterion, and, for the purpose of this example, we assume that the other commerciality criteria are met.) At the "Evaluation Date" on the *x*-axis, another cumulative line ("Future Cumulative Production") begins and is extrapolated, using the Production Forecast, to both the Economic and the Technical Limits.

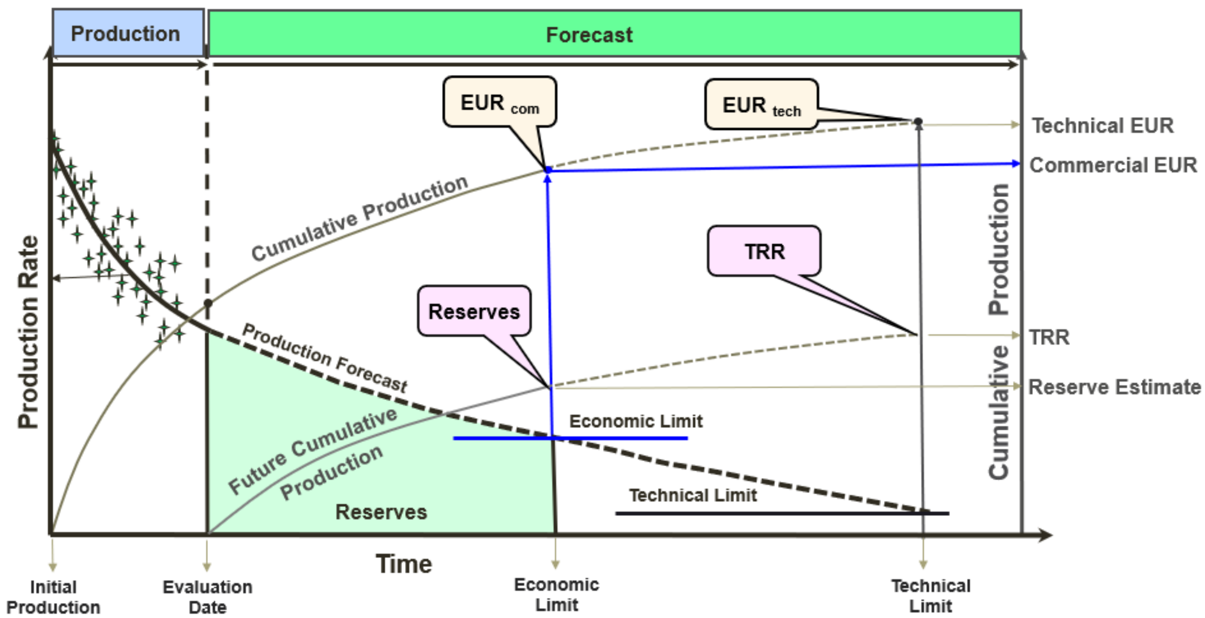


Fig. 2.5—Schematic comparison of Estimated Ultimate Recovery (EUR), Technically Recoverable Resources (TRR), and Reserves.

The area under the production forecast curve between the Economic Limit Date and the Technical Limit Date should be designated as "Contingent Resources." As pointed out before, a single project may not contain recoverable quantities in different resources classes under the PRMS because this constitutes split classification. In a situation where the product pricing forecast is unchanged, lowering the economic limit to the technical limit will necessitate some form of cost reduction or facility modification, for example, thereby extending the economic life. This project would normally require investment decisions (such as implementing new or changing out artificial lift methods) and is not part of the existing project development plan.

In this example, the Economic and Technical Limits for the EUR case are assumed to be the same for the TRR case, although they do not need to be, depending on, for example, the technology employed. Again, assuming the two curves are based on the same applied technology, Fig. 2.5 has two cumulative production lines, one for the EUR and one for the TRR (which excludes prior production), and these lines are parallel but shifted by the cumulative recovery at the Evaluation Date.

Therefore, if we take the EUR_{com} and subtract the cumulative production at the Evaluation Date, then we arrive at the "Reserves" (if the production forecast is a 2P projection, then the Reserves are the 2P quantities; in this situation, the EUR may be designated as "EUR 2P," because it is the sum of the cumulative recovery as of the Evaluation Date plus the 2P projection). Likewise, if we subtract the cumulative recovery at the Evaluation Date from the EUR_{tech}, then we obtain the TRR, as shown in **Table 2.3** below, again using the same production forecast, applied technology, etc., for both the EUR and TRR projections.

Furthermore, if Fig. 2.5 represents a project that has a cumulative production of 100 (units of your choice) as of the evaluation date with a production forecast that predicts an EUR (to the technical limit of production) of 250 units, then Table 2.3 indicates that the project's TRR (at the evaluation date) is 150 units. Considering economic parameters, the EUR_{com} (to the economic limit) is 175 units, which is 75 units less than the EUR_{tech}. The Reserves (being the remaining commercial quantities) would then be 175 – 100 units, i.e., 75 units at the evaluation date.

Cumulative Production at Evaluation Date	100	
EUR_{tech}	250	
TRR	150	EUR_{tech} – Cumulative Production *
EUR_{com}	175	
Reserves	75	EUR_{com} – Cumulative Production *
** For this example, this is not always true (see text).*		
All quantities must be measured on the same basis (e.g., raw, sales quantities, etc.), but "Reserves" are recommended to be sales quantities per the PRMS.		

Table 2.3—Comparison of recoveries.

Other adjustments that can be made to these projections include consideration of royalties, license term, variation in applied technologies, other commercial criteria, and so on.

2.11 Example Application of Commercial Maturity Sub-Classes

Five coalbed methane exploration/appraisal wells were drilled in the southern part of a license block in 2017. In 2018, a production pilot project using these wells commenced with the commissioning of flowlines and a compression station selling gas to pressurized-gas filling stations in the vicinity under a 15-year gas contract.

In early 2019, five new wells were drilled and completed in the northern part of the license **(Fig. 2.6).** Coal characteristics as evaluated from logs were found to be similar to the southern pilot wells. A decision was made to not acquire core data. The producing company decided to complete these wells due to the similarity to the pilot geology, but without testing them. Contracts to sell the gas from all five wells were negotiated. Compression units and flowlines were included in the budget as part of the business plan.

Fig. 2.6—Coalbed methane development.

However, development of the 2019 wells faced opposition from the communities living in this remote area close to a national park. Public demonstrations and complaints filed with the local council resulted in delays to the permit to produce and pending hearings.

Nevertheless, the company committed to drill 20 new wells in five years from 2020 to 2024 as part of a Phase II development of the southern area. The first four wells were drilled in 2020, and another six wells were scheduled to be drilled in 2021. The last 10 wells will be drilled thereafter.

Log data from the 2020 wells showed geological and petrophysical properties similar to the 2017 southern pilot wells. It was decided not to test the wells but to complete them as producers. As of the 31 December 2020 evaluation date, the first four wells were ready for production.

Fifteen-year sales contracts are being negotiated to secure gas sales from the first 10 wells from Phase II. The wells will provide gas to several gas filling stations, and new gas stations have been approved to be built in 2022 to take gas from the remaining 10 wells.

The following questions pertaining to the above scenario reference **Fig. 2.7,** which is duplicated from PRMS Figure 2.1:

- Can the Entity Claim Any Reserves from the Five Southern Area (Pilot) Wells? This development project is currently producing under a 15-year sales contract to an existing market. Assuming the entity would not embark on development of these wells without having satisfied all commerciality criteria, Reserves (maturity sub-class On Production) may be assigned for the 15-year contract duration. Beyond that date, any further quantities would be classified as Contingent Resources, with the maturity sub-class being either Development Pending or Development On Hold, depending on the likelihood of extending the gas contract.
- Can the Entity Claim Reserves from the Five Northern Area Wells? The wells have been completed, and facilities have been committed in the budget; a market exists, as evidenced by the contract negotiations; however, the public opposition poses a contingency to development. Although the northern area project could be considered as Reserves with a maturity sub-class of Approved for Development, the PRMS notes that this sub-class requires that the project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Similarly, a requirement for the Justified for Development sub-class states there is reasonable expectations that all necessary approvals or contracts will be obtained and there must be no known contingencies that preclude the development from proceeding. The public protest may stop the project from moving forward, and as such, the northern area project should be classified as Contingent Resources, sub-class Development On Hold. A Contingent Resources, Development Pending sub-class is not recommended due to the prospect that "critical contingencies…are reasonably expected to be resolved within a reasonable time frame," which, at this point, has not been determined.
- Can the Entity Claim Reserves for the Phase II 2020 Wells? How about for the Phase II 2021 Wells? Sales contracts are being negotiated and will likely be concluded without contingencies; the entity has already drilled four wells and is committed to drill six 2021 wells, with a further 10 wells drilled thereafter. The first four wells, although not currently on production, are capable of producing and selling petroleum to market, and therefore they qualify as Reserves (Developed status) with the sub-class On Production. The second six wells have yet to be drilled, and so they have Undeveloped Reserves status with the sub-class Approved for Development, because all necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way. It must be noted that these second six wells will be drilled at a tighter well spacing than the previous four wells drilled in 2020 and the original five wells drilled in 2017; therefore, the reserve assessment must account for the risk of well interference and potential lower recovery per well resulting from the tighter spacing.
- Can the Entity Claim Reserves for the Undrilled Post-2021 Phase II Wells? The development project is commercially viable at the time of reporting, based on the

reporting entity's assumptions (Forecast Case). There is a firm intention to proceed with development within a five-year window. The development plan is well defined, and there is "Reasonable Expectation" that the sales contract required prior to project implementation will be forthcoming. There are no known contingencies that could preclude the development from proceeding. The last 10 Phase II wells have yet to be drilled, and so they have Undeveloped Reserves status with the sub-class Justified for Development. They do not meet the requirements for Approved for Development established by the decision gate that specifies the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development. As stated above, these remaining wells will be drilled as infills, and at tighter well spacing than the current wells, so the reserve assessment must account for the risk of well interference and resulting potential for lower recovery per well.

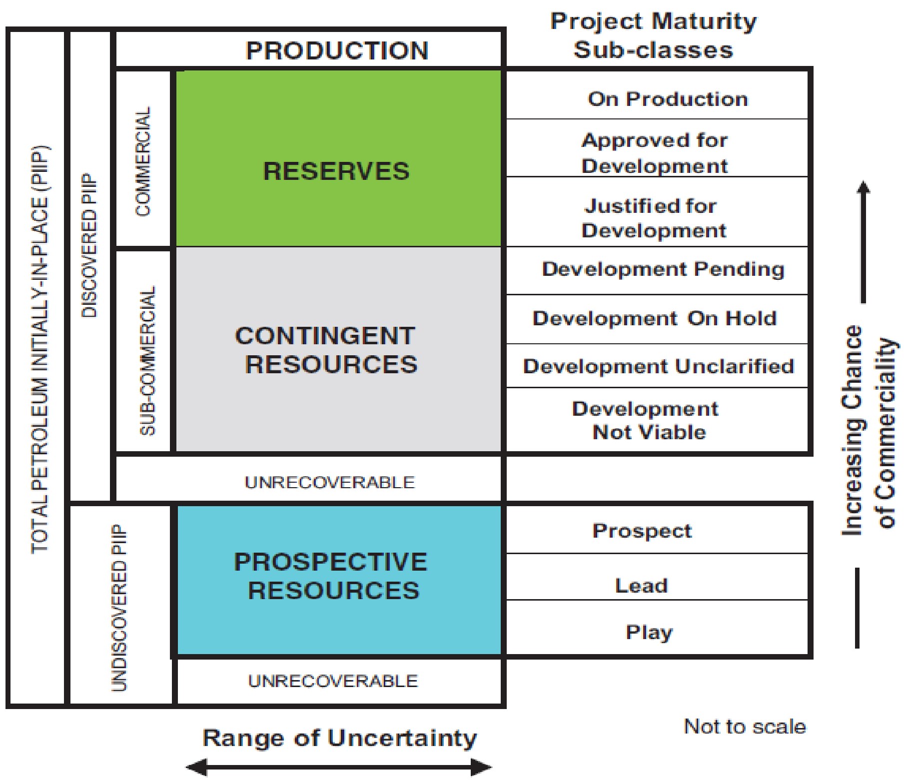


Fig. 2.7—Sub-classes based on maturity.

2.12 Acknowledgments

The authors wish to acknowledge the contribution of James G. Ross, author of this chapter in the previous version of the *Guidelines for Application of the PRMS*. In addition, important feedback and editorial effort have been provided by Charles Vanorsdale, Dan DiLuzio, Carolina Coll, Bernard Seiller, and Ian McDonald.

2.13 Reference

Petroleum Resources Management System, Version 1.01. 2018. Richardson, Texas, USA: Society of Petroleum Engineers.

Chapter 3
Seismic Applications

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3.1 Introduction and Overview

Geophysical methods, and especially surface and borehole seismic surveys, have been used for decades by the petroleum industry for exploration and development. As a cornerstone subsurface discipline, the field of geophysics offers practical tools with which to describe and characterize the subsurface, including the locations and the volumes of in-place hydrocarbons.

In general, geophysical applications contribute to the definition of the technical basis for the estimation of resources and their volumetric uncertainty in the subsurface. Technical advances continue to be made as a result of improvements in all facets of the seismic data value chain: acquisition, seismic processing, imaging, advanced signal data analysis, inversion, and interpretation. The quality of seismic data has improved through time, as much as the ability of experienced professionals to associate seismic responses with reservoir and fluid properties under both static and dynamic conditions. This has resulted in notable improvements in the reliability of seismic technology to support the mapping and modeling of hydrocarbon accumulations. Advances in areas such as full waveform inversion have resulted in higher-fidelity understanding of the three-dimensional (3D) velocity field, which allows for improved estimation of the shape of reservoirs and reduced uncertainty in depth predictions.

When seismic inversion and time-lapse [four-dimensional (4D)] seismic results are linked to geostatistical modeling and to assisted history matching of dynamic models, geoscientists and engineers are now able to build more robust ranges of uncertainty in the quantities of recoverable hydrocarbons. This linkage enables engineers and geoscientists to more efficiently and accurately build and test integrated geologic models and reservoir simulation models that agree with well, seismic, and production data. These models, which inform the uncertainty space, are based on multiple scenarios of 3D reservoir architecture and tie fluid movement in time through a field development plan. They help in defining ranges of technically recoverable resources from a field, based on the existing well stock, in addition to possible future production or injection wells.

This chapter introduces and explains the application of seismic methods in reserves and resources assessment in line with the PRMS guidelines. There is a vocabulary associated with geophysical concepts in addition to the application and interpretation of these concepts, which are beyond the scope of this brief chapter. The reader is encouraged to refer to the Glossary at the end of this volume, and to seek deeper understanding from their geophysicist colleagues, references within this chapter, and the Society of Exploration Geophysicists as well.

3.2 Shared Earth Modeling

A Shared Earth Model (SEM), also called a Common Earth Model, is a multidisciplinary computerized digital 3D representation of Earth's subsurface containing a petroleum reservoir system. It can be used to determine the size and uncertainty of total petroleum initially in place (PIIP) in the system, predict production performance for wells, and optimize the field development. This model is created by inputting all the available data from geology, geophysics, petrophysics, and reservoir engineering, in different scales, and mathematically integrating these data sets. Besides representing the subsurface as realistically as possible, the SEM should be updated constantly to stay current as new data are acquired and imported.

The SEM can be subdivided into two types: a static model and a dynamic model. In general, geologists, geophysicists, and petrophysicists mainly work on the geologic framework or static model (geomodel), which is about geology, rock, and pore matrix. Reservoir engineers and petrophysicists mainly work on the dynamic model (or reservoir model), which is about behavior of fluids in the matrix. A reservoir simulation usually runs on these models to estimate the pore fluid dynamics and to predict the field performance under a series of different producing strategies. (See Chapter 6—*Reservoir Simulation*, herein, for more detail on the aspects of dynamic simulation.)

In the last decade, with the rapid advances of modeling software, computational hardware, and information technologies, it is more common and practical for companies to build an SEM to manage the development, performance, and life cycle of oil and gas reservoirs, as well as for the purpose of improving estimation of reserves/resources and making decisions.

3.2.1 Static Model—Geologic Framework Architecture. A static model is often called a geologic model. It integrates all available geological, geophysical, and petrophysical data and is constructed to focus on the structure (including horizons, faults, folds, and unconformities), rock properties (including lithology, clay content, porosity, pore fluids saturation, permeability, natural fractures, and distribution), reservoir properties (including thickness, net-to-gross ratio, and geometry), depositional environment and stratigraphy (including sequence stratigraphy, facies distribution, and petroleum system), and other geological features pertinent to the model. Those components are relatively static during the production period. A static model represents the subsurface geology and container of hydrocarbons with calculatable properties and uncertainties for resource estimation and classification.

A 3D seismic survey samples the 3D space of the subsurface evenly in both lateral and vertical directions. A grid of multiple two-dimensional (2D) seismic lines samples the subsurface evenly in the line direction and vertical direction but may have large gaps between lines. In contrast, a drilled well samples the subsurface at a single location, with much higher resolution along the wellbore trajectory but much less detection and resolution laterally away from the wellbore. Being able to "see" the entire picture of the subsurface makes seismic surveys natural and effective tools to define the medium- to large-scale features for constructing the framework of the static model beyond the existing wells. After carefully correlating seismic data with well data and time-depth conversion, the accuracy of depth from seismic interpretation could be as high as 1 to 2 m (3 to 6 ft) for clean and less noisy, shallow data.

The process of seismic inversion turns seismic trace amplitude information into rock properties by using well data as input. The result from this process could be used to fill the framework of the static model constructed from seismic interpretation. The advantage of seismic inversion is that the rock properties in the inter-well space are transformed from seismic measurements to petrophysically tied rock and fluid properties, rather than relying on a mathematical interpolation of the well data, especially when two wells are far apart.

3.2.2 Dynamic Model—Reservoir Simulation. A dynamic model may be upscaled from the static model to integrate all available reservoir engineering and petrophysical data. A good dynamic model needs to be based on a good static model.

Reservoir simulation combines geological, geophysical, engineering, and production data to model fluid saturation and pressure changes, primarily, as the reservoir is produced. These dynamic reservoir models are typically used to influence field development decisions and to estimate reserves, as further discussed in Chapter 6—*Reservoir Simulation*. During field production, history matching is used to validate the underlying SEM, to fine-tune volume estimates, and to better predict future reservoir performance.

Time-lapse (4D) seismic data, acquired during field production, are used to inform both static and dynamic models. The 4D seismic data provide additional constraints on structure and static properties such as lithofacies, reservoir continuity, and stratigraphy. In a process called seismic history matching, 4D seismic data also help to determine reservoir compartmentalization due to lateral facies changes and faults, and to constrain properties such as permeability and fault transmissibility.

3.3 Volumetrics, Trap Geometry, and Gross Rock Volume

3.3.1 Defining Seismic Data. Volumetric analysis is one of the means in the PRMS (§ 4.1.2) by which the PIIP may be calculated using reservoir rock and fluid properties. The term "volumetrics" refers to a static calculation based on a geologic model dependent upon geometry to describe the bulk volume of hydrocarbons in the reservoir. The uncertainty of the estimation depends on the amount of data available and the quality of that data. Uncertainty is high in the early stages of exploration but decreases as wells are drilled and the reservoir is developed.

A volumetric estimate of in-place volumes is the product of trapped reservoir area, net reservoir thickness (see Chapter 5—*Petrophysics*, herein, for a discussion of net pay), porosity, water or hydrocarbon saturation, and formation volume factor. At prediscovery (exploration) and early postdiscovery (early appraisal) stages, with limited well information, reservoir (or prospective reservoir) geometry interpreted from 2D/3D seismic surveys is likely the only direct way that is available to assess PIIP. Global-average single values of porosity and saturation across the reservoir, regional mapping, and analogous field data are commonly used in volumetrics estimation with a range of uncertainties.

Defining trap geometry is essential for volumetrics. For all three types of conventional reservoir traps (structural, stratigraphic, and combination), trap geometry consists of the top and base of reservoir boundaries and the top and lateral seal/barriers and constraining or limiting faults, forming the trap. All of these should be in the physical depth space.

A 3D seismic volume allows an interpreter to map the trap as a 3D grid of seismic amplitudes reflected from acoustic/elastic impedance boundaries associated with the rocks and fluids in and around the trap. Mapping traveltimes to selected acoustic/elastic impedance boundaries (geoscientists often call these boundaries seismic horizons), displaying seismic amplitude variations along these horizons, delineating isochrons between horizons, noting changes in amplitude and phase continuity through the volume, and displaying time and/or horizon slices and volumetric renderings of the seismic data in optimized colors and perspectives all contribute to the detailed picture of the trap's geometry.

Such seismic interpretations are made either in the time domain (and then converted to the depth domain by time-to-depth conversion) or in a depth domain in a depth-migrated data set (sometimes a depth-to-depth adjustment is needed when more wells are incorporated into or after seismic depth-processing). Velocity data from wells, optionally supplemented with seismic velocity data, are used to convert the horizons picked in time into depth and thickness. The resolution of 3D seismic data typically ranges from 12.5 to 50 m laterally and from 8 to 40 m vertically, depending on the depth and properties of the objective reservoir, as well as the nature of the seismic survey acquisition parameters and the details of the subsequent processing.

It is important to appreciate that the relative uncertainty in predicting depth to a trapping surface at a new location some distance from an existing borehole is much less than the errors in predicting trap depth in an exploration setting prior to the drilling of the first well. That uncertainty generally is tens to hundreds of meters because there is no borehole control on the vertical velocity from Earth's surface down to the trap. Effectively, the early wells help to "anchor" the 3D seismic volume at several key points in measured depth, assisting the subsurface interpretation in further refining the accumulation's geometry into undrilled areas.

Gross Rock Volume (GRV) is defined as the total volume of rock within the hydrocarbon trap, bounded by top and base of the reservoir, and any lateral barriers, above and below the hydrocarbon-water contact. The fundamental and traditional role of seismic data in the past has been directed towards the mapping and construction of a 3D geologic model of hydrocarbon traps and in establishing the GRV for a reservoir. The seismic-interpreted trap geometry, calibrated by reservoir thickness from well data, leads to the calculation of GRV, which is a critical factor in the calculation of PIIP.

The same procedure is necessary for each fault block of a fault-controlled, compartmentalized reservoir and each pool of a stacked reservoir. Also, it is important to assess fault transmissibility, by analyzing the fault configuration, fault complexity, and the juxtaposition of reservoir-to-reservoir contact across the fault, and to compare this to a well's performance, fluid and pressure data in the surrounding area, along with the regional geologic characterization. The 3D seismic data directly help to define, classify, and configure the middle- to large-scale faults.

In the case that reservoir formations are interbedded with nonreservoir formations under and within the trap geometry, reservoir bulk volumes could be obtained by using the GRV and net-to-gross ratio, after defining the reservoir rock by cutoff values of petrophysical parameters like porosity, clay content, or a certain log measurement or log interpretation from wells. The net-to-gross ratio often has a relationship to geological depositional environment, which could be estimated from 3D seismic surveys, and hence the spatial distribution of net-to-gross ratio could be estimated and then applied to estimate the reservoir bulk volumes.

Methods and technologies in geophysics advance rapidly. It is especially important to keep in mind that seismic survey acquisition and the data processing history affect the subsurface imaging. Recent advances in seismic data processing have improved velocity estimation (including anisotropy), depth imaging, time-depth conversion, depth-depth conversion of depth-imaged data, and structural attributes. Detailed seismic velocity analysis can provide a range of uncertainty on GRV and hence impact ranges in resources volumes.

3.3.2 Uncertainty in GRV. The GRV of a field is defined by structural elements, such as depth maps and fault planes, resulting from an interpretation based on seismic and well data. If the trap volume under the seal is completely filled with reservoir rock, then the GRV of the trap is the same as the reservoir bulk volume. Though ideal, this is generally not the case, and the thickness and geometry of the one or more reservoir units within the trap have to be estimated to derive reservoir bulk volume. Uncertainties in the GRV associated with seismic analysis, and hence uncertainties in the in-place volumes, reserves, and production profiles, can arise from:

- Incorrect positioning of structural elements during the processing of the seismic data.
- Thinly layered reservoir and nonreservoir intervals below well and seismic resolution.
- Incorrect interpretation of trap geometry and reservoir geometry.
- Errors in the time-to-depth conversion.

An assessment of these uncertainties is an essential step in a field study for evaluation, development, or optimization purposes. Generally, the relative uncertainty in predicting formation depth on seismic data is inversely proportional to the number of wells in the seismic covered area; i.e., the more wells used to calibrate the model, the less uncertainty there is in the predicted depth. Lack of well control could lead to large uncertainties in general seismic interpretations, for example, in a very early stage of exploration.

The accuracy of the estimate of the thickness (gross and net) of each reservoir is a critical element in assessment of in-place volumes. Estimation of gross reservoir thickness is dependent on the bandwidth and frequency content of the seismic data and on the seismic velocity of the formation rocks. Broadband, high-frequency seismic data in a shallow clastic section where velocity is relatively slow can resolve a much thinner bed than, for example, narrowband, low-frequency seismic data deep in the subsurface in a fast carbonate section. Fortunately, geoscientists can analyze seismic and sonic log data to estimate the thicknesses that can reasonably be measured for particular formations/reservoirs under investigation. Again, the reasonableness of these ranges can be compared to and constrained with regional data and other oil and gas fields found in analog plays and basins.

Stacked reservoirs in a trap can be resolved individually, and separate reservoir bulk volumes can be computed, if the reservoirs and their intervening seals can be interpreted separately and individually based on the minimum thickness derived from the relevant tuning model. Under these conditions, a deterministic estimate of reserves in each reservoir is possible. When the individual reservoirs and seals are too thin to satisfy these conditions, then seismic modeling can be used to get a general idea of the hydrocarbon reserves that might be present in a gross trapped volume. In some circumstances, it may be possible to detune the seismic response of thin reservoirs to estimate the total net or gross reservoir. The reliability of these calculations will depend on the formation's geological setting, such as bed thicknesses, spacing between beds, porosity variation, and quality of seismic data.

3.4 Amplitude Variation With Offset and Direct Hydrocarbon Indicator Analyses

3.4.1 Introduction. The use of seismic reflection data to reduce uncertainties associated with hydrocarbon assessment has been well documented since the mid-1970s. The term "direct hydrocarbon indicator," or DHI, refers to the use of seismic data to indicate the presence of hydrocarbons. DHIs include flat spots, bright spots (strong amplitude reflections), and dim spots, as well as more subtle changes in seismic phase (see Fig. 3.1). To maximize the confidence, DHIs must be interpreted by experts and, in the context of a rock physics model, be calibrated to well data.

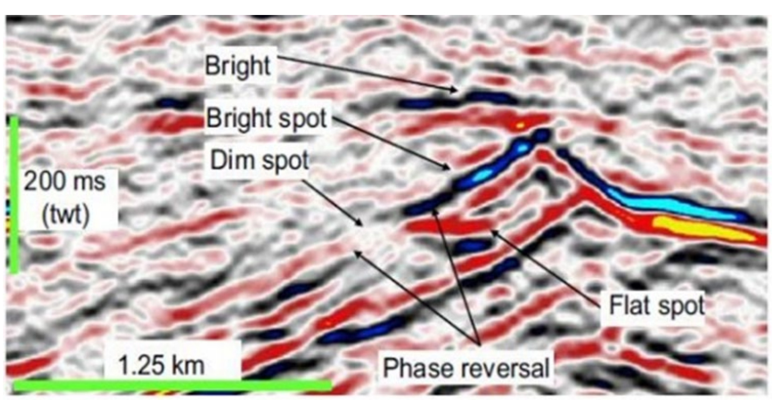

Fig. 3.1—Common Direct Hydrocarbon Indicators (DHIs), where twt indicates two-way traveltime.

Rutherford and Williams (1989) classified amplitude variation with offset/amplitude variation with angle (AVO/AVA) anomalies into three classes, based on three reservoir types: **Class 1** reservoirs have higher impedance than the surrounding rocks; **Class 2** are reservoirs with very small, either positive or negative, impedance contrast; and **Class 3** are reservoirs with lower impedance than the surrounding rocks. This was later refined by Castagna and Swan (1997), who introduced a fourth AVO class, which corresponds to low-impedance reservoirs similar to Class 3, but where the magnitude of reflectivity decreases with offset/angle **(Fig. 3.2).**

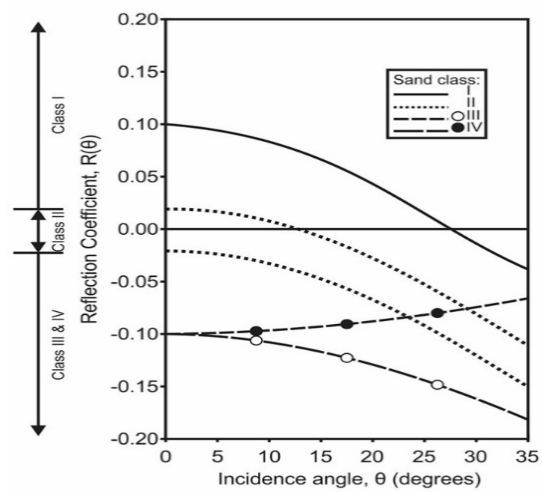

Fig. 3.2—Definition of four classes of amplitude variation with offset/angle (AVO/AVA) (from Castagna and Swan 1997).

When a known hydrocarbon accumulation is being appraised, seismic flat spots and/or seismic amplitude anomalies can be used to increase confidence in the identification of fluid contacts when the following conditions are met:

- The flat spot and/or seismic amplitude anomaly is clearly visible in the 3D seismic data and is not related to imaging issues.
- Within a single fault block, well logs, pressure, well test, and/or performance data demonstrate a strong tie between the calculated hydrocarbon-water contact (not necessarily drilled) and the seismic flat spot and/or downdip edge of the seismic anomaly.
- The spatial mapping of the flat spot and/or downdip edge of the amplitude anomaly within the reservoir fairway fits a structural contour, which usually will be the downdip limit of the accumulation.

Seismic amplitude anomalies may also be used to support reservoir and fluid continuity across a faulted reservoir provided the following conditions are met:

- Within the drilled fault block, well logs, pressure, fluid data, and test data demonstrate a strong tie between the hydrocarbon-bearing reservoir and the seismic anomaly.
- Fault throw is less than reservoir thickness over (part of) the hydrocarbon-bearing section across the fault, and the fault is not considered to be a major, potentially sealing, fault.
- The seismic flat spot or the seismic anomaly is spatially continuous and at the same depth across the fault.

If these conditions are met, the presence of hydrocarbon in the adjacent fault block above the seismic flat spot or seismic amplitude anomaly may be judged to be sufficiently robust to qualify the hydrocarbon volumes. If these conditions are only partially met, the interpreter must consider the increased level of uncertainty inherent in the data and appropriately classify the volumes based on the uncertainty components.

Synthetic seismic AVO modeling (also called forward elastic seismic modeling) is the key tool used to model the expected seismic amplitude response based on available well and/or analog data. Perturbations to an AVO model are performed for various ranges in reservoir thickness as well as reservoir lithology, porosity, net-to-gross ratio, overburden, and fluid content (hydrocarbon type, saturation, and pressure). This exercise provides the seismic interpreter with a fundamental understanding of possible scenarios that can give rise to various seismic responses, and the results can be compared to the observed seismic traces. New probabilistic methods allow for the modeling of large numbers of scenarios that are quantitatively matched to the observed seismic response, thus resulting in a probability distribution function that ultimately gives a probability of hydrocarbon presence.

The presence of a robust DHI can have a substantial influence on the establishment of the risk and/or volumes associated with a potential reservoir interval. The recommended practices in the following sections demonstrate ways to quantify the uncertainty and improve the confidence of a DHI associated with seismic amplitudes to aid in reducing uncertainty in the estimation of resource volumes.

It is noted that in many other examples, in which the seismic evidence (e.g., seismic DHI) is not as convincing, other data sources (e.g., pressure data, well performance data, geologic deposition model) will also contribute as part of an integrated analysis to achieve comparable confidence of the hydrocarbon volumes below the lowest known hydrocarbons, as observed in the wells.

Common pitfalls in seismic amplitude interpretation from DHIs are generally associated with variables including: low gas saturation; seismic data artifacts due to multiples, noise, and anisotropy; unusual lithology (e.g., abnormally high porosity sands, coals, and other unusual lithologic variations); and formation thickness (i.e., tuning and lateral variations).

3.4.2 Confidence Measures. Practitioners (Roden et al. 2012, 2014), as well as many oil and gas companies, have compiled databases to quantify the success of using seismic amplitudes to identify hydrocarbons prior to drilling. Scoring systems vary between companies and consortia, but they are typically based on two criteria: confidence of the DHI and maturity of the analysis/data quality. Such scoring systems can be used as a template to help interpreters characterize an undrilled accumulation.

- **DHI confidence** is established according to the following characteristics:
    - **Amplitude conformance** to structure, which is the amplitude termination at the closing contour of the structure.
    - Presence of a **flat spot** associated with the hydrocarbon contact.
    - **AVO response** and **amplitude standout,** matching the expected response from synthetic seismic modeling.
    - **Match to local analogs** (well control), where amplitude is supported by nearby wells in similar reservoir zones.
    - **Quality control of seismic observations with AVO analysis** using gathers, far-offset/angle stacks, and/or windowed attributes.
- The **DHI maturity** of the available data and its interpretation are based on the following characteristics:
    - **Seismic data availability and quality,** including 2D/3D, prestack or poststack, and time or depth data.
    - **Well-log data availability and quality,** including acoustic (compressional and shear sonic) logs, high-quality density logs, lithology interpretation, and fluid saturation interpretation.

- **Seismic data calibration,** where seismic data are calibrated to well control to allow quantitative comparisons of synthetic models to seismic observations.
- **Interpretation,** where the maturity of the interpreted strata and their depositional environments are interpreted to allow appropriate amplitude extractions and other seismic guided analysis, calibrated to well data for both geology and rock physics perspectives.

Based on the established confidence and maturity characteristics, a DHI score can be determined and refined over time. This allows for continuous learning and calibration. A consistent peer-review process should be employed to establish a robust score and remove any bias in the analysis. As the accumulation is developed and additional data are acquired, DHIs can be updated and rescored if needed.

3.4.3 Evaluation of Resources Using Seismic and Well Data. The use of seismic data in the evaluation of resources has been discussed in the literature by Ogilvie and Keyser (2004), Kloosterman and Pichon (2012), Pichon et al. (2012), and Roden et al. (2012), among others. Seismic data can be used for assessment of the structure, reservoir thickness/extent, fluid contacts, and, in many cases, reservoir rock quality (such as low/high porosity and permeability). The presence of DHIs can have a significant impact on methods used to assess Prospective Resources in the exploration stage, i.e., for the aspect of area and thickness determination. Using seismic data as a support for reservoir extension may allow for booking volumes beyond well spacing. An appropriate level of rigor is necessary to assess Proved Reserves using seismic surveys, and seismic data must be integrated with other direct indicators of hydrocarbons, but it is important to keep in mind that seismic data alone may not be sufficient to define fluid contacts for Proved Reserves (PRMS Table 3). Strict criteria are required to provide a body of evidence and to demonstrate that the seismic survey can establish a deeper contact than that established by wells **(Fig. 3.3).** Note, however, that although the presence of hydrocarbons below the lowest-known hydrocarbon in the figure may be inferred from the seismic signature, evaluators cannot determine "reasonable certainty" in the absence of other data. A loss of amplitude suggests the presence of a hydrocarbon-water contact in the cross section, above which may be inferred hydrocarbons capable of economic producibility. When appropriately analyzed and applied, seismic DHI can help to reduce the associated uncertainty of resources categories.

Once seismic observations have been calibrated and made to corroborate with DHIs (such as from cores, logs, and wireline formation testing), DHI workflows should be deemed reliable, as discussed above.

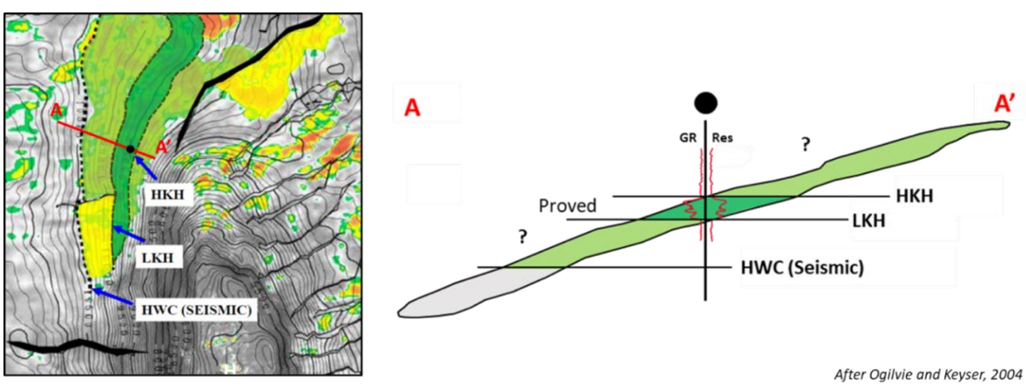

Fig. 3.3—Example showing where seismic amplitudes may aid in the booking of reserves below the lowest-known hydrocarbon (LKH) down to the termination of seismic amplitude at the hydrocarbon-water contact (HWC) (after Ogilvie and Keyser 2004), where HKH indicates highest-known hydrocarbon, GR indicates natural gamma ray log, and Res indicates resistivity log.

3.4.4 Recommended Guidelines for Using Seismic DHIs. Effective DHIs must be derived from the highest-quality seismic data available and must be shown to have a high degree of confidence to delineate a Proved area. This can be achieved through confidence measures as discussed previously. An appropriate level of sophistication and redundancy is necessary to evaluate reserves/resources using seismic data (Ogilvie and Keyser 2004). The scoring measures should be documented. If that is not possible, then the following criteria need to be clearly demonstrated and documented to provide an appropriate "body of evidence."

- **Appropriate seismic data quality available:** Angle/offset gathers and angle/offset stacks must be available for proper analysis. It needs to be demonstrated that high-quality 3D seismic coverage (depth-migrated volume with accurate velocity control) exists over the entire structure. The reservoir zone also must be shown to have high signal-to-noise ratio and appropriate angle coverage to enable appropriate observations of the expected AVO response. The seismic image must be shown to be free of any noise affecting the ability to utilize amplitudes to infer the presence of hydrocarbon reservoirs.
- **Expected DHI response observed and validated:** AVO synthetic modeling with appropriate perturbations to the rock physics model (porosity, saturation, hydrocarbon type, thickness) must be shown, using local well control. AVO synthetic models of local reservoir analogs from nearby wells must be shown to directly match the observed seismic responses with no ambiguity.
- **Amplitude standout from background:** The seismic amplitude signature of the hydrocarbon response must be easily discernible from that of a brine amplitude response with no ambiguity. For example, typical seismic amplitudes of hydrocarbon-filled sands with Class 3 AVO (per Section 3.4.1) are on the order of two to three times greater than the amplitude responses of the equivalent sands filled with brine.
- **Amplitude conformance to structure:** The downdip limit of the amplitude anomaly should conform to depth structural contours **(Fig. 3.4).** Lateral velocity variations should be taken into account or be shown to have a minimal impact. Time contours may be used when insufficient formation velocity data are available; i.e., there not enough wells to calibrate depth.

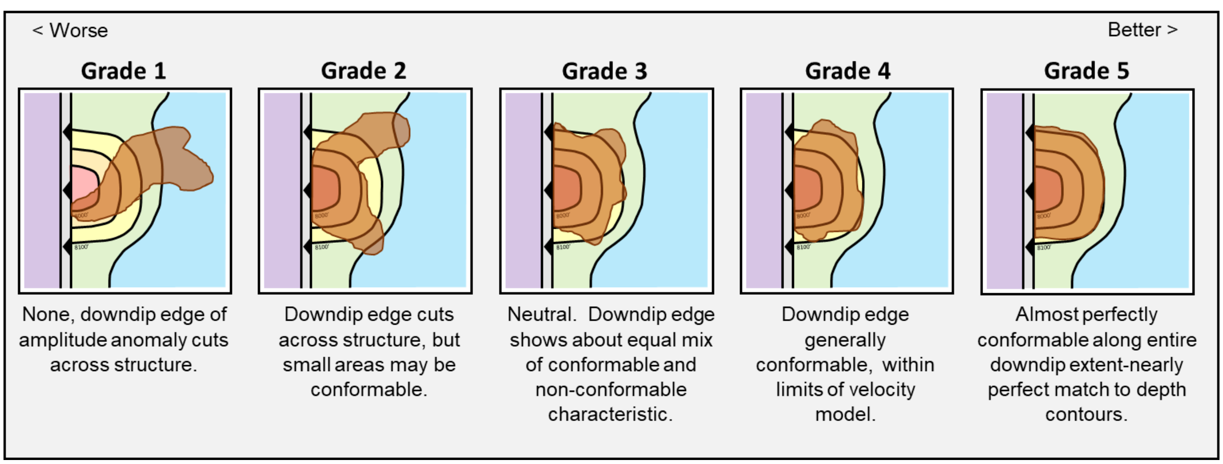

Fig. 3.4—Grading of amplitude conformance (after Roden et al. 2012).

- **Continuous seismic amplitude response:** Amplitude responses must be shown to be continuous from the existing well control with productive hydrocarbons to the area of structural conformance or "flat spot" **(Fig. 3.5).** No discontinuities should exist in the area of amplitude to be booked. Discontinuities can indicate variable reservoir quality or possible seismic data quality issues that affect the reliability of the amplitude interpretation.
- **Pressure and fluid data:** Seismically inferred fluid contacts must be integrated, and in agreement, with reliable high-quality pressure or pressure gradient data (e.g., wireline formation testing, regional mapping, and models of log and capillary pressure based on heights above free-water level in the reservoir zone being characterized.
- **Endorsement:** It is imperative that the recommendation to book resources and reserves using seismic interpretation has been reviewed and endorsed by a technical peer-review team, internal reserves group (geoscientists and engineers), and/or independent consultants.
- **Documentation:** Geophysical techniques and applications must be well documented and show that all the above criteria have been met.

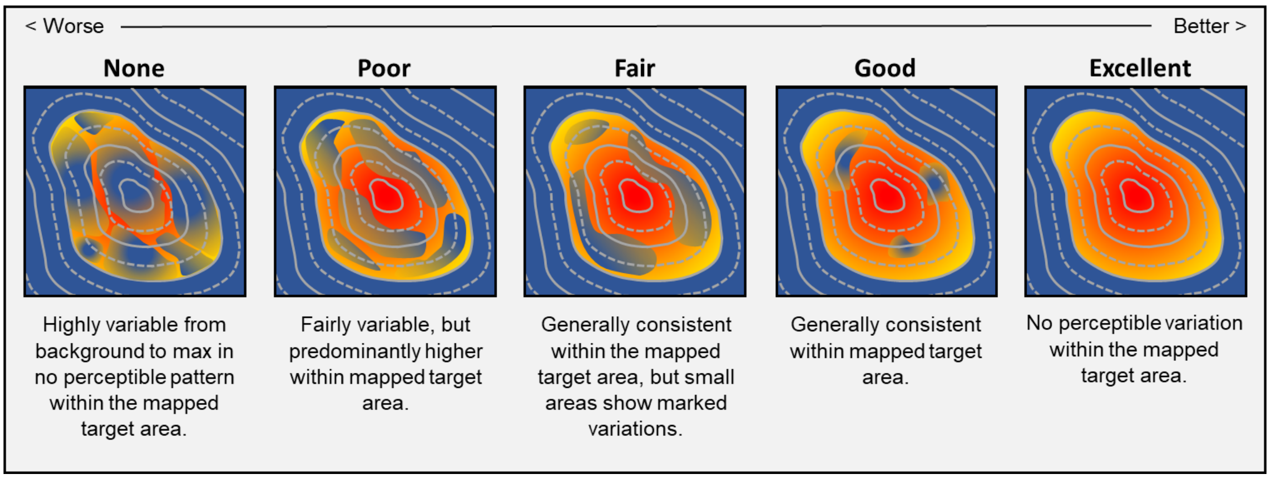

Fig. 3.5—Grading of amplitude continuity (after Roden et al. 2012).

Fundamental analysis by an AVO/DHI expert should be part of the seismic interpretation because not all anomalous amplitude events are DHIs, and not all geologic settings exhibit DHIs equally.

After completion of a confidence assessment to evaluate their robustness and their uncertainty, AVO/DHIs can be qualified and integrated into the evaluation of reserves/resources as key elements in assessing fluid contacts as well as reservoir extension or compartmentalization.

A grading system was developed by an industry DHI consortium (Roden et al. 2014), based on AVO characteristics when compared to drilling results. The DHI consortium concluded that the correct interpretation of DHIs is a critical component in the risk analysis process for exploration and development wells. **Fig. 3.6** shows their statistics for AVO success rates, in terms of proximity to well control and calibration to AVO modeling. Their findings demonstrate the decline in success rate as the prospect distance from well control increases, or when the quantity/quality of seismic input to the AVO model diminishes. The study noted that, "When a well-defined model with reliable inputs closely matches the seismic, the success rate for [AVO] Class 3 reservoir prospects is approximately 30% above average, and for [AVO] Class 2 reservoir prospects 40% above the average success" (Roden et al. 2014, p. SC66) (AVO classes were discussed in Section 3.4.1.).

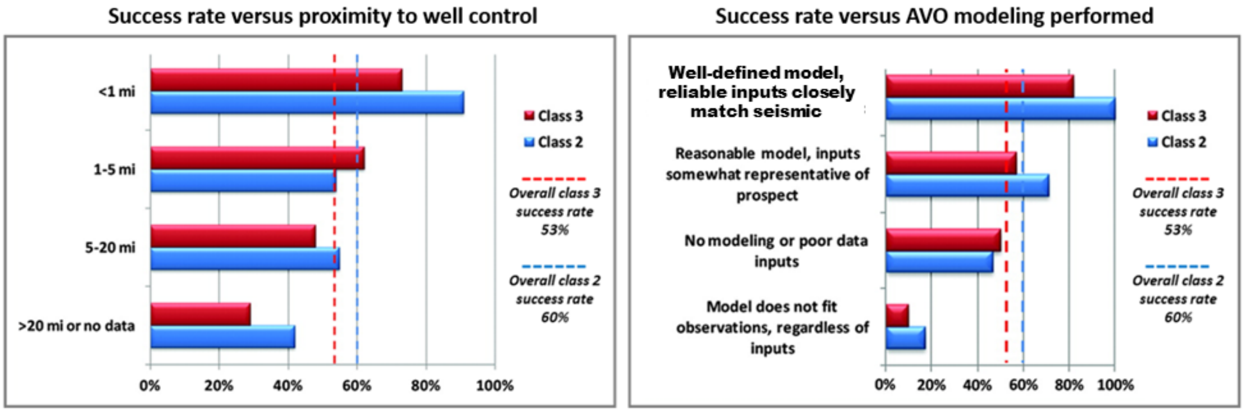

Fig. 3.6—For Class 2 and 3 AVO (see Section 3.4.1), the well success rates based on the proximity to well control (left) and on performance of AVO modeling (right) (after Roden et al. 2014).

It is usually not possible to distinguish a fully saturated gas accumulation from a partially saturated column (residual gas) using full-stack or conventional (two-term) AVO analysis, so this may remain an unresolved risk.

In terms of the AVO/DHI prediction failure cases, the statistical data for unsuccessful (both geologic and economic) wells, as reported by the above consortium (Roden et al. 2014), have identified:

- Wet sands—about 49% of failures
- Low-saturation gas—about 23% of failures
- Lack of reservoir presence—about 17% of failures
- Tight reservoir—about 11% of failures

In addition, diagenetic changes that modify rock properties (e.g., facies transformation from opal-A [amorphous] siliceous shale to opal-CT [α-cristobalite-tridymite] siliceous shale) have been mistaken for flat spots.

In conclusion, the successful application of quantitative seismic interpretation techniques requires a systematic and comprehensive methodology to interpret DHIs as well as domain expertise in AVO interpretation to understand potential pitfalls. Detailed seismic-based reservoir characterization is made possible by combining a rigorous assessment of the quality of the seismic data with an understanding of the reliability of a rock physics model that is calibrated to the local geology and nearby wells. In addition, peer reviews will help to place the AVO interpretation and quality into the context of similar valid analogs and make appropriate estimates of model uncertainty and potential resources/reserves categorization.

3.4.5 DHI Examples. ***3.4.5.1 Example 1—Oil-Water Contact Evaluation.*** An example of fluid contact evaluation using DHI is shown in **Fig. 3.7** (Pichon et al. 2012). Well GF-1 was drilled in a clastic environment and encountered two oil-bearing sand reservoir intervals and a gas-oil contact, thus only have lowest-known hydrocarbon (oil) or "oil down to" for the two reservoirs. Furthermore, the seismic survey was tied to the well, and seismic amplitudes within the interval showed excellent conformance to structure at that level. A key outstanding question after this first well was to determine the depth of the oil-water contact (OWC) and to define its degree of confidence.

Good quality high-resolution marine seismic data were available. The seismic data were calibrated at the well, and a time-to-depth conversion was achieved. A detailed structural and stratigraphic interpretation was required, because the reservoir thickness was less than the seismic resolution. Synthetic seismic responses of fluid-substituted oil and water sands matched the actual seismic responses very well. Furthermore, AVO calibration from nearby wells gave confidence in the interpretation of the fluid contact from seismic data.

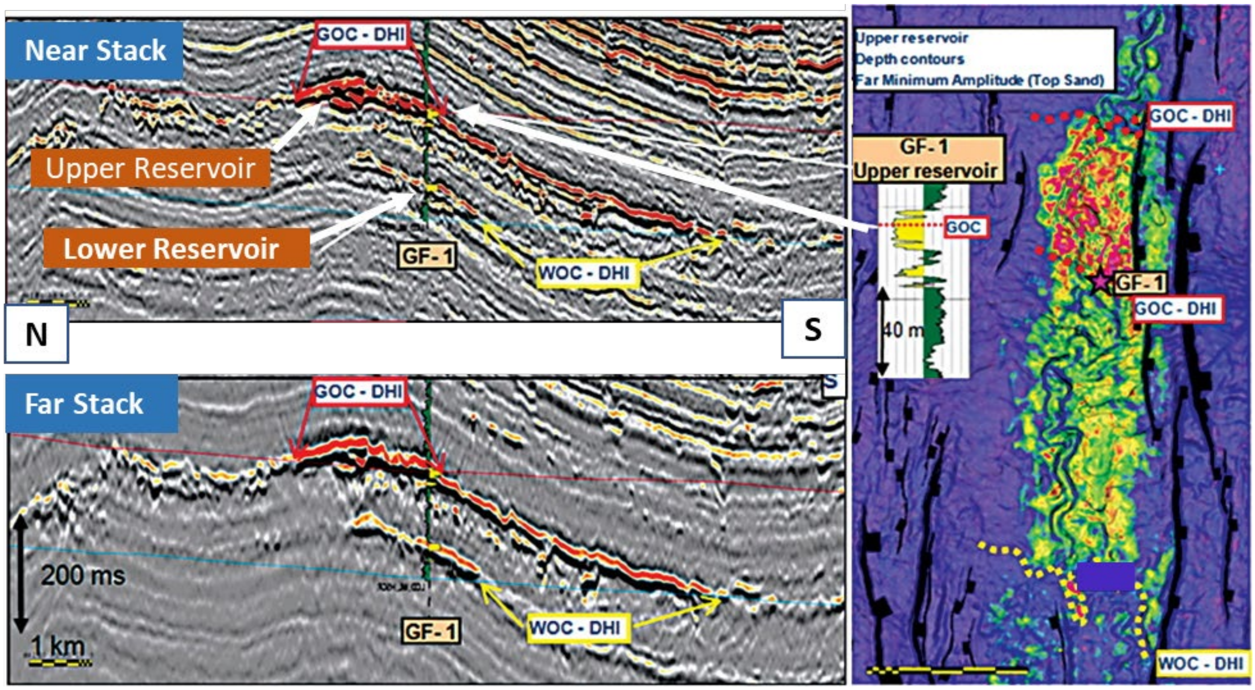

Fig. 3.7—Fluid contacts definition from seismic cross section and amplitude map (after Pichon et al. 2012), where GOC is gas-oil contact, and WOC is water-oil contact.

The seismic interpretation of both upper and lower reservoirs indicated that they likely were connected, and amplitude patterns were continuous. The seismic AVO attributes were conformable with the depth contours and consistent with the spill limits for the structure. Furthermore, the GF-1 well confirmed the connectivity of the upper and lower reservoirs through pressure gradient analysis from a wireline formation test. In conjunction with the pressure data from a nearby, downdip well wet in this reservoir, an OWC (WOC in Fig. 3.7) honoring the regional aquifer trend was in agreement with the DHI depth interpreted from the seismic data.

The quality of DHI and consistency between seismic and nonseismic information provided a high degree of confidence for both the gas-oil contact and OWC depth estimates. The corresponding hydrocarbon volumes could then be qualified as Contingent Resources with their associated range of uncertainty reflected in the C1, C2, and C3 categories until all other criteria for Reserves were met.

3.4.5.2 Example 2—Gas-Water Contact and Compartmentalization Evaluation. **Fig. 3.8** (Pichon et al. 2012) is an example of a turbidite reservoir that was interpreted to be a distal lobe eroded by a channel. Well-2 was drilled within the lobe and discovered a full column of rich gas, thus establishing the lowest-known gas, as no gas-water contact was encountered.

The seismic data have excellent quality and exhibit a high signal-to-noise ratio. The reservoir section shows characteristic seismic attributes with a strong amplitude and, after calibration to well data, good structural conformance to the depth map at top reservoir. Seismic data clearly indicate the difference between hydrocarbon-bearing and wet sands (i.e., the amplitude attenuation corresponds to a hydrocarbon-water contact), but rock physics modeling shows that oil having a high gas-to-oil ratio cannot be discriminated from gas. A range in the hydrocarbon-water contact was estimated by using the hydrocarbon pressure data from the well and aquifer pressures from nearby wells. The seismic DHI-derived fluid contact depth falls within the depth range that was estimated independently from pressure trends, the lowest-known gas, and the spill point. It is concluded that the seismic contact estimation is reasonable and provides a narrower range of uncertainty than the use of pressure data alone (Fig. 3.8, upper right).

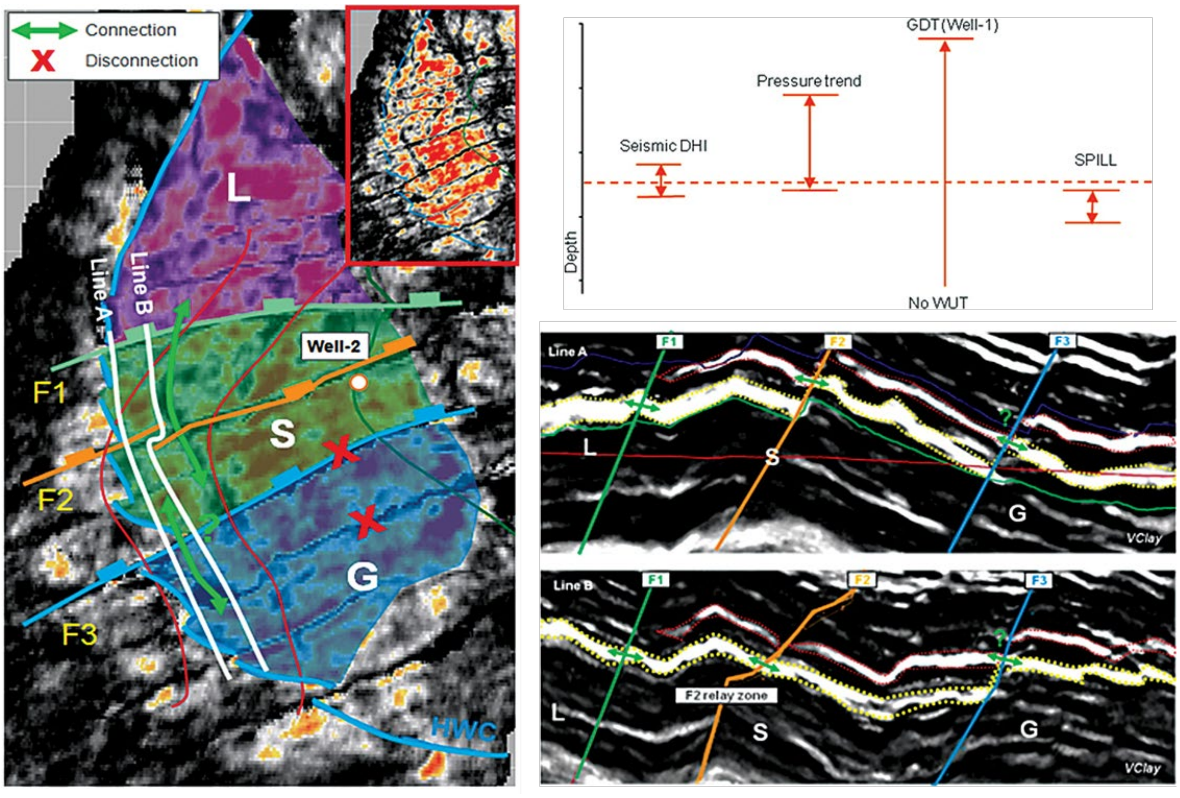

Fig. 3.8—Compartmentalization analysis using a seismic amplitude map, seismic lines, and pressure data. Ranges in contact uncertainties are shown for different data (upper right) (after Pichon et al. 2012), where HWC is hydrocarbon-water contact, DHI is direct hydrocarbon indicator, GDT is gas down to, and WUT is water up to.

The main concern in this example is to understand the potential connection between the three faulted blocks L, S, and G. Three major faults (F1, F2, and F3) are mapped, and minor faults are also present. The seismic survey shows a continuous high amplitude that is consistent for all three blocks. F2 appears to die out at line B, but both parts of the S block are connected via a relay zone. In addition to the analysis of the seismic character across the three blocks, a connectivity assessment was conducted, including the analysis of sand pressures, the analysis of faults (flexural versus brittle), and the analysis of fault plane/juxtaposition. The conclusion was that blocks L and S are very likely connected (high confidence) and that they share the same fluid and hydrocarbon-water contact, but the connection between blocks S and G cannot be proven from the available data, and this “disconnection” is shown by the red “X.” A similar disconnect is suspected across a minor fault within block G. The resources/reserves recognized in the various fault blocks should be assigned by taking into account the confidence in communication that has been assessed.

3.5 Seismic Inversion

3.5.1 Concepts and Definitions. Seismic inversion, in its many forms, is an industry-standard technique that is the process of converting seismic traces to a vertical sequence of rock and fluid properties at each trace location **(Fig. 3.9).** One may think of this like performing a medical computerized tomography scan of the human body, but the object is changed to Earth's subsurface: It is a process to transform the remote-sensing measurements/signals of subsurface Earth into a series of its physical properties, in a quantitative sense. The narrowest definition of seismic inversion is the removal of the wavelet of each trace and the derivation of layer acoustic properties (typically, acoustic impedance). The broadest definition of seismic inversion is the process of reconstructing Earth properties by combining seismic and well data to estimate reservoir properties, such as depositional facies, lithology, porosity, net-to-gross ratio, fluid type, and saturation, across a seismic survey. There are typically relationships between the rock's elastic properties (acoustic and shear impedance) and reservoir properties (i.e., lithology, porosity, and pore fill) via localized rock physics analysis/modeling, and hence, estimates of these parameters could be achieved by seismic inversion, guided by rock physics analysis.

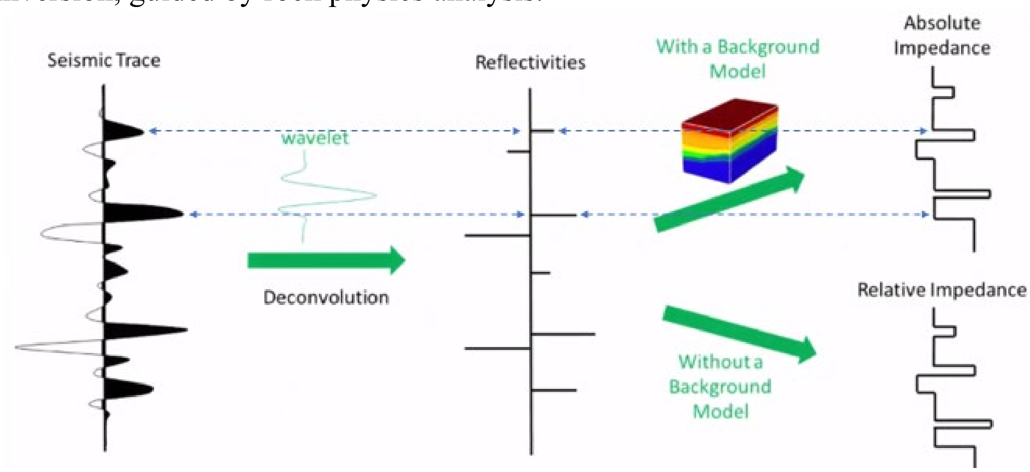

Fig. 3.9—Simplified schematic description of seismic impedance inversion (after Society of Exploration Geophysicists Wiki 2022).

Seismic inversion can be done on full-stack data, partially stacked data (near-, mid-, and far-angle/offset stack), AVO-derived attributes data, and prestack data. In all cases, the quality of the track record and confidence ranges, either locally within the 3D volume or regionally, will need to be considered when determining the reliability of seismic-based estimates. Additionally, a relationship between acoustic impedance or elastic impedance and petrophysical properties must be established at log-scale resolution. The inversion method should be considered as well as the confidence in the well-based background model used for generating the low-frequency component.

Once properly calibrated with geological and petrophysical information from local wells, seismic inversion is able to inform the spatial distribution of reservoirs, to provide accurate information on stratigraphic variations, and to predict changes in formation properties away from the wells. This information can be used to populate an SEM.

When geophysicists say impedance, they usually refer to acoustic impedance or P-impedance (product of P-wave velocity and density), in contrast with shear impedance or S-impedance (product of S-wave velocity and density). One common means of differentiation is that "acoustic" means P-wave (compressional wave) only and "elastic" means P-wave (compressional wave) and S-wave (shear wave) together.

Seismic inversion can be classified in different ways:

- By the type of input data, i.e., poststack or prestack.

- By the type of inversion algorithm, i.e., deterministic versus stochastic (probabilistic or geostatistical).
- By the type of output, with either acoustic/elastic layer properties or reservoir/ petrophysical properties.

Inversion algorithms have inherent nonuniqueness, meaning that there is more than one model that can give rise to the same seismic data. Because of this uncertainty, a probabilistic approach can be followed to capture the full range of possible outcomes. The uncertainty analysis should cover the nonuniqueness of the inversion process and the uncertainties arising from the rock property model. The probabilities of the various outcomes can then be used as input to reserves and resource volume assessments. However, estimating all the uncertainties in the process is difficult. Use of this technology would need to be supported by a strong track record of successful and unsuccessful cases in similar settings.

It is important to emphasize that the quality of seismic inversion is directly related to the quality of the input, such as bandwidth, surface and/or near-surface layer influence, signal-to-noise ratio, and prestack amplitude preservation during data processing. To avoid misleading results, it is critical to quality control the seismic inversion process (data quality and inversion approach).

3.5.2 Well-to-Seismic Correlation via Synthetic Seismograms. Since well data are the input and calibration for seismic inversion, a reasonably good correlation between the seismic trace and synthetic trace generated from well logs should be established prior to performing the inversion **(Fig. 3.10).** Usually, a few wells are set aside as blind tests for inversion when sufficient wells are available.

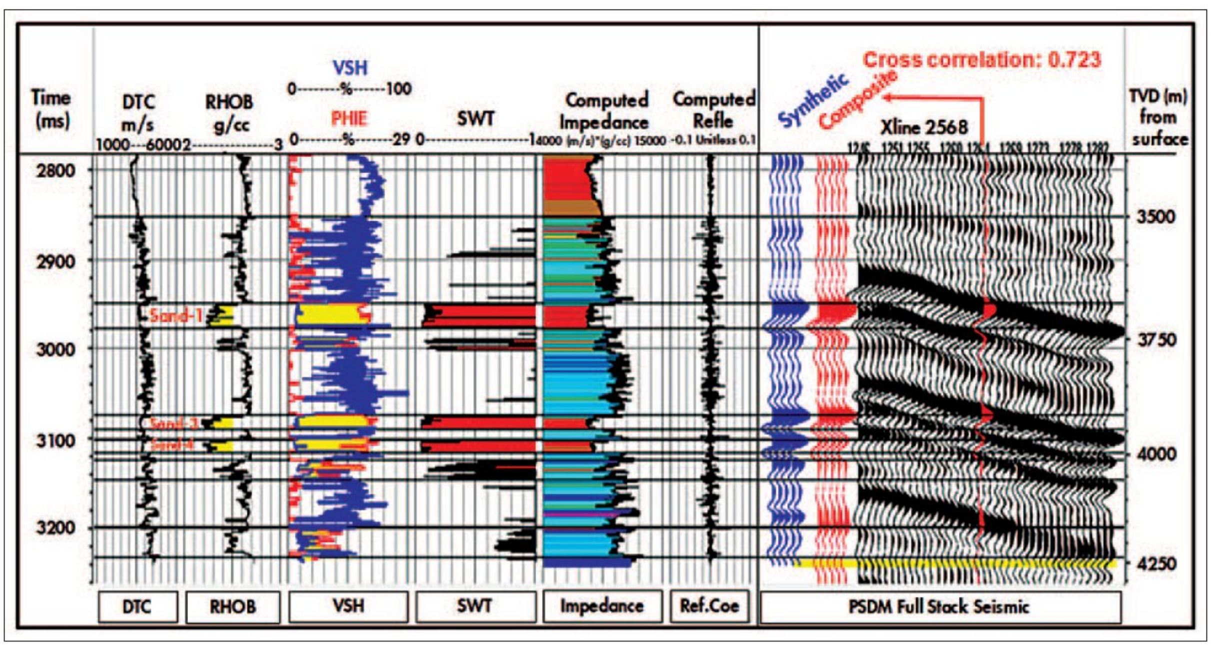

Fig. 3.10—A well synthetic seismogram correlates with seismic data (van der Weiden et al. 2012), where DTC represents P-wave velocity, RHOB is density, VSH is shale volume, PHIE is effective porosity, and SWT is total water saturation.

Well scenario modeling (1D and/or 2D) is needed to understand how changes in reservoir parameters, e.g., reservoir thickness, lithology, porosity, fluid saturation (gas, oil, and water), influence the seismic response.

3.5.3 Rock Physics Modeling/Analysis. Rock physics plays a fundamental role in seismic quantification. It links elastic properties to reservoir properties (or petrophysical properties) via core measurement and well-log information. Lithology (or matrix components), clay content, porosity, pore fluid, pore pressure, and compaction affect a rock's elastic properties. Modification in elastic parameters leads to changes in seismic response. Therefore, seismic amplitude carries information about reservoir properties and makes rock physics a bedrock on which to carry out derivation and interpretation of reservoir properties from seismic data. With calibration from local well logs, the combination of rock physics and seismic inversion is a robust method to obtain seismic-driven reservoir properties and facies. In this process, uncertainty analysis must be considered through statistical inferences.

To conduct rock physics analysis for quantitative seismic interpretation, it is recommended to start with theoretical or empirical modeling. Rock matrix and pore-fluid properties must be given as input to calculate the effective elastic moduli through a theoretical equation. A simple theoretical effective elastic medium is useful to describe simple grain contacts like unconsolidated siliciclastic reservoirs. If a reservoir underwent a diagenetic process, cementation models may be suitable for rock elastic parameters. In carbonate reservoirs, pore type is an important aspect that leads to more complex models (e.g., the differential effective medium used to calculate the dry effective bulk and shear moduli for different geophysical pore types represented by the pore aspect ratio).

With seismic inversion, one can derive the rock's elastic properties (or geomechanical properties) such as P-impedance, S-impedance, V_p-to-V_s ratio, Poisson's ratio, and Young's modulus. It is important to understand how elastic properties are related to reservoir or petrophysical properties. As an example, a quartz-rich turbidite reservoir may have different values of P-velocity and P-impedance at different parts of the turbidite system. Unconsolidated rocks have lower values of P-impedance than consolidated rocks, even if they have the same porosity. Compaction, cementation, and diagenetic processes all change the relation between elastic and petrophysical properties.

After demonstrating a relationship between rock elastic properties and reservoir properties at a log scale, the geoscientist should demonstrate that the data quality of the seismic survey at the reservoir level is good and that, for example, overburden effects do not obscure or distort the imaging of the reservoir. It is critical for all the rock physics analysis used in seismic inversion to be conducted under the condition that well synthetics (modeled seismic data derived from density and sonic logs) adequately tie to the seismic data.

3.5.4 Seismic Impedance Inversion. Seismic impedance inversion is a mature and robust technique that provides impedance layer properties at every seismic sample across a data set. Wells are used to derive an initial impedance model. Because inversion accounts for wavelet effects, it provides a superior definition of stratigraphic layers and an increase in vertical resolution.

A good example of a workflow that uses seismic technology to "generate a high-confidence case which formed the basis for proved reserves" by integrating seismic and well data was shown for the Gorgon gas field, offshore Western Australia (van der Weiden et al. 2012, p. 1056). The referenced article is an example of how the subsurface team characterized the resource quantity (actually Contingent Resources until all contingencies are met for 1C to become 1P), and the process was used to document appropriate compliance with US Securities and Exchange reporting. The workflow steps are as follows:

1. Define with reasonable certainty the "reservoir tank" upon integrating seismic, well log, and wireline pressure data.
    a. Establish well-to-seismic ties for each reservoir and define the top and base events on seismic surveys. Most wells in this example have a high correlation factor for synthetics with corresponding seismic traces, giving high confidence in seismic-to-well ties.
    b. Establish confidence in the quality of seismic data sets, such as prestack time migration (PSTM), prestack depth migration (PSDM), industry standard P-impedance inversion, and near-, mid-, and far-angle stack data sets. All seismic data in this example show a moderate to large fluid effect. The gas sands are soft and show Class 3 AVO response, i.e., have lower acoustic impedance than the formation above them.
    c. Map the reservoirs and their extent away from well penetrations on seismic data. Through wedge modeling analysis **(Fig. 3.11),** the tuning thickness was determined to be 28 m ± 4 m (~15 ms), and the reservoir becomes unmappable below a 5 m thickness resolution. (The major reservoirs in this field ranged from 20 to 70 m in thickness.) For each reservoir, up to 15 different thickness map scenarios were generated. The highest and lowest thicknesses in the range of realizations were taken as high and low cases, respectively.

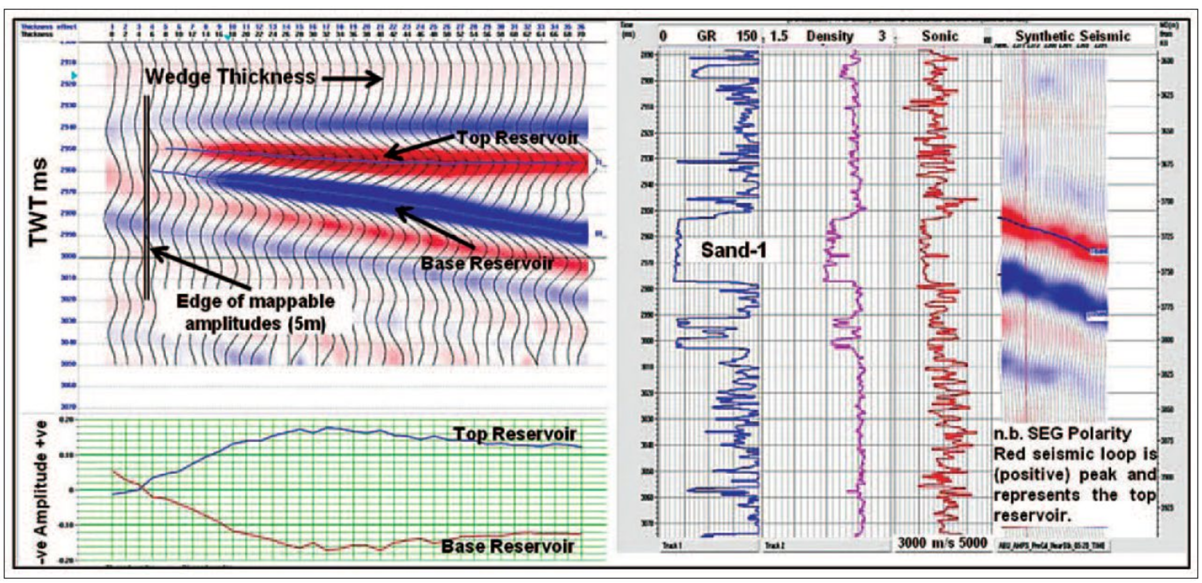

Fig. 3.11—2D wedge model to predict the seismic tuning thickness and the detection limit of this seismic survey (van der Weiden et al. 2012), where TWT is two-way traveltime, and GR is gamma ray.

2. Establish the internal continuity of the reservoirs with reasonable certainty.
    a. Identify potentially offsetting faults through seismic interpretation and mapping, to ensure that the reserves are not assigned to the adjacent reservoir blocks isolated by major potentially sealing faults. Analyze the fault sealing potential using reservoir juxtaposition plots and pressure data **(Fig. 3.12).**
    b. Extend the reservoirs away from wells over long distances within the field using seismic interpretation techniques such as amplitude extraction and geobody extraction.
    c. Define seismic analogs from nearby fields with similar geology. (In the authors' example, there was a positive track record of sand predictability in 40 out of 40 exploration and appraisal wells in a nearby field.)

3. Establish the reservoir properties and their continuity with reasonable certainty.
   a. Define the indicator that separates the sands from the shales. Here, all the gas reservoirs are lower-P-impedance sands encased in bounding shales. A separation of 500 P-impedance units, as indicated by well logs, is a robust indicator of the sand line.
   b. Use well-log information to generate models for seismic inversion on stacked data. Show a good match between the seismic inverted impedance and the well-log measured impedance to demonstrate that impedance is a reliable predictor of sands away from well control.
   c. Establish the relationship between P-impedance and reservoir properties. The linear relationship between total porosity and P-impedance defined for the gas sands from the wells can be applied to predict porosity using the seismic inverted impedance volume, and to map the continuity and extent of the reservoirs **(Fig. 3.13).**

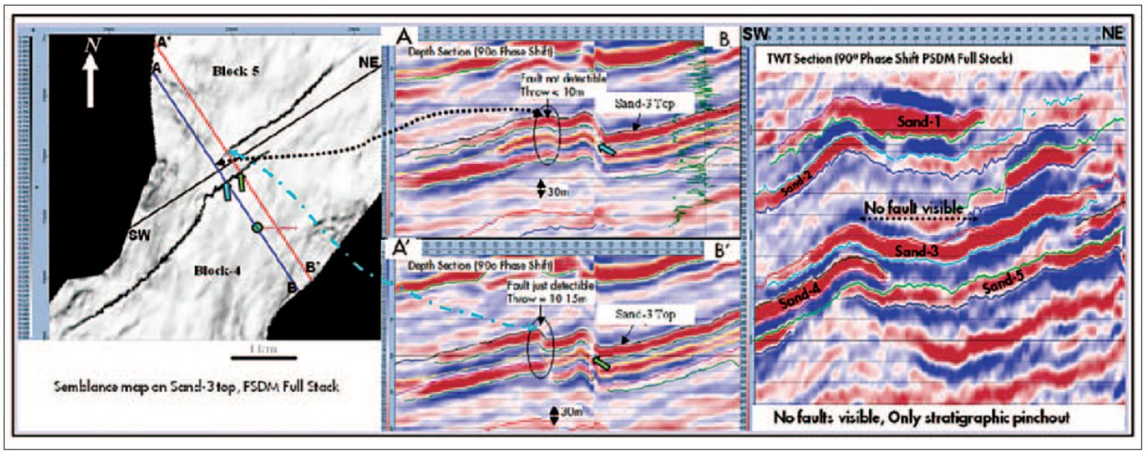

Fig. 3.12—Major and minor faults on seismic attributes and traverses (van der Weiden et al. 2012), where TWT is two-way traveltime.

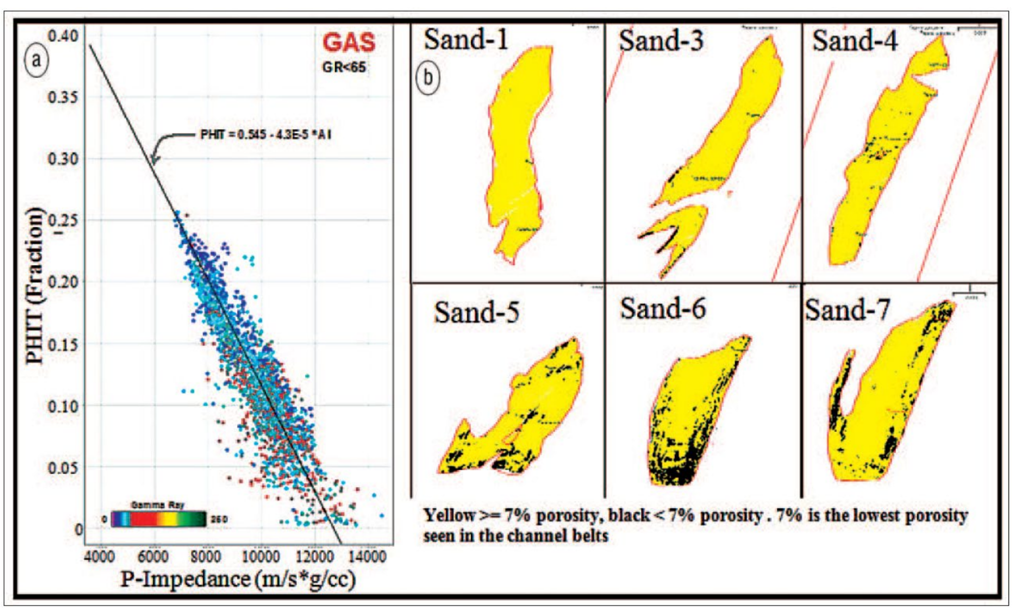

Fig. 3.13—(a) P-impedance versus porosity relationship for gas sands, where GR is gamma ray. (b) Sands with P-impedance–derived porosity higher than 7% in the proved areas (van der Weiden et al. 2012), where PHIT is total porosity.

The integrated interpretation of the wells and the seismic impedance inversion results were used to create a base-case reservoir static model. A full-field uncertainty analysis was performed to identify the key static parameters such as reservoir thickness, time-depth conversion, porosity, and gas saturation. To generate a high-confidence case that formed the basis for the low-estimate Contingent Resources (1C), these uncertainties were combined with the expectation case static model in a probabilistic way. Dynamic simulations of the field were established to demonstrate economic producibility.

Both reflection and inversion seismic data were used exhaustively to demonstrate the continuity of reservoirs beyond the radius of investigation seen by the well tests. As a consequence, a larger resource accumulation was established with fewer wells.

3.5.5 Stochastic Inversion. In recent years, prestack stochastic seismic inversion has gained considerable attention and application. The seismic inversion process is inherently nonunique, which means that there are numerous elastic property models that fit the same seismic data with equal probability. Interpretation geophysicists must deal with this nonuniqueness problem and discard scenarios that are not realistic.

During stochastic inversion, the large model space is constrained with geological information and is sampled to identify geologically consistent solutions. Stochastic seismic inversions use a Bayesian framework to determine the impedance probability density functions from seismic and well information. Four key steps are usually followed during stochastic seismic inversions: geological model building, well data upscaling, prior model building, and variogram modeling.

Prestack stochastic inversions generate equally probable, high-frequency layers of elastic impedances with layer thicknesses that could be as small as 1 ms two-way time (roughly equivalent to 1 to 1.5 m for midrange formation P-wave velocity). Such fine-scaled layer definition ensures that results are closer to the desired vertical (well-log) scale for static geomodels.

Using the stochastic inversion impedances and the rock physics model between impedance and porosity (similar to Fig. 3.13a), large numbers of porosity realizations are generated mathematically, e.g., through collocated sequential Gaussian simulation. The multiple porosity solutions allow uncertainties to be accounted for that are evaluated in a suite of numerical models to obtain a Best Estimate (P50) geomodel.

Consider the crossplot in **Fig. 3.14,** where elastic properties from well-log data are colored by interpreted lithofacies. In a first analysis, geophysicists will look for visual facies discrimination by determining if it is possible to distinguish facies for a range of elastic properties that can be derived from seismic data. In the example shown here, two elastic properties are key to discriminating lithofacies: acoustic impedance and the compressional (P-wave) to shear (S-wave) velocity ratio (V_P/V_S). Geophysicists will then define the probability density functions for each of the four facies and apply these to the seismic inversion to achieve seismic-derived facies, which can be further populated into each cell of an existing geomodel by proper scaling.

In summary, seismic inversion's utility in support of reserve/resource estimation is best suited for reservoir property mapping (inferring reservoir presence, thickness, saturation, and reservoir quality). Due to its inherent nonuniqueness, seismic inversion works best where the field properties are well constrained, e.g., a sand reservoir deposited in an offshore deepwater setting encased in shales and where good-quality well control is available for calibration. In this instance, linking the elastic properties measured by the seismic survey to well-derived relationships for sand presence, quality, and thickness can result in a robust interpretation that can drive the assignment of reservoir properties in 3D away from well penetrations. Additionally, if the acoustic signature of an oil/gas-bearing reservoir is distinctly different from a water-bearing reservoir, it may be possible to confidently map a field's hydrocarbon-water contact to aid in quantifying hydrocarbons below the lowest-logged elevations. **Fig. 3.15** is an illustration of an estimated OWC and associated indicative oil saturations, as they were derived from inverted data, around an injection well.

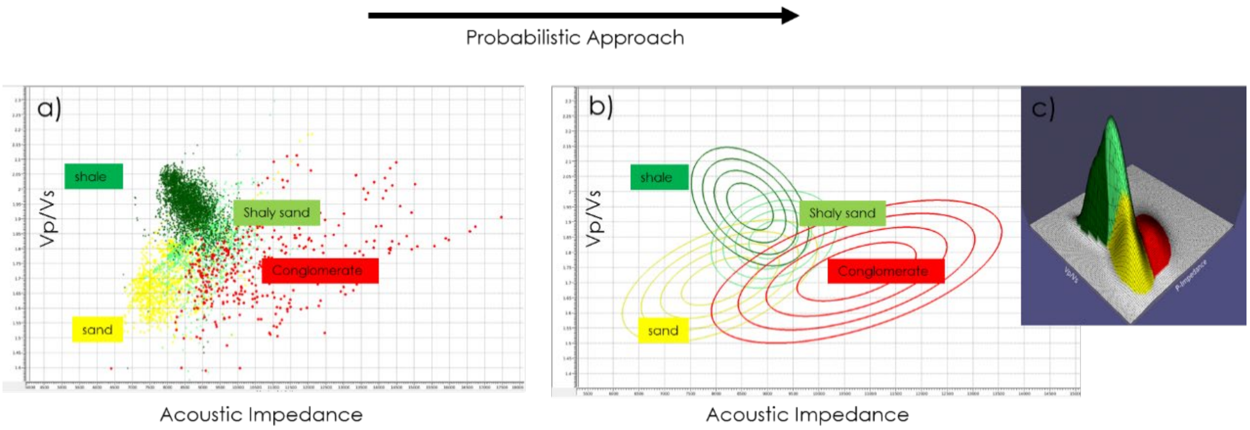

Fig. 3.14—Lithofacies classification using elastic properties. (a) Crossplot of acoustic impedance versus V_p/V_s, colored by facies. (b) Probabilistic approach for seismic classification: for each facies, a probability density function is modelled. (c) 3D view of (b) (after Teixeira et al. 2017).

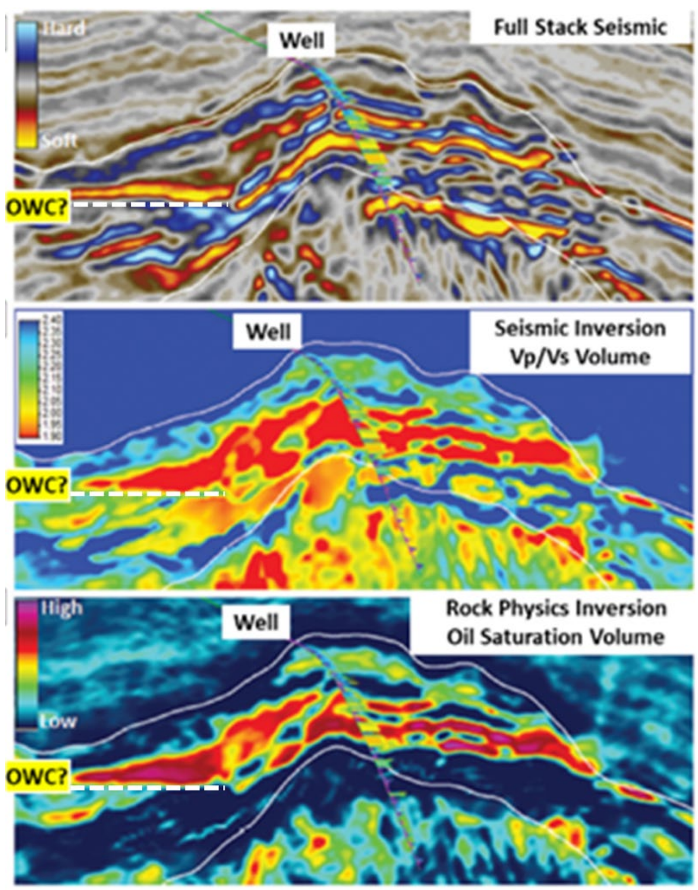

Fig. 3.15—Illustration of reservoir discrimination, oil-water contact (OWC), and indicative oil saturation from normal seismic reflectivity (top), inverted V_p/V_s (middle), and prestack inversion for relative oil saturation (bottom) with calibration along an injection well trajectory and the penetrated OWC (Nasser et al. 2016).

3.5.6 Uncertainty Assessment. In assessing volume variance in a discovered resource, seismic information has often been used to evaluate changing container shapes that could come from variability in the modeled velocity field used for depth conversion. The volume uncertainty in such an approach is driven by structural uncertainty. In the past, this GRV uncertainty was often the main "seismic" uncertainty that was considered in resource variance analysis.

With modern rock physics inversion workflows, it is possible to make reasonable quantitative estimates in variance between the base-case stratigraphic model and other possible spatial distributions of the reservoir rocks and their associated properties. In this way, the seismic data can also inform the uncertainty in reservoir properties away from wells.

When developing relationships by crossplotting elastic properties versus reservoir properties of interest such as net-to-gross ratio, facies, and porosity, there is often sufficient overlap or nonuniqueness to allow multiple models to be selected to distribute the properties in the geomodel in a manner that honors the observations on seismic data.

Using the modeled relationships between elastic properties and reservoir properties, it is possible to generate multiple realizations for a property distribution that can be ordered on a property of interest. This approach includes more variance than typical "deterministic" inversions. In **Fig. 3.16,** 500 realizations were made and sorted by sand volume. Statistical analysis estimated P10, P50, and P90 values from the distribution, thus allowing for selections of high, best, and low cases. A single realization that has a volume at the P50 level is shown for illustration.

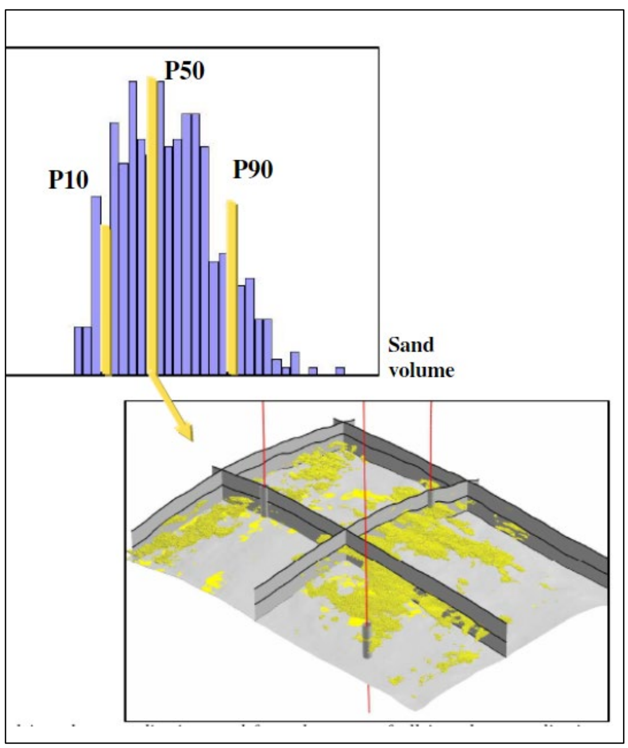

Fig. 3.16—Illustration of distribution of 500 sand probability runs and one example P50 proxy case (Moyen and Doyen 2009).

Quantifying uncertainty is a fundamental step in seismic inversion and seismic classification. Statistical rock physics methods use statistical techniques to quantify uncertainties in theoretical and empirical rock physics relations. For the same range of elastic properties, there may be many associated facies. Instead of circling a region in an elastic parameter crossplot and associating it with a given facies in a deterministic approach, the uncertainty of a seismic classification should be considered. For each facies, one can describe a probability distribution function as a conditional probability (Fig. 3.14b). Using Bayes' theorem, an a posteriori probability distribution function is constructed and applied sample-by-sample in the seismic cube. As result, a seismic-derived probabilistic facies cube is obtained, illustrated in cross section in **Fig. 3.17.** Well facies are not considered hard data, but seismic probability cubes are consistent with well information used for calibration.

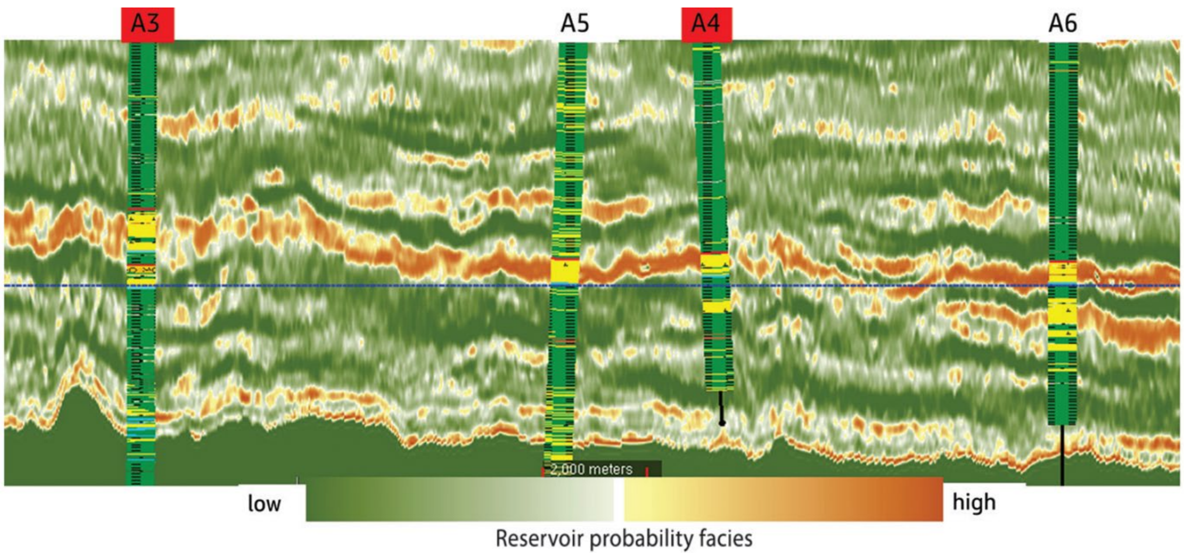

Fig. 3.17—Seismic section showing reservoir facies probability from a stochastic seismic inversion. Facies displayed on well path: reservoir (yellow) and nonreservoir (green). Wells A3 and A4 are blind tests (after Teixeira et al. 2017).

A probabilistic seismic cube is a seismic attribute obtained from coupling rock physics properties and seismic inversion. As an attribute, it is subjected to geophysical interpretation to achieve its value for seismic reservoir characterization. A posteriori probabilistic information allows the geoscientist to estimate uncertainty and, hence, to derive several scenarios from seismic data. For example, a conservative approach would consider the reservoir facies to include all areas with a probability higher than 80% to 90%. Conversely, an optimistic approach may incorporate as reservoir facies all regions with probabilities higher than 20% to 30%. This kind of information can be used in uncertainty analysis to define the PIIP scenarios (low, best, and high estimates).

It is important to emphasize that areas assigned with a high probability of good reservoir/facies through seismic inversion cannot be considered as discovered based on seismic data alone if they are disconnected from an area that has well penetrations. (Per the PRMS § 2.1.1.1, "A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation.") Instead, these volumes are considered as undiscovered and should be categorized as Prospective Resources. The shallowest reservoirs that were penetrated by wells as shown in Fig. 3.17 were wet and were not considered in PIIP. Similarly, the deeper reservoirs that were not drilled by any of the wells cannot be included as discovered PIIP until they are drilled.

Well-test interpretation provides key data that are used to characterize how fluid-flow properties may change around a well. These changes can be associated with modifications in petrophysical properties that are connected to elastic properties through rock physics. In such cases, seismic attribute interpretation can be a very useful tool to support dynamic data interpretation and thereby mitigate risks and reduce uncertainty due to ambiguity of seismic interpretation **(Fig. 3.18).**

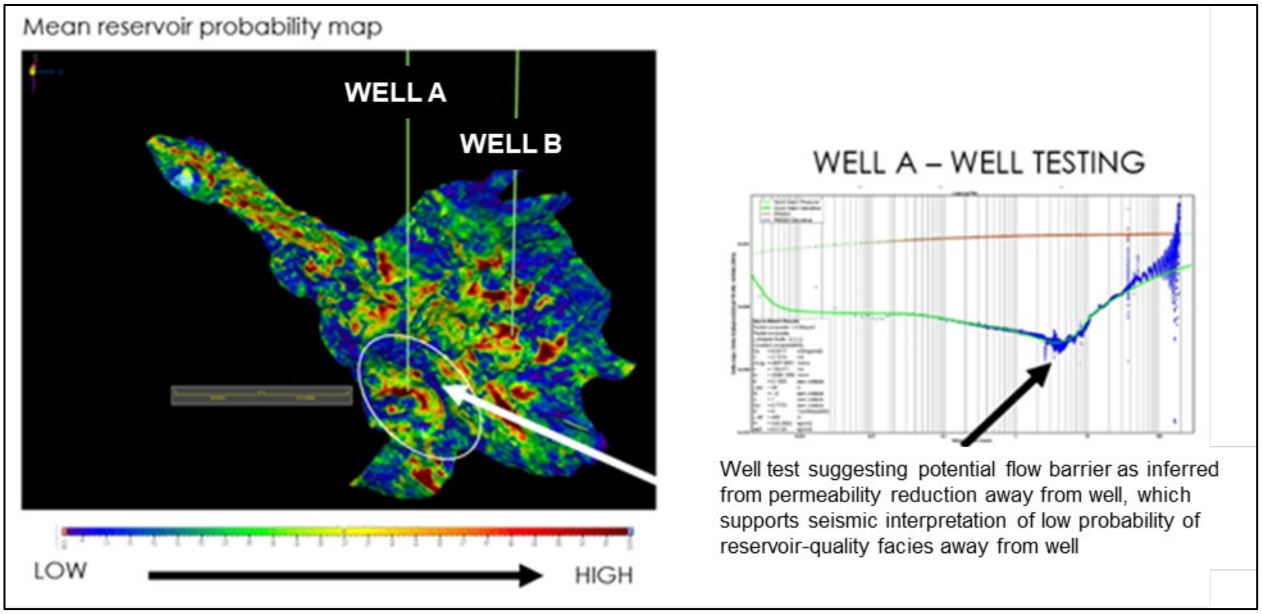

Fig. 3.18—Interpretation of static data integrated with dynamic data. Seismic information from facies (left) matches well testing interpretation (right). This consistency helps to mitigate risk and reduce uncertainty (after Teixeira et al. 2017).

As shown in the example (Fig. 3.18), a best estimate reservoir probability map was extracted from the probability reservoir facies cube obtained by the statistical rock physics process. It should be noted that in the region of well A, and in the region of proposed well B, there is a high probability for the occurrence of reservoir facies. However, the seismic inversion indicates that the probability of finding reservoir facies drops off quickly away from well A. This suggests we may find nonreservoir facies at a short distance from well A. Similarly, the interpretation of a well test from well A shows that there is a significant permeability reduction (possibly a flow barrier) away from the well. When data that are combined from different independent sources (such as static and dynamic data) lead to the same understanding of the reservoir, the integrated interpretation becomes more robust, and confidence in the interpretation increases substantially.

3.6 Seismic Surveillance

A third general application of 3D seismic analysis is monitoring changes in reservoir properties (fluid saturation, pressure, temperature, porosity) that occur due to production. This application highlights seismic differences at various stages of production and is often called time-lapse or 4D seismic.

Seismic surveillance is possible when one:

- Acquires a baseline seismic data set, preferably before the start of production or before a change in field depletion strategy (e.g., water injection).
- Acquires additional 3D seismic data sets (called monitor surveys) after the baseline.

- Observes amplitude and traveltime differences between the baseline and monitor surveys that can be related to reservoir property changes through rock physics analysis and seismic modeling.

Time-lapse seismic data influence resource estimation and classification in several ways by:

- Illuminating previously unidentified reservoir areas, impacting estimates of net reservoir volume.
- Identifying swept and/or unswept hydrocarbon, resulting in resource reclassification.
- Improving time-depth relationships, which are then used to update GRV.
- Improving static and dynamic reservoir models used to estimate recoverable hydrocarbons.
- Identifying depleted and/or undepleted reservoirs, resulting in resource reclassification.
- Establishing whether different fields are in pressure communication and if undeveloped resources are being accessed by existing wells.

The reliability of 4D seismic data is determined by:

- The similarity of the baseline and monitor seismic images outside of the produced reservoir area. This is called repeatability and is a measure of the signal-to-noise ratio of the 4D seismic data. More repeatable data are more reliable.
- The accuracy of the rock physics model, derived from a relevant set of well-log and core data, which links the physical changes related to the hydrocarbon recovery process to the changes in the rock's elastic properties. The interpretation of larger elastic property changes is generally more reliable than interpretations for smaller changes.
- The number of monitor surveys. Multiple repeat surveys reduce interpretation uncertainty by separating signal from noise, allowing fluid fronts to be tracked with more confidence.

Repeatability, and thus reliability, of 4D seismic data is controlled by the similarity in baseline and monitor survey geometry and processing. Changes in the seismic image that result from acquisition and processing differences may be mistaken for production-related time-lapse changes. Repeatability can be quantified using multiple measures, most notably the normalized root mean square difference calculated for each trace between two seismic surveys (Kragh and Christie 2002). Normalized root mean square difference measures the percent nonrepeatability of the seismic surveys. Away from facilities such as platforms, modern marine 4D seismic surveys can be highly repeatable and thus very reliable. Onshore 4D surveys are generally less repeatable mainly because of time-dependent variations in the near surface.

The ability to relate the changes in the seismic response that result from production to the changes in fluid saturation, pressure, and other rock properties depends on the accuracy of the rock physics model, which is typically derived from well-log data and supplemented by core data. There can be uncertainties in the prediction of the 4D seismic response, especially for changes in reservoir pressure. However, with proper calibration and sufficient understanding of the reservoir's depletion processes, rock physics models can be used for 4D seismic modeling to aid interpretation and for updates of reservoir geologic and flow simulation models. If the change in seismic response that occurs due to production is greater than the nonrepeatability of the data, then the 4D signal is considered to be robust.

There are many examples of 4D seismic signals, including:

- Water displacement of hydrocarbons as a result of aquifer influx and/or water injection is common in many published case studies (such as Example A below).
- Amplitude and traveltime changes can often delineate original and producing fluid contacts.

- Gas injection and/or gas cap expansion also result in changes in the seismic response of the reservoir.
- Demonstrating the movement of water or gas in the reservoir can highlight zones of greater reservoir quality and permeability pathways and can delineate fluid-flow barriers.
- Pressure increases, particularly associated with injection wells, can also result in 4D seismic changes.
- If reservoir pressure declines below the bubble point, liberated gas can sufficiently change the seismic response, illuminating a reservoir that may not have been seismically visible on the baseline data.
- As reservoir pressure declines further, the reservoir may compact, reducing its thickness and porosity. As shown in Example B, compaction is often inferred from 4D seismic changes in the overburden and underburden as they geomechanically respond to the change in reservoir thickness.

In general, the seismic surveillance tool is useful in time-lapse mode as a check on the validity of the assumptions in the geologic model that is used in a reservoir simulation of fluid flow. Because seismic monitoring is more spatially specific than pressure monitoring, estimation and extraction of reserves can be optimized over time by using the seismic data to guide detailed simulations of depletion and to resolve contradictions between the seismic survey and the reservoir model. In general, the incorporation of time-lapse seismic results prompts geologic model updates that usually improve production history matches.

3.6.1 Seismic Surveillance Example A: 4D Interpretation and 3D Inversion Lead to Reassessment of the Resources and Reserves. In this first example (Johnston and Laugier 2012), the key uncertainties in resource estimation for the Paleocene reservoir in the North Sea Ringhorne Field were the effective reservoir thickness and the area above the inferred original oil-water contact (OOWC), determined by logs and extrapolated using seismic data. Much of the sand thickness was below seismic resolution. An added complexity was that the reservoir was nearly transparent on the preproduction baseline stacked seismic data. Reservoir interpretation was complicated by seismic interference from an underlying strong top chalk reflection. The nearby flat areas of the reservoir in the north and south of the field were particularly sensitive to depth conversion, adding to uncertainty in volumetrics. Water sweep from a regional aquifer resulted in a robust 4D (difference) seismic signal, which can be observed to encroach on the structure as a result of production from wells C07, C09, and C10 **(Fig. 3.19).**

The extent of the 4D swept volume outside the originally interpreted OOWC is a clear indication of reservoir volumes that were not included in the initial assessment. The new (true) OOWC, defined by the downdip limit of the 4D geobody, provided a strong constraint on seismic velocity and time-depth conversion, particularly in the northern part of the field, away from well control. The 4D data provided the justification to lift and expand the flank of the reservoir. Evidence from the 4D data also suggested increased sand thickness in certain areas. These interpretations of swept oil were validated by matching the swept volume obtained by the 4D seismic data with the produced volume through material balance calculations.

In addition to the differencing of the 4D seismic stacked data, prestack AVO elastic inversion of the baseline 3D seismic survey was used to better characterize the reservoir and extend its pinchout limit further updip. Based on the 4D interpretation and the 3D inversion, a reassessment of resources led to a 40% increase in the resource base for the reservoir.

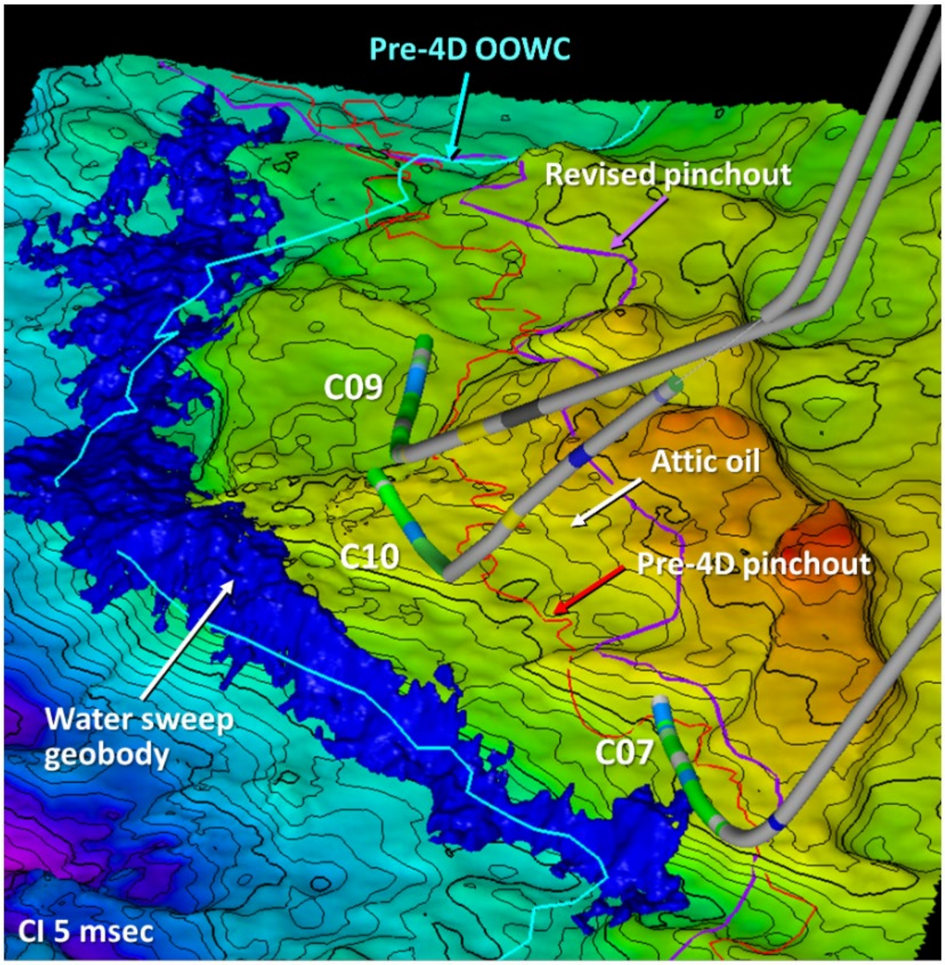

Fig. 3.19—Water sweep geobody (dark blue), extracted from the 4D amplitude difference, displayed on the base reservoir time surface. Also shown are the pre-4D interpreted original oil-water contact (OOWC) in seismic two-way time (light blue) and updip pinchout (red). The revised pinchout interpretation, based on elastic inversion of the baseline 3D survey, is shown in purple. Note that the 4D response extends outside the initial OOWC interpretation. The time-depth relationship for the reservoir was adjusted so that the OOWC was conformable to the downdip limit of the 4D signal (modified from Johnston and Laugier 2012).

Of that increase, 60% was applied to Proved and Probable Reserves (P1 and P2) based on the increased in-place volumes (from the combination of lifting the reservoir above the OOWC in certain areas, thicker reservoir in some places, and a shallower updip limit of the trap), continued strong reservoir performance, and planned infill wells. (The development project was based on a final investment decision and plan for the infill wells.) A second 4D monitor survey confirmed the locations of two planned infill wells. Probable Reserves were assigned where data control or interpretations of available data were less certain than in the Proved Reserves areas, and they were estimated as an incremental quantity as opposed to a cumulative (2P) assessment.

The remaining 40% of the increase in the resource base was applied to the Contingent Resources class based on additional infill drilling potential and the possible development of attic oil and/or thin reservoir sands. No incremental Possible Reserves (P3) were assigned due to the fact that the geoscience and engineering data, although able to define the area and vertical reservoir limits from which production should be economic, did not cover an area with a defined, commercially mature project. The area updip of the existing project did not have a development plan in place at the time of the assessment and was classified as Contingent Resources.

3.6.2 Seismic Surveillance Example B: Evaluate the Stress Change in the Overburden. In this second example, pressure depletion of the high-pressure, high-temperature (HPHT) North Sea Shearwater Field, in combination with the high compressibility of the reservoir rock, resulted in compaction of the reservoir sandstone and led to displacements, deformations, and stress changes in the overburden rock due to stress arching (De Gennaro et al. 2017). The stress changes in the overburden resulted in significant wellbore integrity issues, which led to a decision to shut in damaged wells and postpone an infill drilling program. In order to reinstate drilling, the operator began a study to better understand the overburden based on the integrated evaluation of all available subsurface and drilling data, including information obtained from geochemical analyses, geomechanical modeling, and 4D seismic surveys.

The 4D seismic data recorded compaction within the reservoir and stress changes outside of the reservoir. Shifts in seismic arrival time between baseline and monitor surveys, which could be robustly measured to a high degree of precision, were most diagnostic of these changes. Overburden and underburden reflections in the monitor survey were delayed in time relative to the baseline because of extension and a decrease in the vertical stress, which resulted in a decrease in seismic velocity **(Fig. 3.20a).** The derivative of the time shifts, called the time strain, indicated zones with the greatest changes in velocity (Fig. 3.20b). The time strain also showed an increase in velocity within the reservoir due to compaction.

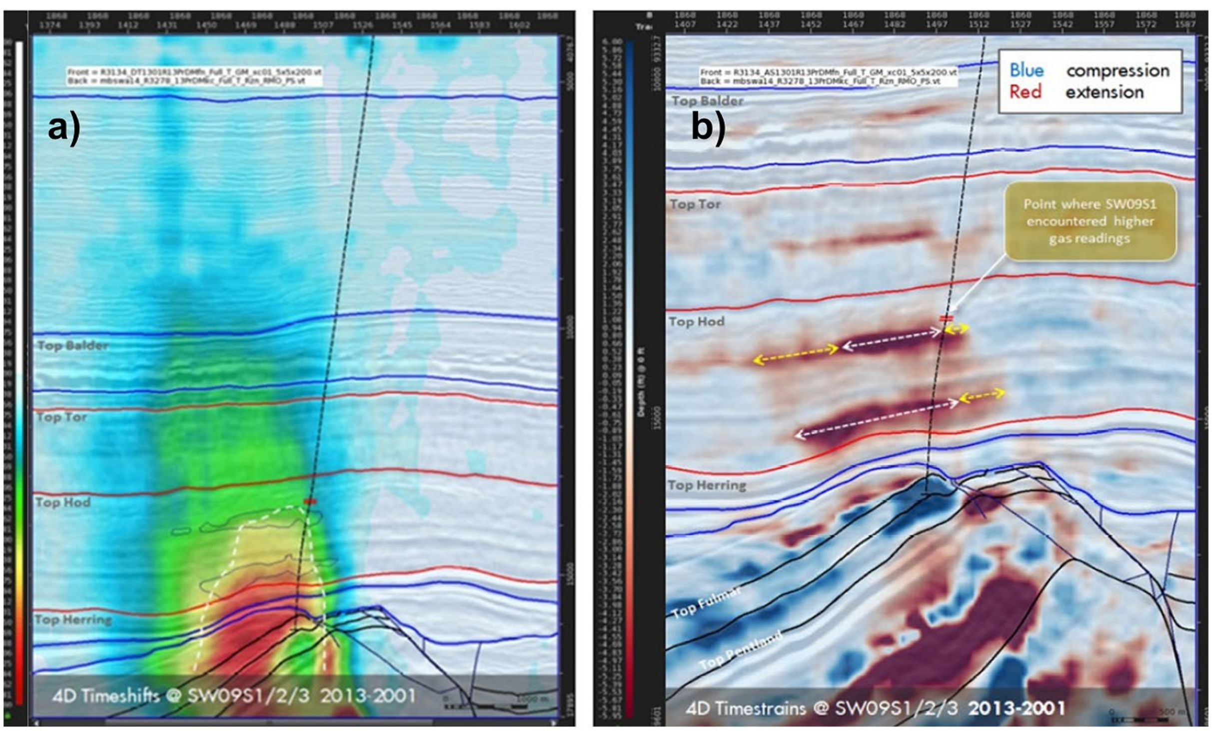

Fig. 3.20—(a) 4D time-lapse shifts between the baseline and monitor surveys showing the overall slowdown of seismic velocities between the surveys. (b) 4D time-lapse strains between the baseline and monitor surveys indicating the locations where the largest rate-of-change within the time shifts occurred. Red colors indicate a deceleration of seismic velocities (e.g., in the overburden), whereas blue colors indicate an acceleration of seismic velocities (e.g., related to compaction in the reservoir), after De Gennaro et al. (2017).

Analysis of the 4D data suggested that the overburden was not as homogeneous as previously thought and that localized zones existed where enhanced permeability and flow potential through conductive fractures was possible. In addition, comparisons of the 4D seismic results to predictions based on geomechanical modeling were utilized to update and improve the geomodel, which was then used to more confidently estimate volumetrics and to design the reinstatement wells.

3.6.3 Seismic Surveillance Example C: Evaluate Fault transmissibility and Reservoir Compartmentalization. One of the key applications of 4D analysis is in the observation of barriers and/or baffles. Because 4D data record changes through time due to production, it is a dynamic surveillance tool. For example, the analysis of the time shifts at the top of the reservoir at the North Sea Elgin Field **(Fig. 3.21)** indicated that some faults could act as pressure barriers, compartmentalizing the reservoir, while other faults allowed communication between producing and undrilled areas (Taylor et al. 2007). In Fig. 3.21, the fault block to the southeast showed very little 4D response, suggesting that it was isolated from the producing wells and was undrained. The east-west fault that formed the northern limit of that fault block was likely a barrier. Conversely, the area to the north of the field, which was located across a bounding fault, showed a significant 4D response and was therefore likely to be in pressure communication with the producing wells. One should keep in mind, however, that this area was located near the platform, and thus the seismic data would have poorer repeatability and would be less reliable compared to elsewhere in the field.

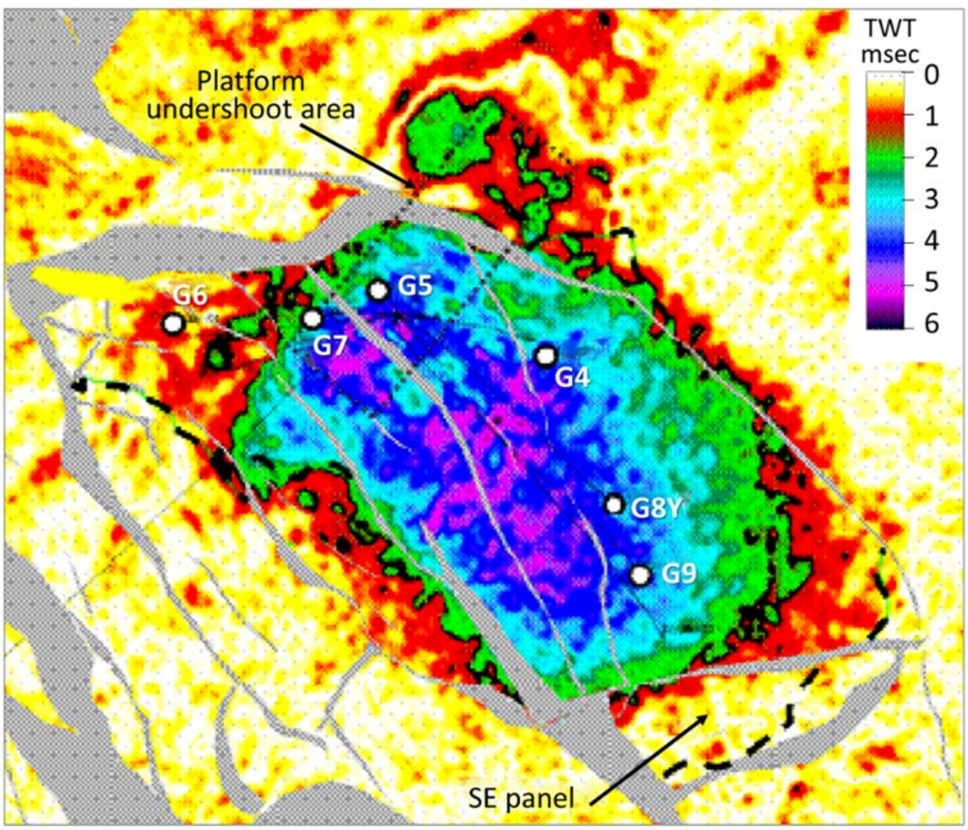

Fig. 3.21—Measured 4D time shifts above a compacting reservoir. Reflections in the monitor survey are delayed in time relative to the baseline survey as a result of extension in the overburden due to compaction of the reservoir (modified from Taylor et al. 2007), where TWT is two-way traveltime.

A coupled geomechanical and reservoir engineering model of the field was created and used to generate synthetic 4D time shifts. The model was calibrated by matching the synthetic time shifts to the observed time shifts. The improved model helped to determine the actual stresses within and around the reservoir and to better predict the field behavior. The ultimate goal of the model update was to define new drilling targets and mitigate casing integrity risk. These observations and hence updates of overburden and reservoir modeling, along with other data, resulted in a decision to resume infill drilling in the field.

3.6.4 Seismic Surveillance Example D: Monitor Water and Gas Sweep Efficiency. In this fourth example, an Angolan deepwater field consisted of unconsolidated turbiditic sand systems (Berthet et al. 2015). Understanding heterogeneities within these systems is essential to locate infill wells. Oil was produced using water and gas injection to support the reservoir pressure. The primary purpose of the 4D seismic surveys was to monitor the water and gas sweep efficiency. However, because the reservoir was initially undersaturated, depletion drove the pressure below the bubble point. This resulted in free gas in the reservoir that was detectible on the 4D monitor surveys, delineating areas of the field that were in pressure communication with the depleted areas. **Fig. 3.22a** shows the 4D response related to the gas effects, i.e., a decrease in velocity within the reservoir. The spatial limits of the 4D signal could be interpreted to define reservoir baffles (faults and sedimentological limits such as a channel abandonment or erosive surface), which were incorporated into the reservoir model. Transmissibility multipliers were then optimized in a seismic history match in the dynamic simulation model to minimize the difference between the initial model 4D velocity change (Fig. 3.22b) and the observed velocity change (Fig. 3.22c).

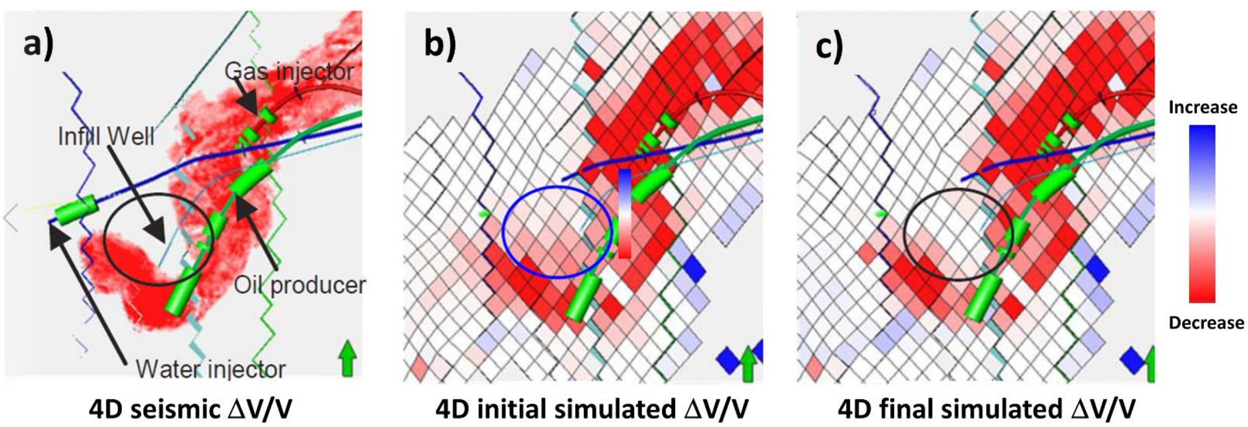

Fig. 3.22—(a) 4D seismic response showing a decrease in velocity between the baseline and monitor seismic surveys as a result of gas exsolution in the reservoir. (b) Simulated 4D response based on the initial dynamic reservoir simulation model. (c) Simulated 4D response based on the history-matched simulation model. Green bars indicate perforated intervals (modified from Berthet et al. 2015).

Analysis of the 4D response data indicated that the water injector did not support the oil producer because of a sedimentological baffle. Pressure support was noted to the north through several sources, as noted in the paper. The seismic interpretation provided a good pressure match and improved the match to the water-cut. The 4D data showed an area where gas had not come out of solution (no color change in Fig. 3.22a), contrary to the initial model prediction. Thus, there was potential for an infill well (either a producer or an injector) in this area (subject to further simulation scenarios).

3.7 Conclusion

Seismic methods have been used in petroleum exploration and production for decades and have achieved significant success, especially in finding new fields and better characterizing old fields, credited to their spatial coverage and continuous and even sampling of the 3D subsurface. The application of seismic data in petroleum resources management has a wide spectrum, from an intensive usage of the high-quality 3D and time-lapse (4D) seismic data for all the classes of reserves and resources in the classification framework for an offshore oil/gas field to sparse seismic usage in 2D applications in older fields. Eventually, any seismic-driven new discovery in the exploration stage is a case of turning Prospective Resources to Contingent Resources.

An SEM is the place where all the disciplines work together. The application of seismic information, after calibration with well data, is to provide a 3D static model of the structure and stratigraphy, including the reservoir geometry and faults, leading to the estimation of GRV in a reservoir and then PIIP. The uncertainties of these estimates can be reduced as measurements from more wells are incorporated. In certain cases, seismic data can show the OWC and gas-water contact by AVO and/or DHI techniques. The formation's acoustic/elastic properties and reservoir properties can be estimated via seismic inversion guided by well data and then used in 3D static Earth model building for reservoirs. The 4D seismic data can be used to monitor the changes in reservoirs due to production, and then to indicate the sweep efficiency and identify the unswept areas, which contribute to building the dynamic Earth model, understand the depletion sequence, and optimize the field development plan.

The examples presented in this chapter intend to show illustrative scenarios of seismic application in resources management. Since each 3D seismic survey can be different in acquisition time, equipment, ground conditions (on land), near-surface conditions, and data processing, the quality of seismic data can vary significantly. It is important for reserves evaluators to consult with their colleague geophysicists to utilize the seismic data properly and effectively for reserves assessment purposes, and to discuss questions on geophysical theories and concepts. The goal is to adequately maximize the value of seismic data in the entire chain of petroleum resources management while characterizing the controlled quality and range of uncertainty.

3.8 Acknowledgments

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Chapter 4

Assessment of Petroleum Resources using Deterministic Procedures

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Dominique Salacz, Jes Christensen, Joel Turnbull, and Oluyemisi Jeje

4.1 Introduction

This chapter provides additional guidance to the Petroleum Resources Management System (PRMS) § 4.1 and § 4.2 regarding the application of the three broad categories of deterministic analytical procedures for estimating the range of recoverable quantities of oil and gas. These categories are: analogy, volumetric analysis, and production performance analysis methods, which include material balance, reservoir simulation, decline curve analysis, and other techniques.

In the early days of a project's life when the project may not have advanced much beyond the development plan, modeling generally will be simple (such as through the use of analogs or volumetric analysis) and then gradually increase in complexity as the project matures. Depending on the scale of the investment, it is not uncommon to have advanced models available (even full-scale reservoir simulations) and ready at sanction. However, it is more common to see a progression of these models throughout the life of the project as the evaluating entity gathers more data and information about the reservoirs being produced. Once the project is fully mature, and only little further investment (financial and/or data acquisition) is anticipated, evaluators may use simpler models such as decline analysis, which rely mainly on the production performance of existing wells.

If the project is incremental (PRMS § 2.3.0.1) to an already existing project (with an existing resource recovery estimate already attached, often referred to as the base profile), it is important to evaluate the resources for the addition and the existing project together (to take into account effects such as interference amongst wells or back-pressure effect in the production facility) and to compare the resulting profile with the base profile. Sometimes an incremental project will accelerate the production of resources from the base profile, but the acceleration may be accompanied by a deceleration (relative to the base profile) at later time. This is generally a positive situation because it improves the economics, but only the added resources (difference between the total profile and the base profile) of the new project should be counted in the PRMS matrix when booking reserves and resources. Care must also be taken if incremental projects are booked as additive to a base profile/project because these projects may not be independent.

Simpler models used for estimation of resources during the early phases of a project (such as exploration, appraisal, and sometimes initial development periods) can be derived by estimating initially in-place volumes using static-data-based volumetric methods and the associated recovery efficiency derived from analog development projects, or by using analytical methods. As these models generally are not very detailed, their execution may require less computer power and will therefore be a relatively quick exercise. It is common to incorporate these early efforts into multiple models or scenarios, whether deterministic or probabilistic (please see Chapter 7—*Probabilistic Resources Estimation* for further details).

Once on production, resources (now likely to be classified as reserves) may be estimated using dynamic-data-based performance analysis (such as reservoir simulation or advanced material balance models).

The PRMS accepts two deterministic approaches to resource/reserves estimation: the "incremental" and the "scenario" (or "cumulative") methods (PRMS § 4.2.1.1). When both are applied to the same project, they should arrive at comparable results (PRMS § 2.2.2.11), especially when aggregated to the field level; they are simply different ways of thinking about the same problem.

In the incremental approach, more emphasis is placed on the experience and professional judgment of the evaluator in the estimation of discrete quantities to be assigned to each category (e.g., P1, P2, and P3 for incremental reserves). When performing volumetric analyses using the incremental approach, a single value is adopted for each parameter based on a well-defined description of the reservoir to determine the in-place resources, or reserves, volumes. This method works best when there is insignificant interference among the low, best, and high estimates.

In the scenario/cumulative approach, three separate analyses are prepared to bracket the uncertainty through sensitivity analysis (i.e., values estimated by three plausible sets of key input geoscience and engineering data parameters). These scenarios are designed to represent the low, best, and high realizations of original in-place volumes and associated recoverable petroleum quantities (PRMS § 2.2.1.4). Depending on the stage of commercial maturity, these scenarios underpin the PRMS categorization of Reserves (low, best, high or 1P, 2P, 3P) and Contingent Resources (low, best, high or 1C, 2C, 3C) of the projects applied to discovered petroleum accumulations or Prospective Resources (low, best, and high or 1U, 2U, 3U) of the undiscovered accumulations with petroleum potential.

The advantages of a deterministic approach are the following: It describes a specific case where physically inconsistent combinations of parameter values can be identified and removed (i.e., the specific combination of static and dynamic parameters must physically exist); it is easier to prepare; it is easier to audit; and the approach has a history of use with estimates that generally can be reliable and reproducible.

The guidance in this chapter is focused on the deterministic methods where the range of uncertainty is captured primarily using a scenario approach. The reader is referred to Chapter 7—*Probabilistic Resources Estimation*, herein, for guidance on applying probabilistic methods.

4.2 Project Life Cycle

Fig. 4.1 illustrates the range of uncertainty of estimated ultimate recovery (EUR) for any petroleum project, which is expected to decrease over time as the accumulation is discovered, appraised (or delineated), developed, and produced, with the degree of uncertainty normally decreasing at each stage. Once discovered, the length of each period depends on many factors, such as the size of the accumulation (which affects the duration of the appraisal and construction periods) and the development design capacity in terms of annual reservoir depletion rate. For example, projects with lower depletion rates will support a relatively longer plateau period followed by a longer decline period, and the opposite is also true. While the "best estimate" is conceptually illustrated as remaining constant, there may be significant volatility in this estimate in actual projects over the course of the field appraisal and development life cycle.

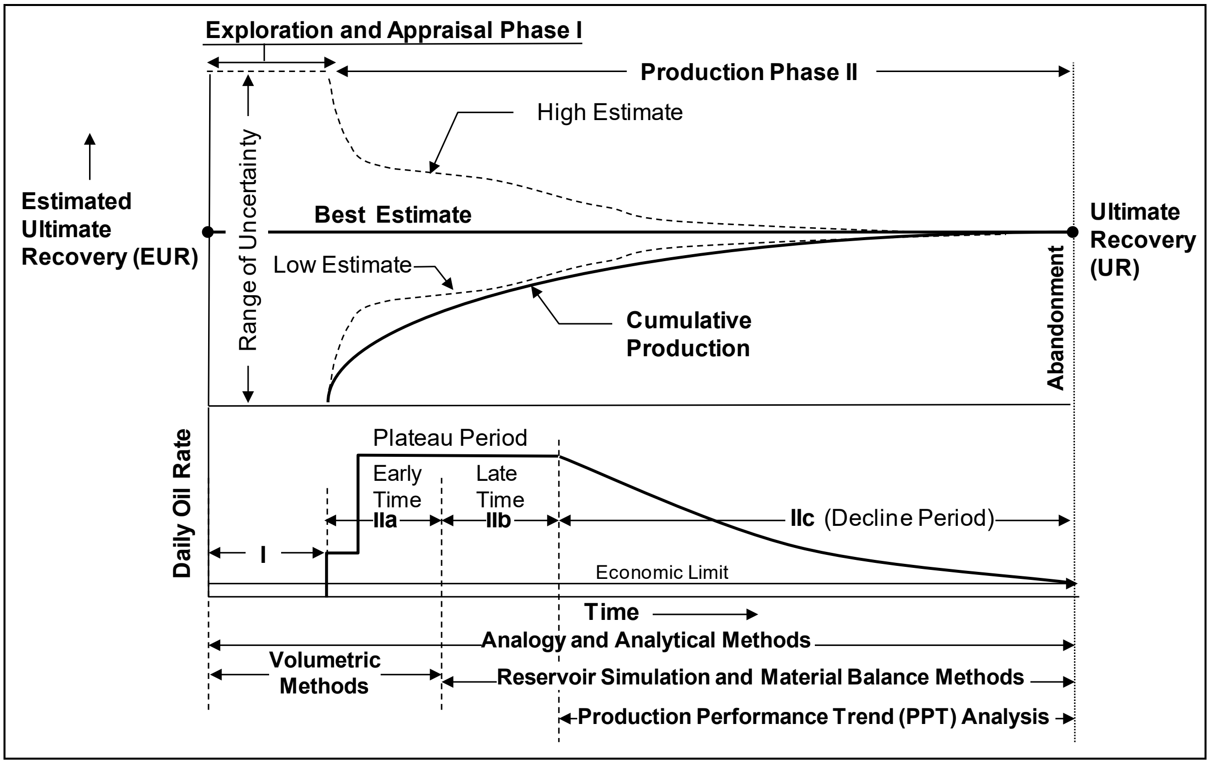


Fig. 4.1—Change in uncertainty and examples of assessment methods over the project's exploration and production life cycle.

The selection of the appropriate method with which to estimate reserves and resources changes for any petroleum recovery project over its life cycle, and the accuracy of estimates depend largely on the following factors:

- The type, quantity, and quality of geoscience, engineering, and economics data available and required for both technical and commercial analyses.
- Reservoir-specific geologic complexity, hydrocarbon type, recovery mechanism, stage of development, and maturity or degree of depletion. (For unconventional reservoirs, the reader is referred to Chapter 10—*Unconventional Resources Estimation* herein.)
- Partnership agreements—Many petroleum accumulations are developed by joint ventures, with one company conducting operations. While generally the operator will have a preferred modeling type/approach, and the other partners either may adapt to the operator or supplement provided estimates with their own independent work, it is good practice to have multiple model types to increase the reliability of the estimate. Other types of agreements may only address a shared cost with the operator, and in those cases, all evaluations are done independently of the other interest holders in the project.
- The anticipated size of investment (higher investment normally requires more initial work to reduce uncertainty, e.g., by applying more complex models).

Although certain estimation techniques are better suited to a particular stage in the project as per the application ranges indicated by the arrows at the bottom of Fig. 4.1, the reader should not consider the indicated limits as strict. The darker areas of the bars in **Fig. 4.2** generally conform to the stages at which each technique is most applicable.

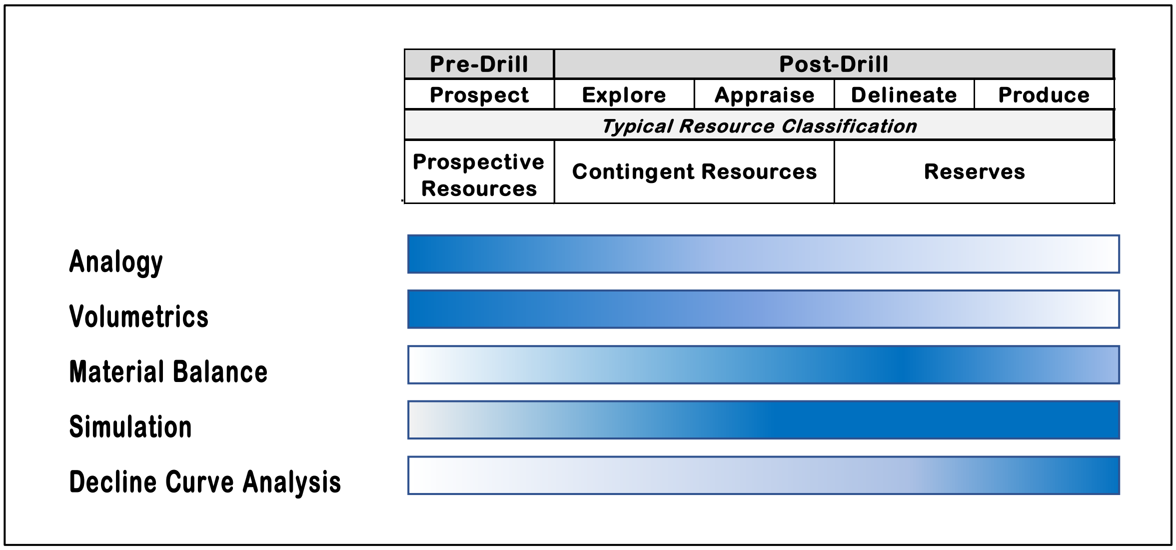


Fig. 4.2—Change in assessment methods over the project's exploration and production life cycle.

For example, simulation is most applicable in a project where sufficient data have been acquired to enable a history match of performance. However, a near-field prospect might already be covered by an existing geocellular model and have sufficient offset wells to provide meaningful input to the subject model. Likewise, a material balance approach is helpful in the initial stages to test scenarios, and it is also useful with postproduction data.

Depending on the amount and quality of historical pressure, production, and other reservoir performance data available, a combination of reservoir simulation, material balance, and production performance trend (PPT) analyses (such as decline curve analysis) can be used not only to estimate directly the recoverable petroleum, but also to estimate the petroleum in-place quantities (by the first two methods only) and thereby provide a useful second check and validation of estimates obtained earlier by volumetric methods.

4.3 Analogy-Based Assessment

According to Hodgin and Harrell (2006, p. 2), an analog reservoir is one that is "at a more advanced stage of development than the reservoir of interest and thus may provide concepts or patterns to assist in the interpretation of more limited data." The PRMS added further emphasis when evaluating analogs to incorporate the development plan elements, which are often a material consideration in the resultant applicability of the proposed analogous reservoir(s).

Although there are several suggestions in the literature as to how an analog should compare with the reservoir in question, the suitability of the analog fundamentally depends on the purpose of comparison. The PRMS allows some flexibility in the choice of the analog, but certain fundamentals must be considered.

The evaluator should start by considering four aspects: the depositional environment, the fluid type, the reservoir drive mechanism, and the development type. Should any of these factors be materially different between the subject reservoir and the proposed analog, it is highly likely that the analogy will be poor. Once these four aspects have been considered, the remainder of the aspects (PRMS § 4.1.1.2) can be reviewed in detail.

Subsequently, the petrophysical properties (termed as the "familiar six" by Sidle and Lee 2010) should be considered explicitly: porosity, permeability, permeability distribution, net thickness, continuity, and hydrocarbon saturation.

In certain resource classifications, additional mandatory requirements for the analog are stipulated, as described below.

Note that, apart from certain exceptions pointed out below, the analog reservoir does not need to be in the same geographic area as the subject reservoir, nor should geographic proximity be the foremost consideration in assigning analogy (PRMS § 4.1.1.5).

4.3.1 Purpose of Analogs. Fundamentally, there are two reasons why analogs are used in resource management: classification of resources and estimation of resources. The former typically has more stringent expectations of the analog than the latter.

4.3.1.1 Classification of Resources. The PRMS system explicitly references four situations where analogs may be used to justify classification in a given resource class:

- Economic producibility without a flow test (PRMS Table 1: Reserves): In this situation, the analogous reservoir should be in the same area.
- Applicability of workover, treatment, and changes of equipment (PRMS § 2.3.1.1): Incremental recovery from such treatments may be classified dependent on analogous reservoirs.
- Improved recovery (PRMS § 2.3.4.3): Commerciality may be justified based on a reservoir with analogous rock and fluid properties where a similar improved recovery project has been successfully applied.
- Unconventional Contingent Resources without a flow test (PRMS § 2.4.0.4): In this situation, log and core data and nearby producing analogs provide evidence of potential economic viability.

4.3.1.2 Estimation of Resources. The extent to which analogs are used in the estimation of resources will depend largely on the maturity of the project in question. For Prospective Resources or predevelopment Contingent Resources, there will be limited information on the reservoir in question, so some fundamental questions will need to be answered with the help of analogs, perhaps in combination with other analytical methods, including:

- Recovery efficiencies (primary/secondary/tertiary)
- Production rates and profiles
- EUR/well
- Reserves life index (defined as reserves divided by average or current production rate)

As the project becomes more mature, it is likely that alternative analytical techniques will be used, but analogs still may be necessary to fill in the blanks, at least prior to establishing meaningful production trends.

Note that the estimation of a resource quantity may well impact the resource classification (e.g., a review of the profile or EUR/well might indicate questionable commerciality).

4.3.2 Methodology for the Application of Analogy. The procedure for using analogy should be applied in a consistent, rigorous manner [the following is modified from Hodgin and Harrell (2006)]:

1. Determine the purpose of the analog and explicitly define the parameters that will impact the validity of the analog. For resource classification, there may be some mandatory parameter requirements.
2. Identify multiple analogs and compare the results with reference to the input parameters. As described by Sidle and Lee (2010), should there be any outliers in terms of performance, they need to be fully understood before progressing.

3. Evaluate the subject reservoir in light of the analog. In general, the subject reservoir should be better than the analog reservoir, at least "in the aggregate" for recognizing Proved Reserves. For example, for economic producibility, the porosity of the analog reservoir may be better than the subject reservoir, but a more germane test would be the reservoir transmissivity (Kh/μ, where Kh is horizontal conductivity, and μ is viscosity), which should be better in the subject reservoir than in the analog reservoir.
4. Establish the proof of analogy under the relevant Reserves definitions to a mature reservoir and recovery process.

The analog normally will help to generate the best estimate, or 2P, but it will inform the 1P and 3P estimates too. If there are any weaknesses in the analog, this should give the evaluator thought to widen the resource range. Such examples could be:

- Few applicable analogs
- Analogs with one or more parameters better than the subject reservoir
- Large range of "output values" (e.g., EUR/well) among the analogs
- A difference in scale between the analogs and the subject reservoir (e.g., small subject reservoir, large analog reservoirs)

The *Canadian Oil and Gas Evaluation Handbook* [Society of Petroleum Evaluation Engineers (Calgary Chapter) 2019] gives some useful advice on certain specific reserves parameters (*Canadian Oil and Gas Evaluation Handbook* § 6.4.4.2). On areal assignments, when the analog is being used to estimate the areal extent, it should be noted if progressively smaller pools are encountered in a mature area, so the subject area should be reviewed on a regional basis. On recovery factors, key elements such as abandonment pressures and fluid displacement efficiencies must be considered, but the *Canadian Oil and Gas Evaluation Handbook* suggests that geographic proximity, while desirable, is not essential. On performance characteristics, analogs can help greatly, not only on the explicit decline, but also to understand the reservoir engineering aspects such as water loading of gas wells in the future.

4.3.3 Application of Analogy to an Oil Example. Consider the case of a small offshore oil discovery in a mature province with two appraisal wells in the reservoir. No core has been taken, and no flow test has been conducted. The evaluator would like to estimate the recovery efficiency (RE). It is assumed the development will be a subsea tieback to a host platform operated by a third party. Gas lift will be supplied by the host platform.

The first question to be answered is whether there is an active aquifer or not. Absent a well test, it will be necessary to use analogs. Using the methodology outlined above, the following steps should be taken:

1. The purpose of the analog is to determine whether a natural aquifer will provide adequate pressure support and thereby a reasonable RE, without recourse to the use of injection wells. The analog will only be valid if it is in the same geological setting in the same reservoir and it has similar petrophysical parameters, the same development scheme, and similar fluid types. Given that a natural aquifer waterflood is the primary recovery method, there are no additional requirements in the use of analogs for resource classification.
2. Next, it will be necessary to gather multiple analogs by relying on internal, commercial, regulatory, or other public data. Assuming there have been multiple developments in the geological setting, how many developments have relied on natural aquifer support, and how many have required injection wells? Have any of the analogs run into difficulty from

a recovery point of view? If there are any fields that are outliers (either they chose water injection wells or relied on natural aquifer waterflood and ran into problems), then these need to be understood in detail before progressing.

3. Assuming for this example that the natural aquifer is the norm in the geological setting, that any outliers can be explained as being not relevant, and that the regional fields are true analogs, then it will be necessary to compare petrophysical parameters between the analog(s) and subject reservoir. This may be problematic if the regional analog data are not public. In this instance, it may be necessary to cast the net wider using analog data away from the regional area.
4. Following this process, other key questions must be answered using analogs, including economic producibility, production rates, production trends, etc. A test against the Reserves definitions must be made at this point.

Starting with the first two points, several analogs are gathered, concentrating on aspects that would impact the aquifer support. **Table 4.1** outlines the relevant parameters from analogs with aquifers. Note that "overpressure" can indicate limited geological extent. Analog reservoirs are also chosen based on magnitude/ranges of measurable reservoir factors such as permeability, porosity, transmissivity, etc., as indicated earlier in this section.

	Reservoir				
	Deposition	Type	Quality	Extent	Overpressure
Subject	Deepwater marine	Turbidite	Excellent	Continuous	None
Analog A	Deepwater marine	Turbidite	Excellent	Continuous	None
Analog B	Shallow marine	Sheet deposits	Excellent	Limited	None
Analog C	Deepwater marine	Turbidite channels	Excellent - fair	Channelized	None
Analog D	Shallow marine	Tidal channels	Good - fair	Channelized	None
Analog E	Shallow marine / deltaic	Elongate / lobate	Excellent - fair	Continuous	None
Analog F	Shelf marine	Shelf deposits	Good	Limited	Significant

	Faulting			Aquifer		
	Density	Throw	Seal	Strength	Size	Support
Subject	Limited	Sub-seismic	Unknown	Unknown	Unknown	Unknown
Analog A	Limited	Sub-seismic	None	Excellent	Large	Excellent
Analog B	Limited	Sub-seismic	None	Fair	Fair	Fair
Analog C	Significant	10 m max	None	Good	Large	Good
Analog D	Limited	Sub-seismic	None	Good	Large	Good
Analog E	Some	20 m max	Sealing	Poor	Large	Poor
Analog F	Limited	Sub-seismic	Baffle	Good	Fair	Fair

Table 4.1—Example analog parameters for aquifer support.

The next step is to interrogate the data, identify any outliers, and determine whether they are relevant to the subject reservoir. In the example above, the only reservoir with poor aquifer support (Analog E) is one with seismically identifiable fault throws, which we know is not the case in our reservoir. However, there are two reservoirs (Analogs B and F) with fair support, but with limited sand extent (identifiable through regional correlations).

In this instance, there is no strong evidence against good aquifer support, but the analogs are few, and there are significant differences between the analog reservoir and the subject reservoir. It is suggested that the evaluator assume a low case scenario, which has "fair" aquifer support, while the best estimate is based on "good" aquifer support.

The analyst must employ their judgement to consider two options, either: to plan for injection wells to be included in the low case, with a similar RE to the best case but with significantly more capital expenditure, or to assume a reduced RE for the low case and add a new, separate project for incremental resources attributable to water injection in the event of finding poor aquifer support.

In this example, Analog B could be a good candidate for the low case scenario (based on the fair aquifer support and fair aquifer size rationale; Analog E has poor support but a large aquifer size, plus some seismically identifiable faults); Analog C could be a good analog for the best case scenario (choice based also on the aquifer support rationale, as well as on the reservoir characteristics); and Analog A could be used for the high case scenario (based on analogy of reservoir characteristics associated with excellent aquifer support).

4.4 Volumetric Analysis

Volumetric analysis, as described in the PRMS § 4.1.2.1, "uses reservoir rock and fluid properties to calculate PIIP [petroleum initially in place] and then estimate that portion that will be recovered by a specific development project." Volumetric analysis is the most widely used technique for early stage developments, but there can be many pitfalls associated with its use.

It is essential to consider the range of uncertainty throughout the estimation process, whether via deterministic or probabilistic methods. Within deterministic procedures, it is normal practice to consider low, best, and high estimates, but it is also advisable to consider alternative scenarios, particularly for the fundamental assumptions, including horizon interpretation, velocity modelling, structural interpretation, depositional environment, and geological unit correlation.

Consider the well and reservoir schematics in **Fig. 4.3** below. Without additional data, such as a detailed sequence stratigraphic model, there are numerous possibilities for correlation of the flow units.

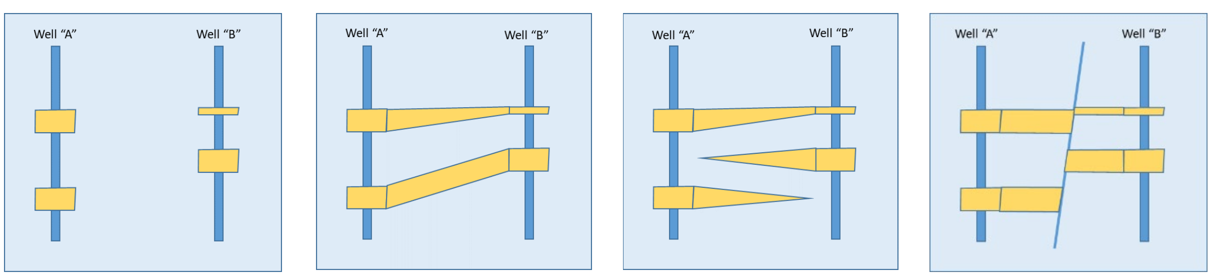


Fig. 4.3—Example of interwell correlation uncertainty.

The issue of reservoir continuity is a major concern in the volumetric estimation of petroleum initially in place (PIIP). Geologic understanding of the depositional environment(s) and the use of pressure and fluid data are key factors in the establishment of reservoir continuity or compartmentalization. A field example of how correlations can change as more data are acquired was discussed in Ray et al. (2010). In this field, a change in correlation following initial development drilling moved a significant portion of the PIIP from a lower-quality unit to a higher-quality unit, thereby dramatically increasing reserves and resources.

The general volumetric equation may be expressed in terms of EUR by:

EUR (STB or scf) = PIIP (STB or scf) × RE (fraction of PIIP), ... (4.1a) dependent upon average values for area (A), net pay (h), porosity (ϕ), initial water saturation (S_{wi}), and initial hydrocarbon formation volume factor (B_{hi}) for oil (RB/STB) or gas (Rcf/scf), where R indicates reservoir conditions. The generalized classic volumetric equation for the PIIP [oil initially in place (OIIP) or gas initially in place (GIIP)] is given by:

PIIP (STB or scf) = $Ah\phi(1 - S_{wi})/B_{hi}$, ... (4.1b)

where oil or gas volumes are in barrels or cubic feet, abbreviated as STB and RB or scf and Rcf, respectively, representing the measurements at standard surface and reservoir conditions, based on prevailing pressure and temperature standards.

4.4.1 Estimating Volumetric Parameters. Volumetric analysis should be generated by an integrated technical team, including geoscience, reservoir and production engineering, and facilities/process engineering. The first step is to quantify the static parameters, followed by an assessment of the RE based on dynamic parameters. The RE is also a function of the anticipated depletion strategy, and it can be either calculated or supported through the use of analogs.

4.4.1.1 Static Parameters. The gross rock volume is often the parameter with the greatest uncertainty, and it must be explicitly defined. An area-depth map, whether generated traditionally or as an output from geocellular models, is an excellent tool for estimating gross rock volume ranges. The interpreter should consider alternative horizon and fault picks from seismic data as well as alternative velocity modelling if there is any doubt in these areas. For regions of dense well control, this will be less of an issue.

Other static parameters (porosity, net-to-gross ratio, hydrocarbon saturation) can then be estimated from available data and/or supplemented by analogs. It is advisable, however, that thought be given to the depositional setting, since a mathematical average of the wells may not be appropriate in channelized systems, for example. Similarly, parameters may degrade further from the sedimentological source, or they may degrade with greater depth due to diagenesis.

Geological conceptual models capturing the deposition of the sand bodies, particularly when there are multiple/stacked sands, should be created. The way in which each sand body connects to another (laterally and possibly vertically) will be critical in understanding PIIP and RE. Unless the region is very well understood and shows strong correlation throughout, or if there are unambiguous geological or geochemical markers, then it is expected that the sand correlation will be nonunique and should be explicitly considered as an uncertainty. In addition to depositional reservoir architecture, faulting within the field must also be considered because it will similarly have an impact on RE as well as resource category.

Care must be exercised with the estimation of hydrocarbon phase contacts. Pressure gradient measurements yield invaluable information, but all possibilities must be considered outside of well control. For example, the existence of a thin oil rim may not be encountered with initial drilling, yet it might make a significant impact on the development scheme, investment scope, and ultimate recovery. A gas cap above the highest known oil is also possible, although the degree of undersaturation should provide an indication of the potential for a gas cap. It should also be recognized that the quality (i.e., representativeness) of the pressure-volume-temperature data is paramount in establishing appropriate hypotheses. Representative pressure-volume-temperature data are required for dynamic simulation and material balance calculations as well as for volumetric estimates, which are dependent upon accurate formation volume factors for PIIP assessment, considering the surface separation conditions.

Attention should also be paid to petrophysical cutoffs. Not all the microscopic hydrocarbon pore space will contribute, and it is important for PIIP and RE to be calculated on the same basis. There are arguments for and against using cutoffs, but this question should be explicitly considered. Further discussion on petrophysical cutoffs may be found in Chapter 5—*Petrophysics* herein.

4.4.1.2 Dynamic Parameters. It is useful to break down RE into its component parts as discussed in the subsections below and suggested by Smalley et al. (2009). The aim of their paper was to maximize efficiency for a producing field, but it is also useful in early estimates.

- Pore-Scale Displacement Efficiency: This refers to the microscopic (displacement) efficiency of the reservoir, and it also serves as the maximum theoretical RE obtainable under waterflood. For example, microscopic RE for a waterdrive oil reservoir may be given by:

$$RE_{\mu} = \frac{1-S_{wi}-S_{or}}{1-S_{wi}}, \quad (4.2)$$

where:

RE_{μ} = microscopic RE of oil, fraction
S_{wi} = initial water saturation, fraction
S_{or} = residual oil saturation, fraction.

Rough estimates for the fluid saturations can be made through initial core and log measurements or through judiciously chosen analogs. This displacement is a function of rock-fluid and fluid-fluid interaction properties, such as wettability, fluid mobility, relative permeability, and capillary pressure. In some textbooks, RE_{μ} is referred to as "displacement efficiency" with the symbol E_D.

- Areal Sweep Efficiency: This refers to the areal connectedness of the producing well; i.e., the producing well may not be connected to other parts of the reservoir as a result of faulting or the fact that the various sands are not stratigraphically connected. Smalley et al. (2009) referred to this as "drainage efficiency." Thought should be given to the depositional environment (sand continuity, sand consistency, net-to-gross ratio), the mobilities of the fluids, and the degree of faulting seen at seismic and core scale.

For early stage estimates, analog EUR/well gives a very good sense that drainage efficiency has been appropriately considered. Some textbooks give areal sweep efficiency the symbol E_A.

- Vertical Sweep Efficiency: Vertical sweep efficiency concerns the fraction of the vertical section of the reservoir actually contacted by displacing fluid(s). This parameter is also affected by fluid mobilities, in addition to vertical heterogeneity, any gravity segregation forces, the quantity of injected fluid(s) if any, and so on. In some textbooks, vertical sweep efficiency is denoted by the symbol E_V.
- Volumetric Sweep Efficiency: In the literature, volumetric sweep efficiency is the product of vertical and horizontal sweep efficiencies, and it represents the percentage of the oil that is moved to the producing wells within the drained area. This would be a low number for depletion-drive reservoirs and a higher number for waterdrive reservoirs.

4.4.1.3 Recovery Efficiency. The total RE, often referred to by the symbol E_R, is the multiplicative product of the microscopic displacement and volumetric sweep efficiencies or:

$$E_R = E_D \times E_A \times E_V. \quad (4.3)$$

As mentioned previously, RE may be calculated, although it is acknowledged that this estimate is inferior to RE determined from actual, lengthy, and reliable performance data. It must be stressed that RE is a function of many parameters, such as the reservoir drive mechanism, any improved oil recovery applications, the rock and fluid properties (e.g., wettability, relative permeability, etc.), "complex situations" (discussed later), development characteristics, and even the project economics.

For example, within the industry, there are empirical RE formulae generated "in-house" by larger producing companies based on the reservoirs developed and producing by the company. These REs are typically predicated on the study of RE performed by the American Petroleum Institute in 1967 (American Petroleum Institute Subcommittee on Recovery Efficiency 1967; Arps 1968) and are expressed in the following form:

$$RE = A \times \left\{\frac{\phi(1-S_w)}{B_{oi}}\right\}^B \times \left(\frac{k\mu_{wi}}{\mu_{oi}}\right)^C \times (S_w)^D \times \left(\frac{p_i}{p_a}\right)^E, \quad (4.4)$$

where:

RE = RE of oil, fraction
A, B, C, D, E = displacement-dependent coefficients **(see Table 4.2)**
ϕ = effective porosity, fraction
S_w = initial water saturation, fraction
B_{oi} = initial oil formation volume factor, reservoir barrels per stock tank barrel (= bubblepoint formation volume factor for solution gas drive reservoirs without primary gas cap)
k = arithmetic average of absolute permeability, Darcies
μ_{wi} = initial water viscosity, centipoise (= 1 for solution gas drive)
μ_{oi} = initial oil viscosity, centipoise (= μ_{ob} for solution gas drive at bubblepoint pressure)
p_i = initial reservoir pressure, psig (= bubblepoint pressure for solution gas drive)
p_a = abandonment reservoir pressure, psig.

Drive Mechanism	A	B	C	D	E
Solution gas	0.41815	0.1611	0.0979	0.3722	0.1741
Waterdrive	0.54898	0.0422	0.077	- 0.1903	- 0.2159

Table 4.2—Recovery efficiency displacement-dependent coefficients.

"Complex situations" may include reservoirs that are nonvolumetric, stratified, fractured, or overpressured, those characterized by thin oil rims with large gas caps and/or underlying aquifers, dual-porosity/dual-permeability reservoirs, and so on. The fundamental equation above was not formulated using examples of such reservoirs.

The reader should also be aware that the API (API 1984, p. 6) followed up the 1967 study with a statistical review cautioning "against continued use of the (1967) correlations…to predict recovery or recovery efficiency for any one reservoir." Nevertheless, the 1967 equations are widely used still, with local or company-specific variation as noted.

There are a number of other RE correlations available in practice, such as that developed by Guthrie and Greenberger (1955), formulated as

$$RE = 0.272\log(k) + 0.256(S_w) - 0.136\log(\mu_o) - 1.538(\phi) - 0.00035(h) + 0.114, \quad (4.5)$$

where k is in millidarcies (md), but all other parameters are in the same units as in Eq. 4.4. This correlation was developed for waterdrive sandstone reservoirs specifically. The use of recovery factor correlations is cautioned, because they were developed for specific conditions with limited databases using values for the key parameters that are subject to uncertainty.

Finally, several published empirical correlations that can be used to estimate RE can be found in Cronquist (2001), Walsh and Lake (2003), and Craig (1971). However, it should be emphasized that even a rough estimate of RE from a near-analog or a value determined by using a physically based analytical method is preferable to using empirical correlations.

4.4.2 Application of Volumetrics to Oil Example. Let us consider the same example as presented previously (Section 4.3.3), consisting of an offshore oil discovery with two appraisal wells. The most usual method for determination of resources at this stage of development would be through a combination of volumetrics and analogs, although a simple material balance model might also be appropriate.

For the volumetric analysis, the first step is to establish the parameters that should be included to define the range of PIIP and technically recoverable resources. A common mistake is to make the assumption that the uncertainty range is limited to traditional parameters such as gross rock volume, porosity, and the like, whereas more fundamental questions such as depositional environment, reservoir correlation, top structure pick, and velocity model should be explicitly considered.

Some example parameters are shown below in **Table 4.3** for our offshore oil example. Note that there is a mix of static and dynamic parameters. The evaluator assumes that, while the horizon interpretation is unambiguous (hence a single interpretation), the velocity model is highly uncertain, and there are three possible scenarios or characteristics. These scenarios will be used in defining the low, best, and high estimate cases.

		Scenarios		
Parameter	Uncertainty Aspect	Low	Mid	High
Depositional environment	Regionally understood	Shallow marine / deltaic	Shallow marine	Shallow marine
Correlation	Two geological models	Correlation style "A"	Correlation style "A"	Correlation style "B"
Horizon interpretation	Unambiguous	Interpretation 1	Interpretation 1	Interpretation 1
Velocity model	Significant uncertainty	Methodology 1	Methodology 2	Methodology 3
Compartmentalization	Low uncertainty	Central fault sealing	Central fault baffle	Central fault open
Phase contacts	Significant uncertainty	Oil-water contact = Oil-Down-To	Oil-water contact between Oil-Down-To position and spill	Oil-water contact at spill point

Table 4.3—Fundamental uncertainty parameter table.

Next, a standard volumetric calculation is performed. The two key elements in **Table 4.4** below that will have the most impact in the static calculation are the velocity model, which generates differing top structure maps, and the treatment of the contact or lowest known hydrocarbon (LKH). The column "low/best" highlights the relative difference between input parameters. (Since this is an oil reservoir, the term OIIP has been used in place of PIIP. GRV is gross rock volume, NTG is net to gross, S_o is oil saturation, and B_o is oil formation volume factor.)

			Scenarios			
Parameter	**Units**	**Source**	**Low**	**Best**	**High**	**Low/Best**
GRV (spill)	MMRB	Velocity model 1	550	887	1,842	62%
GRV (intermediate)	MMRB	Velocity model 2	413	665	1,107	62%
GRV (LKH)	MMRB	Velocity model 3	275	444	739	62%
NTG	fraction	Analogs	0.80	0.89	0.97	90%
Porosity	fraction	Analogs	0.27	0.29	0.31	93%
S_o	fraction	Analogs	0.81	0.85	0.91	95%
B_o	rb/STB	Analogs	1.07	1.10	1.16	97%
OIIP	MMSTB		45.0	132.7	434.6	34%

Table 4.4—Example volumetric calculation: static parameters, where MM indicates million.

The dynamic aspects are considered next. Again, the two key uncertainties in **Table 4.5** below are correlation style (the degree of compartmentalization), which will affect the connectedness, and the treatment of the faulting.

Recovery Efficiency			Scenarios			
Parameter	**Units**	**Source**	**Low**	**Best**	**High**	**Low/Best**
Pore/micro	%	Inputs from analogs	75%	76%	78%	98%
Drainage (open)	%	Correlation	80%	85%	93%	94%
Drainage (baffle)	%	Correlation	78%	83%	91%	94%
Drainage (sealing)	%	Correlation	70%	75%	83%	93%
Sweep	%	Range from analogs	53%	62%	71%	85%
Overall	%	Range from analogs	28%	39%	52%	71%
Tech resource	MMSTB		12.6	52.2	223.8	24%

Table 4.5—Example volumetric calculation: dynamic parameters, where MM indicates million.

Note that the parameters that have the biggest influence are the fundamentals in the table (such as the velocity model and the correlation) rather than the individual petrophysical parameters.

For the example above, the overall low case is a simple product of all the low input variables, for clarity of the procedure only. In reality, the analyst should consider the combinations of parameters that would represent a reasonable low case.

4.5 Performance-Based Methods

Performance-based methods include material balance, reservoir simulation, and PPT analysis. PPT analyses are commonly used methods to directly estimate the technically recoverable resources for oil and gas wells, reservoirs, and specific development (or recovery) projects. PPT analyses are traditionally known as decline curve analyses (DCAs) but may also be considered to include techniques that have found acceptance in unconventional resources assessment, such as rate transient analysis and production decline analysis. (The reader is referred to Chapter 10—*Unconventional Resources Estimation*, herein.) The theory behind traditional DCA was crystallized in 1945 by Arps (1945), and it still remains one of the most prevalent and dependable methods for production forecasting today, under specified flow conditions.

Historical production performance trends observed in mature wells, reservoirs, or projects may generally be extrapolated to the cumulative production at the economic limit, and this will provide a reasonable assessment of the technically recoverable resources when lift type and well design are also considered.

To better comprehend the limitations of PPT analysis, Harrell et al. (2004) pointed out the following conditions under which production decline trends would provide acceptable projections of production profiles and resulting reserves estimates for the asset under study:

- Production conditions, methods, and the overall production strategy are not changed significantly over the projected remaining producing life.
- The reservoir has been fully developed, and the well count is relatively stable. There is no new project that may change the behavior of the reservoir.
- Wellbore interventions and other remedial work can be classified solely as maintenance.

This also implies that the evaluator will have sufficient reliable production data for the analysis, and that the production for all phases, including oil, gas, condensate, and water, is well established, with an emphasis on understanding water breakthrough maturity when an active waterdrive is present.

PPTs are not only reservoir-specific, but they also depend on the particular reservoir management, production practices, and facility constraints used. Any significant change in these practices could easily lead to erroneous results. Therefore, the validity of production profiles projected using DCA depends on both the quality and quantity of the past production data and also on the evaluator's professional experience gained through working on many hands-on assessments and reconfirmations of results over time with actual performance, including the use of appropriate analog reservoirs.

4.5.1 Material Balance. Material balance data include production and injection history, volume-weighted average reservoir pressures, and reservoir-specific relevant fluid and rock properties, all as a function of reservoir pressure and temperature. Independent of the volumetric methods, the material balance methods can be used to directly and simultaneously estimate in-place volumes, the relative size of a gas cap, and/or the water entering the reservoir through influx or injection.

The results of material balance analysis are considered more reliable when longer performance histories, high-quality production data, and high-quality stabilized reservoir pressures are used. A well-established and reasonable assumption is that use of the material balance analysis to estimate in-place volumes is often considered valid if the cumulative production exceeds 10% of the original in-place volume {Cronquist 2001, 30; or *Canadian Oil and Gas Evaluation Handbook* § 2.9 [Society of Petroleum Evaluation Engineers (Calgary Chapter) 2019]}, provided the development of the accumulation is such that the pressures used in the analysis represent an average over the entire reservoir. Uncertainty in the estimate is expected to decrease over time as historical production performance data cover at least the early production period (shown in Fig. 4.1 as IIa) and beyond. A material balance analysis using all available data and information typically should result in a best estimate of the in-place volume.

Technical principles and definition of the terms involved in developing the conventional material balance equation (MBE) applicable to any oil or gas reservoir (i.e., black or volatile oil and retrograde or nonretrograde gas) and applications may be found in Walsh and Lake (2003) and Towler (2002). Modern flowing and dynamic material balance analyses developed by Mattar and McNeil (1998) and Mattar and Anderson (2005) may also be used. The main difference between a flowing material balance and a classic static material balance lies in the source of the pressure data. The flowing material balance uses flowing pressures to estimate in-place volumes instead of buildup or other static pressure measurements. One significant benefit to the flowing material balance is that, so long as the data are of sufficient quality and frequency, it is not necessary to shut in well or field production in order to obtain a good estimate of gas initially in-place (GIIP). While the flowing material balance technique is more computationally intensive, the methodology is generally intuitive to someone accustomed to classical material balance analysis.

A general discussion of the use of material balance methods follows, but more detail on special topics is provided in Appendix A to this chapter.

4.5.1.1 Technical Principles of Oil Material Balance. *The* general MBE is commonly expressed as:

$$N = \frac{N_p\left[B_o+\left(R_p-R_s\right)B_g\right]-\left(W_e-W_pB_w\right)-G_{\text{inj}}B_{g\text{inj}}-W_{\text{inj}}B_{wi}}{\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g+mB_{oi}\left[\frac{B_g}{B_{gi}}-1\right]+B_{oi}(1+m)\left[\frac{S_{wi}c_w+c_f}{1-S_{wi}}\right]\Delta p}, \quad (4.6)$$

where

N = initial oil in-place, STB
N_p = cumulative oil produced, STB
B_o = oil formation volume factor at current reservoir pressure, RB/STB
R_p = cumulative produced gas-oil ratio, scf/STB
R_s = current solution gas-oil ratio, scf/STB
B_g = current gas formation volume factor, RB/scf
W_e = cumulative water influx, RB
W_p = cumulative water produced, STB
B_w = water formation volume factor, RB/STB
G_{inj} = cumulative gas injected, scf
$B_{g\text{inj}}$ = gas formation volume factor of the injected gas, RB/scf
W_{inj} = cumulative water injected, STB
B_{wi} = injected water formation volume factor, RB/STB
B_{oi} = oil formation volume factor at initial reservoir pressure p_i, RB/STB
R_{si} = gas solubility at initial pressure p_i, scf/STB
m = ratio of gas-cap gas volume to oil volume, RB/RB
B_{gi} = gas formation volume factor at p_i, RB/scf
S_{wi} = initial water saturation, fraction
c_w = water compressibility coefficient, psi^{-1}
c_f = formation compressibility coefficient, psi^{-1}
Δp = change in average reservoir pressure, $(p_i - p)$.

There are several practical aspects to consider when using oil material balance techniques that will affect the quality of analysis results, a few of which are outlined in the sections below. For additional detail on applying the methodologies presented, it is suggested to consult a textbook such as Dake (1986, 2001) or Ahmed (2001).

4.5.1.2 Technical Principles of Gas Material Balance. In volumetric gas reservoirs, there is by definition no (or insignificant) aquifer water influx, and the volume of initial hydrocarbon pore volume will not significantly decrease from its initial value, but it will remain constant during reservoir pressure depletion. Therefore, with no adjoining aquifer or water influx ($W_e = 0$), no water production ($W_p = 0$), and no injection of gas ($G_{\text{inj}} = 0$), the generalized conventional MBE for a volumetric, normally pressured gas reservoir reduces to (Lee and Wattenbarger 1996):

$$GB_{gi} = (G - G_p)B_g, \quad (4.7)$$

where

G = GIIP, scf

B_{gi} = gas formation volume factor at p_i, RB/scf

G_p = cumulative gas produced, scf

B_g = current gas formation volume factor, RB/scf.

Assessment of abnormally pressured gas reservoirs will necessitate the introduction of water and formation expansion terms (i.e., $\Delta V_w + \Delta V_f$) that must be added in Eq. 4.7; the reader is referred to Lee and Wattenbarger for further detail. Otherwise, Eq. 4.7 may be rewritten to:

$$G_p = G\left(1 - \frac{B_{gi}}{B_g}\right). \quad (4.8)$$

The gas formation factor (B_g) can be calculated using $B_g = \frac{zTp_{sc}}{T_{sc}p}$, where standard surface pressure (p_{sc}) and temperature (T_{sc}) conditions are 14.65 psia and 519.67°R (60°F), subject to local, contractual, or regulatory variations.

It is common practice to express this relationship in terms of average reservoir conditions by combining and rearranging the different elements to yield this well-known equation applicable only to volumetric gas reservoirs:

$$\frac{p}{z} = \frac{p_i}{z_i} - \frac{\frac{p_i}{z_i}}{G}G_p, \quad (4.9)$$

where

p_i, p = average reservoir pressure (psia) at reservoir datum, and "i" stands for initial

T = average reservoir temperature at reservoir datum (°R)

z_i and z = gas compressibility factors evaluated at p_i and T and any p and T, respectively

G = GIIP (scf)

G_p = cumulative gas production (scf) at reservoir pressure (p).

Eq. 4.9 simply asserts that in volumetric gas reservoirs, the gas production, and therefore the ultimate recovery under natural pressure depletion, is a direct function of the expansion of the free gas initially in place. Furthermore, Eq. 4.9 suggests that a plot of (p/z) vs. G_p should yield a straight line with an intercept (p_i/z_i) and a slope of [$-(p_i/z_i)/G$], from which the GIIP = G relationship can be estimated. When an abandonment pressure is assumed (p_{ab}), the z factor at that pressure (z_{ab}) and a corresponding EUR may be estimated.

An example of a (p/z) plot for a conventional, normally pressured volumetric gas reservoir, with the variables mentioned above, is shown in **Fig. 4.4.**

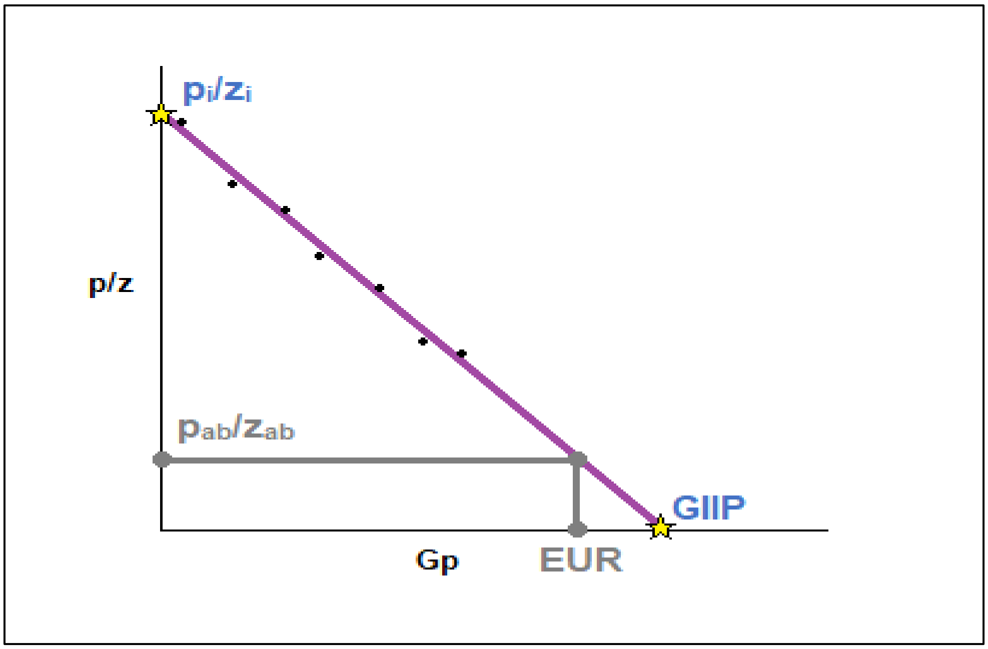


Fig. 4.4—Conceptual plot of *p/z* versus cumulative gas production.

4.5.1.3 Considerations When Applying Material Balance to Gas Reservoirs. There are several practical aspects to consider when using gas material balance techniques that may improve the quality of analysis results, some of which are outlined in Appendix A. For additional detail on applying the methodologies presented, the reader may consult a textbook such as Lee and Wattenbarger (1996) or another source as presented in the references.

4.5.1.4 Material Balance: Comparison with Results from Other Methods. Once a material balance analysis has been completed, it should be compared against other methods used to estimate in-place volume, especially volumetrics. If there are conflicts between the material balance result and other estimation methods, an attempt at reconciliation should be made to avoid over- or underestimation of in-place volumes and technically recoverable resources.

Here are a few examples of situations that may arise:

- If the volumetrics-estimated in-place volumes are higher than the material balance–estimated in-place volumes, and enough oil and/or gas has been produced from the reservoir to provide confidence in the material balance results (generally at least 10% of the in-place volume), perhaps there is compartmentalization in the field resulting in the current wells only accessing a portion of the total volume in the area. In other words, the MBE is indicative of the contacted area only.
- For a gas reservoir, if the volumetrically estimated GIIP volumes are lower than the material balance estimated GIIP, and the initial reservoir pressure is high, it may suggest that this is a case of an overpressured reservoir, and the p/z analysis is overestimating the GIIP.
- If the technically recoverable resources estimated by production decline analysis are significantly less or greater than the value estimated by material balance, perhaps an incorrect value was applied as an abandonment pressure in performing the material balance.

- If the recovery factor estimated by material balance differs greatly from the values obtained from analogs, perhaps a closer look at the analogs' parameters is required to explain the differences. In many cases, the reservoir properties may be a good match, but there are differences in the recovery process that may not have been considered.

4.5.1.5 Application of Material Balance to Oil Example. The example oil project is a black-oil reservoir, initially undersaturated (i.e., no gas cap) with partially active water influx, which was developed by peripheral downdip water injection to supplement reservoir energy and to help maintain a constant reservoir pressure 100 to 200 psia above the bubblepoint pressure. The project produced 220.8 million STB of oil (15.4% OIIP of 1,429.6 million STB estimated), 126 billion scf of solution gas, and 80 million STB of water and injected 385 million STB of produced and supply water into the aquifer below the original oil-water contact. Furthermore, above the bubblepoint, solution gas-oil ratios are equal ($R_s = R_{si} = R_p$), as all gas produced at the surface would be dissolved in the oil. The straight-line MBE (Havlena and Odeh 1963, 1964) is suitable for this particular case, and its details may be found in the references cited.

$$\frac{F_p}{(B_{oi}\ c_e \Delta P)} = N + \frac{(W_e + W_{\text{inj}} B_w)}{(B_{oi}\ c_e \Delta P)}, \quad (4.10)$$

where

F_p = cumulative net reservoir withdrawal, RB
N = oil initially in-place, STB
B_{oi} = oil formation volume factor evaluated at p_i and T
ΔP = change in pressure from p_i to p, psia
W_e and W_{inj} = water influx (in RB) and water injection (in STB), respectively
B_w = water formation volume factor, RB/STB
c_e = effective saturation-weighted compressibility of the reservoir system, $(S_o c_o + S_w c_w + c_f)/(1 - S_w)$, psi^{-1}
S_o = oil saturation, fraction
c_o = oil compressibility coefficient, psi^{-1}.

This MBE represents reservoir depletion under a combined waterdrive (i.e., water influx and/or downdip water injection into the aquifer) that is effective and strong enough to maintain average reservoir pressure above the bubblepoint pressure. Since water is injected into the aquifer at the periphery, it is treated as part of the water aquifer irrespective of how much of the water actually enters the oil zone and helps to displace oil or how much of it enters the aquifer.

Eq. 4.10 suggests that a same-scale Cartesian plot of the left-hand side vs. the second term of the right-hand side should yield a unit slope intercepting the ordinate at N (i.e., PIIP), as in **Fig. 4.5.**

Data necessary for this plot can be generated at each timestep as follows: At any time period with an appropriate ΔP, (1) the F_p and c_e data can be calculated using the relevant relationships and measured production and injection data, (2) the unsteady-state water influx theory of Van Everdingen and Hurst (1949) may be used to estimate dimensionless influx rates (W_D), and (3) then the water influx (W_e) can be calculated.

Based on the average reservoir pressure observed and production and injection performance data recorded over an 8-year period (the first-year data were erroneous, out of scale, and excluded), the terms in Eq. 4.10 were calculated and plotted **(Fig 4.6)** in the same fashion as in Fig. 4.5.

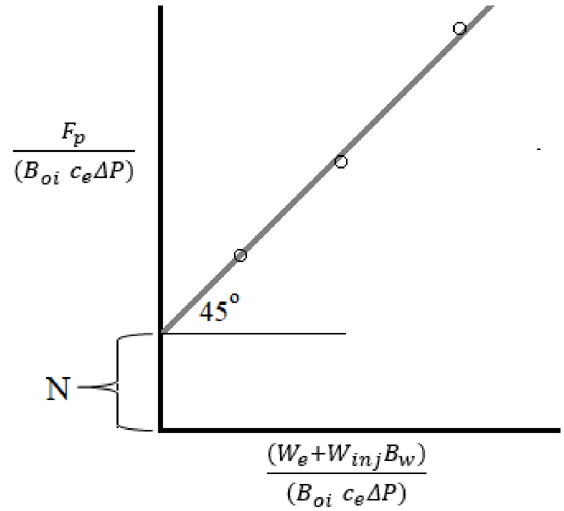


Fig. 4.5—Material balance plot for oil reservoir with waterdrive.

With the variations shown in the plotted data, three parallel straight lines were drawn with a unit slope supporting the value of the dimensionless radius, $r_D = 5$ (defined as a ratio of the aquifer radius to reservoir radius), and bracketing the degree of uncertainty in the measured and interpreted data. These minimum, most likely, and maximum interpretations of PIIP (in this situation, oil, hence OIIP or *N*) values of 1,300, 1,600, and 2,000 million STB were assumed to represent the low, best, and high estimates, respectively.

Over the past 8 years, the ongoing peripheral waterflood project confirmed similar performance to the analogs nearby, one of which had been since converted to a CO_2 pilot, while another was recently initiated, with encouraging performance similar to the initial response seen in the first CO_2 pilot. Recovery potential due to the implementation of a CO_2 pilot in this project would be incremental and subject to development contingencies.

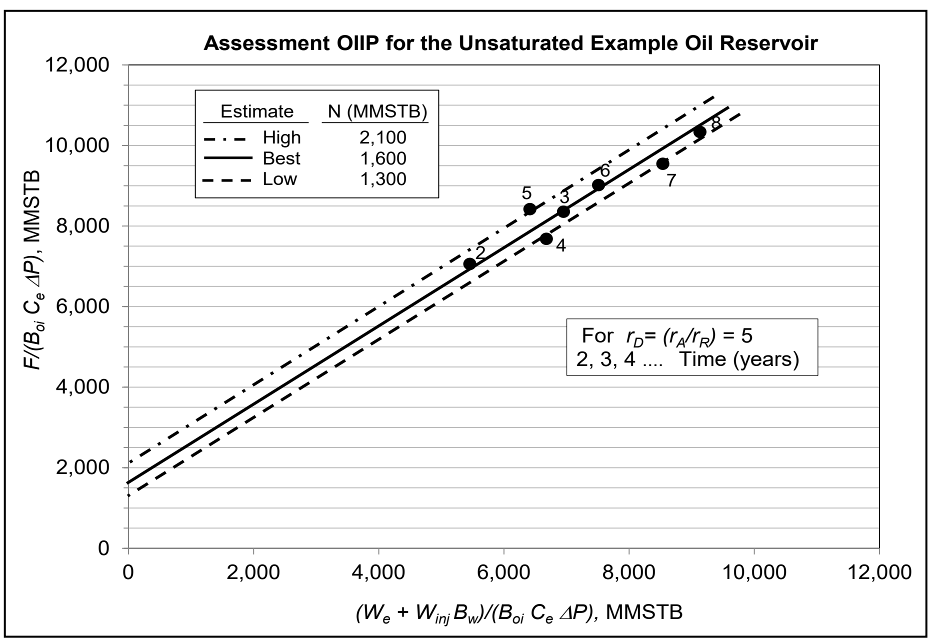


Fig. 4.6—Assessment of OIIP by material balance methods (early production stage), where MM indicates million.

Based on these low, best, and high estimate OIIPs, the respective Technically Recoverable Resources (under the ongoing peripheral waterflood project) and Contingent Resources (under a proposed CO_2 miscible project) were calculated as presented in **Table 4.6.**

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves and Resources Category		
			Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Oil	MMSTB	**220.8**	**220.8**	**220.8**
		% OIIP	17.0%	13.8%	11.0%
	- Raw Gas	Bscf	**125.9**	**125.9**	**125.9**
Original Oil In-Place (OIIP)		MMSTB	**1,300**	**1,600**	**2,000**
Recovery Factor[1]		% OIIP	40%	45%	50%
Recoverable Oil (EUR)*	- Original	MMSTB	**520.0**	**720.0**	**1,000.0**
	- Remaining[4]	MMSTB	**299.2**	**499.2**	**779.2**
Initial Solution Gas-Oil Ratio (R_{si})		scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas		Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)		Bscf	**741.0**	**912.0**	**1,140.0**
Recoverable Raw Gas (EUR)	- Original	Bscf	**296.4**	**410.4**	**570.0**
		MMBOE[2]	69.0	95.5	132.7
	- Remaining[4]	Bscf	**170.5**	**284.5**	**444.1**
		MMBOE[2]	39.7	66.2	103.4
			Basis and Categories of **Contingent Resources**		
		Units	Low Estimate	Best Estimate	High Estimate
Recovery Factor[3]		% OIIP	5%	10%	15%
Recoverable Oil[4]		MMSTB	**65.0**	**160.0**	**300.0**
Recoverable Raw Gas[4]		Bscf	**37.1**	**91.2**	**171.0**
		MMBOE[2]	8.6	21.2	39.8

1 Under Peripheral Water Injection Scheme that maintains reservoir pressure above the bubblepoint.
2 Calculated using an average conversion factor of 5.8 MMBtu per BOE.
3 Under a CO_2 Miscible Flood based on the results of one CO_2 Pilot already implemented and a positive response from a second pilot being applied in another nearby analog reservoir.
4 Estimated categories of Oil and Gas Reserves of **1P, 2P** and **3P** and Contingent Resources of **1C**, **2C** and **3C**.

Table 4.6—Assessment using oil material balance methods (early production stage), where MM indicates million, B indicates billion, and BOE is barrels-oil-equivalent.

4.5.1.6 Application of Material Balance to Gas Example. **Fig. 4.7** depicts the p/z vs. G_p performance plots for this example volumetric wet-gas reservoir. Because of variations in the observed data under pressure depletion, it was possible to draw three different straight lines bracketing the potential degree of uncertainty in the measurement and interpretation of the historical data. These low, best, and high estimate interpretations of PIIP (in this case, gas, therefore GIIP) estimates from Fig. 4.7 may be used for assigning different reserves categories of 1P, 2P, and 3P, respectively, based on an estimated (p/z) economic limit of 1,500 psia. The resulting implied volumetric reservoir RE is calculated to be about 75% to 76% of GIIP. Estimates are further supported by the following factors and considered reasonable because: (1) the reservoir has been established to be volumetric with nonretrograde gas; (2) it is fully delineated and developed with a best estimate GIIP of 1,800 billion scf using volumetric methods; (3) it has already produced 316.2 billion scf, which is more than 17.6% of this volumetric GIIP or 21.1% of the low GIIP estimate from Fig. 4.7; and (4) the project economics based on these three different scenarios are all determined to be viable with discounted cash flow rates of return exceeding 20%.

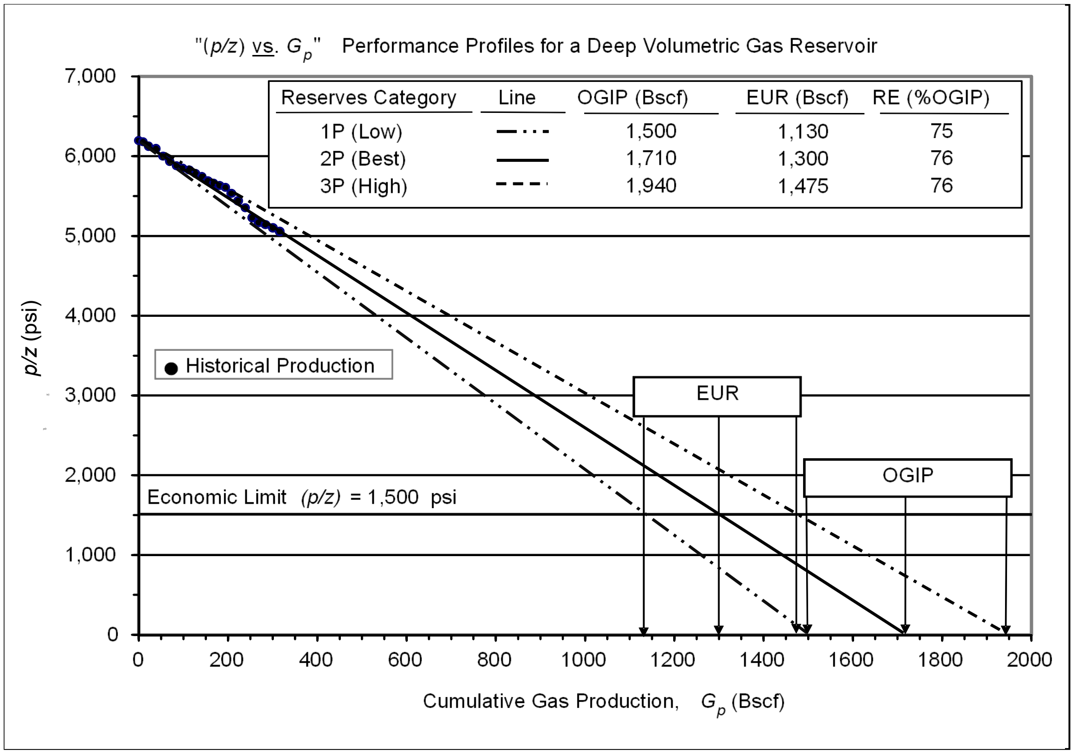


Fig. 4.7—Gas reserves assessment by material balance methods (late production stage), where OGIP is original gas in-place, and B indicates billion.

Based on the initial condensate gas ratio of 30 STB/million scf raw gas (with a gross heating value of 1,100 Btu/scf) and a recovery factor of 60% original condensate in-place from the nearby analog reservoirs, the in-place and reserves estimates for this gas reservoir are summarized in **Table 4.7.** Note that the recoverable raw gas volumes (in terms of both scf and therefore barrels-oil-equivalent, BOE) summarized in Table 4.7 must be reduced by approximately 20% for the surface loss to yield their residue sale gas equivalents or Reserves (EUR), consisting of 3.2% for the shrinkage of condensate reserves and 16.8% for the subsequent processing to remove non-hydrocarbons (8.1%) and recovery of C_2 plus natural gas liquids (8.7%). For more detail, readers should refer to Chapters 11—*Production Measurement & Operational Issues* and 12—*Resources Entitlement and Recognition*, herein, on production measurement, reporting, and entitlement issues.

It is a common practice to determine whether "gas compression" is economically viable and can be used to lower wellbore backpressure to help gas wells produce at lower average reservoir abandonment pressures (or associated p/z economic limits) and thus provide additional reserves.

The wellbore backpressure is the sum of the backpressure imposed by the sales gas pipeline and the pressure drops in the gas gathering system at the surface and in the tubing string in the wellbore. A gas well will stop flowing when the average reservoir pressure drops to this wellbore backpressure. This "no flow" average reservoir pressure, and therefore its (p/z) value, does not necessarily represent the economic limit because the wellbore-imposed backpressure can be reduced by designing and installing an optimal gas compression facility (with an optimal compression ratio) at the point of sales (or plant feed) to significantly reduce the sales gas pipeline-imposed backpressure.

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves Category: Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Raw Gas	Bscf	**316.2**	**316.2**	**316.2**
		% GIIP	21.1%	18.5%	16.3%
	- Condensate	MMSTB	**9.4**	**9.4**	**9.4**
Gas Initially In-Place (GIIP)[1]		Bscf	**1,500**	**1,710**	**1,940**
Gross-Heating Value of Raw Gas		Btu/scf	1,100	1,100	1,100
Recoverable Raw Gas (EUR)[1]	- Original	Bscf	**1,130**	**1,300**	**1,475**
		MMBOE[2]	214.3	246.6	279.7
	- Remaining[4]	Bscf	**813.8**	**983.8**	**1,158.8**
		MMBOE[2]	154.3	186.6	219.8
Implied Recovery Factor		% GIIP	75%	76%	76%
Initial Condensate-Gas Ratio (CGR_i)		STB/MMscf	30	30	30
Condensate Initially In-Place (CIIP)		MMSTB	**45.0**	**51.3**	**58.2**
Condensate Recovery Factor[3]		% CIIP	60%	60%	60%
Recoverable Condensate (EUR)	- Original	MMSTB	**27.0**	**30.8**	**34.9**
	- Remaining[4]	MMSTB	**17.6**	**21.4**	**25.5**

[1] Estimated directly from Figure 4-8 based on (P/Z) values of 0 and 1,500 psia (economic limit), respectively.
[2] Calculated using an average conversion factor of 5.8 MMBtu per BOE
[3] Based on several nearby analog reservoirs and accounts for condensate dropout in the reservoir, if any.
[4] Estimated Gas and Condensate Reserves categories of **1P, 2P** and **3P**, respectively.

Table 4.7—Gas reserves assessment by material balance methods (late-production stage).

The economic limit (p/z) of 1,500 psia for this example reservoir represents a point where the value of production is just equal to the operating cost of producing the project under pressure depletion without compression. It is a deep gas reservoir, and although gas compression is expected to reduce the economic (p/z) limit to as low as 1,000 psia, it is uneconomic because the value of incremental gas reserves realizable is determined to be less than the capital and operating costs of installing and running the compression facility. Thus, the incremental project volumes associated with compression are considered as Contingent Resources pending future updates for cost reduction and/or higher gas prices.

4.5.2 Reservoir Simulation. Traditional material balance analysis using analytical procedures is routinely being performed during reservoir simulation studies. A history-matched numerical simulation is a powerful tool, capable of modelling the complex interactions of production and injection from multiple wells, changing pressure-volume-temperature properties, and changing pressure gradients within a field to provide a rigorous material balance–based solution and, of course, to compare alternative development scenarios. Reservoir simulation is further discussed in Chapter 6—*Reservoir Simulation* herein.

4.5.3 Decline Curve Analysis. Decline curve analysis is well known and widely used because it provides a visual illustration of the historical production performance of a well, a group of wells, or a reservoir. The established trend can be extrapolated beyond the economic limit to estimate petroleum reserves as well as subeconomic remaining resources. Review, derivation, and understanding of these governing equations (summarized in **Table 4.8**), representing each decline model, are very important for correct use and application of traditional DCA.

	Exponential $b = 0$	Hyperbolic	Harmonic $b = 1$
$q(t)$	$q(t) = q_i e^{-D_i t}$	$q(t) = \dfrac{q_i}{(1 + bD_i t)^{1/b}}$	$q(t) = \dfrac{q_i}{1 + D_i t}$
$N_p(t)$	$N_p(t) = \dfrac{q_i - q(t)}{D_i}$	$N_p(t) = \dfrac{q_i^{\,b}}{D_i(1-b)}\left(q_i^{1-b} - q^{1-b}\right)$	$N_p(t) = \dfrac{q_i}{D_i}\ln\dfrac{q_i}{q}$
r	$r = \dfrac{q_i}{q_a}$	$r = \dfrac{q_i}{q_a}$	$r = \dfrac{q_i}{q_a}$
t_a	$t_a = \dfrac{\ln r}{D_i}$	$t_a = \dfrac{r^b - 1}{bD_i}$	$t_a = \dfrac{r - 1}{D_i}$
N_{pa}	$N_{pa} = \dfrac{q_i - q_a}{D_i}$	$N_{pa} = \dfrac{q_i^{\,b}}{D_i(1-b)}\left(q_i^{1-b} - q_a^{1-b}\right)$	$N_{pa} = \dfrac{q_i}{D_i}\ln\dfrac{q_i}{q_a}$
$D(t)$	$D(t) = D_i$	$D(t) = \dfrac{D_i}{1 + bD_i t}$	$D(t) = \dfrac{D_i}{1 + D_i t}$
D_{ei}	$D_{ei} = 1 - e^{-D_i}$	$D_{ei} = 1 - \dfrac{1}{(1 + bD_i)^{1/b}}$	$D_{ei} = \dfrac{D_i}{1 + D_i}$
D_i	$D = -\ln(1 - D_e)$	$D_i = \dfrac{1}{b}\left[\dfrac{1}{(1 - D_{ei})^b} - 1\right]$	$D_i = \dfrac{D_{ei}}{1 - D_{ei}}$

i = initial time or point at which the decline trend has started

b = decline exponent

D_i = nominal decline rate as fraction of $q(t)$ with a unit of inverse time ($1/t$), equal to D_i when $q(t) = q_i$

$q(t)$ = oil or gas production rate at any time t

t = time

$N_p(t)$ or $G_p(t)$ = cumulative oil or gas production at any time t

D_e = effective decline rate

D_{ei} = effective decline rate at initial conditions (time = 0)

q_a = production rate at abandonment

Table 4.8—Governing equations for decline curve analysis.

DCA is based on the solution of the following generalized differential hyperbolic equation defining the nominal decline rate (D) as the fraction of "change in production rate with time (t)" as:

$$D = -\frac{1}{q}\left(\frac{dq}{dt}\right) = Kq^b, \qquad \text{(4.11a)}$$

where

D = nominal decline rate (related but not equal to the slope of the tangent to the line) at time (t); a fraction of production rate (Q_t) with a unit of reciprocal time ($1/t$) per month, year, etc., consistent with the units of production, frequently expressed as percent per year

q = production rate (STB/D, STB/month, or STB/yr)

b = hyperbolic decline exponent

K = integration constant.

The reciprocal of the nominal decline rate is called the "loss ratio":

$$\frac{1}{D} = -\frac{q}{dq/dt} \quad \text{(4.11b)}$$

The hyperbolic decline exponent, b, is defined as the derivative of the loss ratio:

$$b = \frac{d}{dt}\left[-\frac{q}{dq/dt}\right] \quad \text{(4.11c)}$$

The *hyperbolic decline model* is not only the most common decline trend observed in the actual performance of oil and gas wells and reservoirs, but it also represents the most general and challenging decline trend with two unknown parameters of initial nominal annual decline rate (D_i) and decline exponent (b). Moreover, the decline exponent (b) may have any value except $b = 0$ and $b = 1$, which represent the special cases defined by exponential and harmonic models, respectively.

Note that the exponential and harmonic models are just specific cases of the hyperbolic model. When originally conceived, the Arps-style approach assumed boundary-dominated flow, with an upper limit of 1 for the harmonic decline case. Investigations since this original formulation have demonstrated the presence of "hyperharmonic" exponents associated with transient flow regimes in unconventional reservoirs. For example, the exponent observed for transient linear flow is 2, while that for transient bilinear flow is 4. This is described further in Chapter 10—*Unconventional Resources Estimation*, herein.

Initial nominal decline rate (D_i) is the *nominal* (or continuous) decline rate corresponding to the initial production rate at which decline begins **(Fig. 4.8).** It is a tangent to the initial production rate at a given time. The ratio of nominal decline rate at any time t (i.e., D_t) to initial decline rate (D_i) when production decline first begins is proportional to a power b (except 0 and 1) of the respective production rates and defined by:

$$\frac{D_t}{D_i} = \left(\frac{q_t}{q_i}\right)^b \quad \text{(4.12)}$$

D_i is related to the initial *effective* (or stepwise) decline rate (d_i), which is a step function rather than a continuous function between two consecutive rates, represented as the secant of a rate-versus-time arc connecting the two rates by the following relationships:

$$D_i = -\ln(1 - d_i) \text{ or } d_i = 1 - e^{-D_i} \text{ [exponential decline],} \quad \text{(4.13a)}$$

and

$$D_i = \frac{1}{b}\left[\frac{1}{(1-d_i)^b} - 1\right] \text{ or } d_i = 1 - \frac{1}{(1+bD_i)^{1/b}} \text{ [hyperbolic decline]} \quad \text{(4.13b)}$$

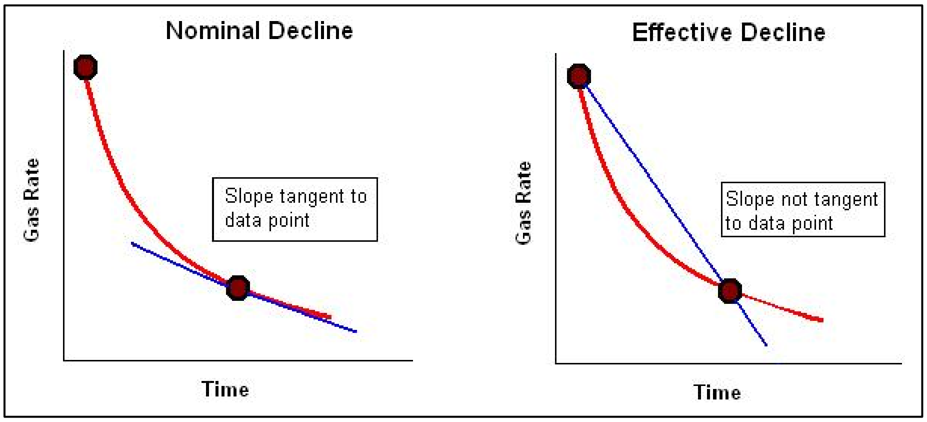


Fig. 4.8—Nominal compared to effective decline rate (IHS Markit 2022).

For example, if D_i = 0.25/yr and b = 0.5, then $d_i = 1 - \frac{1}{(1 + 0.5 \times 0.25)^{1/0.5}}$ = 0.21/yr.

The effective decline rate, d_i, is the one petroleum engineers are most familiar with, as it is typically read directly from a rate-vs.-time plot. Many commercially available DCA packages rely on the effective decline rate (secant) in their analysis; usually, there is not much difference between the nominal and effective decline rates except in the case of unconventional reservoirs, where initial steep declines have a significant impact—the larger is the D_i, the greater is the difference with d_i.

Rate of decline depends on several factors, such as the reservoir depletion rate, the reservoir maturity, the average reservoir pressure, the reservoir rock and fluid properties (magnitude and distribution), and the reservoir management and production practices.

The decline trend analysis of production rate vs. time advanced by Arps (1945) employs hyperbolic equations similar to Eq. 4.11a, which are summarized in Table 4.8.

It has been widely reported that the value of "b" varies with reservoir drive mechanism. Although the development of unconventional reservoirs in North America has resulted in observed "b" values significantly exceeding one (e.g., b = 2 for linear flow and b = 4 for bilinear flow; see Chapter 10—*Unconventional Resources Estimation* herein), the following generally applicable values may be expected **(Table 4.9):**

Value of Decline Exponent (b)	Governing Reservoir Drive Mechanism
0	Single-phase liquid (oil above bubblepoint)
0	Single-phase gas at high pressure
0.1–0.4	Solution gas drive
0.4–0.5	Single-phase gas
0.5	Effective edge waterdrive
0.5–1.0	Commingled layered reservoirs
$b > 1$	Observed in unconventional reservoirs

Table 4.9—General hyperbolic exponents related to reservoir drive mechanisms (after IHS Markit 2018).

The governing rate-time relationship of a general hyperbolic decline model (Table 4.8) is:

$$q_t = \frac{q_i}{(1+bD_i t)^{1/b}} \quad \text{(4.14a)}$$

Eq. 4.14a may also be rewritten as:

$$log\ q_t = log\ q_i - \frac{1}{b}\log(1 + bD_i t) = log\ q_i - \frac{1}{b}\log(1 + Ct), \quad \text{(4.14b)}$$

where $C = bD_i$, which is an unknown constant (refer also to Table 4.8). For a correct value of C, Eq. 4.14b suggests that a log-log plot of q vs. $(1 + Ct)$ should yield a straight line with a slope of m $(=-1/b)$ and intercept of q_i at time zero.

Given the initial production rate at the onset of decline (q_i) and other oil or gas production data observed over the decline period, DCAs have been largely an exercise in curve fitting to establish characteristic straight lines and/or type curves and conducting nonlinear regression analysis to simultaneously estimate the correct values of these two unknown parameters D_i and b.

With estimated correct values of these two unknowns, the cumulative production at any given time can now be directly calculated using the following relationship:

$$N_{pt} = N_{pi} + \frac{q_i^b}{(1-b)D_i} \times \left[q_i^{(1-b)} - q_t^{(1-b)}\right], \quad \text{(4.15)}$$

where q_i and q represent the production rate at initial time i and any time t, respectively, and N_{pi} and N_{pt} represent the cumulative oil production at the initial (i) production rate (q_i) or from time zero ($t = 0$) up to the time t.

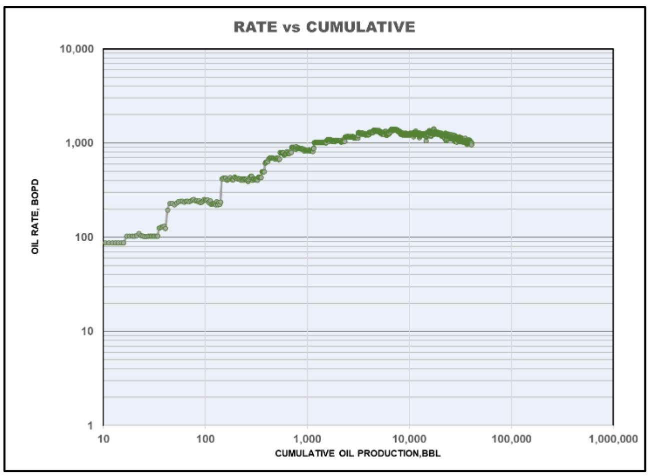
It is difficult to determine the correct value of the decline exponent (b) while attempting to estimate two unknowns (C and b) simultaneously. It is quite possible to have the same b but different D_i values matching the same decline trend that extrapolates to different estimates of reserves, and this must be taken into account to quantify the uncertainty associated with the analysis.

Ideally, one would estimate the nominal decline (D_i) first and then perform a simple trial-and-error procedure iterating on this single insensitive decline exponent b to evaluate and establish the best-matched decline trend that corresponds to the best value of b. Also, b can be calculated as follows: from Eq. 4.14b, when $Ct >> 1$ (which happens soon enough), we can determine b from the slope of a log-log plot of q vs. t. This is almost always possible for wells in transient flow (when D is large), whereas it might be more difficult for wells in boundary-dominated flow (when D_i is much smaller, and so time to reach $D_i bt >> 1$ is longer).

In most cases, the well count in a producing asset (reservoir, field, etc.) changes with time. The conditions may not be stable enough to perform the DCA on a reservoir basis. Also, as the reservoir produces, wells will die, and the slope of the declining asset will change to reflect only the remaining wells, a situation known as "survivor bias." To remedy this situation, DCA should be performed on a well-by-well basis (or completion-by-completion basis). The engineer will need to use their judgment to extrapolate production trends despite inherent errors that will be caused by noise in the data, inaccuracies in the b and D parameters, or even potential changes in dynamic conditions that may not be obvious by looking at the data.

Well-by-well DCA, originally performed manually, is most often carried out using relevant software. However, the results provided by commercially available software should always be scrutinized in light of the characteristics of the reservoir as well as the depletion drive mechanisms, which must be understood by the evaluating engineer. Production down-time, curtailment, stimulation, platform maintenance activity, and other factors impacting production at capacity must be understood. Furthermore, particularly in the case of hydraulically fractured wells, early time cleanup must be excluded from the decline analysis. Determination of the end of the cleanup period is often assisted by analyzing secondary phase ratios such as the gas-oil or water-oil ratios. The analysis is typically completed based on plots such as the following (example shown is a hydraulically fractured, low-permeability oil well):

Fig. 4.9 shows a log-log rate vs. cumulative production plot (left) and the same plot when the production rate is adjusted by normalizing for pressure drop [i.e., $q/(p_i - p_{bhf})$] on the right. No trend can be identified without pressure-normalizing the rate. However, this technique requires the availability of bottomhole flowing pressure data at intervals similar to the production data.



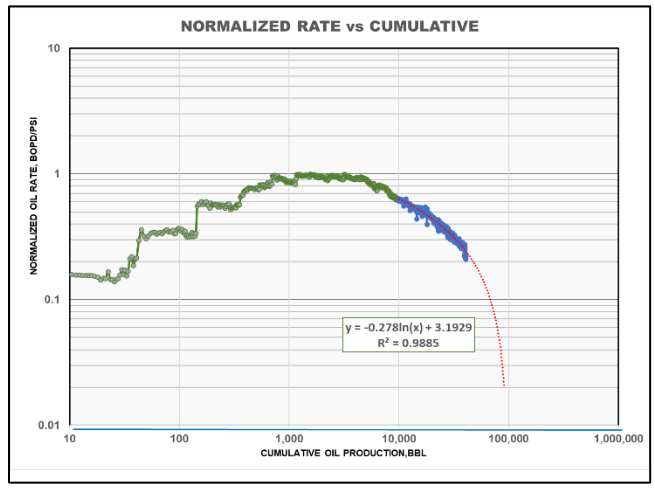


Fig. 4.9—Rate vs. cumulative oil (left); pressure-normalized rate vs. cumulative oil (right), where BOPD indicates barrels of oil per day.

Fig. 4.10 illustrates the use of secondary ratios in identifying the portion of the production history that extends beyond the cleanup period and thus may be used for DCA. In this example, the evaluator defined the first 7 days as the cleanup period, based on the stabilization of the oil production rate and the gas-oil ratio. However, the water-oil ratio (WOR) has not yet stabilized, although it is declining favorably. The figure also includes the choke setting to ensure that production fluctuations are not due to the changing of choke settings.

Fig. 4.11 is a typical semi-log plot of primary phase production rate vs. time. Again, this is an example of a low-permeability oil reservoir, and the production history is quite short; nevertheless, the figure demonstrates the way in which such a routinely used plot can be employed to determine the decline rate under an exponential depletion mode. Semi-log plots have been used as the main DCA tool for decades and are quite easy to generate and analyze in commercial software as well as spreadsheet programs.

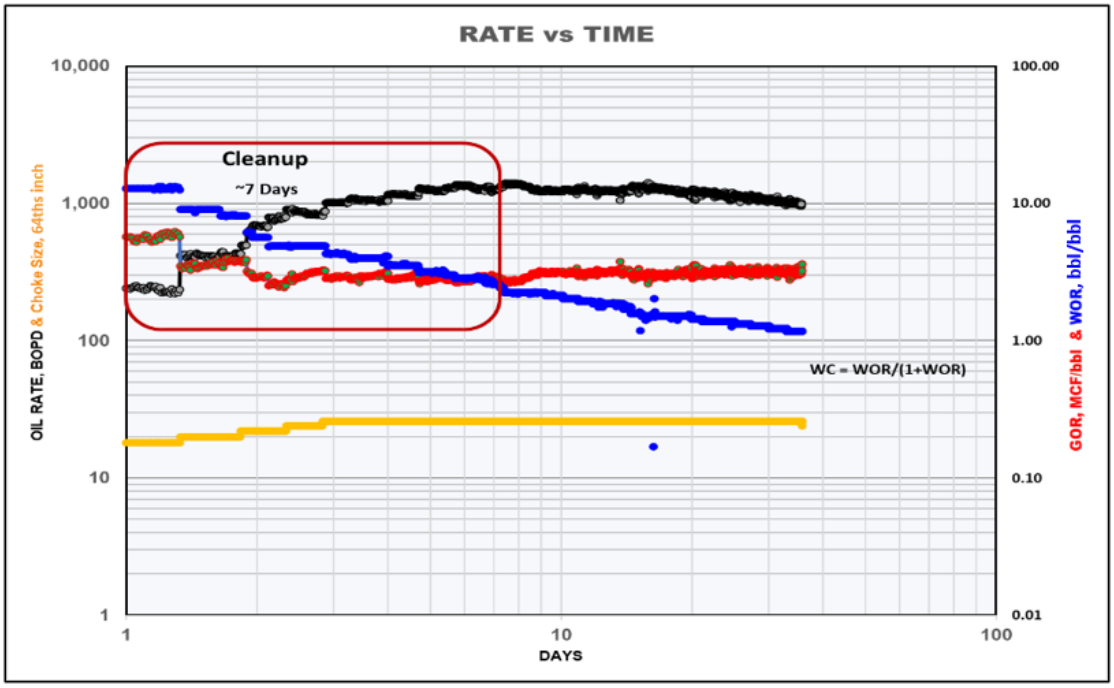


Fig. 4.10—Rate vs. time showing cleanup time, choke size, and secondary ratios, where GOR is gas-oil ratio, WOR is water-oil ratio (both dimensionless), and WC is water cut (as a fraction).

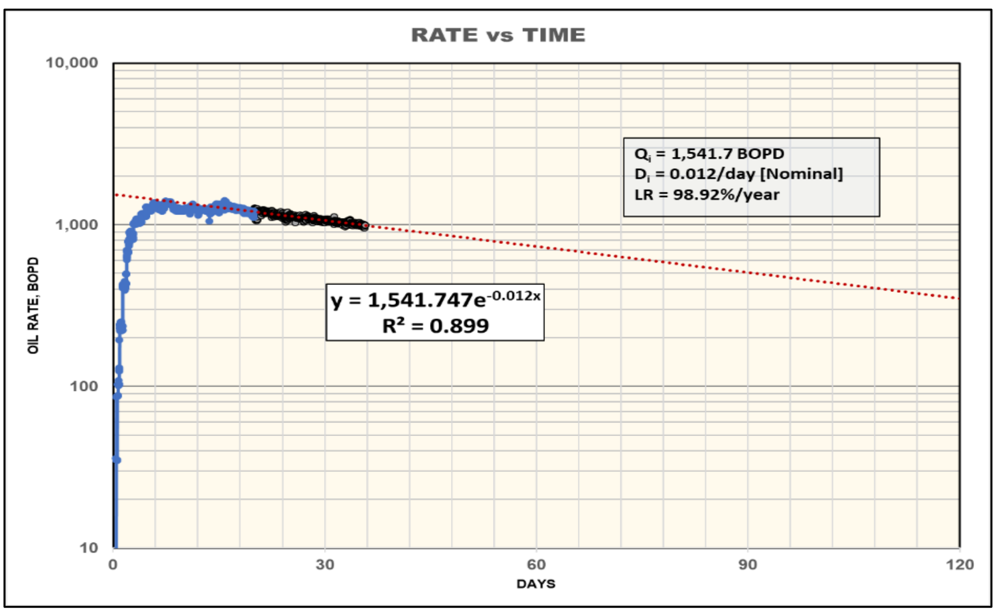


Fig. 4.11—Rate vs. time, semi-log, primary phase, exponential fit. LR = loss ratio.

While the foregoing discussion has been on per-well DCA, DCA may be conducted for a group of wells (such as for a unitized project); however, in doing so, the details of the underlying individual well performances will be lost, and the aggregate production history likely will provide misleading forecasts. This will be mentioned in Section 4.5.3.3. In addition, a curve fit of past performance to extrapolate future production does not necessarily yield the Proved (1P) Reserves forecast, as mentioned in Section 4.5.3.5. The evaluator needs to be aware that, for each DCA-generated fit of past performance, there is a range of uncertainty for the predicted performance that may be expressed in terms of 1P, 2P, and 3P quantities, as shown in the example of Section 4.5.3.4.

4.5.3.1 Supplementary Decline Curve Analysis Techniques. There are other well-established production performance analyses that may be used to predict recoverable volumes based on trends exhibited for a well and/or a reservoir even before the production rate begins to decline. These reservoir drive-specific analyses were briefly discussed by Cronquist (2001). Salient points of these methods may be summarized as follows:

- Cumulative Gas Production vs. Oil Production Trends: For oil reservoirs with solution gas drive, a semi-log plot of log G_p vs. N_{pt} may develop a trend that could be extrapolated to estimate oil recovery, with the maximum G_p being equal to the original solution gas in-place (GIIP = R_{si} × OIIP).
- Water Cut, Oil Cut, or WOR vs. Cumulative Production Trends: These performance trends have been found to be particularly useful in analyzing an oil reservoir producing with waterdrive or producing with downdip water injection or a pattern waterflood. The established trend is extrapolated to the economic water cut (f_w) or WOR to obtain EUR under the prevailing production method with which the trend has been established. It may be useful to note the following reported observations:
    - A plot of "log f_w (or f_o) vs. N_{pt}" (i.e., semi-log plot) trend may turn down at small values of f_o, but this will occur earlier for light oils and later for viscous oils (Brons 1963).
    - A semi-log plot of (WOR + 1) and total fluids withdrawal (F_p) vs. time (t) may help to define oil rate trend (Purvis 1985). Additionally, a semi-log plot of "(WOR + 1) vs. N_{pt}" tends to be linear at WOR values less than 1 and therefore may help to define performance trends at low values of WOR or water cuts.
    - Ershaghi and Omoregie (1978) and Ershaghi and Abdassah (1984) recommended that a plot of $\{\ln[(1/f_w) - 1] - (1/f_w)\}$ vs. N_{pt} should be linear. However, they noted that due to the inflection point of the f_w vs. S_w curves, the method will work only at higher water cuts when $f_w > 50\%$.
    - For reservoirs with an active waterdrive or that are under waterflooding operations, a semi-log plot of cumulative oil production (x-axis) versus oil cut can yield an excellent extrapolation (at high water cuts) to the EUR. Generally, this method works best for $f_w > 50\%$.

Actual PPT analyses require a thorough understanding of their semitheoretical technical bases and the well-established and widely used methods and procedures. However, the correct application of these procedures is not straightforward. One could easily and incorrectly obtain an excellent match but end up with unreliable reserves estimates.

4.5.3.2 Type Curve Analysis. Fetkovich (1980) introduced a robust means with which to match performance data to empirical type curves for the purpose of estimating not only decline parameters but also certain productivity properties, such as skin or flow capacity. This approach relies on the assumption that there are basically two flow regimes during the producing life of a well, namely, a transient period (when the drainage radius is expanding, usually in early time) and semi-steady-state or depletion stage (when the boundaries have been reached, and pressure in the drainage area declines in an approximately uniform fashion). The approach is further predicated on single-phase, slightly compressible, radial flow from a homogeneous reservoir.

Other forms of type curve analysis exist, such as Carter's (1985) gas type curves and the gas-to-liquid equivalent type curves of Palacio and Blasingame (1993), but discussion of the selection and use of type curves is beyond the scope of this work. The reader is referred to the sources at the end of this chapter.

4.5.3.3 Pitfalls and Potential Issues Associated with DCA/TCA. During any DCA exercise, the evaluator also will need to consider carefully all the elements that will affect the behavior of the wells. Such parameters will include, for example:

- Physical cutoff rates and maximum water cuts: Production trends can be extrapolated to very low production rates [or very high basic sediment and water, (BSW)]; however, the expected vertical flow performance of the wells must be taken into account (through lift curves, for example) to ensure that the technical forecast is truncated according to physical constraints. Likewise, water handling can constrain production rates due to facility limitations.
- Test data vs. actual production data: The evaluator should review the data and filter carefully any element that will affect the production trend. This includes potential downtimes, allocation issues, validity/thoroughness of field measurements, noise, etc.
- Well aggregation: While DCA may be performed best on a well-by-well basis (or even completion-by-completion basis), this may be an issue for the well aggregation in large assets. The deterministic sum of P90s will be very pessimistic, and the sum of P10s will be very optimistic. (The reader is referred to Chapter 8—*Aggregation of Reserves*, herein.) What may appear to be a reasonable low case on a well-by-well basis may lead to an unrealistic forecast when many low cases are aggregated.
- Individual vs. group level inputs: DCA likely will be misleading if performed for a group of wells where production is reported, or at least supplied to the evaluator, at the group level. This may be the case for a waterflood unit, in which the aggregate production trend does not identify well workovers or rapidly rising individual well water cuts, for example, or an asset that is operated by another entity that does not provide individual well performance data.
- General decline trends and external parameters: The evaluator should understand the general decline trend and avoid the influence of external parameters such as choke changes. For example, a well may have a very low decline rate because the choke is opened slightly on a regular basis until it reaches the maximum choke setting. Similarly, some companies may set an annual depletion rate for their reservoirs or fields, and the wells are choked back to adhere to this practice.
- All produced phases and constraints: The evaluator should consider all produced phases in the DCA and any facilities or regulatory constraints. The evaluator should not merely focus on the major phase production forecast, and a restriction may be caused by secondary phase production.
- Outliers: Some reservoirs cannot easily be evaluated with DCA. Fractured carbonate reservoirs may produce dry oil at a plateau rate for a long time, but the well will die very quickly when water breakthrough starts. Low-permeability reservoirs cannot easily be evaluated because the *b* factor will vary with depletion stage, and it can be greater than 1 in unconventional assets.
- Production metrics: Producing days vs. calendar days trends will be very different. Calendar day production will introduce external parameters, shutdowns, etc. PPTs are not only reservoir specific, but they also depend on the specific reservoir management and production practices. Any significant change in these practices could easily shift and change the previously established decline trends and invalidate their extrapolations.

Therefore, proper application of these procedures, to a large extent, depends on the experience and skill levels of the professional evaluators and their ability to judge the reasonableness of results obtained by comparing them to known analogs and/or other performance-based methods.

4.5.3.4 DCA Application Example. A well of interest is located in the New Mexico side of the US Permian Basin. The laminated sand-shale turbidite reservoir produces black oil under solution gas depletion drive. Crude quality is 39 °API with a solution gas-oil ratio of 350 scf/STB and initial formation volume factor of 1.25 RB/STB. Water production exists from the start, but data from more mature wells indicate that the wells do not water out regardless of structural position (this is a stratigraphic trap). Thirty-six months of capacity production has yielded the semi-log rate-time relationship plotted in **Fig. 4.12.**

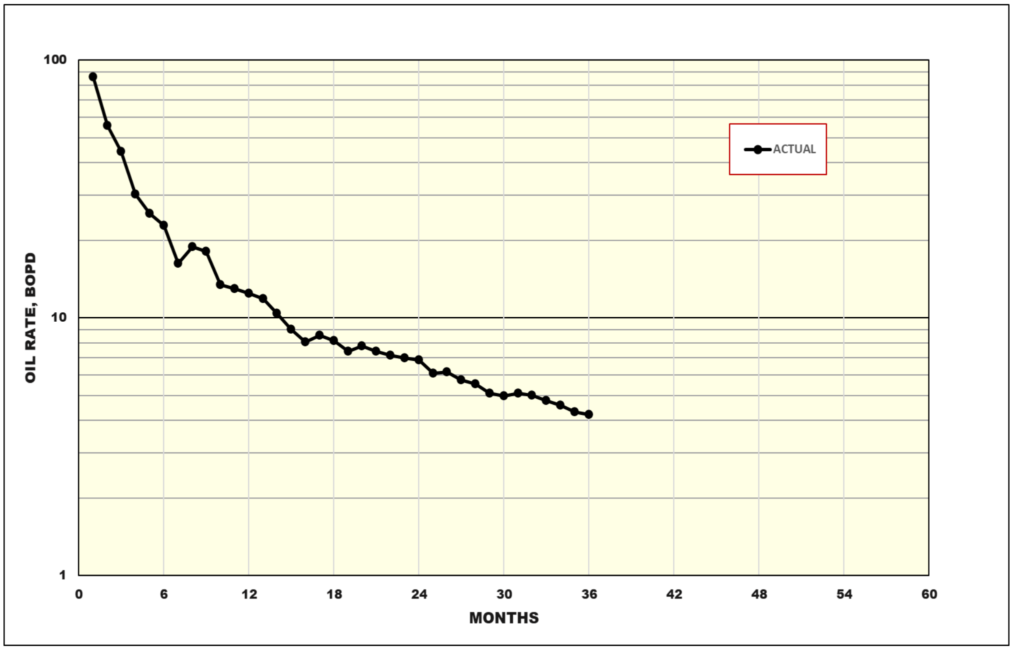


Fig. 4.12—Semi-log rate-time graph.

A curve fit of the data should represent the most likely, or 2P, forecast **(Fig. 4.13).** Honoring the most recent data (approximately the last 18 months) results in a hyperbolic fit with a *b* exponent of 0.75 and an initial nominal decline rate of 0.015/D (loss ratio of 88.6%/yr). The evaluator checks the exponent against empirical values and finds that multilayered reservoirs usually may be matched with values between 0.5 to 1.0. As a further check, the evaluator notes that core data analysis characterizes the reservoir as extremely heterogeneous, with a Dykstra-Parsons coefficient of 0.87.

However, the first half of the data is not matched as well. This may be explained as a revision in decline as the more permeable layers have depleted to the point that the lower-permeability layers contribute a greater percentage of the total flow rate at the later time. If the evaluator believes that the late-time data actually represent all layering, a high-side projection results in **Fig. 4.14.** In this case, the *b* exponent has been increased to 0.9, and the initial nominal decline rate has been increased to 0.022/D (loss ratio of 90.4%/yr).

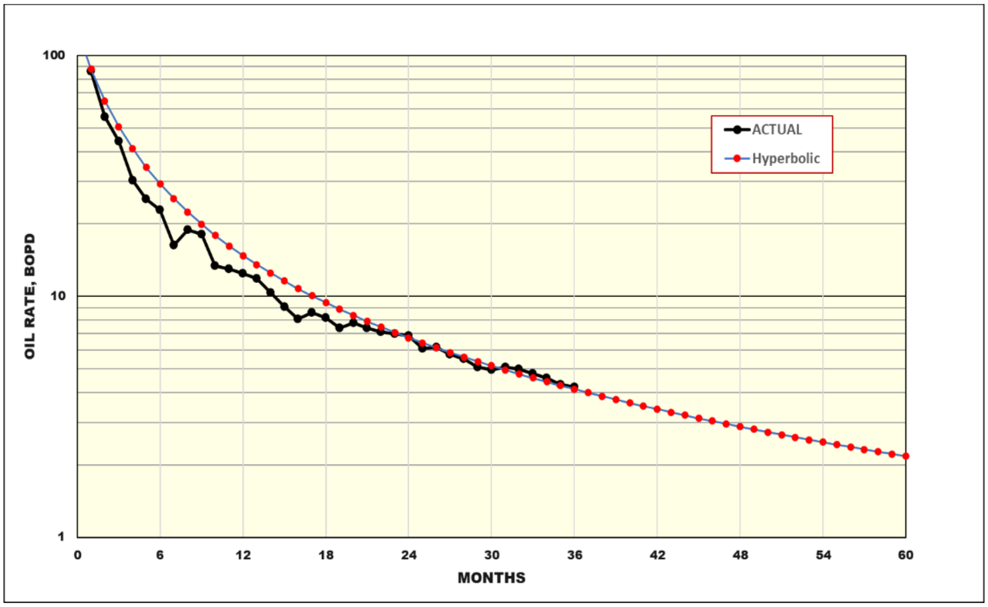


Fig. 4.13—Hyperbolic curve fit.

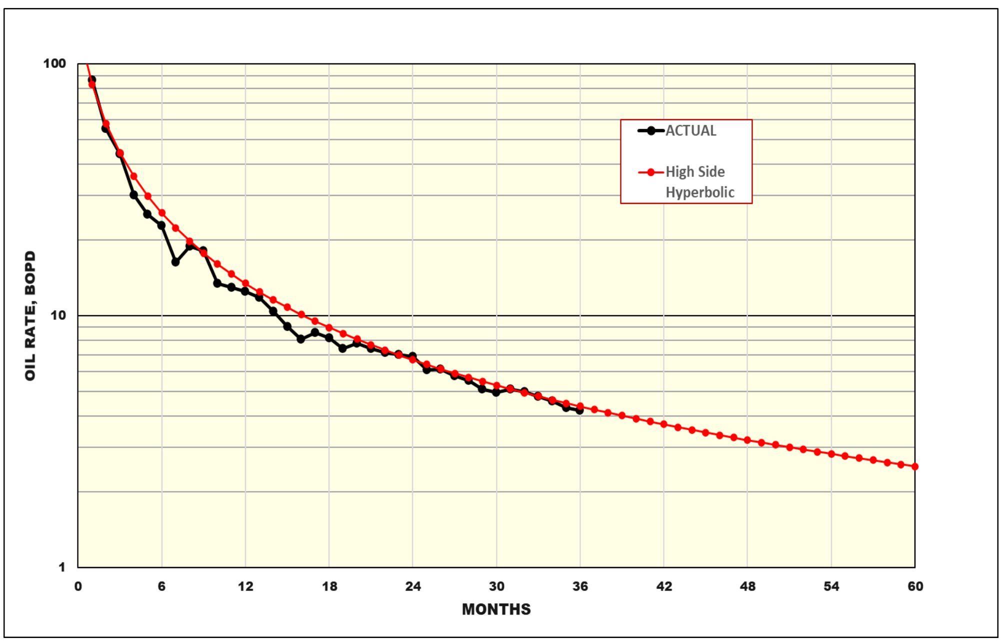


Fig. 4.14—High-side hyperbolic fit.

Finally, again looking only at the late-time trend, an exponential trend may also be fit, with the resulting trendline (correlation coefficient of 0.977) shown in **Fig. 4.15.** This exponential decline is 36.7%/yr and can serve as the 1P projection.

A comparison of the three profiles, now designated as 1P, 2P, and 3P, is depicted in **Fig. 4.16.** A slight adjustment was made to the initial rates at the beginning of the projections.

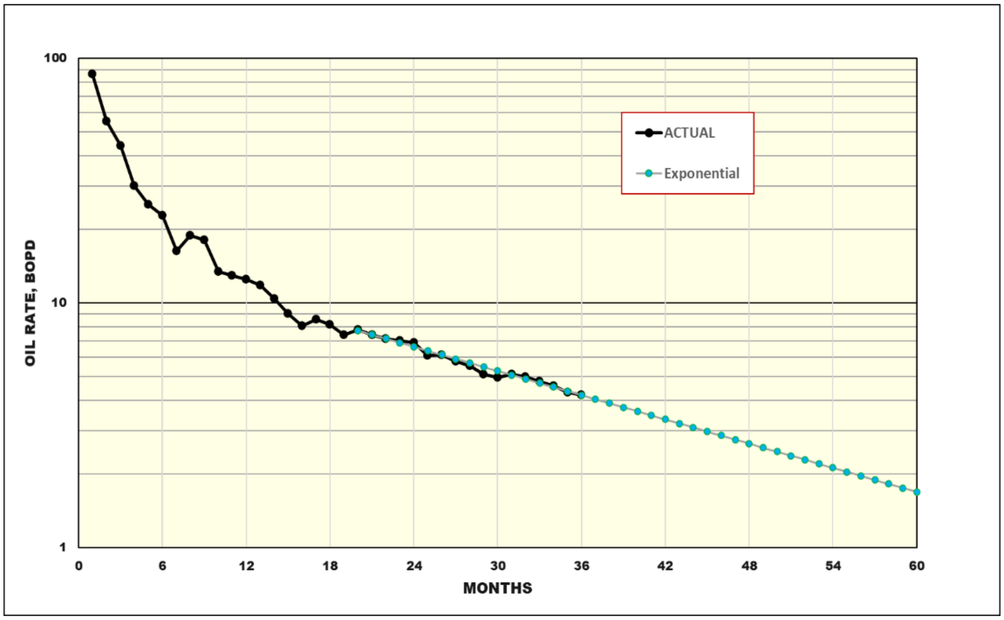


Fig. 4.15—Exponential late-time fit.

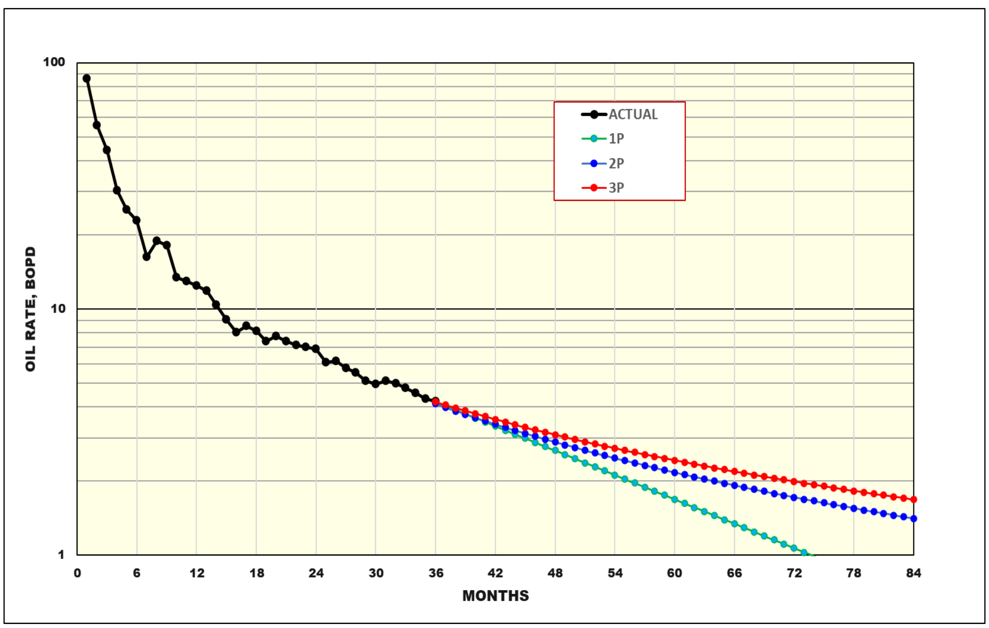


Fig. 4.16—1P, 2P, and 3P projections.

The evaluator has independently verified that the economic limit, on a per-well basis, is 1 barrel of oil produced per day (BOPD), under the defined operating conditions of primary (solution gas drive) recovery only. A terminal decline rate switching from hyperbolic to an 8%/yr exponential decline has been observed in other wells producing from the reservoir, but the switch point occurs beyond the remaining economic life of the well in question. Consequently, the reserves (and EUR, including the prior production) for the three cases may be summarized as in **Table 4.10.**

Case	Reserves*	EUR
1P	83	15,820
2P	4,371	20,108
3P	4,423	20,160
* Reserves to 1 BOPD Economic Limit		
Actual Cum. Production =		15,737 STB

Table 4.10—Summary of 1P, 2P, and 3P projections.

The reserves evaluator will note the difference between the 1P and both the 2P and 3P reserves. The 2P and 3P projections have economic lives of 6.2 and 8.3 years, respectively, compared with 3.1 years for the 1P; however, the real effect is the initial instantaneous decline rate of about 29%/yr for the 2P and 3P estimates relative to 37%/yr for the 1P estimate. The variance increases steadily as the hyperbolic decline rate progressively becomes more shallow, nearing 9% at the economic limit.

4.5.3.5 Uncertainty. As explained above, until the wells or the field have reached the end of field life, there will always be some uncertainty inherent to this analysis. Even with good-quality data, the *b* and *D* parameters may not be quantified satisfactorily for a number of reasons. In the example above, the evaluator may get different outcomes despite a very steady trend compared to most actual data observed.

It is important to note that, even an No Further Activity (NFA) case computed with DCA may not correspond to a "Proved Developed Producing" case. The DCA should always be representative of the full range of uncertainty, and the evaluator should be able to quantify a 1P NFA (PDP), 2P NFA, and 3P NFA case. This also means that all flowing wells should contribute to the 1P, 2P, and 3P cases, or, incrementally, that all flowing wells should have a Proved, Probable, and Possible component.

However, uncertainty may be much lower for flowing wells than for new development projects **(Fig. 4.17).** Using a single trend for the DCA instead of a full low-best-high range would suggest that the uncertainty is so small such that the approximation 1P = 2P = 3P can be used. While this may be practical in a very mature asset, it may not be realistic.

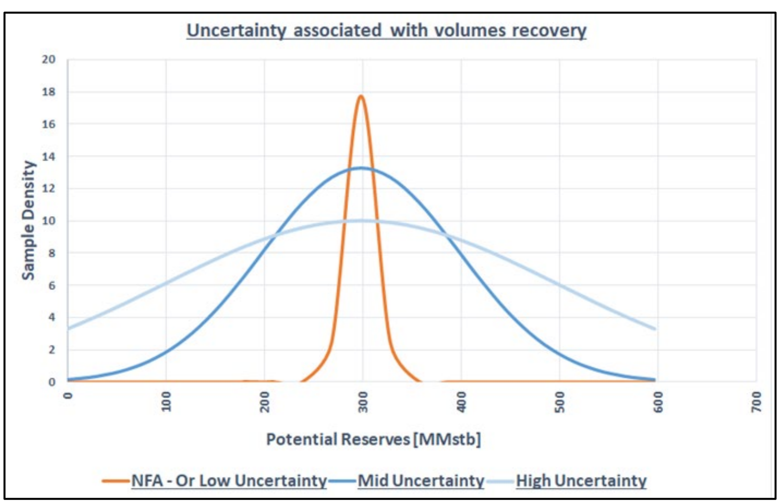


Fig. 4.17—Range of potential reserves narrows as uncertainty decreases.

Finally, DCA will provide very little information in the early stage of a field's life when few production data are available, and uncertainty is driven by the geology (gross rock volume, net-to-gross ratio, porosity, etc.). In late life, performance curves may be used to assess the reservoir production as geology is better understood and uncertainty is driven by fluid dynamics, connected zones, pressure communication, etc.

4.6 Summary and Conclusions

Consistent with the PRMS guidelines on petroleum resources and reserves definitions, classification, and categorization, different deterministic assessment methods and procedures have been illustrated to estimate oil and raw gas resources and reserves.

Key takeaways from this chapter are as follow:

- Petroleum resources assessment is and must be a continuous ongoing technical process supported by good practices and collaborative efforts across many disciplines.
- Petroleum resources assessment should use the methods most suitable for analyzing the data available, including static geoscientific and engineering approaches as well as dynamic actual production performance (both subsurface and facilities considered), and these methods should be carried out by a collaborative multidisciplinary team of expert evaluators.
- Assessment of subsurface petroleum resources is complex and subject to many uncertainties in static and dynamic reservoir parameters coupled with regulatory, operational, and economic uncertainties. Although exceptions will continue to exist, the quantity of reliable data and degree of certainty in the estimates of PIIP and EUR are expected to increase over time.
- Material balance methods rely upon pressure data gathered from wells. Ideally, collected data should have sufficiently long testing times to reach stabilized buildup pressures. For shorter shut-in durations, pressure points used for analysis should be the result of extrapolation from pressure transient analysis of the acquired data or a comparable correction method that can be used to estimate an appropriate stabilized pressure.
- A good practice when employing material balance is to first review reservoir pressure data as a function of time through use of a plot (see Appendix A to this chapter). This is especially helpful in low-permeability reservoirs, where pressures may not equilibrate throughout the whole reservoir, causing multiple trends to appear. In cases where significant pressure differentials exist, some means of averaging is needed to estimate a uniform trend for the reservoir as a whole.
- In gas material balance analysis, initial p/z trends may suggest a linear relationship, but care must be taken to understand the reservoir drive mechanism. Several drive mechanisms may cause significant deviation from a straight p/z relationship over the life of the reservoir and can lead to materially incorrect GIIP estimates.
- Irrespective of project maturity and the amount and quality of performance data available, the reliability of the resource estimates largely depends on the ability of experienced reserves evaluation professionals, not only to know the most appropriate methods to use, but also to exercise prudent judgment, ensuring the reasonableness and validity of these estimates by always comparing them with those estimated using different methods and/or with known analog reservoirs.

- Use of the full PRMS classification and categorization matrix provides a standardized framework for characterizing the estimates of marketable hydrocarbon volumes according to their associated risks and uncertainties.

4.7 Acknowledgments

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Appendix A—Special Considerations for Material Balance Analyses

4A.1 Diagnostic Plots

A good practice when employing material balance methods is to first review reservoir pressure data as a function of time in a plot. Major events that have occurred during the life of the reservoir should be noticed as changes in the trend of the data, and they should be annotated on the plot or included in the documentation supporting the estimate, as appropriate. For example, if the reservoir pressure drops below the bubblepoint in a solution gas reservoir, then this will be evident as a decrease in the rate of pressure decline, as shown in **Fig. A-1.**

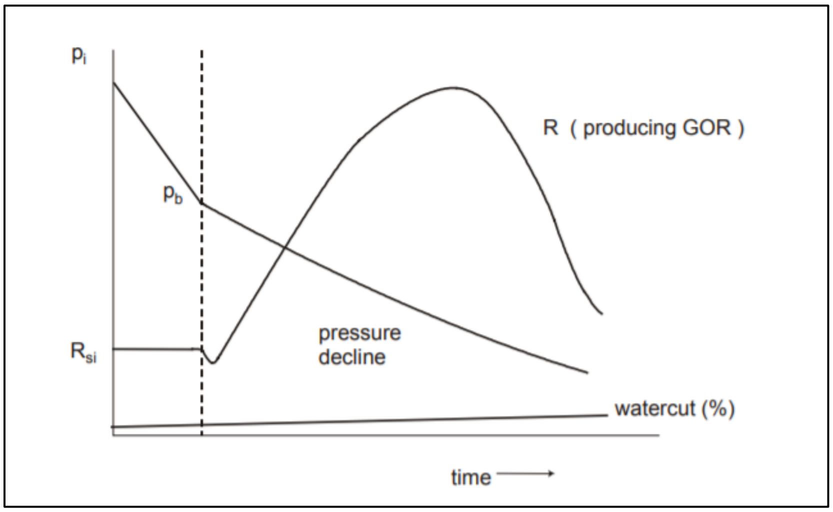

Fig. A-1—General pressure-time plot for a solution gas drive reservoir (Dake 1986), where GOR is gas-oil ratio.

Other noteworthy items include the following, some of which are presented in **Fig. A-2:**

- There may be measurement errors, which may be evident in pressures that are too high or too low when compared with the main pressure-depletion trend. This includes cases where pressures have inadequately built up prior to measurement.
- There may be measurements that are taken from a separate reservoir or fault block that exhibit a different, nonparallel depletion trend.
- There may be evidence of pressure support, causing a flattening or bending upwards of the pressure data, especially in later times.
- There may be significant historical operational changes, including field shut-ins for maintenance or abrupt production changes.

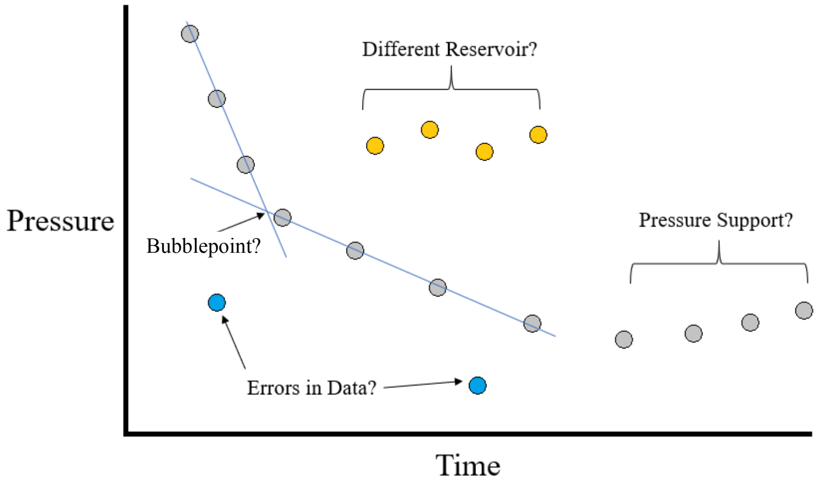

Fig. A-2—Example of effects in a pressure-time plot.

Diagnostic plots can greatly enhance the material balance analyses. Care must be taken to use the correct plot to represent the active drive mechanism because interpretation of an incorrectly selected plot will give misleading results. For example, **Fig. A-3a** represents a gas cap drive material balance analysis plot using the Havlena-Odeh approach, in which the in-place oil volume is represented by the slope of the line, whereas in Fig. A-3b, which is used for waterdrive reservoirs, the in-place oil volume (N) is represented by the y-axis intercept. In addition, an appropriate straight-line analysis must be created, as indicated by the various possible incorrect analyses indicated in Fig. A-3a and A-3b.

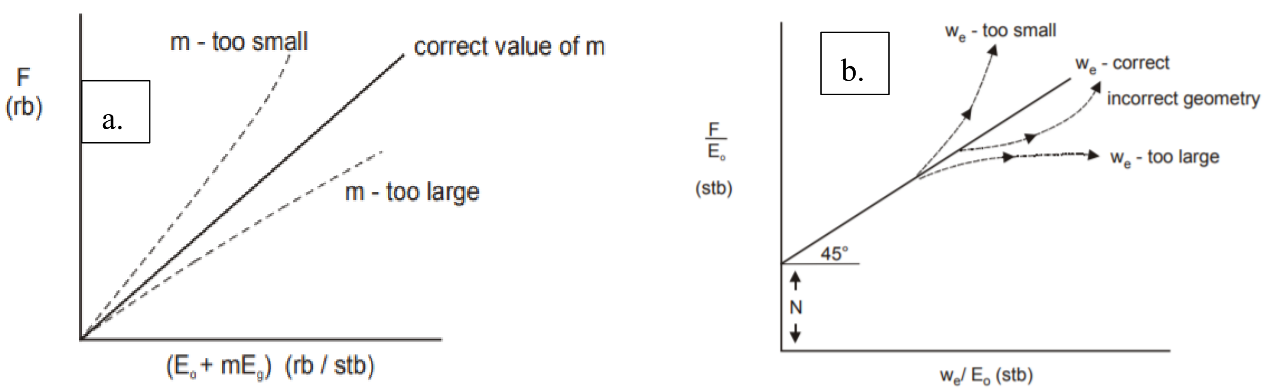

Fig. A-3—Oil material balance analysis plots: (a) estimating gas cap size; (b) estimating aquifer size (Dake 1986).

The terms in the figure above are defined as follows:

$$F = N_p\left(B_o + \left(R_p - R_s\right)B_g\right) + W_pB_w,$$

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s)B_g,$$

$$E_g = B_{oi}\left(\frac{B_g}{B_{gi}} - 1\right),$$

where:

F = production term in the material balance equation, bbl

E_g = expansion of gascap gas term in material balance equation, rb/STB

E_o = expansion of oil and its originally dissolved gas term in the material balance equation, rb/STB

m = ratio of gas-cap gas volume to oil volume, bbl/bbl

W_e = cumulative water influx, bbl

N_p = cumulative oil produced, STB

B_o = oil formation volume factor at reservoir pressure, rb/STB

R_p = cumulative produced gas-oil ratio, scf/STB

R_s = current gas-oil ratio, scf/STB

B_g = current gas formation volume factor, bbl/scf

W_p = cumulative water produced, STB

B_w = water formation volume factor, bbl/STB

B_{oi} = oil formation volume factor at initial reservoir pressure pi, rb/STB

R_{si} = gas solubility at initial pressure pi, scf/STB

B_{gi} = gas formation volume factor at pi, bbl/scf.

4A.2 Low-Permeability Reservoirs

While permeability is not a direct input into material balance equations, it is important to consider the effect of reservoir permeability on pressure. In a low-permeability reservoir (and also, in certain conditions, in a reservoir developed with large well spacing), pressures may not equilibrate throughout the whole reservoir. **Fig. A-4a** presents an example of a high-permeability reservoir where all the pressures have equilibrated for each measurement, while Fig. A-4b presents a low-permeability case where each well has a different pressure trend.

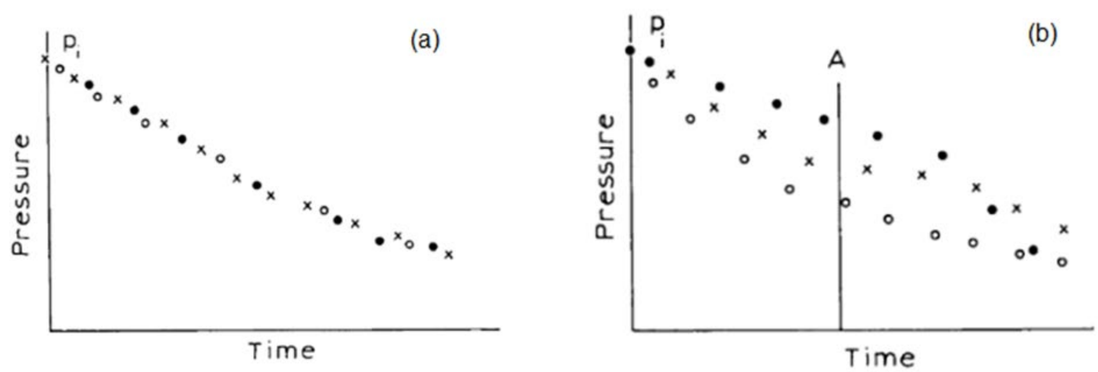

Fig. A-4—Comparison of high- and low-permeability reservoir pressure-time plots (Dake 2001).

In cases where significant pressure differentials exist, some method of averaging individual well pressure declines is needed to estimate a uniform trend for the reservoir as a whole. One simple approach recommended for oil material balances by Dake (2001) is to assign drainage areas to each well and then estimate the average pressure decline by volume weighting of the pressures for each drainage area.

4A.3 Volatile Oils

It is assumed that there is pressure equilibrium in a reservoir for each measured pressure data point, and that fluid samples are representative of in-situ conditions. For a volatile oil system, more caution is required around those assumptions due to the dynamic nature of compositions and increased liquid dropout from produced gases. Conventional material balances with standard laboratory pressure-volume-temperature (black-oil) data tend to underestimate oil recovery for volatile oils (Ahmed 2001).

A volatile oil analysis requires use of a modified form of the oil material balance, such as that presented by Walsh and Raghavan (1994). As reservoir pressure drops below the bubblepoint, and there is a release of gas, there will also be an amount of volatilized oil present in the gas. The MBE is modified by including the ratio of the volume of stock-tank oil to surface gas existing in a vapor phase at reservoir conditions (Rv), representing the volatile gas-oil ratio.

4A.4 Material Balance Pressure Data Quality

Estimates of average reservoir pressure rely upon data gathered from wells. In an ideal situation, all pressure measurements taken and appropriately corrected would represent the true average reservoir pressure. This is generally a reasonable assumption for gas reservoirs where sufficiently long testing times have allowed for a stabilized buildup pressure to be measured. As a guideline, a pressure can be considered to be stable if evidenced by an increase in pressure of no more than 2 kPa/hr (0.3 psi/hr) over a 6-hour period (Alberta Energy Regulator 2013).

For shorter shut-in durations, where pressures may not be stabilized, pressure points used for analysis should be the result of extrapolation from pressure transient analysis of the acquired data or a comparable method, to estimate an equivalent stabilized pressure. If there is no evidence provided of the length of shut-in of pressure data, a wider range of uncertainty should be considered to encompass the possibility of insufficiently built up pressures.

All pressure data should be appropriately corrected to a common datum depth, such as the reservoir midpoint in a well or the field-wide average depth of a reservoir. If wellhead pressure measurements are used, then they must be properly corrected to estimate reservoir pressures at the datum depth, considering fluid property variations that may occur throughout the length of the wellbore. A common method of wellhead-bottomhole pressure drop estimation is to divide the wellbore into segments and estimate the pressure drop for each segment, assuming each segment has uniform fluid properties due to its relatively short length.

4A.5 Abandonment Pressure and Compression

The bottomhole flowing pressure of a well is the sum of a delivery point pressure (typically a plant inlet pressure or sales pipeline pressure) and the pressure drops that occur in the gas gathering system on the surface and in the tubing string in the wellbore. A gas well will stop flowing when the average reservoir pressure approaches the minimum bottomhole flowing pressure at which the system is able to operate. This minimum pressure is also known as the abandonment pressure.

Gas well abandonment pressure (p_{ab}) depends on surface and/or subsurface constraints as well as economics. At the surface, the constraint is typically the pipeline gathering pressure; in the subsurface, the reservoir permeability has a significant influence on the abandonment pressure (low permeability usually results in higher p_{ab}, while higher permeability may result in lower p_{ab}). In the absence of a predetermined p_{ab}, there are rules-of-thumb as a function of the completion depth that may be applied for initial conventional gas reserves estimates. One such rule-of-thumb for Canadian reservoirs (Petroleum Society of the Canadian Institute of Mining Institute 2004) is to use 1500 kPa per 1000 m of depth (approximately 66 psi/1,000 ft). Similarly, a value of 100 psi/1,000 ft of depth has long been used for US fields in Texas and Oklahoma. These figures do not reflect the benefits of compression.

The abandonment pressure and its corresponding (p_{ab}/z_{ab}) value do not necessarily represent the economic limit because the minimum achievable flowing pressure can be reduced by subsequent design and installation of a compression system in the gas delivery system (typically installed at the plant or at the well). It is a common practice to determine whether gas compression is economically viable and can be used to lower well flowing pressures to help gas wells achieve lower abandonment pressures (and associated p_{ab}/z_{ab} values) and thus increase EUR. An example showing an increase in EUR after installation of surface compression can be observed in **Fig. A-5.**

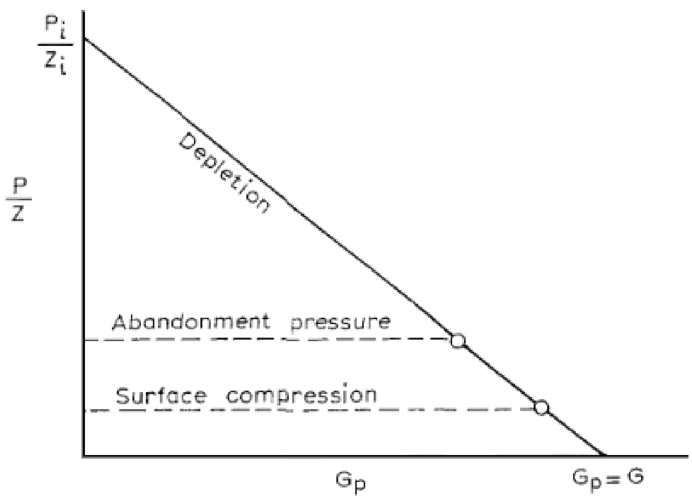

Fig. A-5—Conceptual plot showing the effect of compression on EUR (Dake 2001).

Due to a reduction in flowing pressure, compression may significantly increase the gas production rate of a well, which needs to be considered when modelling gas forecasts and estimating economic viability.

4A.6 Nonlinear *p/z* Relationships

The key assumption of straight-line *p/z* analysis of a volumetric reservoir is that the system behaves like a single tank; i.e., there are minimal pressure variations within the reservoir and no other sources of addition pressure support. Although initial data points may show a linear trend, depending on the drive mechanism present in the reservoir, there may be a deviation from a linear *p/z* analysis trend, such as that shown in **Fig. A-6.**

Note that for most of the mechanisms shown in Fig. A-6, it can be observed that the curves initially appear to exhibit a linear relationship. If only the early data are used for *p/z* analysis estimates, then this would lead to erroneous GIIP estimates.

If the reservoir drive mechanism can be correctly identified, then appropriate correction factors may be applied to either adjust or relinearize the *p/z* plot. In many cases, a more complicated solution, such as the solving of multiple simultaneous material balances, may be required—a task often undertaken using reservoir simulation.

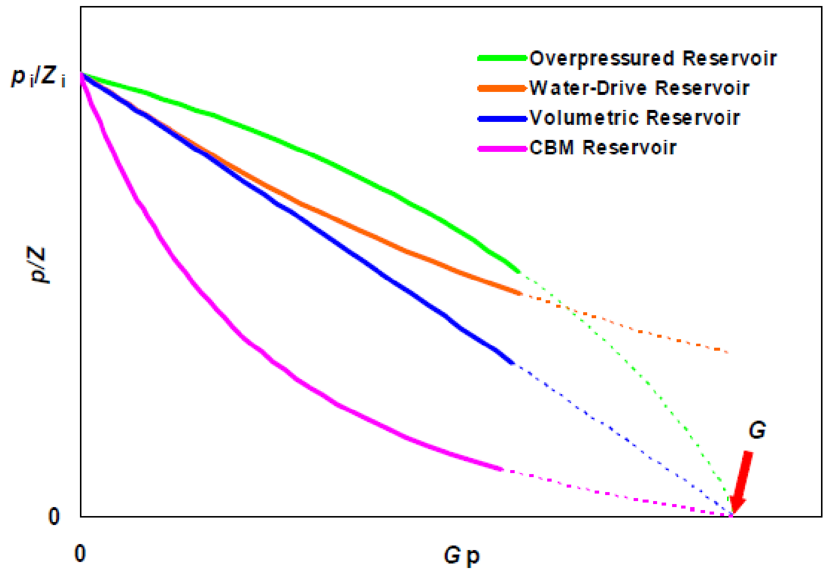

Fig. A-6—Conceptual *p*/*z* plot showing nonlinear curves due to various reservoir drive mechanism types. CBM stands for coalbed methane (Moghadam et al. 2011).

4A.7 Overpressured Reservoirs

An overpressured reservoir, which includes abnormally pressured and geopressured reservoirs, is defined as a reservoir with a high pressure gradient, generally above 0.5 psi/ft (Ahmed and McKinney 2005). In an overpressured reservoir, the initial formation compressibility may be the same order of magnitude as the gas compressibility. Initially, the formation contributes a significant amount of energy to the reservoir. As the pressure in the reservoir is depleted, the compressibility of the gas increases much faster than the formation compressibility, until the effect of the formation compressibility is negligible.

Material balance analysis of an overpressured reservoir yields two distinct slopes: a shallow trend in the pressure range where the formation expansion plays a significant role and a steeper trend when gas expansion is the single dominant production mechanism. A *p*/*z* analysis of initial data would significantly overestimate GIIP for an overpressured reservoir, as shown in **Fig. A-7.**

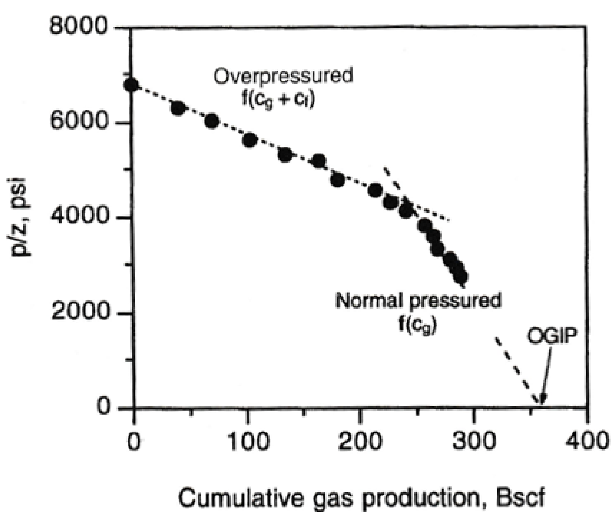

Fig. A-7—Typical overpressured gas reservoir dual-slope *p*/*z* plot (Poston and Berg 1997), where c_g indicates compressibility of gas.

4A.8 Waterdrive Reservoirs

As pressure declines in a reservoir, there may be influx of water from an aquifer, which acts to provide pressure support. This is generally shown as initial volumetric behavior followed by an upwards bend in the p/z analysis line. The strength of the pressure support system can be inferred by the time at which the bend in the analysis line is evident after initial production and the magnitude of the deviation from volumetric behavior.

While the p/z analysis line may indicate the presence of a significant waterdrive mechanism, it generally does not allow for identification of the magnitude of the drive. Cole (1969) suggested a simple plot of $G_pB_g/(B_g - B_{gi})$ vs. G_p that would provide an indication of the strength of a waterdrive depending on the shape of the resulting curve, as shown in **Fig. A-8.**

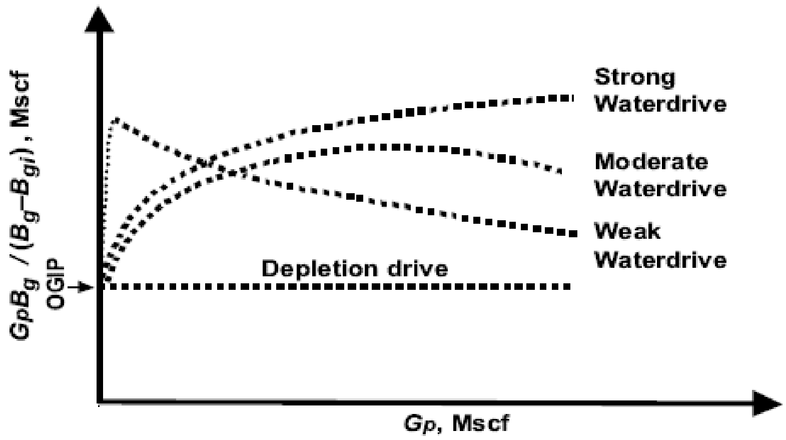

Fig. A-8—Cole plot comparing different waterdrive efficiencies (Pletcher 2002).

Due to gas being trapped by encroaching water, recovery factors for gas reservoirs with a significant waterdrive component tend to be 30% to 50% lower than their dry gas expansion counterparts; this effect may be partially mitigated in high-pressure and high-temperature (HPHT) reservoirs. Identification of the correct pressure support mechanism may be helpful in avoiding overestimation of recoverable volumes.

4A.9 Retrograde Condensate Reservoirs

When performing a material balance on a gas condensate reservoir, it is good practice to use a two-phase gas deviation (z) factor when estimating volumes of gas below the dew point and at higher condensate yields.

The two-phase z factor is used to account for liquid dropout in the reservoir as pressure declines and changes occur in fluid composition in the reservoir. Generally, if only single-phase compressibility factors are used, then there will be an underestimation of gas and condensate recoverable volumes. **Fig. A-9** shows a conceptual example of how the two values may differ, although the shape of the curves will vary based on composition and in-situ conditions.

In Fig. A-9, the two curves would provide similar results when the pressure is close to initial conditions. As the pressure in the reservoir is depleted, condensate dropout commences, which leads to a divergence in the behavior of the z factor curves.

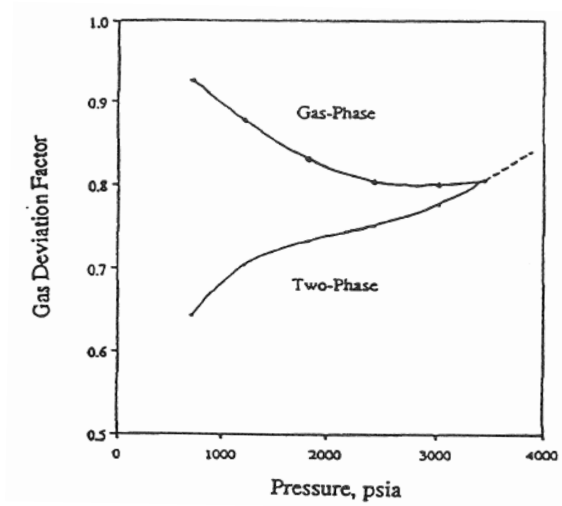

Fig. A-9—Example of equilibrium and two-phase gas deviation factors for a gas condensate reservoir (Lee and Wattenbarger 1996).

Two-phase z factors may be obtained from laboratory tests or estimated from fluid composition through use of an equation of state. Specifically, two-phase z factors are measured from constant-volume depletion tests (Lee and Wattenbarger 1996).

4A.9.1 Considerations Related to Liquid Recovery Comments. When estimating liquid recovery from gas condensate reservoirs, note that the condensate yield changes as the reservoir pressure is depleted. A typical condensate yield curve is shown in **Fig. A-10.** Estimating liquid recovery using a gas EUR estimated from material balance and an initial condensate gas ratio may lead to significant overestimation of liquid recovery.

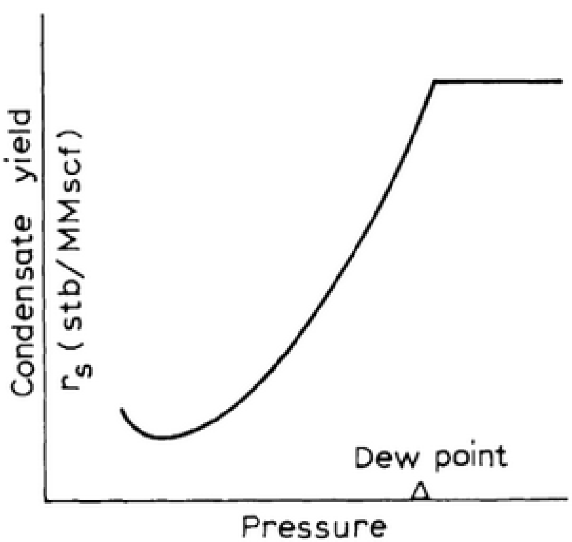

Fig. A-10—Example of condensate yield curve (Dake 2001).

To properly provide an economic estimate of natural gas liquid reserves and/or resource volumes, the following must be known:

- The reference point:
  - As described in § 3.2.3.1 of the PRMS, the reference point location will define if produced gas will be sold as wet gas or as dry gas and extracted liquids. The

economic value of those two products may vary significantly depending on geographical region and available transport facilities.

- The equipment available at the facilities used to treat the gas:
    - o The processing equipment used will define the technical limits of liquid extraction efficiency. In a smaller facility, only heavier hydrocarbons, such as pentane and heavier hydrocarbons, might be easily extracted from the gas stream, whereas a full-size gas plant facility may be able to remove virtually all liquids and even components as light as ethane from a gas stream.
- The contractual arrangement related to the value of the liquids:
    - o Assuming liquids are removed prior to the reference point, there must be a contract or arrangement in place that allows the producer entitlement to their value.

Chapter 5

Petrophysics

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Javier Miranda, Joshua Oletu, Cecilia Flores, George Dames, and Philip Gibbons

5.1 Introduction

Petrophysics (from the Greek πέτρα, *petra*, "rock" and φύσις, *physis*, "nature") may be defined as the study of rock properties (physical, electrical, chemical, and mechanical) and their interaction with fluids (gases, liquid hydrocarbons, and aqueous solutions) (Archie 1950, 1967; Tiab and Donaldson 2004; Chen and Pagan 2013). *Petrophysical*, or *formation*, evaluation (used interchangeably; Archie 1967; Asquith and Krygowski 2004) is thus a practice that integrates knowledge from several disciplines, including, but not limited to, geology, geochemistry, geophysics, physics, chemistry, and reservoir and production engineering.

The discipline of petrophysics provides key parameters (e.g., net pay thickness, porosity, and saturation) used in the volumetric estimation of petroleum initially in place (PIIP), helps to determine reservoir fluid type, and characterizes the ability of the fluid to flow (permeability); these properties are critical in assessing the potential and development of any petroleum resources or reserves. The fluid type can be characterized with properties such as density, hydrogen index, and viscosity, among others. All these properties are the subject of wireline electrical logs, formation testing/fluid sampling devices, and core sampling.

Fig. 5.1 shows generalized sources of petrophysical data over different phases of exploration, appraisal, and field development, aligned with the Petroleum Resources Management System (PRMS) resources framework.

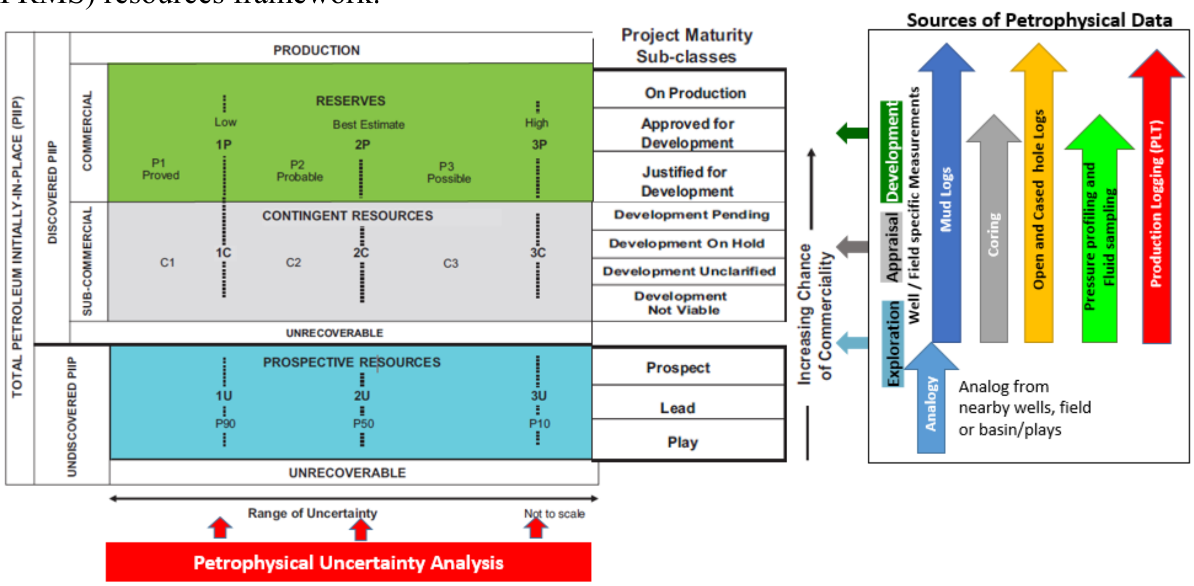

Fig. 5.1—Petrophysical support for resources and reserves classification and categorization (modified from PRMS § 1.1).

The range of petrophysical data acquisition will vary depending on basin, cost, environmental issues, and/or local regulations. However, the overriding objective is to acquire as much quality data on prospective reservoirs from exploration through appraisal phases to aid decision making and move each project through the different resources classes. In practical terms, while some petrophysical data are acquired throughout the life of the project (basic well logs, mud logs, etc.) others, such as core and special well logs, are mostly focused toward the early stages. Additionally, uncertainty analysis of subsurface petrophysical data assists in defining the appropriate resources classes and categories as shown in Fig. 5.1.

Early in the life of a project, volumetrics and/or analogy are the foremost methods by which PIIP and resources are assessed. As a project matures, performance and/or material balance methods, including reservoir simulation, may supplant volumetric and/or analog methods. However, the in-place volumes derived from these methods should remain consistent with PIIP volumes from petrophysical evaluations (see volumetric Eq. 4.1b in Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures*, herein).

Petrophysical parameters generally are the primary means of qualifying analogs used as the basis of the range of potential recovery factors expected from a development project, the optimal type of development project to be used, and the development spacing. The resources associated with a project are dependent on the development plan and the expected recovery factor, both of which may be supported by proper application of petrophysically based analogs. Analogous resources founded, in part, on petrophysical parameters may also be used as the basis to declare a discovery where a flow test is not performed, but it requires confidence in the presence of hydrocarbons and evidence of producibility (PRMS § 2.1.1.1). See also Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* herein.

This new chapter of the *Guidelines for Application of the Petroleum Resources Management System* emphasizes petrophysical evaluation methods used routinely in the estimation of in-place and recoverable volumes of petroleum. This chapter provides a high-level review of relevant petrophysical evaluation methods that are considered pertinent to the assessment of PIIP and resources and the inherent, associated uncertainties. While all the petrophysical input parameters are very important and critical, this chapter will focus on net pay assessment, the importance of establishing reservoir continuity, and core analysis, including residual oil saturation assessment.

The term *net pay*, officially introduced in the PRMS (2018), is defined as “the portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured” (PRMS Appendix A). True vertical thickness refers to the thickness of the bed measured perpendicular to the center of Earth, regardless of bed orientation. Within the PRMS, it is referenced with respect to the analytical procedures of volumetric analysis and analogy for the purpose of estimating recoverable quantities of petroleum. A goal of this chapter, therefore, will be to address the identification and application of net pay and pay cutoffs from the petrophysics perspective.

5.2 Volumetric Estimation of PIIP and Estimated Ultimate Recovery

A time-honored means for estimating the amount of PIIP is the *volumetric method*, defined by the PRMS (§ 4.1.2) as a "procedure (that) uses reservoir rock and fluid properties to calculate PIIP and then estimate that portion that will be recovered by a specific development project." Details regarding the volumetric method may be found in Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures*, herein.

In Eq. 4.1b (Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures*), petrophysical evaluation results comprise fundamental inputs to the assessment of PIIP: the hydrocarbon-bearing area above fluid contacts or limits (A), net pay thickness (h), porosity (ϕ), and initial water saturation (S_{wi}). Other petrophysical inputs, including, but not limited to, permeability (k), capillary pressure, relative permeability, and wettability, are used to assess the ability of fluids to flow, informing the assessment of the recovery factor or recovery efficiency (RE) in Eq. 4.1a (Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures*). These inputs may be incorporated into dynamic models to assess potentially recoverable volumes under various development scenarios. The PIIP and recoverable resources associated with a project are dependent on the development plan and the expected recovery efficiency.

5.3 Petrophysical Evaluation

Petrophysical evaluation involves the integrated analysis of wellbore information, including cuttings and data from core samples, well logs, fluid samples, and pressure tests in both a static (geological) and dynamic context. Physical rock sample (cores and cuttings) data may include lithologic and mineralogical data, laboratory-derived measurements of porosity, permeability, and fluid saturation, and pore and pore throat size characterization data (e.g., from capillary pressure or nuclear magnetic resonance measurements). Fluid samples may provide both water and hydrocarbon property data, such as water salinity and fluid viscosity. Well logs, collected via tools run into the borehole while drilling, after drilling, and/or during production testing, provide additional information, including, but not limited to, electrical potential, electrical resistivity, natural and/or induced radioactivity, electron density, acoustic velocity, nuclear magnetism, borehole configuration and orientation, pressure differential, temperature, and fluid flow rates. Pressure test data may include point measurements of reservoir pressure and apparent mobility from well logs and/or pressure transient data collected during production tests. These data are reviewed and analyzed using a variety of established industry practices, relations, equations, and trends to determine the rock and fluid properties, forming the basis for estimates of PIIP and resources in hydrocarbon- and non-hydrocarbon-bearing formations.

It is noteworthy that most industry-accepted equations or algorithms are empirical in nature and vary in their applicability and uncertainty, depending on the characteristics of the formation. According to Worthington (2011), quantitative petrophysical evaluation is mostly data driven, and interpretive algorithms change from reservoir to reservoir. Hence, the uniqueness of the reservoir, the quantity and quality of data and information available for analysis, the applicability of various industry algorithms, and associated uncertainties should be considered in every petrophysical evaluation.

5.4 What is "Net Pay"?

The concept of "net pay" originated in the early days of petroleum engineering when producing companies, and their investors, were interested in knowing the portion of a reservoir that is capable of providing a return on their investment, and therefore the portion that would "pay" for development (in the context of other commerciality considerations).

Within the industry, net pay assessments may include a lithologic/mineralogical, minimum porosity, minimum permeability (where such information is available), and maximum water saturation cutoff. A related but different industry term, known as *net reservoir*, excludes a water saturation and/or permeability cutoff. In other words, net reservoir is the portion of the gross rock that contains mobile, producible fluids including water and/or hydrocarbons, whereas net pay is that portion of the reservoir from which petroleum may be produced or extracted for exploitation and/or development. A schematic illustration of the application of cutoffs was described by Worthington and Cosentino (2003) and is presented here in **Fig. 5.2.** Moving from left to right, this illustration offers proper distinctions among "gross rock," "net reservoir," and "net pay."

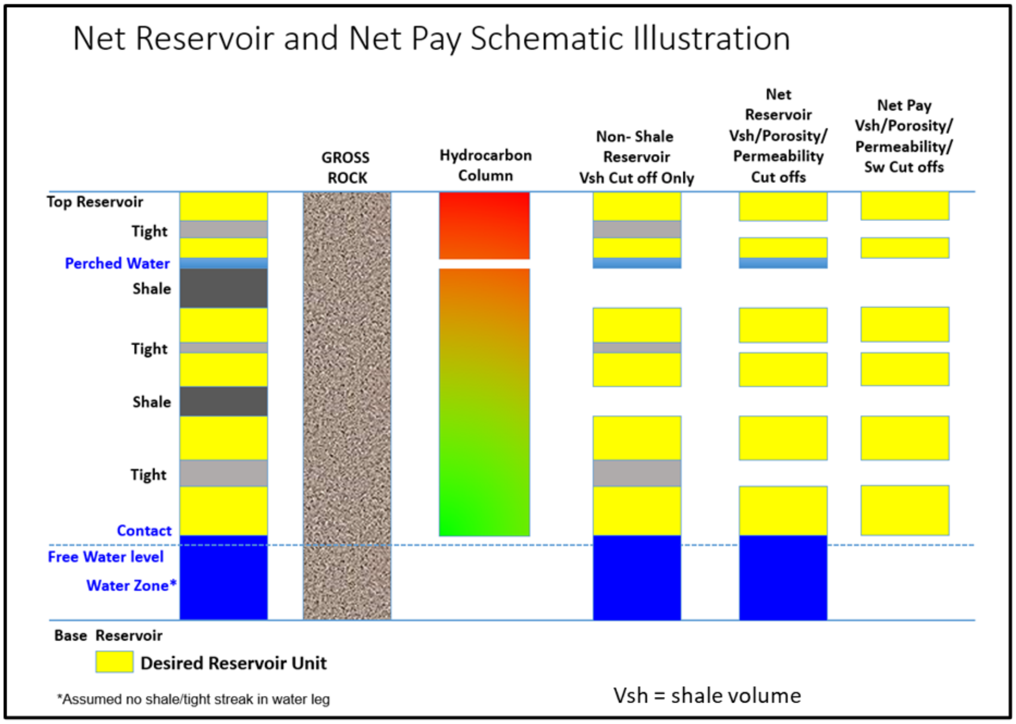

Fig. 5.2—Net reservoir and net pay description (modified from Worthington and Cosentino 2003).

5.4.1 Pay Cutoffs. In order to differentiate the pay section from the gross volume, petrophysicists rely on pay cutoffs. Although the term is used in the PRMS, it was not defined. There are several methods to establish cutoffs, out of which three are fairly common: the statistical approach, whereby the operators' cumulative experience in the area dictates cutoff values; the no-harm approach, whereby no cutoffs are applied, and a dynamic reservoir simulation defines those volumes of fluids that will flow; and the petrophysical approach, in which the rock and fluid properties dictate the moveable hydrocarbon (under the proposed displacement mechanism). This chapter will elaborate only on the petrophysical approach.

A typical process for selecting cutoffs to delineate the pay section involves:

- The selection of petrophysical parameters that relate to hydrocarbon presence and flow potential.
- The selection of a cutoff value for each petrophysical parameter.

Pay cutoffs are used to delineate the pay sections because:

- Not all rocks (or layers of rocks) in a target formation host moveable fluids (water and/or hydrocarbon).

- Not all rocks host potentially moveable hydrocarbon (and/or water) that may be recoverable based on the extraction technology employed.
- Not all fluids in the rock significantly contribute to the energy of the reservoir system.

Historically, pay cutoffs are assigned to well log characteristics based on past performance of other reservoir analogs until actual performance in the subject reservoir supports a revision of one or more such cutoffs. It is not unusual for a minimum log porosity cutoff to be further reduced after dynamic data establish fluid flow to a lower threshold. This uncertainty may constitute the difference between resource category assignments for the evaluator.

The selection of petrophysical parameters depends on the quality and quantity of available data and the formation complexity. Worthington and Cosentino (2003) compiled some of the industry classification schemes and pay cutoff parameters as shown in **Table 5.1a** and **Table 5.1b.**

Table 5.1b shows various combinations of petrophysical parameters that have been used for assessing net pay in the literature, including shale volume, porosity, permeability, water saturation, resistivity, and mobile fluid index. Applying cutoffs to the said properties serves to delineate the portion of the reservoir in which hydrocarbon is stored and able to flow under the anticipated production mechanism.

In addition to typical shale volume, porosity, permeability and water saturation cutoffs, parameters such as mobility from formation pressure data and fluid entry data from production logging tools in conventional plays or geochemical (e.g., total organic carbon) and geomechanical (e.g., brittleness) properties in unconventional plays may be used as cutoff parameters.

In the early exploration and appraisal phase, when well and/or core data are absent, insufficient, or not fully representative (as discussed later), the selection of a cutoff (or range of cutoffs) is often based on experience. As relevant log and core data and/or production tests become available, cutoff parameters may be refined. In the development phase, when significant petrophysical data exist, it is advised that cutoffs be data-driven, through the integration of available well log, core, fluid, pressure, and, especially, production data.

Worthington and Cosentino	Snyder [2]	Bailey & De Crespo [3]	Márquez et al. [4]	Cheatwood & Guzman [5]
Gross sand	Gross reservoir interval	Gross sand	Gross sand	Gross sand
Net sand	Gross sand	Net sand		Net sand
Net reservoir	Net sand		Net sand	
Net pay	Net pay	Net oil sand [a] Net exploitable sand [b]	Net oil sand	Net pay [c] Productive zones [c]

Notes:
(a) *Net oil sand* has sufficient porosity and hydrocarbon saturation to allow oil to be movable: this parameter is used for hydrocarbons in place.
(b) *Net exploitable sand* is a net oil sand that should be produced although not necessarily commercially as a stand-alone.
(c) *Productive zones* have a higher porosity cut-off than *net pay* intervals: this higher porosity is needed for flow to occur.

Table 5.1a—Some net pay classification schemes (from Worthington and Cosentino 2003; see original publication for references cited in table).

Investigators	Reference No.	Lithology	Hydrocarbon Type	Investigators' Classification[a]	Cut-off Parameter(s)[b]					
					V_{sh}[c]	ϕ	k	S_w	R[d]	MHI[e]
Berruin & Barlai (1980)	38	Shaly sand	Oil	Net pay	✓					✓
Bailey & De Crespo (1981)	3	Shaly sand	Oil	Net oil sand					✓	
Wilson & Hensel (1982)	39	Tight sandstone	Oil & gas	Net effective pay		✓				
Hall (1983)	20	Dolomite	Oil	Net pay		✓				
Molnard et al (1983)	11	Laminated sandstone	Gas	Net		✓	✓	✓		
Sallee & Wood (1984)	40	Laminated sandstone	Oil	Net pay					✓	
Boyer (1985)	16	Sandstone	Oil	Net pay	✓	✓				
Desbrandes (1985)	8	Sandstones & carbonates	Oil & gas	Net hydrocarbons in place	✓	✓		✓		
Finley (1985)	41	Sandstones	Gas	Net pay		✓		✓		
Bigelow (1986)	42	Sandstone	Oil	Producible zones	✓	✓		✓		
Hunter et al. (1990)	43	Limestone	Oil	Net pay		✓	✓	✓		
Craft et al. (1992)	44	Sandstone	Gas	Net pay	✓	✓				
Howell et al. (1992)	45	Dolomite	Oil	Net pay		✓		✓		
Coll et al. (1996)	46	Laminated shaly sands	Oil	Net pay					✓	
Coskuner & Lutes (1996)	17	Silty sandstone	Gas	Net pay			✓	✓		
Deakin & Manan (1996)	12	Shaly sand	Gas condensate	Net pay	✓		✓			
Doane et al. (1996)	18	Sandstone	Oil	Net pay		✓	✓			
Joshi & Lahiri (1996)	47	Limestone	Oil & gas	Net pay	✓	✓	✓	✓		
Mohan et al. (1996)	48	Sandstone	Oil	Net pay		✓				
Thompson et al. (1996)	49	Shaly sandstone	Oil & gas	Net pay						✓
Burch & Clough (1998)	50	Sandstone	Gas	Net pay	✓	✓		✓		
Flølo et al. (1998)	51	Laminated muds & sands	Oil	Net pay		✓				
Martin et al. (1999)	6	Sandstone	Oil	Net pay	✓	✓		✓		
Pekot et al. (1999)	52	Sandstone	Gas	Net pay	✓	✓				
Kessler et al. (2000)	53	Sandstone	Gas	Net pay	✓	✓	✓	✓		
Schoeling & Mark (2000)	54	Sandstone	Oil	Net pay		✓				
Kopper et al. (2001)	55	Sandstone	Extra-heavy oil	Net oil count	✓				✓	
Márquez et al. (2001)	4	Sandstone	Heavy oil	Net oil sand	✓	✓	✓	✓		
Cheatwood & Guzman (2002)	5	Silty sandstone	Oil	Net pay	✓	✓				
Forup et al. (2002)	56	Sandstone	Oil	Net pay		✓		✓		
Sakurai et al. (2002)	57	Sandstone	Gas & oil	Net pay	✓	✓		✓		

Notes:
(a) The investigators' use of the term *net pay* does not necessarily conform to the definitions in this paper: for selected correspondences, see Table 1a
(b) Cut-off parameters can be tied back to other hydraulic parameters such as (relative) permeability or residual fluid saturations
(c) This column also includes source parameters such as natural gamma log response.
(d) R = formation resistivity
(e) MHI = movable hydrocarbon index

Table 5.1b—Selected examples of cutoffs application in reservoir studies (Worthington and Cosentino 2003; see original publication for references cited in table).

The complexity of the formation should be considered when selecting the relevant pay cutoff parameters and values with which to reasonably assess net pay. In certain clastic reservoirs, as shown in Example A (at the end of this chapter), commonly acquired well logs may be sufficient to define net pay intervals. However, in more complex formations, additional data sources such as nuclear magnetic resonance logs or core data may be utilized, as shown in Examples B and C, respectively. Other information that may be utilized in complex formations includes, but is not limited to, dielectric data, mineralogy, and production test data. Examples of reservoirs requiring additional logs and data include, but are not limited to, shaly sands, radioactive sands, freshwater sands, reservoirs dominated by microporosity, complex/mixed lithology reservoirs with varying grain density, thinly laminated and low-reservoir-quality formations, fractured and/or tight formations, and unconventional reservoirs.

It is important to keep in mind that one of the criteria for "Recoverable Resources" is that the petroleum should be producible (PRMS Glossary). Most of the petrophysical techniques described above are "static" in nature, and any pay cutoffs derived from these techniques may not reflect the "dynamic" aspect of producibility. Consequently, a production logging tool may be incorporated to identify, under flowing (as well as static) conditions, intervals of a reservoir that will contribute to production (whether petroleum or water). Example D shows the application of a production logging tool in the identification of pay zones. Furthermore, the application of cutoffs should be reviewed as a recovery mechanism progresses from primary depletion to secondary or enhanced oil recovery.

For unconventional petroleum accumulations, in which advanced extraction techniques typically define the recovery, the determination of net pay does not necessarily follow the traditional petrophysical workflow developed for conventional accumulations. For instance, in tight oil and gas plays, net pay is back-calculated by combining data from the stimulated reservoir volume and the production performance response from the well. In other words, the net pay is estimated after the well has been on production.

Stimulated reservoir volume data refer to parameters that describe the producing volume such as fracture density, fracture conductivity, cluster spacing or completion design, parameters affected by geologic conditions, reservoir permeability, or fracture design conditions. In practice, the stimulated reservoir volume data and the production response, and not the petrophysical parameters, are used to estimate net pay in unconventional plays. The reader is referred to Chapter 10—*Unconventional Resources Estimation*, herein, for more details.

5.5 Core Analysis

Core data are integral in the assessment of resources. Actual samples provide hard data with which to characterize the reservoir(s) in question, by means as diverse as defining the rock wettability, quantifying the relative permeability of the rocks to fluid flow, assessing the continuity of the reservoir, modeling the saturation profile(s) of the reservoir, identifying transition zones, etc. An adequate treatment of the value of core data analysis in the evaluation of resources is beyond the scope of this current work; however, some key topics are reviewed that will be useful.

5.5.1 How Representative Is the Core Sample? As with any other data acquired from the subsurface, core samples (such as whole core, sidewall cores, even cuttings) are subject to uncertainties that may invalidate their use in proper characterization and mislead the analyst(s). For example, it is not uncommon in thick reservoirs to recover whole core only from the poorer-quality sections when higher-quality sections may be too friable or fractured to be recovered. Utilizing only this data set will penalize the ensuing geological (and, consequently, simulation) model when the higher-quality rock cannot be characterized. A qualified reserves evaluator, if they recognize this situation, may consider the models to be conservative and categorize the resources accordingly. Similarly, intervals selected for sidewall cores (plugs) may favor the better-quality rock, and if the analytical results are applied without adjustment to lower-quality intervals, then this would tend to exaggerate the PIIP and recoverable resources.

The core itself may be characterized by its state of preservation as native-state, cleaned, or restored-state. Native-state core represents unaltered wettability conditions, while cleaned core has been swept with solvents to remove all organic material (thereby altering its state to water-wet or strongly water-wet). Restored-state core has also been cleaned but then resaturated with brine (preferably matching the reservoir salinity) and then flushed with reservoir oil before being aged at reservoir temperature, commonly for over a month. Core may be cleaned for porosity and permeability measurements and then restored for relative permeability studies; if not restored, the core cannot be used for relative permeability studies.

Core prepared for waterflood studies has the potential to provide misleading outcomes. Coreflood tests must be certain to use water of the same composition, as well as salinity, as the proposed injected water. For example, switching from a freshwater to a brine-water source normally would be advised if the sandstone proposed for waterflooding contains clays or salts (such as halite). However, if the reservoir has a high feldspathic content, a sodium chloride (NaCl)–based water could cause ionic dissociation, whereby the sodium and potassium ions are chemically exchanged in a process causing salt dissolution, whereas the original intention by using "brine" was to avoid this process. Likewise, coreflood tests are typically set up in the laboratory for forward (one direction) throughput of water volumes. Reversal of flow direction has a vital purpose in identifying any predisposition toward "deflocculation," in which the reversal causes migrated (but stabilized) fines to dislodge within the core and cause plugging as flow ensues in the opposite direction. In waterflooding operations, this has an impact on recovery when pressure gradients induced by injection wells interfere and can result in unintended flow baffles.

For reservoir simulation of large areas or full-field models, the core coverage is also a concern. For example, core recovered from wells situated at the crest of a structure are not expected to be representative of the reservoir at its structural flanks. Likewise, core recovery only from wells from, for example, the north end of a full-field model may not be representative of the reservoir quality at the southern extreme.

Aspects such as these, and others not mentioned for lack of space, highlight uncertainties that the qualified reserves evaluator should be aware of when categorizing the results of recoveries estimated through the utilization of core data.

5.5.2 Capillary Pressure. Core data analysis frequently depicts the rock fabric as being composed of a bundle of tubes of different diameters. This is a rudimentary but easy-to-grasp description of the capillary system in a reservoir. The pressure exerted within each tube is one of the forces influencing fluid flow and is referred to as capillary pressure. This pressure must be overcome by a fluid in order to permit its entry into the pore space of the capillary tube; the pressure at which fluid may enter the system is known as the displacement pressure. The displacement pressure required for a capillary system of large pores is much less than that for a system of small pores. This force (along with gravity forces) influences the rise of fluids within each capillary tube. To properly characterize a reservoir and its ability to permit the flow of fluids, especially when multiple fluids are in contact with each other, capillary pressure measurements must be taken in the core laboratory. The capillary pressure data can be used to describe the fluid saturation distribution versus height relative to the depth at which the particular capillary system is 100% water saturated. (This depth may be called the free water level, or the depth corresponding to zero capillary pressure in a water-wet system.)

Capillary pressure data may be generated in the laboratory most commonly by two methods: mercury injection or centrifuge. Mercury injection capillary pressure data must be converted from a mercury-air system (under which the data are obtained) to an oil-water system; there are several caveats inherent in this approach (see, for example, Masalmeh and Jing 2007). The centrifuge method spins the core at various speeds and measures the stabilized saturation at each speed, from which a pressure-saturation relationship may be derived. Notably, this method is capable of reaching a lower residual oil saturation than conventional coreflooding because it incorporates a gravity force effect; the qualified reserves evaluator must recognize this effect and consider how gravity forces are likely to influence fluid displacement in the reservoir in question when estimating recovery efficiency (see also Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* herein).

Saturation-height relationships should then be developed for each representative capillary system. To complement this, relative permeability data should also be prepared for each capillary system. This is particularly important in transition zones, i.e., zones in which oil and water both exist and from which both may flow (the vertical distance over which the water saturation ranges from 100% to the irreducible saturation). An example of a capillary pressure relationship converted to a saturation-height profile (top), with a relative permeability relationship (bottom) as measured with a conventional coreflood, is shown in **Fig. 5.3** (Fanchi et al. 2002).

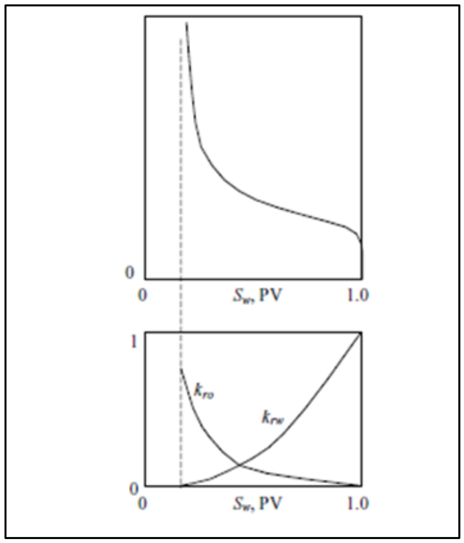

Fig. 5.3—Capillary pressure (top) and relative permeability (bottom) relationship (Fanchi et al. 2002). [Note: capillary pressure, relative permeability to oil (k_{ro}) and relative permeability to water (k_{rw}) plotted as functions of water saturation (S_w) as a fraction of the pore volume, PV.]

The validity of a model prepared with saturation-height functions tied to relative permeabilities necessitates acquiring core data representative of the productive or potentially productive reservoir. The use of analog data (see Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* herein) introduces uncertainties that the qualified reserves evaluator needs to be aware of when classifying and categorizing model-predicted recoveries. Further, saturation-height functions should be compared against calculated log interpreted saturations to explain any discrepancies.

Other means of populating the saturation within a reservoir column, such as the Leverett-J function, exist but are beyond the scope of this chapter (Leverett 1941; Hassker et al. 1944; Tiab and Donaldson 2004).

5.5.3 Core Wettability. Wettability is a key concern in planning the development of an oil reservoir. Wettability is “the term used to describe the relative adhesion of two fluids to a solid surface” (Tiab and Donaldson 2004). These fluids are treated as immiscible, such that their characteristics may be measured separately. A widely used rule of thumb in defining rock wettability, in terms of the reservoir being oil-wet, water-wet, or mixed-wet, hinges on relative permeability data. One of the most easily identifiable characteristics that may be used to identify wettability is the water saturation cross-over point of the oil and water relative permeability curves.

Craig (1971) stated that if the oil and water relative permeability curves cross (i.e., have the same value) beyond a 50% water saturation, then the rock from which the core sample was taken is water-wet **(Fig. 5.4a).** If the curves cross below 50% water saturation, then the rock is oil-wet (Fig. 5.4b). How strongly wet the rock would be in terms of water-wet or oil-wet would depend on the distance of the cross-over from the 50% mark. Granted, this is a rule of thumb, and the mixed-wet possibility is not satisfactorily addressed; however, Craig also suggested other rules of thumb to help in this situation **(Table 5.2).** The reader is referred to Craig (1971) for further detail. Warner (2015) cautioned, however, that most oil reservoirs should not be described as being water wet or oil wet, but rather mixed wet with an appropriate scale, and Craig's rules of thumb do not consider rock heterogeneity.

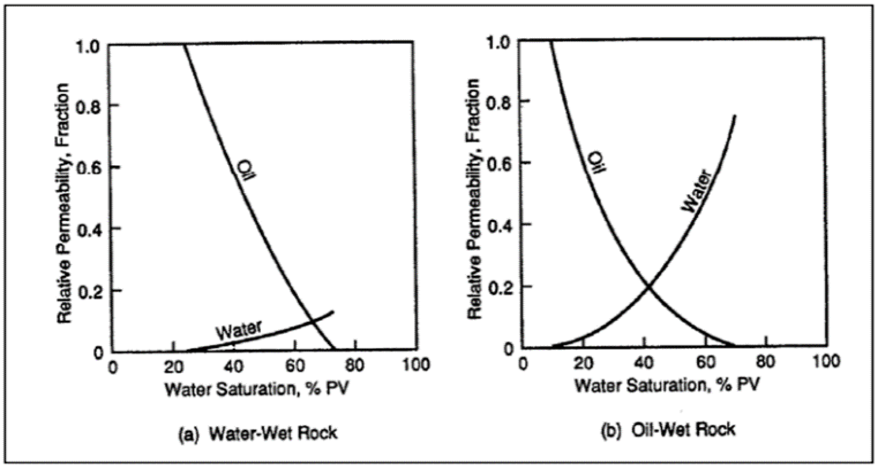

Fig. 5.4—Relative permeability assessment of wettability (Craig 1971).

	Water-Wet	Oil-Wet
Interstitial water saturation	Usually greater than 20 to 25% PV.	Generally less than 15% PV. Frequently less than 10%.
Saturation at which oil and water relative permeabilities are equal.	Greater than 50% water saturation.	Less than 50% water saturation.
Relative permeability to water at the maximum water saturation (i.e., floodout); based on the effective oil permeability at reservoir interstitial water saturation.	Generally less than 30%.	Greater than 50% and approaching 100%.

Table 5.2—Rules of thumb for wettability assessment (Craig 1971).

Wettability may also be determined in the laboratory through the use of the Amott wettability index, the US Bureau of Mines (USBM) method, measurement of the contact angle of the fluid-solid interface, and other techniques (Tiab and Donaldson 2004). The scale to which Warner (2015) refers for wettability characterization is the Amott-Harvey scale (+1 for water-wet, −1 for oil wet) as described in Boneau and Clampitt (1977).

It is crucial to determine the wetting phase from a wettability analysis. If an oil reservoir is water-wet, then the relative permeability measured when the core is flushed with water represents an imbibition process (i.e., an increasing wetting phase saturation). Conversely, if the oil reservoir is oil-wet, then the resulting relative permeability measured during core flushing with water reflects a drainage process (i.e., a decreasing wetting phase saturation). If an oil reservoir is subject to capillary hysteresis, in which there is a departure in the oil relative permeability relationship with increasing water saturation between drainage and imbibition, then proper modeling of the oil/water flow characteristics (and projection of the oil recovery with the least uncertainty) necessitates application of appropriate imbibition and drainage relative permeability (and capillary pressure) data in the simulation. [It is not uncommon for an oil reservoir to undergo multiple cycles of drainage and imbibition, resulting in conditions including transition zones and residual (paleo) oil zones, further complicating modeling. This area is beyond the scope of this chapter.]

Oil recovery is affected by wettability. Generally, under conditions of oil displacement by water injection, oil recovery is lower in water-wet rock. In this instance, water adheres to the pore surface while oil occupies the larger pore space and pore connections. As water moves through, oil may become trapped in larger pores (a process known as "snap-off"), and the continuous phase of oil is broken. On the other hand, oil-wet formations have oil adhering to the pore surface. The movement of water through the system is less likely to break the oil continuity. The net result of these situations, as demonstrated in core analysis, is that the residual oil saturation in oil/mixed-wet reservoirs is typically lower than that for water-wet reservoirs; i.e., there is a higher oil recovery in oil/mixed-wet reservoirs (all else being equal).

5.5.4 Rock Typing. "Rock typing" refers to the process of identifying reservoir rocks with a characteristic set of petrophysical and flow properties. Generally, there are two ways to develop rock typing for a reservoir: depositional rock typing and petrophysical rock typing. Depositional rock typing deals with sedimentary deposition and the associated lithofacies, and it is dependent on identified depositional environments (such as deltaic, alluvial, glacial, tidal, etc.). This approach does not typically consider postdepositional activities, such as diagenesis or fracturing, or complex pore systems, particularly in carbonates. Generally, depositional rock typing is a larger-scale assessment, while petrophysical rock typing is focused at the log and core scales. As such, petrophysical rock typing looks at the pore types and structures (e.g., pore throat sizes) as well as the relationship between porosity and permeability. Petrophysical rock typing may be utilized for dynamic (flow-based) analysis, such as through the use of "flow zone indicators" (Amaefule et al. 1993) and the Winland R35 method (Kolodzie 1980), which is dependent upon mercury injection capillary pressure data to characterize the pore systems.

The population of rock types or facies has a major impact on the results and their associated uncertainty analysis from dynamic simulation. Petrophysical rock typing is instrumental in building geological models that are typically imported into dynamic (reservoir) simulations, as the facies described in the process represent flow characteristics with their own dedicated models (e.g., saturation-height, porosity, relative permeability, fluid properties, etc.). Again, this topic cannot be adequately covered in the scope of this chapter, but the characterization of the various facies is one of the most important contributions of core analysis.

5.5.5 Reservoir Continuity. Even when a field has had significant exploitation, i.e., there have been many wells drilled, a reservoir of interest may appear to be correlated by log analysis, but production performance data may suggest otherwise. For example, structurally high wells may produce water while downdip wells produce water-free resources from the "same" reservoir. The integration of core and log data with other analyses (such as fluid compositions) can shed light on why a reservoir that can be correlated between wells may be disconnected depositionally. Sequence stratigraphy is a tool that can be used to explain this apparent disconnect.

Sequence stratigraphy may be described as "a branch of sedimentary stratigraphy … which deals with the order, or sequence, in which depositionally related stratal successions … were laid down in the available space" (Society for Sedimentary Geology 2021). It is a tool used to "interpret the depositional origin and predict the heterogeneity, extent and character of the lithofacies" (Society for Sedimentary Geology 2021). Sequence stratigraphy seeks to identify reservoir zones that are stratigraphically connected through a combination of such means as time of deposition, chemical composition, magnetic properties, fossil evidence, etc. Physical core data are, therefore, crucial in establishing the connectedness of the reservoir(s) and subsequently extending the individual well responses to seismic signatures.

Fig. 5.5a shows an example of the traditional (lithostratigraphic) log correlation (from Van Wagoner et al. 1990), constructed using the top of the shallow marine sandstone in each of the four wells. The top of the reservoir was picked based on either the spontaneous potential or gamma ray data and the resistivity deflections. This interpretation shows the sand to be continuous across the four wells.

Using sequence stratigraphic (chronostratigraphic) analysis (Fig. 5.5b), however, the sandstone is not continuous at all. Van Wagoner et al. (1990, p. 22) noted that, if only the lithostratigraphic correlation had been performed, "the continuity of the reservoir is exaggerated, genetically different sandstones are linked together, and shallow-marine sandstone reservoirs change facies up dip into marine shales and mudstones."

Reservoir continuity is always a major concern for the qualified reserves evaluator due to its influence on, among other things, project development costs, volumetric assessment of PIIP, recovery efficiency estimates, etc. These factors represent uncertainties that will enter into the resource classification and categorization.

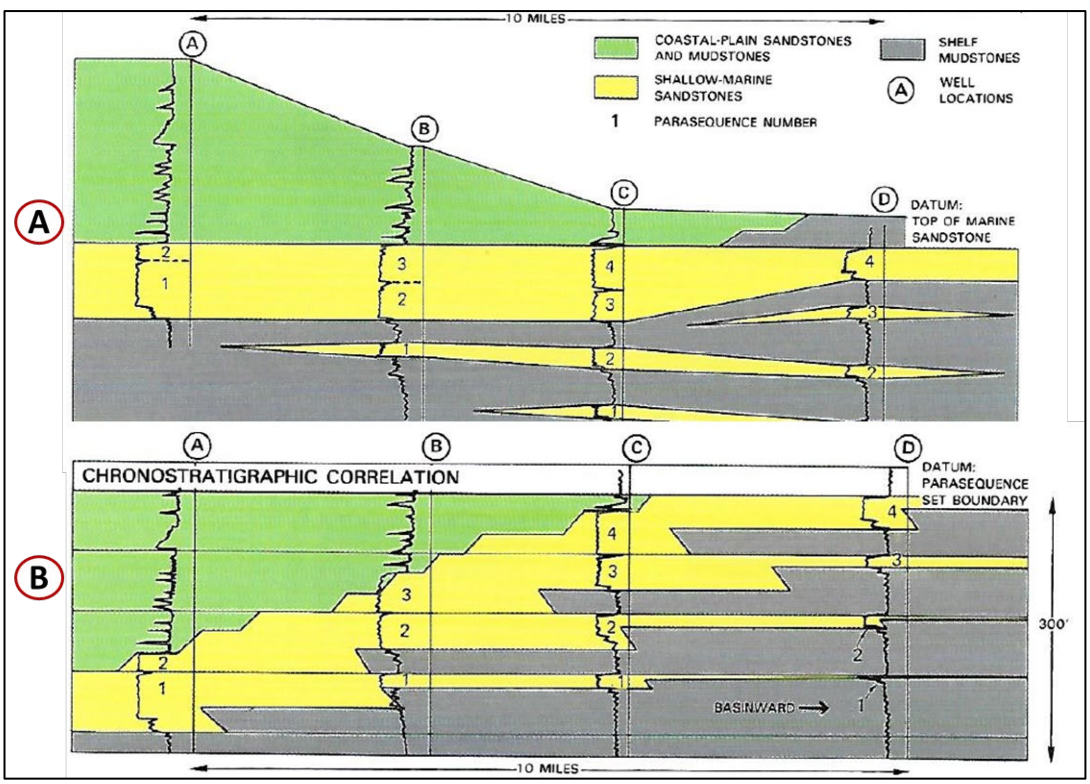

Fig. 5.5—Sequence stratigraphy application (Van Wagoner et al. 1990).

5.5.6 Quantifying Residual Oil Saturation. Knowing the hydrocarbon target facilitates the proper assessment of project development plans and accompanying economic requirements. For example, the well-known equation for calculating maximum possible waterflood displacement efficiency is:

$$RE = \frac{(1-S_{wc})-S_{or}}{(1-S_{wc})}, \quad (5.1)$$

where
RE = displacement efficiency, fraction of PIIP
S_{wc} = connate water saturation, fraction
S_{or} = residual oil saturation, fraction.

As expressed, this is the oil saturation that is residual to a water-displacement mechanism. (Recovery efficiencies are discussed in more detail in Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures*, herein.) Further, the recovery efficiency calculated in this manner is inclusive of the primary recovery efficiency; i.e., if the primary recovery is estimated separately (perhaps by decline curve analysis) to be 15% of PIIP, and the recovery efficiency calculated using Eq. 5.1 above is 25% of PIIP, then the incremental technical recovery due to the secondary process of waterflooding is 10%. On the other hand, if the primary recovery is already 20%, will the incremental 5% of PIIP be economically justifiable for the installation and operation of a waterflood?

The residual oil saturation (S_{or}) is dependent on the displacement process. If miscible carbon dioxide flooding is implemented, the improved oil recovery process is expected to reduce the S_{or} below that of a waterflooding process. (In this case, the calculated recovery efficiency includes all recovery through the miscible flooding process.) Provided that relative permeability data are available to identify the residual oil saturation under both waterflooding and miscible displacement processes, the evaluator may address the upside potential in different categories within the resource class; however, the development scope and associated expenses will generally result in separate projects.

Residual oil saturation typically is determined in the laboratory by flushing a number of pore volumes of water (preferably of the same chemical composition as the planned injection water) through a representative core sample. This procedure is continued until no further oil is recovered at the core outlet. Higher core waterflooding rates are usually implemented near the end of the coreflood to overcome the capillary end effects while determining S_{or}. (Other methods of estimating S_{or} include log-inject-log techniques, such as the thermal decay time log and nuclear magnetic resonance imaging logs. Sponge coring, on the other hand, may give an estimate of the remaining—rather than the residual, oil saturation, as discussed below.)

The remaining oil saturation reflects the oil saturation left behind when water displacement has not been optimized. In actual field operations, a well may be drilled in an area believed to have been swept by an existing waterflooding operation, and a sponge core may have been recovered for the subject formation. The oil saturation determined from the sponge core will not necessarily be the *residual* oil saturation but rather the *remaining* oil saturation S_{orem}, which is normally taken to be higher than the S_{or} to water displacement. The difference is due to the sweep efficiency of the waterflooding process.

Example E in the following section illustrates the re-evaluation of S_{or} for reserves booking revision (assuming all other criteria for reserves classification are satisfied) using log interpretation and tracer testing. An alternative approach is to take the oil-saturated core and centrifuge it to displace the oil. This technique usually results in the lowest S_{or} and, in the process, mimics the added effect of gravity drainage. For reservoirs in which gravity drainage is expected to be negligible, the centrifuge S_{or} will be lower than the value expected to be achieved in actual practice.

5.6 Examples

5.6.1 Example A: Basic Logging Suite in Conventional Clastic Reservoirs. Since the mid-1980s, gamma ray (GR), resistivity, neutron porosity (NPHI), and bulk density (RHOB) logs have comprised the basic set of tools used to quantify rock and fluid properties and estimate net pay. **Fig. 5.6** shows an example of these data from a high-porosity sandstone reservoir in deepwater Nigeria. In this example, net gas pay intervals are delineated using neutron/density cross-over and the operator's pay cutoff criteria. In the presence of gas or light hydrocarbons, the low electron density of the pore fluid results in a higher apparent density porosity. Conversely, the apparent neutron porosity is low due to the lower concentration of hydrogen in the pore fluid. When presented on consistent lithology scales, the apparent density porosity and the apparent neutron porosity curves "cross over" (third track from left) in intervals with relatively low clay content.

The magnitude of the cross-over would depend also on shale content, and so the effect should be viewed qualitatively, and the evaluator should avoid application of absolute porosity unit cross-over rules of thumb. In contrast, oil- and water-bearing intervals do not exhibit "cross-over." The water-bearing interval is delineated from the gas- and oil-bearing intervals based on lower resistivity values.

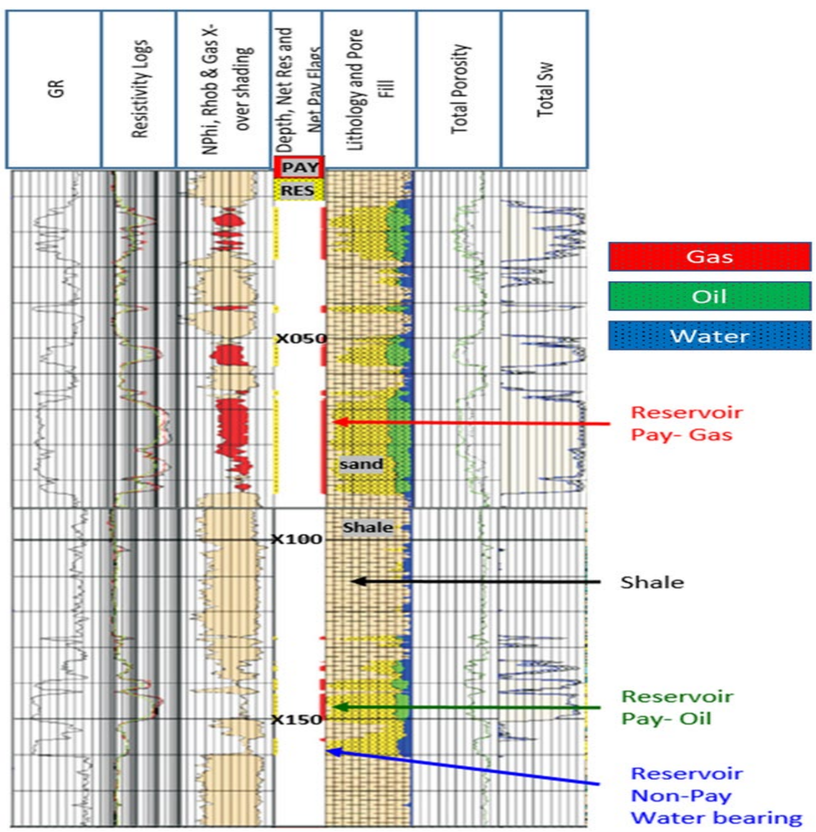

Fig. 5.6—Lithofacies-based corrections to density-neutron porosity showing hydrocarbon intervals from a turbidite sandstone (modified from Spears 2006).

5.6.2 Example B: Coupling Basic Logs with Nuclear Magnetic Resonance Data in Carbonate and Complex Reservoirs. In complex/mixed lithology and/or carbonate reservoirs, nuclear magnetic resonance (NMR) logs may be coupled with basic log suites to identify pay zones. NMR logs can provide lithology-independent estimates of porosity and inform fluid characterization. NMR data provide information about the pore size distribution and quantities and properties of the contained fluids, providing a means to identify mobile water in a prospective reservoir interval.

Fig. 5.7 shows a Middle East heavy oil carbonate example where NMR is used to delineate pay intervals that will produce only oil, pay intervals that will produce oil and water, and non-pay intervals that will produce only water. The technique described in the paper (Liu et al. 2013) utilizes a variable, as opposed to fixed, set of pay cutoff criteria relying on NMR discrimination of bound water and movable water volumes. (Note the integration of log interpretation with wireline sampling.)

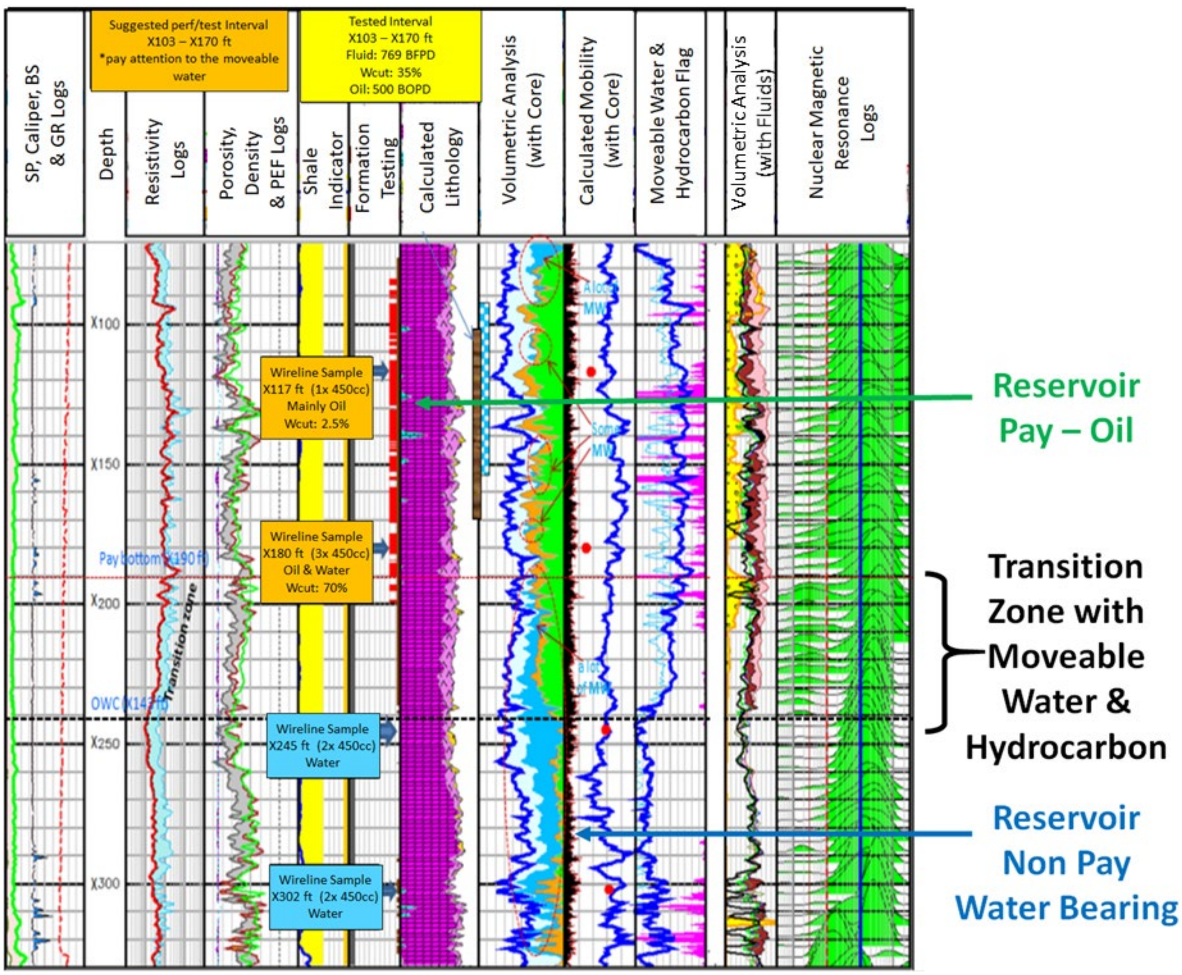

Fig. 5.7—Movable water controlling the hydrocarbon production (modified from Liu et al. 2013), where SP is spontaneous potential, PEF is photoelectric factor, and BOPD is barrels of oil per day.

5.6.3 Example C: Thinly Laminated, Low-Resistivity Reservoirs. Thinly laminated, low-resistivity reservoirs comprise sequences of thin interbeds, or laminations, of sandstone and shale (or mudstone). Because lamination thicknesses are less than the vertical resolution of most conventional logging tools, the resistivity of hydrocarbon-bearing sandstones in such settings is suppressed by the interbedded shale. This may result in water saturation overestimation and porosity underestimation in porous intervals due to tool resolution and measurement averaging in such reservoirs, particularly when pay cutoffs are applied.

Multiple techniques have been published to address this reservoir type, including, but not limited to, high-resolution core- or log-based image analysis methods and lower-resolution, conventional log or NMR-based assessments of bulk volume hydrocarbon. One such approach (Thomas-Steiber method) is used in **Fig. 5.8** (Stromberg et al. 2007). The Thomas-Steiber method identifies laminated and dispersed clay components in shaly sands to estimate the net-to-gross (NTG) ratio. The box in the figure highlights a section that was not perforated but was subsequently interpreted as containing net pay. In this example, it is evident that relying solely on ultraviolet fluorescence (image track in center) to estimate net pay in thinly laminated intervals is complicated by the presence of residual hydrocarbons in the low-resistivity, non-pay interval at the bottom of the core. Dynamic data from formation tester tools, production logging tools, or production tests may be required to confirm moveable hydrocarbons in such intervals. The reader is encouraged to read Stromberg et al. (2007) for further details.

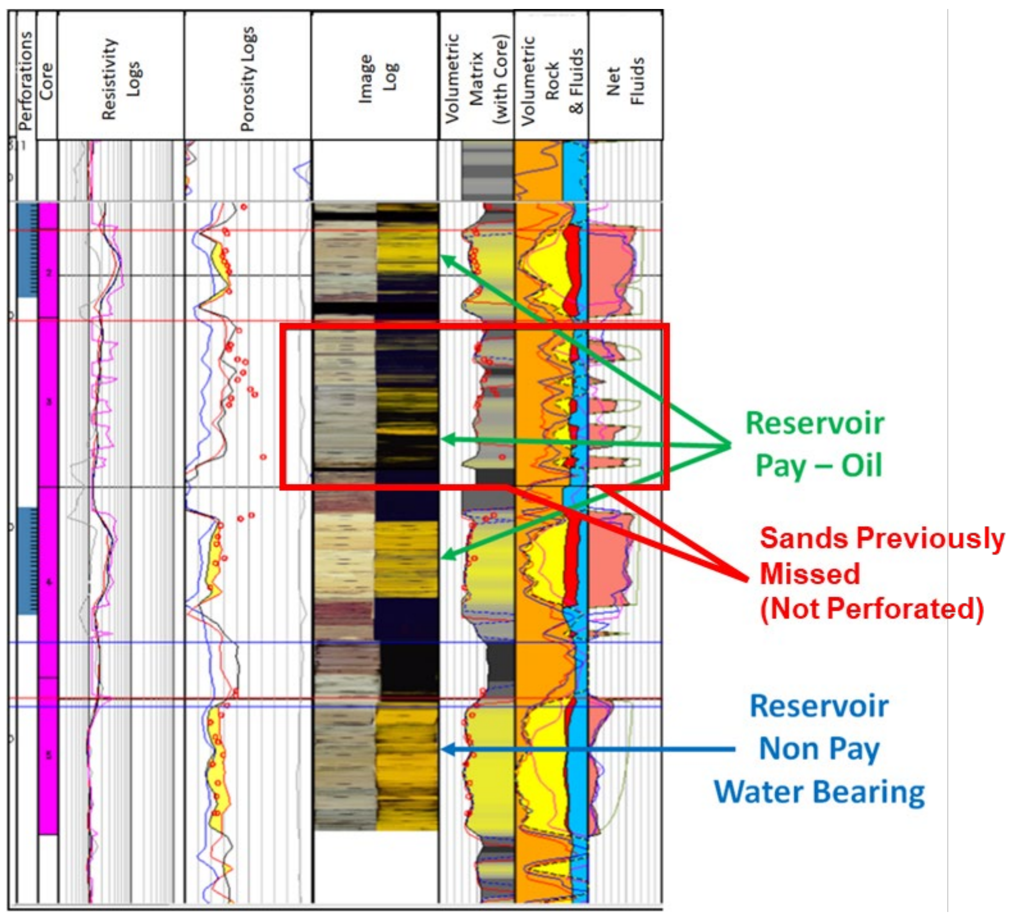

Fig. 5.8—Identifying net pay zones in laminated reservoirs in Oman (Stromberg et al. 2007).

5.6.4 Example D: Integrating Production Logging Test to Determine Net Pay in Laminated Sands. Laminated sand-shale sequences are characterized by suppressed resistivity, elevated gamma-ray values, and increased separation in neutron-density logs that are below the vertical resolution of the log data, which make net pay easy to overlook during well log interpretation. Combining log and core data with production contribution from the intervals is the key to quantifying the net pay thickness in this type of reservoir.

In this example **(Fig. 5.9),** the contribution from laminated sands in the well was quantified by integrating production logging tool data. The thin beds of sand in the laminated section were difficult to interpret from basic logs because of limitations in vertical resolution but were clearly identified from core ultraviolet light photos (showing high oil saturations) and mud log shows, among other measurements. Though oil is visible, dynamic data were necessary to confirm producible hydrocarbons across the laminated sequence. Perforated intervals are shown by the tan markers.

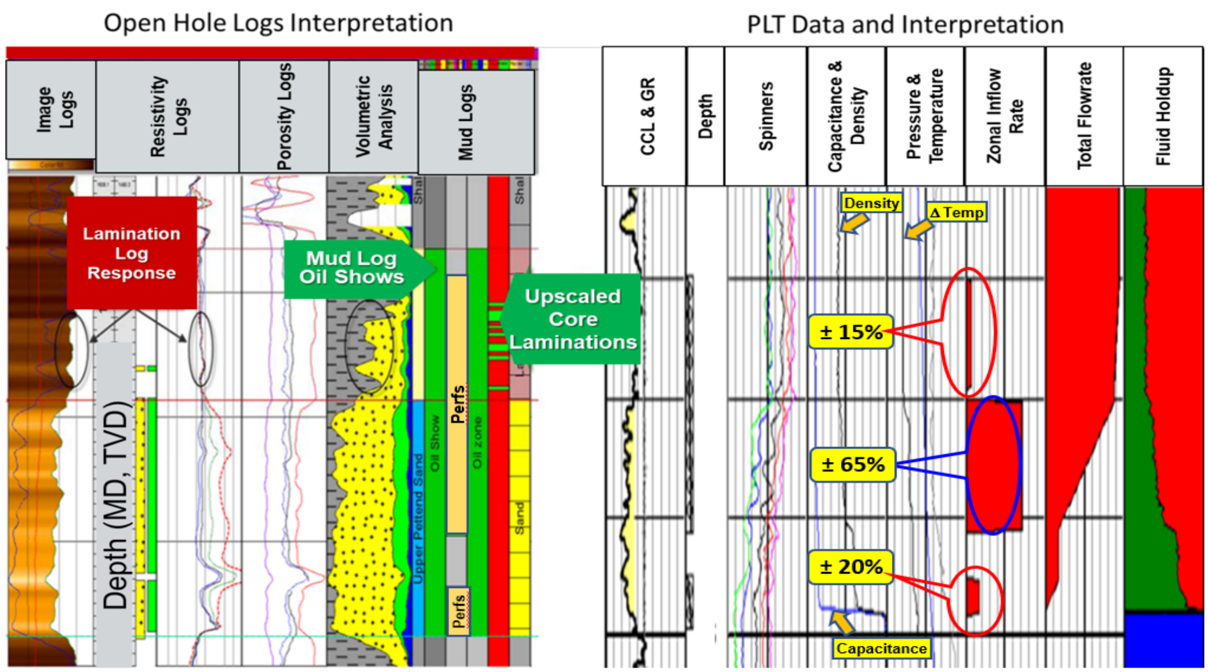

Fig. 5.9—Wireline logging tools response integrated with production logging tool (PLT) data in a laminated sand interval (perfs indicates perforated intervals).

Production logging tool data indicated three sharp cooling effects (Δ temperature track), identifying inflow. Gradiomanometer (or density) data were used to identify different fluid phases. A density curve can be created from the pressure data by comparing flowing and shut-in passes to indicate fluid entry. The density and capacitance data also show a decrease moving up the wellbore from brine to oil to light oil/gas condensate. Four spinner passes (i.e., spinner run at four speeds) highlight flow starting at the base of the lower perforated intervals. By integrating these results, we estimate that most of the oil inflow (approximately 65%) is coming from the good-quality reservoir section at the base of the upper perforated interval. However, we also observe flow contribution (approximately 15% of the total inflow) from the laminated section at the top of the upper perforated interval. As a result, the production logging tool data confirm production (pay) from the laminated sections, which may have been ambiguous based only on the open hole logs.

5.6.5 Example E: Reevaluation of Residual Oil Saturation. In a mature oil field with 15 years of production, studies were performed to reevaluate the residual oil saturation (S_{or}), which could have a material impact on the estimated recovery under the planned development program. Initially, a value of 38% was obtained from relative permeability curves in laboratory tests and used for 2P estimates. However, this S_{or} may be high, since the tests were performed on plugs of core with permeability lower than the average reservoir permeability, due to the difficulty in recovering representative rock samples from the unconsolidated rock.

Three data sources were considered for the studies: wells with open hole logs, in an effort to define the fluid saturation in a washed-out area; cased-hole logs from a recent well (using a carbon-oxygen log); and recent tests with a chemical tracer [single well tracer test (SWTT)]. **Table 5.3** presents the values of S_{or} developed from each source:

S_{or} initially used	Log S_{or} values (open/cased hole studies)		SWTT S_{or}
	Average	Minimum	
38%	33%	17%	23%

Table 5.3—S_{or} values considered from each source.

The S_{or} value obtained from the SWTT was considered to be more representative compared to the values from other studies, so it was decided to adopt this result in the 2P (best estimate) volume. Furthermore, the minimum of 17% was selected for the high estimate (3P) volume; results of all three cases as determined through simulation are presented in **Fig. 5.10.**

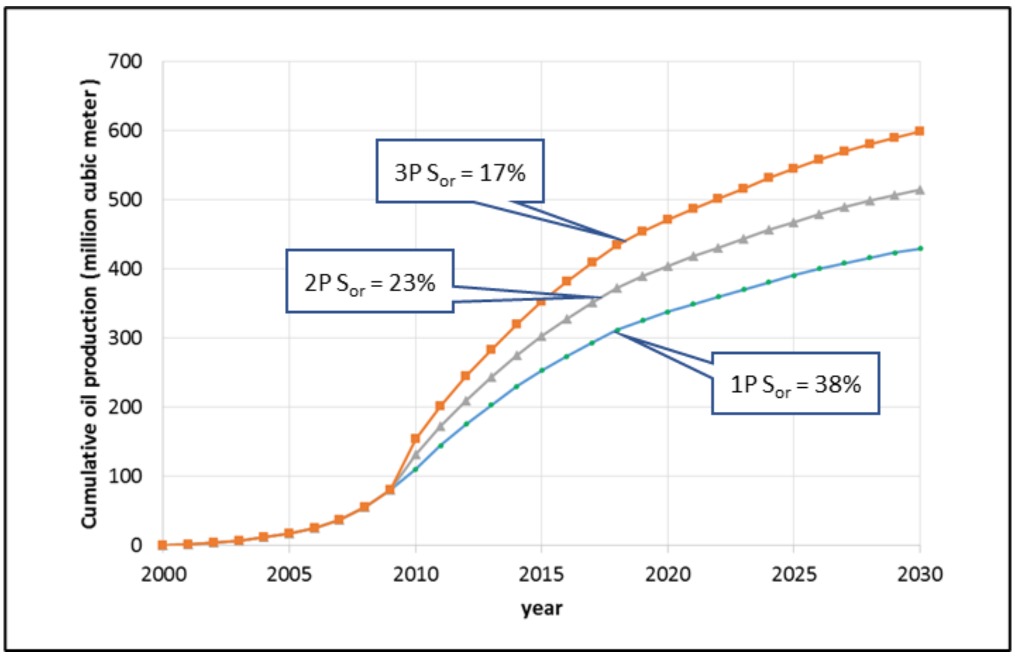

Fig. 5.10—Estimated ultimate oil recovery prior to and after tests with chemical tracers.

5.7 Conclusion

Resource assessment has evolved immensely over the last few decades, and numerous petrophysical analytical processes have been at the forefront of this evolution. These processes rely fundamentally on two types of parameters: those which describe the static properties of the rock, fluid(s), and their interaction, such as grain size, porosity, fluid density, capillary pressure, fluid saturations, wettability, etc., and those which are determined by the dynamic phenomena of hydrocarbon or water production. Examples of such parameters are net pay, irreducible fluid saturations, mobility, gas-oil ratio, and oil rate.

Net pay is obtained by applying the dynamic process of hydrocarbon extraction to a rock that contains such hydrocarbon and has the potential to produce. Since the extraction typically is the consequence of a necessary pressure differential, net pay can only be estimated under given pressure regimes.

Conventional and advanced wireline logging, mud cuttings, sidewall and whole coring, production logging tools and pressure tests, and similarity to producing formations are some of the tools used by petrophysicists to determine net pay.

5.8 Acknowledgments

Important feedback and editorial effort were provided by Charles Vanorsdale and Danilo Bandiziol.

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Chapter 6

Reservoir Simulation

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6.1 Introduction

The practice of dynamic reservoir simulation dates back to the first analytical models of the late 1940s and early 1950s, but widespread use did not occur until the advent of commercial simulation packages in the late 1980s. Detractors of the use of reservoir simulation refer to the process as a "black box," but, in the hands of an experienced petroleum engineer working with an experienced geoscience team, reservoir simulation can materially help to evaluate the uncertainties associated with investment decisions and consider development planning scenarios. It is a tool that can be used to improve the understanding of reservoirs and their performance data, facilitate the decision-making process, aid in the selection (in conjunction with economic analysis) of the optimal development scenario, assess the range of resource potential, and so on. Nevertheless, there are limitations to reservoir simulation and the reliability of its results that need to be clearly conveyed to end users and decision makers.

The objective of this chapter is to focus on the application of reservoir simulation for the estimation of reserves and resources in alignment with Petroleum Resources Management System guidelines. The process and methodology of model construction, history matching, and running predictive cases are touched on, but the detailed techniques that should be applied are better addressed in other sources in the petroleum engineering literature. It is assumed for the purposes of reserves and resources estimation that both existing and future development projects have been established, and reserves and resources are being estimated for those distinct development plans.

6.2 What is Reservoir Simulation

Reservoir modeling or simulation has been described by the Petroleum Resources Management System (§ 4.1.3.2) as:

> "a more rigorous 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, fluid properties, and constraints (e.g., wells, facilities, and export) are critical. Predictive models are most reliable in estimating recoverable quantities when there is sufficient production history to validate the model through history matching."

Reservoir simulation is a computational modeling process that attempts to model the behavior of fluids moving through porous media. Reservoir simulation can be used to emulate flow behavior in one to three dimensions, and with a wide variety of fluid behaviors usually represented by the results of pressure-volume-temperature (PVT) experiments. Reservoir simulation models (or simply simulation models) render a representation of an actual reservoir honoring the laws of material balance and multiphase flow in porous media and incorporating the effects of changing reservoir conditions over time and throughout the reservoir. While the central formulations of reservoir simulation address the flow of multiple phases given the impact of convective and gravitational forces, assuming relatively simple tabular black-oil fluid treatments, more sophisticated formulations include any number of additional reservoir phenomena, such as compositional, thermal, or chemical effects. In addition, the utility of reservoir simulation has been expanded significantly through the addition of options to interpret pressure loss between the subsurface and surface in tubing, to obtain the simultaneous solution of the reservoir model with representations of gathering systems, or even to incorporate sophisticated production plant processes (also known as subsurface-surface reservoir coupling models).

The majority of commercial reservoir simulation code relies on a finite-difference discretization scheme, but commercial code relying on other formulations such as stream-line simulation is also available. In general, the guidance provided by this chapter does not depend on the form of simulation that is used, as we are accepting that these tools provide a reasonable representation of the physics of flow in a porous media, given the confidence of the input data for the reservoir and the project.

Reservoir simulation is an integrated form of analysis, not a stand-alone or isolated form of assessment. Integral components are discussed within several other chapters in this document, most notably in Chapter 4—*Assessment of Petroleum Resources Using Deterministic Procedures* and Chapter 5—*Petrophysics*. It is a powerful tool because it allows the inclusion and integration of all relevant reservoir information with details of the development plan. However, as a form of analysis, it is very dependent on the input data and their certainty, and small changes in the underlying input can yield substantial differences in the output.

While this chapter focuses on the traditional use of reservoir simulation as a deterministic tool (see Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures*), reservoir simulation can also be applied in a probabilistic fashion (see Chapter 7—*Probabilistic Resources Estimation*). While this extension of the use of reservoir simulation to the probabilistic methodology is not discussed in detail herein, most of the guidance presented here applies equally well to probabilistic use of reservoir simulation. Careful attention should be paid to maintain that selected Proved cases conform to the strict limitations imposed on deterministic Proved Reserves model.

6.3 Use of Simulation in Resource Estimation

A simulation model used to develop an estimate of recoverable resource quantities should generally include the entire petroleum initially in place (PIIP) that is the target of the development in question. If an estimate is for the entire development plan for a whole field, then the modeled reservoir(s) must include the entire PIIP in order to serve as a means to assist in the management of resources, including all the PIIP from the free-water level up, inclusive of the transition zone, the main pay zone, and any "tar" or residual oil zone. One of the key challenges to the application of reservoir simulation to resource estimation is modelling, for the appropriate level of uncertainty, reservoir connectivity (and hence effective drainage area) and drive mechanisms. To the extent that identified geological features such as faults or changes in stratigraphy are understood or anticipated to impact reservoir connectivity, they must be included in the description. However, often and especially for newer fields, such features and their dynamic impact may not yet be understood. Therefore, it may be appropriate to include a more conservative description for a "low case" (1P or 1C) estimation, and a less restrictive, more widely connected description for a "high case" (3P or 3C) estimation.

As will be discussed in greater detail later, simulation models are calibrated to historical performance data through the history matching process. When considering the use of a simulation model in resource estimation, attention must be paid to the maturity of the development of the reservoir or field, with consideration given to the principal development process used to produce the remaining recoverable resources. For instance, it is clear that a new field in the process of being developed, where the only dynamic data may be limited to well tests or even repeat formation tests, must be recognized as immature for reservoir simulation purposes. There will be a significant amount of uncertainty in the outcome of development scenarios at such an early stage of development. On the other hand, a field that has been waterflooded to a high water cut can be treated as mature, unless a new physical process (for instance, some form of tertiary recovery) is anticipated to be introduced for the purpose of extracting a significant fraction of the remaining in-place resources.

6.3.1 Immature Reservoirs. As would be expected, immature reservoirs in particular have a large range of uncertainty. The project may have little or no production history, few wells to provide data coverage across the field, insufficient samples of rock and fluid property analyses with which to characterize the reservoir(s) and its fluids, or other limitations on data available to describe the reservoir(s).

How would we qualify a reservoir as "immature?" When reservoir simulation is viewed in the context of a material balance approach (the reader is again referred to Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures*), a generally accepted industry rule of thumb states that a reservoir is considered immature for such an analysis if it has not yet produced about 10% of its PIIP or if its reservoir pressure has not yet declined by approximately 10% (assuming volumetric behavior). We likewise may categorize a reservoir as immature for simulation purposes by applying this material balance analogy.

Another instance of immaturity would be associated with a significant redevelopment or the introduction of a production mechanism that has previously been untested or has just commenced in the reservoir, for example, the introduction of a secondary recovery project in the case of a reservoir at the end of primary depletion, or the introduction of a tertiary project at the end of secondary recovery. Judgement must be used in such situations to arrive at a determination of the degree of maturity of the process. Issues to consider when appraising the maturity of such a process would need to include whether there are pilot projects to include in history matching, or whether there are analogous accumulations where the new recovery mechanism is more mature. For instance, if a simulation model of a field with two fault blocks establishes a good history match of the mature waterflood operations in the reservoir in Block A, although the operator has yet to initiate waterflooding in Block B, the results from Block A very likely establish the analog for Block B modeling.

Because an immature reservoir lacks the requisite amount of performance data with which to properly calibrate the dynamic model, the industry widely recognizes the greater degree of uncertainty in the predictions of such a dynamic model. In the absence of performance data with which to adjust and constrain the input geological description, along with other input information such as relative permeability properties and possibly PVT properties, the output is highly dependent on the assumptions made during model construction.

Because of these issues, the key use of reservoir simulation for resource estimation in immature reservoirs should focus on sensitivity analysis, where the ranges of potential outcomes are assessed by varying the values of key input parameters. Key parameters may be identified using, for example, tornado diagrams (see Chapter 7—*Probabilistic Resources Estimation* herein). Projecting Proved Reserves (as compared to "Proved + Probable" or 2P reserves) for immature reservoirs requires special attention in most cases. This topic is discussed further in Section 6.6.

A special caution in history matching is the reliance on reservoir conditions in history that may not be representative of the forecast conditions. For example, the history match of wells that have produced during the above-bubblepoint period in the reservoir may not reflect how the wells will perform once reservoir pressure falls below the bubblepoint. Data such as three-phase relative permeabilities and critical gas saturation must be validated (not just measured in the laboratory) before a reliable forecast can be developed.

6.3.2 Mature Reservoirs. Mature reservoirs are those where a lengthy history of production has occurred due to the application of the recovery mechanism upon which most of the remaining recoverable quantities also depend. A mature reservoir has a significant history of performance data that can be used to calibrate the input of a simulation model. At a minimum, such a history will include rate (all hydrocarbons and other streams) and pressure data, but it may also include formation pressure tests, open hole well logs, and cased hole logs taken over the course of production of the reservoir. The available data may even include time-lapsed seismic data capable of imaging the movement of fluids over the course of production.

In most cases, the integration of these data into the dynamic model through the history matching process leads to modifications of the underlying static model description. If diligently incorporated, such changes lead to a dynamic model that can, within a reasonable tolerance, explain the historical pressures and fluid production from the reservoir. This does not ensure that the resulting model is the only dynamic model that could explain the production history, or even that it is a likely explanation for the dynamic history. Therefore, even in the case of mature reservoirs, it is important to understand that there is still uncertainty in the future outcomes for the reservoir, and any simulation-based prediction is only one predicted outcome within a range of possible outcomes. For this reason, it is always useful to compare simulation results with other approaches.

Although it may be argued that at an advanced state of depletion, reserves may be more easily quantified using decline curve analysis, there are still many reasons to include simulation models in the tools used for resource estimation for such a mature reservoir. First, there are many mature reservoirs that are not in production decline, due to aquifer or gas cap pressure support, capacity limitations on facilities, sales contracts, export options, or market conditions. Reservoir simulation is usually an excellent tool for such a scenario.

Furthermore, reservoir simulation is often employed to provide estimates of the recovery for ongoing development or redevelopment options for which other performance-based methodologies such as decline curve analysis or material balance analysis may be difficult to adapt, or where simulation models combined with tools such as nodal analysis are likely to render a more accurate and physically realistic portrait of future reservoir performance. Examples of such situations include flood pattern realignment or infill drilling. Another similar situation is a change in prevailing production constraints such as increasing water handling from a field or increasing the gas available for injection. Reservoir simulation models provide the option to link wellhead pressures to gathering and plant inlet points. This renders straightforward the process of predicting the effects of modifications to facility capacity or the gathering system layout or constraints.

The following is a partial list of scenarios where simulation models of mature reservoirs may provide more reliable predictions of future performance than other methods:

- Changes in facilities rate constraints
- Changes in constraining surface pressures
- Changes in injection rates or pattern realignment
- Redevelopment drilling campaigns
- Changes in well and completion design

- Introduction or alteration of artificial lift
- Production of an undersaturated oil as the reservoir goes below the bubblepoint

6.4 Fundamentals of Simulation Quality Assessment

As noted earlier, there has been a "black box" stigma associated with reservoir simulation due, in many instances, to unfamiliarity with the inner workings of simulations on the part of the end user of the simulation results. In contrast, there has been a tendency to accept the results of reservoir simulation without first achieving a measure of confidence in the underlying geological model, understanding the level of reliability of dynamic data, or assessing whether an acceptable match of the model results to that of actual reservoir performance history has been achieved. In many cases, once a simulation model has been constructed and accepted, users may begin to depend on a model without appreciation that the accuracy of predictions from the same model varies depending on what is being predicted and when. For instance, a well history-matched model will, in general, provide more accurate predictions for the near future than for the distant future.

It is not the intent of this chapter to provide instructional material for simulating fluid flow or reservoir properties. There are, however, elementary techniques used to assess the quality of a reservoir model and its fitness for predicting hydrocarbon recovery. While evaluators are likely to differ in the techniques they apply, there are four primary elements of simulation modeling that should be examined when considering the reliability of reservoir simulation results used for any purpose, including resource estimation.

These include:

(1) the construction of the underlying static model;
(2) the integration of dynamic data;
(3) the history matching process and results; and
(4) the construction and validity of predictions.

These four areas will be treated individually in the following sections.

6.4.1 Static Model Construction. The building blocks of a good reservoir model are the underlying geological characterizations. It is important, however, that the geoscientists involved have a clear understanding of the required output from the simulation model. For example, the ways in which geological rock types and flow units are modeled will impact results regarding assessment of recovery efficiency. If a reservoir is modeled using flow units, and a flow unit consists of several rock types, while certain rock types are deemed hydrocarbon-bearing but unproductive, it may be difficult or impossible to remove those rock types from the flow units in the model to properly calculate a recovery factor using the PIIP.

The geological description consists of two primary constituent parts. The first of these is the structural framework, which describes the physical container holding the PIIP, the physical limits of the petroleum accumulation, compartmentalization, and (where appropriate) the underlying aquifer. The second of these parts is the description of the rock within the structure, the characterization of the formation, ultimately resulting in the distribution of attributes of reservoir rock that are directly utilized by the reservoir simulation software, most notably distributions of facies or rock type, porosity, permeability, and (depending on the preferences of the team constructing the model) the net-to-gross ratio.

Structural frameworks should adhere to, and honor, several important pieces of data, starting with the correlation scheme adopted by the geoscientists. The tops and bases of key zones and subzones should be included, and vertical zonation should be adequate to capture the heterogeneity of the reservoir, particularly heterogeneity impacting fluid flow and recovery. This likely depends upon the recovery mechanism responsible for petroleum recovery from the subsurface. For instance, the same heterogeneity could have a significant impact on the results of the waterflood of an oil reservoir but only minimal impact on the results of primary depletion of a gas reservoir.

The structural framework also includes the areal gridding of the reservoir description. Grids should have adequately fine definition to allow for the capture of lateral variations in properties between wells. The grid block size is a compromise between accuracy and the computational resources and time available to conduct a study. It is essential to capture the heterogeneity of the geology in addition to the rock and fluid description in the model while allowing manageable computation. The selection of fine grids requires detailed information and sufficient understanding of the reservoir to guide the process of populating the grid properties and combining various data from different scales.

Descriptions lacking sufficient definition, either vertically or laterally, will tend to allow unjustifiable communication, as the averaging of the formation characterization through upscaling will tend to increase connectivity. This is due to averaging finer-scale data values into coarser grid blocks inappropriately, which is likely to occur for properties where averaging should be associated with transmissivity (mostly permeability) rather than properties where the average should be more strongly tied to storage capacity (porosity). Averaging the properties of porous media can lead to severe errors if not practiced with insight on the process and the different mathematical approaches.

In practical terms, most modeling practitioners are going to be limited to those upscaling options that are supported by the geomodeling or simulation software suite(s) used by their organization. These software suites usually provide detailed explanations of the methodologies, along with recommendations about which methods to apply in which circumstances, and how to review the results for reasonableness and reliability, complete with references to the original source materials in the upscaling literature.

The areal spacing of the grid should be adequate to address the nature of the development plans under consideration. Grid cells that are 100 m by 100 m may be adequate for some models of wells on very large spacing but will likely prove inadequate for a model of a heavy oil reservoir developed on very tight well spacing. Additionally, the structural model should capture, to the extent practical, structural offset due to faulting, particularly where faults are of significant magnitude and are known or may prove to meaningfully impact communication across the reservoir.

The petroleum engineering literature historically has recognized (Mattax and Dalton 1990) that the utility of the gridding scheme can be enhanced through orientation of the grid with the direction of the principal permeability tensor. Anisotropy in the permeability influences flow rates and pressure depletion and propagation in the porous media. Having this information analyzed and understood before construction of the geological model grid can improve the quality of the static model and induce better estimation of pressure gradients and fluid saturations.

A grid may undergo modification to be used for specific studies or to address operational conditions. For example, the size of the grid blocks might be reduced or increased. A very common reservoir simulation technique is local grid refinement, which is widely supported in commercially available simulation software. Local grid refinement can be used to replicate induced hydraulic fractures, capture the transient effects of a low-permeability environment, or study the impact of condensate drop-out near the wellbore for gas-condensate reservoirs. On the other hand, it is usually possible to coarsen the grid blocks by increasing their dimensions in order to reduce the computational load. This might be done in areas of low dynamic activity, for example, away from the fluid front or outside the area of interest (such as in water-filled grid cells in an aquifer, but relatively distant from the petroleum accumulation).

The second constituent part of the static model is the distribution of rock properties imported into the simulation model. At a minimum, reservoir simulation software requires the input of porosity, permeability, and saturation arrays. Most modern models also include the import of other parameters such as rock type or facies. As noted earlier, vertical and areal grid resolution should be of adequate refinement to capture important heterogeneities in input arrays that may affect flow.

Two important aspects of reservoir characterization that should always be reviewed when considering the distribution of properties in the static model are (1) the degree to which the properties in grid cells match the accepted petrophysical interpretation in the grid cells penetrated by wells, and (2) the method by which those properties are populated between the wells.

In general, while the simulation model will not have the same vertical resolution as a well log, the statistics of the important parameters such as porosity should be matched within a reasonable tolerance by the grid cells along the paths of the wells in the static model. The grid cell properties in zones tested or completed should be closely scrutinized. Zones indicating high flow intervals, barriers, tar, etc., should be accounted for and reflected in the properties of these zones. Further, data collected from vertical, deviated, and horizontal wells should be incorporated when feasible to be used as control points in order to enhance the modeling results. In an age of widely available three-dimensional geological description tools, proper workflows should result in upscaled grids that agree with petrophysical interpretations within a reasonable tolerance with appropriate upscaling. Likewise, the statistics and variograms for the different three-dimensional grid properties must be examined to ensure reasonable consistency between the log (and/or core) data, the fine-scale static geological model, and the final dynamic model.

When populating properties between (or beyond) the existing well control points, the distribution of properties must appear to be geologically defendable. If the distribution of values of petrophysical properties away from well control is significantly different from the distribution from grid cells intersected by existing wells (control points) and averaged into those cells, explanations of this behavior must be sought.

It is not uncommon to review the distribution of porosity or permeability along a vertical plane of grid cells and find that the values of these properties become distinctly higher or distinctly lower between (or beyond) the cells where actual well control data are available. This phenomenon may be due to the misapplication of a methodology for the spatial distributions of properties. **Fig. 6.1** illustrates a scenario where a subzone in a dynamic model has been populated with rock capable of producing petroleum, despite the lack of pay in the same subzone observed in the well log. In this case, the statistics for the distribution of porosity for this subzone in the dynamic model are not representative of the porosity distribution observed in the well logs, likely indicative of an improperly implemented geostatistical distribution methodology.

The static properties must reasonably honor the acquired data and laboratory measurements. Grid cell porosity or permeability values should not exceed observed data unless justified. If a model is set up to estimate 1P or Proved Reserves, as discussed in Section 6.6.1, any improvement in porosity, permeability, or hydrocarbon saturation between or beyond the control points will have to be supported by the reasonable certainty standard.

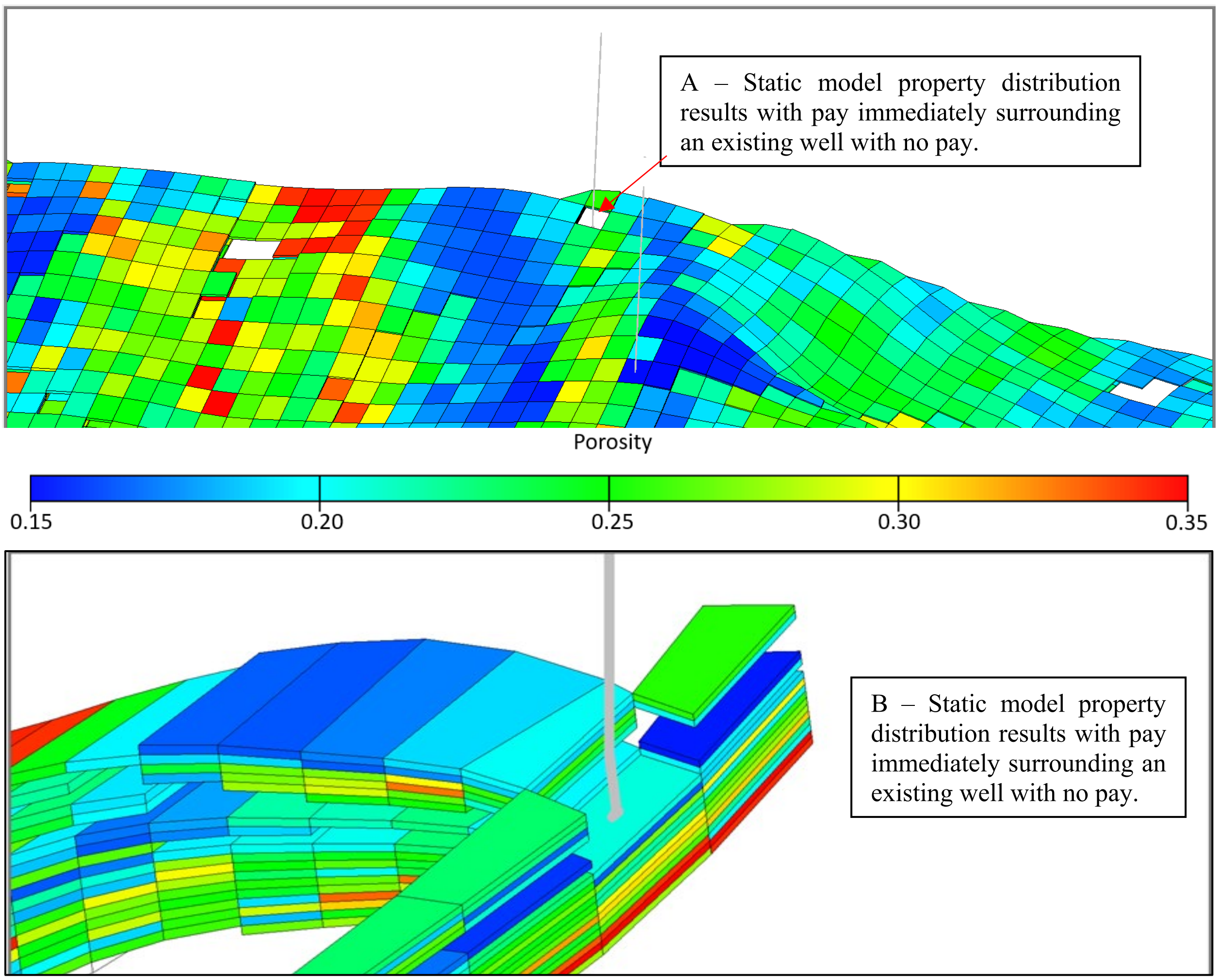

Fig. 6.1—A common issue with rock properties between wells not matching observations at wells illustrated with a display of porosity in dynamic model grid cells. Clear cells at the well are not being assigned pay (and have no pore space).

Fluid contacts and surfaces are also generated in the process of constructing the static model. Oil-water contacts, gas-water contacts, lowest-known hydrocarbon, free-water level, and transition zones control the volumetrics of the model. Different contact depths can be set in different areas of a field, for instance, in different zones or different fault blocks. In general, some degree of pressure isolation between regions of varying contact depths is required for the regions to be in a state of quiescence or pressure equilibrium. A good practice is to run a simulation model through a quiescence checking case. The model is run from initial conditions with no production, and all wells are shut-in for a prolonged period of time, typically years. (The wells should also not allow crossflow between grid cells in this static condition.) If the model initialization is appropriate, fluid saturations and pressures should not change by more than trivial amounts. If this is not the case, and either pressures are changing significantly or fluids move around with no production, it indicates that there is likely an issue with the model initialization. Models with multiple fault blocks and multiple intervals with varying initial contacts are prone to have unexpected communication due to juxtaposed grid cells from different intervals across fault planes. This can generally be dealt with through sealing faults when clearly required to maintain initial pressure equilibrium.

6.4.2 Dynamic Data Integration. Aside from the initial static geological model, the simulation model must also incorporate various types of dynamic data. Within dynamic data in this chapter, we are including the description of fluid properties (PVT), the descriptions of rock-fluid interactions (through special core analysis), pressure transient information, and the locations of wells and description of their completions, as well as the historical production or injection associated with those wells.

PVT properties are a fundamental aspect of any simulation model. Most simulation models rely on the traditional "black oil" tabular PVT treatment, but advances in computer processing power have led to an increase in the prevalence of the more sophisticated compositional PVT treatment, where equations of state are used to calculate fluid properties considering variations in composition, pressure, and temperature. In general, the traditional black oil treatment can address most reservoir problems, but compositional treatment should be employed if there are processes in play that may require it, such as volatile oil or retrograde condensate reservoirs, gas cycling in condensate reservoirs, miscible gas injection, chemical enhanced oil recovery, or injected gas where the composition is significantly different from that of native gas.

Regardless of treatment, the input should be checked to make sure that it matches experimental data (laboratory reports) or that differences are explained. It should be confirmed that an equation of state can reasonably reproduce laboratory experiment results. Simulation output to the grid cells should be examined to confirm that the calculations of the simulation code arrive at the expected results. For instance, outputting an array of fluid formation volume factors at initial conditions can help to diagnose a mistake in the implementation of the PVT treatment in the model. Furthermore, the movement and mobility of the different fluid phases are governed by the relative permeability input combined with the PVT input.

The user (whether the modeler or a qualified reserves evaluator) of a simulation model should review the treatment of capillary pressure data in the model to determine if they appear sound, and if they are a reasonable match to laboratory measurements. Distribution of the water saturation by a saturation-height function and interaction of the different fluids are controlled by the method of implementing the capillary pressure and petrophysical data. The output saturations in the grid cells along the path of wells with logs should be reviewed and agree reasonably with those logs.

Pressure transient analyses that indicate changes in completion efficiency, effective permeability, and/or skin factor with producing time should be used as input when appropriate and of useful quality.

Once these types of data have been incorporated, it is important to check that the dynamic model PIIP and the hydrocarbon pore volume match the same values from the initial static model within a reasonably narrow tolerance. Variance between these numbers beyond a reasonable tolerance should be explained, and its potential influence on resource estimates should be given consideration. "Reasonable tolerance" may be defined on a company-by-company basis (discussed further in Section 6.4.3 below), but it is not unreasonable to expect the hydrocarbon pore volume from the two models to be within ±5%. The variance between the total pore volume of the dynamic and static models should generally be very small (assuming consistent application or nonapplication of pay cutoffs), as it is not impacted by differences in PVT or saturation-height function modeling between the static and initial dynamic models.

Additional dynamic data that require integration within a simulation model include well data specifying both the trajectory of wells and a description of their completions, as well as the available history of production from and injection into the wells. Important aspects of this data set include the diameter of the well, the range of depths of perforations, the presence or absence of stimulation treatments, and the use of pertinent tubing tables to capture pressure drop from the subsurface to the surface. It should be recognized that wells change over time and are frequently recompleted, plugged back, and/or stimulated over the course of their life cycles. Such changes in wells should be incorporated into the model at the appropriate times.

6.4.3 History Matching. The robustness of any predictions from a simulation model is directly related to the quality of the history match. On most occasions, a newly constructed simulation model will not adequately explain the historical performance of a well or reservoir without further adjustment.

The process of history matching is one of modifying reservoir simulation inputs in an attempt to mimic the historical pressure depletion and the physics of fluid flow within the model. For example, for an oil reservoir, the produced oil, water, and gas rates from the wells are input into the simulation model as historical rates. Reservoir simulators cannot generally be forced to withdraw the exact observed flow rate of more than one phase (in this case, phases generally include oil, water, gas, total liquid) for any timestep. When one such phase is specified, the other phases are the result of producing the observed rate of the specified phase. The simulator output will be (usually monthly) oil, water, and gas rates, bottomhole pressure, and, if tubing tables are provided, wellhead pressure. These outputs are then compared to actual measurements.

Normally, for a newly constructed model, these quantities will not match historical observations satisfactorily or impart confidence to the evaluator at the initial stages of dynamic modeling. History matching starts with the desire to improve the quality of the match to historical data. As described below, it is vital to constrain changes made to the initial input values so that they are supportable within available geological and engineering data. The resulting model should be considered capable of reasonably explaining the actual performance of the reservoir.

There are several limitations to this process. First, any single history match is nonunique. There are usually numerous alternative sets of input parameters that would arrive at equally good matches of the actual observations. While the matches of historical data might be equivalent, this does not ensure that predictions from the different history matched cases will be equivalent; indeed, the predictions could be quite different. Second, it is usually possible to make history match modifications to the underlying description that are unrealistic, and in some cases even physically impossible. While unrealistic input may still explain historical performance, it is not likely to produce reliable estimates of future recovery. Third, reservoir simulation modeling, as compared to a tool such as decline curve analysis, tends to be very data intensive, requiring a great deal of quality control. It is easy to make mistakes in the data import process, which may go undiagnosed.

Companies may have internal guidelines constituting “good,” “acceptable,” and “poor” matches to actual conditions. Time-variable parameters typically used to assess the quality of a match at the field and well levels with time include:

- Static bottomhole pressure
- Fluid production rates (oil, nonassociated gas, water)

- Cumulative fluid production by phase
- Secondary ratios (gas-oil ratio, condensate-gas ratio, water-oil ratio, or water cut)
- Fluid injection rates (if applicable) and cumulative injection volumes
- Fluid breakthrough (water, free gas, injected CO_2, etc.) time and trends

It is important to repeat that a history match is not usually unique, as there are normally different combinations of reservoir parameters that result in a match to historical data equally well, but the underlying fundamentals could be materially different.

Matching of the major producing phase in a model is not a reliable indicator of a good overall match because the major phase production history will usually be a primary input to the model. It is important to recognize the production parameters that have been input to the simulator before making a judgment call on the quality of the match. Likewise, history matching of cumulative quantities of a produced phase are inadequate because trends in production tend to be obscured in cumulative data. Therefore, it is important to attempt to match all fluid rates and *not* just the rates used to constrain the wells during matching. In **Fig. 6.2,** the history match of rate vs. time was performed using total liquid rate, and it shows a good match, as expected. However, when we look at the oil rate, the match usually shows some discrepancy with actual data. Further, the gas and water rates should also be checked against actual rates.

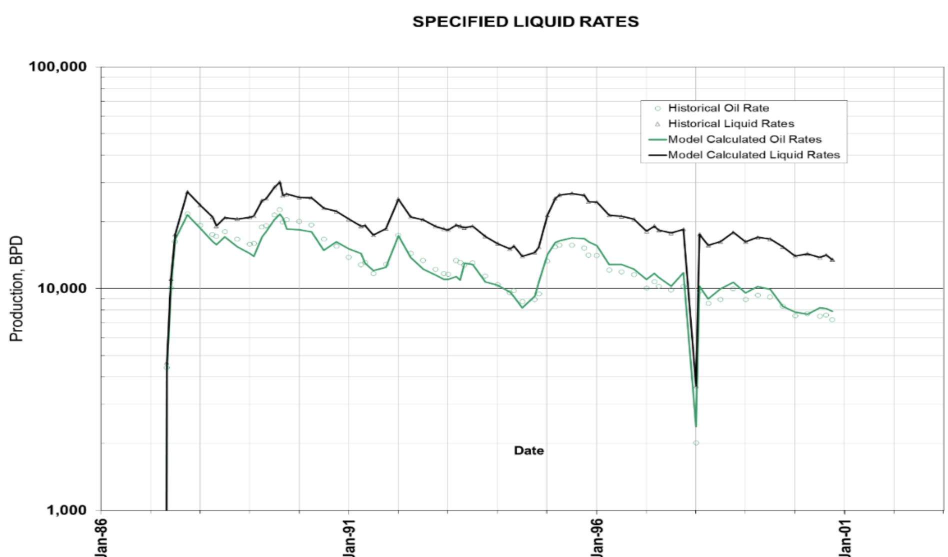

Fig. 6.2 History match of model total liquid and oil rates to actuals, where BPD is barrels per day.

Secondary phase ratios and well pressures (bottomhole or surface) are also important parameters to attempt to match. If good data from new wells is available after the start of production, such as repeat formation test data or well logs capable of monitoring fluid sweep or the movement of contacts, then this data can also provide insight into flow patterns to incorporate in the matching process. When applicable, a good match of the breakthrough timing of free gas or water in the wells helps to validate the accuracy of the dynamic model. **Fig. 6.3** shows a common suite of routine history matching plots (actual data are represented by dots).

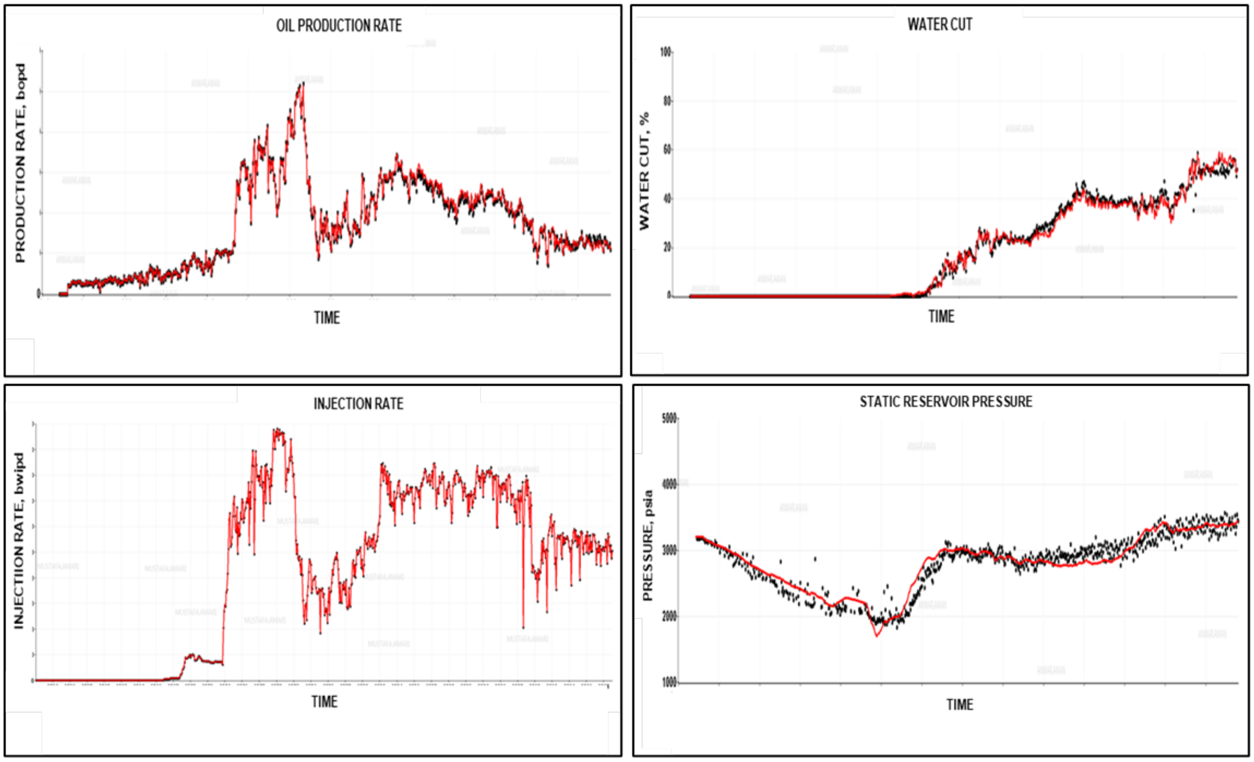

Fig. 6.3—Common suite of history matching plots, where bopd indicates barrels of oil per day, and bwipd indicates barrels of water injected per day.

A factor of equal importance to the quality of the history match is whether the modifications used to create the match are sensible from both geological and engineering perspectives. If possible, it is preferred to rely on parameter values derived from observation rather than history matching modification (Lee and Sidle 2011). As mentioned earlier, commercial simulation code allows great latitude in the values applied as input, and it is relatively easy to apply values that do not make physical sense. Good history matching practice depends on the following:

- Varying global or "big picture" input before introducing more localized changes
- Varying parameters with uncertain values before varying parameters with more certain values
- Varying parameters where changes within the reasonable range of values lead to a meaningful change to simulation output, e.g., a small and otherwise reasonable change in porosity might change simulation results by the same amount as a large and difficult-to-defend change in capillary pressure
- Not implementing changes that are not defendable based on the best technical understanding of the reservoir rock and fluid characterization

A careful review of the match must identify whether any "convenient features" have been included to obtain the match. Examples of these features include zones or layers of very high permeability ("super-*k*" zones), unrealistic vertical to horizontal permeability (k_v/k_h) ratios, strings of cells acting as "pipelines" to aquifers or injection wells, "leaky" tar mats, frequent compartmentalization, disappearing faults, and so on.

When history matching, it is also important to bear in mind uncertainty in the historical observations. Oilfield data may be questionable, and in many cases is subject to a significant degree of adjustment before being treated as factual, with the best example of this perhaps being production allocated to individual wells. It is important to question the reliability of historical observations, and to not overemphasize exact matching of data that is far from exact, especially when doing so requires the introduction of unrealistic input. Produced phases that are not sold will usually be measured less accurately than produced fluids that are sold.

As mentioned above, history matching is typically carried out by using the measured fluid production rates to calculate corresponding pressure and saturation distributions in the reservoir. During predictions, however, the simulator calculates fluid rates using Darcy's law for flow to the wellbore, and tubing performance curves for flow to the surface. The calculated flow rates are controlled by the wells' productivity indices and the backpressures imposed on the wells. These backpressures can be flowing bottomhole pressures or flowing wellhead pressures, which may, in some cases, be a function of the line pressure. A calibration step is usually required to ensure that the model, when used in a predictive mode (constrained by pressure rather than flow rates, which is standard in history matching), reasonably reproduces the recent historical rates.

Reservoir history matching should include the matching of static reservoir pressures observed at the wells, whenever possible. In some instances, there are few or no static reservoir pressures available to match, as is frequently the case for unconventional reservoirs. In these cases, other data related to formation pressures should be used as available. This should always include flowing pressure, whether surface or bottomhole, measured at wells, but could also include increases or decreases of the gas-oil ratio or condensate yield. These types of data are related to the pressure out in the formation, but they are also influenced by wellbore factors such as skin or completion efficiency. While history matching without static reservoir pressures is possible, it should be recognized that the results are more uncertain than those provided by matches of static reservoir pressures.

Before using a simulation model for predictions, the reliability of a history matched model is often checked using a "blind test." In this process, the most recent (6 months to a year) historical data is omitted from the history matching process. A well can be run under pressure control (using average flowing bottomhole pressures or flowing wellhead pressures over the period) or maximum rate control (oil production rate or total liquid rate) during the blind test. The simulation output in terms of production rates or pressure is compared with the actual recent historical data and should reasonably match the data from the blind-test period. A variation of this process is to test the model using wells that were not part of the history match and evaluate the model response. Generally, these "blind wells" come on production after the input historical production data cutoff date, although they may also be existing wells deliberately omitted from history matching (in this case, the well must remain in the model, and it must produce its associated constraining phase rate in order to ensure appropriate material balance is achieved). A successful "blind test" should increase confidence in the reliability of the model for making predictions of future well performance.

6.4.3.1 Material Balance Error. An especially important indicator of the overall accuracy of computational results is the material balance error. This value indicates deviation of the solved numerical approximation from the exact solution. Material balance error is calculated per timestep for each cell of the simulation model. Typically, it is reported as a mass accumulation at the end of the simulation output. The solution method (fully implicit, adaptive implicit, etc.) along with the numerical tolerance parameters and the nature of the reservoir control these values. Since reservoir simulation is a numerical approximation, scenarios with high material balance error values should be examined closely. Material balance error should generally be far less than 1% of the initial volume for each phase, and if error values exceeding that magnitude are encountered, then further analysis of the predictions from the model should be undertaken to be comfortable they are reliable.

6.4.3.2 Three-Dimensional Visualization. Visualization software is a very effective tool for assessing the simulation output and ensuring consistency. Initial pressure and water saturation can be displayed using vertical cross sections to verify assignment of the datum pressure and initial saturations and compositions. Time-lapse maps showing output pressure, fluid saturations, and component concentrations are useful to understand reservoir changes. Furthermore, water cusping, tracking of liquid fronts, and gas coning can be analyzed from the simulation results and used as a verification of the model quality. Details about the concentrations of different components in the phases can be traced to study fluid changes and phase interaction during the life of the reservoir and are a very practical way to confirm validity and reliability of the computations.

6.4.4 Validity of the Predictions. Once the model reasonably duplicates the physics of reservoir fluid flow based on historical performance, the next step is to check the reasonableness and reliability of predictions.

There are several exercises that serve to help check the reliability of simulation predictions. A common practice is the "productivity calibration" exercise, which is usually performed prior to generating prediction scenarios. The task is to run predictions with the wells constrained to representative recent rates for some duration in the near future and analyze the output flowing well pressures (with bottomhole or surface pressures, depending on data availability). If the model is showing higher or lower pressure than observed values, adjustment to the productivity of the wells might be applied. However, as is the case with all such adjustments, these must be recorded and justified to model reviewers. The same exercise can be conducted by constraining the wells to representative recent flowing pressures and then comparing the resulting rates to recent rates. Typically, in the predictive mode, the simulation model is best held in check by continuing the actual constraints imposed on the wells by the day-to-day operations of the field. For instance, a gas field might be constrained by the pressure of the pipeline it produces into, or by the total gas rate that field compression provides, while a mature oil field may be constrained to fluid rates set by artificial lift.

First, the results of a status quo/no further action (NFA)/"do nothing" predictive case should be examined. This is a simulation case where the model is changed from being constrained by historical rate limits to the prediction stage but without any operational changes to the field such as adding new wells, introducing pressure support, etc. In such a case, the prior performance trends should continue. For instance, if gas wells were in rate decline before transitioning to predictive mode, but production flattens as the wells enter predictive mode, then this likely indicates an issue with the history match, or with the setup of the status quo case, and it calls into question the reliability of predictions from the model. **Fig. 6.4** illustrates a comparison of the actual history and the predicted NFA performance under two scenarios, only one of which appears to be reasonable.

Such a status quo/NFA case must itself be carefully constructed. The decline trend from a large field that has benefited from an ongoing program of drilling and well work will not be maintained if that activity is simply halted in the NFA case. In an instance such as this, it would be incorrect to expect the prior trends (which includes activity) to continue while knowing the investments stopped for the NFA case.

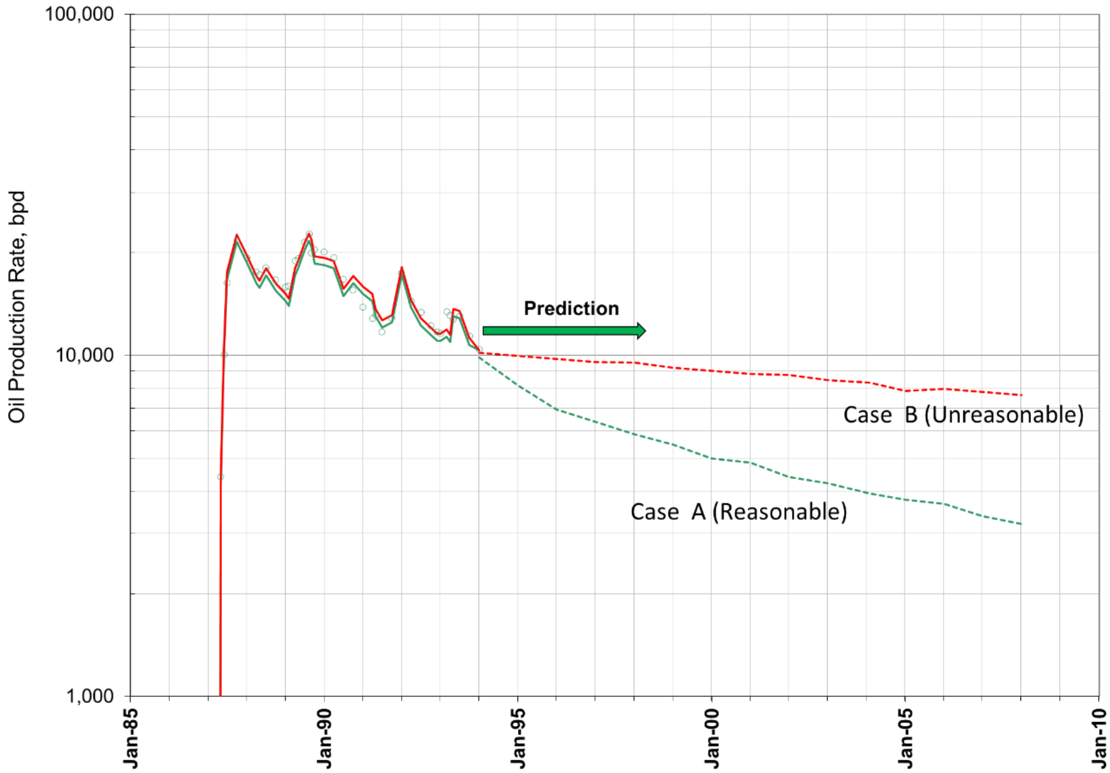

Fig. 6.4—No further action case with two forecasts.

Predictive case constraints for the status quo case, along with cases featuring further development options, should be carefully reviewed. The constraints imposed on the model in predictive mode should be representations of how wells or facilities will be operated in the future. However, it is relatively easy to generate results that are not realistic. For instance, wells placed on a constant liquid rate as their future constraint will produce at that rate until their flowing bottomhole pressure reaches an extremely low value (typically near 1 atmosphere). Such an outcome is usually unrealistic. Therefore, it is generally better to constrain wells with realistic surface pressure limitations during the predictive model runs, when such constraints are appropriate. Poorly implemented constraints, in particular, constant liquid or phase rate constraints, are likely to provide unrealistically high estimates of future recovery under many circumstances.

Fig. 6.5 shows one of the diagnostic plots frequently used in validating predictions. This prediction of oil rate and water cut (at the reservoir level) shows a "bump" in the oil rate occurring in year 2020. The source of this uptick should be investigated, and, if due to drilling, it should be determined whether these wells should be drilled earlier if it would benefit the project net present value. The water-cut signature should be smooth, and, if there are step changes or aberrations, they should also be explained.

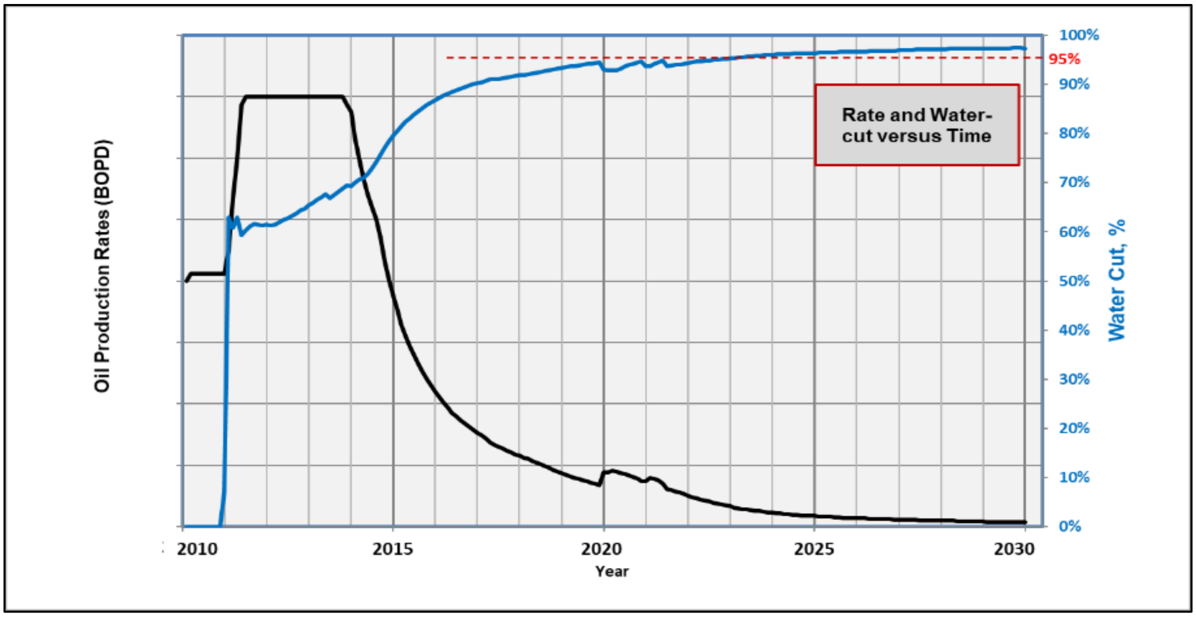

Fig. 6.5—Diagnostic plot of oil rate and water cut vs. time.

Further, Fig. 6.5 shows that, with the oil rate increase in the year 2020, there is a decrease in the water cut, suggesting that new wells or workovers in 2020 did not result in an incidental increase in water production. In other words, the new wells came on production at water cuts less than the average of the other producing wells. On the other hand, if the oil rate had been maintained but the water cut diminished, one possibility could be the shutting-in of high water-cut wells.

Fig. 6.6 shows the voidage replacement ratio (VRR), also called the injection-withdrawal ratio, from the output. Typically, the VRR rises as fill-up conditions are approached in the reservoir. Interpretation of such a graph assists the evaluator in waterflood monitoring and potentially improving both sweep efficiency and the project economics, by addressing questions such as:

- Are we injecting too much or withdrawing too little (VRR > 1)?
- Are we injecting too little or withdrawing too much (VRR < 1)?

Similarly, for a waterflood project, the VRR can provide an indication of whether the reservoir is processing too many (or too few) injected hydrocarbon pore volumes. With too few injected hydrocarbon pore volumes, the reservoir may not be swept efficiently; with too many, the operator could be damaging the economics of the project and the recovery. **Fig. 6.7** shows an example of the diagnostic plot with an ending injected hydrocarbon pore volume of 1.575, which suggests more could be injected than currently modeled. However, the flattening slope of the curve at 1.575 does indicate that the point of diminishing returns is being approached, and the economics of continuing the flood deserve careful attention.

When an oil reservoir is under active waterdrive or waterflooding operations, a key diagnostic plot is a semilog oil cut vs. cumulative oil production graph, as shown in **Fig. 6.8**. A similar plot of water cut vs. cumulative oil production becomes more difficult to check and extrapolate at high water-cut values, i.e., in the later stages of the operating life, as the curve is rising, the semilog scale narrows, and a limiting condition (e.g., water cut) cannot be readily identified. This situation can be improved by using oil cut or water-oil ratio plots instead. Shifts in the curve (such as shutting in high water-cut wells, drilling in bypassed oil areas, etc.) must be understood.

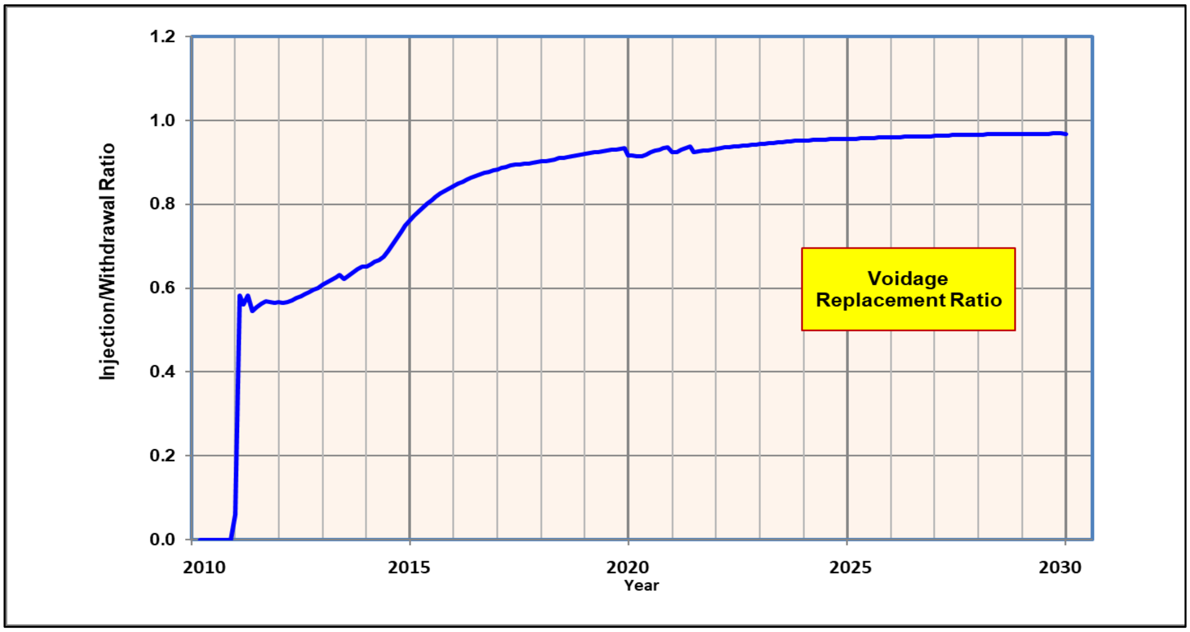

Fig. 6.6—Diagnostic plot of voidage replacement ratio.

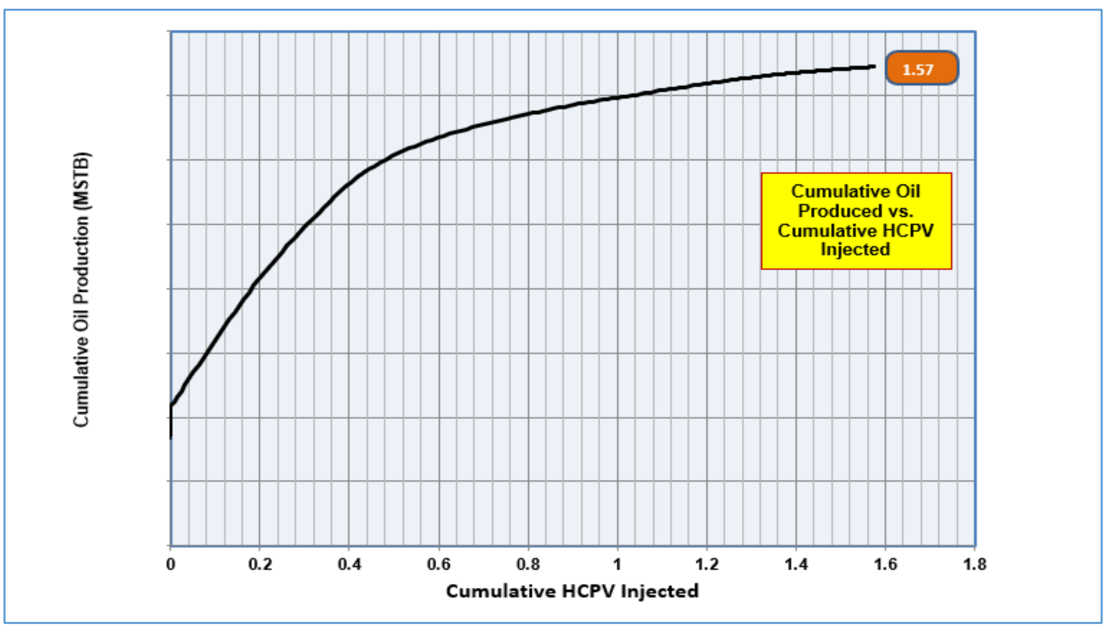

Fig. 6.7—Diagnostic plot of cumulative hydrocarbon pore volumes (HCPV) injected vs. cumulative oil production, where MSTB is million stock-tank barrels.

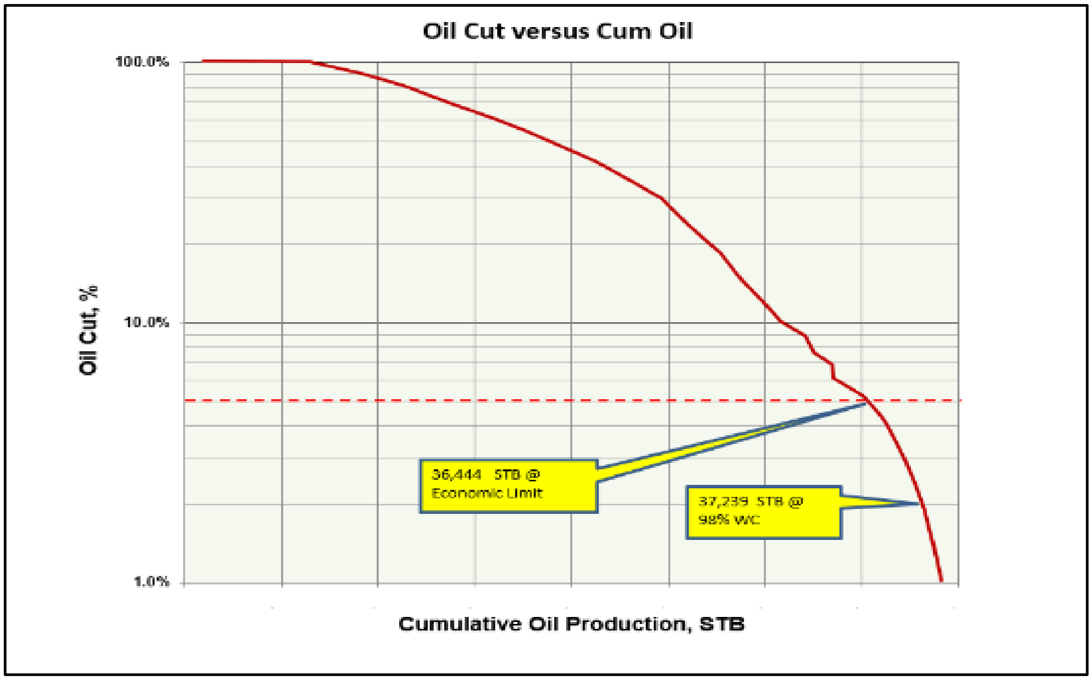

Fig. 6.8—Diagnostic oil cut vs. cumulative oil production.

6.5 Proved (1P) Reserves Cases

Evaluating Proved Reserves (as compared to 2P or 3P Reserves) for immature reservoirs requires special attention, regardless of the assessment method used (Palke and Rietz 2001). Notwithstanding progress made in the application of probabilistic approaches to reservoir simulation, in many cases only a single, well-calibrated, deterministic simulation case is developed. Such a model is much more likely to be consistent with a 2P scenario rather than a 1P scenario. This is the typical situation since simulation models serve many purposes other than reserves or resources estimation.

Simulation model cases can, of course, be developed that could be used directly to estimate Proved Reserves. However, constructing models that conform to limitations imposed on Proved Reserves estimates may require a significant amount of effort. For strict adherence to the reasonable certainty requirement, restrictions are placed on the geological modeling of Proved Reserves. For an immature reservoir, the entire geostatic model would need to be constructed honoring all constraints imposed for Proved Reserves volumetric estimates, such as not including any porosity-thickness (ϕh) greater than that observed in wells. Generally, this would imply an improvement of the reservoir quality beyond the actual data; improvement of porosity should not be allowed for Proved Reserves due to the reasonable certainty requirement. There are exceptions that allow for higher ϕh away from wells, such as when the subject reservoir is demonstrated by seismic interpretation to be structurally higher (e.g., above the oil-water contact), and so net thickness may increase. Provided the porosity is less than or equal to the porosity found in nearby wells, the thickness (hence ϕh) increase may be justifiable. Defendable seismic attribute mapping (see Chapter 3—*Seismic Applications* herein) may be used to justify improvements in reservoir quality <u>provided</u> the mapping has been ground-truthed in the area. Care must be exercised regarding hydrocarbon producibility and reservoir quality beyond well control such as the volume between flank wells and the structural limit. Other constraints include allowing no volumes in undrilled, potentially sealing fault blocks, and limiting the depth of contacts to lowest known hydrocarbon depths. Furthermore, the dynamic model would need to be carefully constructed to not overestimate the reasonably certain strength of the drive mechanism to improve the recovery process, to make sure that well productivity indices in the simulation model meet the required level of certainty, and that operating limitations are consistent with those likely to be achievable in the field.

In many cases, a model conforming to all the constraints described above cannot be constructed. In these instances, decisions should be made as to whether a model that is more consistent with a 2P outcome can be adapted for Proved Reserves estimation as discussed in the following sections, or whether another methodology would be better used for Proved Reserves estimation.

Proved Reserves estimates arising from simulation, whether from a model constructed specifically for that purpose, or following one of the approaches taken below, need to be examined carefully to ensure that they satisfy the requirement that Proved Reserves are reasonably certain to be recovered. For instance, simulation results that indicate a recovery factor for a reservoir that significantly exceeds recovery factors for analogous reservoirs should be investigated to review whether they are reasonably certain.

6.5.1 Adjusting 2P Results for 1P Reporting. It is widely recognized that, in many cases, a deterministic modeling approach will yield prediction results that are a "most likely" or "best estimate" case, thereby approximating 2P reserves (assuming compliance with the commerciality criteria). However, companies may need to report only 1P outcomes, in which case, the 2P output must be adjusted.

Adjustment of the deterministic model results may be performed in basically two ways:

- Modification of the input data to generate proved output
- Modification of the 2P output data to develop proved output

Each will be discussed in turn in the following sections.

6.5.1.1 Modification of Input Data. In this situation, the data provided to the model adhere to the *reasonable certainty* requirement for 1P reserves reporting. For example, when no water contact is otherwise identified, the 1P reservoir booking depth is predicated on the lowest-known hydrocarbon from the well logs within a structural trap. If a downdip well encountered the reservoir as wet, <u>and no pressure gradient data exist</u>, no water contact or free-water level can be interpolated between these wells. Consequently, a 1P model could be built containing no hydrocarbon accumulation below the lowest-known hydrocarbon.

Another possible means by which to constrain the dynamic model is to establish pay cutoffs and impose them in the model, thereby making the hydrocarbons in certain cells immobile. While disagreement exists in the industry about this practice, it is still widely applied in the industry.

Although modification of the input data serves to strictly honor the guidelines for Proved Reserves, it actually may introduce more uncertainty. For instance, by limiting the accumulation to a lowest-known hydrocarbon, water breakthrough may become difficult to match, possibly to the point of requiring other modifications that are not physically reasonable. Further, in history matching, the degree of pressure depletion measured in the field will either necessitate additional revision of the model PIIP and/or changes in the underlying aquifer size and strength. Imposing pay cutoffs in the dynamic model may create flow barriers or baffles and alter fluid migration paths and interwell pressure differentials and cause conformance problems. In some cases, these barriers to flow may improve the ability of the model to match performance, and in other cases, they may restrict the flow too much. Barriers and baffles should not be imposed merely to achieve a match unless there is supportive geoscience or engineering data for their existence.

6.5.1.2 Modification of Output Data. If a deterministic model (static and dynamic components) is created without 1P constraints, then the resulting output will usually reflect a "most likely" or "best estimate" scenario as noted previously. There are several ways by which we can adjust the output to honor a 1P evaluation.

The first method assumes that the model serves as its own analog. In this scenario, the model output enables the calculation of a recovery efficiency (model recovery divided by model PIIP reflecting relevant petrophysical cutoffs). The resulting recovery efficiency or recovery factor (RF) should be compared against other analogs or analytical methods to ensure it is within the expected range, and it should be adjusted if it is not within that range. (Further adjustment of the RF may be necessary if there are concerns about, for example, the reservoir continuity or quality away from the current well control points.) A 1P estimate of PIIP (likely from a volumetric assessment) can then be assumed, and the modeled RF may be applied to arrive at the 1P ultimate recovery. The output rate forecast will have to be adjusted to honor the 1P ultimate recovery.

Such rescaling requires careful consideration. It is usually inappropriate to simply rescale the entire production curves for each phase up or down. Further, care needs to be taken that if the model is run out to a technical limit, then the RF achieved is likely larger than the effective RF at economic limits. Therefore, it would be expected that the ultimate recovery from the adjusted production curves would end up being diminished by the application of the economic limit.

A second method also requires review of the model production forecast. In the Petroleum Resources Management System, Table 3 spells out how to characterize undeveloped locations (wells) that would be considered Proved relative to those incremental locations considered as Probable or Possible. Similarly, if the model contains multiple reservoirs, some of the reservoirs themselves may be categorized as Probable or Possible, incremental to the Proved reservoir. In this scenario, any predicted recovery from undeveloped locations or reservoirs that would be categorized as anything other than Proved would be subtracted from the total model production profiles and ultimate recovery to develop a Proved production profile. Fortunately, most commercial simulation code can be configured to quantify and report exactly those wells and intervals that produced hydrocarbons during the forecast, making it relatively easy to estimate the amount of production that is arising from non-Proved sources, and allowing it to be subtracted from the otherwise 2P forecast to provide a 1P forecast.

As a reminder, care needs to be taken to differentiate quantities that are technically recoverable according to the simulation model from those that honor economic or contractual limitations.

6.5.2 Further Comment on Adjusting 2P Results for 1P Reporting. Both of these methods have their disadvantages. In the first (modification of input data), the RF that is back-calculated may not be limited to the quantities considered Proved; recovery from the model may include volumes from lower-quality, higher-water-saturation content rock that—without being isolated from the Proved volume—likely would result in a lower RF than the higher-quality, lower-water-saturation content rock alone. For example, in a structural trap, the development wells may be positioned at the crest, while the flanks represent reservoir rock increasingly deeper within the transition zone. Overall, the RF from deeper pore volume should be less than the RF associated only with the better-quality rock higher in the transition zone (or even in the dry oil zone only). Consequently, the back-calculated RF from the model is expected to be more representative of the 2P or 3P RF, which could be lower than the 1P RF. Under some circumstances, application of this first method will yield conservative 1P quantities.

In the second approach (modification of the output data), simply removing the production from non-Proved wells does not remove their effect on the flow streams within the model. Probable and/or Possible producers nonetheless create pressure sinks, which alter the path, magnitude, and even composition of the production from the Proved wells; this is a major concern when treating the recovery on an incremental as opposed to a cumulative basis. Special consideration should also be given as to whether a model that includes an element of nodal analysis, such as a shared surface gathering network, is appropriately modeled when the probable volumes or wells are removed from the production streams.

6.6 Other Output from Simulation

A frequently requested result from a simulation model is the average formation volume factor. For ease of discussion, we will refer to an undersaturated oil reservoir and the calculation of an average initial single-phase B_{oi} in reservoir barrels per stock tank barrel (RB/STB). To support and be consistent with a volumetric estimate, the hydrocarbon pore volume and PIIP both must be calculated using pay cutoffs. Provided that the values for these quantities match within approximately 5% between the static and dynamic models (judged without pay cutoffs), either source could be used for the calculation, but it is generally easier to impose pay cutoffs in a static model. Provided the values with cutoffs can be obtained, dividing the hydrocarbon pore volume by the PIIP will yield a reasonable B_{oi} (in RB/STB) that may be used in volumetric documentation.

Similarly, the recovery efficiency must be based on the volume of hydrocarbon that initially is located within rock of high enough quality to flow (rock volume considered pay after the application of petrophysical cutoffs) under the planned development operation. Simulation output does not usually yield "reserves," as there has been no economic or commerciality evaluation performed at that stage. The forecast production from simulation provides only the Technically Recoverable Resources. When the simulation forecast is incorporated into a suitable economics program, and the economic limit is estimated, the reserves will be determined (subject to other constraints, such as technical or contractual). This volume will then be divided by the PIIP (using pay criteria) from the model to arrive at the recovery factor to be used in volumetric calculations. Note that this RF represents a project area RF and is not necessarily reflective of a per-well RF, the difference between which is more pronounced in unconventional reservoirs. As pointed out earlier, division of the production forecast into 1P/2P/3P categories will likewise influence the associated recovery factors.

6.7 Acknowledgments

Thanks are owed to our employers in availing the time and resources to produce this chapter.

6.8 References

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Chapter 7

Probabilistic Resources Estimation

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7.1 Introduction

The prediction of reservoir properties and quantities (such as petroleum initially in place and Technically Recoverable Resources) is subject to uncertainty due to the limited reservoir sampling provided by data control points (e.g., wells), yet these predictions are major determinants in reservoir performance forecasting. These production forecasts are then used for decision making, driving investment in future projects where, in many cases, large sums of capital are required.

Industry uses various methods to understand and quantify the impact of reservoir uncertainty on production forecasts and estimates of resources. These vary from purely deterministic methods, where single values of each parameter are considered, to multi-scenario methods (hybrid methods considered an extension of deterministic methods), to fully probabilistic methodologies, where input parameters (e.g., porosity) are defined by probability distributions that are then combined to obtain cumulative distributions of the outcomes (e.g., in-place estimates).

The purpose of this chapter is to provide technical guidance on the use of probabilistic methods for resources and reserves estimation compliant with the Petroleum Resources Management System (PRMS 2018) guidelines. Deterministic reserves estimation is explained in detail in Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* herein and will be referenced throughout this chapter.

Resource evaluators often use deterministic methods to produce a "best estimate" of reserves and resources based on a defined "base case" reservoir model. The result of this deterministic base case model is usually close to the P50 estimate of the output quantity (where 50% of the estimates exceed the P50 estimate). When using deterministic methods, low, best, and high estimate cases are derived to assess the influence that a downside or upside of the input parameters could have on the best estimate outcome. As with the best estimate and the P50 case, the selection of these cases does not necessarily correspond to a 90% (P90) or a 10% (P10) probability of occurrence despite the terms often being used interchangeably. When a probabilistic model of the same project is assessed and compared with the outcomes from the deterministic approach, the resultant P90, P50, and P10 scenarios should, however, reconcile with the low, best, and high estimates, respectively (PRMS § 4.2.3.3). For example, the review of contacts and areal extent are common items where such reconciliation may need to occur. Section 7.7 of this chapter discusses comparison of the results from the two methods.

Although the deterministic approach is preferred by many evaluators due to its relative ease of use and transparency, some of the difficulties with this approach relate to the natural tendency of practitioners to aggregate upsides and downsides of the inputs for the level of confidence of the forecast referenced. Combining all the "low-end" or the "high-end" values of the input parameters can result in low cases that are too pessimistic or high cases that are too optimistic (and would have more than 90% probability for the downside and less than 10% probability for the upside).

This topic is discussed in more detail in Chapter 8—*Aggregation of Reserves and Resources* herein. Differences between the low deterministic estimates (1P, 1C, 1U) and P90 estimates can be substantial, with similar issues for the high estimates (3P, 3C, 3U) compared to the P10 estimates. In probabilistic methods, the outcome of the analysis is P90, P50, and P10 estimates that can be used for the 1P/1C/1U-2P/2C/2U-3P/3C/3U reserves/resources ranges, ensuring that values correspond to the level of confidence required by the PRMS guidelines.

There are different probabilistic methods, and the applicability of each is related to the phase of the field development. Methods more appropriate for the exploration phase include pure Monte Carlo simulation (MCS), multi-scenario, or multiple realizations approaches (such as a hybrid mix containing deterministic and probabilistic aspects), and experimental design with global optimization methods are more suited for fields that are in the development phase, where production exists, as observed in **Fig. 7.1.**

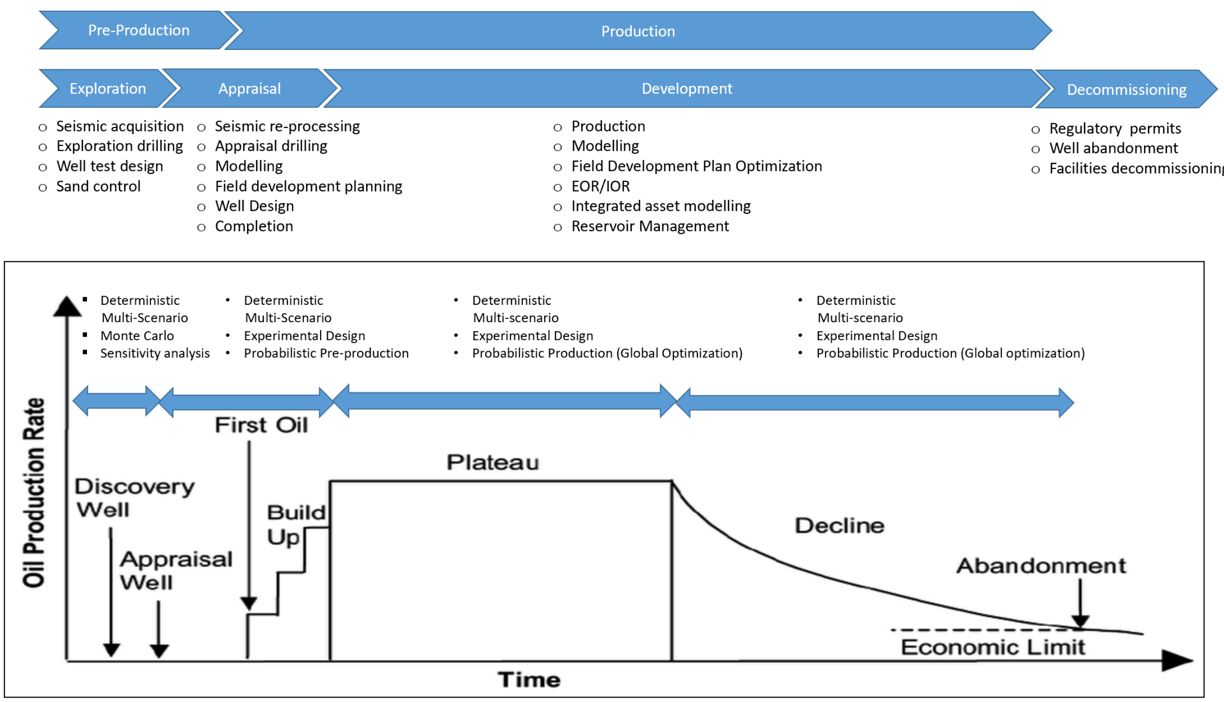


Fig. 7.1—Generalized field life cycle with associated probabilistic methods. EOR/IOR = enhanced oil recovery/improved oil recovery.

As more performance data become available, the deterministic method is more frequently used; however, in several situations (as shown in Fig. 7.1), some of the probabilistic methods are still applicable.

The selection of the appropriate probabilistic method with which to estimate reserves and resources depends on multiple factors, including:

- The type, quantity, and quality of geoscience, engineering, and economics data available and required for both technical and commercial analyses
- The reservoir-specific data, including, but not limited to, the geologic complexity, the recovery mechanism, the stage of development, and the maturity or degree of depletion of the reservoir
- The knowledge and judgment of experienced professional evaluators, which are not to be underemphasized when relying on reserves and resources assessments for decision making

Fig. 7.2 shows the most common probabilistic methods. The application of the methods is related to the development phase of the field as shown in Fig. 7.1. Simpler approaches such as Monte Carlo methods are often used during exploration and appraisal phases, while other techniques such as experimental design (ED) methods are used from the appraisal to the development phases (Section 7.5.2). There are more sophisticated methods such as stochastic optimization or ensemble Kalman filter methods (Section 7.5.3) that should be used once production data are available.

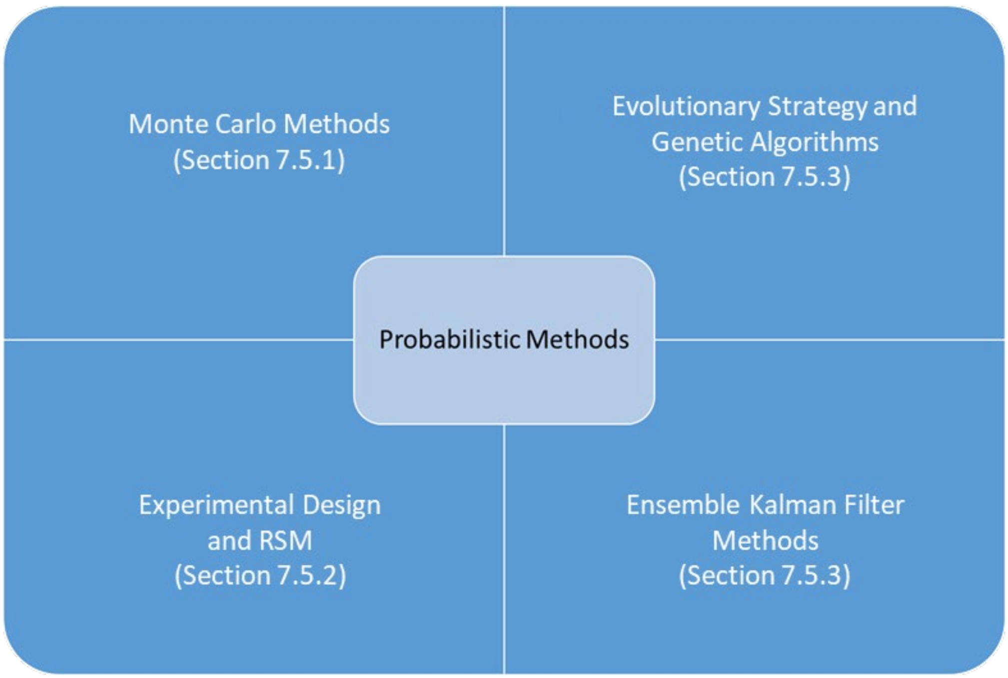


Fig. 7.2—Probabilistic methods (where RSM is response surface model).

It must be stressed that, in most cases, the outcomes of the probabilistic method are P90, P50, and P10 estimates of Technically Recoverable Resources (TRR). This estimate of TRR must be converted into a forecast (i.e., production rate vs. time) for each of the low, best, and high cases. After satisfying the commercial conditions required in PRMS § 2.1.2 and § 3.1, these P90, P50, and P10 forecasted quantities become the 1P, 2P, and 3P Reserves. The commercial considerations are key factors and must not be overlooked when using deterministic or probabilistic methods to classify recoverable quantities as reserves.

7.2 Resources Uncertainty

Recoverable resources are a function of multiple uncertain parameters (e.g., areal reservoir extent, pay thickness, porosity, permeability, etc.). Uncertainty may be due to several sources, including measurement error, modeling, or incomplete data sets. Uncertainty also can be related to lack of knowledge, for instance, fault geometry and/or extent, which may be resolved (or diminished) by acquiring more data (e.g., drilling another appraisal well). Uncertainties are also related to the inherently random nature of some reservoir properties, such as permeability, with values affected (for example) by grain size, stratigraphic units, cementation, or fracturing. In the case of variability due to reservoir heterogeneity at different scales, data collection might not always help to reduce uncertainty.

Uncertainty in data acquisition/processing is often small compared to that of characterizations and data population in reservoir models (see Chapter 6—*Reservoir Simulation* herein).

7.2.1 Uncertainty in Input Parameters. To evaluate the uncertainty in resources estimates, we first should look at the sources of uncertainty and their influence. **Table 7.1** outlines the major parameters used in volumetric calculation of recoverable resources, their sources of uncertainty, and their influence on the resources estimates.

Input Reservoir Parameter	Major Sources of Uncertainty	Comments
Gross Rock Volume (GRV)	• Reservoir limits/area • Time to depth conversion • Existence/position of faults • Migration through faults	A major source of uncertainty for volumetric methods. The GRV depends most critically on the height of the hydrocarbon column and increases proportionally with the cube of the column in an anticline.
Net to gross (NTG) and porosity	• Rock heterogeneity • Diagenesis • Small scale • Depositional environment	Determined through petrophysical evaluation, core measurements and seismic response. Porosity depends on many factors, including the rock type and how the grains of a rock are arranged. Logs and core samples are representative of limited portions of the subject rocks.
Water saturation	• Lack of core data • Limited log data • Model uncertainty	Uncertainty exists when water saturation is calculated from limited core (e.g., electrical properties, capillary pressure) or log data. Further, there are a number of models (e.g., dual-water, Simandoux) that can produce different S_w results.
Fluid properties	• Limited fluid samples • Data after production • Sampling issues • Storage issues • Production allocation	Lack of sampling of fluid at initial reservoir conditions causes uncertainty. Good quality, representative samples and accurate lab analysis are required to accurately model reservoir fluids. Fluids stored in unpreserved conditions, such as in a warehouse, are not likely to be representative of the reservoir fluid. Lack of production data per reservoir could also cause uncertainty.
Recovery factor	• Reservoir heterogeneity • Fluid properties • Development plan • Project execution	Recovery factor/efficiency will be affected by project execution, reservoir geology and fluid properties amongst other factors. Accuracy of the reservoir characterization impacts the efficiency of the development plan and the resultant recovery. Reservoir models are used to assess the impact of key reservoir uncertainties and estimate resources ranges through sensitivity analyses.

Table 7.1—Sources of uncertainty for volumetric estimates.

The evaluator needs to define not only the key uncertainties, but also their reasonable ranges and the type of distribution. Ranges should be defined based on the geoscience information or on analogs if data are not available. Distributions should be selected to represent the data and/or analog models, avoiding extrapolations beyond the understanding of the reservoir. Typically, normal and log-normal distributions are used with truncation applied to avoid infinite tails. Uniform distributions are used when data are limited, while triangular distributions are often used if data are limited and ranges are narrow. Independent of the distribution used, it is important to ensure that ranges are wide enough to consider the potential outcomes. A common mistake is to limit the ranges based on data from the subject project, especially during exploration, ignoring data ranges from analog reservoirs. Another aspect to consider is dependency; uncertainties among parameters controlling reservoir performance may not be independent. In many cases, there are dependencies between uncertainties (Carter and Morales 1998) that can cause unexpected and significant deviations from expected project outcomes, if they are not taken into account (e.g., porosity and permeability).

Evaluators need to spend time trying to understand the influence of these subsurface reservoir uncertainties, together with facilities and other constraints, on the estimation of resources quantities.

7.2.2 Project Uncertainties. Some authors (Acuña and Harrell 2000; Wheaton and Coll 2010) have grouped project uncertainties that should be considered during the resources evaluation process into three main groups: technical, project maturity, and economic.

7.2.2.1 Technical Uncertainty. The ranges for geological and engineering uncertainties described above are typically very large before discovery, primarily impacting prospective resources, and generally narrow through the appraisal and production phases.

Technical uncertainties mainly refer to geological and engineering parameters related to the subsurface and surface aspects of the project. Geological uncertainties related to the volume of hydrocarbons (e.g., gross rock volumes, net-to-gross ratio, porosity, hydrocarbon saturations) have a large influence on the in-place estimates as described before. Engineering uncertainties (e.g., drive mechanism, relative permeability, capillary pressure, viscosity, development plans, surface facilities, well spacing) influence the quantity of hydrocarbons that can be recovered through a particular process and therefore will be key factors in the estimation of resources.

Project investment decision making is largely influenced by technical subsurface uncertainties that can put at risk large sums of capital investment. The range of these technical uncertainties can make the difference between project success or failure, stressing the importance of understanding the uncertainties and associated risks for the project. (Note that this also applies to deterministic methods.) Legal, contractual, and regulatory aspects as well as social and environmental aspects should be considered (PRMS § 2.1.2.1).

7.2.2.2 Project Maturity Uncertainty. Project maturity concerns the classification and sub-classification of resources based on contingencies and uncertainties. Uncertainty related to legal, contractual, regulatory, governmental, working interest entities, market availability, or transportation elements, along with the time required for full field appraisal, could, following discovery, represent a significant uncertainty for potential value.

7.2.2.3 Economic Uncertainty. Future prices and costs (development and operating) represent another type of uncertainty with a large influence on the economics of a project and therefore on the commercial viability of a project for reserves estimation.

Economic uncertainties are mainly related to uncertainty in economic parameters used to evaluate a project such as price and costs, and this may be addressed with sensitivity scenarios; however, an evaluator needs to be careful because the PRMS does not allow split conditions (i.e., the same commercial conditions must be applied to the different categories within a resource class). Companies take great effort to define ranges of forecast price scenarios that can be used for the internal investment process and used for sensitivity cases. Economic evaluation is based on the entity's reasonable forecast of future conditions that will exist during the life of the project. Economic evaluation is discussed further in Chapter 9—*Evaluation of Petroleum Reserves and Resources* of this volume.

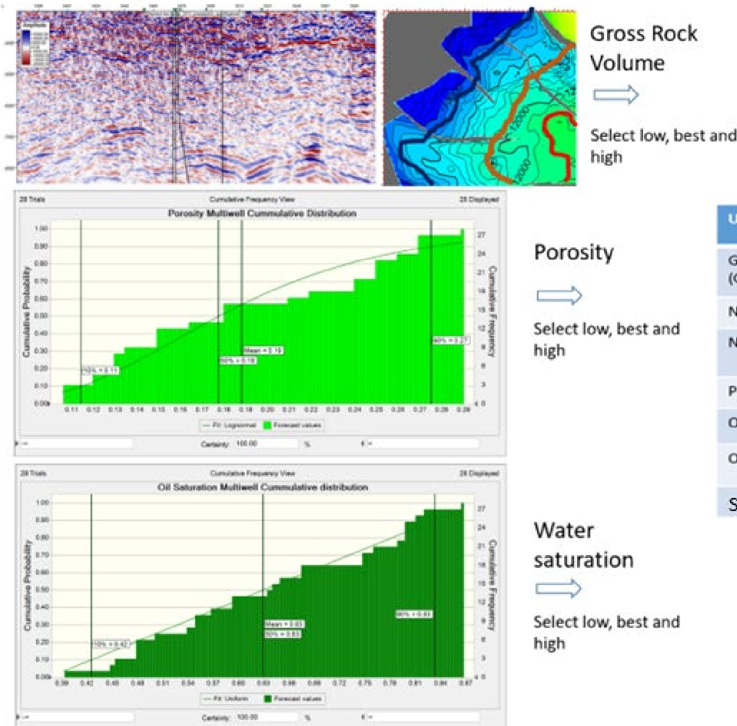
7.3 Deterministic Methods

The PRMS defines the deterministic approach as an "assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty" (PRMS Appendix A, Glossary). Deterministic methods are applied by making discrete estimates of hydrocarbons initially in place or recoverable quantities, each based on a single set of input parameters.

7.3.1 Deterministic Analysis. The results of a deterministic analysis can be a single best estimate, or they can be sensitivities of the best case representing a range of resources outcomes (i.e., the low and high cases). To understand how each uncertain input reservoir parameter influences the outcome, the evaluator can use a sensitivity analysis (the deterministic scenario method), where "the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario" (PRMS § 4.2.1.2). The selection of the best estimate for each input parameter may be straightforward. The parameter selection should be agreed upon by a multidisciplinary team with the objective of appropriately representing resources uncertainty. A more difficult task is to select the combination of input reservoir parameters to use for the low and high cases to produce realistic low and high resources estimates.

An example of the application of simple deterministic methods is shown in **Fig. 7.3.** As tabulated, three values (low, best, and high estimates) are developed for each uncertain input parameter, based, if possible, on distributions of reservoir properties derived from available information and analogs.

Some of the advantages of making discrete deterministic estimates are that the results are reproducible, fast to implement, auditable, and transparent in honoring resources guidelines constraints (e.g., lowest known hydrocarbon, proved area), the results reflect a combination of static and dynamic parameters that can physically exist, and they are relatively simple to prepare. These methods allow input parameters to be selected that help to eliminate any inconsistent (nonphysical) combinations of properties. Further, these methods are simple to interrogate and, therefore, are popular among investors, companies, and regulatory agencies. However, to estimate confidence levels associated with these reserves/resources estimates, hybrid deterministic or probabilistic approaches should be used.



Uncertainties	Units	Low	Best estimate	High
Gross Reservoir Volume (GRV)	1000 Acre-ft	700	1300	2100
NTG	%	40	65	84
Net pay thickness	ft	120	190	250
Porosity	%	11	19	27
Oil saturation (So)	%	42	63	83
Oil shrinkage (1/Bo)	v/v	0.7	0.8	0.9
STOIIP	mmbbls	70	595	2760

Fig. 7.3—Deterministic estimation for in-place volumes, where NTG indicates net-to-gross ratio and STOIIP indicates stock tank oil initially in place.

7.3.2 Sensitivity Analysis and the Multiple-Realizations Method. Sensitivity analysis consists of using deterministic runs to evaluate the potential influence of various parameter uncertainties. Changes are performed to one parameter at a time on the best estimate parameters. These sensitivities are typically run using the low and high values for each parameter, and the impact on the response variable under evaluation is observed (e.g., recoverable volumes). Sensitivity analysis is an integral part of probabilistic methods to estimate recoverable resources. This allows the evaluation of the key uncertainties and their impact on the outcome variable. Plots such as tornado diagrams are used for this purpose (as explained below) to determine the key uncertainties.

The multiple-realizations method (often called multi-deterministic scenarios method) is essentially an extension of the deterministic scenario method described in Section 7.3.1, combining the main advantages of the deterministic approach with those of a simple Monte Carlo approach (see Section 7.5.1). The multiple-realizations method involves the identification of key parameters (static and dynamic) from a sensitivity analysis, which are then ranked to identify those with the greatest influence on the outcome (e.g., hydrocarbon recovery). The use of tornado diagrams in identifying key parameters has been widely addressed (e.g., Twartz et al. 1998; Van Elk et al. 2000; Vahedi et al. 2005) and should be considered in sensitivity studies and uncertainty reduction, thereby simplifying the overall estimation workflow. This analysis results in the generation of multiple physically realistic reservoir descriptions (or realizations) that can be reconciled with specific probabilities while meeting certain constraints (e.g., fluid distribution limited by fluid contacts or lowest known hydrocarbon, or dealing with unpenetrated fault blocks). These realizations can then be used to calculate a cumulative distribution function (CDF) as opposed to three discrete scenarios generated from a deterministic scenario method. From the CDF, the evaluator can select scenarios with at least a 90% probability for the low case, 50% for the best case, or 10% for the high case in terms of quantities actually recovered.

The main advantage of this method is to help establish a sound and well-structured uncertainty assessment and management process with a transparent audit trail while honoring the physical understanding of the models and realizations. However, an exhaustive analysis and quantification of the effect of key uncertainties is not feasible if there are large numbers of parameters and combinations to consider, such that the time required for data preparation and computation becomes unrealistic. During recent decades, the multiple-realizations/scenario method has evolved into what is now widely used and referred to as the experimental design method or EDM, which is a more practical option (see Section 7.5.2).

In the multiple-realizations method, the steps are:

(1) Identify the key uncertainties that significantly affect the outcomes through a sensitivity analysis.
(2) Establish discrete ranges of outcomes for key parameters with their chance of occurrence.
(3) Build a realization tree.
(4) Derive a pseudo-CDF.
(5) Select P90, P50, and P10 outcomes.

Tornado diagrams are constructed using the results of a sensitivity analysis in which one parameter is varied at a time from the base case while keeping all the other parameters unchanged. Each parameter is set to a "low" and a "high" value, and the response variable is measured [e.g., oil in place, ultimate recovery, or net present value (NPV)]. The range of variation of the response variable is captured on the *x*-axis, and parameters are ranked from largest variation down to smallest. A threshold in the variation can be chosen to bracket the most important parameters.

Fig. 7.4 shows an example of a tornado diagram where, for this specific case, the gas initially in place (GIIP) uncertainty range is being studied. In this example, the most impactful uncertainties are the structure (e.g., due to time-depth conversion uncertainty) and the position of the gas-water contact (GWC), as well as reservoir properties such as porosity combined with net-to-gross thickness ratio. These key uncertainties significantly affect the value of the parameter under evaluation (in this case GIIP) with more than ±25% impact. This assessment must ensure that the key parameters with large impact are identified, so further analysis avoids spending time on sensitivity studies of variables with negligible impact.

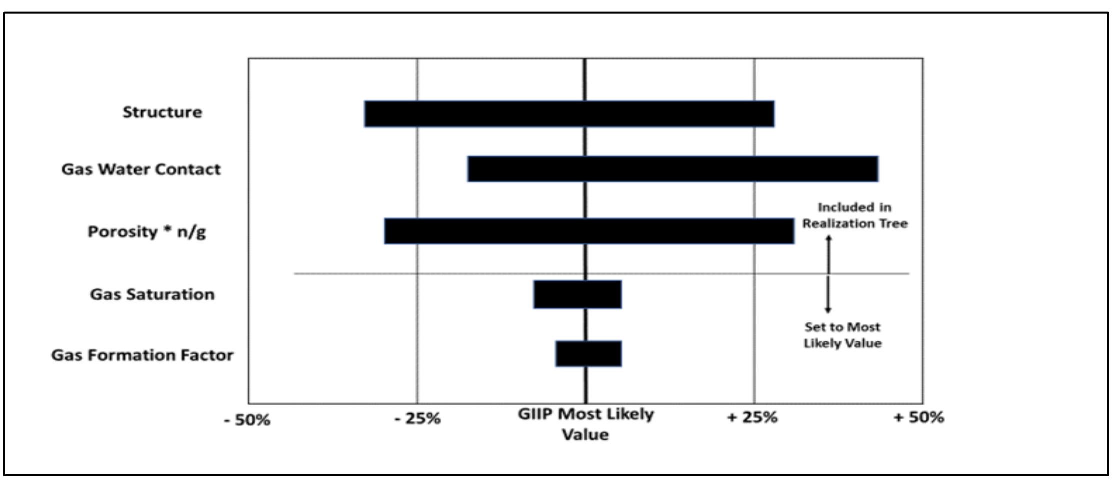


Fig. 7.4—Tornado diagram for parameters impacting gas initially in place (Twartz et al. 1998, simplified).

Similarly, **Fig. 7.5** shows an example of a tornado diagram highlighting the key uncertainties in the estimation of gas recoverable volumes. In this case, the key variables are GIIP, aquifer support, and cross-fault transmissibility.

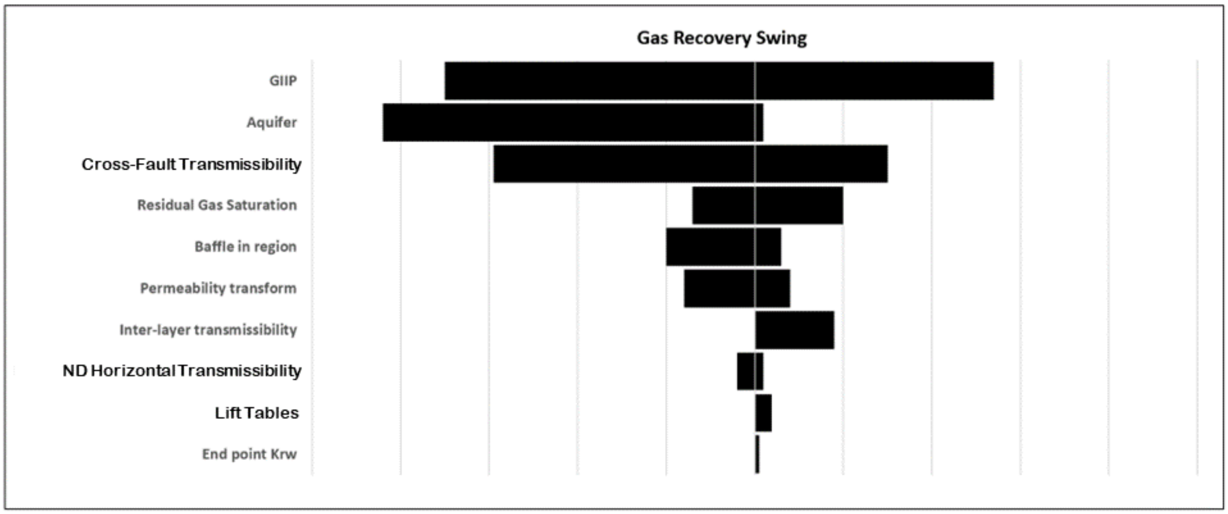


Fig. 7.5—Tornado diagram for parameters impacting gas recoverable volumes (Twartz et al. 1998, simplified).

This approach can be easily implemented and is most valuable when investigating the effect of uncertain input parameters in the outcome (static or dynamic) in a multi-scenario approach.

One of the main limitations of this method is that each calculation only considers the effect of one input uncertainty at a time and ignores all potential interdependencies and interactions. The interdependencies between input reservoir parameters can be an important factor in the outcome of the analysis. On the other hand, changing two parameters simultaneously from the base case makes this method cumbersome as the number of simulations increases, but there is no set systematic methodology with which to decide the number and the combinations that should be attempted. It is recommended that interdependencies of parameters be carefully evaluated during reservoir characterization so the selected workflow takes into account these key interactions. Such interactions can have a more important effect than the individual uncertainties. An exhaustive evaluation of the impact of these interdependencies is time-consuming and computationally intensive, particularly in mature projects requiring numerical simulation and history matching. However, such an evaluation can be accomplished using commercial software that combines all parameters as part of a probabilistic workflow, minimizing the manual process of setting up all the numerical simulation runs.

7.4 Hybrid Methods

7.4.1 Probability Tree Analysis. Probability tree analysis is similar to the multiple-realizations method described previously, where the nodes in the decision tree represent realizations of key uncertainties shown in the tornado diagram (i.e., the most important ones), but it has the advantage of assigning a probability to each realization. **Fig. 7.6** shows an example of this method used to estimate recoverable volumes compared to a multiple-realization approach. Three different static reservoir models were built based on three structural model realizations (low, middle, and high) using different time-to-depth conversions and variable GWCs, two of the key uncertainties impacting the GIIP in Fig. 7.4. Two GWCs were considered for each structural realization based on a low and a high GWC value to generate six GIIP realizations. Ranges of recovery factors could then be estimated for each static realization using tornado diagram analysis of key uncertainties as explained in Fig. 7.5. This generated ranges of TRR for each static realization.

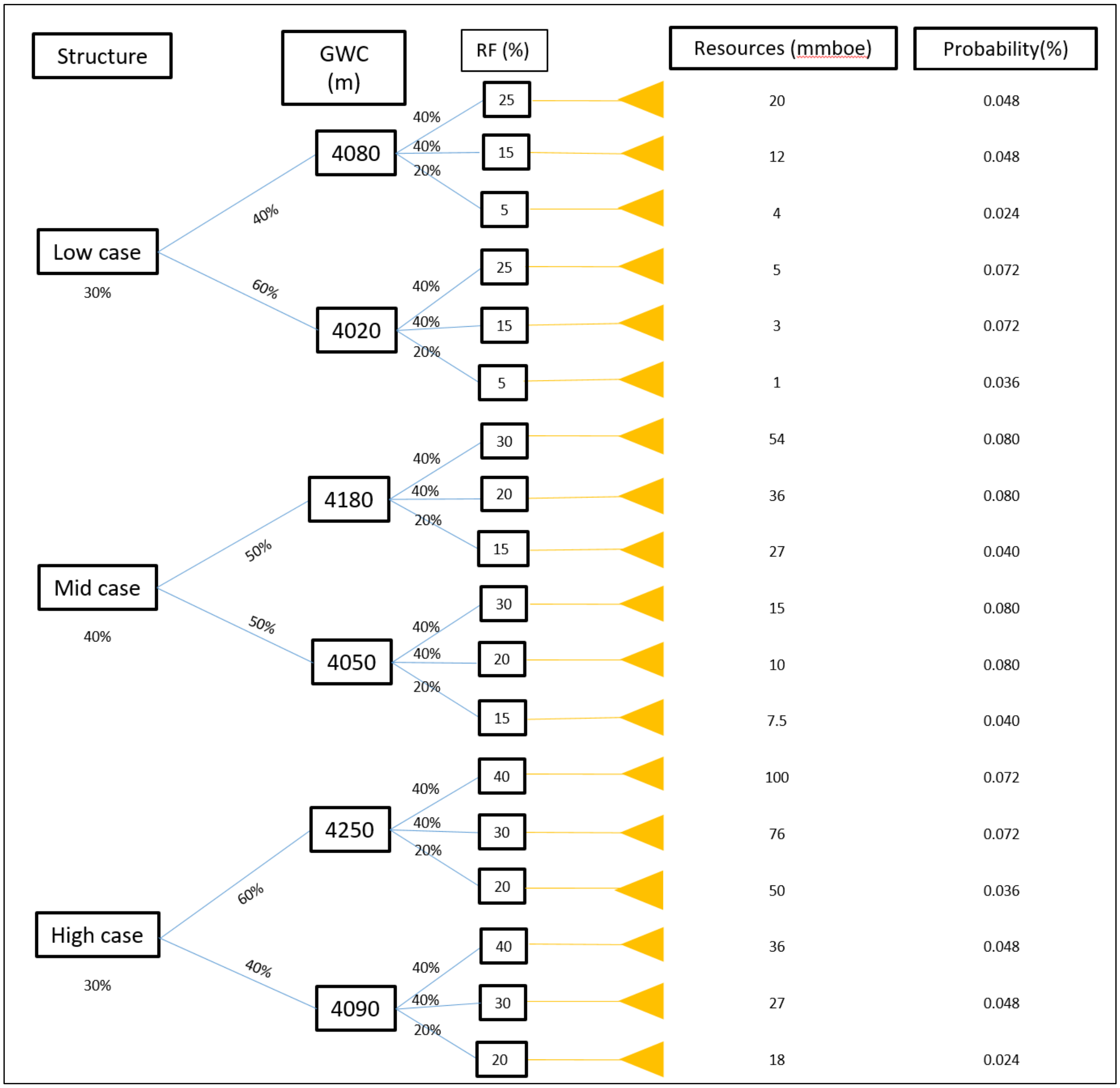


Fig. 7.6—Probability tree analysis for Technically Recoverable Resources (TRR), where RF is recovery factor.

The combined probability for a branch was estimated and plotted against the recoverable volumes using a reverse CDF as shown in **Fig. 7.7**. Results show that the P50 estimate is close to 22 MMSTB, whereas the P10 and P90 estimates are 80 MMSTB and 4 MMSTB, respectively. However, it must be pointed out that, while selecting an estimate from a probability tree analysis (e.g., TRR from Fig. 7.7), values will not necessarily be linked to a subsurface realization but to an extrapolation between two scenarios. For instance, the P10 TRR in Fig. 7.7 does not exist physically but is an extrapolation between realizations, so the closest realizations available should be identified to help define a P10 case taking into account assumptions that are consistent with the guidelines, for instance, fluid contacts such as the lowest known hydrocarbon and GWC.

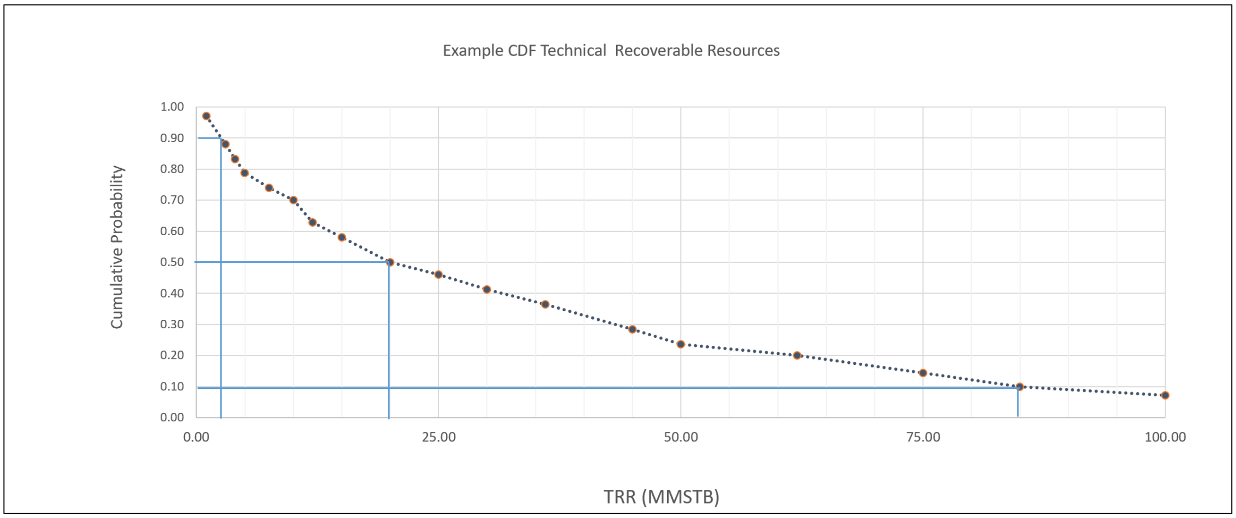


Fig. 7.7—Reverse cumulative distribution of TRR using decision tree analysis.

The application of probability tree analysis is probably more familiar through its use with decision making under uncertainty. One such application occurs during field development by looking at, for example, the expected monetary value because it allows assessment of alternative options that may maximize the outcome (e.g., recoverable resources volumes or project value). For example, **Fig. 7.8** illustrates an example of a prospect with sparse two-dimensional seismic data across the area of interest, where the seismic survey was run as part of an area survey around another, existing, field. The accumulation in question has not yet been drilled. A decision tree is developed to understand the economic impact of acquiring new three-dimensional seismic data vs. drilling an exploration well without additional seismic surveys. The expected monetary value of drilling an exploration well using three-dimensional seismic information is estimated at USD 18 million compared to an expected monetary value of USD 14 million for drilling the exploration well without acquiring the three-dimensional seismic data (assuming a simple discount net back of USD 1/bbl).

Probability tree analysis is a useful tool to provide a CDF of resources when multiple geological scenarios are considered. This method has become popular during exploration, appraisal, and early stages of development to evaluate the economic benefits (such as the potential to identify larger quantities of petroleum initially in place) of data acquisition relative to the cost required (such as acquiring three-dimensional seismic data or drilling a well) to obtain that data for value of information decision analysis. The method offers user-friendly graphical representations to help with the analysis and is intuitive to use. However, its accuracy is related to the assignment of the probabilities for each branch, which are selected by the evaluator and therefore subjective. A recommended approach is to conduct framework sessions with the multidisciplinary team to agree on the probabilities to use.

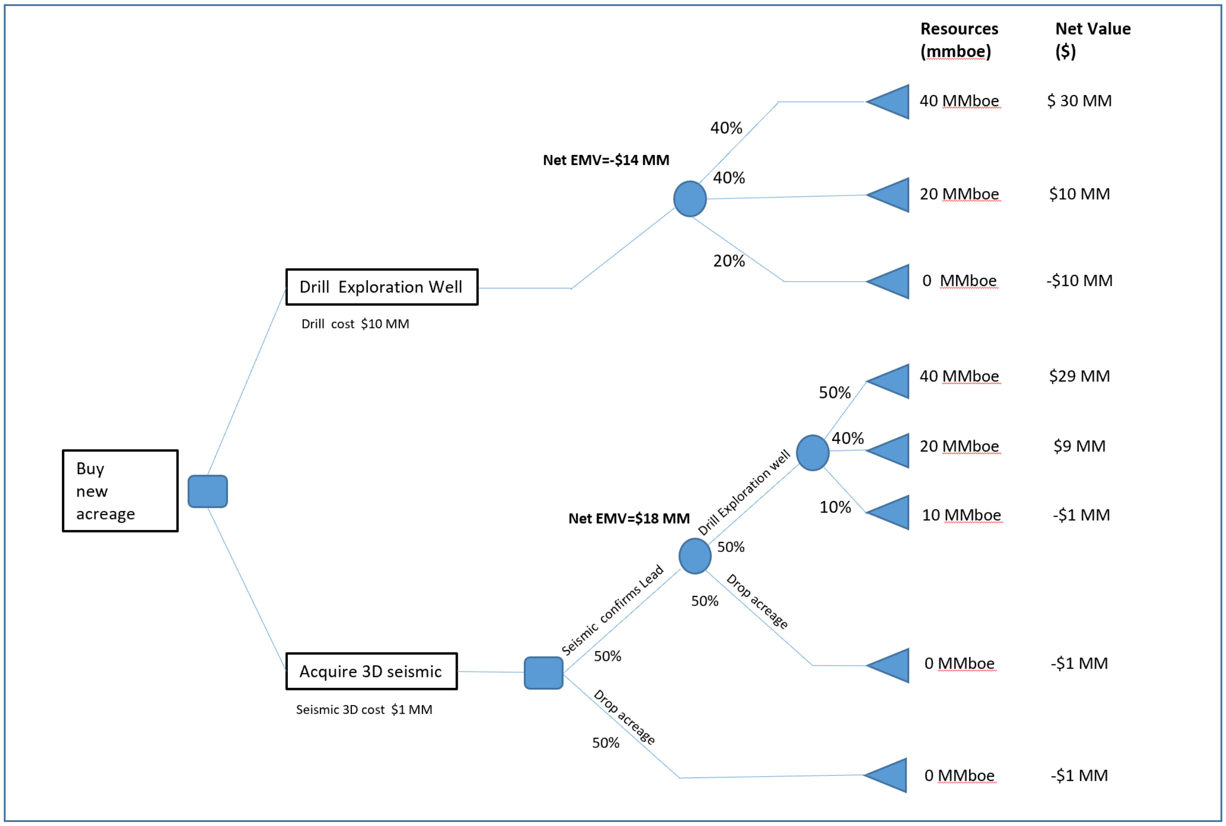


Fig. 7.8—Example expected monetary value (EMV) probability tree for exploration well.

7.4.2 Multi-Scenario Method. The sensitivity analyses described in the previous section focused on reservoir properties. However, there are also uncertainties related to the field development plan, such as size of processing facilities, number of wells, delivery pressures, etc. Different development scenarios can be selected that are technically feasible combined with different subsurface realizations (Twartz et al. 1998; Van Elk et al. 2000). For instance, well optimization can be a key uncertainty requiring evaluation because it will affect well count and well spacing, which will determine sales volumes; other factors include delivery/arrival pressures, minimum tubing head pressure, and compression facilities. All will affect the development plan and production forecast.

An example of combined scenarios that are often considered during field development planning is shown in **Table 7.2.** It is a common practice to run different development scenarios using petroleum initially in-place (PIIP) ranges and then consider other variables that will affect TRR (such as through the use of tornado diagrams). The number of scenarios to be considered will depend on the project characteristics. As the number of parameters to be considered increases, so do the number of simulation runs required to determine the low, best, and high case TRR scenarios.

Reservoir Scenarios /Development Options	In Place Estimates PIIP			Reservoir Connectivity /Faulting			Aquifer/ Fluid Properties (Sor,Swi)			Permeability/Relative permeability		
Cases	Low	Mid	High	Low	Mid	High	Low	Mid	High	Set 1	Set 2	Set 3
Development 1 (1 Production platform, 3 horizontal wells, 1 pipeline)	X			X	X	X	X	X	X	X	X	X
Development 2 (4 sub-sea wells, 1 pipeline , onshore processing plant)		X		X	X	X	X	X	X	X	X	X
Development 3 (1 Production platform, 6 vertical wells, 1 pipeline)			X		X		X	X	X	X	X	X

Table 7.2—Example of multi-scenario method.

Multi-scenario methods allow for the explicit evaluation of different geological models and development scenarios and therefore can be used to explore the wide range of outcomes required during project screening. A simplifying assumption for these scenarios is that they be equally probable, although different probabilities can be assumed if justified. A good understanding of project and reservoir uncertainty effects on resources estimates can be achieved if enough cases are considered to yield statistically representative results. Running a sufficient number of combined scenarios can be time-consuming, so care should be taken in selecting the cases to run. One of the main disadvantages of this method is that the quantitative treatment of probabilities is more limited compared to the probability tree analysis method (Section 7.4.1).

The difference between the multi-scenario and the probability tree methods is that the former considers development options along with certain combinations of reservoir uncertainties, and the input parameters to use in each scenario are selected by the practitioner(s). These scenarios are selected based on the multidisciplinary team views on key uncertainty and ranges. By comparison, in ED, a statistical design of experiments is used to develop the scenarios and is more of a true probabilistic approach.

The added value of using multi-scenario methods in the hydrocarbon maturation and production process is that they:

- Identify the key parameters (static and dynamic) and their uncertainties, which play a role in the project or field development and recovery, and which must be carefully addressed, monitored, and managed
- Describe the full range of uncertainty and reveal upsides (opportunities) and downsides (risks)
- Can reduce the range of uncertainty, especially when using performance data
- Can be used to estimate the value of information of potential activities aimed at addressing upside or downside uncertainties
- Allow evaluation of the impact of interdependencies
- Provide a good interface with decision support and financial modeling methods
- Can easily be applied across the full life cycle from exploration to production activities
- Yield probability outcomes that can easily be inspected and quality controlled to ensure they are related to a physically realistic discrete reservoir description (or realization), which can be used to ensure regulatory or other constraints are accounted for (e.g., check

for volumes below the lowest-known hydrocarbon or in noncommunicating unpenetrated blocks being included in the Proved Reserves estimation)

The chosen multiple realizations of the subsurface should be pragmatic and thus:

- Be based on a small number of key uncertainties (e.g., 3 to 5), obtained from ranking the static and dynamic uncertainties using some quantitative approaches (e.g., sensitivity analysis with tornado diagrams). (Some uncertainties are not significant and should be set at their best estimate value to avoid an unmanageable number of combinations and computational effort.)
- Have internally consistent realizations (i.e., a realization should consist of parameter values or sets of conditions that can physically exist together).
- Be associated with a probability of occurrence (but not necessarily equally probable).
- Be related to technically sound development options.

The multi-scenario method also can be used with each branch representing an individual simulation run (history matched, if production history exists). By assigning probabilities to these branches, it is possible to identify appropriate P90, P50, or P10 realizations of recoverable volumes. Because this is not strictly a probabilistic method, it is not necessary to select outcomes at precisely the probability equivalents of these categories (e.g., at 90% probability).

Although the most probable value of the distribution is the mode, common industry practice (as in the PRMS) is to use the median (P50) as the best estimate for a single entity (reservoir or zone). Using the median implies that half the outcomes will be greater than this value, and half will be smaller. Under the PRMS guidelines, the commerciality test for reserves determination is applied to the best estimate (P50) forecast quantities (PRMS § 2.1.2.2).

7.5 Probabilistic Methods

The PRMS notes (§ 4.2.3.1) that in the probabilistic method, "the evaluator defines a distribution representing the full range of possible values for each input parameter. This includes dependencies between parameters that must also be defined and applied." The PRMS (Appendix A, Glossary) also clarifies that 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." Chapter 4 of Society of Petroleum Evaluation Engineers Monograph 3 (Hall et al. 2010) describes a statistical methodology with which to estimate proved undeveloped reserves for a resource play.

The objective of applying probabilistic volumetric methods is to estimate probability distributions of TRR (Acuña and Harrell 2000). These are obtained by combining probability distributions for all the parameters in the volumetric equation (see Eq. 4.1a in Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* herein) through random sampling (e.g., using Monte Carlo methods or stochastic geological modeling). The probability density functions for the input parameters may or may not be stochastically dependent.

As an example, when estimating in-place volumes, input uncertainties such as gross rock volume, net-to-gross (NTG) ratio, porosity, and fluid properties need to be addressed (refer to Table 7.1). In the case of gross rock volume, one of the key uncertainties for in-place estimates is the locations of any faults that are present (for the purpose of resource categorization). This example is addressed more fully in Chapter 8—*Aggregation of Reserves and Resources* herein.

The type of distribution to use should be based on the existing data, provided enough data exist (El-Khatib 1999; Annan et al. 2020). The evaluator should consider the range and shape of the input distributions based not only on the existing information from project area wells (which often represents a limited sampling), but also on geoscience information or direct reservoir and geoscience information from appropriate analogs. Recall that the range of values required is that which represents the evaluator's uncertainty in the value of the mean, rather than the distribution of the data itself. Always keep in mind that the distribution function should describe the distribution of the reservoir-averaged parameter value.

The most common distributions of reservoir properties are normal and log-normal distributions. Average porosity is often found to exhibit a normal distribution, while average permeability is typically modeled with a log-normal distribution. When there is not enough information about the distribution (perhaps there are minimum, maximum, and mean values from analogs), then a triangular distribution could be used to help avoid extrapolation to infinite values. Triangular distributions are suited when extrapolation of the minimum and maximum needs to be controlled but is not robust at the "tails," e.g., P1 or P99.

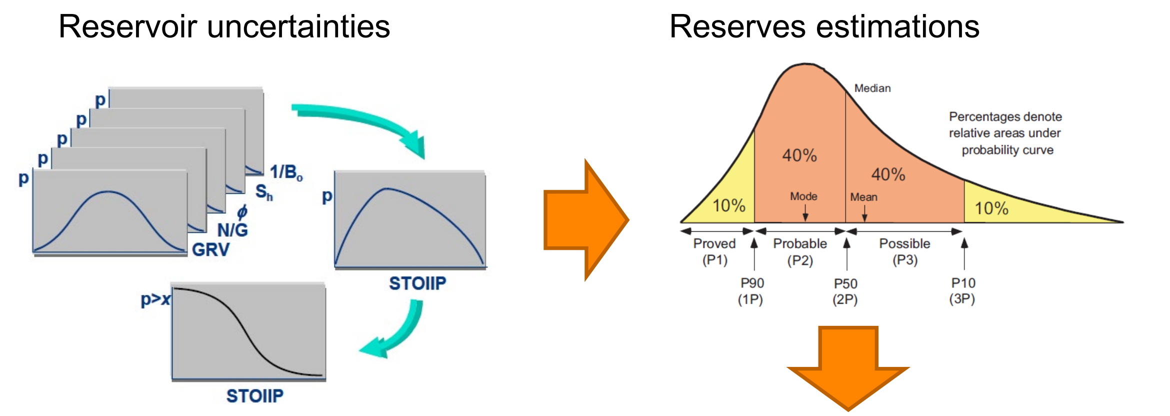
Truncated distributions may prevent extrapolation to negative values but can affect the overall shape of the probability density function, which is not recommended. Truncated curves also can be used to account for cutoffs; for instance, a normal porosity distribution for a gas reservoir could be truncated at a 5% porosity pay cutoff, if anything less than that was not expected to contribute to flow.

For variables where all the values are considered to be equally probable, a uniform distribution can be used. Examples of this could be formation volume factors as determined from the laboratory. Results of the probabilistic analysis depend greatly on the type of probability distribution used for the different reservoir parameters. Therefore, available data should be carefully analyzed. At the exploration/appraisal stage, limited data exist, and thus confidence in the derived distribution is low. At this stage, the use of analog data and prior geological knowledge can help to define probability distributions that properly represent reservoir uncertainty.

A CDF of the outcome (e.g., recoverable quantities) will be obtained as part of this process, along with the P90, P50, and P10 estimates (**Fig. 7.9**). If dynamic (reservoir simulation) models are created, then the associated production forecasts generated must be screened for economic viability with the applicable cost/investment profiles, economic limit, and other commercial requirements as described in the PRMS in order to derive the corresponding low/best/high estimates of the resource quantities (or 1P/2P/3P Reserves, if commercial). The relationship between the P90, P50, and P10 estimates and the 1P, 2P, and 3P Reserves in terms of the reserves guidelines requirements is explained in Section 7.7.

One of the main advantages of using probabilistic methods is that the confidence levels or probabilities associated with the low, best, and high reserves can be calculated. This is important information to consider for resources and reserves. For example, 1P Reserves or 1C Resources should correspond to a low estimate (P90) of the quantity that actually will be recovered. The best estimate (2P/2C) case will correspond to a P50 estimate, and likewise the high estimate (3P/3C) case should correspond to the P10 estimate of the resources that actually will be recovered.

Fig. 7.10 shows the results of a probabilistic MCS using the example in Fig. 7.3. As observed, the low case is lower than the P90 probabilistic estimate, whereas the high case is higher than the P10 estimate due to the selection of all low input parameters for the low case and all high-case input parameters for the high case. The best case is close to the probabilistic P50 as expected (Carter and Morales 1998; Morales and Lee 2014). This demonstrates the importance of selecting the correct input parameters to define low and high cases closer to 90% and 10% probabilities, respectively.



Reserves	1P	2P	3P
Probabilistic Techniques	P90	P50	P10
Deterministic Techniques	Low	Best	High

Fig. 7.9—Probabilistic methods (in this case, commercial analysis has been performed and reserves categorized).

Fig. 7.10 also shows the effect of changing two of the input probability distributions (porosity and S_w) from a normal to a uniform distribution on the P90, P50, and P10 petroleum initially in place values (here denoted as stock-tank oil initially in place, STOIIP).

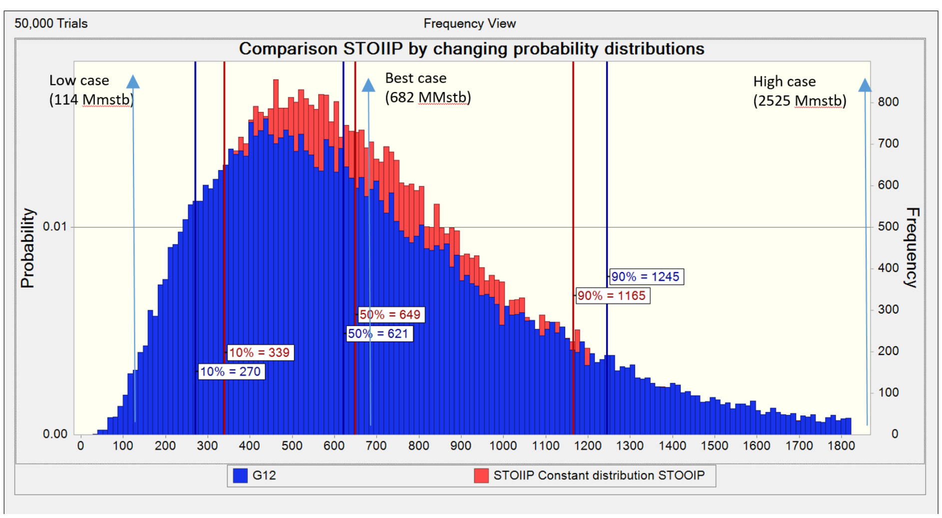


Fig. 7.10—Example probabilistic estimations for in-place volumes.

Fig. 7.11 shows the forward and reverse CDFs generated from the constant distribution in Fig. 7.10. The left-hand side of Fig. 7.11 shows a forward cumulative distribution. To create this chart, the frequencies are added cumulatively, starting from the lower end of the range, and then plotted as a cumulative frequency curve.

To create the reverse cumulative distribution, on the right, the frequencies are added cumulatively starting at the higher end of the range, and then plotted as a declining cumulative frequency curve. In the PRMS, the low-magnitude value is associated with the 90% probability, whereas the P10 estimate is associated with a high-magnitude value, which corresponds to a reverse cumulative distribution. However, some companies prefer to use a forward cumulative distribution where P10 relates to a low case and P90 corresponds to the high case.

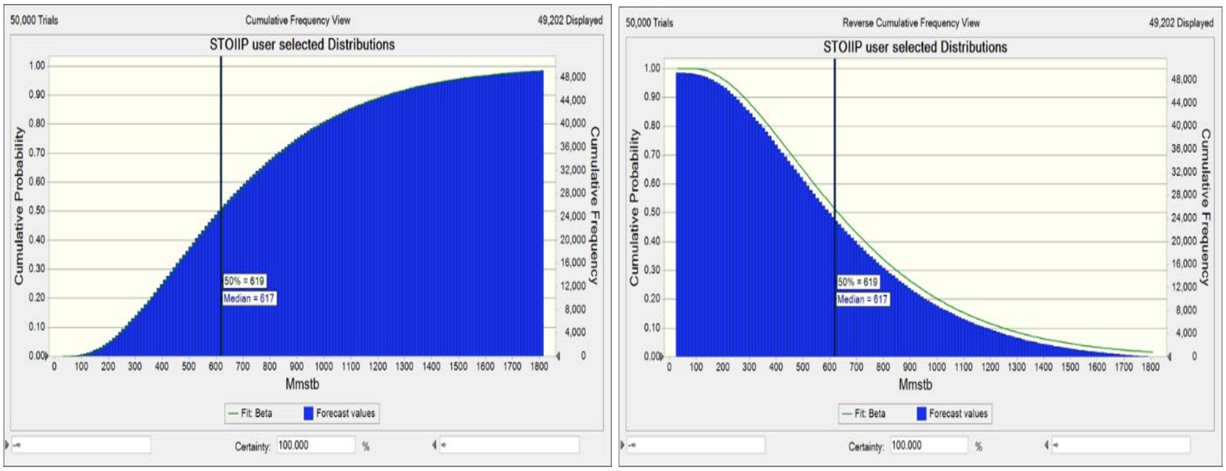


Fig. 7.11—Example cumulative distributions (forward and reverse).

Probabilistic methods can vary from Monte Carlo techniques that use simple analytical approaches to estimate recoverable volumes (Minin et al. 2011) to complex methods such as global optimization workflows with algorithms that attempt to find the global minima or maxima of a response function (e.g., recoverable volumes) using dynamic simulation models (Ogbeiwi et al. 2020). These algorithms are often described as minimization routines that are iterative and computationally intensive using full-field simulation models. Some of these methods of stochastic optimization include more sophisticated algorithms such as evolutionary strategy and genetic algorithms (see Section 7.5.3 and Fig. 7.2) and ensemble-based methods.

The ensemble Kalman filter method, one of the global optimization methods, was introduced to petroleum science by Lorentzen et al. (2005) to help solve complex history matching problems. This method provides a workflow to incorporate diverse data types from seismic data to production. The ensemble Kalman Filter method relies on a cross-covariance matrix (see chapter *Glossary*) computed from an ensemble of reservoir models to relate reservoir properties to production data. Many equally probable reservoir models can be created to honor the data/information (both static and dynamic), making it possible to represent the uncertainty in the modeling.

The number of models used needs to be kept small for computational efficiency, but, if an insufficient number of simulations are run (less than 100), then the results can include spurious estimates (Arroyo-Negrete et al. 2008). One of the advantages of these methods is that petrophysical properties between wells can be modified to improve the history match. Another advantage is that correlations between uncertain parameters and the response can be investigated efficiently.

Selecting between the different probabilistic methods depends on the technology available to (and the skillset of) the practitioner, the particular characteristics of the study, and the stage of field development (as described in Fig. 7.1). A common and simple method used by practitioners for resources estimation is decline curve analysis. Well-by-well production decline analysis is often used to define a range of estimated TRR (see Chapter 10—*Unconventional Resources Estimation* herein) and the parameters used for the decline equations (Coll and Elliott 2013). Probability distributions of the different input parameters, such as the hyperbolic exponent factor "*b*," can be used with MCS to determine the P90, P50, and P10 ranges of the Estimated Ultimate Recovery.

7.5.1 Monte Carlo Methods. Monte Carlo methods are a class of computational algorithms that rely on repeated random sampling to provide solutions to problems, particularly where there may be significant uncertainty in reservoir description. MCS will provide ranges of solutions of the outcome parameter. In a standard MCS, the probability distribution of the input parameters is sampled at random from their specific distributions (Wadsley 2005; Komlosi and Komlosi 2009).

A mathematical model in which a dependent variable is a function of the independent variable(s) is developed. The dependent variable is the response function, for instance, recoverable resources or in-place volumes, whereas the independent variables could be uncertain parameters such as gross rock volume, porosity, permeability, and/or net-to-gross ratio. Distributions are then assumed for each independent variable based on the evaluator’s experience and the available data. Once the mathematical model is built for the dependent variable (e.g., resources volumetric estimate), random numbers will be generated for each independent variable based on user-defined statistical distributions. Monte Carlo methods used for most forecasting methods can be easily implemented in a spreadsheet formula (volumetric, analytical, or decline curve analysis) if the uncertain parameters are described by a probability function. Other uncertain parameters related to production can also be included in the analysis (such as processing plant availability), which will influence yearly production.

For example, the in-place volumes and ultimate recoverable quantities are estimated by using computationally simple volumetric and material balance equations, permitting many Monte Carlo simulations (see **Fig. 7.12**) to be performed (typically >1,000 and <10,000), because the only requirement is to solve simple algebraic equations.

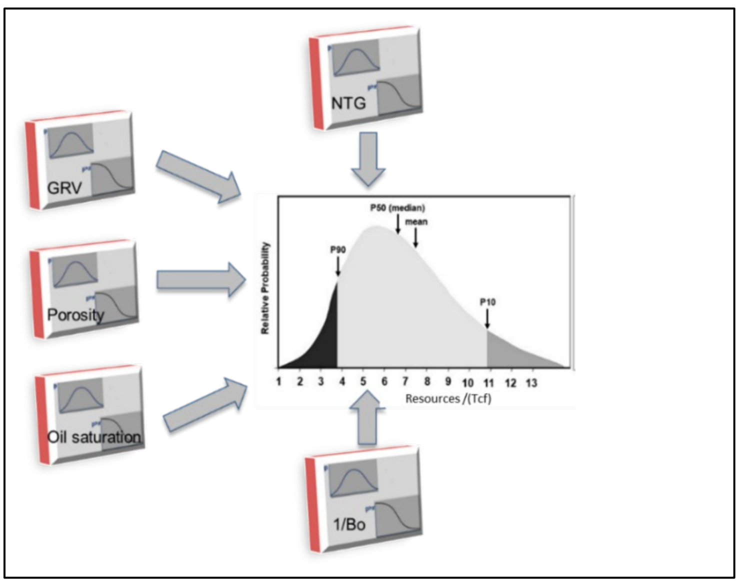


Fig. 7.12—Monte Carlo approach to volumetric estimates, where GRV is gross rock volume, and NTG is net-to-gross ratio.

The CDF obtained with such a procedure contains the estimates of recoverable volume ranges, but there is no information on the combination of input parameters (related to a subsurface realization) that will produce a value for the resource estimate. For this reason, these methods are mostly used during the exploration and early appraisal phases, when limited information exists with which to build geological models.

7.5.2 Experimental Design Methods and Response Surface Models. ED methods are a group of techniques that perform statistical design of experiments to maximize the information from a minimum number of experiments (simulations). They have been used extensively in the oil industry for uncertainty analysis since the 1990s (Elvind et al. 1992; Van Elk et al. 2000; Manceau et al. 2001; Kabir et al. 2002; Cheong and Gupta 2005; Vahedi et al. 2005; Coll, 2019) and for optimization (White and Royer 2003; Zhang et al. 2007; Fetel and Caumon 2008). ED methods search the solution space by exploring the effect of reservoir uncertainty on forecasts using reservoir models such as material balance (Vahedi et al. 2005) that can vary from basic reservoir engineering analysis (e.g., production decline analysis) to more sophisticated workflows such as multiphase simulation models.

The approaches can be thought of as an extension of the sensitivity analyses of the previous section. The main difference here is that, instead of considering one parameter changing at a time, multiple combinations are used. This allows interactions and nonlinear effects to be measured from the models. If the response variable is thought to be a linear function of the parameters with no interaction, then the Plackett-Burman method (see chapter *Glossary*) can be used. Combinations of high and low values of parameters are used based on an algorithm. This requires slightly more simulation runs than the number of parameters being investigated and can be more efficient than one parameter at a time as typically used for tornado diagram analysis. If the response is thought to vary in a quadratic sense with the parameters, then three values of each variable are needed so that the number of models needed is three to the power of the number of parameters, if even sampling is used. This reduces the need for every combination to be used.

Examples of alternative ED methods include Latin hypercube sampling and orthogonal sampling (see chapter *Glossary* for definitions). Latin hypercube sampling is a statistical method for generating a near-random sampling of parameter values from a multidimensional distribution (Mishra and Datta-Gupta 2017). In statistical sampling, a square grid containing sample positions of an uncertainty distribution is a Latin square if there is only one sample in each row and in each column. In **Fig. 7.13,** two uncertainties are denoted as u_1 and u_2. The ranges of uncertainty are divided into four bins. Latin hypercube sampling experiments are constructed in such a way that each one of the dimensions (i.e., uncertainties) is divided into equal intervals or bins, and there is only one point (or sample) in each interval (four intervals in Fig. 7.13).

In the orthogonal model, the sample space is divided into equally probable subspaces. All sample points are then chosen simultaneously, making sure that the total set of sample points is a Latin hypercube sample and that each subspace is sampled with the same density.

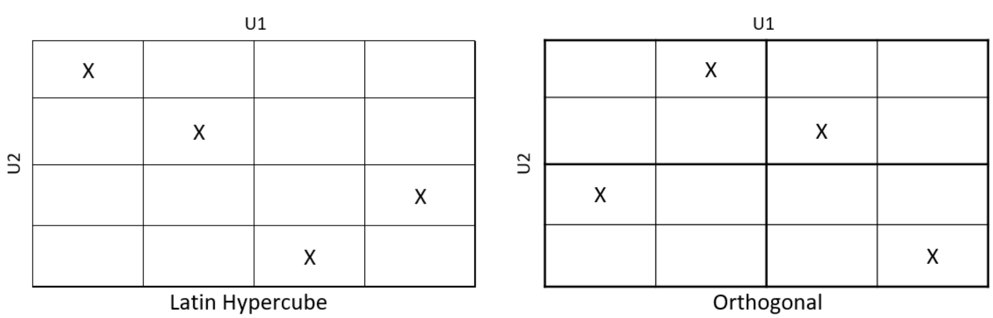


Fig. 7.13—Examples of experimental design (ED) for two uncertain variables.

Results of experimental designs are then used to generate a proxy model (which can be a more accurate mathematical function including interaction terms between input variables) by using a high-order polynomial function to generate a response surface model (RSM), as plotted in **Fig. 7.14**. A higher-order function RSM is a quadratic polynomial function that is required when interaction of parameters is needed to minimize the error (e) between the data and the simulation model due to curvature of the solution space or interaction of uncertain parameters. An example of a higher-order RSM is shown below, where u_i are the uncertain parameters, a_i are the unknown coefficients we need to determine, and e is the error:

$$RSM = f(u1, u2, \ldots. un) = a_0 + a_1u_1 + a_2u_2 + a_3u_3 + a_{11}{u_1}^2 + a_{22}{u_2}^2 + a33{u_3}^2 + \ldots e.$$

Ultimate recoverable resources or recovery factors are examples of the RSM function obtained using different uncertain input parameters (such as porosity and permeability). We call $u_1, \ldots, u_n$ explanatory or uncertainty variables. A reservoir simulator can be seen in this case as a complicated function that relates the response RSM (e.g., Estimated Ultimate Recovery) to the explanatory variables (input uncertainties). The RSM function in Fig. 7.14 assumes no interaction or dependencies between the uncertain parameters ($u_1, \ldots, u_n$). This is a simplification, because, in most cases, uncertain input parameters can have dependencies.

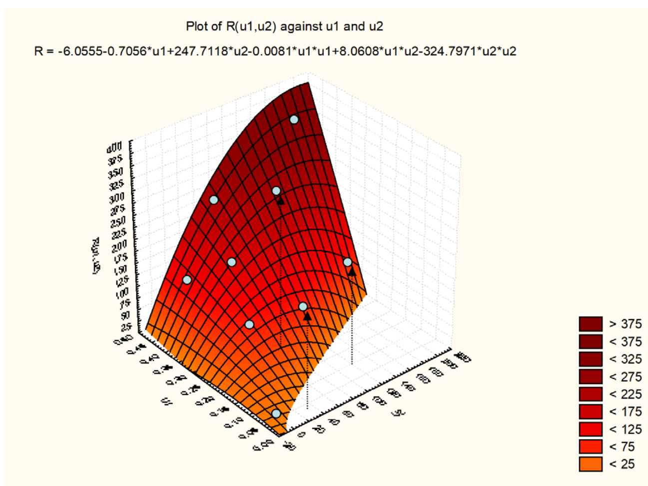


Fig. 7.14—Response surface model (RSM) along with simulation results (blue circles) selected using ED methods (after Coll 2019).

The advantage of using a polynomial function as the proxy model is that it can be interrogated to determine those parameters that are important. Simple EDs such as Plackett-Burman can be used to eliminate unimportant parameters, and then higher-order EDs can be used to improve the accuracy of the proxy model (e.g., **Fig. 7.15**).

MCS is then performed using the polynomial function (or whichever proxy model or function is derived to approximate the full model) to estimate the cumulative distribution of the RSM function (e.g., TRR), and, from there, the P90, P50, and P10 estimates of recoverable volumes are obtained. If the interaction of input parameters is critical, then a different polynomial function should be used that includes curvature terms instead of the simpler equation in Fig. 7.14. Fig. 7.15 summarizes the recommended workflow using the two methods (ED and MCS) explained previously.

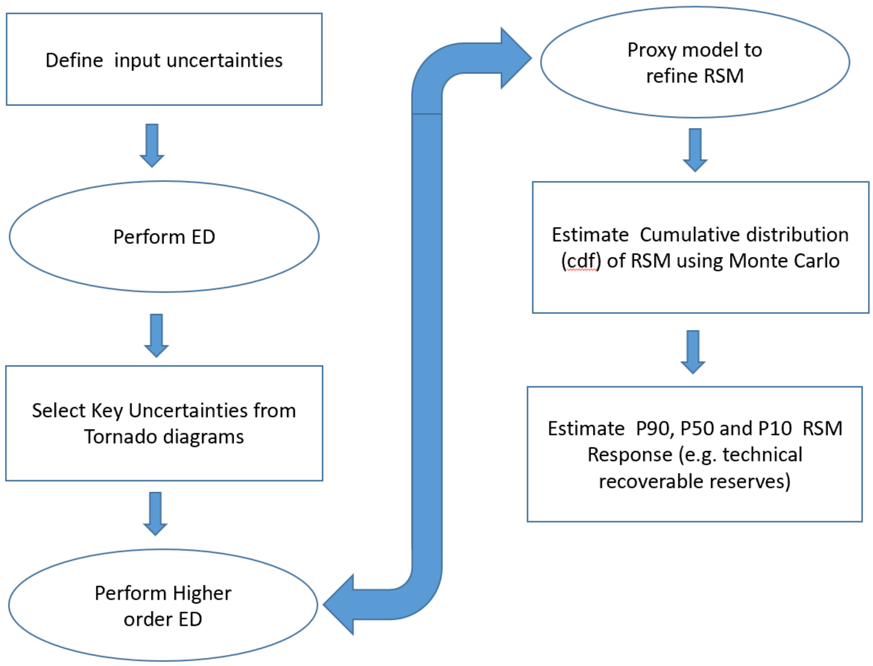


Fig. 7.15—Example workflow using ED and Monte Carlo analysis.

7.5.3 Global Optimization Methods. In fields with production data, a history matched model can be used to better quantify ranges for in-place quantities and forecasts of production. Given the nonuniqueness of history matching, it is necessary to find a set of dynamic models that more closely approximate physically real combinations of input parameters and better understand the uncertainty range. For this purpose, more sophisticated methods beyond ED and MCS, such as global optimization methods, are necessary. Global optimization methods (also called direct search methods) are used in different areas of engineering (Hooke and Jeeves 1961). These methods are based on using an objective function to determine the next steps to search for the solution instead of using gradient information (Schulze-Riegert et al. 2006, 2007). The objective function is the difference between observed and modelled data. Several global optimization methods have been developed for oil industry use, including an objective function defined, for instance, to minimize the difference between measured and simulated bottomhole pressure during history matching (Al-Shamma Teigland 2006; Schulze-Riegert et al. 2006, 2007; Choudhary et al. 2007).

Examples of these methods include evolutionary algorithms called genetic algorithms, evolutionary strategies, and evolutionary programming. From these methods, the most common are evolutionary strategies (Cheng et al. 2008; Abdollahzadeh et al. 2013; Ghamdi et al. 2020) and genetic algorithms (Castellini et al. 2008; Sanghyun and Stephen 2018) based on biological processes. In evolutionary strategies and genetic algorithms, the algorithm will search for the best combination of the uncertain parameters in the simulation that will produce the best history matches. In using these methods, many reservoir models are found that closely match the history data. They can also find solutions that are quite different from each other in terms of the input parameters. The statistics of the models can then be used to infer probabilities for uncertainty (or risk) analysis (Stephen 2018).

As noted in Section 7.2, the ensemble Kalman filter is a method that is useful for modifying reservoir properties away from the wells. The ensemble Kalman filter method is based on a formulation of optimization where data are assimilated based on calculations of probabilities (Aanonsen et al. 2009). The probabilities of existing models are used to update the model at the next step. Once history matching is complete, the CDFs of model parameters can be evaluated by resampling probabilities. Ensemble-based optimization is another popular method for history matching that incorporates production history data into a set of model realizations.

The next section explains how some of these different methods can be used to develop a probabilistic workflow that can be applied to either preproduction or on-production fields.

7.6 Probabilistic Workflows for Recoverable Resources Estimates

There are two main distinctive workflows that need to be considered for probabilistic recoverable resources estimations as depicted in Fig. 7.2 (Coll 2019). The choice of workflow is related to the stage of project development (see Fig. 7.1):

- Probabilistic estimation of recoverable volumes for fields at the preproduction (exploration/appraisal) phase
- Probabilistic estimation of recoverable volumes for fields with production history

7.6.1 Preproduction Phase. There are several steps to be executed in a probabilistic workflow that are common to both preproduction and on-production phases. This section describes an example of the methodology that can be used as part of a probabilistic workflow for fields without production, as detailed below and in Fig. 7.16. Alternatively, if there has been no production, and/or a dynamic model is not available, simpler Monte Carlo methodologies and/or ED can be used instead as described in Section 7.5. The workflow below is based on the different methodologies explained in detail in the previous sections. Actual procedures used will vary from company to company.

1. Define ranges for the uncertain parameters: Ranges for the uncertain parameters should be defined for each input uncertainty as explained in Section 7.2 during asset framework sessions as part of an integrated multidisciplinary effort. Members of the subsurface team should agree on the reservoir uncertainties that ought to be considered, their ranges and the shapes of probability distributions to be used.
2. Use sensitivity analysis and/or ED methods: These methods can be used with the base case static and dynamic reservoir models to identify key reservoir parameters and their influence on the outcome (e.g., in-place estimates, TRR) as described in Sections 7.3.2 and 7.5.2. Tornado diagrams are used for sensitivity analysis to identify key parameters as described in Section 7.3.2. ED will be used to define the cases to run where the uncertainties are combined to explore the impact of interdependencies. It is important to note that a single development scenario (base case development plan) should be used at this stage (see **Fig. 7.16**). The outcome of this step is to identify the key reservoir uncertainties with a "major impact" on the outcome as well as the effects of their dependencies/interactions.
3. Perform risk analysis: This can be performed after the sensitivity analysis. This step consists of performing a higher-order ED (e.g., if the response variable is nonlinearly related to the parameters) to improve the RSM (Fig. 7.15) to account for parameter interaction as described in Section 7.5.2.
4. Conduct MCS: These are run using proxy models to define the cumulative probability distributions for the outcomes (e.g., resources). Monte Carlo analysis uses the proxy model to generate the RSM solution (Fig. 7.14) as described in Section 7.5.2.

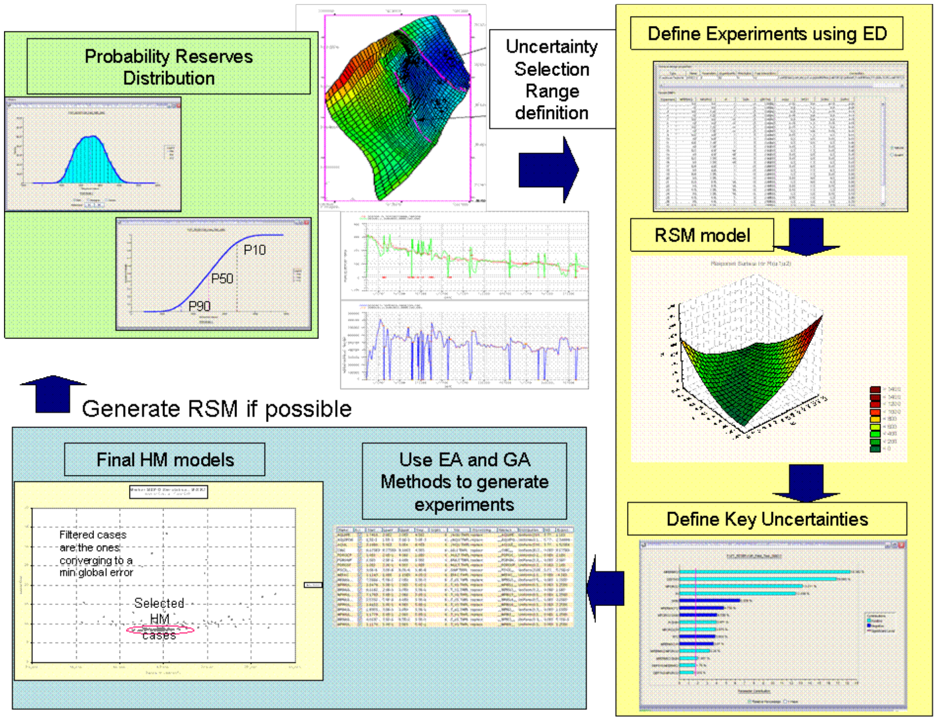


Fig. 7.16—General probabilistic workflow (after Wheaton and Coll 2010), where EA and GA are evolutionary and genetic algorithms, respectively, and HM is history matched.

5. Estimate the P90, P50, and P10 recoverable resources: The probability distributions derived in step 4 can be used to determine the P90, P50, and P10 estimates of resources. Production forecasts can be derived for the resources ranges by running the simulation models. The models and profiles are fully auditable and transparent.
6. Construct corresponding deterministic low, best, and high estimate models: Corresponding deterministic scenarios can be derived based on the P10, P50, and P90 resource estimates from the previous step, as obtained from the CDFs. In most cases, the input parameters used to derive the P90, P50, and P10 probabilistic estimates might need to be recombined to select a realistic set of input parameters consistent with the PRMS requirements. These production forecasts will also need to be processed through commercial analysis to establish, among others, the project limit (truncated as necessary by technical, contractual, economic, or other limits), so the quantities can be classified as resources and/or reserves per the PRMS guidelines.

7.6.2 Production Phase. The workflow described in the previous section should be adapted for fields that have enough production data to ensure production history is honored during the probabilistic analysis. To achieve this goal, different methods can be used as described in Section 7.5.

To evaluate the effect of uncertainty, a recommended approach will be to generate three different geological realizations corresponding to low, best, and high cases that represent the static uncertainty. These models can then be transferred to a dynamic model and history matched. However, in many simulation studies, only a best estimate history match (HM) might be available. If this is the case, reservoir uncertainties should be evaluated during history matching by following, for example, the workflow described in Section 7.6.1 Steps 1 and 2.

Multiple reservoir models can be generated using ED methods by varying the input reservoir parameters in the dynamic simulation model. Global optimization methods can be used in Step 2 to speed up the HM process of the different model realizations compared to a manual HM. During Step 3 in Section 7.6.1, many dynamic realizations can be run that take into account the ranges of uncertainty in the input reservoir parameters. These models can be run simultaneously, converging to multiple plausible models that produce a reasonable HM of production and pressure data. These workflows are time-effective, with hundreds of potential solutions to the HM problem, recognizing the reservoir uncertainties, generally made available in a matter of weeks. These methods compare favorably with the traditional manual HM workflow, which is a time-intensive process that produces a few matched models.

Step 4 can be skipped if enough simulation models exist. Cumulative distributions of TRR can be generated using these HM models generated in Step 3 to determine P90, P50, and P10 resources estimates as part of Step 5 in Section 7.6.1. The matched models can be considered as being equally probable in the absence of any other reliable assumptions (e.g., prior probabilities and data errors). Alternatively, the degree of mismatch among the HM models can be used to guide assigned probabilities. A further step (Step 6) is required for estimating resources once the input variables to the P90, P50, and P10 simulation HM models are reviewed to generate the corresponding deterministic 1P, 2P, and 3P Reserves or 1C, 2C and 3C Contingent Resources. If input parameters need to be recombined, the HM of the new simulation model will need to be evaluated to test the validity of the recombined assumptions. The corresponding deterministic models can be used to generate P90, P50, and P10 forecasts suitable to be screened for their commercial maturity as per the PRMS guidelines.

An advantage of probabilistic methods, as described in this section, compared to simple Monte Carlo methods is that the P90, P50, and P10 models derived from the cumulative distribution can be easily interrogated to determine input assumptions in a manner similar to that of deterministic workflows. These methods provide an unbiased and rigorous analysis of the influence of reservoir uncertainties on resources estimates, helping to evaluate and potentially mitigate risks during a field development plan. Another advantage of these methods is that the asset team can have a quantitative tool for evaluating the key reservoir uncertainties for a value of information analysis to justify future data acquisition campaigns with the objective of reducing field development risk. These methods allow determination of P90, P50, and P10 resources estimates that can be used with confidence to represent the low, best, and high estimated resources cases.

A further advantage of these methods is that the production forecasts can be used to optimize facilities design and/or field development scenarios and to evaluate the economic impact of the uncertainty in resources.

Fig. 7.17 shows how the profiles resulting from a probabilistic workflow of 27 example cases were screened economically to determine the uncertainty in NPV and the return on investment (ROI) compared to the internal ROI company threshold (in this example, ROI = 12%) for project approval.

Examination of the economic results indicated that all cases had a positive net ROI, but for some cases, the net ROI was below or marginally above the internal ROI (see cases 7, 8, 16, 17, 25, 26, and 27). The integrated team looked at these lower ROI cases and the combination of uncertainties that generated these results to find opportunities to mitigate the downside through further optimization of the development plan and/or by acquiring new information. Cases with the highest ROI (e.g., cases 1, 2, 5, 10, 11, and 19) were also reviewed by the team to evaluate the combination of uncertain parameters that contributed to generate these upsides. These results allowed the team to evaluate the key development risks and opportunities that justified some changes to the initial development plan. Another outcome from this analysis was a cumulative distribution of the ROI to estimate the P90, P50, and P10 ROIs. The P10, P50, and P90 ROIs shown in the table within Fig. 7.17 were communicated to management to convey the economic uncertainty and investment risk during final investment decision (FID) project approval.

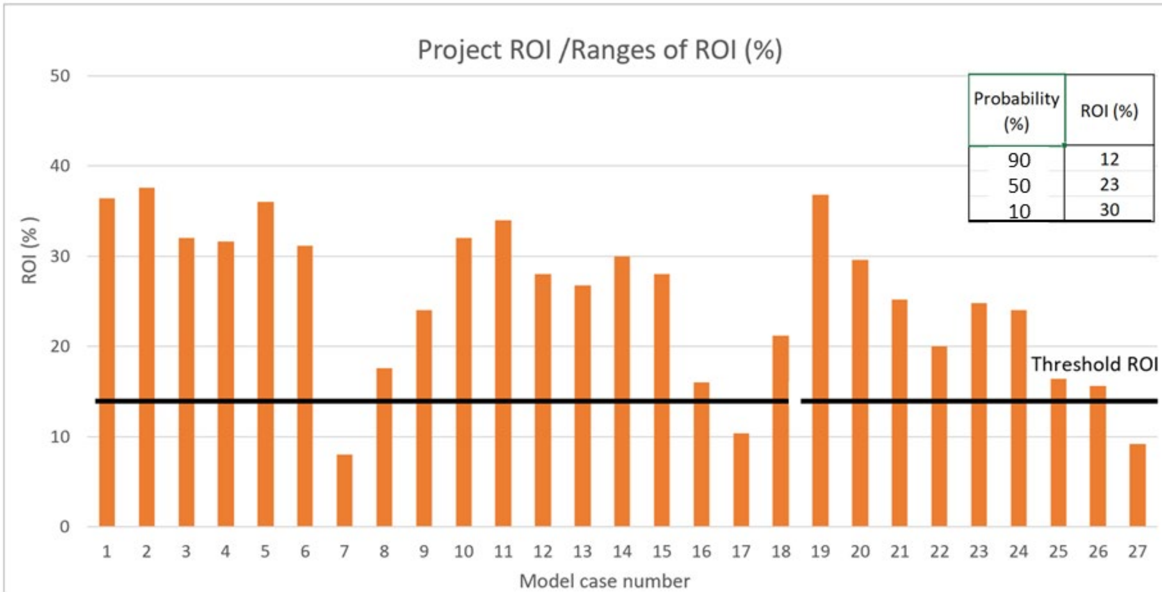


Fig. 7.17—Probabilistic reserves estimations (after economics) used for optimizing facility design.

A disadvantage of probabilistic methods is that these methods can be computationally intensive, requiring a large number of numerical reservoir models to be run, which may not be practical for some fields (for example, in multimillion grid cell simulation models with long production histories). The evaluator should weigh the benefits that these methods can bring in assessing risk during development for each field vs. the associated time and computing cost.

7.7 Consistency between Probabilistic and Deterministic Methods

Probabilistic and deterministic estimates results need to be analyzed for consistency (Purvis and Strickland 2001). Once probabilistic recoverable volumes have been estimated, such as by following the workflows explained in the previous section, the corresponding deterministic recoverable volumes can be estimated following the guidance provided by Wheaton and Coll (2010) and Coll (2019). The PRMS guidelines (PRMS § 4.2.3.3) state that P10, P50, and P90 resources estimates should reconcile with deterministically derived low, best, and high estimate cases. If this is not the case, an evaluation of the reasons for discrepancies must be undertaken to reconcile and update the results as needed.

The following discussion assumes, for simplicity, that all estimated quantities satisfy the requirements for Reserves status; hence, the discussion will focus on 1P/2P/3P and P90/P50/P10 nomenclature. However, the same commentary and process apply for Resources in general.

Under the PRMS guidelines, a low estimate corresponding to Proved Reserves (1P) should meet several criteria, including that the area considered as Proved involves (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. Fluid contact assumptions must be scrutinized. It is a requirement that, in the absence of encountering fluid contacts, Proved quantities should be limited by the lowest known hydrocarbon as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Another criterion to consider could be the correspondence of the P50 case with a P50 in-place volume.

Fig. 7.18a illustrates the response function *R* (in this case, recoverable volumes) against two input uncertain parameters (parameter 1, parameter 2). It also shows the surfaces and contour lines indicating P90, P50, and P10 recoverable volumes estimated following the workflow depicted in Fig. 7.16. If the *R* function were to be created by considering parameter interaction terms, then the solution space *R* would be a more complicated surface (Fig. 7.14). Fig. 7.18 also shows the actual simulation run results from Section 7.6.1 Step 2 (green dots). It could be possible that none of the green dots at a P50 probability is consistent with the P50 in-place volume that could be expected from the PRMS guidance, but rather, they could correspond to a P90 or P10 in-place volume. It is possible that none of the cases at the P90 confidence level satisfies the requirements for Proved Reserves.

If production data exist, the solution space *R* will be restricted to the orange area as shown in Fig. 7.18b. Simulations outside the solution space of valid HM should be discarded. Cumulative distributions of recoverable volumes should be estimated using only the valid HM cases.

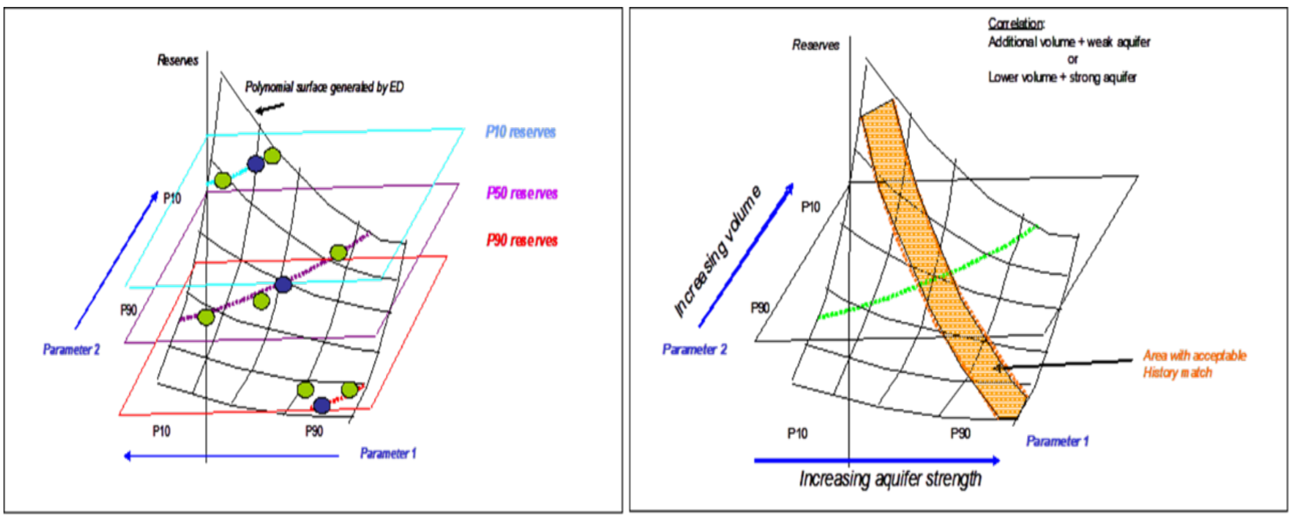


Fig. 7.18—(a) *R* space solution (reserves) showing the corresponding P90, P50, and P10 recoverable volumes as surfaces and contours, with their input parameter values, where symbols indicate simulation results, and (b) R space solution constrained by considering only models that match history (orange shaded area, the constrained space solution) (after Wheaton and Coll 2010).

Table 7.3 shows an example of the input parameters for three runs corresponding to P90, P50, and P10 probabilities (green dots in Fig. 7.18a). As tabulated, the P90 case has a GWC contact that is deeper than the P50 case. In this example, the GWC for the P90 and P10 cases can be switched to ensure consistency with the guidelines. This change will require other parameters to be adjusted to ensure original gas-in-place (OGIP) and TRR are not altered. As observed, the P90 OGIP value is as expected for the low case. Once the parameters are changed, the new runs should produce realistic production profiles with the same ranges of recoverable volumes as the original analysis (blue dots in Fig. 7.18a). The process of recombining input variables to comply with the PRMS guidelines is an iterative process to generate reasonable 1P, 2P, and 3P profiles.

	15_16 Curve P90	HV13_23 Curve P50	HV12_25 Curve P10
G6 Fault #1	0.0022	0.0078	0.0078
G6 Fault #2	0.0180	0.0166	0.0166
G6 Fault #3	0.0176	0.0070	0.0062
G6 Fault #4	0.0112	0.0018	0.0054
Trapped Gas Sat	0.15/0.35	0.15/0.35	0.15/0.35
GWC East of main fault	5610	5600	5600
Compressibility evolution	3	3	2
Water Rel Perm @ Sgc	0.34	0.34	0.34
Vertical Trans. between A sands	0.08	0.01	0.08
G8/G9 area permeability multiplier	2.70	0.50	0.50
Global Permeability Multiplier	0.80	0.85	0.80
PoreVol NE corner East panel	1.80	1.80	1.80
PoreVol East Panel	0.93	1.02	1.02
PoreVol ECentral Panel	0.97	1.10	1.12
PoreVol WCentral Panel	1.07	1.22	1.22
PoreVol West Panel	0.75	0.75	0.75
PoreVol South East Panel	1	1	1
PoreVol West Aquifer	0.60	1.08	1.08
PoreVol East Aquifer	0.68	0.76	0.76
Main Internal Fault Trans.	0.02	0.10	0.03
Main Internal Fault Trans.	0.02	0.10	0.03
North and West Aq Fault Trans.	0.08	0.09	0.09
SE Panel Fault Transmissibility	0.01	0.02	0.02
Small Internal Fault Trans.	0	0	0
G6/G7 Fault Transmissibility	0	0	0
East Aq Fault Transmissibility	0.01	0	0
Skin increase in existing wells	2	2	2
Skin increase in EIA well	2	2	2
Catastrophic failures	3	3	3
EIA well drilled or not	1	1	1
Production Efficiency	0.93	0.93	0.93
Condensate banking	No	No	No
OGIP [bcf]	1731.68	1905.26	1912.91
EUR [mmboe]	567	604	613

Table 7.3—Example input and output parameters for P90/P50/P10 recoverable volumes used for 1P/2P/3P Reserves (after Wheaton and Coll 2010).

7.8 Commercial Considerations

The outcomes of the probabilistic workflows described herein are technical estimates of recoverable resources that will need to undergo an economic evaluation. As stated in the PRMS (§ 2.1.2.1), the commerciality requirements include that "the entity satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate)." As a result of the economic and subsequent commercial assessments, sales products will be estimated that take into account the PRMS commerciality requirements described in PRMS § 2.1.2 and § 3.1. It is the assessment including economic criteria (especially if the assessment includes production sharing contract (PSC) terms and conditions, and a given set of commodity prices and OPEX/CAPEX profile) that will result in key differences between the TRR volumes obtained from probabilistic approaches and the resources scenarios that can be used for project valuation.

Probabilistic workflows will typically contain hundreds of reservoir realizations that represent the influence of subsurface uncertainties on resources estimates and economic value. The amount of information provided by probabilistic workflows allows entities to better assess economic risk associated with investment in a field development plan (as discussed in Section 7.6) to guide investment decisions. Another benefit of probabilistic workflows during commercial evaluation is that results of the economic analysis can be used to justify the acquisition of new data, provided the input for a value of information analysis is aimed to reduce not only the reservoir uncertainty but also the investment risk.

The P90, P50, and P10 scenarios obtained from the probabilistic workflows after commercial evaluation can be used to support public disclosures for project valuation. Corresponding deterministic 1P, 2P, and 3P cases as described in Section 7.7 can be used after commercial evaluation for regulatory reporting. One other benefit of probabilistic methods is that the confidence levels associated with the corresponding deterministic scenarios are fully supported by the probabilistic workflows, making possible a rigorous analysis of the rationale behind the selection of the reserves and resources estimates at each confidence level.

7.9 Final Considerations

This chapter provides technical guidance on various probabilistic methods and workflows that can be applied at different stages of field development. Several methodologies have been used in the oil and gas industry with the objective of promoting integrated probabilistic workflows. These methods provide powerful mathematical tools with which to assess the influences that reservoir uncertainties have on resources estimates.

Advances in technology and computing capacity have allowed these methods to evolve, addressing many of the concerns that evaluators have regarding lack of transparency on the parameters used in the probabilistic models. There are significant potential variations in estimates of P90, P50, and P10 TRR (and eventually the related reserves), which can be due to the selection of unsuitable distributions of the uncertainty parameters that may lead to misleading conclusions. A careful selection of the uncertainty ranges and probability distributions is important to the successful application of any probabilistic method.

As explained in this chapter, the method selected should be dependent on the stage of the field development and available information as summarized in **Table 7.4.** As observed at the exploration stage, sensitivity analysis and MCS are widely used and are sufficient to evaluate uncertainty, whereas ED is recommended for preproduction fields at the appraisal stage where more data and information exist and dynamic reservoir models have been built, justifying the use of more sophisticated workflows. If the field is at the production stage, and production data need to be history matched, global optimization methods are recommended. Deterministic methods such as scenario analysis can be used for all the pre- and on-production stages as well as at different field phases.

Field status		Methodology					
		Deterministic		Probabilistic			
		Scenario (Cumulative)	Incremental (risk-based)*	Sensitivity Analysis	Monte Carlo	Experimental Design with simulation or other eng. methods	Experimental Design with Global optimization (EA or GA)
Pre-production	Exploration	x		x	x		
	Appraisal	x		x	x	x	
	Development	x	x	x		x	
Post-production	Early Production	x	x			x	x
	Mature Production	x	x				x

* mainly used for onshore fields including unconventionals

Table 7.4—Preproduction and on-production recommended workflows (Coll 2019). EA and GA are evolutionary and genetic algorithms, respectively.

The use of probabilistic estimates for recoverable resources without also considering the corresponding deterministic cases as explained in Section 7.7 can compromise the validity of the probabilistic results if the parameters selected for the P90, P50, and P10 cases are inconsistent with PRMS requirements (e.g., fluid contacts). Also, P90, P50, and P10 estimates must be recognized as TRR that need to satisfy economic and commercial criteria before they can be classified as Reserves under the PRMS guidelines.

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7.11 Glossary and Definitions

Cross-Covariance Matrix	In probability theory and statistics, a cross-covariance matrix is a matrix in which the element in the (i, j) position is the covariance between the ith element of a random vector (uncertainty) and the jth element of another random vector (uncertainty). A random vector is a random variable with multiple dimensions. Each element of the vector is a scalar random variable. A covariance matrix measures the degree to which two variables are linearly associated.
Cumulative Distribution Function (CDF)	A cumulative distribution function (CDF) of a real-valued random variable X, or just distribution function of X, evaluated at x, is the probability that X will take a value less than or equal to x. Cumulative distribution functions are also used to specify the distribution of multivariate random variables.
Genetic Algorithms	Optimization procedures motivated by biological analogies. The primary idea is to try to mimic the "survival of the fittest" rule of genetic mutation in the development of optimization algorithms. The process begins with a population of potential solutions to a problem and a way of measuring the fitness or value of each solution. A new generation of solutions is then produced by allowing existing solutions to "mutate" (change a little) or cross over (two solutions combine to produce a new solution with aspects of both). The aim is to produce new generations of solutions that have higher values (from Everitt and Skrondal 2010).
Global Optimization	A branch of applied mathematics and numerical analysis that attempts to find the global minima or maxima of a function or a set of functions on a given set. It is usually described as a minimization problem because the maximization of the real-valued function $g(x)$ is equivalent to the minimization of the function $f(x) := (-1)*g(x)$. (Wikipedia 2022b)
Kalman Filter	A recursive procedure that provides an estimate of a signal when only the "noisy signal" can be observed. The estimate is effectively constructed by putting exponentially declining weights on the past observations, with the rate of decline being calculated from various variance terms. Used as an estimation technique in the analysis of time-series data (from Everitt and Skrondal 2010).
Latin Hypercube	The generalization of a Latin square to an arbitrary number of dimensions, whereby each sample is the only one in each axis-aligned hyperplane containing it. A stratified random sampling technique in which a sample of size N from multiple (continuous) variables is drawn such that for each individual variable, the sample is (marginally) maximally stratified, where a sample is maximally stratified when the number of strata equals the sample size N and when the probability of falling in each of the strata equals $N - 1$ (from Everitt and Skrondal 2010).

Mean, Expected Value or Expectation	The expected value of a random variable *X*, denoted *E*(*X*) or *E*[*X*], is a generalization of the weighted average, and it is intuitively the arithmetic mean of a large number of independent realizations of *X* (Wikipedia 2022a). The expected value is also known as the expectation, mathematical expectation, mean, average, or first moment. It is the average value over the entire probability range, weighted by the probability of occurrence: $Mean = \sum_{i=1}^{n} x_i \cdot P(x_i) \text{ or } \int x \cdot P(x) \cdot d(x)$, where *x* = variable (e.g., reserve value) and *P*(*x*) = probability of *x*. The mean of statistical distributions can be added arithmetically in aggregation.
Measures of Centrality	The simple values that give us information about the distribution of data such as arithmetic mean, median, mode. The three measures of centrality defined below coincide only when probability distribution functions are symmetrical. This is seldom the case for reserves. In general, and for most practical purposes, they differ.
Median (also known as P50)	The median is the value (middle value) separating the higher half from the lower half of a data sample, a population, or a probability distribution; therefore, the probability that the outcome will be higher is equal to the probability that it will be lower. The benefit of using the median compared to the mean ("average") is that it is not skewed by a small proportion of extremely large or small values, and therefore it provides a better representation of a "typical" value. The median is often used for resources best estimates.
Mode, or Most Probable Value	The mode is the value that appears most often in a set of data values or most probable value. If *X* is a discrete random variable, then the mode is the value *x* at which the probability mass function takes its maximum value. In other words, it is the value that is most likely to be sampled. It is the reserves quantity where the probability distribution function has its maximum value.
Optimization Methods	Procedures for finding the maxima or minima of functions of, generally, several variables. It is most often encountered in statistics in the context of maximum likelihood estimation, where such methods are frequently needed to find the values of the parameters that maximize the likelihood (from Everitt and Skrondal 2010).
Orthogonal Design	A designed experiment is orthogonal if the effects of any factor balance out (sum to zero) across the effects of the other factors. Orthogonality guarantees that the effect of one factor or interaction can be estimated separately from the effect of any other factor or interaction in the model.
Orthogonal Sampling	In orthogonal sampling, the sample space is divided into equally probable subspaces. All sample points are then chosen simultaneously, making sure that the total set of sample points is a

	Latin hypercube sample and that each subspace is sampled with the same density.
P10	The 10th percentile (possible) is the highest figure; it means that 10% of the calculated estimates will equal or exceed the P10 estimate. For reserves, it means the quantity for which there is a 10% probability that the quantities actually recovered will equal or exceed the estimate.
P50, or Median	The 50th percentile (the median) is the score below which 50% (exclusive) or at or below which (inclusive) 50% of the scores in the distribution may be found. For reserves, it means the quantity for which there is a 50% probability that the reserves actually recovered will equal or exceed the estimate.
P90	The 90% percentile (Proved) is the lowest figure; it means that 90% of the calculated estimates will be lower. In contrast, for percentiles, a percentage is given, and a corresponding score is determined, which can be either exclusive or inclusive. The score for a specified percentage (e.g., 90th) indicates a score below which (exclusive definition) or at or below which (inclusive definition) other scores in the distribution fall. In reserves estimation, this is the number quoted as the proven value.
Percentiles	A percentile (or a centile) is a score below which a given percentage of scores in its frequency distribution fall or a score at or below which a given percentage fall (inclusive definition). For example, the 50th percentile (the median) is the score below which 50% (exclusive) or at or below which (inclusive) 50% of the scores in the distribution may be found.
Plackett-Burman Design	Type of experimental design (ED) that helps to find the factors in an experiment that are important. This design assumes that the interactions between factors (uncertainties) can be completely ignored, and the main effects can be calculated with a reduced number of experiments (reservoir models with combinations of uncertainties). This means large amounts of data do not need to be collected in experiments (reservoir models with combinations of uncertainties) on relatively unimportant factors.
Polynomial Function	A polynomial function is a function that can be expressed in the form of a polynomial. The definition can be derived from the definition of a polynomial equation. A polynomial is generally represented as $P(x)$. The highest power of the variable of $P(x)$ is known as its degree. The degree of a polynomial function is very important because it tells us about the behavior of the function $P(x)$ when x becomes very large.
Probability	Probability is the branch of mathematics concerning numerical descriptions of the likelihood of an event to occur, or the likelihood that a proposition is true. The extent to which an event is likely to occur is measured by the ratio of the number of occurrences to the whole number of cases possible. Note that the probability used in

	reserves estimation is a subjective probability, quantifying the likelihood of a predicted outcome.
Probability Density Function (PDF)	A probability density function (PDF), or density of a continuous random variable, is a function for which the value at any given sample (or point) in the sample space (the set of possible values taken by the random variable) can be interpreted as providing a relative likelihood that the value of the random variable would equal that sample.
Solution Space	Set of all possible points of the choice variables of an optimization problem that satisfy the problem's constraints, potentially including inequalities, equalities, and integer constraints.
Standard Deviation	The standard deviation is a measure of the amount of variation or dispersion of a set of values around its mean. A low standard deviation indicates that the values tend to be close to the mean (expected value), whereas a high standard deviation indicates that the values are spread out over a wider range. It is calculated as the square root of the variance.
Variance	Variance is a measure of how far a set of numbers is spread out from their average and is the expectation of the squared deviation of a random variable from its mean. The variance is calculated by adding the square of the difference between values in the distribution and the mean value and calculating the arithmetic average: $s^2 = \frac{\sum_{i=1}^{n}\left(x_i - \mu_i\right)}{n} = \int_a^b \left(x - \mu\right)^2 f(x)dx$, where x = variable (e.g., reserves), μ = mean, and $f(x)$ = probability density function. It is convenient to square the differences because this avoids the cancelling of positive and negative values.

Chapter 8

Aggregation of Reserves and Resources

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8.1 Introduction

In reserves and resources assessment, technically recoverable quantities are typically based on the results of analog analyses, performance evaluations, and/or volumetric calculations for individual wells, reservoirs, or portions of reservoirs. These estimates may be combined to arrive at recoverable quantities for fields, properties, projects, and portfolios. The uncertainty of the combined estimates at each of these levels may differ greatly, depending on such factors as geological setting and maturity of the resource. This cumulative process, which takes into account the uncertainty, is referred to as "aggregation." Appropriate aggregation methods enable efficient decision and valuation assessments for both conventional and unconventional assets.

Resource estimates may be stated as single deterministic values, range estimations (such as those derived probabilistically), or aggregated collections of producing or nonproducing assets. The aggregation method used should be associated with the purpose of the assessment. The assessment of discovered resources is usually capable of being combined within the 1P, 2P, and 3P Reserves (or 1C, 2C, and 3C Contingent Resources) categories as outlined in Chapter 2—*Petroleum Resources Definitions, Classification, and Categorization Guidelines*. Simple summation and range aggregation (using probabilistic methods) are both appropriate paths to a valid resource estimate; however, that validity and therefore the aggregation method used are contingent on the purpose of the aggregation and the inherent uncertainty of the components being aggregated.

Oil and gas companies considering long-term development and performance of their assets likely will use an assessment of volumes for investment, development path, infrastructure, and competitive advantage decisions. The Petroleum Resources Management System (PRMS 2018, § 2.2.2.10) states that "for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification" and that (§2.1.3.7.2) the "best estimate (or P50) production forecast is typically used for the economic evaluation for commerciality assessment of the project." Consequently, the PRMS equates "Best Estimate" to the P50 or median result. It is recognized that this term is not used consistently across industry, and, in many locales, it is avoided entirely. The reader is advised that when the term is used within the PRMS and this document, it refers to the median or P50 result.

Of late, some companies have been moving to a more confidence-based approach to resources estimation involving an aggregation process that takes into account the full range of potential outcomes. They work on the assumption that the maximization of their confidence of making the correct development and infrastructure decisions is the efficient path to resource assessment and development, and ultimately the best value of their uncertainty-filled portfolios will be realized.

For multiple reservoir assessments, decision-based evaluation can seem to conflict with the recommended levels of certainty associated with 1P, 2P, 3P and 1C, 2C, 3C categories. For example, what we are at least 90% certain will be achieved from a collection of producing horizons is never less than the arithmetic sum of the 1P components. When uncertain, ranged potential is aggregated across elements of a project or portfolio, our 90% reserves confidence occurs at a reserves tally higher than the simple sum of the 1P Reserves. We will illustrate this aspect several times throughout this chapter and provide guidelines as to how to create, assess, and communicate aggregated results.

Although there are several valid reasons to aggregate volumes, and different aggregation methods have different suitability, there are a few overarching considerations specific to reserves reporting. When considering aggregation of reserves for reporting purposes, reserves classes should not be directly aggregated. The PRMS states (§ 2.2.2.5): "Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency [relationship] between them." The PRMS also states (§ 4.2.5.4): "It is recommended that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. Results reported 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." This chapter will provide detailed discussion of the latter point.

While it is vital to retain the 1P confidence definition on a single assessed project, the link from qualified deterministic calculation to resource confidence on a multiple-reservoir collection is broken in aggregations due to the uncertainty within the contributing reservoirs. In the case of multiple reservoirs, fields, project areas, or any sort of portfolio, the arithmetic tally and assessment considerations of "what has been found" will differ from that of "what do we expect from the portfolio."

The resource assessment approach taken will depend on the intended use of the results. On individual reservoirs, it is best practice to create and report reserves estimates as a range (1P/2P/3P) or, in the case of Contingent Resources, 1C/2C/3C. Where assessments may be based on deterministic methods, summations are typically (but not always) arithmetic and by category. Where probabilistic assessments are available, companies may aggregate probabilistically to the field/property/project level or, for internal use, portfolio level and then use a P10, P50, P90 characterization for the confidence levels within the ranged potential. It is a mistake to assume the P90 aggregate result is equal to the sum of the individual 1P Reserves in multiple or single reservoir evaluations. For internal portfolio analyses, companies may use fully probabilistic methods given that they also include shared chance and correlation as components of the assessment.

Investors, analysts, and utilities independent of development decisions will usually require a high level of certainty and concentrate on the Proved (1P) volumes, or to a lesser extent, the Proved-plus-Probable (2P) volumes. Development and infrastructure investors, wishing to ensure efficient right-sizing of hard assets, will want to understand the aggregated reserves taking into consideration uncertainty across the components. Long-term gas contracting is sometimes based on Proved-plus-Probable Reserves, where there is a large gas resource that is most economically developed over the life of the gas contract.

Accountants may use the ratio of production to Proved Developed Reserves or other reserves categories as the basis for depreciating or depleting the cost of acquiring and developing reserves over time as the reservoirs are produced. In some areas, the ratio of production to Proved-plus-Probable Reserves (including any Undeveloped Reserves) is used as the basis for depreciation. For these calculations, accountants require the reserves to be assessed at the level at which the investments apply. Accounting looks at what has been done and what has been found. As such, preserving 1P and 2P tallies is important across an aggregation, but it should be recognized that simple arithmetic 1P sums will have a high probability of underestimating what will ultimately be produced.

Section 8.2 addresses some general technical issues in resources aggregation. The discussion on the aggregation of resources also addresses the issue that the uncertainty of the sum of volumes will be less than the sum of the uncertainties of the individual volumes. In other words, the uncertainty decreases with an increasing number of independent units available. The implications of the resulting uncertainty reduction in a diverse portfolio, also called the portfolio effect, will be discussed in Section 8.3.

Section 8.4 discusses regional aggregation over resources categories, and the use of scenario methods for reserves aggregation is shown in Section 8.5, followed by Section 8.6, which summarizes the chapter in a few simple guidelines.

8.1.1 Defining Reservoir Relationships. As we aggregate resource estimates from multiple sources, we need to recognize their commonalities and shared assessment components. Collections of reservoirs will have varying degrees of similarity in such elements as depositional character, diagenetic history, economic thresholds, and evaluation bias, which will influence any aggregated assessment.

As we start to work with concepts that relate to a range of possible outcomes, the general naming guideline is to stick with definitive terms in reports and communication. Many companies try to avoid the use of ambiguous terms and be explicit about what they mean. Terms are important, but as long as there is clarity on the definitions, resources and reserves estimates may be calculated and communicated effectively. However, we recognize definitions vary, so we need to be clear as to their use within the PRMS.

Looking at the statistical terms, the Expected Reserves is the Mean reserves amount. While statisticians may differ as to the pure definition of “Mean” vs. that of “average,” for our purposes, Mean, Expected and average will be used interchangeably when describing a continuous distribution. We shall use “P50” or “Median” to describe that point in an uncertainty distribution that will have 50% of the possible outcomes above and 50% below that number.

There are two types of inter-reservoir relationships that must be considered in order to arrive at a valid and reliable aggregation result: Correlation and Dependency. We need to be clear on aggregated Correlation and Dependency because it is critical to keep the two methods separate for valid aggregation. The two topics are discussed in Sections 8.2.3 and 8.2.4, respectively.

Nearby reservoirs that have not been drilled may have shared chance. “Chance” refers to the collection of successful elements needed to be present in order to have an accumulation. While specific chance elements may differ between organizations, they typically belong to one of two categories, container (reservoir, vertical seal, horizontal seal, seal capacity) or contents (source, migration, timing, diagenetic history). The presence or absence of a major chance element in one location that changes the probability of success assessed for a second location indicates a *dependent* relationship between the probabilities of success for the two potential reservoirs. In this chapter, we will refer to this shared chance relationship as *Dependency*. We capitalize “Dependency” to distinguish the shared chance source from the colloquial “dependency,” which is used to denote a nonspecific relationship between two items or event. Dependency, as shared chance, is causative. Similarly, we shall use uppercase to denote the names for statistical positions along the uncertainty distribution (principally Mean, Median, and Mode).

In this chapter, we will refer to the similarity in outcomes of range-based elements of different reservoirs as *Correlation*. We recognize reserves uncertainty in our 1P-2P-3P categorization, but more typically in the predictive probabilistic notation of P90-P50-P10. While there may be some root cause for similar ranged outcomes, positive Correlation should not be taken to imply causation, but merely a similar outcome.

Correlation is usually found at a contributory level shared by correlated entities. For example, two reservoirs on a common hydrocarbon migration path will have their ultimate resources estimates linked to the amount and timing of the migration. The location across the range of potential volumetric results related to trap fill extent will be linked, but not exact. Other factors such as seal capacity, porosity, diagenetic enhancement, or destruction may be independent and mitigate at least a portion of the correlation. As such, the typical correlation we see is not "full correlation." The correlated elements, be they wells in a reservoir, reservoirs in a field, or fields in a portfolio, have a tendency but not a requirement to have a common degree of outcome.

8.2 Aggregating Over Reserves Levels (Wells, Reservoirs, Fields, Companies, Countries)

8.2.1 Reservoir Performance. The most reliable estimate of the recoverable quantity, referred to in the PRMS as the "Best Estimate" and usually equated to the P50 estimate when probabilistic methods are used, is derived through extrapolation of well performance in mature fields [e.g., by decline curve analysis (DCA)]. In applying DCA methods, industry practice is to work from the lowest independent production level (e.g., wells or completions) upwards, comparing both individual and reservoir- or field-level analysis. Unconventional reserves assessment is particularly dependent upon well-level analysis because any unconventional field-level DCA would be, at a minimum, misleading.

Performance extrapolation at the conventional reservoir level can lead to a higher Estimated Ultimate Recovery than the sum of the extrapolated well decline curves for that reservoir for many reasons, including catastrophic failures such as wellbore or completion damage. Also, the comparison of individual-well DCAs to a field-level DCA will highlight small, systematic biases that could otherwise be undetectable at a low level of analysis (where operational activities, such as routine workovers or production downtime such as for maintenance, are typically handled at the field level as opposed to well level for production decline analysis). Field-level economic considerations that may shut in individual wells, thereby elevating the aggregate margin of the remaining wells and extending the mean field producing life, result in a form of survivorship bias.

Another problem, which is specific to gas fields, is that the material balance *p/z* plot per well often does not properly reflect the overall reservoir pressure decline. In these situations, it is preferred to use an overall reservoir-level performance extrapolation.

8.2.2 Issues with Arithmetic Summation. The individual well aggregation vs. reservoir-level aggregation difference, when numerous wells are present, is heightened if we use only 1P/1C estimates for the well extrapolations (taking care that the 1P/1C forecast satisfies the reasonable certainty requirements, as discussed in Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* herein). If we sum the individual well 1P/1C estimates to the reservoir level, then we have assumed full correlation (i.e., that all wells will develop their low case simultaneously). Arithmetically summing the 1P/1C results, while producing a valid 1P/1C total, implies that all wells will be able to develop only their low (90% confidence) case resources. The probability that all wells will only produce their 1P/1C estimate is extremely small and decreases further as more wells are included. When we look at the arithmetic sum of 1P/1C values across a larger area such as a pool or field, the likelihood that reserves will amount to at least a minimum of the sum of those 1P/1C values is dramatically higher than 90%. As such, a simple arithmetic sum of 1P/1C estimates across a reservoir will result in overly conservative predictive estimates at the reservoir level, and most certainly across elements of a portfolio.

Understanding the disconnect between simple arithmetic sums and the aggregate probability of a result is critical to the understanding of appropriate aggregation. **Table 8.1** shows a simple five-well example, where the individual reserves estimates (in Bscf here, with all Commerciality criteria having been met) are identical, and the wells are uncorrelated (the result from one well provides no information about the result from any other well).

Well	1P	2P	3P	Cumulative 1P Sum
1	5	10	20	5
2	5	10	20	10
3	5	10	20	15
4	5	10	20	20
5	5	10	20	25

Table 8.1—Resource ranges and simple 1P sum for five wells in Bscf.

The confidence that each individual well would have at least 5 units of reserves is 90%. In the reverse perspective, the probability of each individual well having its outcome ≤5 units is 10%. Is it reasonable to state that the reserves across all five wells with 90% confidence is a total of only 25 units?

What is the probability that the aggregated result of the first two wells is 10 units or more? It is far better than 90%. We have only a 1 in 10 chance that the result for Well 1 and Well 2 individually is ≤5. The probability that both wells will be at the small end of their range at the same time is going to be even smaller. If we aggregate the distributions for the first two wells, we see the probability of the combined result being less than 10 units is only 2.7%, or the confidence we have that the aggregate result is greater than 10 units (the sum of the 1Ps) is 97.3%. The higher is the number of elements being aggregated, the bigger is the deviation of the aggregate 90% confidence from the simple cumulative sum.

We have discussed the underestimation error at the 1P end of the Proved Reserves uncertainty. Similarly, an overestimation error occurs at the 3P end. Arithmetically summing the 3P results simply provides the sum of the 3P numbers. As shown in **Fig. 8.1,** it does not produce a total that in any way represents at least a 10% probability of occurring.

The results shown in Fig. 8.1 are from a stochastic aggregation of the five independent well distributions shown in Table 8.1. The results were tracked over 10,000 realizations, and the percentiles shown represent the likelihood of arriving at the arithmetic sum or less of the 3Ps through the particular well aggregations (i.e., Well 3 results sum the results from Wells 1–3 and then locate the probability of having ≤60 units of volume within the range of a probabilistic aggregation).

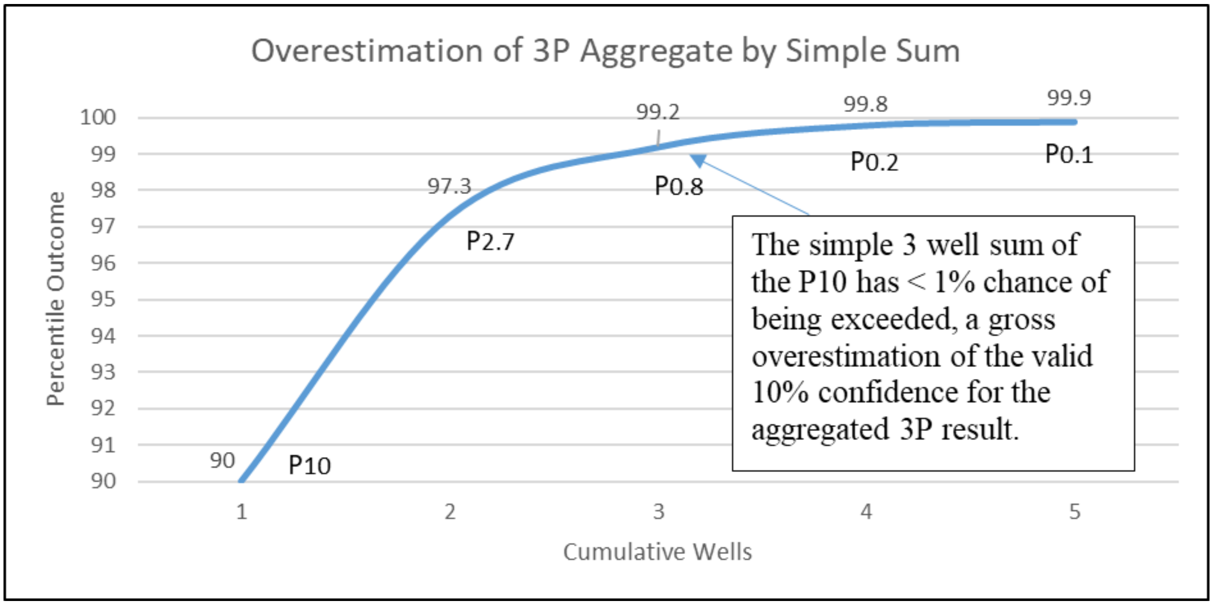

Fig. 8.1—The percentile outcome of achieving at least the simple sum of the 3P Reserves across a portfolio of five independent wells, given a distribution of 5-10-20 units for each individual independent well. The graph was created through a stochastic simulation of the well results.

In our Table 8.1 and Fig. 8.1 example, the aggregated result of five wells that provides an exceedance probability of 10% is 68 units, as opposed to the 100 units created by the simple 3P arithmetic sum (5 × 20 units). In fact, the probability of achieving 100 units or better when we aggregate the five wells is approximately 0.05% or 1 chance in 2,000. To rephrase, the outcome that represents the 3P is 68 units, not the simple arithmetic sum of 100 units. Here, 100 units would be exceedingly rare, and a statement that attributes the simple sum to be the 3P estimate would be a gross overestimation of the true aggregated outcome. Again, while it may be permissible to add the defined 1P, 2P, or 3P Reserves to indicate the specific category total, that sum is not a valid representation of the reserves potential on an aggregated predictive basis.

Let's take a look at this logic. The probability of one well's outcome being in the top 10% of its distribution is 10%. In fact, it should be obvious that the probability of any well being equal to or greater than the 3P of the distribution is 10%. As we aggregate, we are adding together the outcomes. Setting the 3P number equal to the arithmetic sum of the individual 3Ps means that all the wells need to be at the higher end of their uncertainty range at the same time.

What is the probability of every independent well producing greater than or equal to its 3P result? That is equal to the product of the individual probabilities, or 0.1^5, a chance of 1 in 100,000. Clearly this is not 10%.

But wait, didn't we just say (three paragraphs above) that the chance was about 1 in 2,000? Why the 50× difference?

We said in our calculation that each independent well would be "at or greater than" its 3P (or P10) result. It is important to remember as we aggregate distributions that all probabilities relate to a threshold point and beyond. If we are just targeting the arithmetic sum of each well's 3P, then for every well that comes in over the 3P, it allows at least one of the other wells to come in under the 3P threshold in order to have the aggregate sum be equal to the arithmetic sum of the 3Ps. It should be obvious that we cannot aggregate independent well resource/reserve distributions by arithmetically summing their 1Ps or 3Ps. Because of the skewness of the distributions, a similar, though less consequential, error results from the addition of the 2Ps.

Table 8.2 shows the stochastic assessment results for the aggregated distributions cumulatively as we add progressive wells. Note that as we add wells, the magnitude of the arithmetic sum increases. Note also that as we add more population, the magnitude error increases. When more elements are added together, as opposed to being properly aggregated, the calculation will be the further off the valid answer.

Well	Cumulative Arithmetic Sum 1P	**Cumulative Aggregate 1P (P90)**	Cumulative Arithmetic Sum 2P	**Cumulative Aggregate 2P (P50)**	Cumulative Arithmetic Sum 3P	**Cumulative Aggregate 3P (P10)**
1	5	**5**	10	**10**	20	**20**
2	10	**13**	20	**21**	40	**35**
3	15	**22**	30	**33**	60	**50**
4	20	**31**	40	**44**	80	**64**
5	25	**40**	50	**56**	100	**78**
Error	Sum lower than Aggregate		Sum closer but still lower than Aggregate		Sum higher than Aggregate	

Table 8.2—Comparison of cumulative sums vs. cumulative aggregates.

Fig. 8.2 shows the percent error of our independent five-well example. The error is dependent on the underlying uncertainty of the individual members of the collection. After only five wells, the arithmetic sum of the 1P (P90) individual well outcomes is only 63% of the appropriate aggregated number that provides at least a certainty of 90%. This error would continue to widen if we were to increase the population with more independent members.

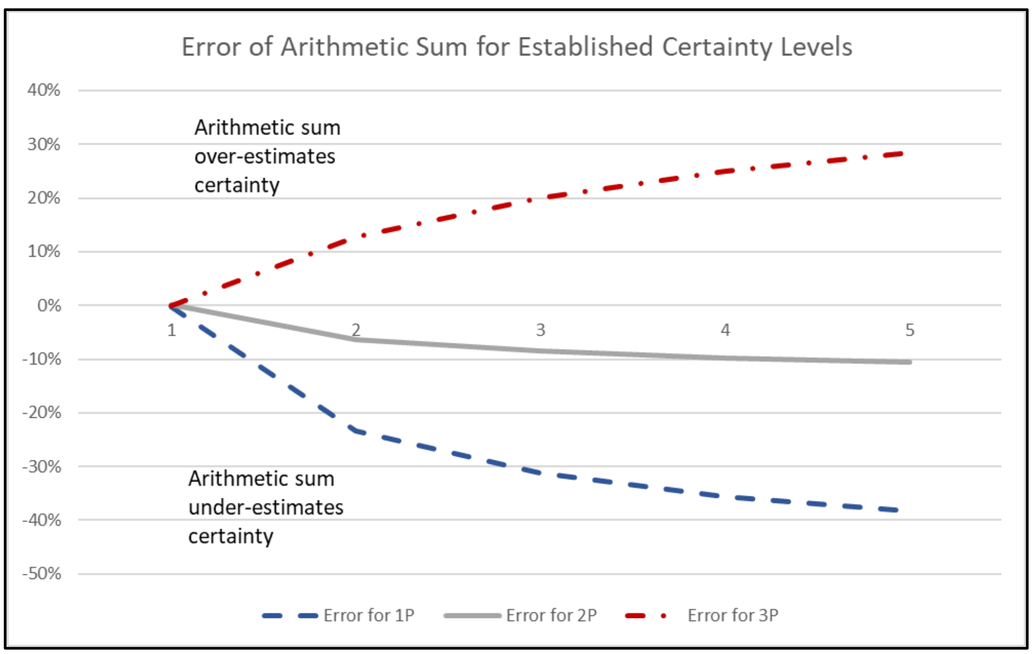

Fig. 8.2—Error in the arithmetic sum as the well population is increased.

Fig. 8.3 shows the 80% certainty range as we aggregate through the five independent wells. It is important to note that as we add more wells, the percent difference decreases. Larger populations of similar members have narrower result ranges. This narrowing can get to the point of feeling too narrow, too confident in a particular group result. This is often because we typically have relationships, links, or commonalities between the members of our aggregated entities.

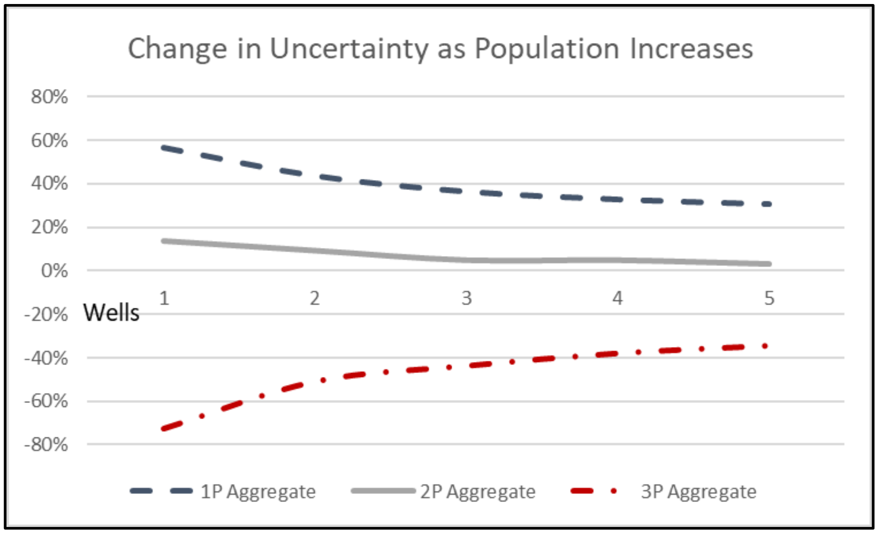

Fig. 8.3—As population increases, the 80% certainty range decreases as a percentage of the Mean.

Well groupings, adjacent pools, or shared structural or depositional settings may provide common causative factors that align or provide linked uncertainties in our reserves calculations. These commonalities can cause a general agreement in uncertainty outcome. As such, the related elements in the aggregation may show a degree of correlation.

As a guideline, anticipate the presence of some degree of correlation between wells in the same reservoir because they have the same geological formation, drive mechanism, mode of production, etc., but they will certainly not be fully correlated. There will be differences between them resulting in a well distribution. Similarly, adjacent reservoirs will also have a degree of correlation, which will provide a tendency to similar outcome. There will be differences well by well and reservoir by reservoir.

1P Reserves are Proved and, by the PRMS definitions, have at least a 90% certainty (when evaluated using probabilistic methods) that the quantities recovered will equal or exceed the estimate. Nonetheless, the three designations 1P-2P-3P or P90-P50-P10 acknowledge uncertainty in the final outcome. As a guideline reminder, we note the use of "at least" in the 1P definition; it cannot be assumed automatically that 1P = P90, 2P = P50, and 3P = P10, especially for aggregation purposes. These are the minimum acceptable confidence levels for these categories. Arithmetic summing of 1P estimates is valid to provide a sum of 1P across a reservoir, across reservoirs, or across a portfolio of projects. However, this simple sum should not be equated to a P90 value of the aggregate (the amount of aggregated reserves having a 90% probability of occurring).

Two approaches have been proposed to avoid the effect of arriving at too-low aggregates for 1P volumes when aggregating populations:

1. For reservoir estimates, apply decline analysis at the reservoir level.
2. Statistically aggregate Proved estimates from well level to reservoir level.

8.2.2.1 Method 1: Performance Extrapolation and DCA at the Reservoir Level. This approach is an obvious and necessary supporting part of the performance analysis. In cases where reliable production data at the well level are not available, DCA at a higher level where the production is reliably measured (e.g., platform, plant, production station, or reservoir) may be the only basis for the performance extrapolation. Another condition that calls for a higher-level DCA is the occurrence of strong interference effects between neighboring wells.

Performance extrapolation at the reservoir level has a number of pitfalls:

- The performance will include the effects of ongoing drilling, development, and maintenance activities. Time slicing the wells into these groups helps to differentiate behavior related to activities.
- The aggregate may include wells at different stages of decline, with different gas/oil ratios, etc. As such, be wary of survivorship bias.
- In multiwell aggregates, the decline may be dominated by the high-rate wells or recent/well-specific activities, which may lead to incorrect estimation of the reserves.
- DCA early well behavior, pre-water breakthrough, enhanced recovery methods, or market or infrastructure capped production may distort the reserves total.
- As parts of the reservoir are shut down due to negative local margin, the remaining wells receive an economic benefit that may extend their anticipated economic life and reserves. For example, offending high water-cut wells may be shut in, thereby reducing water handling and disposal costs. This is a form of survivorship bias and should be taken into account in the initial aggregation.

8.2.2.2 Method 2: Statistical Aggregation of Well-Level Proved Estimates. A different approach to compensate for arithmetic addition of high-confidence estimates may be to apply a form of statistical addition. This method also has elements that will require attention:

- Well-level Proved estimates are often correlated due to common aquifers, formation heterogeneity, facilities, operational constraints, etc. If independence is assumed, it is up to the reserves evaluator to justify this assumption. If full correlation is assumed, a high level of justification is required.
- Probabilistic or statistical methods often rely on statistical simplifications, e.g., the assumption of particular distribution shapes or probability density functions for the reserves estimates. The upper end of such distributions must be appropriately managed with limits (capping the upper ends at a set feasible magnitude as opposed to truncating the upper ends).

It should be noted that many of the above problems may be avoided through the use of stochastic simulation techniques. At the reservoir aggregation level, DCA is the method of choice for 1P/1C and sometimes in cases of low uncertainty 2P/2C ranges (when 2P/2C is close to 1P/1C) when correlation is minimal. Justification from the qualified reserves evaluator should be able to support the aggregation level chosen.

8.2.3 Correlations Between Estimates. A brief introduction to Correlation vs. Dependency has been covered in Section 8.1. We will now delve further into this critical part of an assessment. Aggregation of resources must consider correlation between the items being aggregated. Correlation is present whenever the volume outcome (known or presumptive) from one entity indicates a likely volume tendency of another. It is described in a way that quantifies the degree of similar outcome. Numerically, the degree of similarity of outcome is expressed in terms of a correlation coefficient, which ranges from −1 to +1. A correlation coefficient of zero (0) indicates no correlation; i.e., the knowledge of one outcome has no impact on expectations from another. A correlation coefficient of +1 indicates an exact match (full positive correlation) of probabilistic outcome between entities being aggregated; i.e., the exact same probability range result will be found between wells (Well 1 meeting its P15 result means that Well 2 will also produce its P15 result). A correlation coefficient of −1 indicates a perfect, symmetrical, and certain counter-result situation or full negative correlation (Well 1 meeting a P15 result would mean that Well 2 would produce a P85 result). The end points of −1 and +1 would be extremely unlikely to ever occur in nature. We must remind ourselves that the simple addition of 1P Reserves necessarily defaults to a correlation coefficient of +1. Correlation exists if the outcome from one or more wells in a collection affects the anticipated result from other wells. The degree to which it affects the anticipated result is the correlation coefficient.

Note, in the previous paragraph, we did not mention the magnitude of any particular outcome. We consistently described outcomes by their probability location. It is important to state that when we discuss correlation (the similarity between two outcomes), the correlation to which we refer is a *Rank* correlation. Rank is the probability position of an outcome across the full uncertainty range. Rank correlation, therefore, is the similarity between outcomes on the probability range for the uncertainties, not the actual magnitudes. Items being aggregated will have their own distribution of potential results, but the tendency to have a particular outcome, be it low or high within the respective uncertainty ranges, indicates correlation is present.

Correlation rests at the reservoir component level, and it is possible to have several different levels of correlation within the many parameters in the resource calculation. Correlation originates from common influencing factors such as depositional environment, diagenetic history, shared spill point, and, on the human interaction side, similar evaluation bias and common completion mechanisms. Correlation originating from similar evaluation bias, or modeling bias, is often underestimated in the assessment of overall correlation. Examples of modeling bias include velocity (time-depth) uncertainty or assumptions about decline curve parameters. Recovery factors based on potentially insufficient or imperfect sampling also may not be reliable for estimating future development outcomes.

As the aggregation level increases, correlation coefficients move closer to zero but remain influential. **Table 8.3** shows degrees of correlation for a selection of feasible causative situations.

A positive correlation between two estimates can be illustrated with the depth-area plot of a field shown in **Fig. 8.4,** which consists of two reservoir sands divided by a shale layer within the same enclosing structure. The sands have a common oil/water contact. Obviously, in this case, the reserves for both sands will change in the same direction if an exploration well finds the oil/water contact to be somewhat shallower, if a new seismic interpretation lifts the flank of the structure, or if the time-depth relationship is found to be different. Summation of the low estimate values for the two sands may be used to arrive at a low estimate for the field, but only if all other parameters are also fully correlated, or their variance is very small.

This situation results in a strong correlation coefficient between the individual producing horizons, often in the 0.7–0.8 range. The temptation is to assume a simple arithmetic sum of the high (P10) and low (P90) respective assessments, but this ignores other reservoir and completion uncertainties. A correlation coefficient of +1, which would allow simple arithmetic summing across the predicted range of results, is extremely rare. It dictates that all relevant reservoir characteristics found as reservoir 1 is drilled/completed would enable precise predictive capability of characteristics to be found in reservoir 2. This is not to say that the uncertainties would resolve to have equal magnitudes, but only that the position within the range of possible outcomes would be known (i.e., the rank).

Degree of Correlation	Examples
None – Correlation coefficient = 0 No common factors in deposition, reservoir, method of completion, or assessment.	Local or independent pressure systems, structurally independent, significant vertical separation, different depositional and diagenetic systems, and different completion paths.
Weak – Correlation coefficient < 0.3 A shared uncertainty is not considered to be an important indicator of results between the elements. Correlation does not materially affect the aggregated results.	Common clastic or carbonate depositional system classification. Common source of recovery factor estimates, tools (e.g., reservoir simulator), and ranges Elements having a common saturation-calculation method (e.g., Archie, dual-water, etc.) or saturation-height function (particularly those using a common reference data set).
Medium – Correlation coefficient 0.3 to 0.7 The shared uncertainties and evaluation bias could be real and significant.	Common depositional and migratory path context. The success of a low-pressure compression project in one field is a prerequisite of success in another, and hence the recovery factor uncertainties are likely linked. However, the major components of the uncertainties in reserves of the two fields (structure, etc.) remain independent.
Strong – Correlation coefficient d> 0.7 and < 1 The shared uncertainties are known to be real and significant.	The aquifer and pressure systems between two proximal fields are likely to be common, and actions in one field will affect recovery in the other. Well behavior within an unconventional part-play. Reservoirs with a common structurally defined spill point, leak. Aggregation of unconventional wells across a part-play.
Total – Correlation coefficient = 1 The shared risks are absolute.	Two adjacent accumulations have commonality assumed in all uncertainties (e.g., reservoir unit, velocity model, aquifer drive); thus, their reserves estimates can be added arithmetically.
Negative Ranges – Correlation coefficient between 0 and −1 The shared uncertainties are countervailing or reciprocal.	An oil field is developed in a core area only. Additional upside in stock-tank oil initially in place (STOIIP) in flank areas will result in a reduction in the average recovery factor. Uncertainty in fault location works in the opposite direction for gross rock volume (GRV) in two adjacent blocks. This is an internal negative correlation within a single reservoir. Correlations may be negative (opposing outcomes) but need not be absolute.

Table 8.3—Ranges of correlation between reserves estimates of fields, reservoirs, or wells (adapted from Carter and Morales 1998).

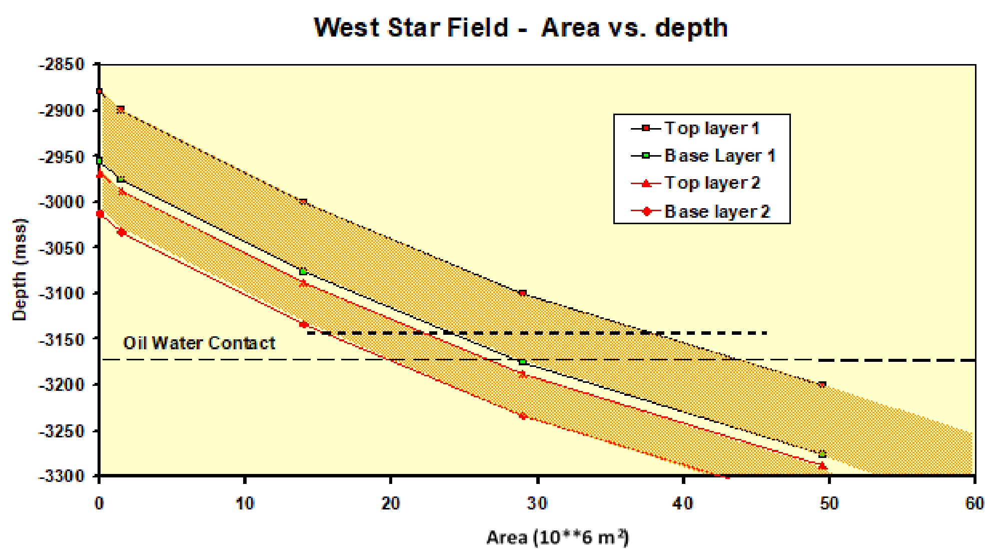

Fig. 8.4—West Star field area vs. depth.

Negative correlation coefficients are possible. They represent a reciprocal behavior between reservoirs (or wells). As an example, **Fig. 8.5** shows two noncommunicating blocks having a common structure separated by a fault of uncertain location. If the fault is found to occur closer to the crest of Block A, then the volume associated with Block A decreases, and the volume for Block B increases. The reverse would occur if the fault was further into the mapped Block B area. At the gross rock volume component level of the reserve calculation, there would be a (−)1 correlation coefficient. At the resource volume level, there would be a negative correlation apparent, but due to all the other uncertainties in the assessment, it would be highly unlikely to be as strong as (−)1.

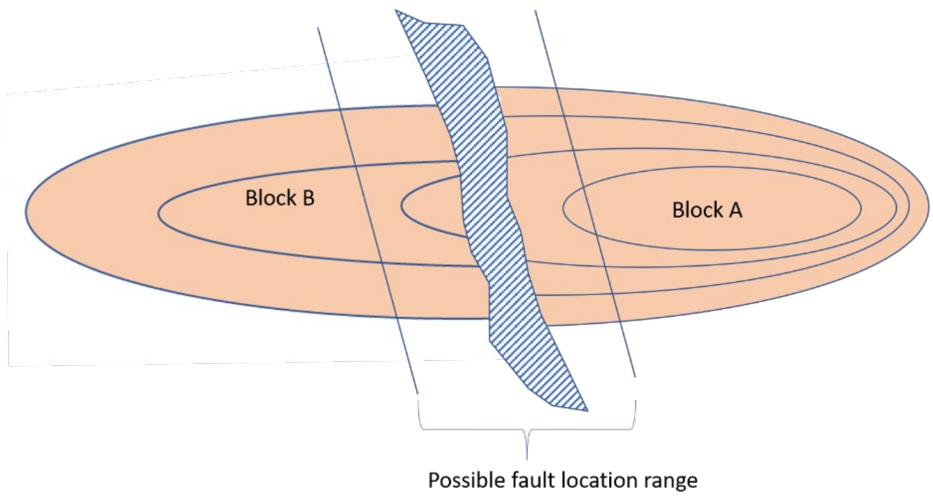

Fig. 8.5—Block A and Block B separated by a fault of uncertain location. As the fault location changes, the volume associated with one side of the structure transfers to the other, thereby creating a negative correlation.

If we arithmetically sum the low estimate values in each of the two blocks, we arrive at the low estimate for the structure. However, given that the individual low estimate assessments for each side must necessarily reflect the amount each block is at least 90% certain to contain, this would require holding the fault location at or near the reasonable minimum proximal location for each individual block. This is not reasonable. The fault cannot be in two different locations at the same time. The arithmetic sum of individual block low estimates will underestimate the aggregate low estimate for the structure. This structure is best and most fairly evaluated at the aggregate level by taking into account the negative correlation.

Another commonly encountered negative correlation is the situation in an oil reservoir with a gas cap, where solution gas below the gas/oil contact is estimated separately. If there is an uncertainty in the gas/oil contact depth, then there is a negative correlation between the gas reserves that are carried above and the oil reserves below the gas/oil contact.

The depth-area plot method for volume assessment is particularly useful in this situation. Fig. 8.4 is an example of such a plot. Depth-area plots are created by taking the area of the reservoir as it appears at a particular depth. Calculation of the resource volume in place becomes a simple integration of the volume below the plotted line. When the reservoir is limited in height, the depth-area plot of the base of the reservoir is needed in addition to the reservoir top. Fig. 8.4 shows two reservoirs. Each reservoir has a top and a base plotted. This method is particularly useful in nonuniformly shaped reservoirs.

Unless information is available, such as detailed fluid properties or verified/conformable seismic amplitude anomalies to guide the placement of the gas/oil contact, it is usually appropriate to assume that the volume above the highest-known oil is occupied by the lower-value product (usually gas) as the less-impactful case.

Adding up P50 (or Best Estimate) values will show a more valid result; however, the only truly valid arithmetic summation occurs (outside of full correlation across all uncertainties) when the Means are summed. Obviously, if the low estimates are added, then the low case for free gas will correspond with a high case for solution gas and vice versa. To handle this, a stochastic procedure referencing a depth-area plot construct (using an Excel™ spreadsheet with stochastic modelling techniques or with a commercial add-in) can be used to arrive at the resultant distributions for predictive gas initially in place (GIIP) and potential reserves at the field level.

Finally, in rare situations, it is possible to have correlations that are more complex than these examples. Resource volume correlations may not be monotonic in nature and can take on a "U" or upside-down "U" shape. For example, there may be situations arising from varied uncertainty reservoir connectivity models, where both a small-volume outcome or a large-volume outcome for one reservoir could be associated with higher volume estimates for a second reservoir. In this instance, outcomes for the first reservoir occurring closer to the distribution center would decrease the reservoir volume of the second. Relationships between reservoirs may be simple or complex, but they should always be taken into account for reserves or resource aggregation.

8.2.4 Dependency. When we examine Dependency, we require at least one member of the "dependent pair" to still have probability of success (or P_g) remaining unresolved. As such, it would be a rare circumstance indeed to see Dependency within a 1P-2P-3P context. However, we would likely encounter it within or across the 1C-2C-3C categories. "Contingent" relates to a condition being established or a threshold being passed. In either situation, the sought-after result is binary: It is either there, or it is not; the threshold is either exceeded, or it is not.

Dependency is assessed between two potentially productive entities. One of the entities may be thought of as independent and bearing its own P_g. The second entity's P_g will be determined dependent on the success or failure of the independent entity. Given resources are identified for the independent entity, the shared chance elements with the dependent entity are moved to 100%. The entities together may be referred to as a dependent pair.

The P_g is a product of its chance element probabilities. These chance elements differ company to company as mentioned previously in Section 8.1.1, but they generally pertain to aspects of container and contents: Source, horizontal seal, vertical seal, reservoir, and timely migration are common chance elements. A Dependency exists when the probability of success for the dependent element is altered by the knowledge of success or failure of the independent element. Dependency must be considered in resource assessment when there is chance learning between elements being assessed, in other words, if knowledge of one binary outcome alters the probability of a second binary outcome.

Valid aggregations of Contingent Resources will require P_g to be kept separate from uncertainty. It is recommended to aggregate the contingent component by sampling from the P90-P50-P10 range P_g % of the time; otherwise, appropriate aggregation that produces a range of confidence will not be possible. For example, as depicted in **Fig. 8.6,** our discovery well had a 40% chance of success. Upon discovery, our assessment of chance factors changes. We now know that the P_g for Reservoir A is 100%, and Reservoir A has a P90-P50-P10 range of 4, 6, and 9 million barrels of oil, respectively. After Reservoir A success, Reservoir B has a 30% P_g, and given success, it is estimated to have a P90-P50-P10 of 2, 4, and 8 million barrels of oil, respectively.

Let's examine how to aggregate these reservoirs when they are independent, and when they share risk, before and after the initial discovery.

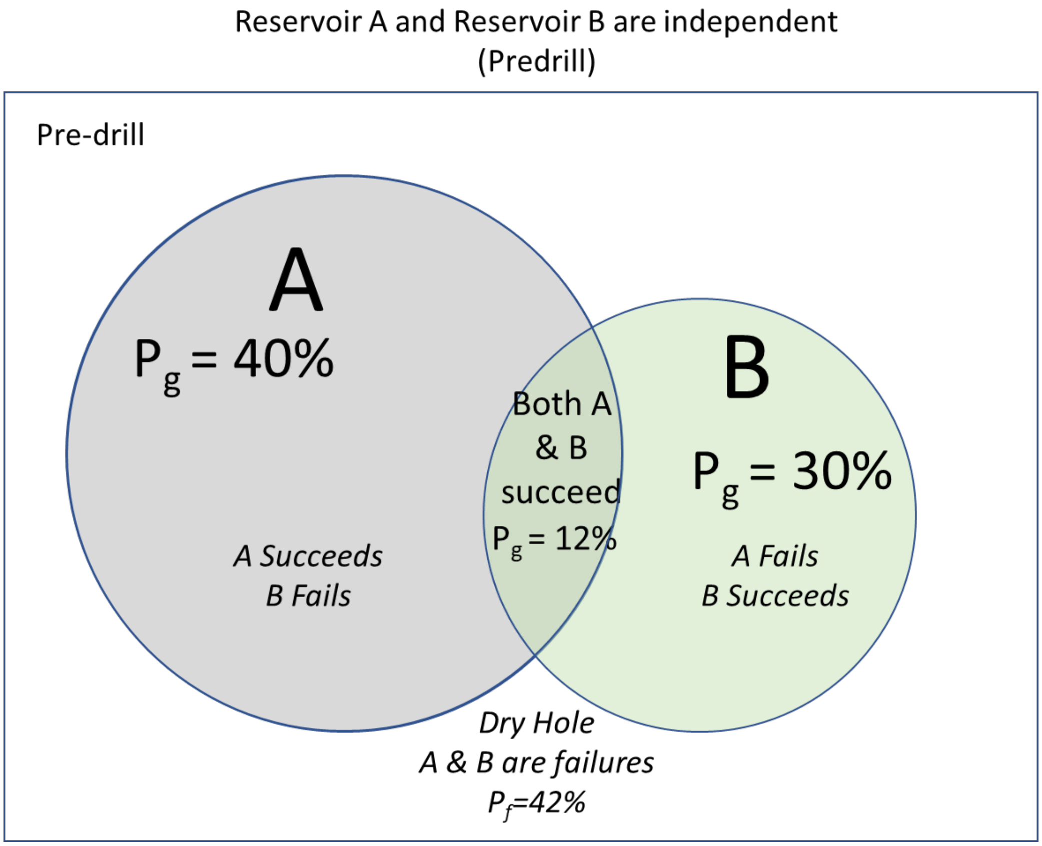

Fig. 8.6—Venn diagram of the prediscovery chance of success state (not to scale).

8.2.4.1 Independent Reservoirs. When reservoirs are independent, the success of one has no effect on the assessment of chance of success for the other. In our independent situation, $P_A = 40\%$, $P_B = 30\%$, and therefore

$$P_{AB} = P_A \times P_B = 12\%,$$

and

$$P_{\text{Failure}} = P_{A\ \text{Fails}} \times P_{B\ \text{Fails}} = (100\% - 40\%)(100\% - 30\%) = 60\% \times 70\% = 42\%.$$

The aggregation needs to take each of the probabilities of success into account. Again, the easiest way to aggregate the two reservoirs is to set up a quick simulation. Use two random number generators, one for each reservoir. If the realization returns a random number less than the probability of success for the reservoir, then sample from the distribution; otherwise, the result for that reservoir in that particular realization (trial) is 0. Sum and track the result for each trial. This will provide a probability of at least one of the reservoirs being successful and the distribution given at least one successful reservoir.

It is incorrect to factor a reservoir's distribution by the chance of success and assume it has meaning.

Let's take a small step to look at the postdiscovery assessment.

Given our discussion above, it should be obvious that all we have to do in the aggregation model is to assign a chance of success to Reservoir A of 100%. In a Venn diagram representation, it looks like **Fig. 8.7.**

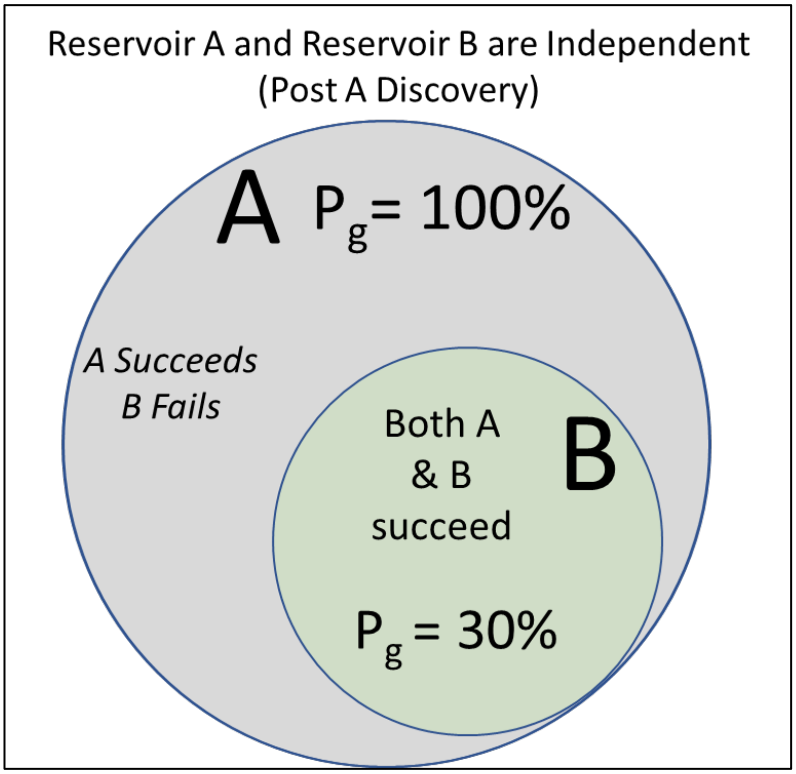

Fig. 8.7—Postdiscovery Venn diagram (not to scale).

Reservoir B's success looks smaller, but it isn't. As they are independent, Reservoir B's success takes up 30% of whatever our "world view" is. Prediscovery Reservoir B took up 30% of the world that included dry holes. Our world has changed to only show the cases in which A is successful. P_B is still 30%.

$P_{AB} = P_A \times P_B = 100\% \times 30\% = 30\%.$

If we aggregate the two reservoirs in this context, we sample every trial from the Reservoir A distribution and only 30% of the data from Reservoir B's distribution. As Reservoir A is successful, we don't have a probability of at least one success. We have Reservoir A's distribution that is bumped by the occasional addition of Reservoir B. This will have a greater effect on the upper portion of the aggregated distribution. In our example, the aggregated distribution is P90 = 2.2, P50 = 5.3, and P10 = 11.8 million barrels of oil.

Other methods, such as prorating the Reservoir B at 30% and allocating it across the Reservoir A distribution, or sampling Reservoir B only for the P10 case of Reservoir A, do not provide valid aggregation.

8.2.4.2 Dependent Reservoirs. What do we do if the two reservoirs share chance, such as a common seal or migration path? This shared chance means that if we are successful at Reservoir A, then the probability of success for Reservoir B has increased (some of its chance threat has been solved). Given that Reservoir A is successful, we see the probability of success for Reservoir B increasing, perhaps to 50%. The formulaic abbreviation for the probability of B given A success is $P(B|A)$. Since Reservoir A's success doesn't solve all of Reservoir B's chance elements, Reservoir B still can fail.

Where do these dependent numbers come from? If the reservoirs share seal and migration risk, and Reservoir A is shown to be successful, then seal and timely migration must also be present for Reservoir B. However, seal is only one of the risks inherent to Reservoir B. A proven seal and timely migration alone do not guarantee success of Reservoir B, but the estimate of the probability of Reservoir B being successful increases when the results of Reservoir A are known.

The rule for the maximum dependency of two dependent elements is: The maximum probability of the dependent element given success of the independent element (the one you find out about first) is equal to the ratio of the dependent element's P_g to the independent element's P_g.

In our example, the highest possible probability of success (prior to drilling) for Reservoir B is 30/40 or 75%. We must always preserve the initial independent probability of success because dependency changes only when something occurs, not when its size changes, and we can never create probability.

When we have a dependent set of reservoirs to aggregate, we have to modify the dependent reservoir's chance of success given the independent reservoir's success or failure outcome.

In the prediscovery aggregation model, we have to account for the percentage of the time A and B will occur together, the percentage of the time they will occur separately, and the percentage of time that neither would occur. These percentages are a function of their individual independent probabilities and their shared chance. **Fig. 8.8** shows the configuration with a degree of partial shared chance ("partial dependency").

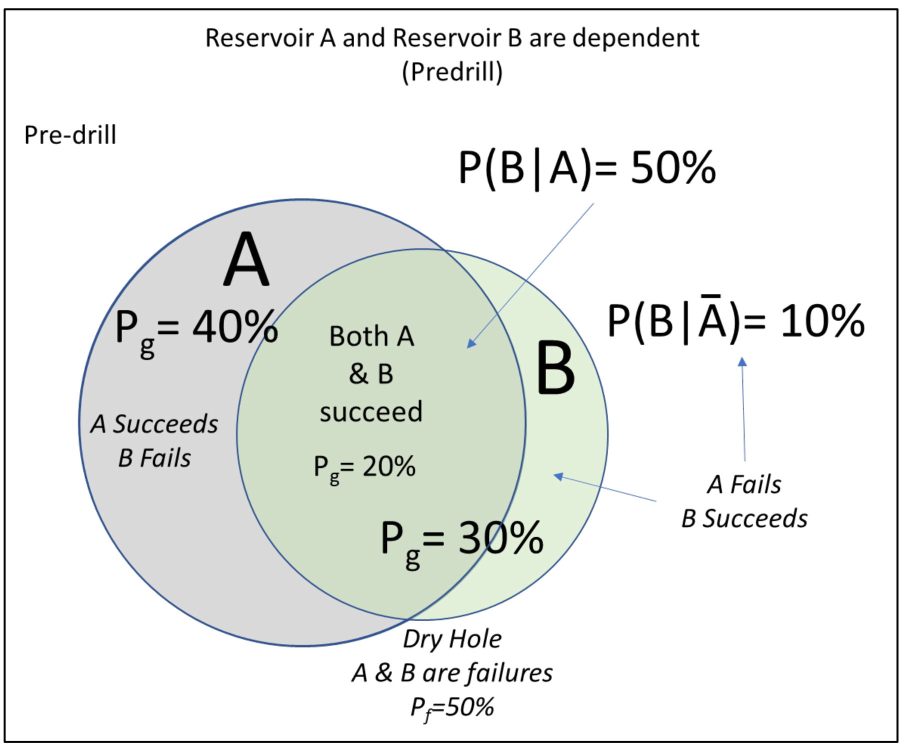

Fig. 8.8—The configuration of probabilities of success in a dependent situation where *P*(*B*|*A*) = 50% (not to scale).

When working with dependencies, it is important to remember that the individual probabilities do not change (predrill) given any amount of positive or negative dependency. Dependency only controls <u>when</u> success happens, not how often it happens. Before we drill Reservoir A, we have assessed the common risk elements between the two reservoirs and have found that <u>if</u> Reservoir A is determined to be productive, then the improvement in probability of success due to the shared risk elements between the reservoirs changes the probability of Reservoir B given A success [$P(B|A)$] to 50%. P_g of Reservoir A is 40%, and so 50% of that is 20%; therefore, the probability of both reservoirs being productive is 20%, an increase from 12% in the independent case.

The opposite action will also be present. If Reservoir B is more likely to occur when Reservoir A is successful, then when Reservoir A is a failure, Reservoir B has a lower chance of success. In our example, the probability of Reservoir B success given Reservoir A failure reduces from the independent probability of 30% to only 10%. This is due to the risk shared between the reservoirs.

Note that the independent probabilities of 40% and 30% for A and B, respectively, are preserved. The only element that has changed is the overlap of the probability circles. The B circle has shifted into the A circle to the extent that it now covers 50% of the A area. In the shift, B converts some of the time it is occurring without A into the time it occurs with A (delta caused by the shared chance). In that process, the probability of both reservoirs failing increases by the same amount as A and B occurring together increases. Dependency in the form of shared chance decreases the probability of having at least one success but increases the distribution of resource when successful. This balance means that risked resources do not change.

When we look at the postdiscovery situation, the dependent question regarding the likelihood Reservoir B will be successful has been solved. **Fig. 8.9** shows the postdiscovery case.

At this point, remember that reserves do not include "risked reserves." Risked aggregation normally occurs at the resource level, but the concepts can also be applied to the lateral extent of a known continuous reservoir, especially when planning infrastructure, appraisal, or development well locations.

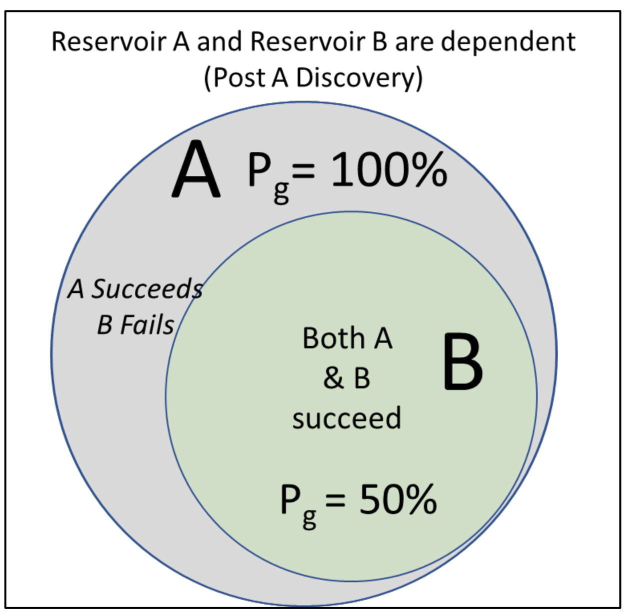

Fig. 8.9—Venn diagram of the dependent (shared chance) situation (not to scale).

8.2.5 Higher-Level Aggregation. As discussed previously, aggregation of resource estimates in a statistical way will usually result in different volumes than simple arithmetic summation. Probabilistic aggregation is valid at the company portfolio or regional assessment level. Industry in general is comfortable with the idea of aggregating probabilistically up to the field level for development and infrastructure decision support, provided correlations and dependencies are handled properly.

The PRMS (§ 4.2.5.4) recommends that reserves figures should not incorporate statistical aggregation beyond the field, property, or project level to allow comparability and consistency. This aggregation method has been followed by many if not most companies in industry for internal use for plays, portfolio management, and broad regional assessment.

It is important to adhere to the specific definition for reserves qualified as 1P-2P-3P or resources qualified as 1C-2C-3C. For example, maturation of reserves on single producing entities may be legitimately tracked as they progress through the categories. However, as we aggregate multiple producing and potentially productive assets, we recognize that their inherent uncertainties contribute to a progressive misrepresentation of the minimum 90% certainty objective. How we phrase the results must take certainty into account in order to provide a fair and reliable assessment of the quantity that is expected to be produced. The rough affiliation between 1P-2P-3P and P90-P50-P10 no longer applies as we aggregate the uncertainty across several assets. Companies, government agencies, and other evaluation entities have recognized for some time that the P90 of the aggregate will be higher than the arithmetic sum of 1P Reserves, and the P10 aggregate will be lower than the arithmetic sum of the 3P Reserves. 1P-2P-3P categories maintain the reserves definition for the quantities that exist by asset. P90-P50-P10 maintains the realistic expectation or reserves certainty for production, transport, and facility decisions.

A field containing different reservoir blocks (layers, pools, accumulations) may be fiscally ring-fenced and developed as one unit. This is the "level of economic decision." Alternatively, the level of economic decision may be based on an area of infrastructure development within a larger fiscal ring-fence. Regardless, stochastic aggregation of reserves to the economic decision level is recommended prior to development/infrastructure decisions.

Resource aggregations used in policy and decision making should ideally be probabilistic in context, reflecting the full spectrum of possibilities. Fiscal unit-of-production depreciation of the assets may be defined at this level. Use of higher-level aggregation for lower levels of economic decisions may lead to poor outcomes. It is best to match the level of aggregation to the level of economic decisions being made.

At the lowest level, deterministic Low/Best/High Estimates, defined consistently using the certainty-based definitions discussed in Chapter 2—*Petroleum Resources Definitions, Classification, and Categorization Guidelines*, may be the starting point for a range-based aggregation. The use of scenarios as a starting point may be appropriate given that the scenarios are mutually exclusive and fully comprehensive, and there is a valid/reliable assessment of individual scenario probability.

It should be noted that if only deterministic estimates are available, then the only option is to use arithmetic summation. The discussion of statistical aggregation only applies for probabilistic analysis (or to convert scenarios to quantitative probabilities).

8.3 Adding Proved Reserves

8.3.1 Pitfalls of Using Arithmetic Addition of Proved Reserves. When investors or companies add 1P Reserves of several reservoirs arithmetically, they typically underestimate the aggregated value of their assets. This is because the upside on most reserves estimates will more than compensate for the downside on the underperforming assets in the portfolio. Portfolio diversification provides downside protection. This will certainly happen if the estimates of the volumes are independent of each other. For this reason, most companies will rely on the 2P numbers rather than on the high-confidence 1P estimates for business planning purposes. The 2P estimates are not additive to the valid aggregate P50, but their use will deliver an answer closer to the aggregate P50 than the summed P90s or P10s will to their respective aggregate values (refer to Table 8.2). Due to the skewed nature of the potential outcomes, the only potentially valid additive point in a range is the Mean, but the elements must be independent and noncorrelated. Addition of individual 2P assessments, even if they are taken to be representative of the P50, will continue to underestimate the actual P50 of the aggregate reserves in right-skewed distributions.

If the resource estimates are independent, then the upsides in one field may offset a disappointing outcome in others. In other words, the statistically aggregated P90 of the group is often significantly higher than the (arithmetic) sum of the P90 volumes of the individual fields (see Schuyler 1998). For the same reason, arithmetic addition of the 3P values of individual reservoirs will likely overestimate the real upside of the combined asset. As reservoir linkage is increased due to common uncertainties (increasing correlation), the total range possibility increases.

If we stick to arithmetic summation of Proved Reserves, we run the risk of systematically underestimating the value of our combined assets. Technically, this can be avoided because tools are readily available to account for diversification, i.e., the favorable condition of having a mix of assets. Such tools enable the investing community (and some government agencies) to value a combination of assets higher than the sum of the Proved volumes of the individual parts. Error at the upper end due to simple summing of 3P estimates can cause commensurate issues, particularly with large area portfolio policy decisions.

Organizations and government agencies often have a responsibility to provide a scope of Proved, Probable, and Possible Reserves across a business unit, basin, region, or total portfolio. Projecting future production, delineating potential regional infrastructure systems, or supporting a nation's strategic energy decisions all rely on the appropriate aggregation of reserves and resources.

Governments of some countries around the North Sea, including Norway and The Netherlands, were early adopters of probabilistic or stochastic aggregation methods. The Dutch Ministry of Economic Affairs has applied the method of probabilistic summation for Proved Reserves since the mid-1980s. The confidence-based approach of P90-P50-P10 has been shown to be a valid and reliable method with which to assess and communicate reserve and resource totals.

8.3.2 Arithmetic or Correlation Inclusive Summation. Arithmetic summation is the usual straightforward way of adding volumes and thus of aggregating reserves. Let us look at two gas-bearing reservoir blocks, A and B, with the parameters in **Table 8.4.**

With the range and probability density function of these parameters, we can construct a probability distribution for each individual block as shown in **Fig. 8.10,** with the cumulative probability of exceeding a given volume on the vertical axis.

Parameter	Units	Block A	Block B	Total
Total gross rock volume (GRV)	10^9 m^3	1.74	1.16	2.90
Porosity	Fraction	0.22	0.22	0.22
Net-to-gross	Fraction	0.85	0.85	0.85
Saturation	Fraction	0.80	0.80	0.80
Gas expansion	m^3/ m^3	205	205	205
Expectation of GIIP	10^9 m^3	53.4	35.6	89.0
Proved GIIP	10^9 m^3	43.3	28.5	71.8

Table 8.4—Example case: Gas reservoirs A and B

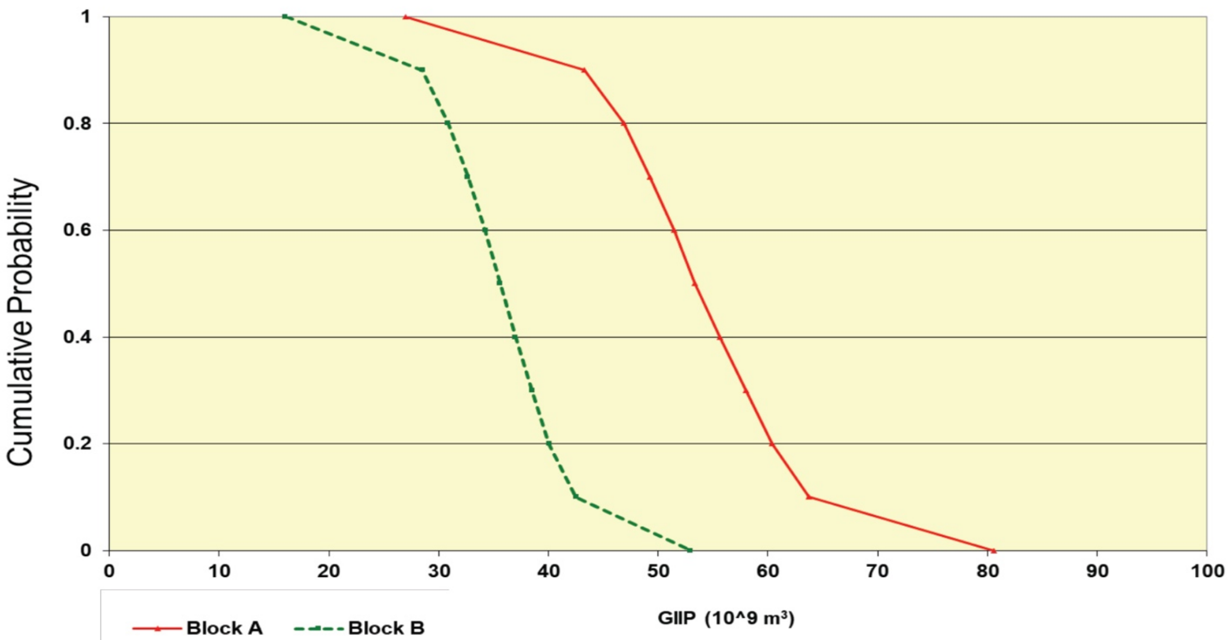

Fig. 8.10—Probability distribution for reservoir blocks A and B.

Note that for the sum of the Proved GIIP figures in Table 8.4, we have taken the arithmetic sum of two Proved numbers, both of which have a 90% probability of being met or exceeded. In fact, by adding the points along each distribution shown in Fig 8.10, we have erroneously assumed complete correlation between the two blocks; i.e., we assume that if the low side of one case materializes, then the same exact outcome will happen with the other block. Summing in this way, we arrive at a pessimistic number for the Proved GIIP, representing the situation that both blocks turn out to be relatively disappointing. While we may think this is possible if both blocks have a common gas-water contact, or if their volumes are determined by the same seismic phenomena, every single uncertainty would have to be fully correlated between the blocks. This is a virtual impossibility. Even the bias introduced by the same subsurface team, applying the same methods, working on two reservoir blocks may introduce a positive correlation.

Mean values are additive given no correlation between the independent entities. A common saying in probabilistic circles is: “The sum of the means equals the mean of the sums.” Correlation can alter this.* It may have an effect on the Mean depending on the skewness, number, and relative magnitude of the aggregated elements. Means may be calculated through statistical methods or stochastic sampling of a range, or by using Swanson's mean approximation method, i.e., [0.4×P50 + 0.3(P10 + P90)].

8.3.3 Probabilistic Aggregation and the Portfolio Effect. Each element in an aggregation has a range of potential outcomes. If we aggregate the ranges instead of individual potential outcomes, we are carrying out a probabilistic aggregation. When we derive the aggregated 1P/1C value from the distribution of the sum (the magnitude at which we are ≥90% confident), we may have situations (e.g., in a probabilistic simulation) where a low outcome of Block A may at times be combined with a high outcome of Block B, or the other way around, and the individual outcomes across the entities compensate for the end-member outcomes in the other cases. The upside and downside aggregated outcomes become muted. It is still possible for them to exist, but they are much rarer. This results in a cumulative distribution curve for the combined GIIP that is steeper (i.e., has a smaller spread) than the curve for the arithmetically added volumes, as shown in **Fig. 8.11.**

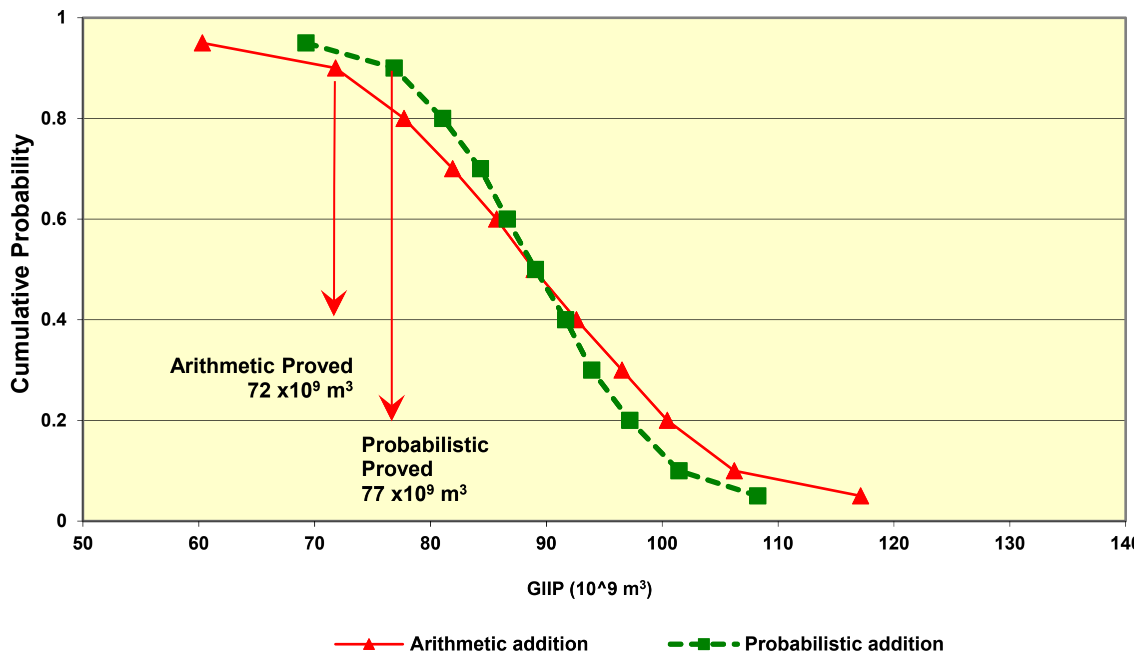

Fig. 8.11—Arithmetic and probabilistic addition, A and B.

This tendency of the uncertainty range to narrow is a statistical truth that will always be observed if we aggregate quantities that have independent statistical distributions. As we increase the number of items being aggregated, the ratios of P50:P90 and P10:P50 decrease, though the magnitude difference between P90 and P10 increases. This "portfolio effect" increases with the

* The best way to prove this point is to look at a negative correlation coefficient. Think of the situation shown in Fig. 8.5, where a fault separates two reservoirs. Is it possible to achieve the mean outcome in each reservoir at the same time? No. As one reservoir increases to the mean, the other has a compensating decrease, since the fault location prevents simultaneous mean outcomes. Adding the means together would overestimate the aggregated value. Provided the population is not correlated, the means are additive.

number of elements being aggregated. One may think of this in a slightly different way: When higher numbers of entities are aggregated, the P10 and P90 (in percentage magnitude) will be closer to the mean, and the addition of another similar entity will have less influence on the distribution.

In our example, applying this approach and assuming complete noncorrelation, we can state with 90% certainty that there is at least 77×10^9 m^3 of gas in both reservoir blocks, as opposed to 72×10^9 m^3 of gas using arithmetic summation. In situations where gas contracts are based on Proved Reserves, this may have considerable business implications. This difference is significant, and we are only aggregating two items. The effect increases with increased uncertainty in the individual portfolio elements.

Methods to aggregate volumes independently (assuming no correlation between aggregated items) are:

- Stochastic methods, using a spreadsheet or commercial tool sampling techniques.[**]
- Scenario trees, representing the possible outcomes as branches of a tree and calculating the overall outcome. This method is treated in Section 8.5 (and Chapter 7—*Probabilistic Resources Estimation*, Section 4).
- Compiling distributions statistically using Mean, Standard Deviation, and Variance.

8.3.4 Simple Probabilistic, Stochastic Simulation, and Correlation Matrices. Initial corporate ventures into simulation as an aggregation method typically combine elements based on submission of P90-P50-P10 values. Simple probabilistic sampling randomly chooses one of the P90-P50-P10 values for each of the elements, and, within an element, the choice among P90-P50-P10 defaults to the Swanson's mean approximation method. This sampling method holds true to a valid center-weighted approach, which, ultimately, over 1,000 or so realizations, provides a valid sampled mean for each component. If moderate to high correlations exist between any of the elements, the simple probabilistic method is not appropriate for aggregation. If the population of elements being aggregated is greater than 20, and correlation is not present, it is acceptable to use a simple probabilistic method. Corporate portfolios are often aggregated based on P90-P50-P10 realizations of reserves and capital requirements.

Stochastic simulation is the most flexible and comprehensive method used to aggregate. It is possible to construct a probability density function for each element based on resource assessment for Low/Best/High Estimate definitions. The ranges are then sampled over a large number of iterations. The number of iterations (or realizations) desired will be a function of the skewness, population, and consistency of the elements being aggregated.

While most companies and government agencies use one of the several off-the-shelf commercial products (typically add-ins to Excel), it is possible to design a custom simulation spreadsheet completely within Excel. There are non-Excel based custom software products on the market as well. Each has its advantages and disadvantages, but it is important to cross-check dependency and correlation methods to ensure correct calculation.

Most of the time, the distribution shape for an element will be skewed, and a log-normal probability density function will be appropriate. However, the upper end of the distribution must be managed in the assessment, especially distributions having an infinite upper endpoint, such as log-normal distributions. Consequently, a maximum low estimate is established for the

[**] Stochastic simulation is often referred to, improperly, as "Monte Carlo" simulation, but Monte Carlo is simply a sampling technique, and not the best one. Latin hypercube, where the distribution is binned, and all bins are sampled before any repeat, gives a far more robust/stable result with fewer iterations.

"acceptable" sampling. The raw untruncated distribution is sampled, and when the sample exceeds the limit, it is reset to the limit. This method preserves the number of samples created above the P10 to 10% of the realizations. It also conforms to the Swanson's mean approximation and natural data set deviation from skewed probability distribution functions. This effect can be seen in **Fig. 8.12,** which shows a log-probability plot of Estimated Ultimate Recovery (EUR) for an unconventional play in Texas.

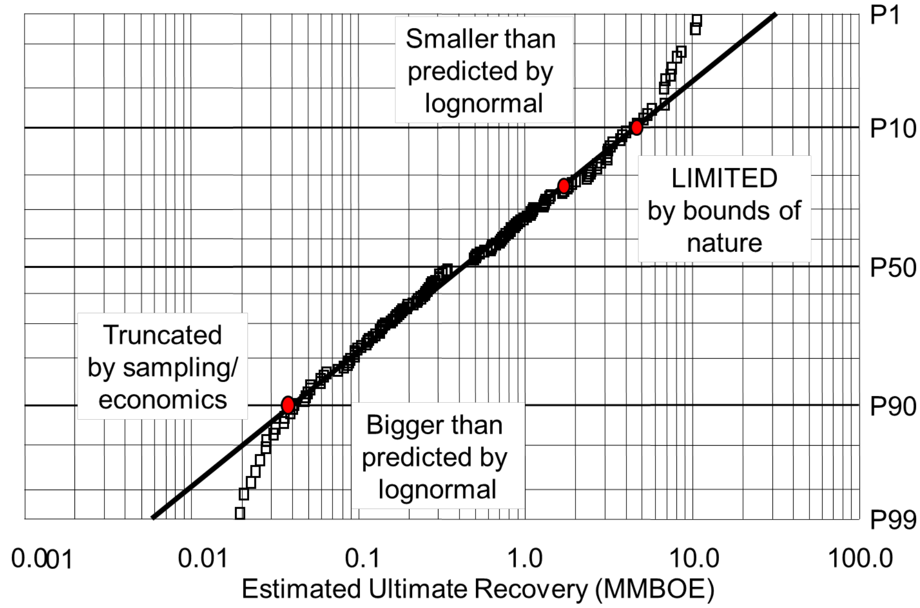

Fig. 8.12—Log-probability plot of well Estimated Ultimate Recovery for a liquid-rich Texas unconventional play (in millions of barrels of oil equivalent).

Failure to account for the upper deviation from log-normal will corrupt the resource/reserve aggregation, leading to an overestimation of potential.

Correlation may be handled within a commercial product using correlation matrices or by simple pair-wise assignment of correlation coefficients. It is also possible to design a window-sampling technique in Excel that equates to correlation coefficient–based sampling (the higher the correlation coefficient, the narrower the allowed sample space).

Most practical situations will be in between the three simply handled correlation coefficient endpoints of 1, 0, and −1. Some parameters of our estimates will be correlated, while others will be completely unassociated. This results in different degrees of correlation.

Ignoring correlation produces invalid results. The rigorous solution in this situation is to calculate probability distributions, specify the correlation between them, and generate the resulting probability distribution for the aggregate. The aggregation may be combined using advanced statistical methods, though those methods assume consistency in distribution shape and work best when skewness is minimized. Stochastic simulation is the obvious and most expedient method to achieve this.

Carter and Morales (1998) provided a real-life example of correlation in a portfolio of 25 fields sharing common production facilities. Each field had a range of gas reserves, expressed at the P90 (Proved), P50, P10, and expectation (mean) levels. The Proved Reserves per field were defined as the volume that had a 90% chance of being met or exceeded. Adding the P90 volumes arithmetically results in a volume of Proved Reserves across the project that is 15% lower than the stochastically combined P90. Because neither full correlation nor full noncorrelation can be assumed, the authors then proceeded to analyze the areas of potential correlation between the individual estimates by applying the following procedure:

1. The areas of correlation were tabulated for individual fields to identify common factors between fields. These areas included technical, methodological, and natural subsurface commonalities between the GIIP estimates of the fields. Commonality was classified as weak, medium, or strong (examples of which have been previously shown in Table 8.4).
2. An estimate of correlation coefficients was made by assigning values for a weak, medium, or strong correlation and combining them into an array suitable for use in a Monte Carlo presentation.
3. The reserves distribution (for each field) as defined by the P90, P50, and P10 confidence levels was expressed as a double-triangular probability distribution function.
4. A matrix of correlation coefficients was used to describe the shared risks between fields, with a coefficient for each pair of fields varying from 0 to ±1 correlation coefficient.
5. The reserves distributions for each field were then stochastically sampled and aggregated using the previously defined correlation matrices employing stochastic simulation software stand-alone tools or spreadsheet add-ins.

The result of applying this method for the case described was that the gas reserves at the 90% confidence level were some 9% greater than those resulting from arithmetic summation. Not taking the dependencies between the fields into account, the increase would have been 15% over the straightforward arithmetic summation. Correlation stretched the reserves range.

The linked risks resulting from shared surface facilities and constraints were also excluded from the analysis. They are considered to be common (project) risks, and problems with facilities are considered surmountable if they materialize. This type of shared risk can be included in the analysis, if required.

Use of correlation matrices as described above is similar to other reserve estimation methods in two important aspects:

- The figures used are subjective and change when new insights are gained. However, in view of the large number of correlated reservoir elements resulting in varying degrees of field-level correlation, the aggregated result is relatively insensitive to individual error. Major reversals of opinion must occur to change the overall result by a significant amount.
- As the established risks are addressed in more detail, specific correlation coefficients will be updated with the proper audit trail. For example, a new seismic interpretation by a new team may result in the shared uncertainties in seismic interpretation being removed after the new interpretation has been accepted.

Correlation matrices are a good way to lay out correlations between individual members of an aggregation. However, there is a significant danger to create impossible correlations, or impossible circular calculations, and thereby destroy the validity of the aggregation unless the aggregator is cautious and attentive. For example, let’s assume three partially correlated Reservoirs A, B, and C. If we correlate B and C to A at a rank correlation coefficient of 0.7, that precisely defines a minimum degree of correlation between B and C.

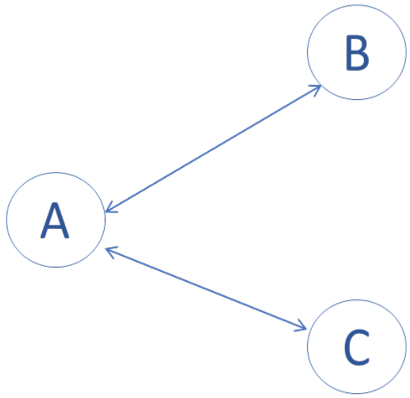

Fig. 8.13—Three correlated elements.

This example is illustrated in **Fig. 8.13.** We see both B and C have a relationship with A. The coefficient of 0.7 would be a moderately strong correlation, so as A's outcome is high, B's outcome would track similarly higher. C's outcome would also track generally higher. Therefore, there is also a positive correlation between B and C, but it will not be defined by our input; it is mathematically determined. An imprecise correlation between B and C is roughly equal to the correlation coefficient of A-B multiplied by the correlation coefficient of A-C. As A-B is 0.7 and A-C is 0.7, a rank correlation coefficient is automatically formed for B-C of $0.7 \times 0.7 = 0.49$.

As we apply rank correlation between elements, there is an important factor to think about: How best do we apply a rank correlation coefficient across a large number of wells? Our well collections may be generally good, middling, or generally poor. We have significant variability in the quality of our well families, but along trend or within a sub-play, wells may be strongly correlated. Correlation typically originates from a common natural (and unaltered) rock, containment, or diagenetic characteristics. Drilling, completion, and producing activities may mask the "natural correlation." These activities include but are not limited to drilling across technology changes, the use of different production practices, different production starts (well vintages), or infill vs. initial drilling. Rock correlation will still be present, but it may not be fully recognized as one moves from well to well. When we drill a productive area, we may be creating a well family. Although we might expect a strong relationship between neighboring wells, we cannot depend on one.

If we have a well program that drills a number of wells sequentially, i.e., Wells A, B, C, D, E, and F, with each well having a rank correlation coefficient of 0.8 with the preceding well, by the time we get to well F, the correlation back to well A is equal to 0.8^5 or ~0.33, representing a negligible correlation. Sequential correlation does not preserve correlation across the entire set of wells. We need to reconfigure the correlation so that we correlate all wells to a dummy distribution. As we are rank correlating, it does not matter what distribution shape we use.

Fig. 8.14 shows an illustration of central correlation. Each of the well distributions is correlated to a dummy distribution prior to sampling and aggregation. In this case, they are all correlated to the dummy at 0.8, which maintains a family correlation (the correlation between any two members) at about 0.64. Correlation precision is not important. Unique individual correlations can be handled by changing the correlation of an item with the dummy. All relationships will track appropriately. When a group of nearby wells is aggregated, any correlation must be taken into account; otherwise, the true upside potential of the group may be lost. It is important to capture the distinct probability that the wells will behave as a group. This is where this method can be very useful.

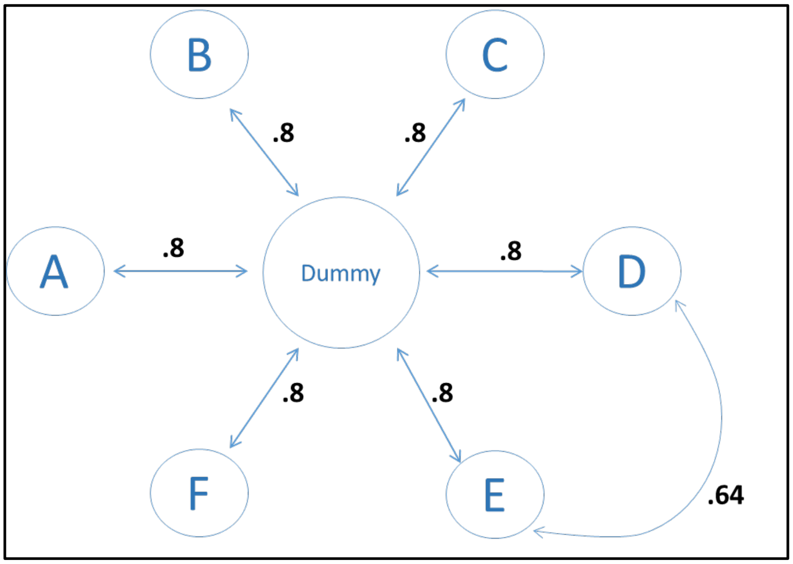

Fig. 8.14—Central correlation method.

8.4 Regional Aggregation

The aggregation framework described herein is applicable at the lowest to highest aggregation levels. While Proved Reserves have a distinct definition, 1P-2P-3P categories typically have a narrower range as compared to the 1C-2C-3C categories. Aggregation principles work across all categories described in the PRMS. Regional aggregation is often the purview of governments and governmental agencies, while public policy is often influenced by aggregated reserves and resources distributions. Unfortunately, unless proper aggregation methodology is followed, confusing or invalid ranges may be communicated to decision makers or cited by the public or the press and relied upon to set, or react to, policy.

Methods described here in the *Guidelines for Application of the PRMS* can assist all stakeholders in assessing and communicating valid and reliable estimates. It is an appropriate public service to follow approved methods and communicate results in a coherent and industry-accepted manner. However, there are choices when we aggregate at the regional level, and the appropriate choices may produce results that seem unusual, with ranges that may be unrealistically narrow or that show unusually large potential at the upper end.

We shall now examine the resource estimate for an area of unconventional (continuous) resource as shown in **Table 8.5.** Examination of this published data will allow us to assess a significant portfolio of real reservoir collections and discuss guidelines for communication of aggregation results.

We will focus on the assessment units, which are defined in this example as oil accumulations, as highlighted.

Total petroleum system and assessment units (AUs)	AU probability	Accumulation type	Oil (MMBO)			
			F95	F50	F5	Mean
		Permian Basin Paleozoic Composite Total P				
Delaware Basin Wolfcamp D Continuous Gas AU	1.0	Gas				
Delaware Basin Wolfcamp C Continuous Gas AU	1.0	Gas				
Delaware Basin Wolfcamp C Continuous Oil AU	1.0	Oil	382	1,467	3,477	1,635
Delaware Basin Wolfcamp B Lower Continuous Oil AU	1.0	Oil	2,642	5,297	8,838	5,458
Delaware Basin Wolfcamp B Upper Continuous Oil AU	1.0	Oil	4,606	8,861	14,657	9,154
Delaware Basin Wolfcamp A Continuous Oil AU	1.0	Oil	8,406	12,791	19,556	13,229
Third Bone Spring Continuous Oil AU	1.0	Oil	4,941	6,468	9,521	6,739
Second Bone Spring Continuous Oil AU	1.0	Oil	3,869	5,096	6,878	5,191
First Bone Spring Continuous Oil AU	1.0	Oil	658	2,113	3,588	2,113
Lower Avalon Shale Continuous Oil AU	1.0	Oil	507	1,096	1,984	1,153
Upper Avalon Shale Continuous Oil AU	1.0	Oil	718	1,573	2,576	1,599
Total undiscovered continuous resources			26,729	44,762	71,075	46,271

Table 8.5—Delaware Basin undiscovered resource (Gaswirth et al. 2018).

If we construct a quick stochastic simulation relying on the published data, we can examine the various ways to aggregate the reservoir collections. Organizations often find themselves in a tight spot when communicating aggregated values. A straight stochastic simulation, without correlation, will typically provide an aggregate distribution that appears too narrow. Yet, arithmetically summing the components across the ranges, which assumes an extreme rank correlation of +1, as **Table 8.6** shows, produces an aggregate range that is too wide—underestimating the downside and grossly overestimating the upside.

Using the range data provided for each member of the aggregation, a continuous distribution was developed that honored the data points, including the Mean, within a maximum 3% error. The Mean is not replicated exactly, as the original distribution for the data is unknown, and it had to be approximated. Running with a correlation coefficient of zero, we see the following results for a sampling of 10,000 iterations:

F95	F50	F5	Mean
37000	45230	54900	45500

Table 8.6—Aggregated oil distribution based on data provided by Gaswirth et al. (2018), aggregated through sampling of the component distributions.

The 90% confidence range from F95 to F5, or P95 to P5 as we call it (i.e., 37,000 to 54,900), would be considered too narrow based on the experience and knowledge of most evaluators and earth-science professionals, yet the simple arithmetic tallies (26,729 to 71,075) may seem overly wide. **Fig. 8.15** presents the aggregated volumes range for the data assuming different correlation coefficients.

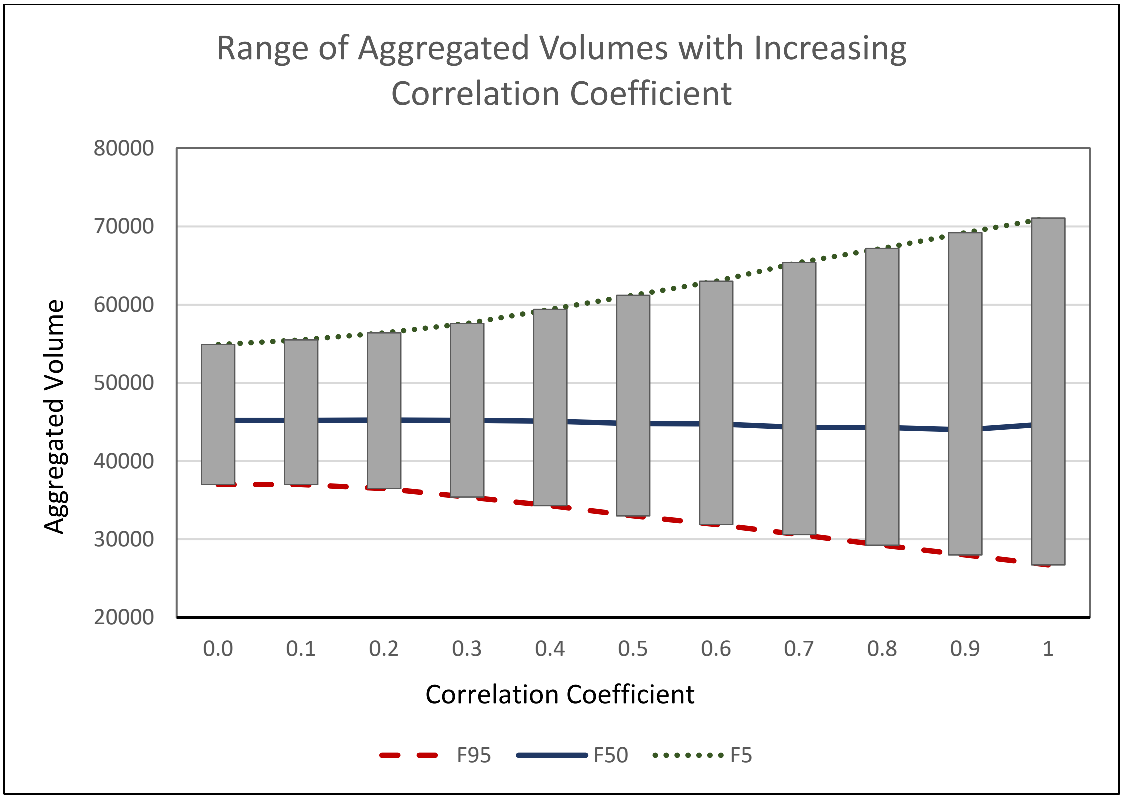

Fig. 8.15—Stochastic simulation results for the Delaware Basin data shown in Table 8.5.

With even minimal knowledge of the basin in question, we can rule out either correlation end member as a valid representation of the aggregate volume range. There is no possibility of reservoir existence and performance being fully correlated across the basin and throughout the section. Similarly, the noncorrelated end member would ignore the common diagenetic history, depositional environment, and sediment sourcing, which would tend to produce similarities through the section.

What degree of correlation is appropriate? In this particular basin, and most basins for that matter, a moderate correlation is likely to best represent the volume range across the vertical section, given knowledge of the geologic uncertainties present and their shared characteristics within a generally prolific section. Within a single horizon, especially in unconventional (continuous) resource plays, a good correlation between individual well uncertainties is the norm. Across a portfolio of geographically diverse, multibasin opportunities, a weak correlation would be expected, if any at all. Note that correlation coefficients of less than 0.3 have little effect on the aggregated outcome range.

As a general note, evaluators should be wary of localized diagenetic and seal failure issues, especially in areas of structural complexity. The integrity and consistency of the area within a part-play have a great deal to do with the level of well-to-well correlation.

When arithmetic summation is used, as in the above table, it is advisable to adjust the referenced probability. Any total will have a place on the distribution and should be stated in context. For example, if we assumed a 0.0 correlation coefficient in the example data, then the arithmetic sum of the F5 in the table (P5 in PRMS nomenclature) equates to a result that is not seen more than 1 in 10,000 times. The F95 in the table (P95 in PRMS nomenclature) was not seen at all through one million iterations. To imply that the simple arithmetic sums define the F5 and F95 aggregated outcomes is misleading.

If we assess the appropriate correlation coefficient between aggregation elements as 0.6, then the arithmetically summed F5 volumes have an aggregate probability of approximately 1%, a four-percentage-point difference in the distribution. If the arithmetic sum is to be used in this case, it should be referenced as the F1 as opposed to F5. At the opposite end, the arithmetic sum of the individual F95 values equates to the F99 of the aggregate when the correlation coefficient is approximately 0.7. The upper and lower printed bounds of the aggregated data exaggerate the high side potential and are too low at the lower end if an arithmetic sum is used. As seen in this case, evaluators and their audiences should not assume the effect of correlation is symmetrical. Due to the skewed nature of the component distributions, it will usually affect the upper end of the aggregation more.

The guideline we can offer for the selection of appropriate correlation is that it must rely on empirical evidence from similar aggregations, or detailed reservoir and diagenetic assessment. If no such benchmark aggregation exists, aggregators are encouraged to reason out an appropriate correlation coefficient based on geologic and anticipated reservoir performance indicators. Aggregate range results should be tested for reasonableness through subject matter expert groups having no stake in the outcome or use of the aggregation results. The degree of correlation used across the aggregated assessment should always be stated.

8.5 Scenario Methods

A mechanical approach to aggregate reserves is the use of scenario methods. A “results tree” (or scenario tree) is constructed to show potential outcomes and contingent (posterior) probabilities of second and third aggregation elements. The technique is only suitable for a limited number of elements being aggregated because the scenario trees get very complicated very quickly. The main requirement is to have enough endpoints so as to mimic a fuller stochastic distribution; as such, there is a sweet spot of three to four aggregate-able items. For any population less than that, an adequate distribution will not be created, while for any more than that, the tree and population process will be very complicated. The number of endpoints is equal to 3^x, where x = aggregated population. While it is usually easier to create an actual stochastic simulation, this method can work for aggregations where the modeling skill set is limited.

8.5.1 Tree-Based Example of Correlation Between Reservoir Elements. This is an example of the aggregation of volumes with a low degree of correlation using a scenario approach. Higher degrees of correlation may be handled similarly. We will aggregate a set of three sands (M, N, and S), for which the reservoir parameters and gross rock volumes are relatively independent. The reason for this independence is that the reservoirs occur in different geological formations at very different depths, so there are few factors that cause low and high cases of the sands to coincide. We recommend giving consideration to the source of the reservoir data. Do all measurements originate from the same source? Is there an incentive to have similar outcomes? If so, then a higher correlation coefficient might be warranted. While it is always good to have the entire range of possible outcomes represented and probabilistically symmetrical (P90-P50-P10), this method allows subject matter experts to incorporate their interpretations and linkages directly into the tool. Both of our cases are correlated at the reservoir level to simplify the example. In an actual aggregation, it is more useful to identify the reservoir component that shares the uncertainty between reservoirs. **Table 8.7** gives low, median, and high recoverable reserves for the sands.

Volumes	Low	Median	High	Mean= Expectation
M sands	17	23	30	23.3
N sands	29	41	54	41.3
S sands	10	15	25	16.7

Table 8.7—Uncertainty range for three oil-bearing sands (MMBO).

To construct the scenario tree for this situation, we have taken the low, median, and high values of volume with probability values equivalent to those in Swanson's mean approximation in the sand with the largest volume, the N sand. As the N sand is dominant, this will ensure a more reliable Mean. We then combine these first with the M sand and subsequently with the S sand by eliciting contingent probabilities from subject matter experts. For example, assuming the outcome of N is known, what are the probabilities of the low, median, and high results for M? The presence of a correlation between the units is shown by a change in the probability of high, median, or low outcomes given a known outcome of the previous sand. Note that the total probability of the limbs leaving a node must equal 100%.

All distributions, if uncorrelated, will follow the Swanson's Mean standard of 30% for the low case, 40% for the medium case, and 30% for the high case. If N is high, M's probability of being the high case increases from the original 30% to 45%. If N is low, then M will tend to track lower with a 45% probability of also being low. If N's result is at the Median, then M will have a higher chance of being at the Median. The probabilities that M will not track with N are reduced from their noncorrelated state.

Let's allow the S reservoir to have a higher correlation with the N reservoir. If the N result is high, then S will have a 60% probability of also being its high case. There will be similar tracking for the low case. **Table 8.8** shows the correlated result probabilities that we will use in our tree when we build it in the next step.

		Correlated Range Outcome	
N Result		**M**	**S**
High Case	High	45%	60%
	Median	35%	30%
	Low	20%	10%
		M	**S**
Median Case	High	25%	20%
	Median	50%	60%
	Low	25%	20%
		M	**S**
Low Case	High	20%	10%
	Median	35%	30%
	Low	45%	60%

Table 8.8—Contingent probabilities given *N* reservoir results.

We set up the tree starting with the N reservoir outcome and then place the probability-adjusted outcomes for the M and S reservoirs. We use the probabilities as shown in Table 8.8 to complete the tree. This results in a scenario tree with 27 end branches for these three sands **(Fig. 8.16).**

As can be seen in Fig. 8.16, there is some correlation between the occurrence of low, high, and median cases for each of the sands (i.e., the probabilities that the M sands have a high value are higher than if the N sands are high, etc.). At the end branches, we can read off the total volume in each of the 27 possible combinations of N, M, and S sands, as well as the frequency of occurrence.

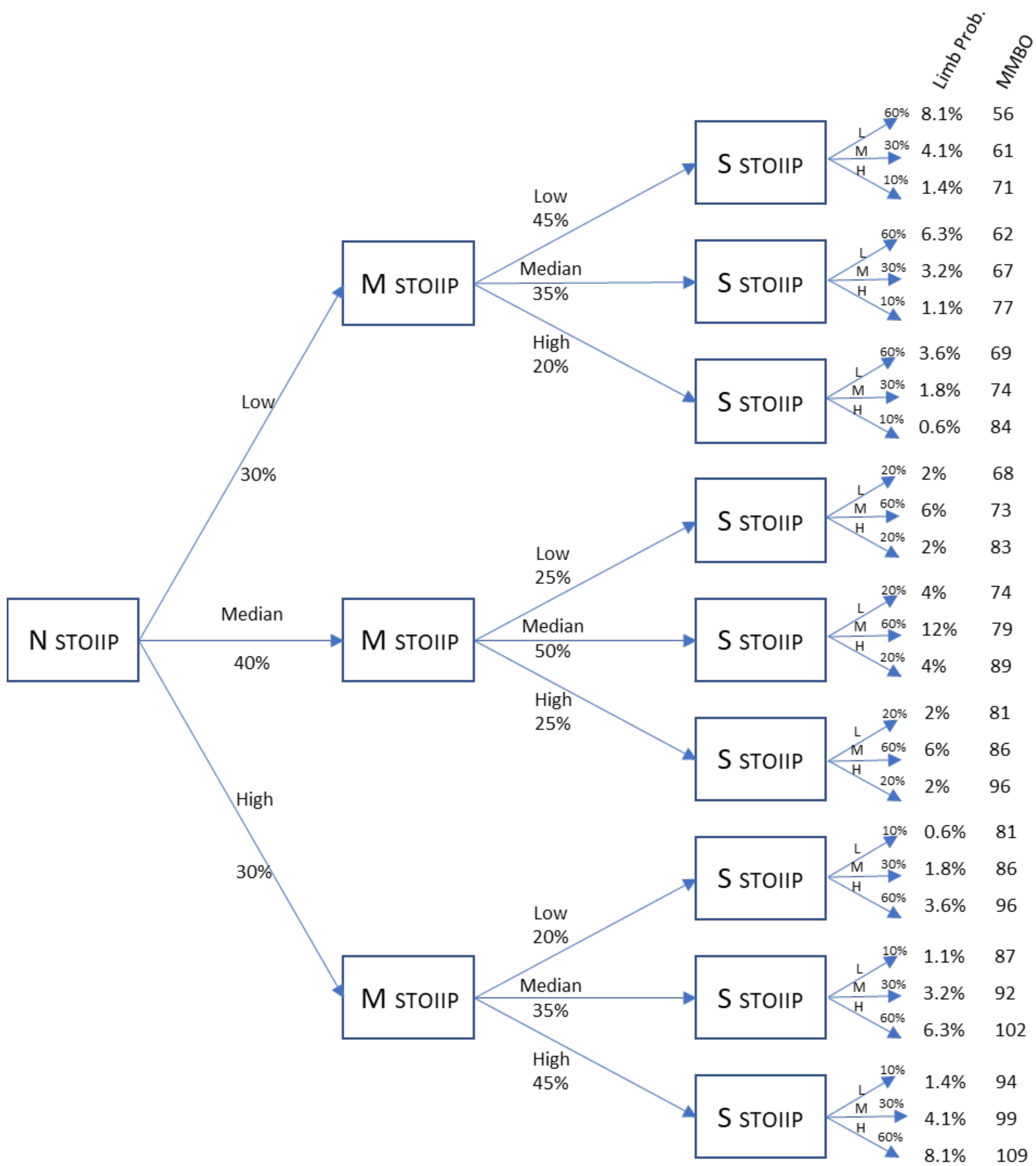

Fig. 8.16—Scenario tree with altered limb probabilities due to correlation. All volumes are MMBO.

Note that each endpoint (limb) probability is the product of the individual branch probabilities (e.g., 30% × 45% × 60% = 8.1%). The volume figures in the far-right column are the sum of the three sands' individual volumes (e.g., N low 29 + M low 17 + S low 10 = 56 MMBO).

If we now reorder this far-right column from smallest to largest and plot them against their cumulative probability, the resulting plot **(Fig. 8.17)** yields the aggregated reserves at any desired probability (confidence level).

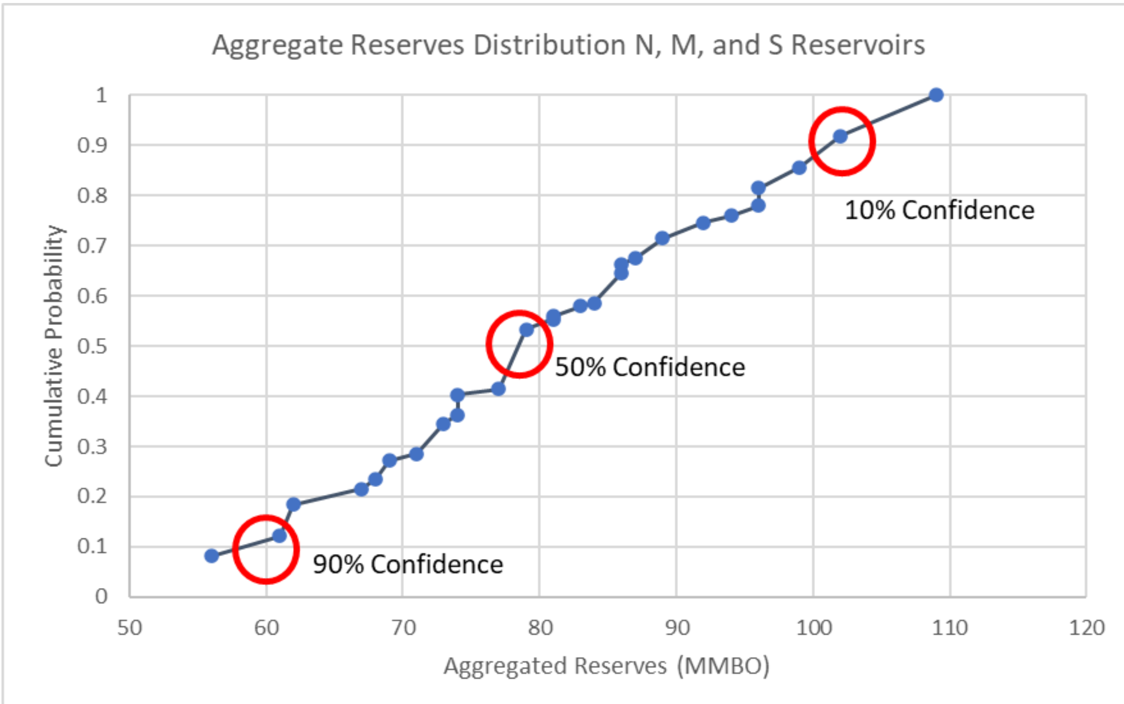

Fig. 8.17—Aggregate correlated reserves distribution of probabilistic aggregation of scenario tree outcomes.

The probability of the branches and the dependencies between these probabilities, as represented in the tree, should reflect the understanding of the geological processes at work. The resulting aggregated distribution can then be used as a building block for a resources assessment in the PRMS.

Caution is urged when assigning correlation coefficients between uncertainties. In the above example, the probabilities of low, median, and high scenarios of the second and third sands were specified given the knowledge of the N reservoir outcome. This is not the same as assigning a correlation coefficient between the uncertainties from the beginning, but it provides a reasonably reliable result for quick assessment of a low number of aggregated elements.

8.6 Summary—Some Guidelines

1. Deterministic 1P-2P-3P aggregation and probabilistic (stochastic simulation) methods are compatible and together can provide reliable reserves estimates for valuation and decision making in projects and portfolio management. Capability in both techniques is required to adequately describe aggregated collections.

2. In summing 2P reserves values, arithmetically add the deterministic estimate of quantities. Recognize that this will usually result in a value less than the real Median of the aggregation, but it may be close enough for most 2P reserves distributions.
3. Arithmetic summation of individual categories of reserves for independent units leads to a conservative estimate for the Proved total and an optimistic result for the upside potential. Methods and tools are available to determine a more realistic value (probabilistic or stochastic simulation, scenario trees, and customized tools) for aggregation of distributions.
4. Adding individual categories of reserves probabilistically without fully accounting for correlation could overstate the Proved total and understate the upside potential. The expected (Mean) aggregate result will increase with correlation because the distribution is skewed and the rate of change between percentiles is much larger at the upper end.
5. In estimating reserves quantities from well-performance extrapolation or DCA, always work up from the lowest aggregation level (e.g., well or completion). Simple sums of Proved Reserves from well-based DCA estimates may lead to overly conservative estimates of reserves at the reservoir level of aggregation; hence, always check with an overall reservoir performance extrapolation that includes development type, available performance suitability, timing of prior activities, common bottlenecks, and market conditions. Review the "history-to-forecast" interface to make sure that the methodology has not introduced any discontinuities.
6. The PRMS allows probabilistic aggregation up to the field, property, or project level. Typically, for reporting purposes, further aggregation uses arithmetic summation by category, but these category aggregations should be labeled as the sum of individual confidence levels and not associated with any particular probability or aggregated confidence. A fully probabilistic aggregation of a company's total reserves and risked (i.e., mean success volumes multiplied by their associated probability of success) Contingent and Prospective Resources may be used for portfolio analysis at the business unit, region, or full company levels as long as the aggregation method handles the chance and uncertainty components separately and provides clarity to the method of aggregation presented.
7. For adding volumes with differing ranges of uncertainty and volumes that are correlated, or in situations where discount factors are applied, it is easiest to use stochastic simulation methods; however, for simple cases, a scenario approach may be sufficient.
8. When adding volumes, make sure they have a common standard of measurement (pressure/temperature, calorific value).

8.7 Acknowledgments

This chapter is based on the framework and discussion provided by Wim J.A.M. Swinkels in the previous version of the PRMS guidelines. Important feedback and editorial effort were provided by Delores (Dee) Hinkle.

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Chapter 9

Evaluation of Petroleum Reserves and Resources

Charles Vanorsdale

9.1 Introduction

The valuation of reserves and resources is about converting a quantity forecast to a value forecast. In that sense, valuation is part of "evaluation," which is defined within the Petroleum Resources Management System (PRMS 2018, Appendix A—Glossary) as: "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." Results from the conversion of a quantity forecast into a cash-flow value assessment may then be used in internal entity investment decision-making regarding commitment of funds for petroleum resources development. The projects can be from either an existing developed project or a future planned petroleum recovery project. The value results will be used to support public disclosures of reserves and resources, subject to regulatory reporting requirements.

These guidelines are provided to promote consistency in project evaluations and the presentation of evaluation results while adhering to the PRMS principles. Note that this chapter is not about fair market value, the value upon which a willing buyer and willing seller agree, neither of whom are compelled to act, and both of whom are knowledgeable of the relevant facts. In this context, a project evaluation will result in a production schedule and an associated cash-flow schedule; the time integration of these schedules will yield an estimate of marketable quantities (or sales) and future net revenue or net present value (NPV) using a range of discount rates, including the entity's internal rate of return. The estimation of value is subject to uncertainty due to not only inherent uncertainties in the petroleum in place and the efficiency of the recovery program, but also in the product prices, the capital and operating costs, the execution of current and future environmental and regulatory requirements, including abandonment, and the timing of implementation. Thus, similar to the estimation of a range of marketable quantities (i.e., reserves or resources), the resulting value estimates will reflect a range of outcomes. The PRMS allows the evaluator to include, and state, the variables that have significant impact on the economic outcome, including uncertainties in volumetrics, product prices, environmental, social, and governance (ESG) costs, and future capital costs.

This chapter will first summarize net cash-flow evaluation and then define and amplify key terms and concepts in Section 9.3. Section 9.4 describes the input to an evaluation; Section 9.5 shows how to generate a cash-flow evaluation; and Section 9.6 outlines how to analyze that evaluation. Section 9.7 compares the terms "economic" and "commercial." Section 9.8 provides an evaluation example and discusses other considerations. Section 9.9 briefly discusses probabilistic evaluation, and Section 9.10 closes the chapter with ESG considerations.

9.2 Net Cash-Flow Evaluation

This chapter seeks to provide guidelines with which to satisfy compliance with the PRMS principles for a net cash-flow (NCF) evaluation. Per PRMS § 3.1.1 Net Cash-Flow Evaluation:

"3.1.1.1 Project-based resource economic evaluations are based on estimates of future production and the associated net cash-flow schedules for each project as of an effective date. These NCFs should be discounted using a defined discount rate, and the sum of the future discounted cash flows is termed the net present value (NPV) of the project. The calculation shall be based upon an appropriately defined reference point (PRMS § 3.2.1) and should reflect the following:

A. The forecast production quantities over identified time periods.
B. The estimated costs and schedule associated with the project to develop, recover, and produce the quantities to the reference point, including abandonment, decommissioning, and restoration (ADR) costs, based on the entity's view of the expected future costs.
C. 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, taking into account any sales contracts or price hedges specific to a property, including that portion of the costs and revenues accruing to the entity.
D. Future projected production- and revenue-related taxes and royalties expected to be paid by the entity.
E. A project life that is limited to the period of economic interest or a reasonably certain estimate of the life expectancy of the project, which is typically truncated by the earliest occurrence of either technical, license, or economic limit.
F. The application of an appropriate discount rate applicable to the entity at the time of the evaluation."

Although the PRMS recognizes that there may be several methods by which to assign value to a project, the PRMS guidelines apply only to cash-flow-based evaluations (PRMS § 3.1.0.1). The cash-flow evaluation must incorporate elements A–F above through the following general process:

1. Test that the project is economic.
2. Determine the project life.
    a. Validate the economic viability for undeveloped projects.
    b. Determine undeveloped project commerciality.

9.2.1 Step 1—Test That the Project Is Economic. Per the PRMS (§ 3.1.2.1), "A project with a positive undiscounted cumulative net cash flow is considered economic. Production from the project is economic when the revenue attributable to the entity interest from production exceeds the cost of operation."

The evaluator may generate a best estimate cash flow using a "forecast case" (which allows for future reasonable variation, such as due to inflation or deflation, of prices, costs, market factors, etc.), a "current economic conditions" (in which the prices/costs/expenditures, etc., are based on historical conditions but may include reasonable inflation or deflation), or a "constant case" (similar to the current economic conditions case but with prices, costs, etc., fixed as of the evaluation date and without future inflation or deflation). In any type of evaluation, contractual obligations must be honored.

In order for a project to be deemed economically viable, at a minimum, the best estimate undiscounted cumulative cash flow must be positive, and undeveloped projects must also then be assessed for commerciality, as below in Step 2b. According to PRMS § 2.1.2.2, "The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves."

This best estimate cash flow must consider all activities necessary to support the project as part of the field development plan required to yield the predicted production profile (e.g., the forecast accounts for any additional water-handling facilities and their associated capital). Production and revenue-related taxes and royalties must be considered (PRMS § 3.1.1, Step D). The resulting forecast of revenues and expenses must indicate a positive cumulative undiscounted NCF in order to identify the economic limit; consequently, the process is called the economic limit test. The economic limit (EL) is defined as the production rate at the time when the maximum cumulative NCF occurs for a project (PRMS § 3.1.3.1). After that point, the remaining expenses are forecast to exceed the revenue attributable to the entity, and this situation results in the ensuing cash flow being negative. Costs for abandonment, decommissioning, and restoration (ADR) as well as income taxes (other than production taxes), any overhead not required for the specific project, and depreciation are excluded at the EL test stage of the evaluation (PRMS § 3.1.3.2) to verify that the project is economically producible. The impact of ADR, taxes, and depreciation will be addressed later in this chapter.

Production forecasts for either developed (ongoing) or undeveloped projects must demonstrate economic producibility. Undeveloped projects must also satisfy economic viability, as below in Step 2a.

9.2.2 Step 2—Determine the Project Life. Having performed the EL test, the evaluator has determined the date beyond which further operation of the project will no longer have a positive NCF to the entity. However, per the PRMS (§ 3.1.1, Step D), the project life "is limited to the period of economic interest or a reasonably certain estimate of the life expectancy of the project, which is typically truncated by the earliest occurrence of either technical, license, or economic limit." Consequently, if the EL occurs after a technical constraint is reached or the license/concession expires, then the project life (and NCF to the interest of the entity) must be truncated by the appropriate limit.

9.2.2.1 Step 2a—Validate the Economic Viability for Undeveloped Projects. Projects that are undeveloped have a further criterion: The project's cumulative undiscounted NCF, truncated as above, must exceed the projected ADR liability. (Remember, ADR costs are not included in assessing economic producibility or the EL calculations.) If this condition is met, then economic viability is confirmed (PRMS § 3.1.2.5), and the undeveloped project's forecasted recovery will be subjected to commerciality assessment to determine if it might qualify as Reserves. For ongoing projects, the threshold of economic viability has been satisfied once the economic producibility check of Step 1 is performed.

9.2.2.2 Step 2b—Determine Undeveloped Project Commerciality. With this step, the cash-flow evaluation expands in scope. The PRMS spells out seven criteria required to achieve commerciality (PRMS § 2.1.2.1), one of which is that there must be a "reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria." The best estimate case NCF prepared previously, honoring the earliest truncation by contract term, operational limitations, or the EL, is then adjusted for the time value of money by using a discounting factor.

This evaluation, performed for undeveloped projects, will include the ADR liability and any other of an entity's internal criteria (beyond PRMS requirements) such as corporate income taxes. The resulting discounted cash flow (DCF), when summed, yields the project's NPV. The discounting factor is usually taken to be equivalent to the evaluating entity's hurdle rate or weighted average cost of capital (WACC) (PRMS § 2.1.2.1). Therefore, if the project's NPV is less than zero, then the project fails the commerciality test, and the projected recovery, although economic, cannot be classified as Reserves. All other internal decision criteria must be satisfied to classify the project's forecasted recovery as Reserves. For example, the entity decision criteria might also include achieving target lifting costs, return on investment, or other profitability metrics, which need to be considered to classify the project's projected recovery as Reserves.

A cash-flow evaluation showing that a project will return the entity's required hurdle rate or WACC provides supporting evidence of the entity's commitment to the project as required in PRMS § 2.1.2.1.

Consequently, under the PRMS, a project assessed to be commercial is necessarily economic. In fact, because Reserves are defined as commercially recoverable quantities, assessing the economic status of the forecast production is a prerequisite to determining commerciality and assigning Reserves.

Petroleum reserves and resources evaluations therefore require integration of multidisciplinary expertise in both the technical and the economic/commercial areas throughout the life cycle of asset development. Petroleum resources, as they progress to Reserves, will change class and/or categories throughout their life cycle due to revision of technical and commercial uncertainties, such as through drilling activity, data acquisition and interpretation, changing costs (among them operating, capital, and sunk costs) and product prices, changing fiscal and/or commercial terms, and development/adoption of new technology.

9.3 Terminology of Cash-Flow-Based Evaluation

The preceding section gives the impression that there is a language specific to the cash-flow-based evaluation of petroleum resources, and indeed certain terminology—such as with the resources definitions themselves—must be clear in order for resulting evaluations to be consistently performed and/or compared and conveyed using that information (whether internal or external). This section will briefly discuss the key terms associated with a cash-flow-based evaluation as addressed in PRMS § 3.1.2. (Section 9.7 provides a more thorough discussion of the difference between the terms "economic" and "commercial.")

9.3.1 Net Cash Flow (NCF). A cash flow is the calculation, at discrete intervals (typically reported on an annual basis but perhaps calculated on a monthly basis), of the cash inflow (e.g., revenue from product sales) and the cash outflow (e.g., operating costs, capital expenditures, taxes, etc.) attributable to a specific project. The NCF is the difference between the inflow and the outflow to the entity's interest. As shown in **Fig. 9.1,** the annual NCF is depicted by the bars. (Factors not depicted individually are revenue, operating costs, and capital expenditures, for the simplicity of presentation.) The cumulative undiscounted NCF and cumulative oil recovery are represented by the red and black lines, respectively. We can see in Fig. 9.1 that the cumulative NCF for the first four years is negative, indicating that the sum of the capital expenditures and operating costs for those four years exceeds the revenue. This situation is reversed in year five, when the cumulative NCF becomes positive.

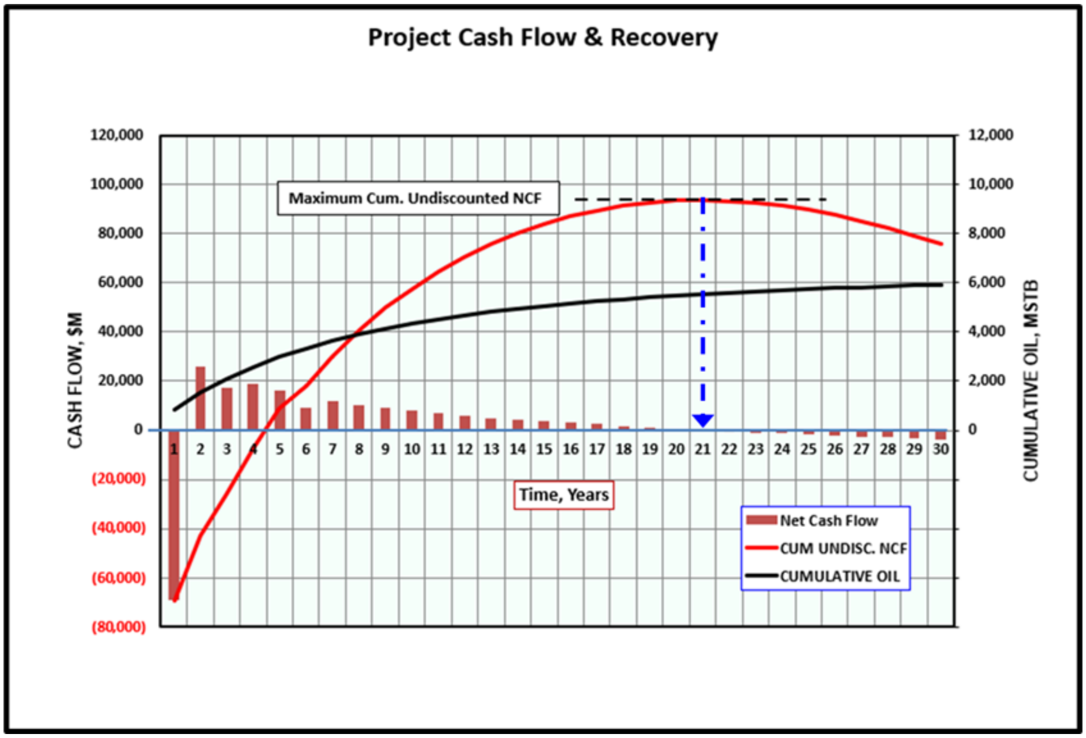

Fig. 9.1—Undeveloped project forecast for EL test. (Note that economic viability determination by comparison of maximum NCF to ADR obligation is not shown.)

9.3.2 Abandonment, Decommissioning, and Restoration (ADR). ADR is defined (PRMS Appendix A—Glossary) as "The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as 'ADR net of salvage.'"

ADR expenses are not used in generating the NCF when estimating the EL, but they are included when performing project economic analysis (unless specifically excluded by contractual terms). Close to the EL, these costs are considered to be an obligated liability that is incurred regardless of the economic producibility (i.e., the net revenue exceeds the net expenses to the entity's interests) of the project. However, if the cumulative NCF (including ADR costs) of an undeveloped project fails to yield a positive figure, then the estimated quantities are not economically viable (PRMS § 3.1.2.5) and cannot qualify as Reserves.

In the case of production sharing contracts (PSCs), the PRMS notes (§ 3.3.2.4) that "the terms governing cost recovery in a particular PSC may require special treatment of items such as taxes, overhead, and ADR to determine entitlement." The entitlement determination must be evaluated to be able to forecast the net revenue for the project, and ADR may not be required as part of the economic assessment for PSCs if, for instance, the host government accepts responsibility when economic production is anticipated to continue past the contract termination date.

9.3.3 Economic Limit (EL). PRMS § 3.1.3.1 describes the EL as the production rate at the time when the maximum cumulative NCF occurs for a project. Continuing to produce beyond the EL results in negative cash flows after the EL date, and therefore the project is uneconomic from that date onward.

For either undeveloped or developed projects, ADR expenses are not used in the NCF when estimating the EL because economic determination of the project is not the objective at this step (however, see the comments for undeveloped projects two paragraphs ahead). The EL of production for the project is based on the defined economic conditions. The use of alternative economic scenarios will likely alter the time and production rate, thereby changing the cash flow establishing the EL. The EL at the forecast production of the low, best, and high estimates are typically different because they have different cash flows (i.e., they have different sales quantities and therefore different revenues). In the absence of other limits (e.g., technical/operating conditions, concession/license term, etc.), the EL defines the production rate beyond which the project is no longer economically producible. The cumulative production to that EL defines the economically producible quantity subject to the final project economic determination.

It is possible that there may be periods of negative NCF during the life of a project (such as forecasted major capital expenditures, development/infill drilling, or during operational maintenance). Interim negative project NCF periods may be accommodated provided that the sum of subsequent positive NCF exceeds the sum of the negative NCF, thus continuing to increase the maximum cumulative NCF of the project. With this confirmation, the entire time period is considered the economically productive life of the project up to the time beyond which there is no increase in the cumulative NCF.

For an undeveloped project, once the EL is determined for the best estimate case, the cumulative NCF at that limit must be compared against the estimated ADR cost associated with the project (PRMS § 3.1.2.5). If the estimated ADR liability exceeds this cumulative undiscounted NCF, then the forecast production is not economic and cannot be recognized or booked as 2P Reserves. The same economic check must be applied for the low estimate case to claim 1P Reserves, but using the low estimate (Proved case) EL.

In many cases, projects must be combined for determining their common EL. Projects may be at various stages of development, and, once the undeveloped projects are confirmed as economic on an incremental basis, those projects are then combined with the developed projects for the combined EL determination, often at a field level (PRMS § 2.1.3.6.3). This typically may occur in additive projects (such as developing and producing a secondary reservoir in a field where the primary reservoir is already producing), in which an ongoing producing project may have its EL affected by the incremental project, or for certain projects that use a common production facility. Multiple projects that share the expense of common major capital expenditures can facilitate the extension or truncation of Reserves booking or even enable the booking of Reserves for a project that, by itself, would not generate sufficient revenue to overcome the cost of installing the facilities necessary for its production. In any event, the undeveloped project or combined projects must pass the EL test to move forward to commerciality assessment.

9.3.4 Economic Conditions. As noted in Section 9.2, the EL is dependent upon the economic conditions assumed in the project evaluation. Generally, such economic conditions are expressed in either a “current economic conditions case,” “forecast case,” or “constant case.”

The “current economic conditions” case (PRMS Appendix A—Glossary) refers to the use of an arithmetic average of the product pricing and operating expenses in the calculation of the NCF, using the average of the prior 12 months of actual data, i.e., the 12 months prior to the effective or evaluation date. (For undeveloped projects with no economic history, carefully selected analogs may be used to estimate the economic conditions.) A shorter time frame may be necessary if, in the course of the prior 12 months, there has been a step change in prices and/or costs that is expected to continue. One such situation may occur when operators experiment with drilling and completion techniques to find and consistently implement the most profitable combination. Once the optimum technique is found, this approach will be done consistently going forward. This repeating of a consistent method may cause costs and/or timing to experience a "learning curve" effect (PRMS § 3.1.2.3) that will enable lower future values to be recognized. A current economic conditions case may incorporate reasonable inflation or deflation scenarios.

The forecast case, on the other hand, permits the use of price and cost escalation with time. The forecast case must be founded on assumptions that are considered reasonable by the evaluator to exist during the course of the forecast period or life of the project. This case may incorporate inflation or deflation effects (PRMS § 3.1.2.2). Prices and costs should not be escalated indefinitely and should be limited either by a cap value or time period. Because the forecast case, with its escalation effect, is commonly used, it is often referred to as the "base case" scenario.

The constant case is similar to the current conditions case, but it holds all product pricing and costs constant, i.e., has no inflation or deflation effects (PRMS § 3.1.2.6).

In all of these NCF case options, any contractual obligations that have defined costs or pricing override any inflation/deflation assumptions because the contract terms apply instead.

The economic conditions must not vary among categories within a resources class. The product price scheme used in evaluating Proved Reserves must be the same for the other Reserves categories; otherwise, a particular category will exhibit an economic bias when the categories are used to reflect primarily technical uncertainties. Adopting, for example, different pricing scenarios within a resources class is known as "split conditions" (PRMS § 2.2.0.3) and is not permitted in the application of the PRMS. Likewise, when the same economic conditions are applied to each category, and the best estimate case is economic but the low estimate (Proved) case is not, then the best estimate case may go on to pass the other commerciality requirements and become 2P Reserves; however, the uneconomic Proved case cannot be Reserves, and so no 1P Reserves may be booked (PRMS § 3.1.2.8).

A given project, however, is based on a certain development plan and commercial maturity level, upon which investment decision-making is founded. Consequently, the project cannot consist of both Reserves and Contingent Resources because they represent different commercial maturities. A project containing multiple resources classes is not permitted under the PRMS (§ 2.2.0.4) because this constitutes "split classification." Where economic production exists beyond the limit of a concession term, decisions must be made between the parties at or before the time of the concession contract expiration to proceed with continued production. If there is no evidence of historical contract extensions between the parties, or the concession terms do not call for automatic extension, then this economic production would be a new, undeveloped project consisting of Contingent Resources; otherwise, the quantities may be booked as Reserves without split classification.

9.3.5 Discount Rate. The determination of an EL relies on a NCF, excluding ADR and income taxes. Once the EL has been found, and the forecasted production has been deemed economic, the undeveloped project must be assessed for commercial viability for the defined conditions in order to recognize Reserves. A project's NCF will be discounted at a rate chosen by the entity to equal or exceed its minimum attractive rate of return, which generally reflects the entity's WACC (PRMS §2.1.2.1). When a discount rate is applied to the NCF evaluation, the resulting cumulative time value reflects the NPV of the future cash-flow stream. For example, if the entity's decision criteria require achieving a 10% WACC, then the resulting NPV discounted at 10%/year must equal or exceed zero to satisfy the required criteria. If the criteria are not met, then the entity may decide to not fund the project, and the volumes are not commercial and therefore cannot be classified as Reserves.

9.3.6 Other Key Terms. "Economic interest" (also known as entitlement interest or "mineral interest") represents the share, right, or title in property (a lease, concession, or license), project, asset, or entity. It typically also represents the percentage of the forecast sales production in the entity resources NCF. There are several forms of economic interest, depending on the specific regime. An economic interest in a concession regime is generally simpler to determine and may be represented by the working interest of the entity, after deducting royalties and any interests owned by others. In more complex regimes, such as PSCs, typically there is a variable economic interest in the production, caused both by cost recovery mechanisms and possibly by variable profit petroleum fraction (with values often listed in tables). This variable interest of "entitlement" for an evaluated party cannot be calculated by simply multiplying, for example, total project volumes or revenue (whether before or after the deduction of any royalties owed to others) by the party's working interest. Chapter 12—*Resources Entitlement and Recognition* herein describes forms of economic interest to be considered for both the entitled quantities and for the share of production revenue in the resources cash flow.

"Royalties" are the payments made to the mineral rights owner for the right to explore for and produce petroleum after a discovery. Depending on the country's regulations, mineral rights may belong to the host government or other mineral rights owners (lessors). In agreements where royalties are taken in kind (e.g., in terms of production) or "cash or kind," the royalty share must be deducted from the entitled quantity of the entity (and the entitled production in the NCF). This treatment is proper in cases where the host or lessor retains a mineral interest in the related volume. In agreements where payments do not relate to host or lessor ownership of a mineral interest, and the payment termed royalty is paid in cash, the default position is to *not* deduct royalty from the entitled quantity of the entity (and the entitled production in the NCF). The foregoing discussion is focused on reporting regulations that require disclosure of net volumes after deduction of royalties owned by others, which is the objective of the entitlement quantities–based PRMS. However, some jurisdictions may require reporting of gross volumes before deduction of royalties, depending on the specific purpose and use of the information reported.

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. In such cases, the royalty quantity may also be deducted from the entitled quantity of the entity. In some agreements, royalties are required to be paid in cash to the mineral rights owner. There are also agreements where cash payments to the host government are termed royalties, but they are recognized as production taxes and are not associated with mineral rights ownership. If this is the case, then the entity's resources NCF royalties shall not be deducted from the entity's economic interest, but those "production taxes" should be treated as an expense in the entity's NCF when determining the EL and in its DCF when recognizing project economics and the entity's associated Reserves. Chapter 12—*Resources Entitlement and Recognition* herein contains further description of royalties.

"Royalty interest" is a mineral interest that typically is not burdened with a proportionate share of investment and operating costs. Royalty owners are responsible for their share of production and ad valorem taxes (i.e., taxes imposed based on production value and/or value of equipment necessary to produce petroleum). Royalty interest may also be defined as the share of minerals reserved in money, or in kind, free of expense, by the owner of mineral rights when leasing the property or contracting another party for exploration and production.

"Overriding royalty interest" is a revenue interest, free of any cost obligation, created by the operating entity and/or working interest owner and paid by the operating entity and/or working interest owner out of revenue from the property. This differs from royalty interest because ownership of the minerals is not the basis for this interest, but rather it is another form of economic interest in the property.

"Fiscal systems or arrangements" made between the producer and the host government may include concession agreements, joint venture agreements, PSCs, and other contracts (refer to Chapter 12—*Resources Entitlement and Recognition* herein).

9.4 Required Input for a Cash-Flow-Based Evaluation

Proper evaluation calls for the preparation and validation of certain data specific to each project, generally including technical constraints (wells, facilities, flowlines, etc.), product prices at the sales/reference point(s), capital expenditures, operating costs, ADR costs, ownership/entitlement and royalties, taxes, and legal/contract/fiscal terms (PRMS § 3.1.1.1).

9.4.1 Net Entitlement Sales Production Forecast. The net entitlement sales forecast is the start of the resources NCF, representing the entity's share of sales quantities that will generate sales revenues in the NCF when multiplied by product prices. This sales production forecast is measured and reported at the reference point, which is typically the point of sale of the marketed quantity. There is a different net sales forecast for each resources category, which will generate different sales revenues. The entity's net sales production forecast is directly affected by the economic interest of the entity in the project, which depends on the contract model. Chapter 12—*Resources Entitlement and Recognition* provides more description on the economic interest of contracts and agreements such as concessions.

9.4.2 Product Prices. Product price forecasts used by the evaluator to apply to the commodities in the future must consider the impact of any sales contracts or price hedges. Fiscal arrangements made between the producer and the host government also may be part of the actual price received for the products. Whatever method is used for setting future prices (forward strip, internal entity estimates, contractual specifications, fixed historical averages, etc.), they are to be applied at the reference point (typically the sales point; see Chapter 11—*Production Measurement and Operational Issues* herein) for the project and should be referenced to an appropriate benchmark (e.g., Brent, West Texas Intermediate, Arab Light, etc.). Historical benchmark pricing is readily available on industry websites, but these reference a particular quality of product. The project being evaluated likely will have a different commodity quality, and so there will be a product price differential associated with the crude quality (API gravity, sweet/sour), natural gas liquid, or gas heating value (calorific content) that must be included when determining the applicable product price.

For gas, it is important to look at the gas composition at the reference point to ensure that the correct differentials are being applied. If the reference point is after gas processing, dry gas and each byproduct (e.g., propane, butane, and condensate) should be evaluated with the appropriate price forecast.

This differential also may be based on the physical sales or reference point and the market for the product in that area. Often, actual historical price differentials from the sales point may be acquired from a lease operating statement, to ensure that the correct differentials are being applied and to tie the evaluation to the forecasted price differentials.

The sales price may also be impacted by certain costs. "Marketing and transportation costs" are the costs incurred to deliver a product to its sales point, and they are to be identified either as part of the operating costs or as a reduction of the sales price if the sales point is not at the wellhead. Both methods typically result in the same economic outcome, but they will result in operating costs and sales price differences, and the approach must be consistent with the financials treatment. The evaluators must clearly identify and document all assumptions used in the evaluation price forecast because this will directly impact the projected quantities eligible for classification as Reserves and Resources.

9.4.3 Project Capital Costs. For undeveloped and partially developed projects, any cash-flow evaluation requires an assessment of the development plan's future capital costs, based on an evaluation of the development expenditures for that specific resource category. In this context, the development costs include all the necessary project capital for wells and facilities to enable delivery of petroleum attributed to the resource category from the accumulation(s) to a product sales point (or to an internal transfer point between upstream operations and midstream/downstream operations).

Capital expenditures (CAPEX) are major expenses that typically encompass items such as land acquisition, exploration, drilling and well completion, and surface facilities (gathering infrastructure, process plants, and pipelines). Additionally, they may include environmental and social costs required to be incurred related to the resources category in the economic evaluations.

Well drilling and completion costs are categorized in terms of tangible (subject to depreciation allowance) and intangible (expensed portion and portion subject to amortization) well costs (for companies that follow the U.S. Generally Accepted Accounting Principles, of GAAP; companies reporting under the International Financial Reporting Standards, or IFRS, must consult the reporting principles used in their respective countries). Surface facility costs are subjected to facility-specific depreciation allowances used in calculating taxes and various incentives. This level of detail regarding depreciation, depletion, and amortization (DD&A) usually does not enter into any cash-flow analyses for economic and commercial assessment, but rather relates to accounting, public disclosure, and reporting for tax purposes.

When a development plan for the project is either incomplete or not available (which may be the case for contingent resources), CAPEX estimates may be made using one of two approaches:

- Top-down approach—This approach uses historical data from similar development projects to estimate the costs for the current project by revising and normalizing these data for changes in time (inflation or deflation), production quantity, facility capacity, location, and other factors. It uses a simple "percentage-of-cost basis" established from the review of historical or current data.
- Bottom-up approach—This is a more detailed method of cost estimation that requires a detailed design that breaks down the processing equipment into small, discrete, and manageable parts (or units). The smaller unit costs are summed (including other associated costs) to obtain the overall cost estimate for the processing equipment.

Total capital investment cost required for any process equipment (or plant with several units of equipment) is generally recognized under four categories (Clark and Lorenzoni 1978; Humphreys and Katell 1981) when there are tax considerations:

- "Direct costs" include all material and labor costs associated with a purchased physical plant or equipment and its installation. They include the costs of all material items that are directly incorporated in the plant itself as well as those bulk materials (such as foundation, piping, instrumentation, etc.) needed to complete the installation.

- "Indirect costs" represent the quantities and costs of items that do not become part of, but are necessary costs involved in, the design and construction of process equipment. Indirect costs are generally estimated as "percentage of direct costs." Indirect costs are further subcategorized as engineering, constructor's fee (covering administrative overhead and profit), field labor overhead, miscellaneous others and owners' costs (such as land, organization, and startup costs). Engineering indirect costs include the costs for design and drafting, engineering and project management, procurement, process control, estimating, and construction planning. Field labor overhead includes costs of temporary construction consumables, construction equipment and tools, field supervision, and payroll burden, etc.
- "Miscellaneous others" include freight costs, import duties, taxes, permit costs, royalty costs, insurance, and sale of surplus materials.
- "Contingency" is included to allow for possible redesign and modification of equipment, escalated increases in equipment costs, increases in field labor costs, and delays encountered in startup.

Further, "working capital" is needed to meet the daily or weekly cost of labor, maintenance, and purchase, storage, and inventory of field materials.

9.4.4 Operating Costs. These expenses are generally recognized under five categories (Humphreys and Katell 1981):

- "Direct costs" are considered to be dependent on production and include variable and semivariable components. Costs are variable when related to produced volumes (or injected volumes for water-disposal or supplemental recovery projects). Such costs are typically expressed in cost per unit volume (e.g., USD/bbl). Variable costs will be zero when there is no production/injection. Examples include lifting costs and chemical treatment costs. Semivariable costs are related to producing operations but not directly tied to volumes. These costs have a fixed component that does not go to zero when production ceases (e.g., plant shutdown). Examples are costs to monitor and maintain wells and facilities. These costs go up as production operations grow (e.g., more wells and facilities) but do not directly tie to produced volumes. These costs are often expressed as cost per unit of operation such as USD/well/month.
- "Indirect costs" are considered fully independent of production and, thus, fixed costs. These include plant overhead, or burden, and other fixed costs such as property taxes, insurance, and depreciation. (Note that depreciation, the reduction of asset book value with time, is typically part of DD&A charges used in accounting practice and is not, as mentioned in Section 9.4.3, above, per se part of the cash-flow analyses performed by the reserves evaluator, except indirectly, via the impact of these DD&A charges on tax considerations.)
- "General and administration expenses (G&A)," or simply overhead expenses, are those costs required to operate the subject property. These costs must be actual incremental costs attributable to the project (PRMS § 3.1.3.2).
- "Distribution costs" are those operating and manufacturing costs associated with transporting the products to market, like pipelines for crude oil, gas sales, and natural gas

liquids. They include the cost of containers and packages, freight, and operation of pipelines, terminals, and warehouses or storage tanks.

- “Contingencies” constitute an allowance made in an operating cost estimate for unexpected costs or for error or variation likely to occur in the estimate. A contingency allowance is just as important in the operating expenses as it is in the CAPEX. However, it must be pointed out that companies may define and categorize their operating costs differently and may not even include some of the components in their project economic analysis if they are not directly related to the project scope for that category.

9.4.5 Ownership and Royalties. Entitlement, as characterized by ownership (or economic) interests and royalties, is covered in more detail in Section 9.3.6 above and in Chapter 12—*Resources Entitlement and Recognition* herein. When evaluating reversionary interests based on a payout quantity, the NCF will be used to determine when this occurs. For example, a partner in a project may have a certain working interest until the time at which the revenue from the project equals the capital investment, subject to the agreement payout terms, to bring the project on production. Known as a Working Interest before Payout (WIBPO or just BPO), this interest then reverts at payout to a Working Interest After Payout (WIAPO or just APO). The same situation may exist for the net revenue interest attributable to the partner. Whether the reversion is from a large interest to a smaller interest or vice versa, the result is a change in the percentage of hydrocarbons to the interest owner, which must be reflected in not only the reserves, but also the project NCF.

9.4.6 Taxes. Taxes that are imposed based on production value and/or value of equipment necessary to produce petroleum must be included in the NCF. Examples are production taxes that may include severance and ad valorem taxes in the US. Income taxes or profit-based taxes (which may include certain types of federal and state taxes) are not included in the determination of the entity’s EL. (Severance tax may be assessed, usually on a state level, based on either the volumes produced, e.g., USD/bbl, or on the value as a percent of revenue. Ad valorem taxes are assessed, usually at the county level, as a percentage of the revenue.) Similar taxes may be assessed in different countries around the world.

9.4.7 Legal/Contract/Fiscal Terms. The revenue and cost components of any term described above (including all other relevant economic and commercial terms) may be defined differently from country to country due to the fiscal arrangements made between companies and host governments, which allocate the rights to develop and operate specific oil and gas businesses. Common forms of international fiscal arrangements are concessions (through royalties and/or taxes), PSCs, and risk service contracts (see Chapter 12—*Resources Entitlement and Recognition* herein). In general, these agreements define how project costs are recovered and how profit is shared between the host country and the entities that take a working interest in the agreement. Detailed knowledge of these governing regulations (regarding, for example, the permitted period of activity; any royalties, income taxes, or other fiscal items; any other obligations, such as the ADR funding mechanism or fiscal incentives) is critical for a credible project reserves assessment and evaluation process.

Additionally, the same can be said of agreements between project co-owners, which can impact an evaluated entity’s cash flows, for example, farm-ins or farm-outs and other situations where the evaluated partner’s monetary entitlements/obligations cannot be determined simply as its percentage working interest in the project multiplied by the total monetary amount in question. Fiscal terms and other conveyances are covered in more detail in Chapter 12—*Resources Entitlement and Recognition* herein.

9.5 Generating a Cash-Flow-Based Evaluation

To reiterate, the NCF evaluation should be performed as follows.

1. Production forecasts of the primary and secondary streams are generated per project and/or per category (e.g., 1C, 2C, or 3C, Development Pending sub-class).
2. The economic conditions (current conditions, forecast case, or constant case) under which a NCF is to be created must be decided.
3. An undiscounted NCF analysis is performed to determine the economic viability and EL for the project. This NCF ignores income tax and (except for certain situations such as with PSCs and as noted in step 5 below) ADR liabilities.
4. The EL must be compared against other constraints, such as operational limitations or concession terms, and the earliest occurrence of these must be applied to constrain the production forecast and the NCF.
5. For an undeveloped project, if the cumulative NCF exceeds the estimated ADR liability, then the project is considered economically viable (PRMS § 3.1.2.5). For developed projects, ADR is excluded from the economic producibility determination (PRMS § 3.1.2.1).
6. If economically viable, the commerciality of the undeveloped project must then be assessed, starting with the application of a discount rate equal to or greater than the entity's WACC. The cumulative discounted NCF (the DCF), which is the sum of the annual discounted cash flows, yields the project's NPV, which then will be compared with the entity's investment decision criteria. (Note: Discounting may result in an EL different from that determined in step 3.)
7. If the project meets or exceeds the entity's hurdle criteria (see Section 9.6.1), and the project satisfies all other criteria used to pass the commerciality test (as listed in PRMS § 2.1.2.1), the projected recoverable quantities attributable to the project may be classified as Reserves.

With commercial software or the use of third-party consulting services, generating the NCF for a project is quite easy from a mechanical standpoint. However, it is important to understand the information required to provide the input to these calculations.

Table 9.1 below shows an example of a NCF/DCF template with the basic output. In this example, ADR is included within the capital costs, but income taxes are excluded.

Reading the template from left to right, we see that most NCF reports employ an annual convention, i.e., all output is in terms of an annual result (or perhaps an average in the case of the product prices). The gross production is then tabulated by product, such as crude oil and associated gas, or non-associated gas and condensate. As further discussed in Chapter 12—*Resources Entitlement and Recognition* herein, the evaluation is conducted for the interest to which the entity is entitled, according to the entity's net revenue interest (NRI), expressed as Net Production = (Gross Production × NRI), which may vary by product and the entitlement terms.

		RUN DATE	2/1/2019
		RUN TIME	
RESERVES AND ECONOMICS			
CLIENT	MEGA OIL	PREPARER	CRV
FIELD/RESERVOIR	BARNBURNER	AS OF DATE	December 31, 2018

	GROSS PRODUCTION		NET PRODUCTION		PRICES		OPERATIONS, M$					10%
YR END	OIL, MBBL	GAS, MMCF	OIL, MBBL	GAS, MMCF	OIL $/BBL	GAS $/MMBTU	NET OPER REVENUES	SEV+ADV TAXES	NET OPER EXPENSES	CAPITAL COSTS, M$	CASH FLOW BTAX, M$	CUM DISC BTAX, M$
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
2029												
2030												
2031												
2032												
2033												
SUB												
REM.												
TOTAL												

CUM	
EUR	

WORKING INTEREST, %	100.0
REVENUE INTEREST, %	87.5

NET OIL REVENUE (M$)	xxx
NET GAS REVENUE (M$)	xxx
TOTAL REVENUES (M$)	xxx

BTAX ROR, %	xx
BTAX PAYOUT YEARS	xx

PROJECT LIFE (YRS)	xx
DISCOUNT RATE (%)	10

PRESENT WORTH PROFILE			
DISC RATE	PW OF NET BTAX, M$	DISC RATE	PW OF NET BTAX, M$
0	xx	40	xx
5	xx	45	xx
10	xx	50	xx
15	xx	60	xx
20	xx	70	xx
25	xx	80	xx
30	xx	90	xx
35	xx	100	xx

Table 9.1—Example NCF analysis.

Next, we have columns containing the annual product reference-point prices, which may be held constant or escalated in accordance with a forecast scenario. As described in Section 9.4.2, these prices should be adjusted for product quality, e.g., whether light or heavy crude, high- or lower-BTU gas, etc., and they must honor any contractual pricing specifications.

Continuing to the right, the next columns are for the calculation of revenue and operating costs for the project. Revenue, net to the evaluated interest, is calculated first (net sales production multiplied by product price), and taxes are then estimated. The taxes column in Table 9.1 specifies "severance & ad valorem" taxes, but the heading more generally could be called "production taxes."

Net operating expenses refer to the charges to the appraised interest for maintaining the project, whether on production or not. These costs include fixed and variable items, as has been discussed previously in Section 9.4.4. In addition, as pointed out in the PRMS § 3.1.3.2, "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 nonhydrocarbons."

The handling of lease use fuel (consumed in operations, CiO) volumes must be done properly to avoid undercounting expenses or overcounting sales revenues. PRMS § 3.2.2.3 states that CiO represents an operating expense reduction when used in place of fuel purchased from external parties, although the CiO quantities themselves are not included in the project economics; in other words, these quantities must not be treated as a revenue stream or as a cost incurred for purchase to recognize a sales quantity. This is easily handled if the CiO quantities are not included in reserves or resources. However, if an entity chooses to include CiO quantities as reserves or resources, then the quantities must be stated and recorded separately from sales quantities to ensure no revenue will be calculated from these CiO quantities.

Next, we have capital expenditures, which are the major expenses (as discussed previously in Section 9.4.3) for undeveloped projects, including ADR for undeveloped projects (and even developed projects, depending on the entity and its use of the cash flow). These costs have a greater impact on the net present value when they occur earlier in the life of the project.

Following these columns, we have the annual undiscounted net cash flow, designated here as "BTAX" or before tax, specifically (since this is a US project evaluation), federal income tax (more appropriately a "BFIT" evaluation). This column is simply the summation of the annual operating revenues less the production taxes, operating expenses, and capital expenditures.

The final column is the discounted cumulative net cash flow, in this example, using a 10% discount rate based on the entity's WACC. As can be found in most economic analysis textbooks, the present worth of a single payment (for the cashflow here, the annual NCF is discounted) may be calculated using the formula:

$$P = F(1+i)^{-(n-0.5)}, \qquad (9.1)$$

where

P = the present value of a future cash flow
F = the future value of cash flow
i = discount rate per interest period (decimal)
n = number of interest periods
$(1+i)^{-(n-0.5)}$ = discount factor assuming midyear discounting, or $(1+i)^{-n}$ for an annual basis.
F = production term in the material balance equation, bbl.

Further, the discount rate may be expressed either as an annual or monthly rate. For more detail on the monthly rate usage, reference may be made to Society of Petroleum Evaluation Engineers Recommended Evaluation Practice 5 (Society of Petroleum Evaluation Engineers 2002).

The DCF output typically should include:

1. Identity of the project being evaluated, including
    a. Entity
    b. Field and reservoir(s)
    c. Other identification as necessary
2. Identification of the evaluator
3. Resources class and category
4. Effective date of the evaluation
5. Discount rate applied in the evaluation
6. Annual output of columnar data described above (Table 9.1)
7. Subtotal of output of columnar data described above (Table 9.1)
8. Any remaining output for the columnar data described above beyond the tabulated time frame
9. Total of items 6 and 7 for each column of data
10. Cumulative production, if any, of the evaluated products
11. Estimated Ultimate Recovery, being the sum of items 9 and 10 to the evaluated interest

12. Disclosure of application of federal/governmental income tax
13. The evaluated working and net revenue interests (reversions noted as necessary)

Optional output could include the per-product net revenue, calculated internal rate of return, payout time, a present worth table showing the effects of varying discount rates on the project NPV, and any concession/contract term limit.

9.6 Analyzing a Cash-Flow-Based Evaluation

At this stage, it is important to reiterate two points:

1. As mentioned previously (Section 9.2), the PRMS guidelines and definitions may be used to estimate project value by cash-flow analyses only. Other value measures, such as historical costs, comparative market values, key economic parameters, etc., are not included in the PRMS guidelines.
2. The PRMS-based DCF evaluation is not a fair market value calculation; it is a net present value estimation based on the defined economic conditions and procedures further set out in the PRMS guidelines. The PRMS establishes no criteria for transactional value assignment. The PRMS-based DCF evaluation may be used as a basis for the further quantification of a fair market value, but such value is dependent upon many criteria (e.g., current market conditions, desirability of certain acreage position, buyer/seller motivation, etc.) outside a principles-based system such as the PRMS.

The cash-flow-based evaluation is a necessary first step in establishing the economic viability of a project. Once the DCF has been generated, it must then be analyzed relative to the entity's hurdle criteria for the project to move toward classification as Reserves (provided other contingencies have been satisfied).

9.6.1 Investment (Hurdle) Criteria. An investment decision is dependent upon several criteria, each specific to the entity by/for whom the evaluation is performed. The majority of the profitability indicators are readily derived from the DCF evaluation. Such profitability indicators are also used in portfolio ranking to plan the development sequence of projects to yield the greatest financial return to the entity and its shareholders, if any. In addition to fulfilling the WACC hurdle mentioned above, an entity may consider other criteria, including (but not limited to):

- The time to payout, i.e., the time required for the cumulative undiscounted net revenue to equal the amount of the initial capital investment (some entities prefer to use discounted payout)
- Net profit index (dollars generated per dollar initially invested, also known as "return on investment"), calculated as the cumulative undiscounted NCF, i.e., cumulative undiscounted net revenue, excluding CAPEX, divided by the initial undiscounted CAPEX
- Discounted return on investment (NPV of cash flow, i.e., cumulative DCF, including CAPEX, divided by discounted investment; or the present value ratio, PVR)
- Magnitude of NPV
- Discounted cash-flow rate of return (DCFROR, the discount rate at which the cumulative NPV equals zero; also known as internal rate of return IRR)

Each of the criteria has advantages and drawbacks, so investment decisions usually rely on a combination of these economic factors. For example, the PVR method is beneficial when considering the time value of money and for choosing investment opportunities when investment capital is constrained, but the magnitude of the calculation is meaningful only in comparison with other competing projects. Similarly, although time to payout is commonly used, it fails to take into account the time value of money or how profitable the investment is after the payout. Furthermore, IRR is occasionally literally incalculable (for example, when all undiscounted future cash flows are positive), and these calculations can also result in multiple IRRs.

9.6.2 Sunk Costs. Because Reserves represent quantities yet to be recovered, their NCF evaluation is always forward-looking for the purposes of applying the PRMS principles. Sunk costs, which are expenditures incurred prior to the effective date of the evaluation, are relevant for accounting or tax purposes, in addition to production sharing contracts and overall project economic determination. Some projects that, upon cash-flow-based evaluation, are sub-economic and fail to meet the requirements to be classified as Reserves may, in subsequent years, achieve Reserves status as capital expenditures are incurred and become sunk costs no longer impacting the future NCF. This situation is discussed in PRMS § 3.1.2.8, where reference is made to uneconomic 1P quantities: "As costs are incurred in future years (i.e., become sunk costs) and development proceeds, the low estimate may eventually become economic and be reported as Proved Reserves."

It should also be recognized that sunk costs can have relevance beyond accounting purposes. Sunk costs can influence future cash flows via their impact on, for instance, future taxable income. For example, a fixed asset purchased before the evaluation date can generate tax depreciation charges and/or tax loss carry-forwards that impact income tax charges in future periods.

Some fiscal regimes such as PSCs use mechanisms based in part on sunk costs that are forecast to be recovered as cost oil, which will influence the evaluated party's entitlement share of project revenue. For example, shares of revenue ("profit-oil") might be based on an "R-Factor," which is often calculated as some measure of cumulative project inflows to date divided by some measure of cumulative outflows to date, including sunk costs.

The use of sunk costs will also be important when entitlement interests are calculated on a before- or after-payout basis.

Therefore, when sunk costs influence future cash flows used in an evaluation, this influence must be reflected in the calculation.

9.7 "Economic" Compared to "Commercial"

According to the PRMS (Appendix A—Glossary), "A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met."

There has been some confusion in the industry over the use of and difference between the terms "economic" and "commercial." As can be seen in the previous paragraph, under the PRMS, a project is commercial when there is evidence that certain conditions are met, one of which is the economic condition. Consequently, being "economic" is a prerequisite for a project to be "commercial." Commercial projects are, therefore, economic; however, an economic project is not necessarily commercial if it fails to pass the other necessary criteria, including providing a positive NPV at the entity's hurdle discount rate.

9.8 Example

An exploratory well, ALPHA-1, results in a discovery in an area with promising seismic signature updip from an old well that was wet in the subject reservoir. Logs from the two wells correlate, and no evidence of faulting can be inferred, supporting the seismic interpretation and suggesting a structural trap. With updip hydrocarbons discovered, the entity engineers and geoscientists use the pressure data from the new well plus the old wet well to estimate an oil-water contact and generate hydrocarbon pore volume maps for low, best, and high case scenarios. Collected fluid samples enable the laboratory analysis of the oil formation volume factor for the proposed surface separation process, permitting the calculation of the oil originally in place (OOIP). The reservoir has booked reserves in nearby fields where it is being produced through pressure maintenance by water injection.

Data are gathered to perform an economic assessment through cash-flow analysis. Based on the well tests and analogy to the nearby fields producing from the reservoir (but in different accumulations), a "most likely" performance projection is created. The proposed development plan for the analysis assumes the re-entry of the discovery well and the drilling of two more producers, three water-injection wells, and a water-supply well. There are production facilities in the vicinity to which the new project can be connected, provided the projected water handling from Project ALPHA can be accommodated. A forecast case is run using a midyear escalation approach. Arrangements with the host government call for a concession term of 40 years with a bonus to be paid to the government in the tenth year of production. The government will impose production taxes as a percent of revenue and will retain a royalty interest. **Table 9.2** summarizes the economic analysis input assumptions, including data pertinent to both the economic and subsequent commercial analyses. Costs are shown before inflation.

INPUT ASSUMPTIONS					
Oil Price, $/bbl	50	Government Royalty	12.5%	CapEx, Wells, $MM	24
Gas Price, $/MMBTU	2.50	Government Bonus, $MM	20	CapEx, Facilities, $MM	100
BTU Content, BTU/SCF	1300	Production Tax, % Revenue	10%	OpEx, $M/month*	112.5
Gas Price, $/MSCF	3.25	ADR Liability, $MM	20		
Oil Price Cap, $/bbl	75	Income Tax Rate, %	10%	Terminal Decline Rate, %/yr	8%
Gas Price Cap, $/MSCF	5	Discount Rate, %	10%	• Pressure Maintenance by Water Injection	
Currency Inflation Rate, %/yr	2%	Concession Term, yrs	40	• Government Bonus Non-Tax Deductible	
Mid-Year Escalation		ADR Incurred in Year	EL + 1	* Three producers, three injectors	

Table 9.2—NCF input assumptions, where OpEx is operating expenses.

Fig. 9.2 depicts the EL test graphically. The annual bars represent the undiscounted NCF, i.e., the difference between net revenue and net expenditures. The cumulative NCF is shown by a red line, which dips in year 10 as a result of the bonus, but which continues to increase thereafter. Cumulative oil recovery is depicted by the black line. The maximum cumulative NCF occurs in year 27 (USD 103 million); beyond that date, costs exceed revenues. As a result, the economic life of the project is 27 years, which is less than the concession term by 13 years. (Further, no technical constraints, such as lift capacity or water handling, occur in the economic assessment.) Subtracting the ADR, which, when adjusted for the currency inflation rate, is USD 34 million in year 28 (i.e., the year after the EL), from the maximum cumulative undiscounted NCF yields a positive number. This establishes economic viability, and the potential oil reserves equal the cumulative oil recovery at the EL, which is equal to 5.2 million STB.

Table 9.3 depicts the NCF as generated for the purpose of establishing the EL. A most likely production forecast in thousands of stock tank barrels (MSTB) is shown on an annual basis in Column B, while the associated gas production is shown in Column C in millions of standard cubic feet (MMSCF). The values shown are to the gross (100%) interest, i.e., a working interest of 100%. However, under the concession agreement, there is a 12.5% royalty owed to the government, so these production figures are thereby reduced as reflected in Columns D and E to obtain the entity's net (entitled) oil and gas produced, respectively. Columns F and G show the oil and gas prices in US dollars per barrel with a 2%/year inflation index applied (using a midyear convention) to yield the inflation-adjusted prices in nominal US dollars. Initial prices are USD 50/bbl and USD 3.25/MSCF for oil and gas, respectively. and are thus escalated until reaching caps of USD 75/bbl and USD 5.00/MSCF, respectively. Annual revenue from net oil and gas sales in nominal dollars is calculated in Column H as the product of Columns D and F plus the product of Columns E and G.

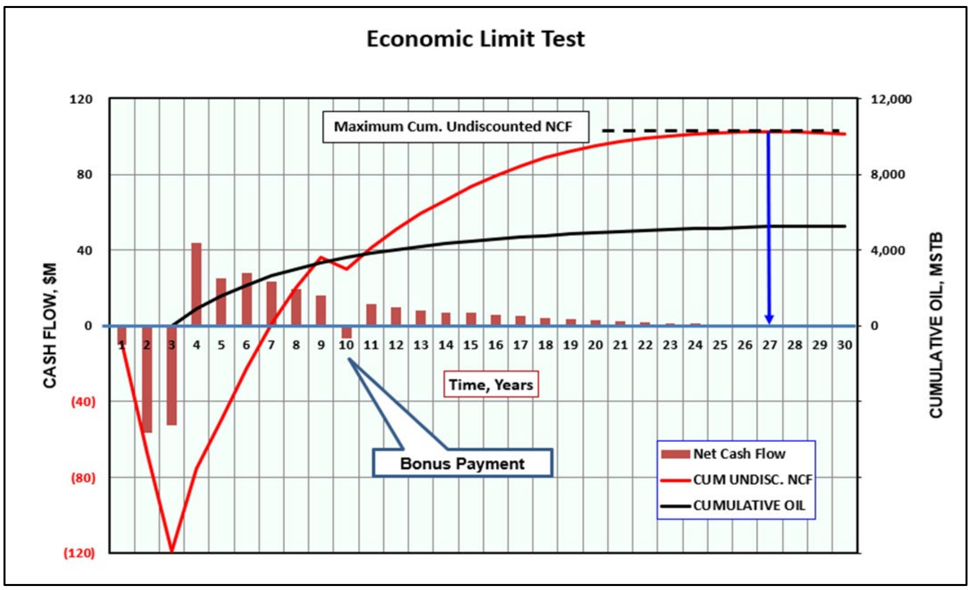

Fig. 9.2—NCF graph for determination of the EL.

In terms of costs and cash outflow, Column I contains the estimated operating expenses (OPEX), Column J represents production taxes (in this case, as a percent of net revenue, although it could be a flat-rate levy or tax, but this does not include income tax), while Column K continues with the capital expenditures (CAPEX) but not yet reflecting the ADR and its spend timing, again with all columns in nominal US dollars. Column L highlights the required bonus payment in year 10 of the project.

The undiscounted NCF of Column M is the difference between Column H (Total Net Revenue) and the summation of Columns I through L (Total Net Costs). Due to the lead time in establishing production from the field, the first 3 years of NCFs are all negative. Once production commences, annual NCF figures (Column M) become positive, with the exception of year 10, when the bonus is paid. Column N is the cumulative undiscounted NCF (for EL test purposes), reflecting the running totals from Column M. It is not until the seventh year that the cumulative NCF becomes positive (note also Fig. 9.2).

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Gross (100%) Production		Net (Entitled) Production		Prices (Nominal)		Net Revenue	Net OPEX	Prod'n Taxes	Capital Costs	Bonus	Net Cash Flow	Cum. Net Cash Flow	Economic Limit Test
Year	Oil	Gas	Oil	Gas	Oil	Gas	Nominal	Nominal	Nominal	Nominal	Nominal	Nominal	Nominal	
	MSTB	MMSCF	MSTB	MMSCF	$/BBL	$/MCF	$MM	$MM	$MM	$MM	$MM	$MM	$MM	
1					50.498	3.282	-	-	-	10.100		(10.100)	(10.100)	-
2					51.507	3.348	-	-	-	56.658		(56.658)	(66.758)	-
3					52.538	3.415	-	-	-	52.538		(52.538)	(119.295)	-
4	1020.179	612.108	892.657	535.594	53.588	3.483	49.702	0.965	4.970			43.767	(75.528)	-
5	808.088	484.853	707.077	424.246	54.660	3.553	40.156	0.984	4.016	9.839		25.318	(50.211)	-
6	649.932	389.959	568.690	341.214	55.753	3.624	32.943	1.505	3.294			28.143	(22.067)	-
7	529.771	317.863	463.550	278.130	56.868	3.696	27.389	1.535	2.739			23.115	1.048	-
8	436.965	262.179	382.344	229.406	58.006	3.770	23.043	1.566	2.304			19.173	20.220	-
9	364.233	218.540	318.704	191.222	59.166	3.846	19.592	1.597	1.959			16.035	36.256	-
10	306.487	183.892	268.176	160.905	60.349	3.923	16.815	1.629	1.682		20.000	(6.496)	29.760	-
11	260.099	156.060	227.587	136.552	61.556	4.001	14.556	1.662	1.456			11.438	41.198	-
12	222.441	133.464	194.636	116.781	62.787	4.081	12.697	1.695	1.270			9.732	50.930	-
13	191.574	114.944	167.627	100.576	64.043	4.163	11.154	1.729	1.115			8.309	59.240	-
14	166.052	99.631	145.295	87.177	65.324	4.246	9.861	1.764	0.986			7.112	66.351	-
15	144.779	86.868	126.682	76.009	75.000	5.000	9.881	1.799	0.988			7.094	73.445	-
16	126.918	76.151	111.053	66.632	75.000	5.000	8.662	1.835	0.866			5.961	79.406	-
17	111.818	67.091	97.841	58.705	75.000	5.000	7.632	1.872	0.763			4.997	84.403	-
18	98.974	59.384	86.602	51.961	75.000	5.000	6.755	1.909	0.675			4.170	88.573	-
19	87.983	52.790	76.985	46.191	75.000	5.000	6.005	1.947	0.600			3.457	92.030	-
20	78.527	47.116	68.711	41.227	75.000	5.000	5.359	1.986	0.536			2.837	94.868	-
21	70.351	42.211	61.557	36.934	75.000	5.000	4.801	2.026	0.480			2.295	97.163	-
22	63.248	37.949	55.342	33.205	75.000	5.000	4.317	2.067	0.432			1.819	98.982	-
23	57.050	34.230	49.919	29.951	75.000	5.000	3.894	2.108	0.389			1.396	100.378	-
24	51.619	30.972	45.167	27.100	75.000	5.000	3.523	2.150	0.352			1.021	101.399	-
25	46.842	28.105	40.986	24.592	75.000	5.000	3.197	2.193	0.320			0.684	102.083	-
26	42.623	25.574	37.295	22.377	75.000	5.000	2.909	2.237	0.291			0.381	102.464	-
27	38.886	23.331	34.025	20.415	75.000	5.000	2.654	2.282	0.265			0.107	102.571	27.000
28	35.563	21.338	31.118	18.671	75.000	5.000	2.427	2.327	0.243			(0.143)	102.429	-
29	32.600	19.560	28.525	17.115	75.000	5.000	2.225	2.374	0.222			(0.371)	102.057	-
30	29.951	17.970	26.207	15.724	75.000	5.000	2.044	2.421	0.204			(0.582)	101.476	-
SUM	***6,073.55***	***3,644.13***	***5,314.36***	***3,188.62***			***334.19***	***50.16***	***33.42***	***129.13***	***20.00***	***101.48***		

Table 9.3—NCF for determination of the EL.

Although the evaluator may simply scan the economic output and/or Fig. 9.2 to determine the time at which the maximum undiscounted NCF is achieved, for the purpose of this example, we have also included Column O in the table specifically to illustrate the determination of the maximum NCF and economic life. Column O is a simple IF statement comparing the corresponding value of Column N to the MAX of the range of values in Column N, and, when they are equal, the IF statement returns the value of the year (from Column A); otherwise, the cell is left blank. This column identifies year 27 as the year in which we reach the maximum cumulative undiscounted NCF.

Finally, a comparison of the cumulative NCF (USD 102.6 million) to the estimated ADR liability (USD 20 million adjusted for inflation to the EL in year 28 is USD 34 million) satisfies the economic viability criterion required to consider the undeveloped project's quantities as Reserves (PRMS § 3.1.2.5). The next step is to assess the project's commerciality. The following text describes the NPV calculation used by this entity for investment decision.

We will consider the impact of ADR and income taxes for this example, assuming that the ADR costs are incurred in the year following cessation of production at the EL.

Columns P and Q in **Table 9.4** reproduce Columns D and E in Table 9.3 (net oil and net gas produced, respectively) but consider only the economic quantities using the economic flag (Column O). Columns R and S are the total net revenue from Column H and the total net costs from the sum of Columns I through L, again considering only the economic quantities. The undiscounted NCF for the economic life is calculated in Column T, and the ADR liability is incurred in Column U by comparing the maximum NCF year (Column O) to the production year (Column A), and, when equal, the ADR costs are imposed in the following year (as per the initial assumptions).

Columns V through AA are concerned with tax considerations.

A	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
							Income Tax Considerations							
Year	Economic Net Oil Produced	Economic Net Gas Produced	Total Net Revenue	Total Net Costs	Total Net Cash Flow	ADR Liability	Newly Incurred	Losses Carried Forward	Total	Taxable Income	Income Tax	Losses to Carry Forward	Cum. Undisc. Net Cash Flow	Cum. Disc. Net Cash Flow
	MSTB	*MMSCF*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*	*Nom. $MM*
1	-	-	-	10.100	(10.100)	-	10.100	-	10.100	(10.100)	-	(10.100)	(10.100)	(9.630)
2	-	-	-	56.658	(56.658)	-	56.658	10.100	66.758	(66.758)	-	(66.758)	(66.758)	(58.740)
3	-	-	-	52.538	(52.538)	-	52.538	66.758	119.295	(119.295)	-	(119.295)	(119.295)	(100.139)
4	892.657	535.594	49.702	5.935	43.767	-	5.935	119.295	125.230	(75.528)	-	(75.528)	(75.528)	(68.786)
5	707.077	424.246	40.156	14.838	25.318	-	14.838	75.528	90.367	(50.211)	-	(50.211)	(50.211)	(52.299)
6	568.690	341.214	32.943	4.800	28.143	-	4.800	50.211	55.010	(22.067)	-	(22.067)	(22.067)	(35.637)
7	463.550	278.130	27.389	4.274	23.115	-	4.274	22.067	26.342	1.048	0.105	-	0.943	(23.253)
8	382.344	229.406	23.043	3.870	19.173	-	3.870	-	3.870	19.173	1.917	-	18.198	(14.810)
9	318.704	191.222	19.592	3.557	16.035	-	3.557	-	3.557	16.035	1.604	-	32.630	(8.391)
10	268.176	160.905	16.815	23.311	(6.496)	-	3.311	-	3.311	13.504	1.350	-	24.784	(11.564)
11	227.587	136.552	14.556	3.118	11.438	-	3.118	-	3.118	11.438	1.144	-	35.078	(7.780)
12	194.636	116.781	12.697	2.965	9.732	-	2.965	-	2.965	9.732	0.973	-	43.837	(4.852)
13	167.627	100.576	11.154	2.845	8.309	-	2.845	-	2.845	8.309	0.831	-	51.316	(2.580)
14	145.295	87.177	9.861	2.750	7.112	-	2.750	-	2.750	7.112	0.711	-	57.716	(0.813)
15	126.682	76.009	9.881	2.787	7.094	-	2.787	-	2.787	7.094	0.709	-	64.101	0.790
16	111.053	66.632	8.662	2.701	5.961	-	2.701	-	2.701	5.961	0.596	-	69.466	2.015
17	97.841	58.705	7.632	2.635	4.997	-	2.635	-	2.635	4.997	0.500	-	73.963	2.948
18	86.602	51.961	6.755	2.585	4.170	-	2.585	-	2.585	4.170	0.417	-	77.716	3.656
19	76.985	46.191	6.005	2.548	3.457	-	2.548	-	2.548	3.457	0.346	-	80.827	4.190
20	68.711	41.227	5.359	2.522	2.837	-	2.522	-	2.522	2.837	0.284	-	83.381	4.588
21	61.557	36.934	4.801	2.506	2.295	-	2.506	-	2.506	2.295	0.230	-	85.447	4.880
22	55.342	33.205	4.317	2.498	1.819	-	2.498	-	2.498	1.819	0.182	-	87.083	5.091
23	49.919	29.951	3.894	2.497	1.396	-	2.497	-	2.497	1.396	0.140	-	88.340	5.239
24	45.167	27.100	3.523	2.502	1.021	-	2.502	-	2.502	1.021	0.102	-	89.259	5.336
25	40.986	24.592	3.197	2.513	0.684	-	2.513	-	2.513	0.684	0.068	-	89.875	5.396
26	37.295	22.377	2.909	2.528	0.381	-	2.528	-	2.528	0.381	0.038	-	90.218	5.426
27	34.025	20.415	2.654	2.547	0.107	-	2.547	-	2.547	0.107	0.011	-	90.314	5.434
28	-	-	-	-	-	34.477	34.477	-	34.477	(34.477)	-	(34.477)	55.837	2.926
29	-	-	-	-	-	-	-	-	-	-	-	-	55.837	2.926
30	-	-	-	-	-	-	-	-	-	-	-	-	55.837	2.926
SUM	*5,228.51*	*3,137.11*	*327.50*	*224.93*	*102.57*	*34.48*								

Table 9.4—DCF for assessment of commerciality.

Column AB presents the cumulative undiscounted NCF including the effects of income taxes and ADR liability. Using the present value formula presented earlier in this chapter, assuming the midyear discounting option, the entity's annual 10% discounting factor is applied to the yearly NCFs, resulting in annual discounted NCFs (DCFs). These annual DCFs are summed for a running cumulative value, as shown in Column AC. The total cumulative DCF of USD 2.9 million is equivalent to the post-tax net present value (NPV), which may be used for investment decisions or portfolio ranking purposes. Because the NPV is greater than zero, the entity's required rate of return has been exceeded.

Finally, the bottom row shows the summation of the potential reserves net to the entity (excluding the royalty interest) and the cumulative undiscounted NCF (before income taxes and ADR) in addition to the cumulative DCF after taxes and ADR. A summary of the output analysis is shown in **Table 9.5**.

OUTPUT RESULTS			
Economic Life, Years	27	Net Oil Reserves, MSTB	5,229
Is Cumulative Undiscounted NCF > ADR?	Y	Net Gas Reserves, MMSCF	3,137
Is Cumulative Discounted NCF > 0?	Y	Cumulative Discounted NCF, $MM (w/ADR)	2.926
		Cumulative Discounted NCF, $MM (pre-ADR)	5.434

Table 9.5—Cash flow evaluation results.

It is necessary to point out that this cash-flow evaluation is only part of the commerciality assessment. Unless all of the requirements spelled out in PRMS § 2.1.2.1 are satisfied, including "legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns," the economically producible quantities must stay in the Contingent Resources class.

9.9 Probabilistic Evaluation

Evaluation may, of course, be conducted using either deterministic or probabilistic methods. Although the generation of cash-flow evaluations is straightforward, the accuracy of the estimates is dependent on the property-specific input data as well as the expertise of, and effective collaboration among, the multidisciplinary evaluation team members.

Each component of the project NCF terms (such as production rate, product price, CAPEX, OPEX inflation rate, taxes, and interest rate) has some element of uncertainty. There may also be some value of information (VoI) component or cost-benefit assessment, such as whether to drill an appraisal well, acquire additional seismic data, or implement pressure-maintenance operations at the outset of production. There are several ways to perform cash-flow analysis under uncertainty conditions, and the reader is directed to Chapter 7—*Probabilistic Resources Estimation* herein, such as for the expected monetary value (EMV) example shown in Section 7.4.1.

9.10 Environmental, Social, and Governance Issues

"Environmental, social, and governance (ESG)" is a general term of reference that encompasses a range of factors, some of which must be integrated into a project's investment and decision-making process. The term has seen increased usage among stakeholders and the investing community, but many of the elements associated with ESG are not new to PRMS.

The term ESG is not explicitly mentioned within the PRMS, but PRMS §1.2.0.10 clearly requires consideration of certain components of ESG pertaining to a project to be able recognize Reserves:

"The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, *environmental, social, and governmental factors* forecast to exist and impact the project during the time period being evaluated" (emphasis added).

Other key PRMS references are in §2.1.2.1, where the commerciality criteria are provided, and in the Glossary definition of Defined Conditions used for an evaluation.

"Governmental factors" and "governance" are not interchangeable expressions. Governance typically refers to the manner in which entities conduct their corporate business, which may in turn affect a project, e.g., commitment to fund and execute within a reasonable time frame.

The PRMS advocates conveying the project uncertainties and risks examined as part of the commerciality assessment process, and this includes ESG factors as well.

9.10.1 ESG Within the PRMS Context. The PRMS is a project-based system, and the concept of a project includes all of the factors that may potentially impact the recovery of hydrocarbon resources from that project. The PRMS requires that Reserves for a project be commercial, and commerciality includes more than technical maturity and economic performance of the project. Historically, ESG emphasis has been placed on compliance and demonstrating "license to operate" in a community. It is beyond the scope of this version of the *Guidelines for Application of the PRMS* to provide detailed guidance on how to evaluate the wide spectrum of ESG factors that relate to resources assessments in various global geographic areas. ESG requirements vary locally and regionally, and it is incumbent upon the project owners to be informed of those requirements and their potential impacts, if any, on their specific project(s).

The effects of ESG considerations may influence resources classification, categorization, and maturity sub-classes, such as in Chapter 2—*Petroleum Resources Definitions, Classification, and Categorization Guidelines* herein, and potentially other topics (probabilistic evaluation, aggregation, and possibly entitlement) as projects are evaluated under different ESG environments and varying contractual regimes.

9.10.2 ESG Impact on Economic Evaluation. As they pertain to this chapter, ESG factors may result in additional costs, revenues, and/or taxes. For example, there are potential active carbon emission credit trading structures that have been regulated by some jurisdictions. While entities generally must invest capital to meet carbon emission reduction goals, the carbon emission credits create the opportunity for another source of revenue for some projects. To the extent that such revenue is attributable to the oil and gas operations of a specific project (as opposed to a corporate-level transaction), the PRMS allows that revenue source (and any associated capital investments and/or additional operating expenses) to be a part of the project's commerciality assessment.

In some cases, ESG factors may result in additional taxes. These taxes may take the form of production taxes, where the tax is directly related to production or emissions of the project, or they may impact the entity's corporate income tax. Most project evaluations are done on a "before corporate income tax" basis. Income taxes are generally applied at the corporate level, and it can be difficult to quantify the true economics of a project on an "after corporate income tax" basis. However, there are some situations, such as PSCs, where petroleum evaluators must consider the "after corporate income tax" aspects of a project in order to calculate the entitlement share of production. In these cases, the corporate income tax associated with a project is considered to be an event that occurs inside the "ring-fence" (or contract area) of the project. By the same token, any specific ESG cost or revenue that can be determined to be inside the "ring-fence" of a project should be a part of the commercial evaluation of that project.

In summary, ESG factors cover a wide spectrum of topics, and, as such, they are incorporated in an entity's investment and decision-making process. The PRMS has always required ESG factors to be reviewed as key input in evaluating a project's commerciality.

9.11 Conclusion

The estimation of resources and reserves is subject to uncertainty, not only due to inherent uncertainties in the petroleum initially in place and the efficiency of the recovery program, but also due to the associated cash-flow assumptions that affect the future net revenue (and NPV). Documentation of the product prices, the capital and operating costs, and the timing of implementation of projects is a fundamental step in the quantification of marketable quantities that result in resources and reserves estimates and their associated classification as Resources or Reserves. These factors are forecast for the project over time, and evaluators must clearly identify and document the assumptions used in their evaluation because these assumptions directly affect the classification as Reserves or Resources. This chapter has sought to spell out the necessary requirements for generating cash-flow-based evaluations that are compliant with PRMS guidelines.

9.12 Acknowledgments

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Chapter 10

Unconventional Resources Estimation

Dilhan Ilk

10.1 Introduction

Unconventional resources, primarily tight gas/tight oil and shale gas/oil, have dominated oil and gas production in North America since the early 2000s, transforming the industry and triggering major changes to worldwide oil prices ever since. Although production from unconventional reservoirs is common in North America, there are many underlying questions yet to be addressed. Industry understanding of fluid flow concepts, storage mechanisms, and the extent of hydrocarbon drainage areas remains quite uncertain, complicating the estimation of reserves and resources.

Table 10.1 presents a summary of the main differences between conventional and unconventional reservoirs (modified from Berg 2013). It is important to mention that some of these points may not be applicable to all unconventional (or low-permeability) reservoirs, but in a broader sense, the list is a good indicator of characteristic differences that would ultimately lead to modification of evaluation and assessment methodologies.

Conventional Reservoirs	Unconventional Reservoirs
Localized structural trap	"Continuous-type" deposit
External hydrocarbons sourcing	Self-sourced hydrocarbons
Hydrodynamic influence	Minimal hydrodynamic influence
Traditional phase behavior	Phase behavior in nano-pores
Minimal extraction effort	Significant extraction effort
Significant production history	Moderate (or limited) production history
Mid-late development life cycle	Early-mid development life cycle
Fewer wells for commerciality	Many wells for commerciality
Production forecasts based on volumetrics for limited production history cases	Production forecasts based on analogs for limited production history cases
Prospects typically defined by volumetrics	Prospects typically defined by drilling

Table 10.1—Main differences between conventional and unconventional reservoirs (modified from Berg 2013).

As mentioned earlier, production from unconventional reservoirs has become common in North America and is emerging worldwide (e.g., Argentina, Australia, China, and Middle East). In addition, very large oil and gas volumes do exist in resources such as oil shale, extra heavy oil, and bitumen, although their commercial recovery would often require new or improved technology and higher product prices. For some of these resources, such as oil shale and gas hydrates, no commercial recovery methods have yet been developed to produce these resources, although some pilot projects have demonstrated methods to extract in-place volumes.

10.1.1 Assessment and Classification Issues. The Petroleum Resources Management System (PRMS 2018) resources definitions and classification framework are intended to be appropriate for all types of petroleum accumulations regardless of reservoir type, completion and production technology applied, or processing requirements. However, differences in concepts, methodologies, and techniques are more pronounced in the evaluation and assessment of unconventional reservoirs due to their unique characteristics.

Once an accumulation has been discovered, the appraisal phase assessment begins by evaluating core, log, and seismic data to evaluate in-place volumes and the extent of the potentially productive area. However, undiscovered hydrocarbon volumes, classified as Prospective Resources, must rely on the application of analogs and/or modeling techniques. It is important to note that there is significant uncertainty at this phase of evaluation, and, as such, estimations of recoverable resource quantities must include an estimate of the associated uncertainty, which would be allocated to the PRMS categories by using probabilistic, deterministic, or both methods.

A significant difference between conventional and unconventional reservoirs is the evaluation of recovery efficiency. In addition to the importance of reservoir quality, for unconventional reservoirs, completion effectiveness plays a more important role in determining the recovery factor compared to conventional reservoirs. In general, recovery must be considered as a function of the development plan combined with a specific completion design/technology. However, the nature of the unconventional reservoir and the limited drainage area of the wells within it necessitate planning for more vertical wells, or longer horizontal laterals, relative to conventional reservoirs. **Fig. 10.1** illustrates conceptual recovery efficiencies and net present value profiles based on specific development scenarios.

Once a discovery is made, and its development scenario is specified, recoverable quantities can be estimated. The most convincing evidence to establish discovery is to have a production test with flow of hydrocarbons to the surface from the reservoir of interest. (Establishing a discovery is discussed in PRMS § 2.1.1.1.) In the absence of a production test, the PRMS allows for discovery based on other sufficient evidence (e.g., core, log, sampling, nearby analogs). If analogy is used, analog data and rationale must be clearly documented and compared with the data from the subject reservoir. In the aggregate, the properties of the subject reservoir should be similar or better than the analogous reservoir.

As indicated in the PRMS, the extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience; otherwise, quantities remain as undiscovered (PRMS § 2.4.0.4). Extrapolation of reservoir presence or productivity beyond the immediate vicinity of a control point (or discovery well) should be limited unless there are clear engineering and geoscience data to validate areas around discovery well(s) or control point(s) (PRMS § 2.4.0.3). Contingent Resources are then categorized in relation to the range of uncertainty associated with estimates of recoverable quantities. Estimates of recoverable quantities must consider the effects of the proposed development plan, reservoir properties, fluid behavior, and completion design on production profiles. Often, this impact may not be easily characterized due to early stage of development and lack of data and well control.

Therefore, it is critical to integrate uncertainty analysis and appropriate analog data into the evaluation to address the range of uncertainty and associated categories.

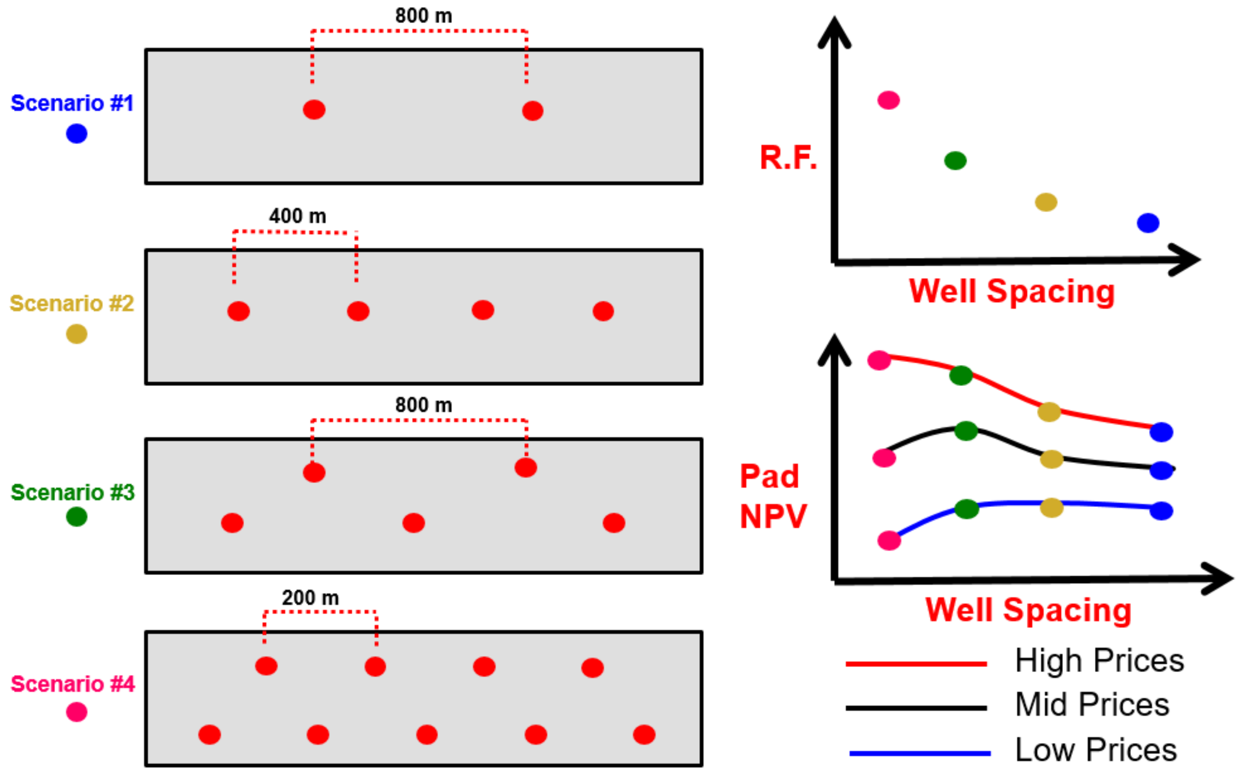

Fig. 10.1—Recovery factor (R.F.) and net present value (NPV) profiles based on various development scenarios (colored dots) and product prices (colored lines).

The PRMS recommends focusing on gathering data and performing analyses to clarify and mitigate key contingencies that prevent commercial development. Assigning project maturity sub-classes is recommended. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied (PRMS Table 1). The same criteria apply for both conventional and unconventional reservoirs.

Resources/reserves categorization should reflect the range of uncertainty in the estimates of recoverable quantities associated with the development project with a single set of defined conditions applied. Use of different commercial assumptions across categories within a resources class is referred to as "split conditions" and is not allowed under the PRMS guidelines. Development projects in unconventional reservoirs may include large numbers of drilling and completion of wells to fully appraise a field or play. However, due to various commercial factors, certain portions of a development may fall outside a reasonable development time frame, and so those specific portions can be associated with other development projects (PRMS § 2.1.2.3). In this situation, because the recovery is beyond the reasonable time frame, it is considered sub-commercial and reclassified as Contingent Resources (PRMS Appendix A—Glossary, "Sub-Commercial").

Typical evaluation methodologies for unconventional reservoirs involve integration of data from various disciplines. It must be remembered that recovery from unconventional reservoirs is a combined function of reservoir, completions, and development plan (e.g., well spacing). Advanced methods are commonly utilized to evaluate well performance and make decisions on future development options. **Fig. 10.2** presents a conceptual view of the performance-based life cycle for an unconventional reservoir. This figure demonstrates that reservoir, geoscience, completions, and production data are all integrated and evaluated continuously to update and execute specific actions related to completion design and well spacing in an unconventional play.

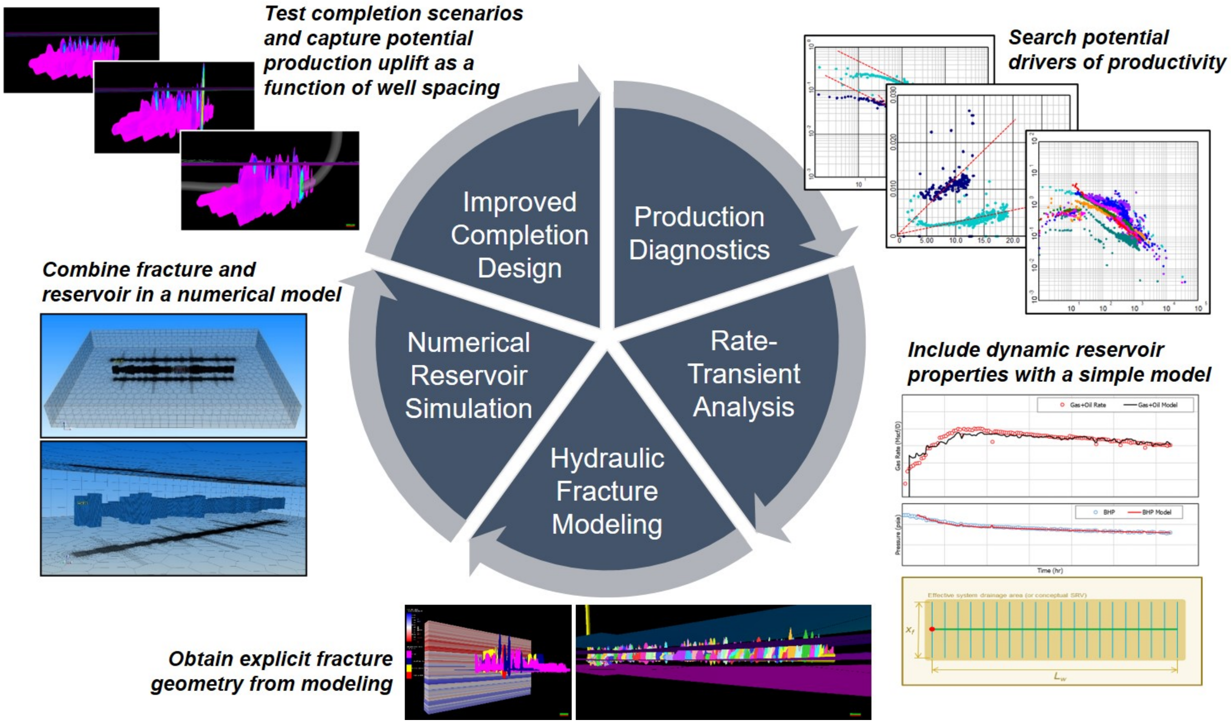

Fig. 10.2—Conceptual view of performance-based life cycle for an unconventional reservoir. This schematic illustrates an evaluation of an unconventional reservoir using "performance-based" methodologies relying on production data while integrating geoscience, reservoir, fluid, and completions data.

The following sections (Sections 10.2 through 10.6) have been prepared by several different authors to provide an overview of each resource type and information on evaluation approaches. In addition to updating the sections on tight/shale gas and oil and coalbed methane from the prior (2011) version of the *Guidelines for Application of the PRMS*, a new section on Evaluation Methodologies has been included. Sections 10.2 through 10.6 address the following subjects:

- 10.2 Tight Gas and Oil
- 10.3 Shale Gas and Oil
- 10.4 Evaluation Methodologies for Tight/Shale Gas and Oil
- 10.5 Coalbed Methane
- 10.6 Other Unconventional Oil

Roberto Aguilera

10.2 Tight Gas and Oil Formations

10.2.1 Introduction. This section in the prior (2011) version of the *Guidelines for Application of the PRMS* discussed only tight gas formations (TGFs), but now, tight oil formations (TOFs) are also included. The word "petroleum" as used in this section includes oil, gas, and natural gas liquids. The word "tight" as used herein includes sandstones, carbonates, and shales. Tight and shale reservoirs are distinguished as follows: In tight petroleum formations (TPFs), petroleum has migrated from a source rock to the TPF. In a shale reservoir, petroleum generated in the shale remains in the shale (Aguilera 2014). This sub-section does not describe shales because they are covered in more detail below in Section 10.3.

The US Natural Gas Policy Act of 1978 (Tight Formation Gas, 1978) defined a TGF as having in-situ reservoir permeability equal to or less than 0.1 md (Kazemi 1982; Aguilera and Harding 2007). For purposes of this section, the definition is expanded such that a TGF includes “a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores” (Holditch 2006, p. 86). The same expanded definition can be used for the case of TOFs, but there is not a specific permeability cutoff for TOFs. Industry experience, however, suggests the permeability cutoff for TOFs is generally larger than that for TGFs (for example, up to 1 md) with the exception of shales, which have permeabilities that are much smaller and can reach the level of nanodarcies.

The industry generally divides TGFs into (1) basin-centered gas accumulations (BCGAs), also known as continuous-type gas accumulations (Law 2002; Schmoker 2005), and (2) gas reservoirs that occur in low-permeability, poor-quality reservoir rocks in conventional structural and stratigraphic traps (Shanley et al. 2004). The PRMS (Appendix A—Glossary) defines a continuous-type deposit as:

> “A petroleum accumulation that is pervasive throughout a large area and that generally lacks a well-defined OWC or GWC [oil- or gas-water contact]. Such accumulations are included in unconventional resources. Examples of such deposits include ‘basin-centered’ gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.”

The same division can be used in the case of TOFs, in which situation, they may be more appropriately termed basin-centered petroleum accumulations (BCPA). This is illustrated in **Fig. 10.3,** which shows both TGFs and TOFs below conventional oil and gas formations in a BCPA.

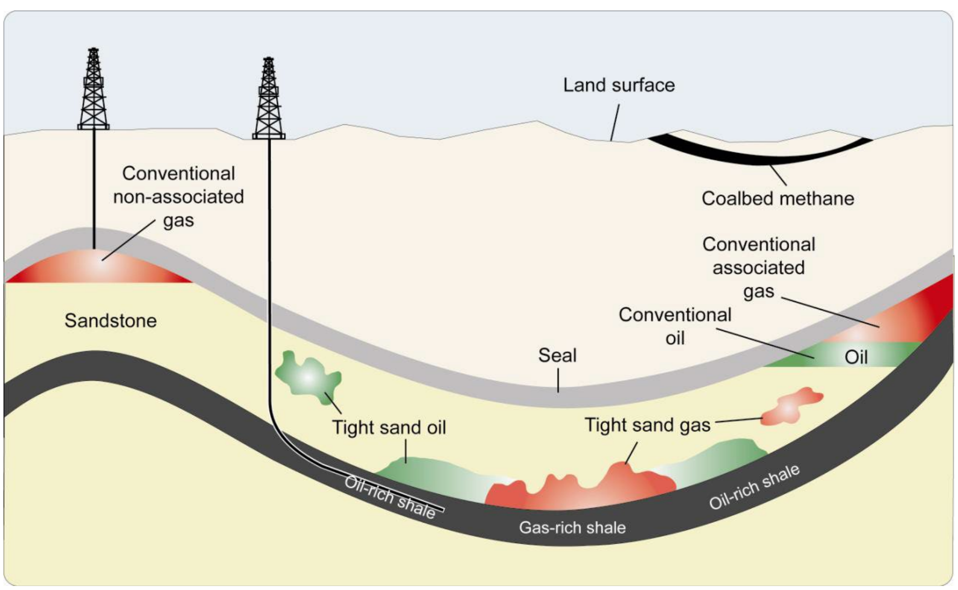

Fig. 10.3—TGFs (shown as tight sand gas) and TOFs (shown as tight sand oil) below conventional oil and gas reservoirs in a BCPA (National Energy Board of Canada 2011).

10.2.2 Reservoir and Hydrocarbon Characteristics. The primary definition used in this chapter assumes that TGFs, including sandstones and carbonates, are characterized by permeabilities of less than 0.1 mD. The hydrocarbons in these rocks are primarily methane with some impurities, but there are also occurrences of associated gas condensate. TOFs, including sandstones and carbonates, are characterized by low permeabilities of up to 1 mD. The hydrocarbons in these rocks are primarily light oil.

Fig. 10.4 shows an example of flow units in an oil formation that includes a TOF. The graph presents data from the Cardium Formation of the Pembina Field (Canada) published by MacKenzie (1975). The crossplot shows porosity vs. permeability, where r_{p35} is the pore throat radii in microns at 35% cumulative pore volume (Kolodzie 1980). Type I and Type II rocks in Fig. 10.4 correspond to a conventional reservoir. Type III rocks represent a tight oil halo around the conventional reservoir in the Pembina Field. Historically, oil production from this low-permeability halo was not possible. In fact, MacKenzie (1975) indicated that Type III was a "poor rock" that should not be included in the estimate of reserves. With the advent of horizontal drilling and multistage hydraulic fracturing, however, economic oil production from this halo became feasible. This could be visualized as oil being released from a "permeability jail" from that part of the TOF that is affected by multistage hydraulic fracturing processes. Note that the TOF (Type III rock) reaches a permeability close to 1 mD.

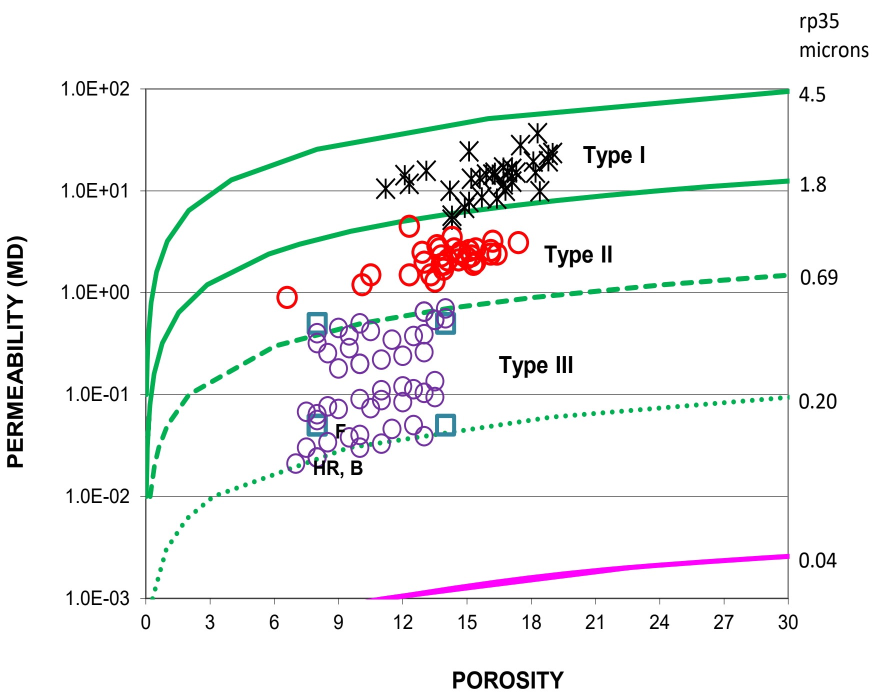

Fig. 10.4—Flow units crossplot showing different r_{p35} flow units of Cardium Formation sandstones, Pembina oil field, Canada. Data points for rock of Types I (asterisks) and II (red circles) were tabulated originally by MacKenzie (1975) and correspond to a conventional oil reservoir. Porosities and permeabilities for Type III rocks (purple circles) were extracted from permeability-porosity (k/ϕ) data published by MacKenzie (1975) and correspond to a tight oil halo (TOF). Ranges of porosities and permeabilities for Cardium tight oil (opena squares) were published by Hamm and Struyk (2011). Source: Aguilera (2014).

Permeability is not the only factor that plays a role in petroleum production from TPFs. A cursory examination of the pseudosteady-state radial flow equation illustrates that petroleum rate is a function of many other physical factors, including pressure, fluid properties, reservoir and surface temperatures, net pay, drainage and wellbore radii, skin, and the non-Darcy constant (discussed for TGFs by Holditch 2006). Furthermore, a TPF can be deep or shallow, high or low pressure, high or low temperature, naturally fractured, contained within a single layer or in multiple layers (discussed for TGFs by Holditch 2006), a continuous BCPA without a water leg (discussed for TGFs by Law 2002; Schmoker 2005), or with characteristics of a conventional trap under hydrodynamic influences (discussed for TGFs by Shanley et al. 2004; Aguilera et al. 2008). To succeed and improve recoveries from TPFs, it is necessary to identify the location and preferential orientation of natural fractures, to distinguish clearly between water- and petroleum-bearing formations, to efficiently drill into and stimulate one or multiple zones, and to enhance the connectivity between wells and their associated drainage volumes (Kuuskraa and Ammer 2004).

10.2.2.1 Continuous Tight Petroleum Formations. Continuous BCPAs are defined by the US Geological Survey (Schmoker 2005) as "those oil or gas accumulations that have large spatial dimensions and indistinctly defined boundaries, and which exist more or less independently of the water column." In addition, they commonly have low matrix permeabilities, are in close proximity to "conventional" reservoir rocks, have low recovery factors (Schenk and Pollastro 2002), and are visualized as a collection of petroleum charged cells. All of these cells are capable of producing petroleum, but their production capabilities change from cell to cell, with the highest production being obtained from cells with connected natural fractures and/or higher matrix permeabilities.

There are four key elements that define a BCGA as published by Law (2002), and these are adapted for the BCPA as follows:

- Abnormal pressure
- Low permeability (generally ≤0.1 md for the case of tight gas and 1 md for tight oil)
- Continuous petroleum saturation
- No downdip water leg

If any one of these elements is missing, the reservoir cannot be treated as a continuous petroleum accumulation. Note that lithology is not part of the four requirements listed above; the same four elements have been reported for both clastic and carbonate reservoirs.

10.2.2.2 Conventional Tight Petroleum Traps. An opposite view to the concept of continuous BCPA discussed above has been presented by Shanley et al. (2004, p.1083). These authors state explicitly that "low-permeability reservoirs from the Greater Green River basin of southwest Wyoming are not part of a continuous-type gas accumulation or a basin-center gas system in which productivity is dependent on the development of enigmatic sweet spots. Instead, gas fields in this basin occur in low-permeability, poor-quality reservoir rocks in conventional traps."

The model used by Shanley et al. (2004) to explain their theory is called "permeability jail." The concept was developed originally by A. Byrnes of the Kansas Geological Survey based on laboratory work conducted at room-temperature conditions and at 4,000 psi overburden stress (Shanley et al. 2004). The "permeability jail" concept indicates that a range of saturations exists, within which the relative permeabilities to gas and water are equal to zero; that is, the relative permeabilities do not cross each other as in the case of conventional reservoirs (or, theoretically, they might cross at extremely low permeabilities).

The controversy over whether TGFs are basin-centered features or occur in low-permeability conventional traps is important because the estimates of original gas in place (OGIP) volumes and mobile gas are much larger in a BCGA compared with those in discrete conventional traps.

Could the TGF "permeability jail" concept have application in the case of TOFs? Probably, yes; if it works for gas, then it should work for oil; i.e., it should work for petroleum. How did oil get into the pores? Probably through normal early migration from a source rock and charge of the pores. Following storage of oil in pores, the pore throats were diminished or destroyed through geologic time, for example, due to burial, creating the jail from which liquids (oil and water) cannot escape.

An example of a TOF is provided by the Cardium Formation in the Pembina Field of Canada. Oil has been produced from conventional Cardium oil reservoirs for several decades, but there is a halo of very low permeability TOF surrounding the good-quality rocks.

10.2.3 Assessment Methods. The integration of geoscience and engineering aspects is of paramount importance in exploring for and assessing TPFs. Folding, faulting, natural fracturing, in-situ stresses, multilayer systems, mineralogy and petrology, connectivity and continuity, permeability barriers, and interbedded coals and shales are just some of the aspects that must be taken into account when evaluating TPFs (Aguilera et al. 2008). These are affected by the dominating tectonics, which in the case of the Rocky Mountain basins are wrench/extensional, while in the Western Canadian Sedimentary Basin, they are compressional (Zaitlin and Moslow 2006). Uncertainty evaluation methods should be used whenever possible while assessing TPFs (see Chan et al. 2012).

10.2.3.1 Exploration Methods. Geoscience focuses on how to identify storage and source rock potential, evaluate thermal maturation history, and locate swarms of natural fractures, positive closures, and "sweet spots" of higher matrix permeability. Once these are located, and natural fracture orientations are determined, wells are drilled in a way that intersects the natural fractures. Inducing formation damage must be avoided as much as possible, which typically involves the use of underbalanced drilling. However, even if the reservoir is not damaged, stimulation(s) of the TPF will likely still be required to establish economic production. To be commercial under PRMS guidelines (§ 2.1.2.1), in addition to technical development feasibility, the project must include economic, legal, environmental, social, and governmental viability.

10.2.3.2 Geophysics. Seismic velocity reductions can indicate zones of high porosity, while variations in seismic velocity with direction (azimuthal anisotropy) can be related to fractures in the rocks. Wide-azimuth seismic acquisition and processing techniques may allow the detection of natural fractures, which appear as wavy or sinusoidal reflectors on the seismic data. Although ideally good seismic data should be used, Wang et al. (2015) have shown a feasible application of using mediocre-quality poststack three-dimensional (3D) seismic data and attributes to improve the characterization of a TGF in the Lower Permian Xiashihezi Formation, Ordos Basin, China. The reservoir evaluation indicates that the Pareto principle (80/20 rule) helps to enhance the insight needed to identify the trend of higher-productivity regions in the Ordos Basin.

Ant tracking (Pedersen et al. 2002; Liang et al. 2015) is another approach that offers hope for locating fracture swarms. The technique has been found to be useful for automatic determination of fault surfaces from conditioned fault-enhancing attributes. In those instances where the fractures are fault related, the method can provide indirect indications of areas where the fractures are located.

10.2.3.3 Geomechanics. An integrated approach using geomechanical methods, shear wave splitting, P-wave azimuthal velocity anomalies, cores, and image logs (Billingsley and Kuuskraa 2006) has proven to be useful for locating natural fractures in three distinct geologic settings and tight gas basins in the US: the Piceance and Wind River basins in the Rocky Mountains, and the Anadarko Basin in western Oklahoma. Under favorable conditions, this technology allows fracture density and apertures to be estimated. This technology was reported to improve ultimate recoveries significantly in lenticular gas plays of the Rulison Field in the Piceance Basin from 0.9 Bcf/well in 1956–1972 to 2.0 Bcf/well subsequently. The number of dry holes also dropped from 45% to a low percentage (Billingsley and Kuuskraa 2006).

The recognition of fractures, slots (Soeder and Randolph 1987; Byrnes et al. 2006a, 2006b; Aguilera 2008), and the best porosities allows optimum positioning of drilling targets and, consequently, a reduction in capital and operating costs (Aguilera and Harding 2007).

10.2.3.4 Hydrodynamic Studies. These studies, often summarized as crossplots of pressure from wireline formation tests vs. depth (Masters 1984; Aguilera and Harding 2007), must be conducted to determine if the TPF is over- or underpressured, whether it has downdip (or updip) water, if it is continuously petroleum saturated, and what the approximate size is of the TPF. This work is useful in determining whether the TPF is a continuous BCPA (updip water) or a conventional structural or stratigraphic low-permeability trap (downdip water leg). This work also is very important in planning the development strategy of the reservoir. If the TPF is a continuous petroleum accumulation, then large problems with water production probably will not be an issue (Solano et al. 2011). However, if the hydrodynamic study shows the presence of a downdip water leg, then it is reasonable to anticipate that eventually there will be water-production problems (Shanley et al. 2004).

TGFs can act in some cases as a natural gas storage facility that feeds gas to a higher-permeability medium that in turn feeds gas to the wellbore. This happens in the Western Canada Sedimentary Basin, with the Cadomin Formation conglomerate feeding gas to the wellbore. As the Cadomin Formation pressures drop, the surrounding TGF starts feeding gas into the higher-permeability conglomerate (Zaitlin and Moslow 2006), which in turn moves gas to the wellbore.

10.2.3.5 Petrophysics. Although porosities are lower in TPFs, this does not necessarily translate into lower calculated petroleum saturations. The reason for this is that there are lower values of the Archie cementation exponent, m, in TPFs, resulting from the presence of fractures and slot pores (Byrnes et al. 2006a, 2006b; Aguilera 2008, 2018). The recovery efficiency, however, would be generally lower than that in a conventional petroleum reservoir due to the low matrix permeabilities.

An excellent and valuable compilation of rock properties for the Mesaverde Group (gas) has been published by Byrnes et al. (2006a, 2006b) for the Green River, Piceance, Powder River, Sand Wash, Uinta, Washakie, and Wind River basins in the Rocky Mountains region of the US. Their work involves routine in-situ porosity, permeability, and grain-density measurements, along with special core analyses, including cementation and saturation exponents, cation exchange capacities, mercury injection capillary pressures, drainage critical gas saturations, thin sections, and core descriptions. Ideally, the same type of information should be collected for all TPFs, along with the most recent generation of well logs, including image logs and nuclear magnetic resonance logs.

The work of Byrnes et al. (2006a, p. 9) also shows that the value of the cementation exponent, m, becomes smaller as porosity decreases. They related the low values of m to the presence of slot pores in the rocks, and they stated that "this pore architecture is similar to a simple fracture that exhibits cementation exponents near $m = 1$." The slot porosity can be visualized as grain-bounding fractures that result from uplifting and cooling (Billingsley and Kuuskraa 2006).

10.2.3.6 Well Testing. The planning and analysis of well tests require specialized methods due to the very low permeabilities of TPFs. Methods for single- (Lee 1987) and dual-porosity gas reservoirs (Shahamat and Aguilera 2008) using type curves are available for this purpose. These methods assume that radial flow is reached during the test, which generally implies the analysis of vertical wells such as those drilled in some thick TPFs. However, horizontal wells are now prevalent, and linear flow is typical in these instances (for basic principles, see, for example, Palacio and Blasingame 1993; Arevalo-Villagran et al. 2006). Under favorable circumstances, estimates of permeability and OGIP can be determined with a flowing-gas material balance (Rahman et al. 2006). Given that well spacing is smaller in TPFs than in conventional reservoirs, single-well simulators can provide reasonable results in some instances.

10.2.3.7 Production Decline. Analysis of decline curves using pressure-drop normalized petroleum rates (see Section 10.4.3) can provide good results for estimating performance in vertical, slanted, and horizontal wells, especially if wells have been producing for several years. If normalization is not possible because of the lack of pressure data, hyperbolic decline can be used to obtain generally reasonable results, provided it is modified with an exponential terminal decline rate. It is important to monitor the forecast production period, so that estimates of ultimate recovery are not skewed by very long production periods.

In addition to the theoretical models mentioned above, there also have been many useful and practical empirical models based on actual recordings of production rates in TPFs. Production examples from the Nikanassin TGF have been published by Solano et al. (2011) and Zambrano et al. (2016). Production examples from the Cardium TOF have been published by Hamm and Struyk (2011) and Aguilera (2014). Additional approaches are presented below in more detail in Section 10.4—Evaluation Methodologies for Tight/Shale Oil and Gas.

10.2.3.8 Machine Learning. Given the large volumes of available data in petroleum reservoirs, machine learning algorithms are increasingly being used in efforts to understand all types of petroleum formations, including TPFs. An important segment of machine learning deals with decline rates of petroleum production. Although machine learning is extremely valuable, it is important to emphasize that it must not be used without consideration of the reservoir physics. Otherwise, results might be greatly misleading.

10.2.4 Drilling, Completion, and Stimulation Issues. Knowledge of in-situ stresses and natural fracture(s) strike and dip is important. Vertical wells are not as efficient for intersecting vertical fractures, which tend to have high inclinations at the depth of interest. This has led to a clear preference for slanted and particularly horizontal wells in TPFs. An important additional benefit is that a larger surface area of the reservoir is contacted by horizontal wells. The accepted concept in TPFs is that the horizontal well must be drilled perpendicular to the open fractures (and perpendicular to the maximum compressional stress). If more than one set of open fractures is present, a properly designed slanted, horizontal, or multilateral wellbore can maximize petroleum production and recovery by intersecting as many fracture sets as economically possible.

In conventional drilling, the mud weight is chosen to exceed the reservoir pressure to avoid potential blowouts. In TPFs, however, mud invasion can result in large values of skin factor because these formations are highly susceptible to damage. The problem is exacerbated because of the complex geology of TPFs, which includes natural fracturing (causing fluid leakoff and potential sand screenouts), folding and faulting (resulting in high stresses that could make initiation of the hydraulic fractures difficult or impossible), and channel sands and interbedded coals and shales (resulting in leakoff into cleats or unexpected fracture-propagation paths) (Bennion et al. 1996).

As a result, underbalanced drilling appears as a reasonable approach for drilling TPFs. In underbalanced drilling, the usual mud is replaced by fluids such as inert gases and foams to make the hydrostatic pressure exerted on the reservoir lower than the reservoir pressure. This eliminates fluid invasion through the fractures and, consequently, minimizes damage to the TPF. Downhole sensors near the drill bit gather and send information to the surface, which permits the bit to be steered through the best portions of the reservoir, improving the probability of success (Bennion et al. 1996).

Unfortunately, underbalanced drilling is not a panacea in TPFs because it can sometimes induce severe unforeseen damage. Some of the potential problems include (Craig et al. 2002): fluid retention, adverse rock/fluid and fluid/fluid interactions, countercurrent imbibition effects, glazing and mashing, condensate dropout, and entrainment from rich gases, fines mobilization, and solids precipitation.

Hydraulic fracturing jobs (single or multistage) are necessary in most cases in TPFs, even when drilling slanted or horizontal wells. However, water retention is a significant problem in some TPFs. As a result, many potential hydraulic fracturing technologies have been attempted in the past, including fluids such as pure oil, CO_2-energized oil, and crosslinked, water-based polyemulsion and water-based foam (Craig et al. 2002; Rahman et al. 2006). Many operators must experiment with the fluid types, proppant concentrations, etc., to find the method that works best for their TPF.

10.2.5 Processing and Marketing. A general observation based on experience is that where there is "conventional gas," there is also "tight gas" (Aguilera et al. 2008). As stated by Salvador (2005), "tight-sand accumulations should occur in all or nearly all petroleum provinces of the world." As a result, the processing and marketing of tight gas could proceed hand-in-hand with that of conventional gas. Stranded gas, both from conventional and unconventional reservoirs (including TGFs), requires special handling and economic considerations due to the very large investments required. TOFs are also present in many places around the world, and processing and marketing of tight oil could also proceed hand-in-hand with that of conventional oil. In all cases, the PRMS guidelines would still apply.

10.2.6 Commerciality Issues. Economic considerations in TPFs have to take into account special drilling, stimulation, and completion practices. In the case of gas wells, transient-flow periods can last for several years before encountering any reservoir boundary or the production effect of an offset well. Larger numbers of wells, whether vertical, slanted, or horizontal, per unit area are always required in TPFs compared to conventional reservoirs (PRMS § 2.4.0.2). In order to move some of the huge TPF resources into Reserves, efforts need to focus on many technological improvements that have the potential to reduce costs and increase production rates. Generally, companies operating in TPFs have been very successful at reducing costs and increasing petroleum production rates. "Learning curves" along these lines as well as uncertainty have been discussed in the literature (Chan et al. 2012) and are now defined in the PRMS as "demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions" (PRMS Appendix A—Glossary). In the case of gas, the handling of liquids, even in continuous accumulations without downdip water, is an important consideration that must be taken into account when producing TGFs in order to optimize production.

10.2.7 Classification and Reporting Issues. The PRMS classification, categorization, and definitions are applicable to TPFs. Depending upon the assessment of commerciality, including the quality and completeness of geoscience, engineering, and economic data, the quantities resulting from the project's evaluation could be classified either as Reserves (categories 1P/2P/3P) or Contingent Resources (categories 1C/2C/3C). The undiscovered petroleum can be classified as

Prospective Resources (categories 1U/2U/3U). Once a project satisfies all the required commerciality criteria, the associated Contingent Resources can be classified as Reserves. (One of the PRMS criteria is that development proceeds within a recommended period of 5 years from the initial classification date, unless a longer time period is justified. Contractual obligations, such as rig availability and mineral extraction agreements, as well as the complexity of the development, such as an offshore environment or governmental negotiation, may justify a longer period.)

However, given the characteristics of TPFs discussed previously, there are some differences with respect to conventional reservoirs that should be highlighted, including the following:

- In spite of low porosities, the expansive continuity of a BCGA suggests that the volume of gas initially in place is generally much larger in TGFs located within BCGAs compared with that in conventional reservoirs. To avoid being overly optimistic (Schmoker 2005, p. 2), the "assessment scope needs to be constrained from that of crustal abundance to resources that might be recoverable in the foreseeable future." Similar principles can be applied in the case of TPFs. The petroleum volume of a BCPA would be classified as total petroleum initially in place in the PRMS guidelines. At a smaller scale, it could be divided between Discovered Petroleum Initially in Place and Undiscovered Petroleum Initially in Place. Although there would be little doubt about the existence of the TPFs, the uncertainties associated with economic productivity (such as the presence of natural fractures, higher matrix permeability, low values of water saturation, resource maturity, and the size of individual well drainage areas) will all affect whether the accumulation can progress from Prospective Resources to Contingent Resources to Reserves.
- The recovery efficiency, as a percentage of the total petroleum initially in place in the entire BCPA without a water leg, is likely much lower (on the order of 10%) than that in a conventional reservoir. However, the recovery efficiency from a given property (lease or license area or study area) located in a sweet spot with high porosity and high permeability (maybe due to natural fractures) within the continuous accumulation can reach 50% or more in the case of gas (see, for example, Jenkins 2009). The bulk of the resources may be categorized initially as Contingent Resources but can move very rapidly to Reserves if the project's commerciality threshold is met. However, care must be exercised because it takes hard data to step out far from discovery or appraisal wells to the bulk of the resources. For a given unconventional property, it is also important to remember that altogether a small percentage of the wells will contribute to the bulk of the petroleum production.

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10.3 Shale Gas and Oil

10.3.1 Introduction. Shale gas and oil are produced from organic-rich mudrocks (siliceous, calcareous, or a combination), which serve as the source, seal, and reservoir for hydrocarbons. Shales have very low matrix permeabilities (tens to hundreds of nanodarcies) and typically require multistage hydraulic fracture stimulations in horizontal wells to produce at economic rates. Any sedimentary basin with a working petroleum system and shale source rocks has the potential for shale gas and/or oil production. The challenge is to locate sufficiently large areas where the rock and fluid characteristics of the shale are favorable and where wells can be drilled, completed, and produced commercially.

10.3.2 Reservoir Characteristics. Organic-rich shales are complex rocks that exhibit submillimeter-scale changes in mineralogy, grain size, pore structure, fracturing, and other properties that control hydrocarbon storage and productivity (Jenkins 2016a). For many decades, shales were considered to be homogeneous, isotropic, and laterally extensive because the degree of heterogeneity was not observable in outcrops, cuttings, or even thin sections. Only in the past decade have we begun to unlock the mysteries of nanoscale variability in these rocks with scanning electron microscopes and other high-resolution tools. This work shows that we should not only be linking variability in well performance to variations in drilling and completion practices, but also to variations in rock and fluid properties within the shale. Shales are not, as one engineer described them, "pristine until disturbed by drilling and completion activity."

Shales, and other unconventional accumulations, are sometimes referred to as "statistical plays," implying that well performance variability is primarily the result of random variations in reservoir properties from well to well. This is misleading because, while there is an element of randomness, there are reservoir property trends controlling the average performance of well groups that can be mapped and quantified. Understanding these trends and the information they tell us about the better-producing areas, or intervals/landing zones, will allow us to concentrate drilling in locations with the greatest production potential.

The complexity of these reservoirs means that a comprehensive suite of information is needed to fully characterize them for the purposes of wellbore design, spacing, and construction **(Table 10.2).** Collecting, analyzing, and integrating this information, and using it to help make good decisions whether to proceed or exit from a project, can be very cost-effective relative to relying on expensive trial-and-error drilling.

Category	Information
Geology	Outcrop descriptions, bedrock geology, mudlogs, formation tops, mineralogy, structural geology, faults, fractures, stratigraphy, biostratigraphy, potential geohazards, topographic maps, geocellular models
Geochemistry	Kerogen types, total organic carbon, RockEval pyrolysis, kinetics, borehole temperatures, thermal maturity, biomarkers, isotopes, analysis of saturates-aromatics-resins-asphaltenes (SARA), gas chromatography
Geophysics	Two-dimensional (2D) seismic lines, 3D seismic volumes, vertical seismic profiles, check shots, microseismic data, gravity, magnetics, remote sensing (satellite images, aerial photos), topography, in-situ stress magnitudes and orientations
Cores	Core descriptions, electrical properties, routine core analyses, sorption isotherms, gas contents (desorption), capillary pressure, formation compressibility, digital rock physics, X-ray diffraction (XRD), scanning electron microscopy (SEM), nuclear magnetic resonance imaging (NMR)
Wireline logs	Spontaneous Potential (SP), spectral gamma ray (GR), array resistivity, microlog, caliper, density, neutron, dipole sonic, image, geochemical, nuclear magnetic resonance, pulsed neutron
Geomechanical properties	Principal stress orientations and magnitudes, elastic properties (Young's modulus, Poisson's ratio), natural fracture orientation and density, unconfined compressive strength, geomechanical models
Reservoir	Fluid types, contaminants (CO_2, H_2S), pressure-volume-temperature (PVT) properties, static reservoir pressures, permeabilities, flowing bottomhole pressures, reservoir boundaries (faults), well testing (e.g., diagnostic fracture injection tests or DFITs), analogous reservoir data, analytical/numerical models
Drilling	Mudgas volumes and compositions, rates of penetration, drilling histories, wellbore configurations, fluid kicks and losses, drilling problems, formation pressure, drilling practices, cementing, casing integrity tests, directional surveys
Completions	Fracture staging, perforation strategies, proppant and fluid types/volumes, pumping schedules, treating pressures, fracture diagnostics, microseismic data, tiltmeters, completion histories, refracturing operations
Production	Bottomhole (preferably) flowing pressures, well rates (oil, water, gas), production logs, radioactive/chemical tracers, compression, artificial lift, choke sizes, water source and disposal intervals, wellbore schematics, distributed temperature and acoustic surveys, facility diagrams and constraints, nodal analysis
Health, Safety and Environment (HS&E)	Wellbore integrity, waste disposal, pollution/depletion of groundwater, air and water quality, spills, noise and light pollution, seismicity, well and site abandonment
General	Well locations, lease boundaries, lease terms, regulatory environment

Table 10.2—Summary of useful information for characterizing and quantifying shale gas and oil reservoirs.

10.3.3 Drilling and Completions. Although initial shale wells may be vertical in order to evaluate reservoir properties with cores and logs, appraisal and development wells are almost exclusively horizontal. These wells, which can be 15,000 ft long or more, are landed in intervals with favorable properties, including geomechanical features, allowing hydraulic fractures to be generated and propagated into adjacent rocks in order to drain them (Jenkins 2016b). The dominant fluid used for stimulation is water containing a friction reducer (slickwater), although gel (linear or cross-linked) may be used to increase the proppant carrying capacity, build greater fracture width, and/or reduce the amount of water used.

In addition to selecting the appropriate fracturing fluid, decisions need to be made regarding the length of the well, length of the stages, perforation density, pounds of proppant per stage, barrels of fracturing fluid per stage, and treating pressures, among others. These factors are sometimes referred to as the "drilling and completion intensity," whereby more perforations, proppant, and fluid pumped in shorter stages at higher pressures result in greater intensity. Increasing the intensity in recent years has been rewarded with higher productivity and value, but there is a point of diminishing returns where stress shadows, interference between stages, and interference between wells can reduce project value.

This situation is most obvious in parent-child well relationships. In the US, horizontal wells are typically drilled at a well density of one well per square mile to hold acreage by production, followed by development infill drilling, if initial production characteristics are favorable. Many companies have overestimated the forecasted production of these bounded infill wells, believing that their rates would be similar to the initial unbounded wells. In addition, multiple companies have implemented a cube strategy, whereby tens of wells are spaced horizontally and stacked vertically to drain multiple horizons in a given area. While some of these projects have met expectations, many have not, because the wells were too close together, the drilling and completion intensity was too great, and/or reservoir heterogeneities such as natural fractures contributed to connecting the wells. Recognition of the uncertainties associated with parent-child well relationships enters into the reserves categorization or resources classification process.

Other production issues that exacerbate commercial recovery include condensate banking in rich gas and rock compaction as the reservoir pressure depletes with production. Effects such as these may contribute to a loss in productivity in excess of 50% (for example, see Ayyalasomayajula et al. 2005), unless properly managed.

These disappointments are best mitigated by demonstration (pilot) projects. For example, establishing a drilling and completion protocol and holding it constant for tens of wells will facilitate understanding the range of well performance caused by changes in reservoir properties and determining whether the average well in this group is a commercial success. Failure to do this may result in a false positive (leading to noncommercial development) or a false negative (walking away from a commercial development project). The same applies to implementing the cube strategy. Demonstration projects using different well stacking/spacing combinations in different areas of the field are recommended, but wells will need to produce long enough in each cube to ensure that the initial rate and subsequent decline of the average well meet expectations and are commercial.

Given the tens of thousands of existing shale wells, there is abundant information available from multiple shale plays regarding well performance and associated drilling and completion practices. This information also includes the time and cost for drilling and completing wells, and the ways in which these factors decrease as companies become more efficient in a new shale play. Analyzing these data with statistical modeling and machine learning can provide insights as to those factors that are the key drivers in maximizing value. These factors, in turn, can be used as a starting point for developing best practices for a target shale reservoir.

10.3.4 Commerciality Issues. A key difference between conventional accumulations and shales is that shales have a much greater chance of discovery, given that a trap is not necessary. This does not mean, however, that the chance of a commercially successful project for shales is greater than for conventional accumulations. In fact, they tend to be similar because while it is relatively easy to get a flow of hydrocarbons from an organic-rich, thermally mature shale, it is much more challenging to obtain economic producibility over critically sized areas.

Over the past decade, many shale projects have failed to deliver the value promised to stakeholders. A common problem is failure to drill enough wells prior to development to understand whether the development project will be a commercial success. This problem is exacerbated by a desire to minimize the time and money spent in predevelopment. Similarly, a large-scale project based on results that are more representative of "sweet-spot" wells is almost certain to underperform.

With this in mind, shale projects should be evaluated in a series of stages **(Fig. 10.5).** The decision to move from one stage to the next should be tied to economic thresholds such as recovering the cost of individual horizontal wells in the deliverability stage and attaining commerciality with pad drilling or cube projects in the demonstration stage. A development project can then be implemented assuming the project is competitive with other opportunities in the company's portfolio. This process incrementally exposes larger amounts of investor capital in a responsible manner.

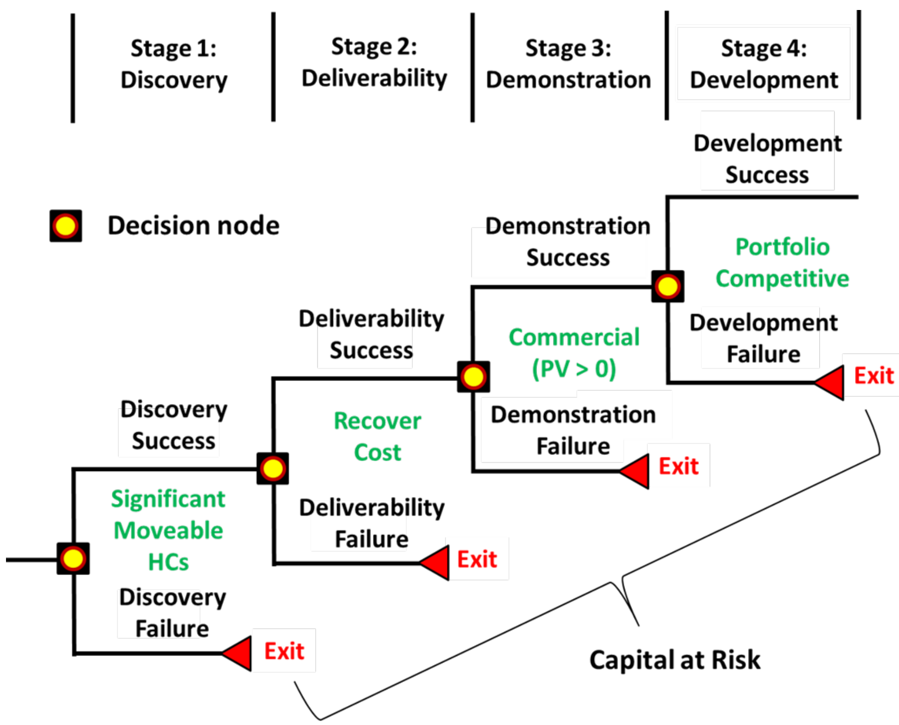

Fig. 10.5—Decision tree illustrating the staged approach, where HC is hydrocarbon. (Note that Stage 3—Demonstration Success considers not only the Present value (PV) > 0 requirement, but other PRMS commerciality criteria as well.)

In each stage, there is a need to identify the key uncertainties and risks, collect the data needed to quantify these uncertainties and risks, and generate a probabilistic assessment of potential outcomes and their associated value in order to compute an expected value for the project (Jenkins and McLane 2019). Estimates of resources and reserves are linked with this staged process. Prospective Resources are estimated prior to drilling the discovery well, Contingent Resources are estimated thereafter, and these are converted to Reserves when the demonstration and development projects are determined to be commercially successful.

Two other elements important to commercial success are assurance and performance reviews. An assurance process within companies includes clear guidelines and workflows to ensure the fundamental quality of technical work and peer reviews and assistance by subject matter experts. Performance reviews help in understanding whether the expectations of a given project stage were met, and if not, what should be done differently to achieve greater agreement. Applying these techniques to assess, approve, carry out, and monitor projects is critical for establishing consistency in performance and generating confidence in the investment community.

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10.4 Evaluation Methodologies for Tight/Shale Oil and Gas

10.4.1 Introduction. Analysis and forecasting of production data in unconventional reservoirs continue to be problematic because there is considerable uncertainty related to our current lack of understanding of the relevant fluid flow phenomena. There are many unknowns, such as the link between flow in nano- and macroscale features, the effect of natural fractures and stress fields/geomechanics, fracture propagation, permeability, pressure-dependent reservoir properties (e.g., permeability, porosity, and fracture conductivity), and phase behavior at nanoscale, which are all primary sources of uncertainty in long-term production performance. Recently, a great amount of research focusing on these unknowns has been performed to understand and relate these issues to well performance analysis and forecasting, but significant uncertainty still remains, particularly for short-term production data.

Generally speaking, conventional decline curve equations are utilized with some adjustments (e.g., the modified hyperbolic equation, Ilk et al. 2008) for forecasting production in unconventional reservoirs. These equations are empirical in nature, and attempts to link the results of batch processing of large numbers of wells and their decline curve relations to detailed reservoir engineering work are not very common. While it is tempting to use these relations due to the notion that they are "easily understood and repeatable," a thorough understanding of uncertainty in forecasts and the effects of well/reservoir properties on performance are generally missed. On the other hand, methods attempting to account for well/reservoir properties, fluid properties, and drainage area complexities are often considered to be elaborate, laborious, and unreliable within the context of production forecasting for large numbers of wells. However, these additional steps, when taken on key wells, often provide time-saving insight in the evaluation of a larger population.

10.4.2 Overview. From a historical perspective of decline curve analysis (DCA), Arps' hyperbolic and exponential relations have been the industry standard for production forecasting and estimating ultimate recoveries for over 70 years. However, in unconventional reservoirs, the application of these relations may be problematic due to invalid assumptions. The main assumptions forming the basis of traditional DCA include the following:

- Any changes in operating conditions or field development during the producing life of the well are minor.
- No major changes occur in well productivity (such as changing skin throughout production).
- Drainage area remains constant.
- Production is achieved against a constant bottomhole flowing pressure.
- A boundary-dominated flow regime (reservoir depletion) has been achieved.

It is common to observe misapplication of traditional DCA in very low permeability reservoir systems by ignoring these assumptions, frequently resulting in overestimation of reserves, especially if the hyperbolic relation is extrapolated with decline exponents (widely known as *b* exponents or *b*-parameter) greater than 1. To prevent overestimation, the hyperbolic equation may be spliced with an exponential decline at late times, resulting in a modified hyperbolic equation. This approach remains nonunique and may yield widely varying estimates of reserves, mainly due to selection of *b* exponents and ambiguity when selecting minimum terminal decline values (particularly in the absence of mature analogs).

Numerous authors [Ilk et al. 2008 (power-law exponential); Valkó 2009 (stretched exponential); Clark et al. 2011 (logistic growth model); Duong 2011, 2014; Mishra et al. 2014; Fulford and Blasingame 2013 (transient hyperbolic equation); Artus and Houzé 2018; Artus et al. 2019] have proposed various empirical rate decline relations, which are principally based on a characteristic feature of the data and appear to match the early time transient and transitional flow regimes.

Each model may best be described as empirical (i.e., no direct link with theory) and generally centered on a particular flow regime and/or characteristic behavior. As such, all of these relations may produce good matches across the entire range of production, but each relation may diverge in the forecast and hence result in a broad range of estimates of ultimate recovery. In addition, each equation may not apply to every play due to the unique production characteristics of the particular unconventional reservoir.

These decline curve relations may be used in combination to obtain a range of outcomes rather than a single estimated ultimate recovery value. The range of outcomes may be associated with the uncertainty related to production forecasts and can be evaluated as a function of time. **Fig. 10.6a** presents an example of the application of various decline curve relations to a shale gas well on a classic semilog rate-time plot, while Fig. 10.6b presents results on a semilog rate-cumulative plot. Note that the forecasts from each of the decline curve relations yield a range of estimated ultimate recovery values, which is mainly a result of the different characteristic behaviors of these decline relations. Aside from the range of estimated ultimate recovery values, no direct link to reservoir and completion parameters can be obtained.

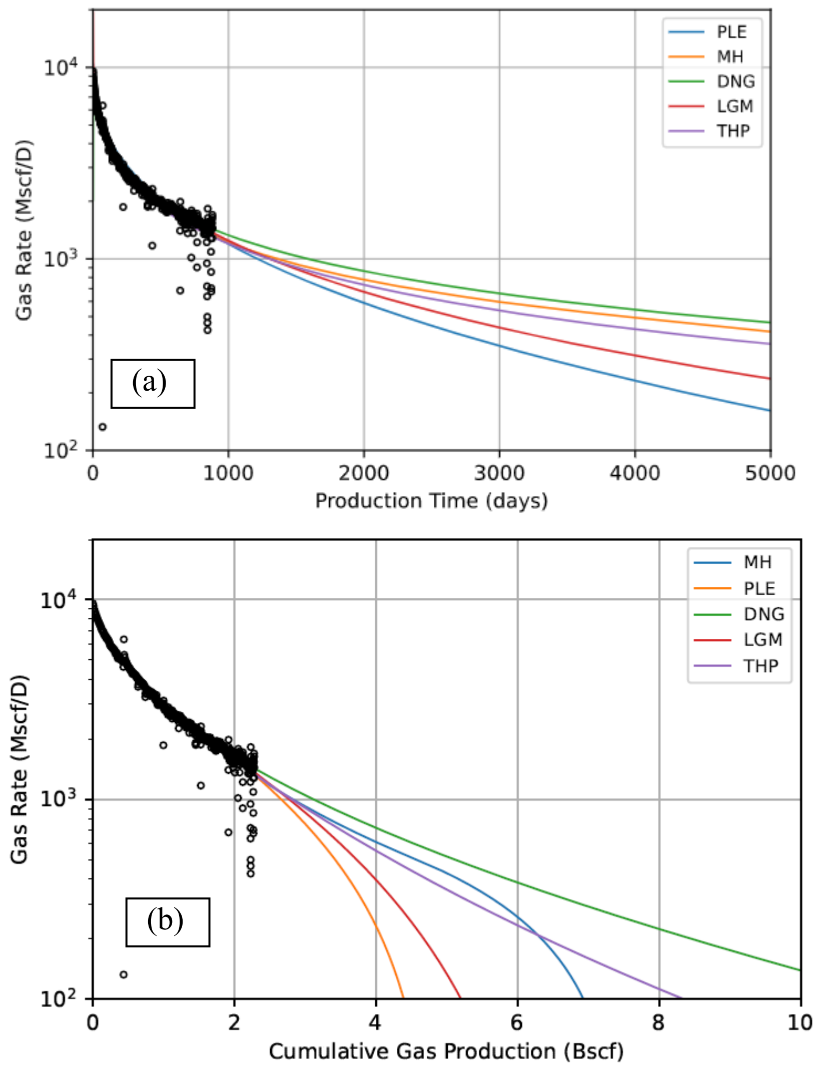


Fig. 10.6—(a) Production forecasting of a shale gas well using various decline curve relations (semilog rate and time plot). Abbreviated decline curve relations: PLE refers to "power-law exponential" decline, MH refers to "modified-hyperbolic," "DNG" refers to Duong, "LGM" refers to logistic growth method, and THP refers to "transient hyperbolic." (b) Production forecasting of a shale gas well using various decline curve relations (semilog rate and cumulative production plot).

Fig 10.7 illustrates the various flow regimes that may be encountered in a multistage fractured horizontal well. It should be noted that this sample illustration is only conceptual and was derived using an analytical or numerical solution for a horizontal well with multiple transverse fractures (for first derivation, see van Kruysdijk and Dullaert 1989). There are many variations of this solution yielding similar behavior (i.e., flow regimes). The following model parameters were assumed to generate the response on Fig. 10.7:

k	=	0.0005 md (500 nd)	(permeability)
x_f	=	300 ft	(fracture half-length)
F_c	=	infinite conductivity	(fracture conductivity)
s	=	0	(skin factor)
n_f	=	40	(number of fractures)
A	=	640 acres	(well spacing)

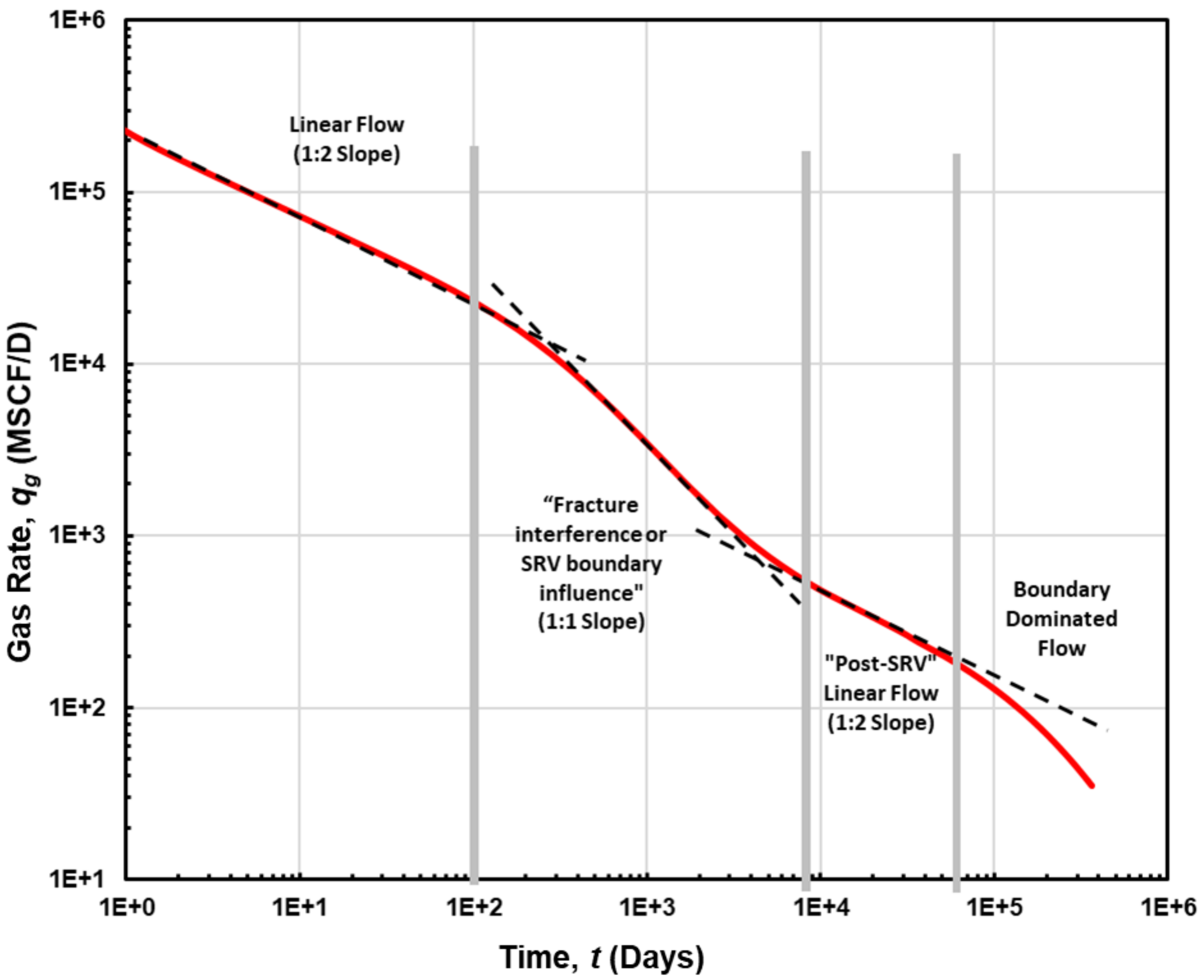


Fig. 10.7—Typical (conceptual) flow regimes for a horizontal well with multiple transverse fractures, where SRV is stimulated reservoir volume.

Fig. 10.8 illustrates actual generic production responses (over 3 years and plotted in terms of pressure drop–normalized rate vs. production time) from several unconventional plays in North America. It should be noted that generic production responses are based on the average behavior of certain well groupings (typically consisting of 100 or more wells) and should not be considered as definitive for each play. In other words, the duration of the linear flow regime and late time decline behavior may be different than what is plotted here due to many factors such as well spacing, completion design, and reservoir and fluid properties. These plots help compare actual well behavior to theoretical responses.

For each play illustrated in Fig. 10.8, an uncertainty region beyond historical production is imposed to illustrate uncertainty with respect to future production behavior. This uncertainty region can be used to derive decline curve parameters associated with uncertainty in estimates of ultimate recovery. Early time behavior appears to be mostly impacted by well cleanup effects. It is interesting to note that, after cleanup, actual production behavior observed in various unconventional plays is typically consistent with the first flow regime (linear flow), but it may differ at a later time. Another point to consider is that linear flow associated with the "post-SRV" is not commonly observed.

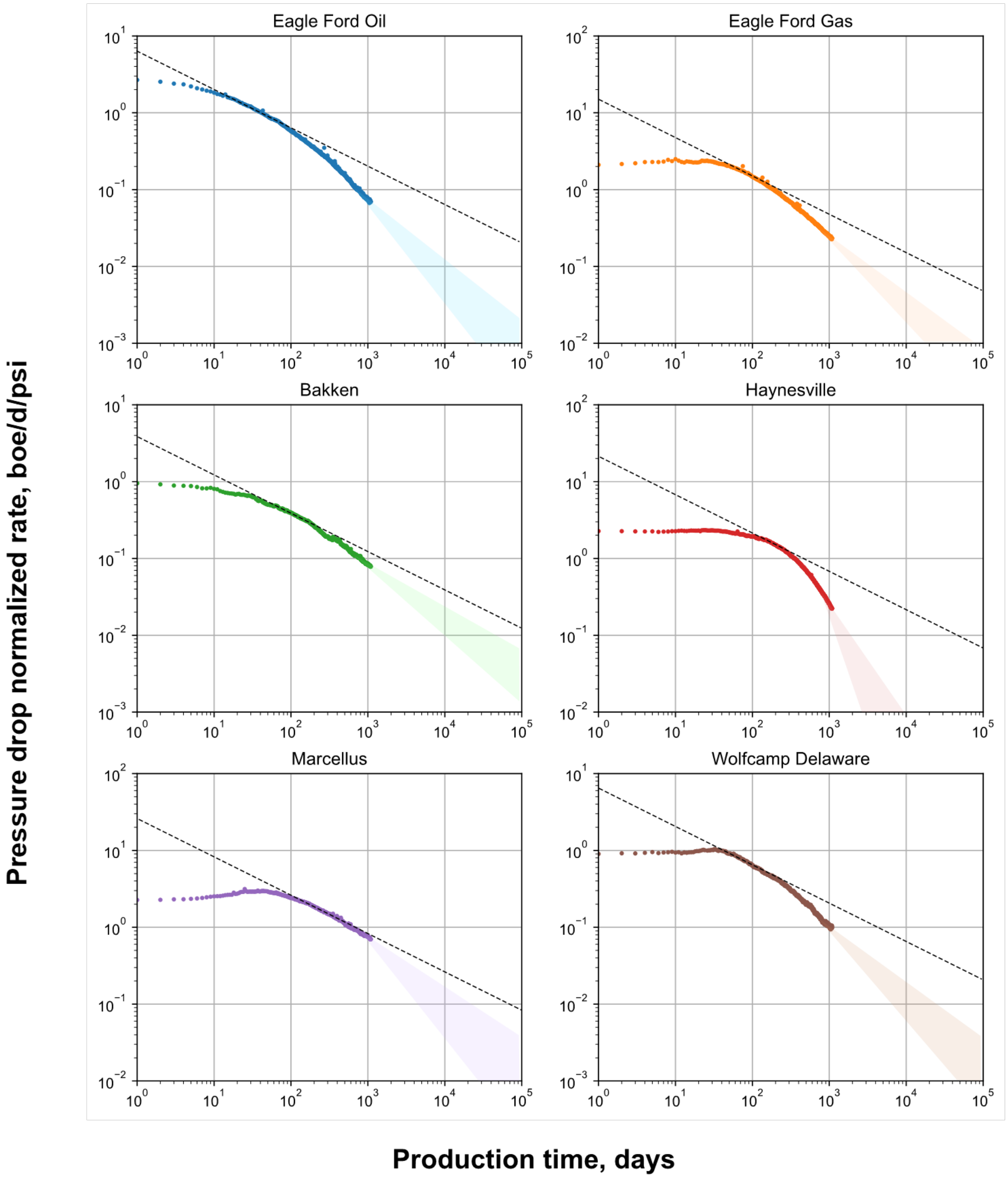


Fig. 10.8—Typical production responses (in terms of pressure drop–normalized rate) in various shale/tight oil and gas plays in North America.

A generic workflow can be considered for analysis and forecasting of well performance, preferably using high-frequency production rate data, such as at least daily pressure and rate data, ideally with individually metered wells. Although it cannot be universally applied to all scenarios, it is consistent and repeatable in many cases. First, data quality control and well performance diagnostics are performed. In this stage, outliers and inconsistent data are identified and may be removed to achieve a better identification of performance trends. Production diagnostics are important when interpreting flow regimes, quantifiable measures of productivity (productivity metrics), well groupings, and characteristic group behavior. Similarly performing wells are identified and well groups are created before representative wells are picked for detailed model-based analysis.

Next, model-based analysis is performed to analyze and forecast well performance. During this step, it is important to consider the most appropriate model to use and incorporate relevant, play-related factors that affect flow behavior, such as stress dependencies, drainage area patterns, and pressure-volume-temperature and multiphase behavior. In this analysis, ranges are estimated for the unknown parameters, which will result in a range of solutions at the end of process rather than yielding a single answer. Finally, model-based analysis results (i.e., forecasts) can be extended to the other wells in the well group.

Sections 10.4.3 through 10.4.5 present detail on the steps of the generic workflow.

10.4.3 Production Diagnostics. The first step in the workflow is to fully evaluate the production data using diagnostic tools. The data utilized for this process are not only production data (time-rate, time-rate-pressure), but also well completion data and reservoir data. A complete diagnostics study should include the following activities:

Single-well basis:

- Review of data quality and consistency
- Identification of data features and characteristics (for example, effects of tubing installation, effects of offset well fracturing, etc.)
- Identification of flow regimes

Multiwell basis:

- Comparison well performance through multiwell plots
- Identification of well performance indicators (productivity metrics)
- Identification of groups of wells with similar behavior
- Selection of representative wells for detailed model-based analysis

Throughout the data quality and consistency checking process, off-trend or spurious data can be removed (or isolated) on diagnostic plots for flow-regime diagnosis. In addition, erratic rate data can be removed from semilog time-rate plots to improve numerical differentiation quality and obtain D and b parameters as functions of time (Ilk et al. 2008). For reference definitions of D- and b-parameters are provided below (where q is rate):

$$D \equiv -\frac{1}{q}\frac{dq}{dt}$$

$$b \equiv \frac{d}{dt}\left[\frac{1}{D}\right] \equiv -\frac{d}{dt}\left[\frac{q}{dq/dt}\right].$$

A visual inspection of production history plots of rate and time and flowing (surface or bottomhole) pressure and time is very helpful to reveal inconsistencies (such as rates and pressures increasing at the same time) prior to analysis. If inconsistencies exist and are not identified, one can end up analyzing artifacts that have nothing to do with reservoir behavior. In all cases, care should be taken to ensure no undue bias is applied that may exclude data points that are, in fact, applicable.

Identification of flow regimes is the key objective of production diagnostics. It is incumbent upon the evaluator to know when to use, or not to use, certain rate-decline relationships as a function of the flow behavior stage of the well. As indicated earlier, the conditions under which the Arps model may be applied are limited. In other words, there is no "one size fits all" empirical rate-decline model. Therefore, it is critical to utilize diagnostic plots to identify characteristic decline behavior, which could indicate an appropriate decline curve model to use or a decline parameter (e.g., Arps' hyperbolic exponent) specific to an area of interest.

For this purpose, log-log plots of rate and pressure drop–normalized rate are utilized. Pressure drop is calculated by subtracting flowing bottomhole pressure from initial pressure (or average reservoir pressure, to be theoretically valid). Practically speaking, average reservoir pressure measurements are not common in unconventional reservoirs, and flowing surface pressure data can be utilized in the absence of bottomhole pressures. On the time scale, standard production time or material balance time (MBT) is used. MBT is the ratio of cumulative production to instantaneous rate. The goal is to identify "power-law" signatures, which are observed as straightline trends on a log-log plot. The observed slope of power-law signatures could translate to possible flow regimes such as:

- Quarter slope → Bilinear flow (finite conductivity fracture)
- Half slope → Linear flow (infinite conductivity fracture)
- Unit slope → Depletion-type flow (this is only valid for the MBT plot)

Fig. 10.9 presents a schematic of "power-law" signatures using a diagnostic MBT plot (sometimes referred to as a "Blasingame plot"). On this plot, red points indicate linear flow behavior, while yellow points suggest bilinear flow behavior, and gray points indicate depletion flow behavior (see Acuna 2016, 2017; Acuna et al. 2018; Chu et al. 2017; Raghavan and Chen 2019 for other interpretations of "power-law" signatures).

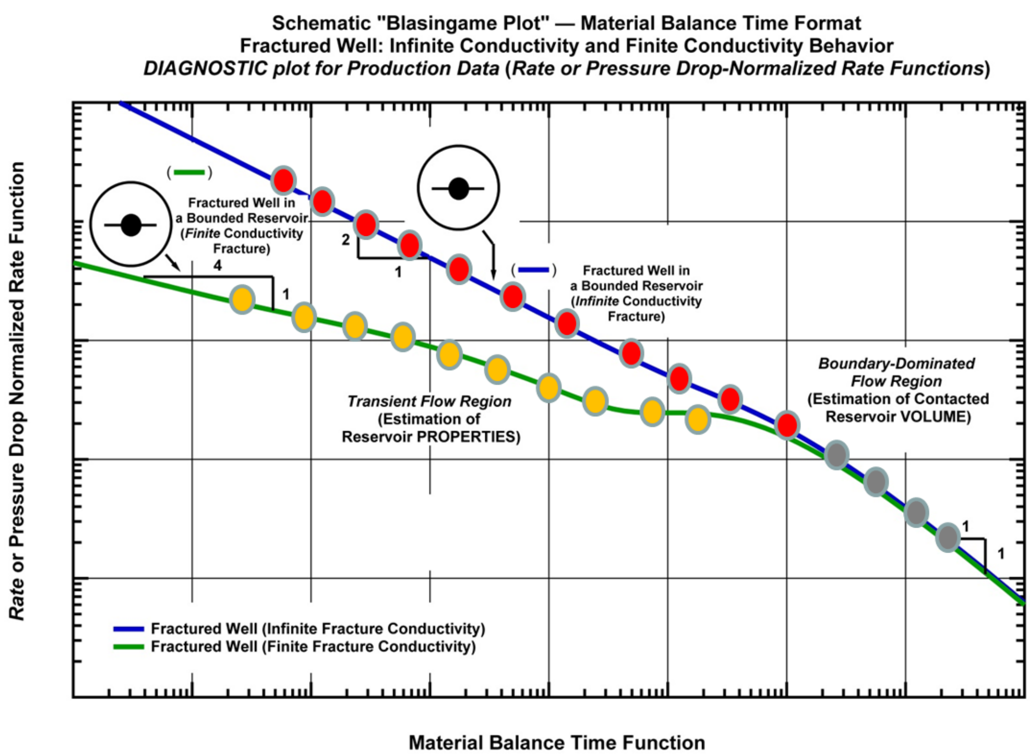


Fig. 10.9—Schematic Blasingame plot for flow regime identification in rate or pressure drop–normalized rate and material balance time (MBT) format.

In addition to production history plots (i.e., rate and production time, flowing pressures and time), the following diagnostic plots are recommended to assist interpretation:

- [Log-log] Rate (or pressure drop–normalized rate) and time for flow-regime identification
- [Log-log] Rate (or pressure drop–normalized rate) and MBT for flow-regime identification
- [Cartesian] Reciprocal rate (or rate-normalized pressure drop) and square root time for well productivity assessment (for productivity metrics)
- [Semilog] Rate (or pressure drop–normalized rate) and cumulative production for production extrapolation

Although these plots are useful in many cases, the use of additional plots, which could be relevant for specific circumstances (e.g., gas-oil ratio as a function of time, water rates as a function of time, water-oil ratio versus cumulative oil production, derivative plots such as *D* parameter and *b* parameter, etc.), is encouraged. Secondary phase relationships are necessary for the forecasting of condensate (in a gas-condensate reservoir) and solution gas (in an oil reservoir), while water-oil or water-gas ratios assist in identifying well cleanup. The evaluator should also monitor changes in choke settings, which may influence flow rates and secondary ratios.

Multiwell diagnostic plots are utilized to identify characteristic group behavior, which may imply a unique flow regime applicable for each well in the grouping. An identified unique flow behavior, such as late time decline behavior, can be translated to a decline curve parameter (e.g., *b* factor) and used for each producing well and further may be utilized as analog behavior. Once the characteristic features of well performance are identified, model-based analysis can be performed to estimate well/reservoir properties, completion efficiency, and, most importantly, future production.

The key step in this process is to group wells exhibiting certain features together. Along these lines, important things to consider for well groupings are wells producing in a similar geological area, similar fluid properties, and similar completions. (For more about assessing analogs, see Chapter 4—*Assessment of Petroleum Resources using Deterministic Procedures* herein.) Next, flow regimes and the other related features of each well are identified using single-well diagnostic plots. After this exercise, wells can be plotted on the same plot to visualize if they exhibit similar trends together or not. At this point, normalization by certain parameters can be used to eliminate differences and to obtain a unique trend. The normalization parameters could be proxy parameters (e.g., the cumulative production value of each well at a specified time) or well completion/subsurface parameters (e.g., lateral length, amount of proppant pumped, propped thickness, and initial reservoir pressure, among others).

10.4.4 Model-Based Analysis. For this discussion, model-based analysis refers to the use of analytical and numerical models to analyze and model time-rate-pressure data in order to estimate dynamic well/reservoir properties such as permeability, effective fracture half-length, fracture conductivity, etc., through history matching (Stalgorova and Mattar 2012, Ilk et al. 2012, Atadeger et al. 2020). Once a history match (such as shown in Section 10.4.5) is achieved, model-based forecasting yields rate (or pressure) forecasts as a function of time.

Model-based analysis will require high-frequency time-rate-pressure data (in particular, bottomhole pressure data). In the absence of bottomhole pressures, surface pressure data will need to be converted to bottomhole pressure by using correlations or nodal analysis. Conversion to bottomhole conditions may add complications to this analysis, especially in the case of multiphase flow and artificial lift.

Pressure-volume-temperature (PVT) and static reservoir properties are also required to construct the model. Actual pressure-volume-temperature laboratory reports are preferrable (particularly for condensate and volatile oil cases), but correlations may be acceptable in the case of dry gas. With ongoing research in progress for phase behavior in nanopores, it might be difficult at this time to conclude how this behavior affects modeling. Petrophysical interpretation is required from well logs and cores to estimate porosity, net reservoir thickness, and initial water saturation. Net reservoir thickness is considered to be a parameter with high uncertainty, and different interpretations are typically possible, such as propped fracture height. In order to quantify this value, microseismic interpretation and geomechanical analysis may be utilized in support of petrophysics.

Finally, well completion data are required to define well/reservoir geometry. Well completion data should mainly include horizontal well length, number of fracture stages, and the number of perforation clusters per stage. When multiple wells are modeled, the amount of proppant and fluid pumped could be utilized to relate model-based analysis results to model parameters such as effective fracture half-length.

There are general issues related to models in unconventional reservoirs. Some of the important ones are listed below:

- Nonlinearities: Stress (pressure)-dependent rock properties, multiphase flow
- Complex fracture configurations, fracture geometries
- Interference between wells
- Uncertainty in drainage area (stimulated reservoir volume concept, discrete fracture networks)
- Very low permeability

Most analytical models require special transformations to deal with some of the challenges listed above. Numerical models, on the other hand, should be able to account for these challenges with proper gridding and due to their ability to incorporate information from all sources (such as geology, geomechanics, geophysics, and completion diagnostics, etc.). Generally speaking, numerical models can be used to mitigate the limitations of analytical models in terms of well/fracture geometry, nonlinearities, and complex diffusion processes. The main problem with numerical models is to properly address high pressure gradients caused by the very low permeability of the system. Correspondingly, this issue needs to be addressed by implementing very refined gridding around the high-pressure-gradient locations such as the interface between fractures and the formation rock. References in this section provide a comprehensive list of various analytical, semi-analytical, empirical, and complex models for modeling flow behavior of multifracture horizontal wells producing in unconventional reservoirs.

10.4.5 Well Performance Analysis and Forecasting Example. In this subsection, examples are shown to demonstrate key aspects of previous subsections with data from producing wells from an unconventional gas play in North America. In the first example, we focus on issues involved with projecting ultimate recovery with limited data. **Fig 10.10** illustrates curve fits to production data at specific times throughout production history with specific *b* factors used for production forecast.

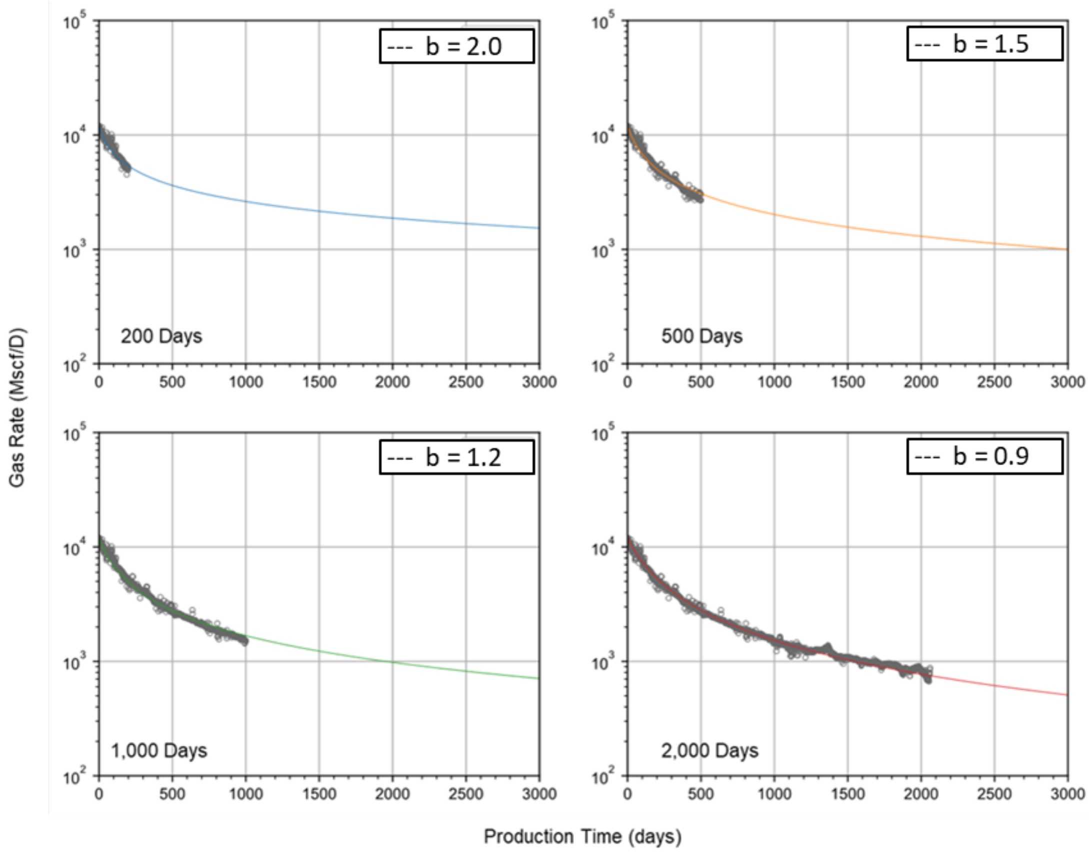


Fig. 10.10—Production forecasts at specific times throughout production history.

It can be observed that the *b* factor continuously decreases compared to the value used in the initial forecast. To summarize this observation, each forecast is plotted on one plot with actual (most recent) production. As observed in **Fig. 10.11**, earlier forecasts with higher *b*-factor values significantly overestimate the production.

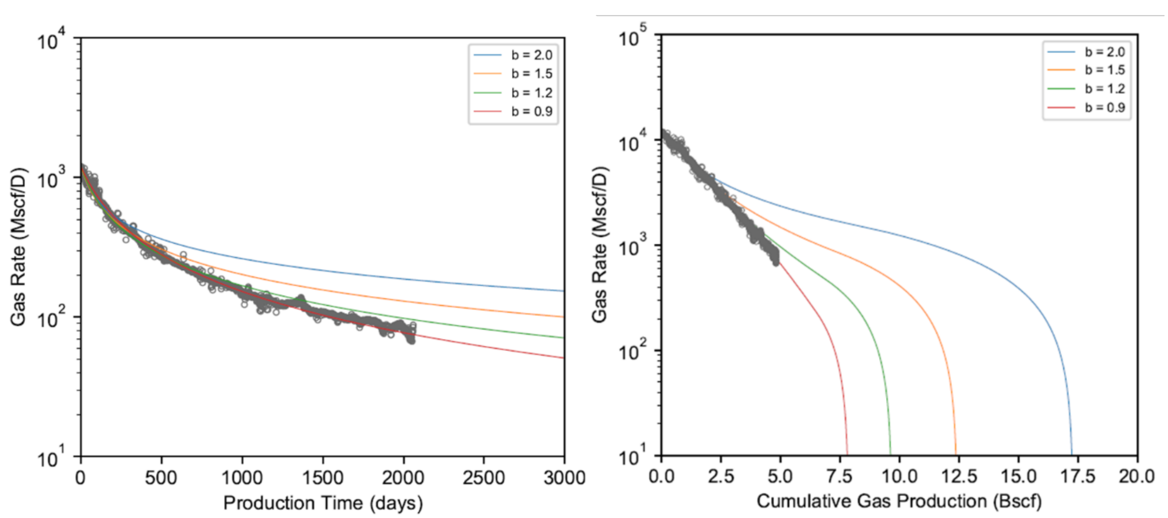


Fig. 10.11—Production forecasts at specific times with most recent production history.

This observation points out the importance of understanding flow regimes encountered throughout a well's production history. In this example, decreases in the *b* factor used for production forecasting are related to changes in flow regimes. Evaluators should be aware of this situation when dealing with wells with limited production history.

The second example focuses on analysis of and forecasting for a group of wells with similar behavior. **Fig. 10.12** presents a log-log flow-regime analysis plot (rate and MBT) for wells producing in a shale gas play. Each colored dots on Fig 10.12 represent a specific well behavior. It can be observed that most of the wells show similar behavior, but the magnitude of production responses is different.

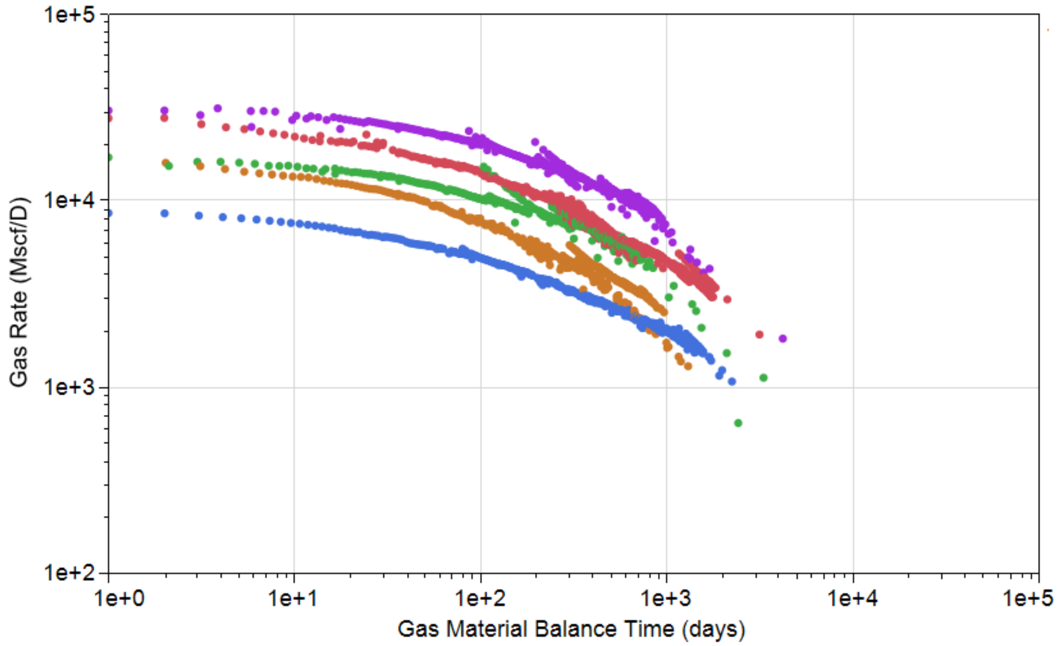


Fig. 10.12—Flow-regime analysis plot for a group of wells.

To approximate the characteristic behavior of this group, rates are normalized by a specific parameter (or a combination of parameters). In this example, cumulative production at 6 months for each well is used as the normalizing parameter. Cumulative production at 6 months can be considered as a proxy for including the effects of completions and localized reservoir properties. Production behavior of this group is shown after normalization in **Fig. 10.13** (note each colored dot represents a specific well behavior after normalization)**.**

Note in Fig. 10.13 that almost all wells exhibit linear flow behavior, and none of the wells falls on the unit slope, which would indicate depletion. This observation may indicate challenges with production forecasts based on existing data (with decline curves) as transition from linear flow is expected at some point in future. Accordingly, model-based analysis is then utilized to account for changing flow regimes.

Model-based analysis can be performed for each well; however, this may not be practical, as it typically takes more time to perform a comprehensive analysis for a single well compared to DCA. Therefore, it may be sufficient to perform model-based analysis for one "representative" well from this group of wells as long as this group of wells exhibits a unique behavior. Accordingly, in this example, we selected a representative well for model-based analysis.

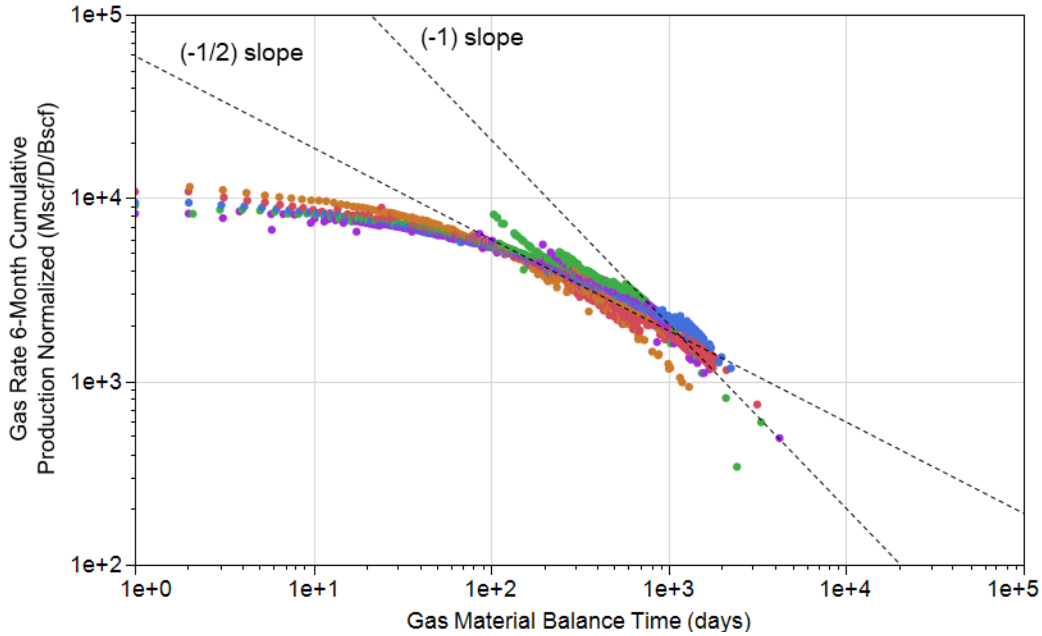


Fig. 10.13—Flow-regime analysis plot for a group of wells after normalization.

After selecting the well, we start with data quality control and identification of specific events or issues throughout the well's history. **Fig. 10.14** shows the rate and calculated bottomhole pressure history from this well. There appear to be no major issues with production and rate, and the calculated bottomhole pressures are in good agreement. Consequently, analysis of this well should not be problematic.

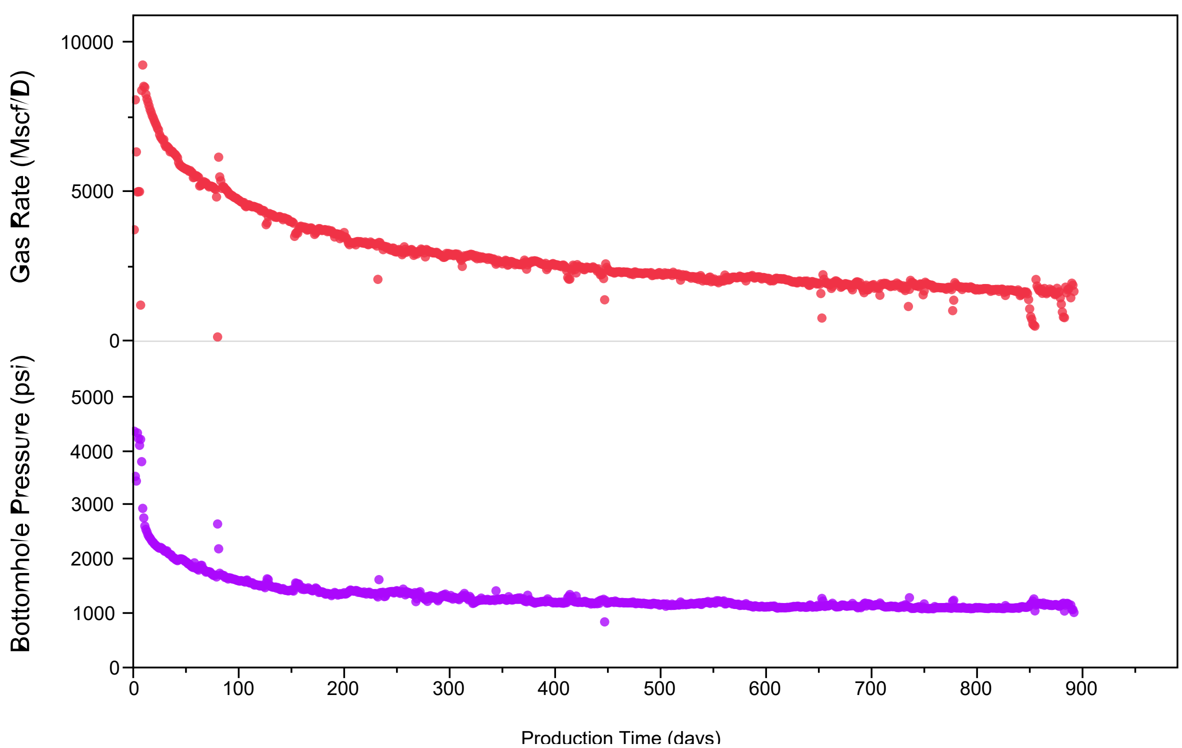


Fig. 10.14—Rate and calculated bottomhole pressure data for selected well for analysis.

After removing outliers, flow-regime analysis is performed next using diagnostic plots. For this well, we observe linear flow behavior for almost its entire production history. Because one can expect deviations from linear flow at a later time, production forecasting based on this observation may potentially overestimate volumes. Considering this uncertainty, we impose an uncertainty region on the diagnostic plot to illustrate potential flow regimes that may be encountered at later times. Possible interpretations for potential decline behavior in this example include potential "longer-term" linear flow, which could be used to model a "high case" forecast, or an immediate transition to a steeper decline trend as depicted by the "unit slope" on **Fig. 10.15** to help model a "low case" forecast. Characterization of the uncertainty using diagnostics helps the evaluator to estimate the ultimate recovery values that can guide assessment of 1P, 2P, and 3P (or 1C, 2C, and 3C) quantities once these empirical model evaluations are tied to actual well recovery outcomes.

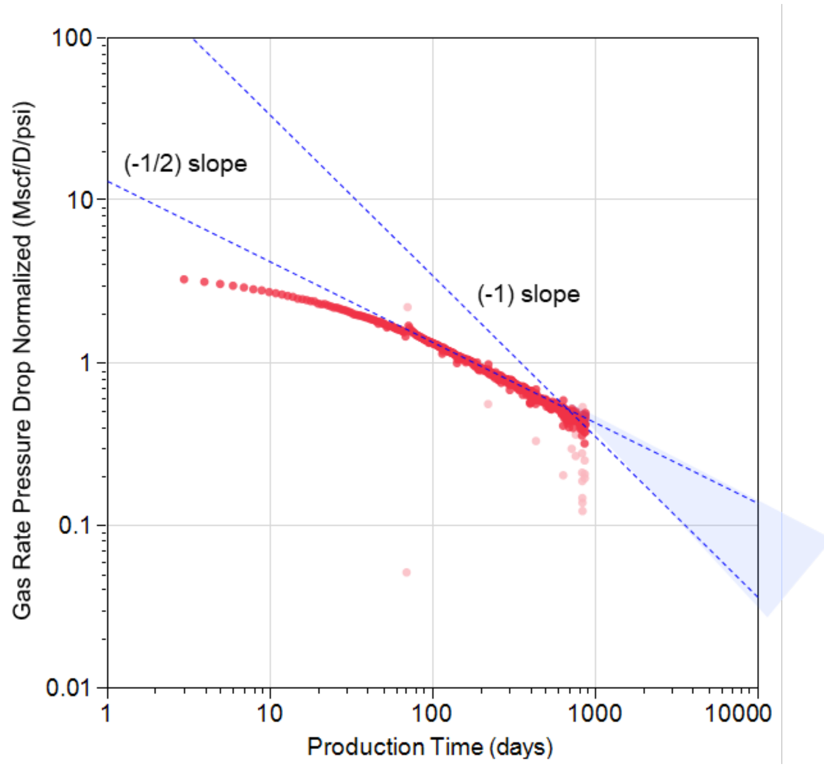


Fig. 10.15—Flow-regime analysis plot for the selected well.

Model-based analysis is then performed for the selected well. Although there are many models described in literature used for analysis and forecasting, this example will be used to illustrate a history match obtained with a relevant model suitable for a multifracture horizontal well. It is recommended to obtain history matches using different combinations of modeling parameters to account for uncertainty and nonuniqueness and to compare these results to the physical characterization of the subject reservoir and fluids to identify those matches that compare favorably to these properties.

Typically, there is significant uncertainty associated with model parameters such as permeability, effective fracture half-length, and drainage area. Therefore, uncertainty analysis is strongly recommended—this can be achieved by experimental design (see Collins et al. 2015) or assuming probability distributions on model parameters (see Anderson et al. 2012). It is always beneficial to incorporate additional sources of information such as reservoir characterization studies and/or completion diagnostics (microseismic, tracer tests, geomechanical models) to constrain key model parameters such as effective fracture half-length and number of contributing fractures.

Fig. 10.16 illustrates the history match of rate and calculated bottomhole pressure data (with only one realization of model parameters) accompanied by history matches on diagnostic plots.

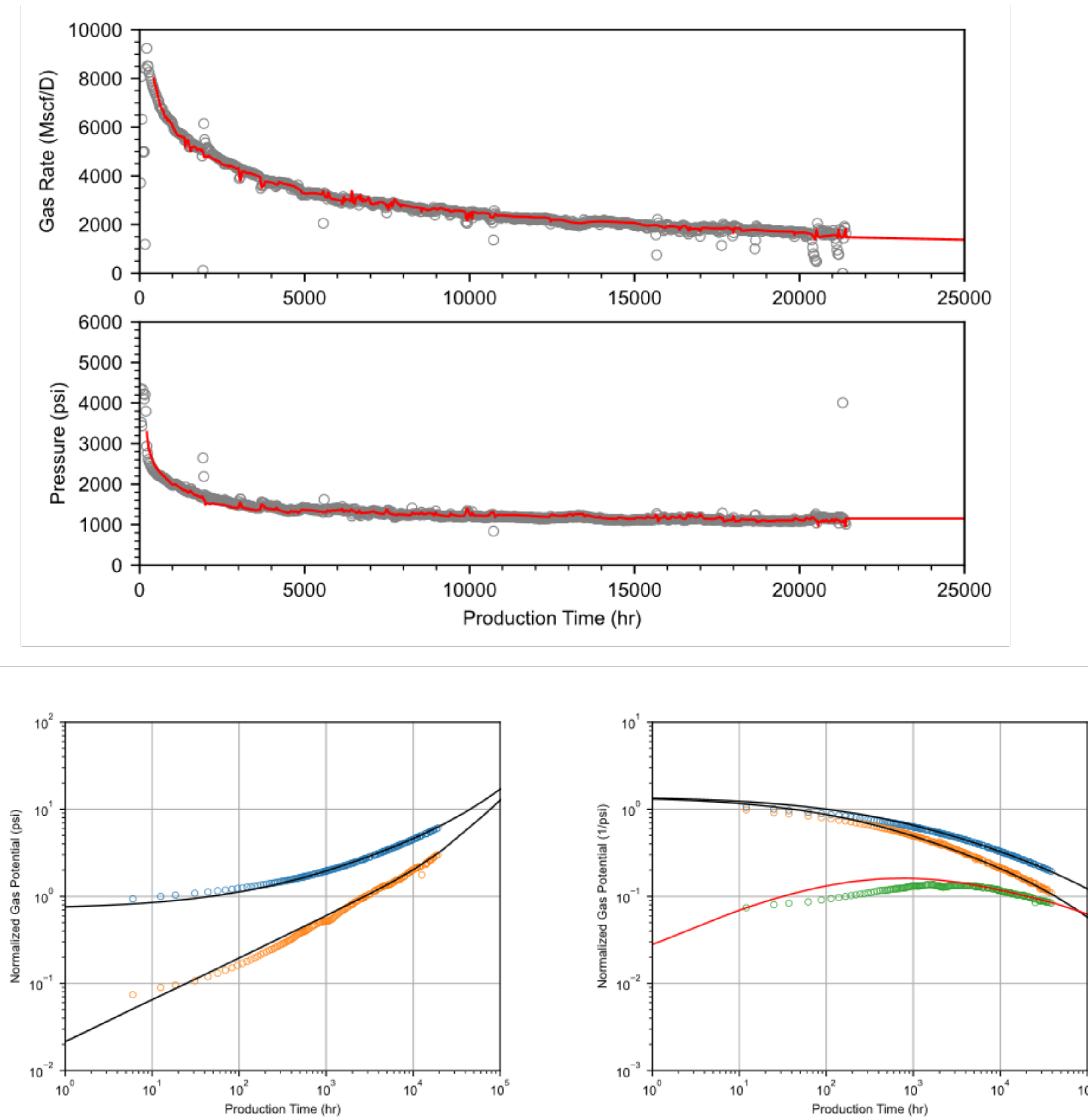


Fig. 10.16—History match with one realization of model parameters. Bottom left plot shows normalized pressure drop data (blue points) and its derivative (orange points). Bottom right plot shows normalized rate data (orange points), normalized rate-integral data (blue points), and derivative of rate-integral data (green points). Solid lines indicate model response.

Once history matches are achieved, production is forecast with various realizations of the model parameters. These forecasts can be achieved deterministically or probabilistically, which should ultimately reflect the uncertainty associated with reserves and resources categories. Low, best, and high case forecasts are achieved for this well using different values for reservoir permeability, as presented in **Fig. 10.17.**

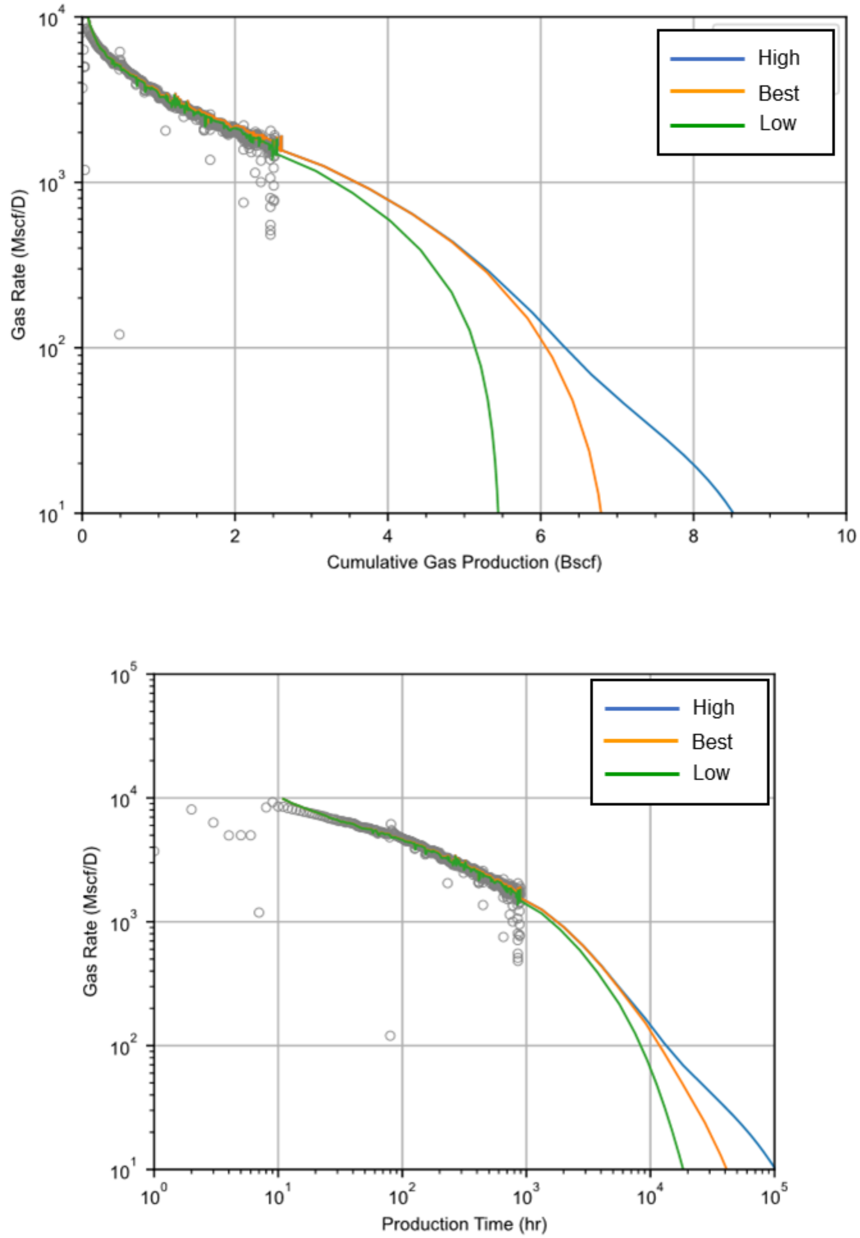


Fig. 10.17—Low, best, and high case production forecasts for selected well.

Finally, model-based forecasts can be extended to the other wells in this well grouping, provided that wells in this group exhibit common characteristics, which are mainly functions of similar completions and, more importantly, similar reservoir and fluid properties. (Correspondingly, this group of wells can be considered as an analog well set.) Extension of forecasts can simply be performed by a process similar to "type curve matching," as illustrated in **Fig. 10.18.** Model responses can be "shifted" on time and rate axes to match the production data of other wells and consequently achieve production forecasts.

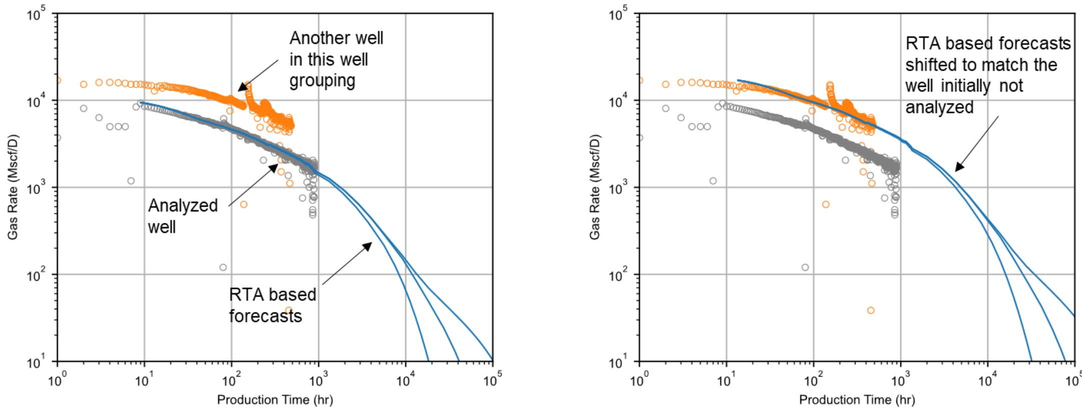


Fig. 10.18—Extension of low, mid, and high case production forecasts for other wells in the well grouping, where RTA is rate-transient analysis.

10.4.6 Estimating Recoverable Quantities in Unconventional Resources. Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly impacted by hydrodynamic influences. Although this definition implies a potentially larger extent of resources in place, performance and productivity can be significantly different across the play, which can greatly affect recoverable quantities. The PRMS (§ 2.4.0.2) indicates that there is a need for increased sampling density to define uncertainty of in-place quantities and variations in reservoir and hydrocarbon quality. Along these lines, extrapolating reservoir presence or productivity beyond control points is not recommended in the absence of technical evidence to support the conclusion. Increased well control/density may demonstrate consistency of well production behavior across an area of interest, thereby bolstering the technical evidence.

As unconventional resource plays are scoped, discovered, and developed, well control and supporting geoscience and engineering data will be acquired and interpreted. As understanding of the play evolves, its maturity of development can be subdivided by phases. Estimation of recoverable quantities in unconventional reservoirs should be conducted within the context of development maturity. For simplicity, the recommended steps in estimating recoverable quantities in unconventional reservoirs can be described as follows:

1. Early phase: This phase consists of a few wells (usually exploratory wells, either vertical or horizontal) with limited production history. This period also may be referred to as the exploration phase. In this phase, more emphasis is placed on data collection and evaluation of uncertainty in reservoir and fluid properties across the area of interest. The following steps are recommended for estimating recoverable quantities:
   a. Evaluate pilot hole well log data.
   b. Evaluate reservoir properties based on core and log data interpretation.
   c. Assess geochemistry of the resource for oil/gas richness and maturation.
   d. Review/evaluate/integrate geology, geophysics, petrophysics, and geomechanics data across area of interest.
   e. Estimate/review in-place quantities.
   f. Establish uncertainty ranges on reservoir/completion parameters for dynamic modeling.
   g. Generate potential production profiles for undeveloped locations using well/reservoir model and/or analog data (based on specific development plan[s]).

Note that approaches based on volumetrics (i.e., recovery factor multiplied by in-place quantities) may not be applicable due to complexities in estimating the influence of well spacing, depletion, completion design, and production operations on production profiles and estimated recoveries from undeveloped areas.

2. Intermediate phase: This phase consists of several wells (on the order of 10 or more), generally with longer-term production histories, but the area of interest is far from fully developed, and completion design and well spacing are yet to be optimized. For this phase, more emphasis is placed on evaluating spatial distribution of reservoir properties and evaluation of potential well completion and field development scenarios. The following steps are recommended for estimating recoverable quantities:
    a. Evaluate reservoir properties based on core and log data interpretation of several key wells.
    b. Assess thermal maturity.
    c. Review/evaluate geology, geophysics, and geomechanics data.
    d. Estimate/review in-place quantities.
    e. Analyze and forecast recoverable quantities for producing wells using model-based analysis (i.e., rate/pressure-transient analysis).
    f. Evaluate potential completion design and sensitivities using model-based approaches and analogs.
    g. Generate potential production profiles for undeveloped locations using well/reservoir model and compare those to analogs.
3. Mature phase: This phase consists of many wells (typically more than 100), most with long-term production histories with established trends, completion design, and well spacing practices. For this phase, generally speaking, the distribution of reservoir productivity is better understood, and most of the efforts are concentrated on performance analysis of existing wells using DCA. Model-based analysis can be performed for select key wells. Statistical methods are generally applicable to assess consistency of well performance and extrapolate reservoir presence and productivity beyond immediate offsets to producing well locations. Statistical methodology commonly used in the industry is presented, for example, in Society of Petroleum Evaluation Engineers (SPEE) Monograph 3 (SPEE 2010). Utilization of the "learning curve" (PRMS § 2.4.0.5) is much more common during this phase. Evaluation steps followed during this period generally consist of the following:
    a. Review reservoir properties based on core and log data interpretation.
    b. Review geology, geophysics, and geomechanics data.
    c. Review in-place volumes.
    d. Generate/review type well areas (i.e., areas with similar well performance and analogous well behavior).
    e. Forecast well performance of producing wells using DCA.
    f. Evaluate potential field development scenarios, completions, and well spacing options,
        i. generally, by using observed (empirical) data, and
        ii. occasionally, by utilizing models.
    g. Generate potential production profiles for undeveloped locations by performance-based analysis results and statistical methods using SPEE Monograph 4 methodology (SPEE 2016).

Table 10.3 summarizes the application of performance-based methodologies at each phase of development maturity.

	Performance-Based Methodology		
Phase of Development Maturity	Diagnostics	Model-Based Analysis	Production Profiles for Undeveloped Locations (Areas)
Early phase	Diagnostics are of limited use.	Use models or analogs to address reservoir and completion uncertainty.	Rely on model results; use distribution of sensitivity analysis results.
Intermediate phase	Full diagnostic interpretation can be performed on some wells.	Rate-transient analysis (model-based analysis) is primary method of analysis.	Production profiles are generated using rate-transient analysis.
Mature phase	Full diagnostic interpretation can be performed on all (or majority) of wells.	DCA is primary method (rate-transient analysis can be used for select wells).	Statistical methods (SPEE Monograph 3; SPEE 2010) are used in consideration of depositional environment.

Table 10.3—Performance-based methodologies by development phase of maturity.

Assignment of resources and classification of undeveloped locations require interpretation of productivity beyond existing location(s) and assessment of the corresponding uncertainty. Various techniques and combinations of methodologies, which have been field tested and demonstrated to provide results with high confidence, can be utilized to interpret reservoir productivity and justify assigning resources categories to undeveloped locations beyond direct offsets.

Fig. 10.19 illustrates examples for the assignment of resources and classification of undeveloped locations in unconventional resource plays assuming horizontal well development. It is noted that this example considers the "deterministic incremental method"; however, results from other methods such as the "deterministic scenario," "geostatistical," or "probabilistic" methods should yield similar remaining recoverable quantities for the area of interest. In the example below, classification and assignment are implied as a function of development phase.

Multiple scenarios are illustrated, and it is worth mentioning that there is no clear rule or procedure for the number of locations and distance from existing producers to be considered.

Put simply, this task is based mainly on documented evidence of the consistency of well performance, interpretation of reservoir productivity, and availability of critical data, and the evaluator's confidence in associating these with the appropriate uncertainty. It is also worth mentioning that increasing consistency in well performance, corroborated by supporting multiple data sources, and better understanding of the distribution of reservoir properties throughout the development area could allow for resources assignment to incremental locations at greater distances beyond producing locations, such as the Proved Undeveloped location in the upper-right corner of the Mature Phase stage.

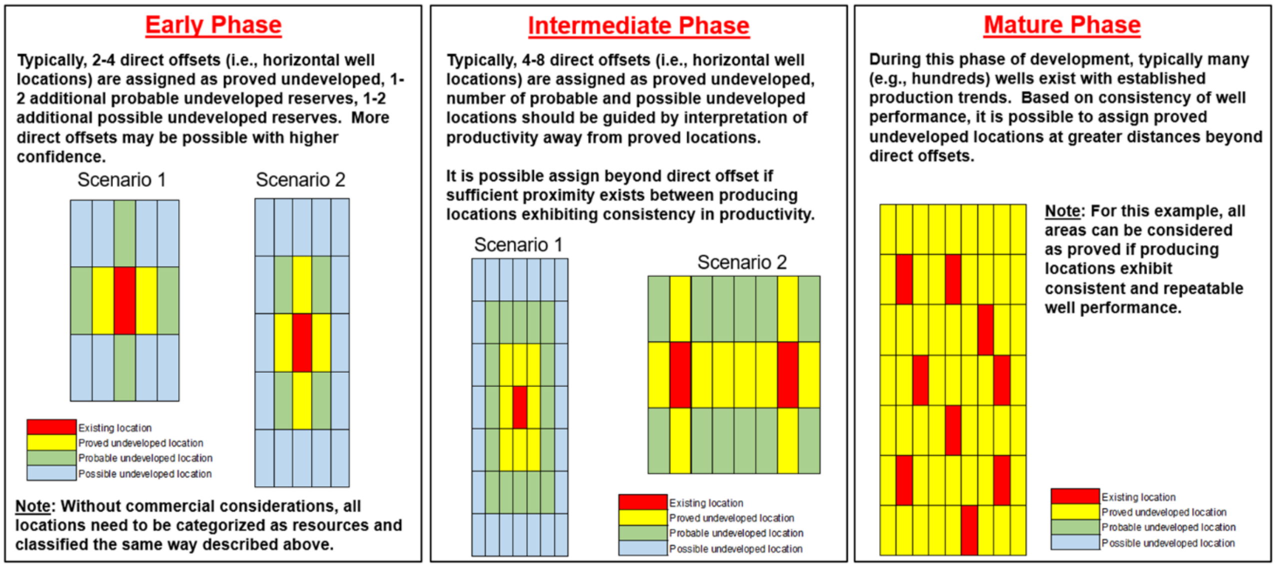


Fig. 10.19—An example illustration of assigning resources to undeveloped locations in the deterministic incremental approach.

Christopher R. Clarkson

10.5 Coalbed Methane

10.5.1 Introduction. The term "coalbed methane" (CBM) refers to natural gas hosted in coal. Coal, in turn, is defined as a "readily combustible rock containing more than 50% by weight and more than 70% by volume of carbonaceous material formed from compaction and induration of variously altered plant remains similar to those in peaty deposits" (Schopf 1956). While gas produced from coal tends to be "dry," often consisting primarily of low-molecular-weight hydrocarbons, with methane being the dominant hydrocarbon component, other non-hydrocarbon components such as carbon dioxide may occur in significant amounts.

Referring to the definition of unconventional reservoirs provided in Table 10.1, coal qualifies as unconventional because it commonly serves as both the source rock and the reservoir for its gas, with much of the gas generated from biogenic or thermogenic processes retained in the coal in the adsorbed state, CBM generally occurs as a continuous, laterally extensive accumulation, and special extraction methods may be required to achieve commercial levels of production. A further component often attributed to unconventional reservoirs (although not applicable to all unconventional reservoirs) is low matrix permeability (often <<0.1 md, although system permeability, which includes natural fractures, may be much higher than this). The high organic matter content of coal is responsible for many of the unique reservoir properties of coal, which are elaborated upon below.

10.5.2 CBM Reservoir Characteristics. Some reservoir characteristics (fluid storage and flow) unique to two-phase (gas + water) CBM reservoirs are illustrated in **Fig. 10.20.** These characteristics include gas storage dominated by adsorption (top left), existence of saturated or undersaturated conditions (top right), gas flow via diffusion in the coal matrix, providing a source to natural fractures through which both gas and water flow to the well (bottom left), and the possibility of gas effective permeability increases due to relative permeability and absolute permeability growth during depletion (bottom right).

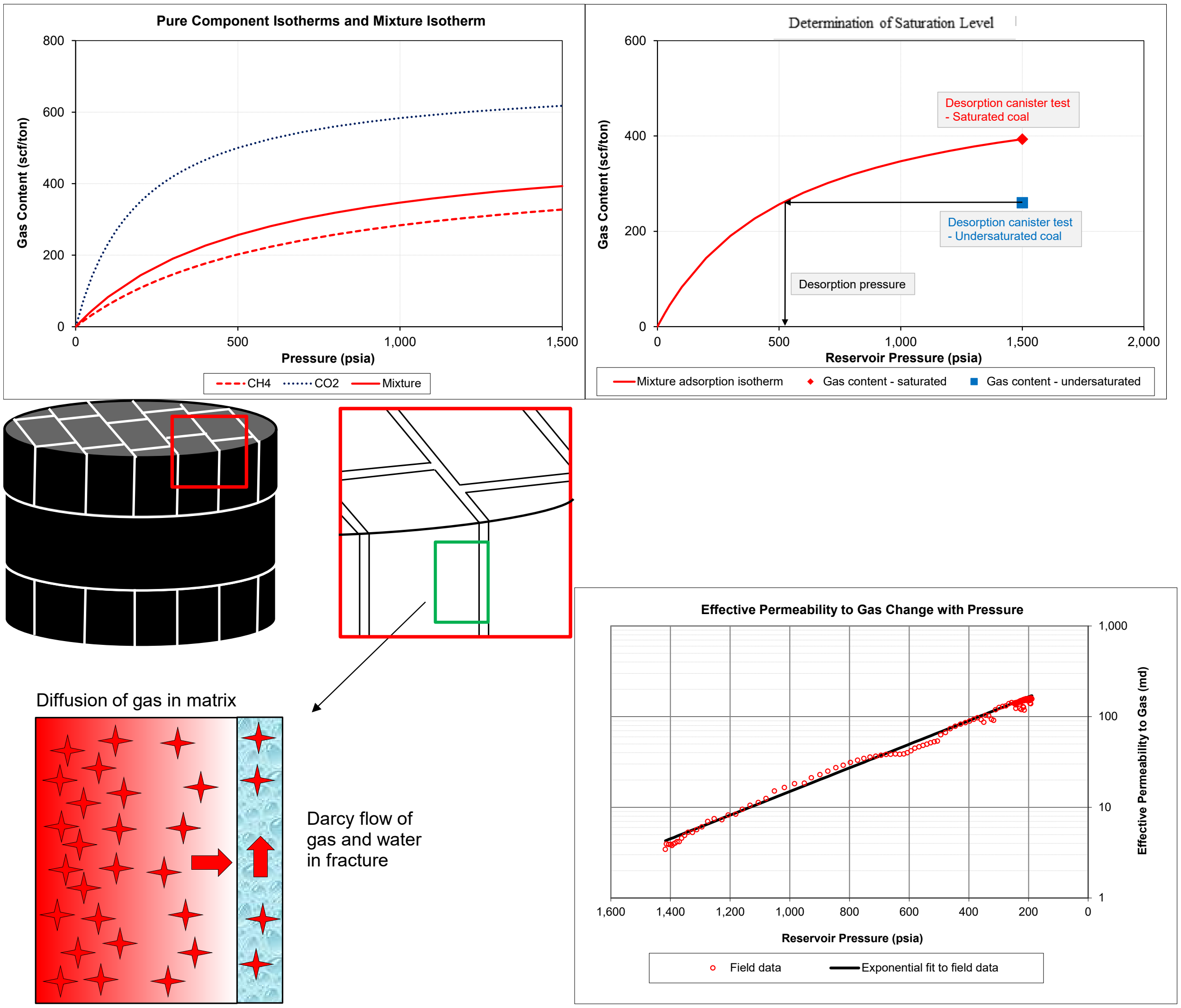


Fig. 10.20—Some reservoir characteristics unique to two-phase coal reservoirs. (Top left) Gas storage due to adsorption, modified from Clarkson (2021). (Top right) Undersaturated vs. saturated coals, modified from Clarkson (2021). (Bottom left) Single-phase flow (diffusion) of gas through matrix and two-phase flow of gas and water through the fracture system, modified from Clarkson (2018), after Clarkson and Bustin (2011). (Bottom right) Effective permeability to gas growth due to changes in relative permeability and absolute permeability (matrix shrinkage), modified from Salmachi et al. (2018), after Clarkson et al. (2007b).

10.5.2.1 Gas Storage Mechanisms. A variety of gas storage mechanisms may occur in coal (Clarkson 2018, 2021), including:

- Adsorption onto the internal surface area of organic matter (within micro-/mesoporosity)
- Free-gas storage in matrix organic and inorganic matter porosity (within meso-/macroporosity)
- Free-gas storage in fractures (microfractures, larger-scale natural fractures)
- Solution gas storage (absorption) in entrained fluids (i.e., water, residual oil)
- Solution gas storage (absorption) in organic matter

A commonly used pore size classification system for coal is the International Union of Pure and Applied Chemistry (IUPAC) system (Thommes et al. 2015), in which micropores are classified as pores <2 nm in diameter, mesopores are pores between 2 and 50 nm in diameter, and macropores are pores >50 nm in diameter.

In high-thermal-maturity (rank) coals, the pore structure in the organic matter tends to be dominated by microporosity (pores <2 nm in size), which results in a large internal surface area, causing adsorption (mechanism 1) to be the dominant means of storage. However, as noted by Clarkson (2018), the relative importance of the five storage mechanisms listed above is a function of coal properties (organic matter content of the coal, its composition and thermal maturity) and pressure-temperature and hydrodynamic conditions, amongst other factors. Normally, free gas is negligible compared to adsorbed gas storage and is usually ignored in CBM reservoirs because of low fracture pore volumes and high water saturations. The exception is for some dry CBM reservoirs, in which free-gas storage may be more significant (Bustin and Clarkson 1999; Bustin and Bustin 2009, 2011). Gas in solution in pore fluids is also usually ignored. Absorption of gas in organic matter could be significant, particularly for CO_2, but this is often not distinguished from the adsorbed gas contribution in adsorption isotherm experiments.

Adsorption isotherms, used to quantify adsorbed gas storage as a function of pressure at a fixed temperature, are measured in the laboratory using well-known methods (McLennan et al. 1995; Mavor and Nelson 1997; Seidle 2011; Clarkson 2018) in order to quantify adsorption of the dominant components of the coal gas (CH_4 and CO_2 are depicted in Fig. 10.20, top left). However, because coal gas is usually composed of gas mixtures (not just methane), the adsorption of this mixture must either be measured in the laboratory or predicted using multicomponent adsorption models (Clarkson 2018). The most popular adsorption model for correlating laboratory adsorption data in the petroleum engineering literature is the Langmuir model (for single- and multicomponent adsorption).

While adsorption isotherm measurements and adsorption modeling are sufficient for quantifying gas content of "saturated" coals, the in-situ gas content of the coal under the conditions of "undersaturation" is less than that estimated with an adsorption isotherm at the initial reservoir pressure of the coal (Fig. 10.20, top right). Practically, this means that a coal seam will need to be dewatered until the pressure reaches the desorption pressure, after which gas will flow along with water to the well. In order to evaluate the state (saturated vs. undersaturated) in which the coal is in prior to production, conventionally, a combination of "direct" (adsorption isotherm measurement) and "indirect" (gas desorption canister testing) methods is used, and the results are compared to ascertain the saturation level (Seidle 2011; Clarkson 2018).

As noted above, the gas storage mechanisms in coal are a function of coal properties, pressure-temperature, and hydrodynamic conditions of the coal reservoir. Adsorption in coal is similarly affected by coal properties and in-situ conditions; for example, adsorption is known to be a function of the amount/thermal maturity/composition of the organic matter. A goal of a coal reservoir characterization program, as it pertains to gas-in-place estimation, should be to establish the primary controls on gas content in the laboratory and then use the resulting correlations to predict gas content variability in the field. There are, for example, well-established procedures (e.g., Mavor and Nelson 1997) for estimating coal gas content using bulk density logs (combined with laboratory data), allowing in-situ gas content to be estimated for noncored intervals in a well.

The unique gas storage properties of coal (e.g., adsorption, saturation level, etc.) need to be accounted for not only in gas-in-place calculations, but also in material balance calculations, and in models used for rate-transient analysis (RTA) and reservoir simulation, as discussed in Section 10.5.4.

10.5.2.2 Gas- and Water-Flow Mechanisms. The simple conceptual model shown in Fig. 10.20 (bottom left) is often used to illustrate gas and water flow through coal. It is commonly assumed that coal is a dual-porosity medium (fractures and rock matrix) with a regular, orthogonal set of macroscale natural fractures (cleats).

When coals are initially saturated, and the pressure is dropped in the natural fracture system during initial production, gas and water will flow through the cleats to the well. Transport of gas and water is commonly modeled using Darcy's law altered to account for relative permeability changes caused by dewatering (reduction of water saturation in the cleats). If the coals are initially undersaturated, dewatering of the fractures (with water flow through the fractures also modeled using Darcy's law) must occur in order to reach desorption pressure, after which gas flows from the matrix to the fractures as in the saturated coal case. It is commonly assumed that only single-phase flow of gas occurs through the coal matrix, and that the dominant gas transport mechanism in the matrix is diffusion (Mavor 1996). Various methods have been proposed for handling matrix transport in simulation, including: equilibrium formulations, which ignore matrix transport and assume desorption is instantaneous; pseudosteady-state formulations, which assume that there is no concentration gradient in the matrix, but that the average concentration changes at each timestep; and unsteady-state formulations, which account for concentration gradients. In several commercial CBM plays, such as the prolific Fruitland Coal Fairway in the San Juan Basin of Colorado/New Mexico, the fracture/cleat spacing is typically quite small, and desorption can be assumed to be instantaneous because of the small matrix block size. However, in lower-permeability coal reservoirs, where fracture spacing is wider, the latter two formulations may be more appropriate.

A truly remarkable aspect of coal that can potentially affect long-term production characteristics of CBM is the dynamic nature of the fracture system (cleats) during production. While it is well known that fractured rock typically exhibits stress sensitivity (i.e., fracture absolute permeability decreases as a function of the increase in effective stress during depletion), in some commercial CBM plays (e.g., the aforementioned Fruitland Coal Fairway, and the Bandana Formation coals in Australia), fracture absolute permeability may actually increase with depletion. This latter phenomenon, referred to as "matrix shrinkage" **(Fig. 10.21),** is caused by desorption of gas from the matrix blocks, which in turn causes the matrix blocks to shrink volumetrically. This in turn causes the fracture apertures between matrix blocks to dilate. In some two-phase field cases, it may therefore be possible for effective permeability to gas to grow with depletion due to a combination of relative permeability to gas increasing and/or absolute permeability growth due to matrix shrinkage. An example is shown in Fig. 10.20 (bottom right) from a Fruitland Coal Fairway well. In this case, the early time (pressures >600 psi) effective permeability growth is likely dominated by relative permeability increases, whereas late time increases (after the coal has been dewatered) are attributable to matrix shrinkage (Clarkson 2018). There are several analytical models now available that can account for the combined effects of compaction, acting to close fractures, and desorption-dependent permeability (matrix shrinkage), acting to dilate fractures. For example, the Palmer-Higgs model, which extended the original Palmer-Mansoori model for the case of vertically cleated coals exhibiting transversely isotropic elastic behavior, is one such model that has been applied to field data (Moore et al. 2015; Clarkson 2021).

Fractures may also affect long-term production characteristics by causing multilayer behavior (differential depletion between coal layers) and permeability anisotropy. The effect from multilayer behavior occurs because fracture density may vary from coal seam to coal seam (as depicted in Fig. 10.20, bottom left) (Clarkson 2018, 2021). In addition, permeability anisotropy is caused by permeability being different in the directions of the two major fracture systems (the more continuous "face cleat" and less continuous "butt cleat").

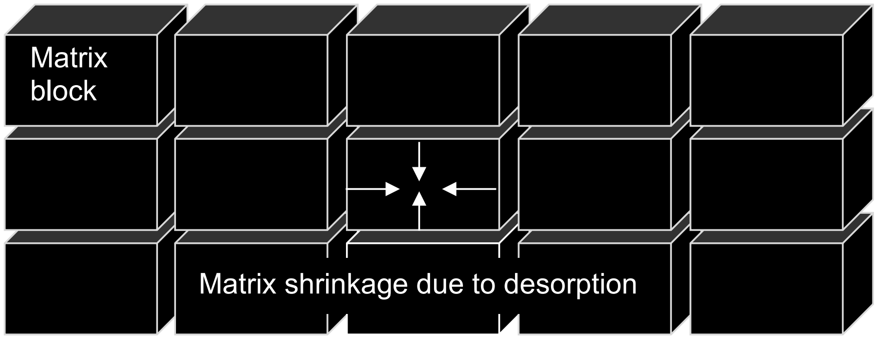


Fig. 10.21—Illustration of the concept of matrix shrinkage caused by fracture absolute permeability increases (due to fracture aperture dilation), modified from Clarkson et al. (2010).

A more thorough discussion of gas storage and gas/water transport mechanisms can be found in various CBM summary papers, book chapters, and books published in the past decade (e.g., Clarkson and Bustin 2011; Seidle 2011; Clarkson 2018, 2021). In these works, laboratory and field techniques used to evaluate coal properties are also reviewed. As with shale gas and oil reservoirs discussed in Section 10.3.2, the complexity of CBM reservoirs necessitates that a comprehensive characterization program (analogous to Table 10.2) be developed to assist with field development optimization.

Because of the unique storage and transport mechanisms associated with CBM reservoirs, CBM wells can exhibit unusual production profiles. The production characteristics of a CBM well exhibiting two-phase flow are illustrated using an example from the Fruitland Coal Fairway **(Fig. 10.22).**

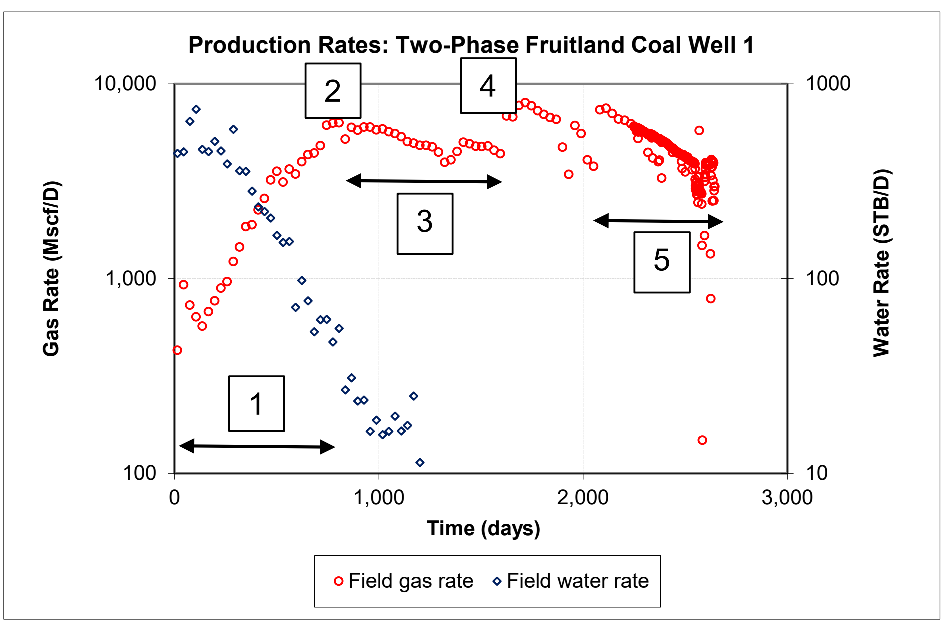


Fig. 10.22—Production profile of a two-phase CBM well (Fruitland Coal Well 1) in the San Juan Basin, Colorado/New Mexico. The numbered "periods" of well production are discussed in the text. Note that monthly production rates for gas are provided until ~2,300 days, after which daily production rates are shown. Figure is modified from Clarkson et al. (2007b).

During period 1 in Fig. 10.22, the well is dewatering, and gas production increases primarily due to increasing effective permeability to gas and decreasing flowing pressures (see Fig. 10.26 for flowing pressure profile for this well). Period 1 is referred to as the "negative decline" period, during which conventional (positive) decline curve methods cannot be applied. After a first peak in production (period 2), the well enters a normal (positive) decline period (period 3). For this example, conventional DCA cannot be performed until several months after peak production is reached (>1,000 days after first production in this example). Due to a combination of well restimulation, wellhead compression installation/upgrades, and surface infrastructure optimization, the well reaches a second peak in production (period 4), after which a second normal decline period is entered (period 5). Clearly, conventional approaches for forecasting wells, such as DCA, are challenged by such complex production characteristics. For this well, a combination of material balance analysis and reservoir simulation was required to provide confident reserves estimates during the first several years of production. Analogous to the discussion in Section 10.4.6 regarding development maturity (early phase–intermediate phase–mature phase), the reserves assessment methods applied to this single well evolved over its production history from material balance and model-based approaches earlier in the well life to DCA methods after a clear decline trend was established (see Section 10.5.4).

In areas outside of the Fruitland Coal Fairway, wells may exhibit very different production characteristics. For example, the dry coal well in **Fig. 10.23** (which exhibits negligible water production) is located only a few miles from the Fruitland Coal Fairway, where wells have production characteristics more similar to that shown in Fig. 10.22. This kind of variability in production characteristics, even in the same basin, makes selection of analogs to support exploration activities quite challenging. Dry coal wells also exist in the Horseshoe Canyon play in Alberta, Canada, and they exhibit a more conventional decline profile, analogous to shallow gas wells.

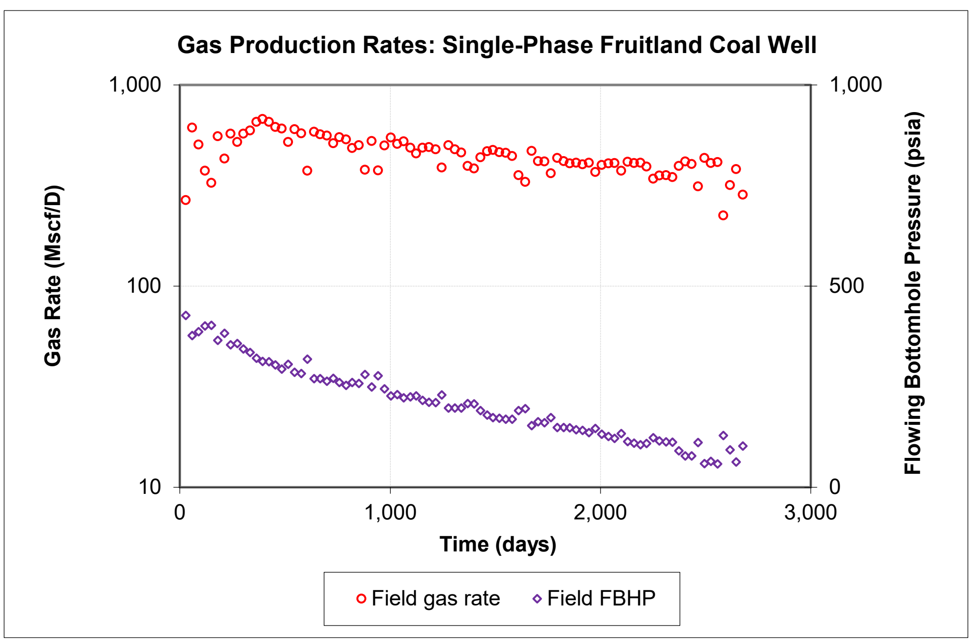


Fig. 10.23—Production profile for single-phase (gas) CBM well in the San Juan Basin. This well is located outside the Fruitland Coal Fairway, where production profiles are similar to that shown in Fig. 10.22. Figure is modified from Clarkson et al. (2007a), where FBHP is flowing bottomhole pressure.

10.5.3 Drilling and Completions. Unlike shale reservoirs, where the primary drilling/completion method used for exploitation is a horizontal well hydraulically fractured in multiple stages (multifractured horizontal wells) (Section 10.3.3), CBM reservoirs have been developed with a wide variety of well architectures, completion methods, and stimulation treatments. The primary criteria used in selection of the drilling/completion method for coal is system permeability, which is highly variable from basin-to-basin and field-to-field, and which is a function of drilling depth and degree of natural fracturing, among other factors. In a comprehensive study by Palmer (2010), the importance of permeability for CBM completion selection was outlined. He detailed the typical completion methods used for various ranges of system permeability, including <3 md ("tight coal completions"), 3–20 md ("low-permeability completions"), 20–100 md ("high-permeability completions"), and >100 md ("ultrahigh-permeability completions"). Although these permeability limits for the different completion styles are somewhat subjective, it is useful to use permeability as a framework for completions decisions. The reader is referred to Palmer's work for the typical completion methods in each of these ranges.

10.5.4 Evaluation Methods for Reserves/Resource Estimation. Consistent with the discussion in Section 10.4.6 for tight/shale reservoirs, methods applied for reserves and resources estimation for CBM wells will vary according to development phase. In addition, as noted in Section 10.5.2 for two-phase CBM wells, the evaluation methodology depends on the period observed in the well's life cycle (Fig. 10.22). Therefore, in the following, reserves/resources evaluation methods for CBM are discussed in the context of the phase of exploration/development (early/intermediate/mature) that is occurring, as well as the period of the well life that is being observed.

10.5.4.1 Early Phase (Development and Well Life). As noted in Section 10.4.6, during this phase of development, an emphasis is placed on data collection and evaluating uncertainties. As such, any forecasting performed should be stochastically based to properly represent the uncertainty. The evaluation methods discussed in this section for this phase apply to exploration activities in a CBM prospect prior to exploration well completion and production/evaluation, but after core and log data collection in the exploration wells, and other wells penetrating the targeted coals, has enabled resource mapping to be performed (coal thickness, density, gas content, gas-in-place) and the prospect(s) to be defined.

The variability of key CBM reservoir properties from basin-to-basin and even field-to-field necessitates a stochastic approach to CBM exploration. Failure to reach economic CBM production is often related to lack of permeability, resulting in subeconomic rates.

Because CBM plays are often characterized as continuous accumulations, it is recommended that CBM prospects be broken up into cells, the sum of which equals the total resource evaluated, as recommended by Haskett and Brown (2005), Schmoker and Klett (1999), and Schmoker (2002). The cell size nominally would be assigned to be a typical well drainage area. Following Haskett and Brown (2005, p. 3), it is also recommended that CBM resource assessment be "run from exploration through the pilot phase, appraisal, development and production" and that a "full value chain" assessment be performed, including multiple decision points.

For CBM exploration and appraisal, a key step is the design of the pilot program (Roadifer and Moore 2009). Uncertainties associated with production forecasting include relative permeability, absolute permeability, and the effect of stress and desorption on permeability during depletion, permeability anisotropy, and multilayer effects (Section 10.5.2). It is for these reasons that pilot projects are needed particularly for undersaturated coal reservoirs, where interior wells are bounded by exterior wells to accelerate dewatering. The interior wells need to achieve significant (economic) gas rates, and effective permeability to gas must be established before reserves bookings can be contemplated. The pilot projects need to be designed to reduce the uncertainty in key reservoir parameters and to test various completion/drilling technologies to determine those that are most cost-effective.

An example approach for CBM prospect evaluation in a low-permeability, slightly undersaturated, two-phase CBM reservoir was provided by Clarkson and McGovern (2005) and is illustrated in **Fig. 10.24.** The various components of the modeling approach were summarized in that work and by Clarkson (2018). After preliminary resource (multiple layers) mapping (Fig. 10.24, top left), "pods" (areas of relatively uniform gas-in-place and apparent reservoir quality) are selected for further evaluation. A key factor in the assessment of each pod in the prospect is the stochastic modeling of a "type" well assigned to each pod using a single-well, multilayer (including coal and noncoal layers, if necessary), analytical simulator coupled to Monte Carlo simulation. At each Monte Carlo iteration, key uncertain parameters (permeability, degree of undersaturation, etc.) are selected from input distributions, and type-well gas and water forecasts are generated (Fig. 10.24, top right). A decision tree is used at each Monte Carlo iteration to advance the prospect analysis (Fig. 10.24, bottom): At decision node 1, the success or failure of the exploration well (E well) representing the pod is decided, based on well deliverability (for undersaturated coal wells, water cumulative production is used as a proxy); at decision node 2, the success or failure of the pilot project (here, the default pilot project is a five-spot well pattern designed to accelerate dewatering of a central, bounded well) is dependent on type-well economics; at decision node 3, the ideal spacing of the development wells is selected based on desired well interference time. For the latter, at each iteration, the time to reach boundary-dominated flow for various spacings is calculated; this is compared to the input desired well interference time, and the optimal spacing to accelerate dewatering is decided upon. An economics module is used to provide both single development well (D well) economics and full-cycle (exploration + development) economics. See Clarkson and McGovern (2005) for further description of the method and an example application.

This method incorporates the components of unconventional reservoir exploration recommended by Haskett and Brown (2005), including cell-based resource evaluation, use of pilot projects, generation of a distribution of well forecasts using a model that honors model input uncertainty (and captures the unique production characteristics of undersaturated/saturated two-phase CBM wells), and a full value chain assessment. In principle, the same approach can be used if horizontal wells are required for resource development using analytical modeling approaches suggested by Clarkson (2018, 2021).

While the above example demonstrates the utility of stochastic CBM well forecasting for CBM prospect evaluation, stochastic modeling may also be required for predicting well performance in undeveloped areas, or for early D-well forecasting after some initial production is available. For example, during the early dewatering phase (Fig. 10.22, period 1), when gas production is still increasing, the peak production rate and timing and the postpeak decline characteristics are still unknown; stochastic modeling can be used at this stage to predict a range of outcomes for the well.

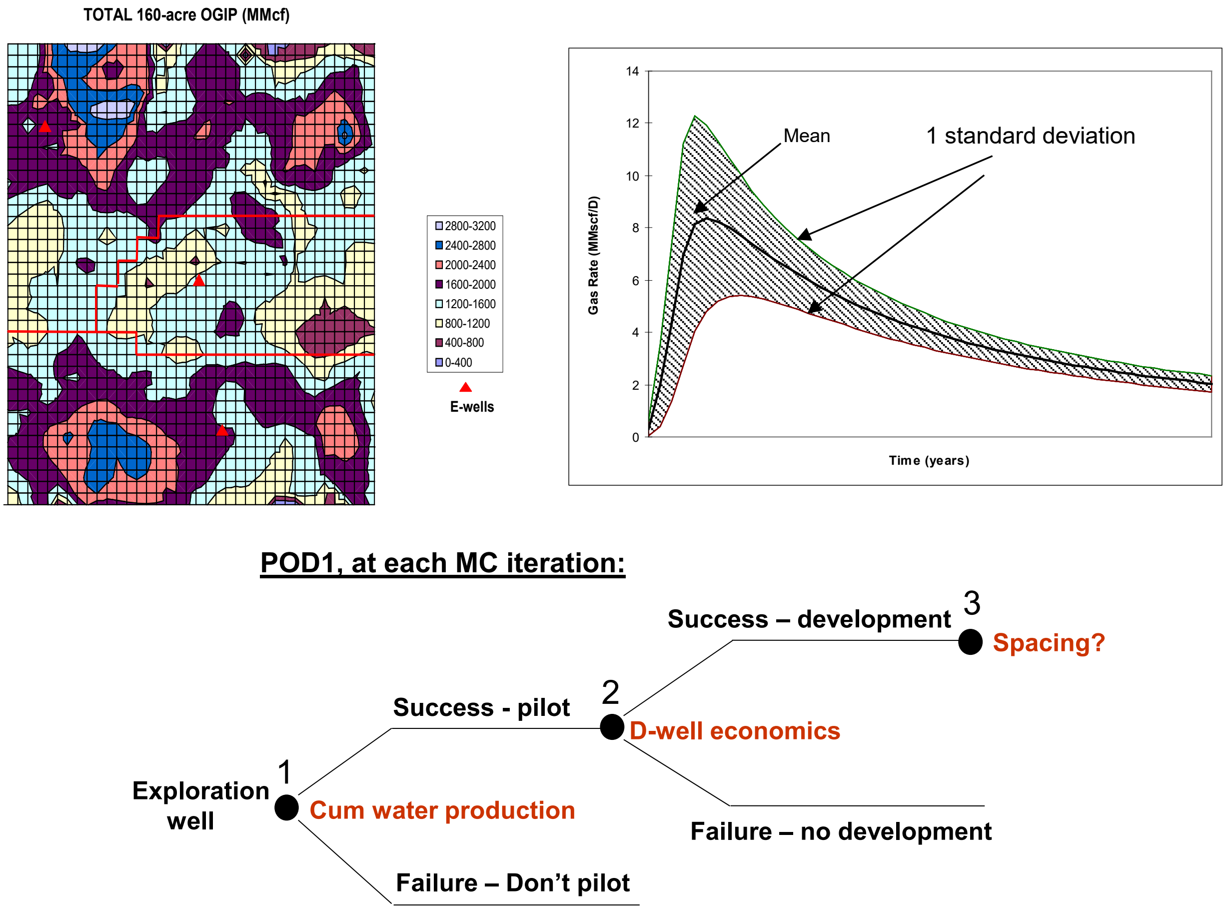


Fig. 10.24—Components of the CBM prospect analysis tool developed by Clarkson and McGovern (2005), modified from Clarkson (2018). See text for description of each component (where OGIP is original gas in place, MC is Monte Carlo method, and Cum is cumulative).

10.5.4.2 Intermediate Phase (Development and Well Life). As noted in Section 10.4.6, during this phase of development for tight/shale reservoirs, model-based approaches are most commonly applied. This is also true for CBM reservoirs, although material balance methods are also commonly used, depending on the availability of shut-in pressure data.

The example two-phase CBM well in Fig. 10.22 was drilled during the first wave of development in the Fruitland Coal Fairway before infill drilling, but it was one of several hundred wells drilled in the field over a short period of time; therefore, it could be classified as an intermediate or mature development phase well according to the criteria provided in Section 10.4.6. However, it serves to illustrate application of evaluation methodologies that can be applied during intermediate stages of well life. Again referring to Fig. 10.22, after the early dewatering period (period 1), material balance and model-based (RTA and numerical simulation) methods can be used to assess reserves for this and analogous wells. Application of these methods is described briefly below. Although deterministic methods are illustrated, stochastic approaches can also be used for RTA and model history matching and forecasting. Importantly, consistency between the parameters (such as OGIP) obtained from the various methods is sought in order to gain confidence in the analysis. In order to achieve this consistency, it is recommended to follow the RTA workflow outlined by Clarkson (2013); Clarkson (2021) also includes discussion of development of RTA methods specifically for CBM wells.

Of the unconventional reservoir types discussed in this chapter, (static) material balance methods are more commonly used in CBM reservoirs because of the relatively high system permeabilities of several of the commercial CBM plays in the US, Canada, and Australia. High permeability is required to achieve estimates of reservoir pressure during well shut-ins in a short period of time. There have been a number of material balance equations (MBEs) developed specifically for CBM reservoirs, including those by King (1993), Jensen and Smith (1997), Seidle (1999), Clarkson and McGovern (2001), Ahmed et al. (2006), Firanda (2011), and Thararoop et al. (2015), amongst others. All CBM MBEs at a minimum account for gas desorption, but they vary in their ability to account for free-gas storage, and additional drive mechanisms. **Fig. 10.25** provides a demonstration of the application of the MBE presented by Jensen and Smith (1997) to the two-phase CBM well in Fig. 10.22. A pressure observation well (POW) located near the producing well (at an equivalent 160-acre spacing) was used to estimate reservoir pressures for MBE calculations in Fig. 10.25. The producing well was also shut-in periodically throughout its history, resulting in reservoir pressure estimates very consistent with the POW pressures measured during the same time frame. A straightline fit to the Jensen and Smith MBE plot, which is a plot of the material balance pressure function ($\frac{p}{p+p_L}$, where p_L is Langmuir pressure from the adsorption isotherm, and p is the estimated reservoir pressure) vs. cumulative production, results in an OGIP estimate of 17.9 bscf. Given an abandonment pressure assumption/calculation, the estimated ultimate recovery for the well can be calculated.

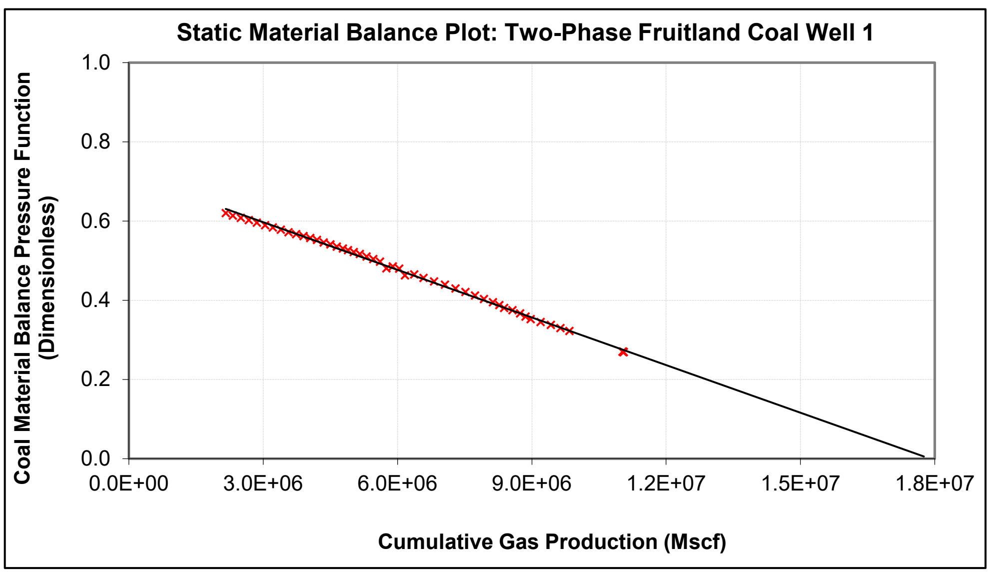


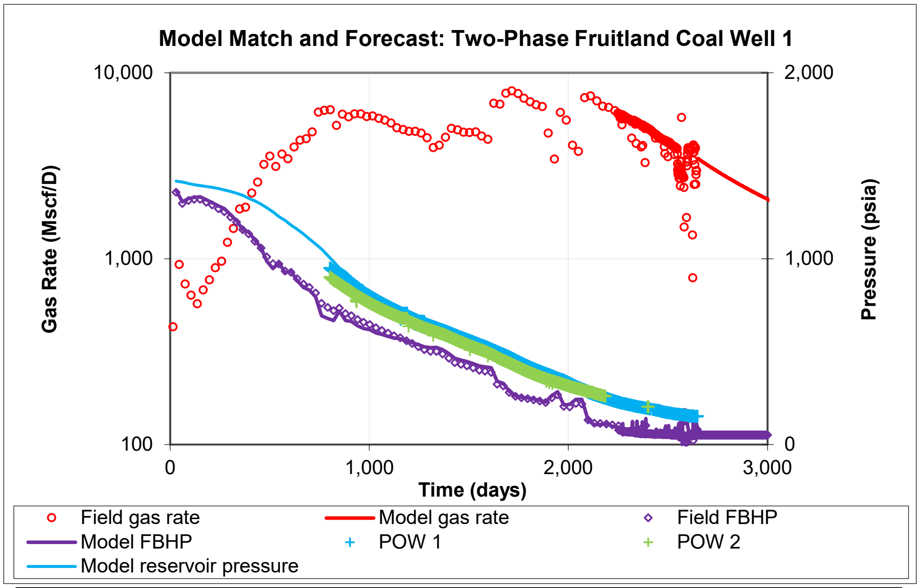
Fig. 10.25—Use of the Jensen and Smith CBM MBE for estimating OGIP for the two-phase Fruitland Coal Well 1 in Fig. 10.22, modified from Clarkson (2021). Reservoir pressures corresponding to the data points were estimated from an offset pressure observation well (POW).

Model-based methods that have been applied to two-phase CBM reservoirs include RTA (straightline methods, type-well profiles) and analytical/semi-analytical/numerical modeling (for history matching and forecasting). These models need to account for the unique CBM reservoir properties described in Section 10.5.2, including desorption, nonstatic fracture permeability, etc. Application of analytical model history matching/forecasting to Fruitland Coal Well 1 is shown in

Fig. 10.26 (top). In order to achieve the history match, gas rates were input, and the well flowing bottomhole pressures and offset POW pressures were matched; Clarkson (2021) also showed a match to this well using flowing pressures as input (gas and water rates were matched in that case). The pressure-dependent effective permeability trend shown in Fig. 10.22 (bottom right) was required to achieve the match; details of the model matching of this well were provided by Clarkson (Clarkson et al. 2007b; Clarkson and Bustin 2011; Salmachi et al. 2018; Clarkson 2021). A forecast was then generated for the well assuming a constant flowing bottomhole pressure. The modeled gas-in-place estimate is 18.1 Bscf, which is in good agreement with the static MBE analysis (Fig. 10.25). Fig. 10.26 (bottom) also shows a flowing material balance (FMB) analysis (a straightline RTA method) of the same well. The version of the FMB equation used in this plot was modified from Agarwal et al. (1999) by Clarkson (Clarkson et al. 2008; Clarkson 2021) to account for changes in effective permeability to gas and desorption. The pressure-dependent effective permeability trend shown in Fig. 10.20 (bottom right) was used in the plot. The OGIP obtained from the intercept of the plot (~18.1 MMscf) is in good agreement with model history matching and static material balance analysis.

A second example of the application of model-based methods is provided for the single-phase Fruitland (non-Fairway) coal well (Fig. 10.23) in **Fig. 10.27.** No flowing pressure data were available for this well for the first 21 months of its life; therefore, calculated sandface pressures from a simulation history match discussed by Clarkson and McGovern (2005) were used in the analysis. No shut-in pressure data were available for this well, so static material balance analysis could not be performed. Unlike Fruitland Coal Fairway wells (such as that analyzed in Fig. 10.26), which typically do not exhibit evidence of transient flow, non-Fairway wells tend to have lower permeability and may exhibit periods of transient flow. Therefore, prior to undertaking the analysis, flow-regime identification was performed to determine the flow regimes that were occurring for this well (Fig. 10.27, top left). For this purpose, a log-log plot of rate-normalized pseudopressure difference (RNP_{pg}) and its semilog (radial) derivative (RNP'_{pg_R}) vs. desorption-corrected material balance pseudotime (for a discussion of this flow-regime identification method for coal, see Clarkson 2021) was used; the appearance of a +1 (unit) slope on the plot suggests that the well is primarily in the boundary-dominated flow regime. With this interpretation, a flowing material balance plot (used to analyze boundary-dominated flow) was applied to estimate OGIP (Fig. 10.27, top right).

Unlike the FMB analysis in Fig. 10.26, a static effective permeability to gas was assumed, but gas desorption was accounted for in the calculations. For this well, OGIP is estimated to be approximately 2,960 MMscf from the x-axis intercept of the plot. Type-curve analysis (Fig. 10.27, bottom left) was performed using the Fetkovich type curves (Fetkovich 1980) and the methods of Clarkson (2013, 2021) for CBM. Note that material balance pseudotime (corrected for desorption) is used in the analysis; this causes the depletion data to follow the $b = 1$ stem because material balance pseudotime converts the data to an equivalent constant-rate case for liquids (which was demonstrated by Palacio and Blasingame 1993). Use of real time results in $b < 1$. Because transient flow is not evident, the Fetkovich type-curve match cannot be used to obtain a unique estimate of permeability and skin; however, as pointed out by Clarkson et al. (2007a), the well is not hydraulically fractured, and therefore large values of dimensionless outer boundary radius (r_{eD}) (5,000 and 10,000) can be selected for the transient stem matching, resulting in permeability and skin estimates of 9.8 md/−0.2 (r_{eD} = 5,000 stems) and 10.7 md/0.5 (r_{eD} = 10,000 stems).



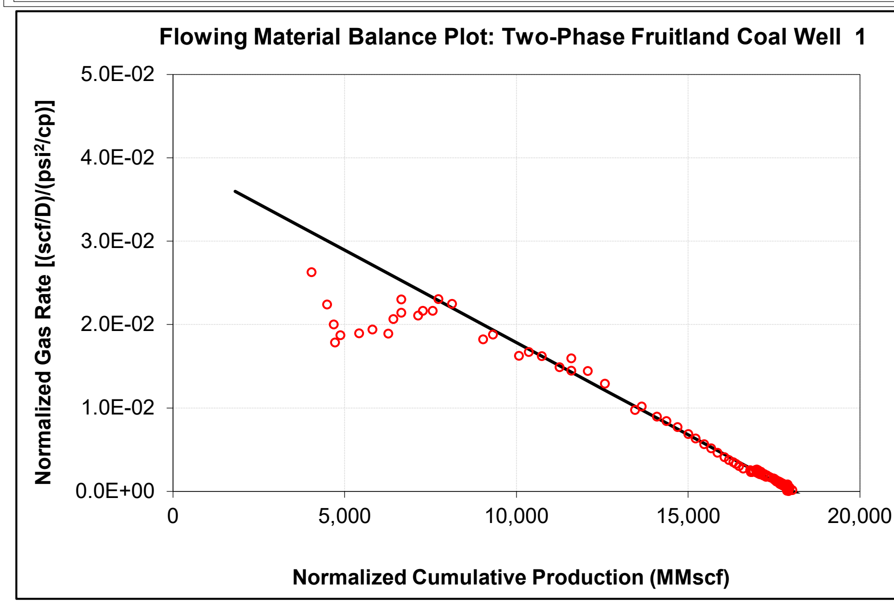


Fig. 10.26—Use of model-based methods to analyze the two-phase Fruitland Coal Well 1 in Fig. 10.22. (Top) Analytical model history match of flowing pressures and offset pressure observation well (POW) pressures, and forecast at constant flowing bottomhole pressure (FBHP). (Bottom) Flowing material balance analysis; the FMB equation was altered to include changes in effective permeability to gas and desorption, modified from Clarkson (2021).

Finally, an analytical model history match and forecast is performed (Fig. 10.27, bottom right) using flowing pressure data as input. The OGIP used in the modeling (~3 Bscf) is consistent with FMB analysis. The permeability and skin obtained from the matching are 10.9 md and −0.3, respectively, and these values are in reasonable agreement with the range from type-curve analysis. Using the skin estimate from modeling, permeability can be estimated from the *y*-axis intercept of the FMB plot using the procedures of Clarkson (2021); the resulting value (9.5 md) is in reasonable agreement with model history matching. This example highlights the need to obtain consistent estimates of properties from all RTA methods to gain confidence in the analysis.

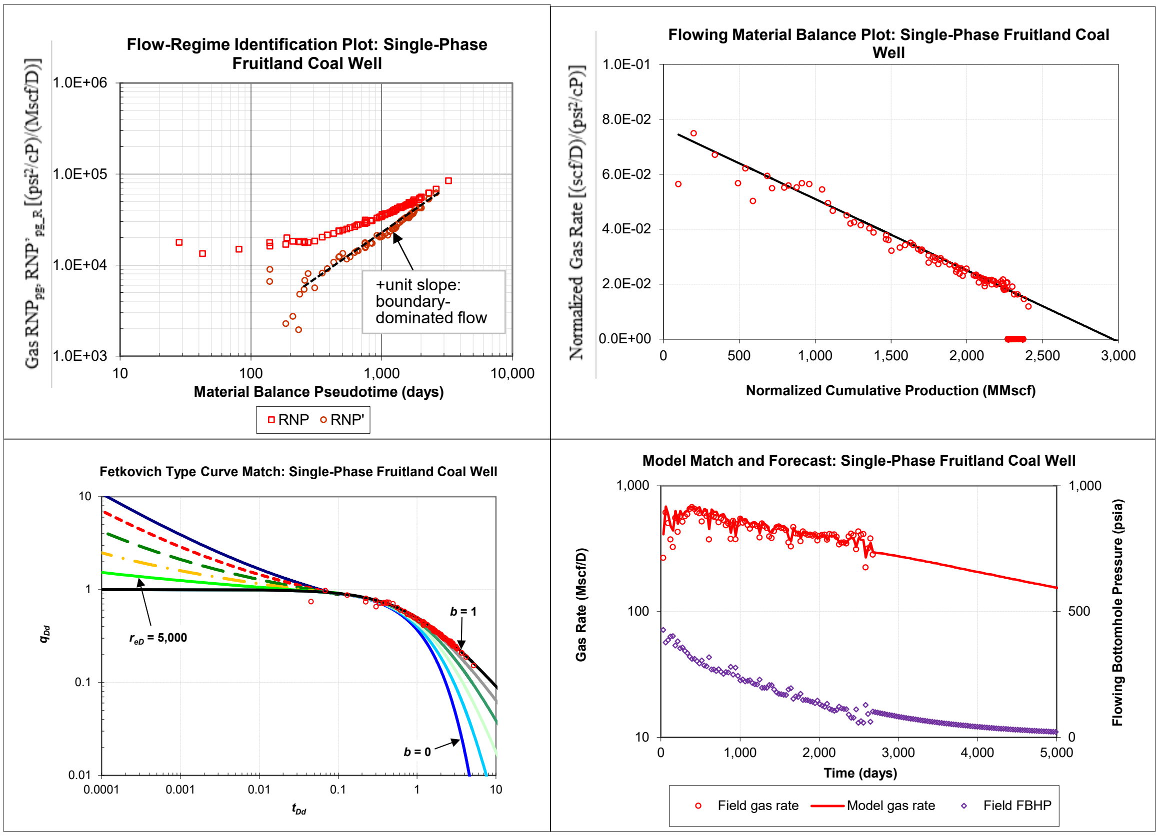


Fig. 10.27—Use of model-based methods to analyze the single-phase CBM well (non-Fairway Fruitland coal) in Fig. 10.23. (Top left) Flow-regime identification plot. The dominant flow regime is identified to be boundary-dominated flow. RNP is rate-normalized pseudopressure difference, and RNP' is its semilog derivative. (Top right) Flowing material balance analysis. (Bottom left) Fetkovich type-curve analysis, where q_{Dd} is dimensionless decline rate, t_{Dd} is dimensionless decline time, r_{eD} is dimensionless outer boundary radius, and *b* is hyperbolic decline exponent. (Bottom right) Analytical model history match. FBHP is flowing bottomhole pressure. Figure is modified from Clarkson et al. (2007a).

10.5.4.3 Mature Phase (Development and Well Life). As discussed for tight/shale reservoirs in Section 10.4.6, during this phase of development for tight/shale reservoirs, DCA is the most commonly applied method, although model-based (RTA) methods may also be applied to select wells to "calibrate" DCA. In the workflow for the latter concept, after data quality control/filtering steps and flow-regime identification, it is suggested that the analysis progress from model-based RTA methods (e.g., straightline, type-curve methods), which are used to derive initial estimates of fracture/reservoir properties and hydrocarbons in place, to model-based history matching and forecasting, which use the RTA-derived property estimates as initial input. As a last step, if DCA methods are used, the empirical DCA model can be fit to the model-based forecast. For example, if the Arps hyperbolic decline model is used for empirical forecasting, then the D_i and b values can be determined through this calibration, which is particularly important for CBM because several CBM properties such as desorption, multilayer behavior, etc., can affect the decline model parameters. Rushing et al. (2008) performed comprehensive analyses of the influences of CBM properties on decline characteristics.

An example application of this DCA calibration approach is shown in **Fig. 10.28** for a single-phase (gas) Horseshoe Canyon coal well (western Canada). Prior to this analysis, the workflow described above (flow-regime identification followed by straightline and type-curve analysis to derive initial permeability, skin, and OGIP estimates) was applied; these steps were illustrated by

Clarkson (2018, 2021) for this well and are not repeated here. Using the RTA-derived input as a starting point, an analytical model history match was performed. Next, the Arps hyperbolic decline model was matched to the same data as well as the analytical model forecast. Using this approach, the b value was estimated to be ~0.4, which is within range of that expected for a low-pressure gas well (Fetkovich et al. 1996). An independent estimate could also be derived from Fetkovich type-curve analysis by matching the data to the dimensionless (Arps model-derived) depletion stems. This approach results in a b value estimate of 0.4–0.6. The uncertainty with the latter analysis is due to the fact that the well is still in early stages of depletion. The b values >0.5 (a general limit for low-pressure, conventional gas wells) are commonly observed for CBM wells because of the aforementioned combination of reservoir properties (desorption, etc.).

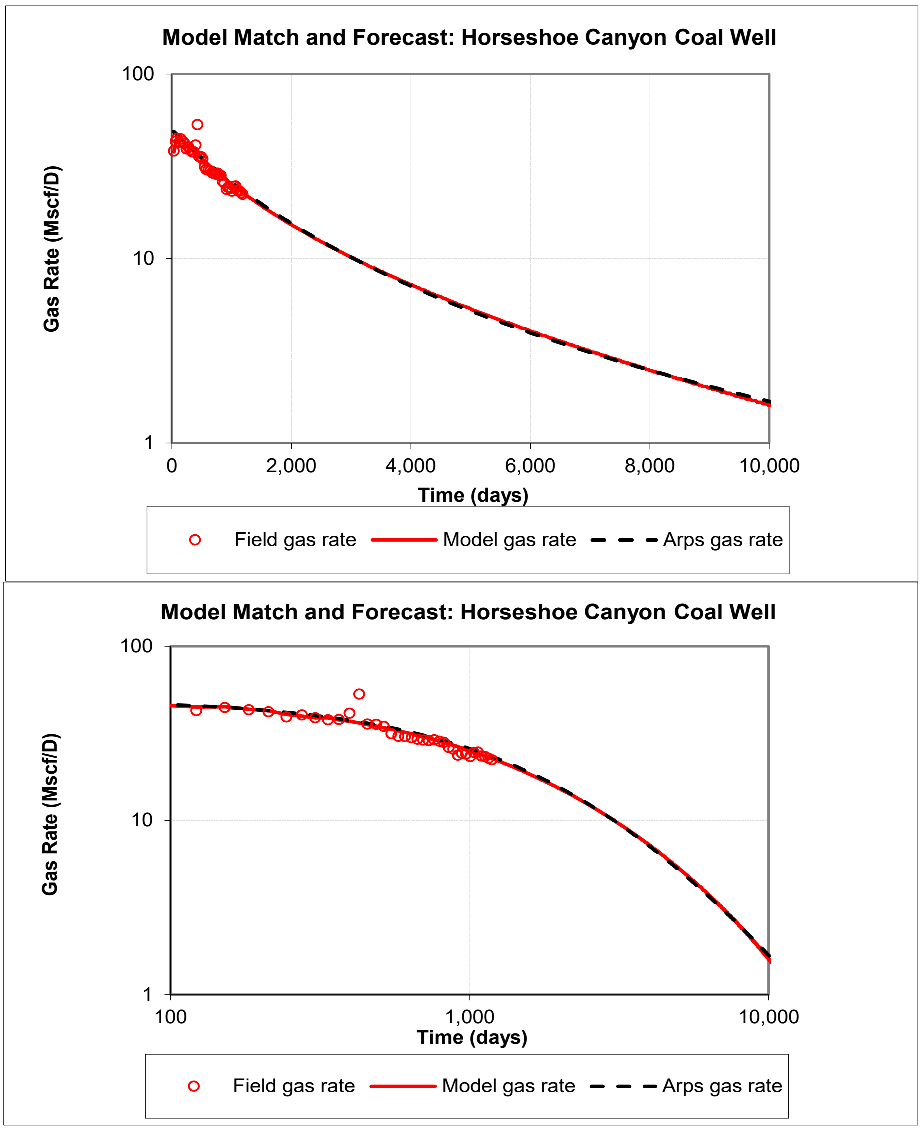


Fig. 10.28—Comparison of analytical and empirical (Arps hyperbolic) model forecasts to aid in the calibration of the latter. The comparison was performed using the data from a single-phase (gas) Horseshoe Canyon coal well. (Top) Semilog plot. (Bottom) Log-log plot.

A similar procedure has been applied to two-phase CBM wells in the Fruitland Coal Fairway. Two-phase Fruitland Coal Well 2 **(Fig. 10.29),** like Well 1 (Fig. 10.22), is located in the Fruitland Coal Fairway, but it was drilled later during more mature stages of development of the field. This is evident from the fact that some dewatering of the well had occurred prior to initial production (the well came on production at peak production rate, unlike Well 1, which had to dewater first), and the initial pressure was several hundred pounds per square inch below initial reservoir pressures in the field. As with Well 1, an analytical model was used to history match flowing pressures and offset POW pressures; unlike Well 1, daily flow rates and flowing pressures were used for this purpose. A pressure-dependent effective permeability trend, analogous to that shown in Fig. 10.20 (bottom right), was again required to achieve the match. Further, as with Well 1, a two-phase FMB plot was used to verify the model OGIP (not shown; for additional modeling details, see Clarkson et al. 2007b, 2010).

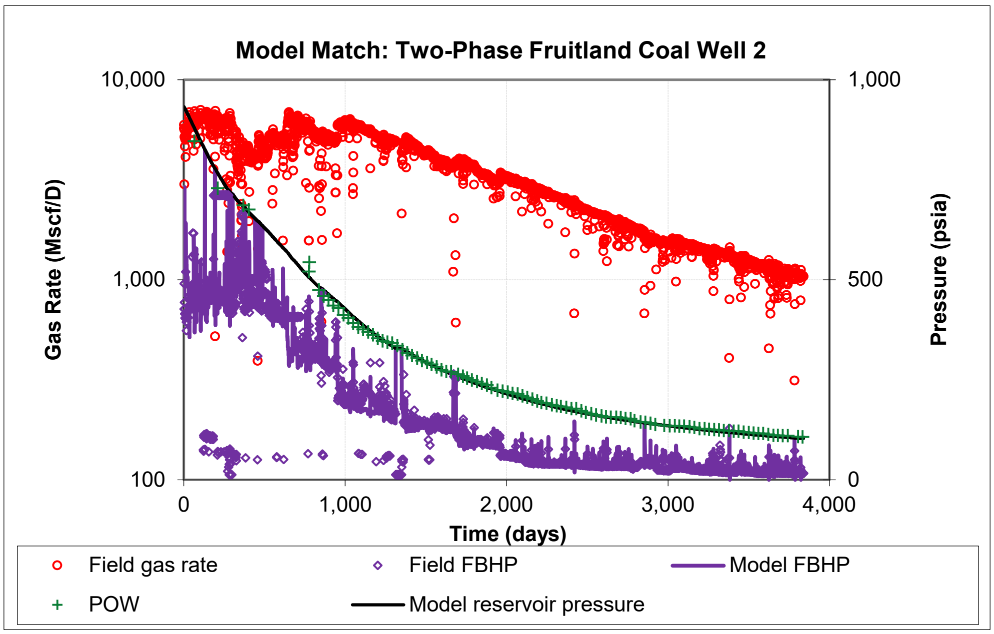


Fig. 10.29—Use of model-based methods to analyze the two-phase Fruitland Coal Well 2. As with Well 1, an analytical history match of flowing bottomhole pressures (FBHPs) and pressure observation well (POW) pressures was performed for model calibration.

In order to generate an Arps hyperbolic decline forecast for this well, the Arps model was first fit to analytical model and numerical model forecasts for wells of the same vintage as Well 1 during the terminal decline period to constrain the range for *b* values (similar to what was done for the Horseshoe Canyon well in Fig. 10.28). An Arps hyperbolic decline model was then fit to the terminal decline period of Well 2 **(Fig. 10.30)** at the point where flowing pressures became approximately constant (at ~2,000 days; see Fig. 10.29). The *b* value selected for the well forecast was consistent with those obtained from model calibration for earlier-vintage wells.

The above-described empirical model calibration method could be applied to a select number of wells in the field, representing different reservoir regions, to ensure consistency in empirical model forecasting for those regions of the field.

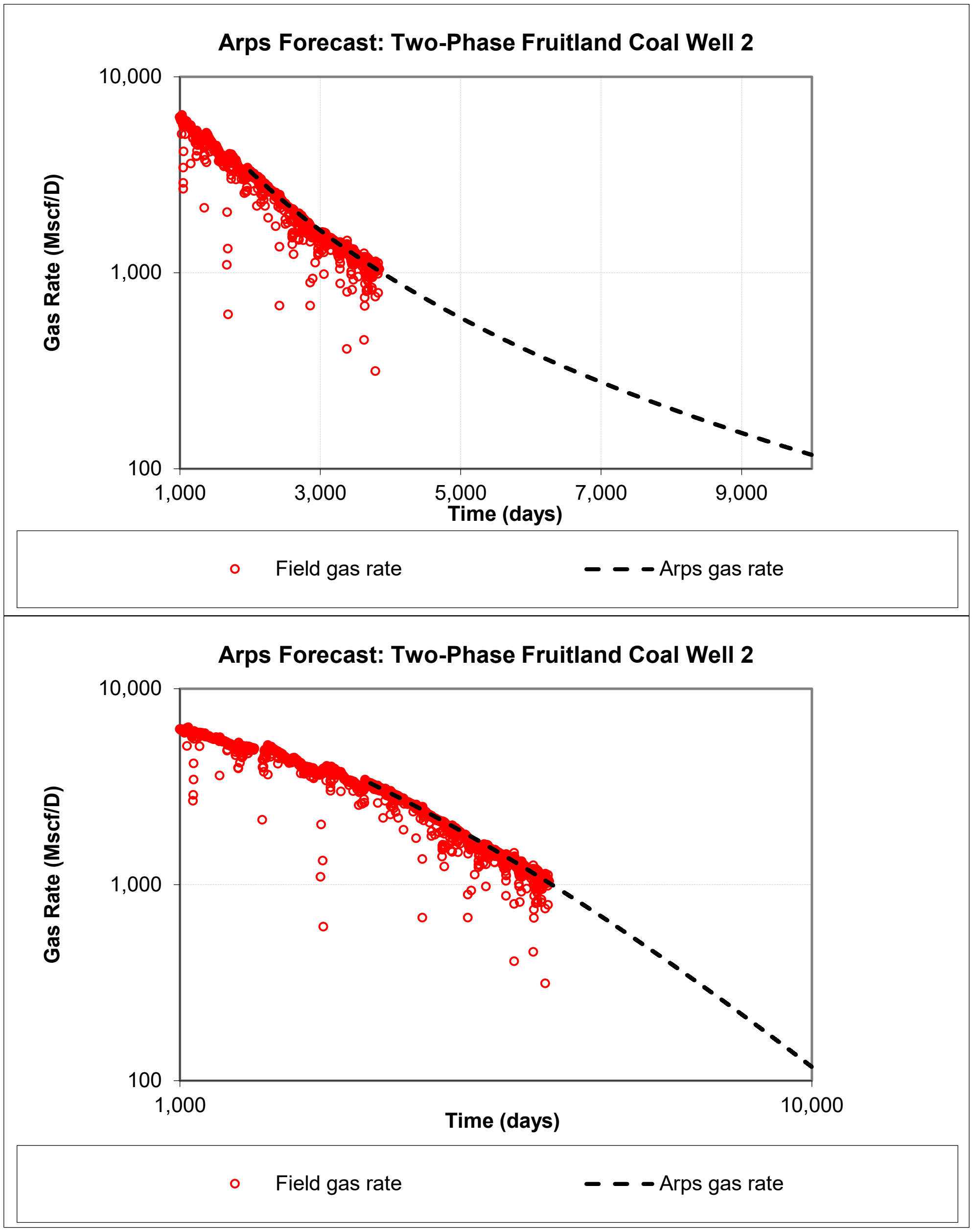


Fig. 10.30—Arps hyperbolic decline model forecast for two-phase Fruitland Coal Well 2. (Top) Semilog plot. (Bottom) Log-log plot.

10.5.5 Additional Exploration and Development Considerations. The unique CBM properties affect all stages of development planning. The two-phase flow nature of most CBM plays means that well spacing, well geometry, and well orientation should be designed to accelerate dewatering, which will, in turn, increase effective permeability to gas, initiate gas production, and reduce the time to peak gas production. Care must be taken, however, not to overdrill or overdevelop, leading to pure acceleration with infill drilling. Critical data gathered during the exploration (early) phase, such as gas contents, isotherm data, pressures (flowing and shut-in), and effective/absolute permeability data, must continue to be collected during intermediate and sometimes mature stages of development because of the heterogeneity (vertical and lateral) of CBM plays. Collection of these key data is necessary to inform development and business decisions.

Because CBM is often composed of a mix of gas components, and these components adsorb to the coal to different degrees (Fig. 10.20, top left), produced gas compositions may evolve during production. For example, in the Fruitland Coal Fairway of the San Juan Basin, initial gas compositions consisted of up to 10% CO_2 (mole fraction), with the balance being mostly CH_4. During production, the CO_2 concentrations in the produced gas increased because CO_2, the more strongly adsorbed component, was released at lower pressures. Because of the potential for evolving gas compositions during depletion, facilities may be needed to scrub non-hydrocarbon gases (such as carbon dioxide) to meet market specifications, as is the case in the Fruitland Coal Fairway play.

Surface operations must also be planned carefully to account for production behavior. Facilities must be designed to dewater coal wells (artificial lift) and to gather, transport (trucking or water-gathering system), and treat (subsurface or surface disposal) large amounts of water, particularly in the early life of a field. Compression must be considered to assist with early dewatering and to optimize well performance.

Finally, because coal can serve as a source rock for other reservoirs, including noncoal intervals adjacent to gas-producing coal seams, it is possible that adjacent or interbedded noncoal intervals could contribute to CBM production through vertical crossflow, even if the noncoal intervals are not targeted for stimulation. This could be enhanced in particular if the noncoal facies consist of organic-matter-rich mudstones capable of significant adsorbed gas storage (Bustin and Bustin 2016). As noted by Bustin and Bustin (2016) in their study of noncoal facies contribution to total gas in place in the Mannville coal measures of western Canada, this contribution may not be recognized and is often not considered in resource assessments for CBM plays.

10.5.6 Commerciality Issues. A primary consideration for commerciality is the resource size, related to the thickness and gas content of the coals. The depth of the coal is an important factor affecting both gas content (through pressure and temperature) and absolute permeability, which generally decreases with depth due to the stress sensitivity of the coal fracture apertures. Economic production of CBM is, generally, limited to depths <4,000 ft for this reason. Factors affecting the timing of first significant gas production (above the economic limit rate in order to pay out operating costs)—such as degree of undersaturation—will impact commerciality. In extreme cases, it could take well over a year for early development wells to achieve significant gas rates. Commerciality will also be affected by factors controlling time to peak production and peak gas rate, such as effective permeability to gas, which changes with saturation and reservoir pressure.

In CBM projects, the following factors are important: Infrastructure must be sufficient to gather and dispose of high initial water volumes; sufficient compression must be installed to improve CBM recovery and assist with well dewatering; artificial lift should be planned for and included in operating costs; facilities should be designed to scrub non-hydrocarbon gas from produced gas to meet market specification (where applicable); and environmental and regulatory concerns must be addressed.

10.5.7 Classification and Reporting Issues. CBM classification and reporting are aligned with the principles and practices used for tight/shale oil and gas detailed in Section 10.4.6. Please also see Barker (2008) for examples specific to CBM.

John Etherington, Charles Vanorsdale

10.6 Other Unconventional Oil

10.6.1 Introduction. This chapter has already discussed tight oil and shale oil within the scope of "unconventional oil." Arguably, these types of unconventional oil reservoirs garner the most attention due to their worldwide prevalence and the resource potential they hold. However, these oils are often low viscosity, medium-to-light gravity crude that facilitates transmissivity (kh/μ) when stored in low-permeability/tight rock. Crude oil may be divided broadly into categories based on density and viscosity. For the purposes of this section of Chapter 10, unconventional oil categories based on density and viscosity criteria may be defined as follows.

- Heavy crude oil is generally defined as having a density in the range of 10 to 23 °API with a viscosity that is typically greater than 100 but less than 10,000 cp. Although heavy oil is often recovered in thermal enhanced oil recovery (EOR) projects, it is typically not a continuous accumulation and often does not require upgrading. Therefore, heavy crude is defined herein as conventional resources with regard to assessment methods and classification under the PRMS guidelines. The definition is included here merely to differentiate "heavy" from "extra-heavy" oil.
- Extra-heavy oil density is less than 10 °API with a viscosity ranging from 1,000 to 10,000 cp. While mobility is limited, accumulations typically have defined oil/water contacts and exhibit normal buoyancy effects. Extra-heavy oil (EHO) is not necessarily a "continuous-type" deposit, but it is herein classified as unconventional resources because it typically requires significant extraction effort (upgrading).
- Natural bitumen typically has a density less than 10 °API and a viscosity greater than 10,000 cp measured at original temperature in the deposit and at atmospheric pressure on a gas-free basis. In its natural viscous state, it is normally not recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Near-surface deposits may be recovered using open-pit mining methods. Bitumen accumulations are classified as unconventional resources because they are pervasive throughout a large area and are not currently affected by hydrodynamic influences such as the buoyancy of petroleum in water. Natural bitumen requires upgrading to synthetic crude oil or dilution with light hydrocarbons prior to marketing.
- Oil shales are fine-grained sedimentary rocks (shale, siltstone, and marl) containing relatively large amounts of solid organic matter (known as "kerogen") from which significant amounts of shale oil and combustible gas can be extracted by destructive distillation. All current commercial extraction projects use surface mining techniques. Similar to extra-heavy oil, oil shale is herein classified as unconventional resources because it requires upgrading.

A general diagram delineating heavy oil, EHO, and bitumen (tar sands) according to API gravity and viscosity, along with some comparative examples, is given in **Fig. 10.31.**

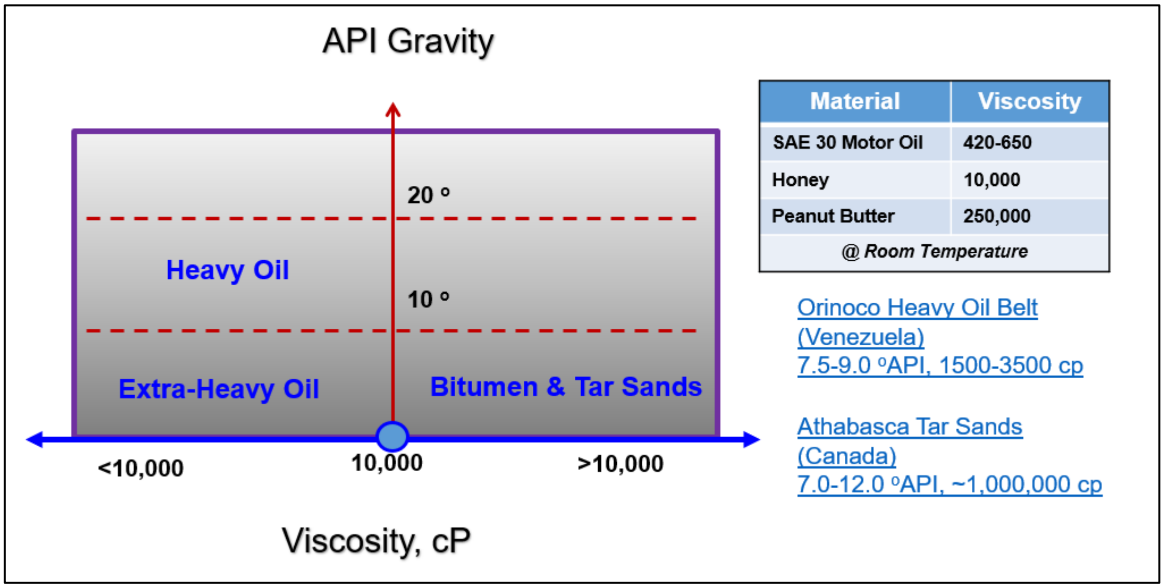


Fig. 10.31—General differentiation of oils based on viscosity and API gravity.

10.6.2 Reservoir Characteristics, Risk, and Uncertainty. ***10.6.2.1 Extra-Heavy Oil.*** About 90% of the world's known accumulations of EHO are in the Orinoco Oil Belt of the Eastern Venezuelan Basin, with over 1.3 trillion STB initially in place (Dusseault et al. 2008). A subsequent study (Attanasi and Meyer 2010) placed the Venezuelan EHO in-place figure at 2.1 trillion STB, comprising 98% of the total world endowment. It is clear that the extent of the resource is considerable, but its assessment contains much uncertainty.

Individual sand bodies in the Orinoco accumulations range in thickness up to 150 ft. The majority of oil-bearing beds are 25 to 40 ft thick, with high porosity (27 to 32%), good permeability (up to 5 darcies), and good lateral continuity (Dusseault 2001). The major uncertainties are fault compartmentalization and water encroachment. With the exception of isolated areas within the belt, the oil is mobile at reservoir conditions.

In the blt, cold production of EHO is normally achieved through multilateral (horizontal) wells that are positioned in thin but relatively continuous sands, in combination with electric submersible pumps and progressing cavity pumps. Horizontal multilateral wells maximize the borehole contact with the reservoir. EHO mobility in the Orinoco Oil Belt reservoirs is typically greater than that of bitumen in the Alberta sands because of higher reservoir temperatures, greater reservoir permeability, higher gas/oil ratios, and the lower viscosity of EHO relative to bitumen. The recovery factor for an EHO cold-production project in the Orinoco Oil Belt is estimated to be approximately 7 to 15% of the in-place oil (Fiorillo 1987).

While upside secondary recovery with thermal projects is forecast, these incremental volumes would be classed under the PRMS as Contingent Resources until pilot projects are complete and thermal projects are sanctioned. Publicly available reserves reported as Proved were substantially increased in 2010 and 2011 in anticipation of widespread application of thermal recovery, but this has not materialized.

The majority of Orinoco production is diluted using viscosity reducers, typically naphtha, either at the wellhead or injected downhole, and transported to the Caribbean coast for upgrading to remove the naphtha and high sulfur content prior to sale. The resulting "syncrude" then has a gravity of approximately 32 °API. Consequently, economics must incorporate upgrading costs either as integrated projects or through reduced pricing at the field-level custody-transfer point.

10.6.2.2 Bitumen. Natural bitumen is the portion of petroleum that exists in the semisolid or solid phase in natural deposits. It usually contains significant sulfur, metals, and other non-hydrocarbons.

Natural bitumen occurs in at least 598 deposits in 23 countries (Attanasi and Meyer 2010). The largest known bitumen resource, accounting for approximately 70% of the world total, is in western Canada, where Cretaceous sands and underlying Devonian carbonates covering a 30,000-square mile area contain over 1,800 billion bbl of bitumen initially in place (Alberta Energy Regulator 2020). Current commercial developments are confined to the oil sands. Individual sand beds in the western Canada oil sands can form thick and continuous reservoirs of up to 250 ft with a net/gross ratio of over 80%. More often, there are stacked series of 50- to 150-ft-thick sands with intervening silts and clays. It is common for the sands to have high porosity (30 to 34%) and permeability (1–5 darcies). The sand grains are often floating in bitumen with minor clay content. Western Canadian oil sands may contain a mixture of bitumen, EHO, and heavy oil, the properties of which differ between and within reservoirs.

Two processes are principally used to extract the western Canada bitumen: open-pit surface mining and various subsurface in-situ recovery methods.

In surface mining, the overburden is removed, and the oil sands are excavated with very large "truck and shovel" operations. The oil sands are transported to a processing plant, where the ore is subjected to a series of hot water froth flotation and/or solvent processes to separate the sand and bitumen. While the process can recover more than 95% of the bitumen in the sand, the intermixing of clays and the mine-layout requirements reduce the actual recovery factor to about 75%. In fact, the Alberta Energy Regulator prescribes a minimum recovery factor of 90% for the "as-mined" ore when the bitumen content is greater than 11% by weight (as per the *Canadian Oil and Gas Evaluation Handbook* [SPEE 2018], a set of resources evaluation guidelines closely aligned with the PRMS). Surface mining is typically considered where the depth to the top of the oil sands is less than 215 ft.

Bitumen that is too deep for surface mining is typically produced using in-situ thermal recovery processes similar to those used in heavy oil projects. Such projects require a reservoir depth in excess of 500 ft to provide an impermeable cap to contain the required steam pressure that provides adequate reservoir energy and temperature. In cyclic steam stimulation operations, a volume of steam is injected into a well, some period of time (soak time) is allowed to pass, and then the bitumen, the viscosity of which has been significantly reduced by the high-temperature steam, is produced from the same well. This process can be repeated ten or more times in the same well, and the recovery efficiency in these projects is estimated to be 5 to 25% of the original bitumen in place, depending on the number of pore volumes of steam injected.

Instead of cyclic steam stimulation, most new in-situ projects employ steam-assisted gravity drainage using a pair of vertically offset horizontal wells. The upper wellbore is used for steam injection, creating an expanding steam chamber. The thermally mobilized bitumen drains into the lower wellbore, from which it is produced. A typical project uses well pairs with horizontal lengths of 2,500 to 3,500 ft, and the injector is placed about 15 ft above the producer. The wells are drilled in patterns from pads consisting of 5 to 10 well pairs spaced 300 to 500 ft apart. Expected production rates are 800 to 2,000 BOPD per well. Recovery efficiencies range from 40 to 75% of oil initially in place (Etherington and McDonald 2004) within the steam chamber; however, at the reservoir level, the recovery efficiency may only be less than 40% of that range (SPEE 2018).

Bitumen, due to its density and immobile character, may require different methods to delineate deposits and estimate in-place volumes than those used for other conventional oil assessments. Conventional production decline and material balance calculations do not apply.

For surface mine planning, a closely spaced grid of core holes is required to support a detailed volumetric assessment. The total cores are analyzed in laboratories to determine the weight percent of bitumen, which is typically 10 to 14 wt%. The versatility of PRMS to adapt to surface mining operations is demonstrated in this example. The PRMS Reserve categorization (i.e., P1, P2, P3) is defined based on confidence in the recovery of product quantities. For surface mining, a key uncertainty is the presence and bitumen content in the deposit. Thus, confidence is tied to the level of core hole sampling (e.g., number of holes and distance between them) that describes ore content in the intended development area. For example, Proved Reserves may require a 1,600-ft grid (61-acre spacing), while Probable Reserves would be assigned to areas with a 3,200-ft grid (247-acre spacing). Further, Proved Reserves in the McMurray Formation of Alberta, Canada, are based on 40-acre spacing if 3D seismic data are not available, but 80-acre spacing if they are available; Probable Reserves would be assigned for 160-acre spacing, with or without 3D seismic data, and Possible Reserves would be assigned for 320-acre spacing, with or without seismic data (SPEE 2018). Thickness and condition of overburden, and volume allowances on the lease for mine layout and tailing ponds are examples of key factors affecting mine economics that would likely be unfamiliar to engineers focused on conventional reservoirs.

The assessment methods for in-situ bitumen-production operations require close well spacing and core analysis but are supplemented by high-resolution 3D seismic data and complete wireline log suites. Thermal processes, such as steam-assisted gravity drainage, are sensitive to reservoirs with associated gas and/or top- or bottomwater zones that may act as potential thief zones. Water zones rob the steam chamber of energy that would be otherwise available to heat the bitumen and result in higher operating costs and poorer oil recoveries.

Similar to improved-recovery projects in conventional reservoirs, reserves attribution requires "a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based" (PRMS § 2.3.4.4). The difference in bitumen projects is that there may be no preceding "primary" production upon which to base improved recoveries. However, as more steam-assisted gravity drainage projects have come on stream, the performance results in adjacent analog reservoirs may be accepted to help underpin the booking of undeveloped reserves.

Under the PRMS, for discovered resources to be classed as Reserves, stakeholding entities must have committed to an approved development plan, including facilities to produce, process, and transport the products to established markets. It would be difficult to apply all classical petroleum reserves criteria such as oil/water contacts and offset-well pressure response to unconventional deposits like the Canadian oil sands. The appropriate assessment methods may be a hybrid of those applied to conventional petroleum reservoirs and those applied to mining deposits. The *Canadian Oil and Gas Evaluation Handbook* (SPEE 2018) provides technical guidance in Canada's petroleum disclosure rules and more detailed best practices for bitumen reserves and resources assessment and classification.

10.6.2.3. Oil Shale. The organic matter in oil shale is composed chiefly of carbon, hydrogen, oxygen, and small amounts of sulfur and nitrogen. It forms a complex macromolecular structure that is insoluble in common organic solvents (compared to bitumen, which is soluble). Because of its insolubility, the kerogen must be retorted at temperatures of about 500°C to convert it into synthetic oil and gas. Oil shale differs from coal in that the organic matter in coal has a lower atomic H:C ratio, and the organic matter to mineral matter ratio of coal is much greater. Oil shale and shale oil are not interchangeable terms; in shale oil, such as in the Bakken, Niobrara, Barnett, or Eagle Ford plays, the kerogen present in the shale has already been converted to oil and/or gas.

Oil shale in place is estimated at 6.05 trillion barrels in more than 600 known deposits in at least 33 countries, and all of these figures are considered to be conservative (World Energy Council 2016). By their estimates, over 80% of the recoverable oil shale oil is located in the US, in particular, in the Green River Formation of the Piceance, Green River, and Uinta Basins.

Oil shales of Estonia are used directly as fuel for power generation and in cement plants. China and Brazil also have significant oil shale production. Brazil has developed the world's largest surface oil shale pyrolysis retort.

Despite very significant research investments in the Colorado Piceance Basin deposits since the 1970s, there is no current commercial production. Initial pilot projects were based on surface mining and associated retort facilities. Typical yields were <1 bbl of hydrocarbon liquids per tonne of shale. Environmental issues include the disposal of large amounts of processed shale with associated contaminants and the potential contamination of groundwater.

Due to the number of contingencies, currently there are no oil shale Reserves under the PRMS guidelines.

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Chapter 11

Production Measurement and Operational Issues

Mohammed Al Alshaikh

11.1 Introduction

Production measurement for reserves and resources quantities is specified under the Petroleum Resources Management System (PRMS 2018, Appendix A—Glossary) to occur at the "reference point," which is the "defined location within a petroleum extraction and processing operation where quantities of produced products are measured under defined conditions before custody transfer (or consumption). This is also called point of sale, terminal point, or custody transfer point."

The reference point then becomes the link among the estimates of subsurface quantities, raw production quantities, sales quantities, and product price. The PRMS provides a series of guidelines to promote a consistent approach to measurement in all types of projects.

11.2 Background

The following discussion provides context for application of the PRMS guidelines regarding the linkage between production measurement and resources estimates in both conventional and unconventional resource projects. **Fig. 11.1** illustrates a simplified oil and gas production operation with local or lease processing; the historical guidance given by the Society of Petroleum Engineers on measurement points was built around such a model. The same principles can be applied to other production models.

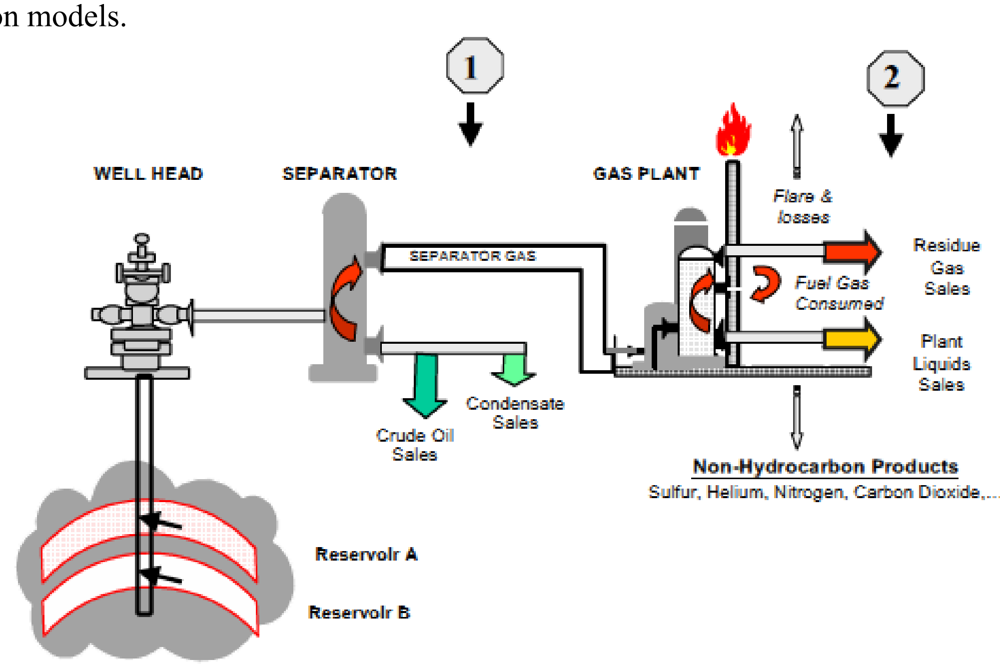

Fig. 11.1—Schematic oil and gas operation.

A reference point must be clearly defined for each project. In many operations, the reference point is at the exit valve of the lease separator (point 1 in Fig. 11.1). Where gas plants are involved as part of an integrated project, the measurement point is typically at the plant outlet (point 2 in Fig.11.1).

Volumes of oil, gas, and condensate are adjusted to a standard temperature and pressure defined in government regulation and/or product sales contracts. Liquid production may be reported in either volume (e.g., barrels of oil with associated density) or mass (e.g., tonnes of oil) units. Natural gas rates are usually reported in terms of volume (e.g., cubic feet or cubic meters), but the gas is normally sold according to heating value (e.g., Btu). Products are further specified by their quality and composition (e.g., sweet light crude, less than *X*% sulfur, etc.).

There is a wide range of complexity in processing facilities. "Local plants" may range from a simple dehydration unit to a sulfur-recovery plant to a liquefied natural gas complex or a bitumen upgrader. The "plant" may be physically located on the producing property or may be a considerable distance away connected by a pipeline. **Table 11.1** lists the levels of processing and example situations:

Level	Description	Example
Level 1	Volumes undergoing purification and physical separation	Separation of condensate and natural gas liquids (NGLs) and removal of sulfur from sour gas with subsequent sale of residual dry gas
Level 2	Volumes requiring more extensive treatment where chemical changes are induced, but no non-reservoir quantities are added	Upgrading by coking, with inert gas and contaminants removed
Level 3	Volumes undergoing significant chemical change or where non-reservoir quantities are added	Hydrotreating that adds hydrogen using catalysts to rechain the hydrocarbon molecules, with inert gas and contaminants removed

Table 11.1—Levels of resource processing.

In Level 1 projects, the processing is primarily physical separation, and outlet quantities are portions of the original reservoir petroleum; thus, resource measurements should be given in terms of the outlet products (point 2 in Fig. 11.1). If natural gas is sold before extraction of liquids (i.e., wet gas), resource estimates are given in terms of that volume. Any further processing beyond this reference point, including additional liquid recoveries (e.g., in "straddle plants"), are not to be reflected in resources quantities.

Typically, product sales contracts (or pipeline constraints) set maximum limits on the non-hydrocarbon "contaminants" content and/or minimum heating value for natural gas deliveries. The volume sold may include some small fraction of non-hydrocarbons (H_2S, CO_2, or N_2) as long as that fraction meets sales specifications. Consequently, the resources volumes captured in the PRMS categories and classifications would be estimated including the same non-hydrocarbon content as in the sales gas.

Examples of Level 1 processes include gas oil separation plants, oil stabilization plants, and NGL fractionation plants. All of those plants use processes that do not chemically alter the inlet hydrocarbon but only change its physical state for further processing and/or transportation.

In the case of liquefied natural gas plants, while significant purification and associated fuel use are involved, there is no intended chemical alteration of the gas. The process only affects the physical properties of the gas for transportation. Non-hydrocarbon gases (inert gases and contaminants) that need to be removed during the process should be accounted for as part of the gas shrinkage. If condensates or NGLs are extracted during the process and reported, the gas volume should be adjusted accordingly. While the output of the liquefied natural gas plant is measured in tons, associated reservoir estimates are stated in terms of equivalent purified/shrunk volume of gas.

Levels 2 and 3 both may be considered upstream manufacturing processes. The actual custody transfer point in integrated upstream projects depends on the legal structure and contract terms. Where the same corporate entity shares in both the upstream and downstream operations, it may be necessary to establish the custody transfer point arbitrarily. Production streams should be physically measured at the plant inlet, or quantities may be estimated from the outlet products with accounting for shrinkage (including hydrocarbon consumed in operation as fuel) and additives.

As an example, in bitumen-upgrading operations, whereas the coking process involves significant shrinkage, the addition of hydrogen results in a volume gain. The synthetic oil delivered at the plant outlet is the final upstream sales product. Where the custody transfer is deemed to be at the upgrader inlet, a virtual inlet price may be derived through a net-back calculation.

This technical analysis must be combined with royalty treatment, regulatory guidance, and accounting to ascertain the logical measurement point for stating resources quantities. In the case of fully integrated extraction and processing operations, transfer prices should be calculated to value quantities correctly at the designated measurement point.

The PRMS recommends that petroleum quantities consumed as fuel in production or plant operations before the reference point, known as lease fuel or consumed in operations (CiO), are not included as reserves or resources. However, if included as reserves or resources, these quantities must be stated and recorded separately from the sales (PRMS § 1.1.0.6.A.2, also § 3.2.2).

A further issue is the treatment of the non-hydrocarbons—whether they are contaminants (with disposal cost and/or no net sales value) or byproducts (e.g., sulfur or helium) that can be sold to produce additional income. There is general industry agreement that these non-hydrocarbons, in excess of sales specifications, are not included in resources quantity estimates; however, the volume should be included as part of the production volume under the PRMS guidelines to preserve the mass balance. Income generated by the sale of the non-hydrocarbons can be used to offset expenses incurred to extract and process the associated hydrocarbons (subject to applicable regulatory guidance) when determining economic producibility for the PRMS classifications. Accordingly, the cost to dispose of contaminants in excess of sales specifications should also be considered when determining economic producibility.

Disclosure under some jurisdictions may require separate reporting of heavy oil from light/medium crude oil. The granularity of reporting by the oil and gas industry is not prescribed here.

11.3 Reference Point

The reference point is a defined location within a petroleum extraction and processing operation where the produced quantities are measured or assessed (PRMS § 3.2.1.1). A reference point is typically the point of sale to third parties or where custody is transferred to the entity's midstream or downstream operations. Sales production is normally measured and reported in terms of produced quantities crossing this point over identified time periods.

The reference point may be defined by relevant accounting regulations 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 the delivery specification at a defined price. In integrated projects, the appropriate price at the reference point may need to be determined using a net-back calculation.

Sales quantities are equal to raw production less non-sales quantities (those quantities produced at the wellhead but not marketable or available for sales at the reference point). Non-sales quantities include petroleum consumed as lease fuel, flared, or lost in processing plus non-hydrocarbons that must be removed before sale. 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 many engineering calculations (e.g., material balance and production performance analysis) based on total reservoir voidage. Substances added to the production stream for various reasons, such as diluent added to enhance flow properties, are not to be counted as production, sales quantities, reserves, or resources.

As an example of the way in which the reference point affects the reporting of reserves and resources, **Fig. 11.2** illustrates one such process for a nonassociated gas system. Factors outlined in **Table 11.2** are the expected quantities to be reported depending on the reference point.

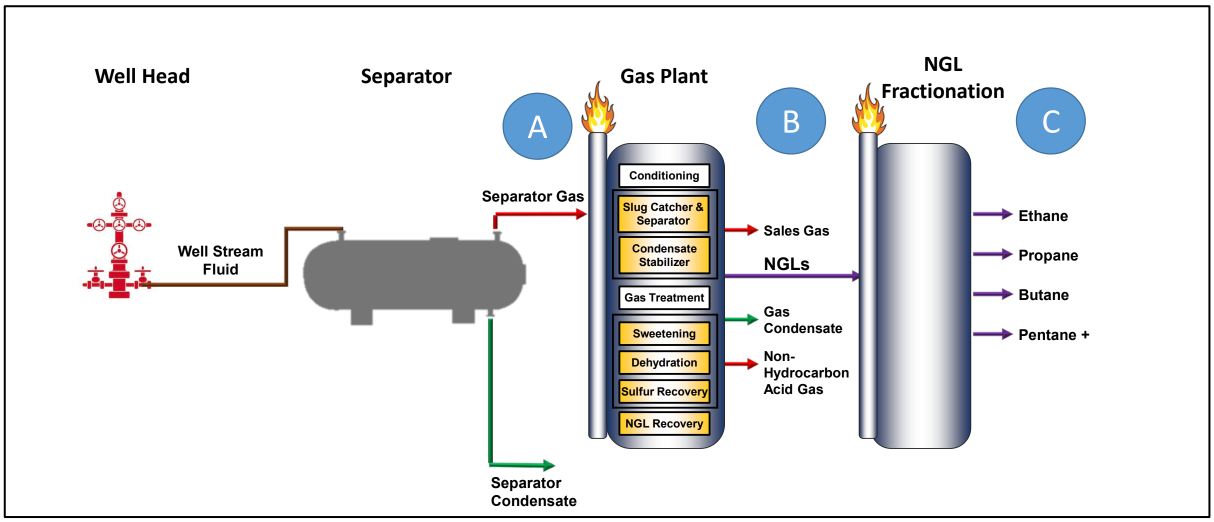

Fig. 11.2—Reference points in a typical gas operation.

Reference Point	Reported Quantities
Point A	Wet gas + condensate
Point B	Natural gas + natural gas liquids (NGLs) + condensate – (lease fuel + flared quantities + system losses)
Point C	Natural gas + ethane + propane + butane + pentane + condensate – (lease fuel + flared quantities + system losses)

Table 11.2—Reference points and typical reporting requirements (CiO not reported as reserves).

11.4 Consumed in Operations (CiO)

Lease fuel, also known as fuel "consumed in operations" or CiO, refers to that portion of produced petroleum consumed as fuel for power generation or other field/plant operations before the reference point.

When gas (or crude oil) consumed in lease operations is treated as shrinkage and excluded from sales quantities, it should not be included in reserves and resources estimates under the PRMS. Many international and national companies do, however, report CiO as part of their “marketable gas” reserves. Although reserves are recommended (PRMS §1.1.0.6.A.2) to be sales quantities, the CiO quantities may be included as reserves or resources but must be stated and recorded separately from the sales portion. Entitlement rights for the fuel usage must be established before recognizing CiO as reserves. Flared gas and oil and other petroleum losses must not be included in either product sales or reserves, but once produced, they are included in produced quantities to account for total reservoir voidage. Third-party gas obtained under a long-term purchase, supply, or similar agreement is excluded from reserves.

The CiO quantities must not be included in the project economics because there is neither a cost incurred for purchase nor a revenue stream to recognize a sales quantity. The CiO fuel replaces the requirement to purchase fuel from external parties and results in lower operating cost. All actual costs for facilities-related equipment, the costs of the operations, and any purchased fuel must be included as an operating expense in the project economics.

11.5 Associated Non-Hydrocarbon Components

In the event that non-hydrocarbon components are associated with production, the quantities reported as reserves or resources should honor is the values measured at the reference point, provided those quantities adhere to specifications in sales contracts and/or by regulatory authorities. Hence, if gas (as produced) includes a proportion of CO_2, then the pipeline may accept sales gas with a limited CO_2 content.

$$\begin{aligned}\text{Reported Quantities (when CiO is excluded)} \\ &= \text{Raw Quantities} - \text{Extracted Nonhydrocarbons} - \text{CiO} - \text{Flared Gas} \\ &- \text{System Losses.}\end{aligned}$$

For example, if produced gas has 4 mol% H_2S, and the development plan is to utilize an existing pipeline that will only accept 2 mol% H_2S, then the following factors need to be considered:

- Additional facilities are required to extract the additional H_2S to meet the pipeline requirement.
- The cost of the additional facilities needs to be added to the total cost of the project.
- The additional gas consumed in operations required for the additional processing needs to be excluded from total reserves or resources.
- If the additional cost takes the project from commercial to sub-commercial, then alternatives need to be considered.

In this situation, the sales gas volume would include 2% H_2S, and natural gas reserves dedicated to that pipeline would be estimated including 2% H_2S. For high concentrations of H_2S (concentrations as high as 90% have been known), the H_2S gas may be separated and converted to sulfur, which can then be sold. In such cases, the natural gas reserves exclude the H_2S volumes, and the sulfur volume may be quoted separately. At times, prices for sulfur can be low, and stockpiling for future sale is not uncommon.

Even if the non-hydrocarbon components are removed before the reference point, accurate records of the raw quantities (voidage extraction quantities) are required for reporting production volumes and engineering calculations.

When the non-hydrocarbon components extracted generate revenue (e.g., sulfur and helium), they still cannot be classified as hydrocarbon reserves or resources under the PRMS but must be reported separately. Revenues realized from the sales can be considered in the economics of the project, which, in return, can result in additional hydrocarbon reserves as a result of a lower economic limit.

11.6 Natural Gas Reinjection

Gas can be reinjected into the same or different reservoirs for many reasons, including gas cycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. Classification of the injected gas depends on the reference point.

If the gas was produced and reinjected before the reporting reference point (i.e., no transfer of ownership), then the reinjected gas can be reported as reserves if it meets all the reserves criteria. The reinjected gas needs to be technically and commercially mature, as well as estimated to be eventually recoverable (marketable, with a distribution/export system available nearby). In the case of miscible injection or other enhanced recovery processes, due allowance needs to be made for any gas not available for eventual recovery as a result of losses associated with the inefficiencies inherent in the corresponding process. Normally, these volumes are not included in any PRMS reserves category. In some cases, the objective of gas injection in a reservoir can be efficient disposal of the gas; consequently, no gas volume should be allocated to reserves.

If the gas injected was produced after the transfer of ownership (perhaps purchased or transferred from another field or reservoir), then the injected gas can be classified as inventory (for the reservoir into which it was injected) but not as reserves or resources. When produced, the gas would not contribute toward field production or sales. If the injected gas was produced from another field or reservoir (perhaps in which the recipient was the same producer) after the reference point, then the produced gas would have been part of the reserves from the donor reservoir, but the recipient reservoir could only consider the gas as part of inventory but not reserves. Otherwise, this would constitute "double-booking" of reserves. When produced, the gas would not contribute toward field production or sales.

Typically, under such circumstances, the field would then contain gas that is part of the original in-place volumes as well as injected gas held in inventory. On commencing gas production from the field, the last-in/first-out principle is recommended; hence, the inventory gas would be produced first and not counted toward field production. Once the inventory gas had been re-produced, further gas production would be drawn against the reserves and recorded as production. The above methodology ensures that the uncertainty with respect to the original field volumes remains with the gas reserves and not the inventory. An exception to this could occur if the gas is acquired through a production payment. In this situation, the volumes acquired could be considered as reserves.

11.7 Underground Natural Gas Storage

One case of gas reinjection is gas storage, where gas is injected into a reservoir to be recovered later, perhaps to meet a higher market demand. Quantities reinjected should not be classified as reserves if the gas was transferred from one lease or field to another with sale or custody transfer between the points. In other words, if the gas passed the reference point pre-injection, then it cannot be classified as reserves but rather as inventory. At this point, produced quantities are accounted for as production from the original reservoir and then as inventory after accounting for system losses.

Commencement of gas production from the field will be handled in the same manner as described for gas reinjection above (Section 11.6).

There may be occasions in which gas is transferred from one lease or field to another without a sale or custody transfer occurring. In such cases, the reinjected gas could be included with the native reservoir gas as reserves.

11.8 Production Balancing

11.8.1 Production Imbalances (Overlift/Underlift). 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 yearend, a company will be in an overlift or an underlift situation. Based on the production matching of 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.

For companies with small equity interests, where liftings occur at infrequent intervals (perhaps greater than 1 year), the option remains to record production as entitlement on an accrual basis.

11.8.2 Gas Balancing. In gas production operations involving multiple working interest owners, an imbalance in gas deliveries can occur that must be accounted for. Such imbalances result from the owners having different operating or marketing arrangements that prevent the gas volumes sold from being equal to the ownership share. One or more parties then become over/underproduced. For example, one owner may be selling gas to a different purchaser from the others and may be waiting on a gas contract or pipeline installation. That owner will become underproduced, while the other owners sell their gas and become overproduced. These imbalances must be monitored over time and eventually balanced in accordance with accepted accounting procedures.

Some points to consider in gas-balancing arrangements:

- In gas swaps, early production from one field may be traded with later production from another field.
- Take-or-pay gas means that the production has to be paid for even if it is not "taken" (i.e., produced).

There are two methods of recording revenue to the owners' accounts. The "entitlement" basis of accounting credits each owner with a working interest share of the total production rather than the actual sales. An account is maintained of the revenue due to the owner from the overproduced owners. The "sales" basis of accounting credits each owner with actual gas sales, and an account is maintained to record the over- and underproduced volumes (relative to the actual ownership). The production volumes recorded by the owners will be different in the two cases. The reserves estimator also must consider the method of accounting used, the current imbalances, and the manner of balancing the accounts.

11.9 Shared Processing Facilities

It is not uncommon in gas production operations for several fields to be grouped to supply gas to a central processing facility (gas plant) to remove non-hydrocarbons and recover liquids. Where a company has an equity interest in one or more of the contributing gas fields and also in the processing facility, the allocation of dry gas and NGLs back to the fields (and reservoirs) for estimation of reserves can be complex. While not addressed specifically in the PRMS, the basic principle that reserves estimates must be linked to sales products applies. Thus, by measuring the volumes and components of the gas stream leaving each lease and the equity share in the lease, the company can calculate its share of the sales products for purposes of reserves. This share is not affected by the company's actual equity interest in the gas plant as long as it is greater than zero.

If the company has no equity interest in the facility, then it is treated as a straddle plant, and reserves are estimated in terms of the wet gas and the non-hydrocarbon content accepted at the lease outlet. The allocation of revenues is subject to the contractual agreement among the lease and plant owners.

When the plant ownership and lease working interest are different, booking may be an issue. This can be highly complex, but some general points are captured in the following:

1. If the plant is associated with unit production and is unit owned (see Chapter 12—*Resources Entitlement and Recognition* for discussion of unit agreements), book residual plus liquids.
2. If the plant is 100% owned by the company sending produced volumes to the facility, then that company books the volumes processed by the plant as residual plus liquids.
3. If the contract directly stipulates the retention, by the producer, of products through plant processing, then the volumes are booked according to contract.
4. If plant ownership and lease ownership interests are different, and existing contracts do not conclusively specify product allocation, then the issues may be complex. In this case, where the trail is not clear, the booking of wet gas is recommended. The asset team responsible for handling the produced stream is afforded, however, the opportunity to present information that describes a specific instance in which the booking of residual plus liquids is reasonable and adheres to applicable contract terms. Where processed volumes are significant, this reconciliation is required.

11.10 Hydrocarbon Equivalence Issues

11.10.1 Gas Conversion to Oil Equivalent. Gas quantities often are converted to barrels of oil equivalent (BOE) to facilitate like-for-like comparison as the term allows for consolidation of multiple product types into a single equivalent type. That said, the conversion is usually performed based on the gross heating content or calorific value of the gas compared to the heating value of a reference barrel of oil.

It is important to note that, when several projects are being evaluated, the gas volumes first must be converted to the same temperature and pressure. It is customary to convert to standard conditions of temperature and pressure (STP) associated with the system of units being used.

One way of calculating the gross heating value (GHV) of a given gas relies on the use of a representative gas composition. As there are industry-recognized standards for reporting GHV for each component (*j*) at STP, the GHV will be the aggregate of the mole fraction of a component multiplied by the GHV of that component.

$$Total\ Gas\ Gross\ Heating\ Value = \sum_j (Mole\ Fraction_j \times GHV_j) \quad (11.1)$$

The calorific value obtained using these formulas can be cross-checked by taking actual calorific value measurements of some gas samples from the sales point.

To further simplify the process, some rules of thumb are used in the industry in the absence of a GHV computation. One very common rule of thumb is 1 barrel of oil equivalent (BOE) equals 5.8 thousand standard cubic feet (Mscf) at standard conditions (15°C and 1 atm). (The conversion is sometimes rounded to 6.0 Mscf per BOE for ease of calculation.) This rule of thumb assumes that the gas has a GHV of 1,000 Btu/scf, and the oil has a GHV of 5.800 million Btu/bbl (based on a 35 °API oil; see **Fig. 11.3**). The 5.8 Mscf/BOE conversion is recommended when the gas is dry at the point of sale.

Another rule of thumb that is common when using the metric system is 5.62 Mscf/BOE. It is based on 1,000 standard m^3 of gas per 1 standard m^3 of oil. A useful formula for changing calorific value from Imperial (customary) to metric units at STP (15°C and 1 atm) is 1 MJ/m^3 = 1 Btu/scf × 35.3 scf/m^3 × 1 kJ/0.948 Btu × 1 MJ/1000 kJ.

The calorific value obtained by the process described above can be used for estimating BOE with a more customized approach for an entity's portfolio by taking into consideration the crude oil characteristics of each reservoir and/or where the gas has a calorific value other than 1,000 Btu/scf. This will enhance the reporting of gas in terms of oil equivalent, but it is more data intensive.

If calorific values of gas volumes are not available at the gas reference point, then multistage pressure-volume-temperature (PVT) experimental data on the gas-liberation process at different conditions mimicking field-gathering facilities may be used. This is done by calculating the calorific value of the total gas output from all separation stages based on the composition. The process is outlined as follows:

- Calculate the gross calorific value (CV) for each stage using the gas composition at that stage.

$$Gross\ Stage\ CV = \sum Component\ Mol\% \times Component\ CV \qquad (11.2)$$

- Calculate the weighted average calorific value using the gas/oil ratio (GOR) as a weighting factor.

$$Total\ GOR = \sum_{Stage=1}^{n} GOR_n \qquad (11.3)$$

$$Total\ Gas\ CV = \frac{\sum_{Stage=1}^{n} CV_n \times GOR_n}{Total\ GOR} \qquad (11.4)$$

- The calorific value obtained using these formulas can be cross-checked by taking actual calorific value measurements of some gas samples from the sales point.

11.10.2 Liquid Conversion to Oil Equivalent. Regulatory reporting usually stipulates that liquid and gas hydrocarbon reserves volumes must be reported separately, with liquids being the sum of the crude oil, condensate, and NGLs. For internal company reporting purposes and often for intercompany analysis, the combined volumes for crude oil, condensate, NGL, and gas as an oil-equivalent value offer a convenient method for comparison.

The arithmetic sum of crude oil, condensate, and NGL reserves volumes can provide an oil-equivalent volume when one product dominates, and the other streams are not material in comparison. This method will not be satisfactory for certain regulatory disclosures because the products have different market values. A more correct, but imperfect, method in terms of value involves taking into account the different densities of the fluids. Further improvement in combining crude oil, condensate, and NGL can be achieved by considering the heating equivalent of the three fluids and combining them accordingly.

The correlation between the heat content (Btu/bbl) of crudes, condensates, fuel oils, and paraffins is illustrated in Fig. 11.3.

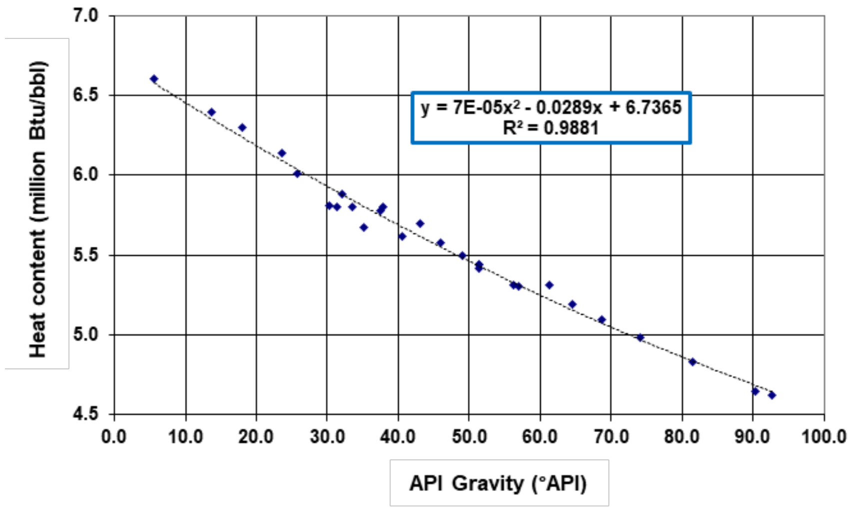

Fig. 11.3—Heat content (Btu) of crudes, condensates, fuel oils, and paraffins.*

11.11 Example

A reservoir with 100 million STB of 35 °API oil reserves has the multistage pressure-volume-temperature experimental data listed in **Table 11.3.** The process to convert the reserves to oil equivalent is as follows:

Hydrocarbon constituents	Stage 1 (mol%)	Stage 2 (mol%)	Calorific Value (Btu/ft^3)
N_2	2.00	0.43	0
CO_2	1.41	1.71	0
H_2S	1.33	0.28	0
C1	78.95	51.85	1010
C2	10.79	23.41	1769.7
C3	3.57	13.41	2516.1
i-C4	0.48	2.18	3251.9
n-C4	0.92	4.33	3262.3
i-C5	0.21	1.01	4000.9
n-C5	0.2	0.91	4008.7
C6	0.14	0.48	4755.9
C7+	0.00	0.00	
Total	100%	100%	
Gas/oil ratio, scf/STB	**750**	**150**	

Table 11.3—Example multistage separation pressure-volume-temperature composition.

$$Gross\ Stage\ CV = \sum Component\ Mol\% \times Component\ CV.$$

$$\text{Stage 1 } CV = 1{,}147 \text{ Btu/ft}^3.$$

$$\text{Stage 2 } CV = 1{,}587 \text{ Btu/ft}^3.$$

* Personal communication from Cronquist *in* McMichael and Spencer (2001).

$$Total\ Gas\ CV = \frac{\sum_{Stage=1}^{n} CV_n \times GOR_n}{Total\ GOR} = \frac{(1{,}147 \times 750) + (1{,}587 \times 150)}{(750 + 150)} = 1{,}220\ \mathrm{Btu/ft^3}.$$

$$Total\ Gas\ Reserves = Oil\ Reserves \times Total\ GOR = 100\ \text{million STB} \times 900\,\frac{\text{scf}}{\text{STB}}$$
$$= 90{,}000\ \text{million scf} = 90\ \text{Bscf}.$$

Using the caloric value of 35 °API oil based on Fig. 11.3 of 5,800 million Btu/bbl, now it is possible to convert the total gas reserves to barrels of oil equivalent (BOE).

$$Total\ Gas\ Reserves\ (BOE) = \frac{90\ \text{Bscf} \times 1{,}220\ \mathrm{Btu/ft^3}}{5{,}800\ \text{million Btu/bbl}} = 19\ \text{million BOE}.$$

$$Total\ Reserves\ (BOE) = Oil\ Reserves + Gas\ Reserves$$
$$= 100\ \text{million bbl} + 19\ \text{million BOE} = 119\ \text{million BOE}.$$

11.12 Acknowledgments

Much of this chapter builds on the work of Satinder Purewal in the 2011 version of the *Guidelines for Application of the PRMS*. Helpful insight also was provided by Monica Clapauch Motta.

11.13 References

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Chapter 12

Resources Entitlement and Recognition

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Elliott Young and Regnald A. (Reggie) Boles

12.1 Foreword

This chapter is about resources entitlement, which refers to the ability of an entity to claim quantities (net to the entity) of reserves and resources in its reports. Entitlement is also referred to as recognition, as the entitled quantities may be recognized in the entity's reserves and resources reports. The term "recognized quantities" is frequently referred to as the "booked quantities." This chapter text is an update to Chapter 10 of the *Guidelines for Application of the Petroleum Resources Management System* published in 2011. Drawing heavily on the prior text, the content has been updated to reflect refinements in generally accepted industry practices commonly used when determining entitlement to production and recognizable quantities of reserves and resources under a range of agreement types and fiscal terms, as well as aligning with the Petroleum Resources Management System (PRMS 2018). It is not the intent of the Society of Petroleum Engineers, or the cosponsors of the PRMS, to comment on the individual disclosure regulations promulgated by specific government agencies regarding entitlement to production or the ability to report reserves. As a consequence, emphasis has been placed on principles for reserves and resources recognition under the PRMS and determination of net quantities, rather than specific government regulations, financial reporting guidelines, or the classification of Reserves, Contingent Resources, and Prospective Resources into the various certainty categories of the PRMS.

12.2 Introduction

The ability to discover, develop, and commercially produce hydrocarbons in accordance with all environmental and safety regulations is the primary goal of the upstream petroleum industry. Aggressive competition, government policies, ever-sharpening scrutiny by the investment community, and volatility in product prices drive companies to search for attractive new exploration and producing venture opportunities that will add the greatest value for a given investment. As a consequence, contracts and agreements for these opportunities are becoming increasingly complex, further increasing the focus on the ability to recognize reserves and resources.

Production-sharing and other nontraditional agreements have become popular because of the flexibility they provide host countries in tailoring fiscal terms to fit their sovereign needs while enabling contracting companies to recover their costs and achieve a desired rate of return. Actual agreement terms, including those that relate to royalties or some royalty payments, cost recovery, profit sharing, and taxes, may have a significant influence on the ability of an entity to recognize and report hydrocarbon reserves and resources. The terms "reserves" and "resources," as used in this chapter, are defined in the context of the PRMS. This chapter focuses on reserves and resources entitlement (quantities an entity may recognize and report as its reserves and resources) under the more common fiscal systems being used throughout the industry. Various types of production-sharing, service, and other types of common contracts are reviewed to illustrate their impact on recognition and reporting of oil and gas reserves and resources in the context of the PRMS framework. This chapter also introduces other agreements and concerns that can impact a given entity's reserves and resources entitlement, in the context of the PRMS, such as conveyances and unitization agreements.

Oil and gas reserves and resources are the fundamental assets of producing companies and host countries alike. They have been literally the fuel that drives economic growth and prosperity. When produced and sold, they provide cash flows and the crucial funding for future exploration and development projects. With the increased focus of the investment community on reserves and resources inventories and the value of externally reported, project-related reserves that are added each year, many companies are reluctant to undertake a project that does not provide the opportunity to eventually report reserves.

12.3 Regulations, Standards, and Definitions

When reporting reserves and resources, it is important to distinguish between the specific regulations governing their external reporting (such as financial reporting to a stock exchange or to a host country regulatory agency), and internal company use for technical and business-planning purposes. In any assessment, the basis used, assumptions, and purpose for which reserves and contingent resources are recognized and reported must be defined. **Fig. 12.1** summarizes the PRMS reserves and discovered resources categories relative to categories that many government regulatory agencies and/or stock exchanges allow in required disclosures.

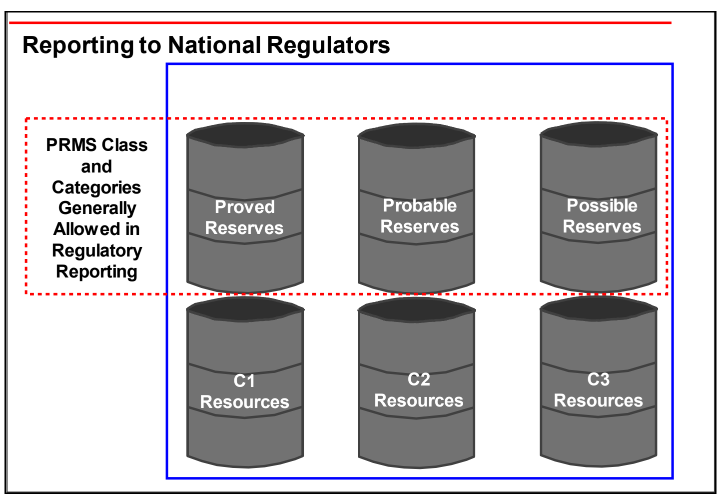


Fig. 12.1—PRMS (2018) discovered categories generally allowed in required disclosures.

Numerous national regulatory bodies have developed regulations and standards for reporting oil and gas reserves (and, in some cases, resources) within their respective countries. These standards provide detailed descriptions of the categories of reserves and resources to be reported, required supporting information, and the format to be used for the disclosures. Those reports will typically require information on the complete (100%) accumulation (e.g., petroleum initially in place, reserves, resources), as national regulatory bodies are interested to know the resources of the country. National regulatory standards and reporting rules do not generally provide guidance on the type or extent of rights to the underlying resource or production that is required for reporting entitled reserves and resources. Stock exchanges will typically require that companies report their entitled quantities and related information in financial reporting. A company's internal planning process will also typically require the entitled quantities. For some unique types of agreements, it may not be clear whether a company is even entitled to report the related reserves and resources. This is particularly the case with agreements in which production ownership and control reside, by law, with the host country rather than with the contracting party. Analysis of the key elements and fiscal terms of these contracts and comparison to those in more widespread use are good approaches to determine whether reserves and resources can be recognized and subsequently reported.

The PRMS acknowledges the concept of an economic interest as the basis for recognizing and reporting reserves and resources. To determine when an economic interest exists, many have referred to the US Securities and Exchange Commission Regulation S-X, Rule 4-10b, "Successful Efforts Method" (US Securities and Exchange Commission 2011) and Financial Accounting Standards Board (FASB) Accounting Standards Codification® (ASC) Topic 932, "Extractive Activities—Oil and Gas" (FASB 2010).

12.4 Reserves and Resources Recognition Under the PRMS

This section describes the basic elements used for determining reserves and resources entitlement.

12.4.1 Reserves and Resources Entitlement Elements. US Securities and Exchange Commission Regulation S-X (US Securities and Exchange Commission 2017) and FASB ASC Topic 932 (FASB 2010) are points of reference for entitlement elements, as shown in **Fig. 12.2.** These references outline fundamental principles of resources entitlement and provide a useful framework and set of criteria for establishing when an interest in a property exists, and guidance on when reserves and resources can be recognized under the PRMS and government regulations.

Properties
Mineral interests in properties (hereinafter referred to as properties), which include all of the following:
a. Fee ownership or a lease
b. Concession
c. Other interest representing the legal right to produce or a revenue interest in the production of oil or gas subject to such terms as may be imposed by the conveyance of that interest.
Properties also include:
a. Royalty interests
b. Production payments payable in oil or gas
c. Other nonoperating interests in properties operated by others.
Properties include those agreements with foreign governments or authorities under which an entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (see paragraph **932-235-50-7**); but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas.

932-235-50-7 Net quantities disclosed in conformity with paragraphs 932-235-50-4 through 50-650-6B shall not include oil or gas subject to purchase under long-term supply, purchase, or similar agreements and contracts, including such agreements with governments or authorities. However, quantities of oil or gas subject to such agreements with governments or authorities as of the end of the year, and the net quantity of oil or gas received under the agreements during the year, shall be separately disclosed if the entity participates in the operation of the properties in which the oil or gas is located or otherwise serves as the producer of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

Fig. 12.2—Text from FASB ASC Topic 932 "Extractive Activities—Oil and Gas."

These references state that, for recognizing reserves, there must exist (or there must be a reasonable expectation that there will exist) the legal right to produce or a revenue interest in the production, which can be summarized into elements that support and establish an economic interest and the ability to recognize reserves and resources. These include the following:

- The right to produce oil or gas
- The right to take produced volumes in kind or share in the proceeds from their sale
- Exposure to market risk and technical risk
- The opportunity for reward through participation in exploration, appraisal, development, and producing activities

In addition, the regulation establishes specific elements that do not support an economic interest and preclude the recognition of reserves and resources. These include the following:

- Participation that is limited only to the right to purchase volumes
- Supply or brokerage arrangements
- Agreements for services or funding that do not contain aspects of risk and reward or convey an interest in the minerals

Note that the FASB Topic 932 permits reporting of Proved Reserves received under long-term supply agreements with governments provided that the enterprise wishing to report the reserves participates in the operation or otherwise serves as the operator. Under the PRMS, applying the principle to this type of agreement, recoverable amounts could be considered for classification as reserves or resources depending on project maturity and technical certainty.

The right to extract hydrocarbons and the exposure to elements of risk and the opportunity for reward are key elements that provide the basis for recognizing reserves and resources. Many companies use these elements to differentiate between agreements that would allow reserves and resources to be recognized and reported to regulatory agencies from those purely for services that would not allow recognition of reserves and resources. Risks and rewards associated with oil and gas production activities stem primarily from the variation in revenues from technical and economic risks. Technical risk affects a company's ability to physically extract and recover hydrocarbons, and it 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 the ability to economically recover the in-place hydrocarbons. It is highly dependent on the economic environment over the life of the project and fluctuates with the prevailing price and cost structures. It should be noted that risk associated with variations in operating cost alone is not generally sufficient to fulfill the requirements of risk and reward and allow reserves to be reported. It should also be noted that the ability or obligation to report reserves to regulatory agencies does not necessarily imply ownership of the underlying resources. Reserves and resources entitlement under the PRMS are reported according to economic interest, after deducting royalties, when appropriate, and any interests owned by others.

Some contracts or agreements may not be satisfactorily clear enough to draw a definitive conclusion about reserves and resources entitlement. In such contracts, the responsibility for payments of royalties and production taxes to the government and contract clauses that may refer to reserves or resources ownership must be analyzed to clarify entitlement.

12.4.2 Working Interest and Economic Interest. An economic interest in minerals (sometimes referred as mineral interest) may result from a working interest (WI) or a non-working interest. Typically, a WI is created when a mineral rights owner, who owns minerals beneath the surface, leases or otherwise contracts another party to access the subsurface and conduct exploration, development, and production activities. The party that conducts such activities will typically have certain cost obligations, which are based on the WI, and may have conveyed to it an economic interest, which is related to the WI, but not necessarily numerically equivalent. The economic interest resulting from a WI is typically less than the numerical WI, being reduced by non-working interests held by other parties (e.g., non-operating WI owners, royalty owners, overriding royalty interest owners, etc.). In this instance, the economic interest may be referred to as the "net economic interest" or "net revenue interest" or even just "net interest." Note that for the purpose of this chapter, the term economic interest is used. As companies undertake joint operations, typically to share costs and risks, WI may be shared among companies. A non-working interest may have a reduced or no-cost obligation, which would include royalties and similar interests (discussed herein). For example, the mineral rights owner may retain a non-operating interest (royalty interest, in this case) when conveying a WI. In such a case, the economic interest of a non-working interest may be equivalent to the interest held. Contracts and agreements may have several types of operating and non-operating interest.

In a joint venture, partners typically align on a best estimate production forecast for project planning purposes. However, other estimates in the uncertainty range are seldom shared or agreed upon due to the fact that each partner will likely have its own perception of particular uncertainties. For example, as each partner estimates 1P, 2P, and 3P reserves as a function of its perceived uncertainties (which may consider the partner's technical experience, its project approval process, its forecast prices and costs associated with the production forecast, and, in the case of non-operator partners, availability of data and time dedicated to the project), differences in estimated reserves may exist between partners. The low estimate is usually more reflective of such differences due to the accentuated effect of varied assumptions and knowledge on lesser quantities. Partners will frequently consider their estimated reserves as strategic information, in consideration of partner transactions such as farmouts (assignment of all or part of the WI, including exploration and/or production rights and obligations, to another party in return for agreed-upon compensation), trades, and exchanges. As such, partners will be less likely to share anything other than the best estimate approximating the 2P reserves. The low estimate (indicative of the Proved Reserves) is particularly protected due to the implications of possibly significant differences, as noted. This does not imply that the economic interest is ignored, but rather it is a recognition that each partner may have a different basis for uncertainties and some economic and commercial elements.

12.4.2.1 Example: Difference Between Working Interest and Economic Interest in a Concession Contract. A government has subsurface mineral rights and leases a property to two companies, retaining 15% of production, free and clear of any costs of exploring, developing, or operating the property. According to the lease contract, Company A has 60% interest, and Company B has 40% interest. Company A is designated as operator.

In this case, the government will have a WI of 0% and a 15% economic interest (a non-working interest). Company A will have a 60% WI, and Company B will have 40% WI. As the operator, Company A will typically manage the day-to-day operations, with Company B being responsible for its proportionate share of expenses, according to a joint operating agreement between both companies. Company A's economic interest in the production and entitled reserves or resources will be 51%, while Company B's economic interest will be 34% (both having their WI shares proportionately reduced by the 15% non-working interest of the government).

In many types of contracts and agreements, the associated economic interest may be less simple to determine. Production-sharing and similar contracts have more complex calculations for economic interest and entitled reserves and resources, involving cost recovery and other mechanisms, which may be variable with time. Additionally, economic interest may be conveyed to other companies.

12.4.3 Mineral Property Conveyances. A mineral (economic) interest in a property may be conveyed to others to raise revenue, to spread economic and technical risks, to obtain financing, to improve operating efficiency, or to accrue tax benefits. Some types of conveyances are essentially financial arrangements or loans and do not carry with them the ability to recognize or report reserves or resources (discussed herein as including no economic interest). The forms that transfer an economic interest would include WIs (operating and non-operating) and non-working interests. A common conveyance transfers all or a part of the rights and responsibilities of operating a property (an operating WI) and the ability to recognize reserves or resources. Alternatively, a party may receive a transfer of a portion of the WI that does not include direct operatorship (a non-operating WI). The transferor may or may not retain an interest in the oil and gas produced that is free of the responsibilities and costs of operating the property (a non-working interest), and/or the transferor may convey an interest to another party and retain a portion of the WI.

Farmout agreements, overriding royalty agreements, or volumetric production payments agreements would typically convey reserves and resources entitlement. The FASB ASC 932-360-55-2 to 932-360-55-14 text (FASB 2010) provides useful guidance on when reserves and resources associated with transfer of interest may be recognized in the PRMS categories. The FASB ASC 932-470-25-1 text (FASB 2010) provides useful guidance on arrangements involving reserves and resources that are, in substance, borrowings and may not be recognized in the PRMS.

As mentioned in Section 12.4.1, in some contracts or agreements, it may not be easy to draw a definitive conclusion about reserves or resources entitlement. In reporting entitled quantities, opinions regarding the responsibility for payments of royalties and production taxes to the government, as well as contract clauses that may be material to reserves ownership, must be properly disclosed.

12.5 Agreements and Contracts

Agreements and contracts cover a wide spectrum of legal arrangements typically established by host countries to best meet their sovereign needs, including conveying licenses, rights, and/or opportunity to potentially profit from petroleum resources under their purview, as well as some other common agreements among entities. While certain approaches have been routinely applied for determining when reserves or resources can be recognized under these contracts and agreements, there is no sanctioned established system of practice for doing so. The purpose of this section is to expand on the text contained in PRMS § 3.3.2 by providing more detailed information for frequently encountered agreement types and to promote consistency in the recognition of reserves and resources under them, based on the essence of the contract. The focus is on the specific elements of the agreements that enable recognition of reserves and resources but not on the specific PRMS classes and categories.

Presently, mineral ownership in most onshore properties in the US belongs to the private landowner (or subsurface mineral owner), who has the authority to execute a lease agreement with a production and development company. Globally, host countries will hold mineral ownership, and companies may be entitled to reserves/resources through what can be described broadly as concessionary fiscal systems or contractual fiscal systems. In a concessionary fiscal system (described in Section 12.5.1), the mineral right owners transfer title of resources produced to companies (contractors). In a contractual fiscal system, typically the mineral rights owners retain ownership of resources produced and grant companies the right to receive a share of production or its revenue. The most frequent oil and gas contract types (including frequent types of conveyances) are described in Sections 12.5.2 through 12.5.12.

This section follows the classification system, modified from the template originally proposed by Johnston (1994) as shown in **Fig. 12.3,** with the broad descriptions of concessionary fiscal systems or contractual fiscal systems**.** In some fiscal systems, an economic interest may be recognized by the contractor or lessee, which will then be entitled to reserves/resources. Contractors and lessees may also arrange for other contracts or agreements (e.g., purchase agreements, production payments, loan agreements). Some of those contracts and agreements may convey an economic interest, initially granted by a fiscal system.

In some types of contracts or agreements, such as concessions, production-sharing contracts, and revenue-sharing contracts (described and discussed in Sections 12.5.1, 12.5.2, and 12.5.3, respectively), considering the host country's regulation, reserves and resources entitlement may be clear. In other cases, careful examination of contract and agreement terms, along with the host country's regulation, is needed to determine reserves and resources entitlement. Furthermore, countries and the oil industry may refer to some contractual arrangement as one contract model, when it is fundamentally another contract model. The expanded template of fiscal systems and some other agreement types along with their potential to recognize reserves and resources and report them under the PRMS is shown in **Fig. 12.4** (modified from the figure originally proposed by McMichael and Young 1997). The greater participation a contractor has in exploration, development, and production activities and exposure to risk and physical production ownership, the stronger is the probability of reserves and resources entitlement.

12.5.1 Concessions, Mineral Leases, and Permits. Historically, concessionary systems, such as leases and concessions, have been the most commonly used agreements between oil companies and governments or mineral owners. In such agreements, typically, the host government or mineral owner grants the producing company the right to explore for, develop, produce, transport, and market hydrocarbons or minerals within a defined area for a specific amount of time. The production and sale of hydrocarbons from the concession are then typically subject to rentals, royalties, bonuses, and taxes. Under these types of agreements, the company usually bears all risks and costs for exploration, development, and production and generally would hold title to all resources that will be produced while the agreement is in effect. Reserves and resources consistent with the net working interest (after deduction of any royalties owned by others) that can be recovered during the term of the agreement are typically recognized by the producing/development company. Ownership of the reserves or resources producible over the term of the agreement is normally taken by the company. However, as described in PRMS § 3.3.3 and in Section 12.6.4 herein, volumes recoverable after the term of the contract could potentially be recognized as Contingent Resources, i.e., contingent on the successful negotiation of an agreement extension. The project(s) under the terms of the agreement would not result in the "split classification" violation noted in PRMS § 2.2.0.4 by having, for example, 2P Reserves with 2C Contingent Resources applicable during a postconcession term. Funding and development of the resources during the postconcession term in this context are considered to be a separate project. If the agreement contained provisions for an automatic extension (or there is an established track record for extensions), and the likelihood of extension was judged to have a reasonable expectation of being achieved, additional reserves could potentially be recognized for the length of the extension period, provided requirements for project commitment, funding, economic viability, and other commerciality requirements were satisfied.

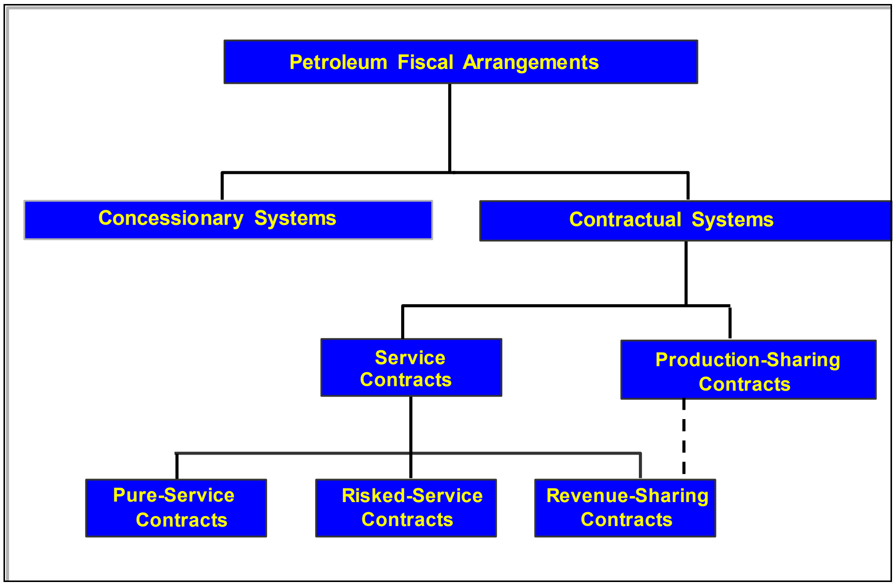


Fig. 12.3—Classification of petroleum fiscal systems.

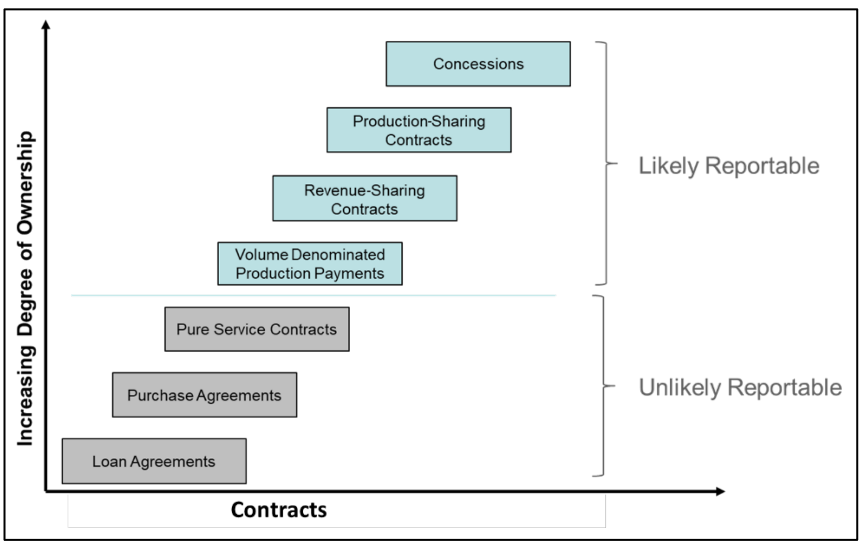


Fig. 12.4—Reserves/resources reporting potential.

12.5.2 Production-Sharing Contracts. In a production-sharing contract (PSC; also called production-sharing agreement, or PSA) between a contractor and a host government, the contractor typically bears all risks and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the investment from production (cost hydrocarbons), subject to specific limits and terms. The contractor also receives a stipulated share of the production remaining after cost recovery (profit hydrocarbons). Ownership of the underlying resource is almost always retained by the host government. However, the contractor normally receives title to the prescribed share of the quantities (an economic interest), based on the cost and profit revenue divided by the average product price, as they are produced or sold. Subject to technical certainty, reserves in one or more of the PRMS categories based on cost recovery plus a profit element for hydrocarbons that are recoverable under the terms of the contract are typically recognized by the contractor. Resources may also be recognized for future development phases where project maturity is not sufficiently advanced or for possible extensions to the contract term where this would not be a matter of course.

As in the case of a concession, volumes recoverable after the term of the contract ends will normally be classified as Contingent Resources unless the contract contained provisions for extension, and there is reasonable expectation that an extension, a renewal, or a new contract will be granted (refer to previous Section 12.5.1 and see also Section 12.6.4). Costs considered for recovery by the contractor are commonly specified in the contract and may be limited to percentages of production or revenues. They are commonly subject to the host country approval (via its regulator or national oil company [NOC]). Under a production-sharing contract, the contractor's entitlement to production generally decreases with increasing prices because a smaller share of production is required to recover investments and costs. This may cause price-related volatility in annual reserves estimates, particularly in cases using a constant price. These agreements may also contain terms that reduce contractor entitlement as production rate (production tranches) and/or cumulative production increases. In many host countries, entitlement will vary according to some sort of specifically defined relation between revenue and costs (termed *R* factors). The *R*-factor value (e.g., R = cumulative revenue ÷ cumulative capital expenditures, or R = cumulative revenue ÷ cumulative expenses) and the corresponding reduction applied to entitlement are typically defined in a tranche table, where increasing R values correspond to decreasing entitlement. **Fig. 12.5a** is a schematic indicating the distribution of yearly project production between contractor and government. Fig. 12.5b shows examples of profit split between the contractor and host government (indicated by NOC in the figure), based on (a) average daily production and (b) an *R*-factor representing the ratio between the contract cumulative revenue and cumulative expenses. Note that "revenue" and "expenses" are defined in the contract and may be gross, net, or some specific description unique to the contract.

12.5.2.1 Example: Resources Estimates in a Production-Sharing Agreement. This example is for an oil project, but references can apply to gas or barrel of oil equivalent quantities. In a PSA, the profit oil and cost oil for each period are calculated as:

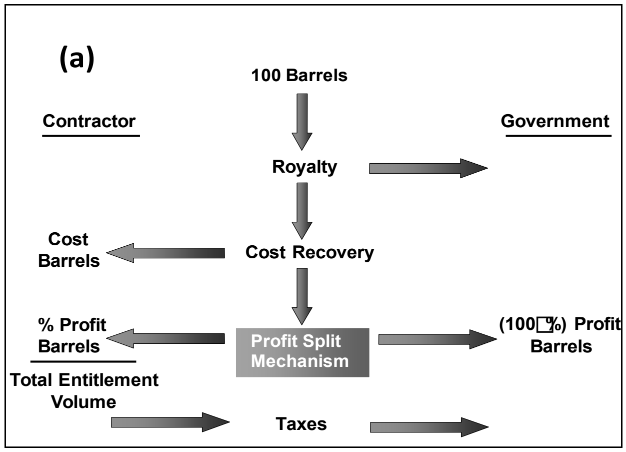
Profit Oil (STB) = [Sales (as defined in the agreement) Oil Production Net of Royalty (STB) – Recoverable Costs (USD)]/Price (USD/STB).

Cost Oil (STB) = Recoverable Costs (USD)/price (USD/STB), where Recoverable Costs ("Cost Recovery") are those costs that are allowed to be reimbursed in oil during the period. Those recoverable costs may arise from costs incurred in the period as well as from past unrecovered investments and operating costs.

In this contract example, there is a limit on the amount of product that the contractor may recover during each period: Cost Oil Limit each period = 70% of Gross Revenue before royalty deduction for each period.

In this contract example, Royalties are paid in kind as:

Royalty (STB) = 15% of sales production (STB).



(b)

Profit Oil based on average daily production		
Average Daily Production (bbl)	Contractor	NOC
0-30,000	40%	60%
30,000-200,000	30%	70%
Above 200,000	20%	80%

Profit Oil based on R-Factor		
R-Factor	Contractor	NOC
R<1.5	50%	50%
1.5 ≤r< 2	45%	55%
2 ≤r< 2.5	40%	60%
2.5 ≤r< 3.5	35%	65%
3.5 ≤r< 4.5	30%	70%
R≥4.5	25%	75%

Fig. 12.5—(a) Example production-sharing contract. (b) Profit-split examples. NOC stands for National Oil Company.

In this contract example, profit oil and cost oil are based on sales quantities. In some contracts, profit oil or gas and cost oil or gas may be based on produced quantities. Each contract will have its own specifications for profit oil or gas, cost-recovery limits, royalty percentages, and other definitions for royalties and cost recovery. The contractor is entitled to a share of the profit oil, based on an *R*-factor variable table (part of the contract), and the contractor is also responsible for income taxes in the host country. The project is already in production, and the best estimate forecast for next year is:

Oil production = 100 thousand STB.

Contractor's forecast price = USD 50/STB.

Recoverable Cost of the period (next year), including unrecovered cost from previous years and forecast cost of year 1 allowed to be recovered: USD 2,500 thousand.

Profit split of the year based on the *R*-factor table for this specific contract: 40% (attributed to the host government).

Fig. 12.6 shows a schematic of how to estimate entitlement resources for next year.

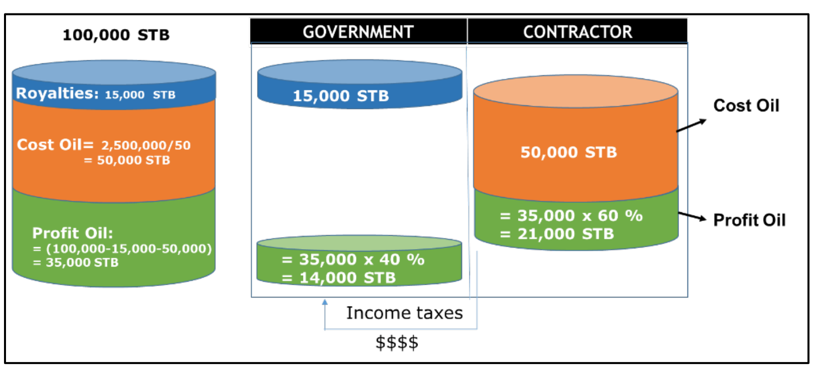


Fig. 12.6—Entitled resources.

The contractor may assume it will recover all recoverable costs (USD 2,500 thousand) next year because the limit of recoverable cost of 70% of gross revenue before royalty deduction (100 thousand STB × USD 50 /STB × 70% = USD 3,500 thousand) is not exceeded.

The contractor best estimate entitled resources corresponding to next year are calculated under this example as:

Cost Oil + [(Production Net of Royalty) – (Cost Oil)] × (1 − NOC Profit Split)
= (USD 2,500 ÷ USD 50/STB) + [(100 − 15) − 50] × 60%]

= 50 thousand STB + 21 thousand STB = 71 thousand STB.

The calculation of entitled reserves/resources that will be produced in the remaining future years will be based on each year's forecast of production, royalty rate, costs to be recovered as cost oil, and forecast profit split based on the *R*-factor table. 2P Reserves associated with this project will be estimated by adding the entitled best estimate resources of each year until the economic limit, if there is no other contingency that would prevent commercial production to that date. The actual economic limit calculation will consider revenues from the contractor's entitled quantities and the contractor's expenses (which may differ from the recovered costs of the period). 1P and 3P Reserves will be estimated based on the same logic used for 2P Reserves.

Note that entitled reserves/resources related to cost oil (50 thousand STB) would be higher if the forecast price were less than USD 50/STB. If the forecast price was USD 40/STB, cost oil would be 2,500 thousand/40 = 62.5 thousand STB, and the recalculated profit oil would be ([85 thousand STB − 62.5 thousand STB] × 60%) = 22.5 thousand STB, where 13.5 thousand STB is entitled to the contractor. This would bring the contractor entitlement reserves/resources corresponding to next year production to 76 thousand STB. Conversely, reserves/resources related to cost oil (50 thousand STB) would be lower if the forecast price were higher than USD 50/STB.

PSCs normally have limits and specifications for cost oil in each period that might be based on production revenues. Therefore, when prices get very low, it might be more frequent for incurred expenses to be recovered in the following year. Each contract and host government will have its own cost-recovery limits and specifications, profit split tables, prices used for cost oil, royalty volumes determination, and other information to be used in the estimation of reserves/resources entitlement. As noted, recoverable costs are usually subject to NOC approval, so estimated future cost oil estimates should consider historic approval level.

Table 12.1 shows an example of estimated entitled quantities, contractor cash flow, and reserves estimates for the remaining years for the best estimate, considering a forecast production decline, as shown in line (B) of the table, forecast price as shown in line (A), and a fixed profit oil split of 40%. For this table construction, sales price was assumed to be the same price used for cost oil calculation. The company's forecast costs displayed in line (G) represent costs allowed to be recovered under this specific PSC contract, while those displayed in line (O) represent costs that will incur but are not allowed to be recovered under this specific PSC. (These are only examples for this table construction.) In this example, the economic limit would occur in year 5 (line P). Estimated 2P Reserves are the accumulated forecast quantities from years 1 to 5 (260.56 thousand STB), if all remaining commerciality requirements are met.

REF	Year	1	2	3	4	5	6
(A)	Price Forecast (USD/STB)	50	45	35	35	35	35
(B)	Gross Oil Production (thousand STB)	100	83	69	58	48	40
(C)	Oil Production net of Royalty (thousand STB): 85% X (B)	85,00	70,55	58,65	49,30	40,80	34,00
(D)	Gross Revenue before royalty deduction (thousand USD): (A) X (B)	5000	3735	2415	2030	1680	1400
	Cost Oil Calculation						
(E)	Limit to Recover Cost Oil (thousand USD): 70% X (D)	3500	2615	1691	1421	1176	980
(F)	Unrecovered Cost from prior periods (thousand USD)	950		15			
(G)	Capex + Opex of the period allowed to recover (thousand USD)	1550	2629	1147	1004	874	770
(H)	Balance to recover (thousand USD): (F) + (G)	2500	2629	1162	1004	874	770
(I)	Cost Recovered in the period (thousand USD): (H), limited by (E)	2500	2615	1162	1004	874	770
(J)	Cost Oil (STB): (I)/(A)	50,00	58,10	33,19	28,69	24,97	22,00
	Profit Oil Calculation						
(K)	Oil to share (thousand STB): (C) - (J)	35,00	12,45	25,46	20,61	15,83	12,00
(L)	Contractor Share (thousand STB): 60% X (K)	21,00	7,47	15,28	12,37	9,50	7,20
(M)	Total Contractor Share (thousand STB): (L) + (J)	71,00	65,57	48,46	41,05	34,47	29,20
	Contractor Cash Flow						
(N)	Revenue (thousand USD): (A) X (M)	3550	2951	1696	1437	1206	1022
(O)	Non recoverable project costs of the period	350	333	319	308	298	290
(P)	Net Cash Flow (thousand USD): (N) - (G) - (O)	1650	-11	230	125	34	-38

Table 12.1—Estimated entitled quantities and reserves estimates. Rounding may cause distortion in numbers.

12.5.3 Revenue-Sharing Contracts. Revenue-sharing contracts are very similar to the PSCs described earlier, with the exception of contractor remuneration. As in a PSA, the contractor typically bears all risks and costs for exploration, development, and production. In return, the contractor is given the opportunity to recover the investment plus obtain a return on the investment from an agreed sharing of the net revenue. There is typically no explicit cost recovery, but rather the contractor is expected to pay its costs with its share of the revenue. The contractor normally receives title to the prescribed share of the volumes as they are produced (just as in a PSA). Subject to technical certainty, reserves/resources in one or more of the PRMS categories based on the revenue share that are recoverable under the terms of the contract are typically recognized by the contractor. Revenue-sharing agreements are commonly referred to as risked-service contracts, or even production-share contracts, in the industry. **Fig. 12.7** is a schematic of the distribution of yearly project revenue between contractor and government.

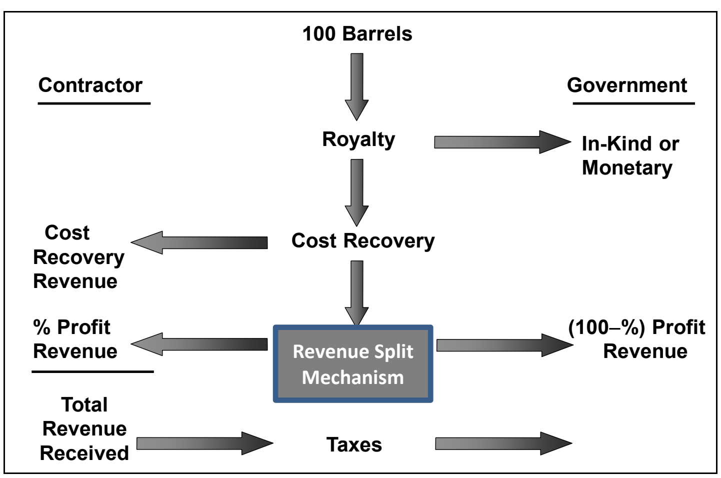


Fig. 12.7—Example revenue-sharing contract.

12.5.4 Risked-Service Contracts. With a risked-service contract, the contractor usually receives a defined remuneration fee, fixed or variable, plus cost recovery (introducing risk/reward due to uncertainty and pace of payout). The contractor has an economic or revenue interest in the production and hence can recognize reserves and resources. As in the PSC, the contractor provides the capital and technical expertise, at its sole risk, required for development. The contractor can recover those costs (as prescribed in the contract) from sales revenues. The remuneration fee typically requires achieving some target of production or incremental production (this adds to the element of risk/reward). Similar to a PSC, resources may be recognized for future development phases or possible extensions to the contract term. Volumes recoverable after the term of the contract ends will normally be classified as Contingent Resources unless the contract contains provisions for extension, and there is reasonable expectation that an extension, a renewal, or a new contract will be granted (refer to previous Section 12.5.1 and see Section 12.6.4).

Fig. 12.8 is a schematic of the distribution of yearly project revenue between contractor and government. This type of agreement is also often used where the contracting party provides expertise and capital to develop and enhance operations in an existing field and has rights and obligations and bears risks similar to those in the previously noted agreement types.

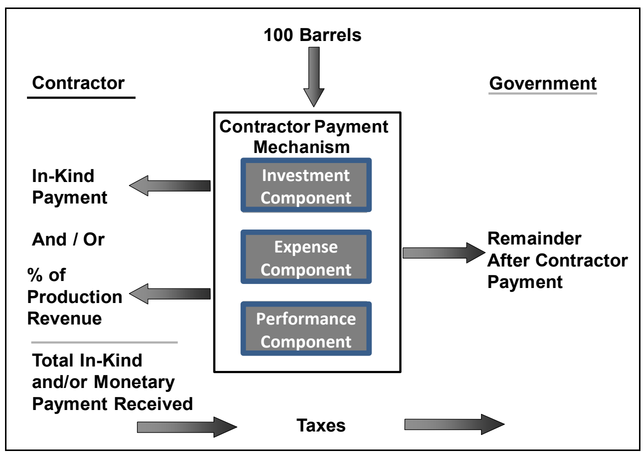


Fig. 12.8—Example risked-service contract.

Reserves and resources recognized under the PRMS and those reported to regulatory agencies would be based on the economic interest held or the financial benefit received**.** Depending on the specific contractual terms, the reserves and resources equivalent to the value of the cost-recovery-plus-remuneration fee (fixed and/or variable) are normally reported by the contractor. In the absence of a cost-recovery mechanism for this type of risk-service agreement, a fixed remuneration fee alone (e.g., USD 100/year or USD 10/STB) would not typically characterize an economic interest in the production (see Section 12.5.5—Pure-Service Contracts). If an incentive that depends on meeting and/or exceeding a baseline of production is part of the agreement (incorporating only a remuneration fee), then there is the potential for an economic interest to be realized. In this circumstance, a common approach is to recognize the incentivized portion of the production as entitled reserves/resources, in accordance with its risk and reward.

12.5.4.1 Example: Risked-Service Contracts. A host country has granted a 6-year, risked-service contract to Company One. The terms of the contract state that Company One will assume management of a producing oil field (called Blue Field) and will be tasked with maintaining and increasing production from the Blue Field. A baseline of production that must be maintained is provided as part of the contract **(see Table 12.2).** As long as average production for any given year meets or exceeds that baseline production, Company One will be paid a remuneration fee equal to USD 1.50 for every whole barrel produced above the baseline production. Company One will be allowed to request 100% repayment of annual approved (by the host country) operating expenses not to exceed USD 20 per barrel of the projected baseline production (or 50% of the prevailing sales price per barrel, whichever is lower) for the life of the project. Capital costs can also be recovered based on pre-approved (by the host country) budgeted capital for Blue Field. Table 12.2 illustrates how the estimate of reserves in the Blue Field would be apportioned to Company One, assuming an estimated constant oil price of USD 50/STB.

A	B	C	D	E	F	G	H=(E+F+G)/USD 50
Year	Estimated Gross Oil Production (STB)	Baseline Production (STB)	Incremental Production Over Baseline (STB)	Approved Operating Costs (USD)	Pre-Approved Capital Costs (USD)	Remuneration Fee Revenue (USD)	Net Entitlement (STB)
1	40.000	40.000	0	200.000	50.000	0	5.000
2	38.000	36.000	2.000	195.000	250.000	3.000	8.960
3	38.000	32.400	5.600	195.000	0	8.400	4.068
4	40.000	29.200	10.800	200.000	0	16.200	4.324
5	36.000	26.200	9.800	190.000	0	14.700	4.094
6	32.400	23.600	8.800	181.000	0	13.200	3.884

Table 12.2—Company One production forecast, contract production baseline, and estimated entitled quantities.

The entitlement quantity is calculated by summing the sources of revenue (cost recovery plus remuneration fee) for the contractor (Company One) and dividing by the prevailing oil price (forecasted as a constant USD 50/STB in this example). Company One is exposed to both market risk and technical risk. For example, if for some reason, Company One's production forecast dropped significantly, then Company One's entitlement would be affected by both the reduced forecast and by the possibility of not being reimbursed for all operating costs (particularly if costs are firm) or investments. There is also the possibility that the reduced production would preclude achievement of an incremental production above the baseline. Price fluctuations may also affect entitlement significantly, as entitled quantities are based on cost plus investment divided by price, with a sales price/barrel limit for operating cost reimbursement. Pre-approved investments are intended to be reimbursed, but with low prices or low production, there might be a possibility of not being fully reimbursed.

12.5.5 Pure-Service Contracts. 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 specified period of time. The service company investment is typically limited to the value of equipment, tools, and 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. Payment for services is normally based on daily or hourly rates, a fixed turnkey rate, or some other specified amount. Payments may be made at specified intervals or at the completion of the service. Payments, in some cases, may be tied to the field performance, operating cost reductions, or other important metrics. In many cases, payments are made from government general revenue accounts to avoid a direct linkage with field operations.

Risks undertaken by the service company under this type of contract are usually limited to nonrecoverable cost overruns, losses owing to client breach of contract or default, or contract dispute. These agreements generally do not have exposure to petroleum exploration, development, production volume, or market price risks or other risks; consequently, reserves and resources entitlement is not (typically) recognized under this type of agreement. The service company may, however, have an obligation to report gross (total working interest basis) reserves and resources to the regulatory agencies of the host country, but this would not imply any ownership or entitlement to reserves. These agreements can be very complex, and an evaluator should carefully analyze the contract terms before characterizing them as pure service and making a decision on whether entitlement of reserves can be claimed. **Fig. 12.9** is a schematic of the distribution of yearly project revenue between contractor and government.

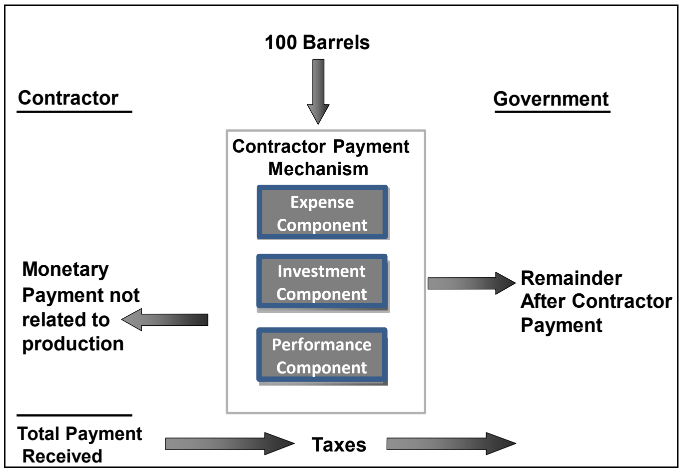


Fig. 12.9—Example pure-service contract.

12.5.6 Loan Agreements. A loan agreement is typically used by a bank, other financial investor, or partner to finance all or part of an oil and gas project. Compensation for funds advanced is typically limited to a specified interest rate. The lender does not participate in profits earned by the project above this interest rate. There is normally a fixed repayment schedule for the amount advanced, and repayment of the obligation is usually made before any return to equity investors. Risk is limited to default by the borrower or failure of the project. Variations in production, market prices, and sales do not normally affect compensation. Reserves and resources would not be recognized in any PRMS categories by the lender under this type of agreement, although they would be reported by the contractor.

12.5.7 Production Loans, Forward Sales, and Similar Arrangements. 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 original interest owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Determination of whether the transaction represents a sale of interest or financing rests on the particular circumstances of each case. If the risks associated with future production, particularly those related to ultimate recovery and price, remain primarily with the original interest owner, then the transaction should be considered as financing or contingent financing. In such circumstances, the repayment obligation will normally be defined in monetary terms and would not enable recognition of reserves and resources by the funding entity under the PRMS.

In cases where funds advanced for exploration are repayable by offset against purchases of oil or gas discovered, or in cash if insufficient oil or gas is produced by a specified date, such arrangements are considered borrowings, and entitlement of reserves and resources remain with the production seller. When funds are advanced to an operator for development of a property (or for increased operating activities) and are repayable in cash out of the proceeds from a specified share of future production from the producing property, until the amount advanced plus interest at a specified or determinable rate is paid in full, these arrangements are typically considered a borrowing, and reserves and resources entitlement remains with the original producer. Such transactions, as well as those described in Section 12.5.11, are commonly referred to as production payments.

If the risks associated with future production, particularly those related to ultimate recovery and price, rest primarily with the funding entity, then the transaction should be considered either a contingent sale or a disposal of fixed assets (and sale of interest). In this case, reserves and resources would be recognized under the PRMS by the funding entity. The ability/duty to report reserves to applicable government agencies may be permissible, depending on their regulation. Volume-denominated production payments (see Section 12.5.11) typify such sales of interest.

For the companies' financial statements, the specific accounting standards for the jurisdiction should be consulted for appropriate treatment. In some regulatory environments, merely holding such a quantity deemed as purchased may not meet the standard of the purchaser as an oil and gas producing entity, which may preclude reporting such volumes as reserves or resources.

12.5.8 Carried Interests. Carried interests cover a broad spectrum of arrangements where one party (the carrying party) agrees to pay for a portion or all of the costs of another party (the carried party) on a license or contract in which both own a portion of the WI. The following discussion is intended to illustrate the basic concepts of carried interests and the reporting of resources under them with a simple type of reversionary agreement. In this example arrangement, the carrying party agrees to pay for the preproduction costs of the carried party. This arises when the carried party is either unwilling to bear the risk of exploration or is unable to fund the cost of exploration or development directly. Owners may enter into carried-interest arrangements with existing or incoming joint venture partners at the exploration stage, the development stage, or both.

If the property becomes productive, then the carrying party will be reimbursed either (a) in cash out of the proceeds of the share of production attributable to the carried party or (b) by receiving a disproportionately high share of the production until the carried costs have been recovered. In the case of mechanism (b), the adjusted share of production held by the parties during the recovery of the carried costs period ("payout") may be referred to as "interest before payout." At the point of recovery of the carried costs (or a multiple thereof), the parties will revert to each respective original share of production, referred to as "interest after payout" or as a "reversionary interest." The carrying party normally recognizes the additional future production received in one or more of the PRMS reserves and resources categories. The estimate of reserves and resources for all the parties would be based on the future projection of production and revenue, to which the interest before payout would be applied prior to the point of payout and the interest after payout (or reversionary interest) would be applied for the remaining period of production. If project maturity is not sufficient to classify the amounts as reserves, then the PRMS resources classes and categories would be used according to the agreed reimbursement terms.

If reimbursements are guaranteed at some level of monetary payment, with the potential for any shortfall from the entity of interest to be compensated from another production stream or just paid in cash, then this is typically considered as removal of the carrying party from the requisite risk of production, and, in that case, quantities should not be booked as reserves or resources entitlement for the carrying party.

12.5.9 Entitlement with Interest Before Payout and Interest After Payout Example. Consider a producing project with two partners (Oil Company A and Oil Company B), each holding 50% of the rights to production (and the same responsibility for costs), where all forecast quantities are categorized as Proved Reserves by Company A. A new infill well is proposed, and drilling costs will be USD 1,000,000. Company B does not have the capital to fund the drilling well, so Company A agrees to pay the full cost of the well in exchange for a higher (25% more) portion of production (and related costs) until the share owed by Company B (USD 500,000, which it was supposed to pay for the well) is fully repaid. The agreed interest before payout is Company A = 75% and Company B = 25%. After payout, the interests will revert to 50% each (interest after payout, also called reversionary interest). **Table 12.3** illustrates how Proved Reserves quantities would be apportioned to each party, considering Company A gross oil, cost, and revenue low estimate forecast, for a period of 6 years to show calculation during and immediately after the payout period. (For this example, there are no royalties due.)

						Company A		Company B	
Year	Gross Oil (STB)	Carried Cost (USD)	Gross Revenue Less Costs from Operations (USD)	Gross Revenue Less Costs from Operations for Payout: 25% (USD)	Year End Balance of Payout (USD)	Net Entitled Gross Oil (STB)	WI (%)	Net Entitled Gross Oil (STB)	WI (%)
1	20.000	500.000	600.000	150.000	350.000	15.000	75%	5.000	25%
2	16.000		440.000	110.000	240.000	12.000	75%	4.000	25%
3	14.000		360.000	90.000	150.000	10.500	75%	3.500	25%
4	13.000		320.000	80.000	70.000	9.750	75%	3.250	25%
5	12.000		280.000	70.000	-	9.000	75%	3.000	25%
6	10.000		248.000	-	-	5.000	50%	5.000	50%
Total	85.000	500.000	2.248.000	500.000		61.250		23.750	

Table 12.3—Apportioned quantities during interest before payout and interest after payout periods using Company A forecast for 6 years.

If the license to produce ended at year 6, then Company A Proved Reserves would equal the total entitled quantities (61,250 STB). Forecasts for the best estimate could be used in a similar logic for 2P Reserves estimates. Considering the remaining forecast years and no expiration date for the license to produce, Company A would determine the economic limit for entitled reserves estimates based on its perceived uncertainties and the same forecast prices, costs, and share of production. Company B would use similar logic based in its perceived uncertainties, forecast prices, and costs, and its share of production to estimate reserves.

In this example, there were no royalties due. If royalties were due, then quantities to settle carried costs would usually be based on quantities and revenues after royalties. The actual payout terms will usually be described in an agreement among partners (e.g., joint operating agreement).

12.5.10 Purchase Contracts. A contract to purchase oil and gas provides the right to purchase a specified volume at an agreed-upon price for a defined term. Under purchase contracts, exposure to technical and market risks is borne by the production seller. While a purchase or supply contract can provide long-term access to reserves and resources through production, it does not convey the right to extract, nor does it convey an economic interest in, the reserves. Consequently, reserves and resources would not be recognized under the PRMS for this type of agreement.

12.5.11 Volume-Denominated Production Payments. Unlike the agreements described in Section 12.5.7, which are essentially loans or borrowings, there are arrangements that result in the transfer of an interest in reserves from one party to another. These types of arrangements are volume-denominated production payments, and they specify terms where assets (typically cash) are transferred between participants in return for the right to take a specified volume from the production stream of a project. In common practice, volume-denominated production payments are also commonly referred to as "production payments," making the distinction between the two different types of production payments less clear. Production payments have been widely used as a hedging vehicle in periods of price volatility.

In volume-denominated production payments, as referenced in Section 12.4.3, reserves and resources may be recognized by the purchaser (entity who takes the production), thus reducing the entitlement of the seller, for quantities associated with a production payment. In such an arrangement, the production seller's obligation is not expressed in monetary terms but rather as an obligation to deliver, free and clear of all expenses associated with operation of the property, a specified quantity of oil or gas to the purchaser out of a specified share of future production. In order to be considered a recognizable quantity for reserves and resources, the essential requirements of Section 12.4.1 must be met. The specific accounting standards for the jurisdiction should be consulted for appropriate accounting treatment of any transaction. **Fig. 12.10** gives an example of a typical production payment arrangement.

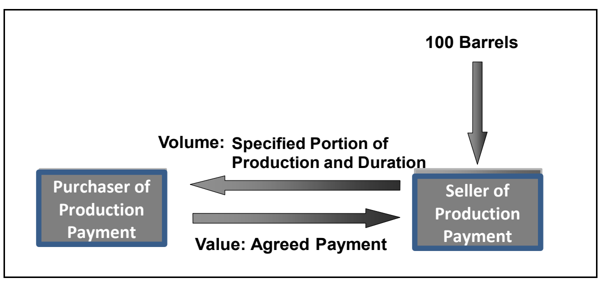


Fig. 12.10—Example conveyance-production payment.

12.5.12 Other Contracts and Agreements. From time to time, evaluators can encounter unique agreements that have elements of the descriptions in Section 12.5.1 through 12.5.11 but are not exactly as described here. These types of arrangements and agreements must be considered in the context of the key principles outlined above, including economic interest and risk exposure. Examples of other agreements that are encountered on occasion include net profits interests, interest swaps, and storage and transfer agreements. Net profits interests are most often encountered in North America where the holder of the interest holds a stipulated portion of the proceeds from a well or other specific field entity. Swap agreements are binding contracts that convey ownership in production from oil and gas properties linked to production in another separate oil and gas property. Storage and transfer agreements do not typically meet the criteria for reserves and resources recognition; however, in certain circumstances, agreements can encompass risk exposure with an economic interest.

12.6 Other Concerns of Resources Entitlement and Recognition

Royalties, taxes, unitization agreements, and contract expiration are commonly present in any contract type. This section discloses considerations that may influence the entitlement of resources.

12.6.1 Taxes and Reserves/Resources. In general, reserves and resources are recognized in situations where there is an economic interest, and after deduction of any royalty (see Section 12.6.2) owed to others. Production sharing or other types of operating agreements lay out the conditions and formulas for calculating the share of produced volumes to which a contracting company will be entitled. As explained above, these volumes are normally divided into cost recovery and profit volume components. The summation of the cost and profit volumes that the contractor will receive through the term of the contract represents the reserves and resources to which the contractor is entitled. In many instances, these agreements may also contain clauses that provide that host country income taxes will be paid to the government by the NOC on behalf of the contractor. While details on the specific hydrocarbons produced and revenues that are used to fund the payments may not usually be specified in the agreement, they are inferred to come from the government's share of production (under the agreement). In such cases, the contractor derives a benefit from the government's share of hydrocarbons used to fund the contractor's tax payments, representing an economic interest in such a share, which may be considered as contractor's reserves or resources. By virtue of the economic interest that the contractor has in these additional volumes, common practice is to include the related quantities in the contractor's share. This also typically requires reporting of the value related to the tax payment that is received in the financial reporting statements. Section 12.7.1 shows an example where volumes related to taxes are included in reserves or resources estimates.

12.6.2 Royalties, Overriding Royalty, and Government Fixed Volume Entitlement and Reserves/Resources. A royalty is commonly retained by a mineral owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce the resources. Royalties are a non-working (and non-operating) type of entitlement interest in resources that is free and clear of the costs and expenses of development and production to the royalty interest owner, as opposed to a WI, where an entity has cost exposure. Royalties are generally a fixed percentage or may have some form of a sliding scale basis. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production in cash or as a right to take a portion of the volume of production (royalties in kind). The royalty terms may also provide the option to switch between forms of payment at the discretion of the royalty owner. In either case, royalty quantities must be deducted from the lessee's or contractor's resources entitlement so that only economic interest quantities are recognized. Conversely, if an entity owns a royalty or equivalent interest of any type in a project, then the related quantities should be included in that entity's resources entitlements and should not be included in entitlements of others. Royalty interest owners are typically responsible for any severance or production taxes assessed on their share of production or proceeds of production.

While the royalty description and treatment with respect to entitlement may appear straightforward, it is not uncommon to see the term "royalty" applied to cash payments that are not, in fact, a royalty as defined above (an interest retained by the mineral right owner). In some agreements or fiscal systems, there may not be a clear distinction between production or other form of taxes imposed by the host government and other payment obligations that may be referred to as royalties. These other payment obligations are expressed in monetary terms with no alternative to take equivalent quantities in kind. They are typically linked to any or all of the following: production rates, quantities produced, cost recovery, or the value of production (price sensitive). In many cases, they can also be offset or reduced by taxes, tariffs, and other obligations, which is contrary to the definition of a royalty noted above. These payment obligations may be referred to as royalties, but they do not represent an interest retained by the lessor/host and are effectively an additional form of tax, and they are therefore not a true royalty. The production and underlying resources are controlled by the lessee/contractor, who may (subject to contractual terms and/or regulatory guidance) elect to report these payment obligations as a tax. Such payments referred to as royalties (but more correctly referred to as a production or other form of tax) must be included as an expense in the resources cash flows used for economic limit and economic determinations, and all quantities should be recognized as reserves or resources by the lessee/contractor without a corresponding reduction in lessor/contractor's entitlement related to such so-termed royalty payments.

In some cases, government legislation, regulations, or contract agreement terms may contain clauses that help to establish if the obligation is a true royalty or not, and how the royalty is to be satisfied in monetary terms. In other cases, judgement must be carefully applied to determine if a payment obligation is a true royalty or actually a form of production or other kind of tax. While there are no published standards to differentiate between royalties and taxes, examination of the specific attributes and the intent of the payment or obligation in comparison to other established royalties and taxes as recognized in the finance and accounting practices of a given country (e.g., as in the US and Canada) is one approach often used to make the distinction. Examples where a case may be made that the obligation referred to as a royalty may in fact be a tax (production or other form) rather than a true royalty could include any of the following:

- The obligation is linked to project profitability rather than a defined interest.
- Costs are deductible from the obligation.
- Cash royalty payments are not based on sales quantities.
- Prices used for cash royalties are arbitrated by the government.
- Provisions only allow for cash payment without an option to take in-kind production quantities.
- The clause describing the obligation is grouped with clauses detailing production or other taxes and tariffs that are due.

Where the payment is not a royalty interest as defined, then the related reserves and resources are included in entitlement quantities recognized by the lessee/contractor, and expenses (including the payment) are recognized in the lessee's/contractor's reserves cash flows. **Fig. 12.11** shows a schematic figure for reserves and resources entitlement when royalties are applied in kind or in cash in a concession contract. **Fig. 12.12** is a schematic figure for reserves entitlement when the term "royalty" is applied to monetary payments that are considered to be production taxes.

It is important to note that a government fixed volume supply (e.g., 100 million CFD) is not considered to be a royalty but must also be excluded from a lessee's/contractor's entitlement.

Similar to royalties, an overriding royalty interest is a non-working interest that is free and clear of the costs and expenses of development and production, as opposed to a WI, where an entity has cost exposure. Whereas royalty interests are derived from an ownership in the minerals, overriding royalty interests are a stated percentage (or they may have some form of a sliding scale) that is typically carved out of the WI share. An entity who owns an overriding royalty interest may claim entitlement of resources that correspond to its proceeds from sales. Conversely, if an entity has WI in projects that also have an overriding royalty interest, the related quantities must be excluded from the entity's entitlement.

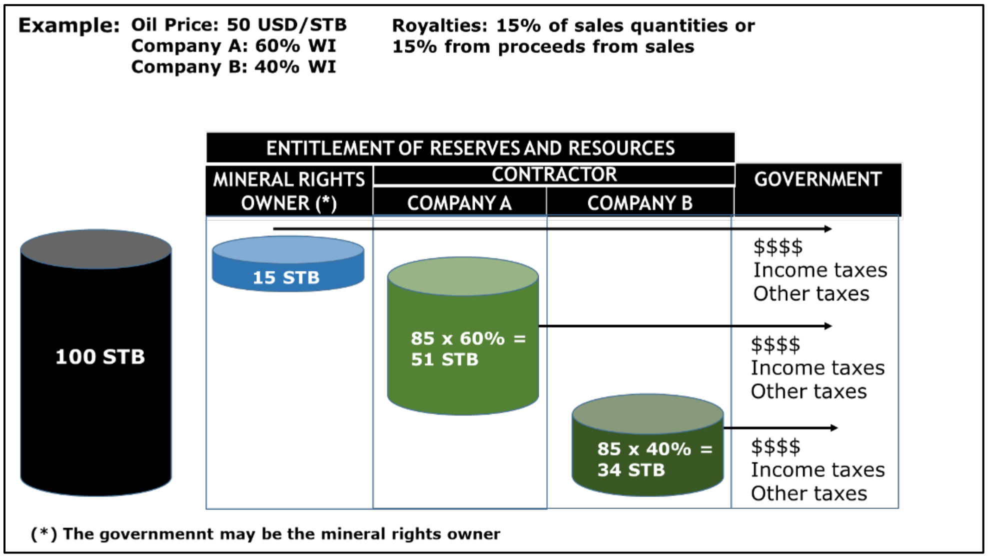


Fig. 12.11—Example of entitlement with royalties in a concession contract for an oil-producing field.

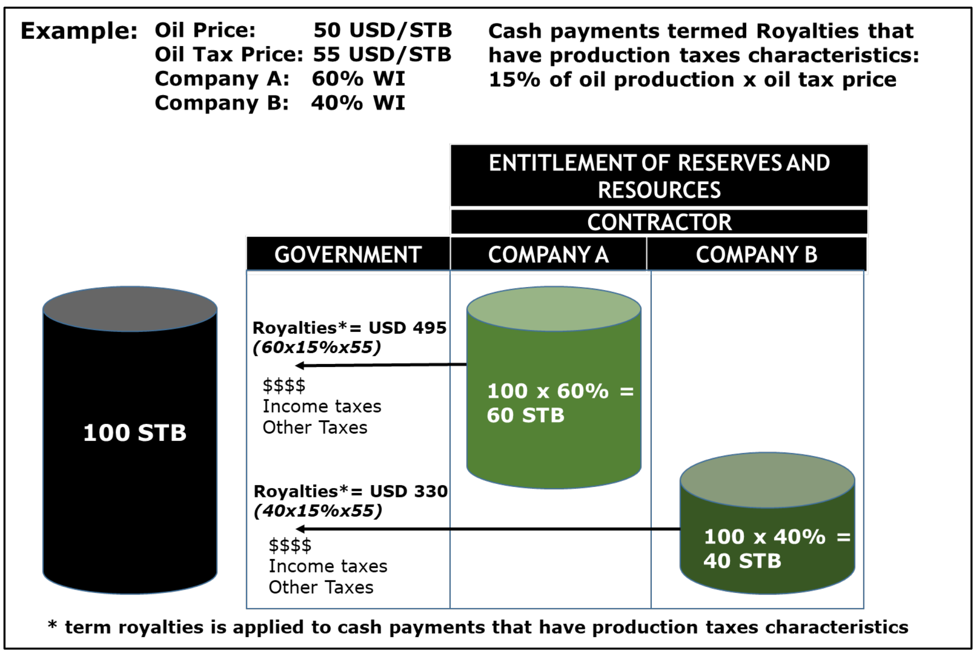


Fig. 12.12—Example of entitlement with payments termed royalties that are considered to be production taxes in a concession contract for an oil-producing field.

12.6.2.1 Example: Reserves Estimates in a Concession Contract with Royalties. *SUN* OIL Co. entered into an onshore concession contract to explore, develop, and produce hydrocarbons in Block A in Country ABC in a government bid, with 100% WI. Block A is located close to several other producing fields. In Country ABC, hydrocarbon resources are owned by the ABC Federal Government, which grants producing companies the right to explore, develop, and produce hydrocarbons under concession contracts for 25 years. The contractor bears all risk and costs for exploration, development, and production and holds title to all produced resources during the concession period.

Over a 2-year period, SUN OIL Co. explored Block A and drilled two exploratory wells, which discovered oil in commercial quantities. The company conceived and approved a project to produce the already drilled wells and two additional wells within the proved area, and the company included this project in the field development plan, attending to all commercial considerations. Production will start in year 3 and will be transferred to a nearby facility, from which it will be sold to local market. In this simplified example case, SUN OIL Co. oil and gas forecast prices are USD 45/STB and USD 10 /Mcf for all future years, respectively.

12.6.2.1.1 Royalties Are Paid in Cash, with Tax Attributes. The contractor is subject to a cash-only termed royalty payment to the government, which has tax attributes. For this contract, those termed royalties are calculated as 17% of total produced hydrocarbons (including gas consumed in operations and any gas loss) multiplied by a government-established tax price. SUN OIL Co. oil and gas forecast prices for those payments are USD 60/STB and USD 14/Mcf for all future years, respectively. **Table 12.4** shows SUN OIL Co. sales production forecast and cash flow for the best estimate case, using SUN OIL Co. forecast prices. Since the termed royalty payments have tax attributes, Sun OIL Co. does not exclude quantities related to such payments from its forecast, and it includes the related payments as an expense in the cash flow. (Note that the gas volume used for "Future Payments Termed Royalties" includes quantities consumed in operation and losses, which are reflected in the "Gas for Payments Termed Royalty" column used to calculate the royalties.)

	BEST ESTIMATE								
Year	Oil and Condensate (thousand STB)	Sales Gas (million CF)	Revenue (million USD)	Future Investment (million USD)	Future Operating Cost (million USD) (*)	Future Payments termed Royalties (million USD)	Future NCF (million USD)	Cumulative Future NCF (million USD)	Gas for Payments termed Royalty Calculation (million CF)
1				4,50			-4,50	-4,50	
2				0,50			-0,50	-5,00	
3	230,53	162,20	12,00		3,27	2,89	5,84	0,84	227,07
4	119,67	84,20	6,23		1,94	1,50	2,79	3,63	117,88
5	72,24	50,82	3,76		1,37	0,91	1,49	5,11	71,15
6	47,82	33,65	2,49		1,07	0,60	0,81	5,93	47,11
7	33,16	23,34	1,73		0,90	0,42	0,41	6,34	32,68
8	23,63	16,63	1,23		0,78	0,30	0,15	6,49	23,29
9	17,35	12,20	0,90		0,71	0,22	-0,02	6,47	17,08
10	12,74	8,97	0,66		0,65	0,16	-0,15	6,31	12,56
11	8,62	6,06	0,45		0,59	0,11	-0,25	6,06	8,48
12	6,63	4,66	0,35		0,58	0,08	-0,32	5,74	6,53

Table 12.4—SUN Oil Co. sales production forecast and cash flow calculation, where the future operating cost (*) column includes applicable severance and ad valorem taxes amounts, and NCF indicates net cash flow.

The economic limit for 2P Reserves is in year 8, at the maximum undiscounted cumulative cash flow, considering incremental costs, as shown in **Fig. 12.13.**

As SUN OIL Co. does not include gas consumed in operations in its reserves estimates, best estimate (2P) reserves are estimated by adding forecast oil and sales gas production from year 3 to year 8, as shown on **Table 12.5.** If SUN OIL included fuel gas as reserves, forecast quantities of fuel gas from years 3 to 8 would also be included as gas reserves.

The 1P and 3P reserves are estimated similarly. In this example, the royalty payments are considered to be similar to production taxes, and they are not considered to be royalty interest. Therefore, they do not reduce the yearly contractor entitlement, which is 100% WI. Such cash royalty reduces the reserves cash flow of SUN OIL Co., but entitlement and revenue of all sales production remain with SUN OIL Co. If those cash payments were considered to be a true royalty interest, then reserves entitlement would be estimated similarly to the method described in Section 12.6.2.1.2 (following section).

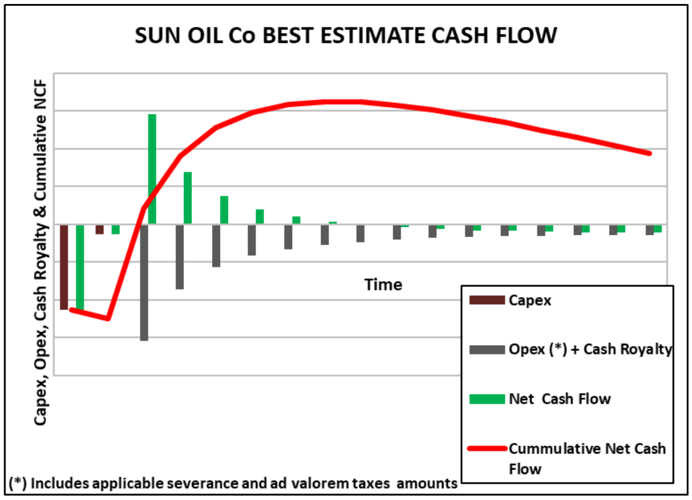


Fig. 12.13—SUN Oil Co. cash flow and economic limit for the best estimate, where cash royalty has tax attributes, and NCF indicates net cash flow.

YEAR	1	2	3	4	5	6	7	8	2P RESERVES
Oil and Condensate (thousand STB)	0,00	0,00	230,53	119,67	72,24	47,82	33,16	23,63	527,06
Sales Gas (thousand CF)	0,00	0,00	162,20	84,20	50,82	33,65	23,34	16,63	370,85

Table 12.5—2P Reserves.

As mentioned in Section 12.6.2, cases of cash royalties should be carefully analyzed to determine the nature of the payment. Each situation will need to be carefully analyzed.

12.6.2.1.2 Royalties Are Paid in Kind. In this case, the contractor bears all risk and costs for exploration, development, and production and holds title to all produced resources during the concession period, except for royalties sent to the NOC. Royalty shares are specified in each contract, and in the case of Block A, the royalty is calculated as 17% of sales quantities. **Table 12.6** shows SUN OIL Co. gross and net-of-royalties sales production forecast for the best estimate, using SUN OIL Co. forecast prices.

Revenue is calculated based on net-of-royalties quantities because SUN OIL Co. is not entitled to the royalties share of quantities. In this case, there is no royalty expense in the illustrated cash flow. The economic limit for 2P Reserves is in year 9, at the maximum undiscounted cumulative cash flow, considering incremental project costs, as shown in **Fig. 12.14.** The economic limit is different from the situation in which the royalties were paid in cash and had production taxes characteristics, which was in year 8.

As SUN OIL Co. does not include gas consumed in operation in reserves estimates, 2P Reserves are estimated by adding forecast oil and sales gas production from year 3 to year 9, as shown on **Table 12.7.** If SUN OIL included fuel gas as reserves, then forecast quantities of fuel gas from years 3 to 9 would also be included as gas reserves.

	BEST ESTIMATE								
	GROSS QUANTITIES		NET QUANTITIES						
Year	Oil and Condensate (thousand STB)	Sales Gas (million CF)	Oil and Condensate (thousand STB)	Sales Gas (million CF)	Revenue (million USD)	Future Investment (million USD)	Future Operating Cost (million USD) (*)	Future NCF (million USD)	Cumulative Future NCF (million USD)
1						4,50		-4,50	-4,50
2						0,50		-0,50	-5,00
3	230,53	162,20	191,34	134,62	9,96		3,27	6,69	1,69
4	119,67	84,20	99,33	69,89	5,17		1,94	3,23	4,92
5	72,24	50,82	59,96	42,18	3,12		1,37	1,75	6,68
6	47,82	33,65	39,69	27,93	2,07		1,07	0,99	7,67
7	33,16	23,34	27,53	19,37	1,43		0,90	0,53	8,20
8	23,63	16,63	19,62	13,81	1,02		0,78	0,24	8,44
9	17,35	12,20	14,40	10,13	0,75		0,71	0,04	8,48
10	12,74	8,97	10,57	7,45	0,55		0,65	-0,10	8,38
11	8,62	6,06	7,15	5,03	0,37		0,59	-0,22	8,15
12	6,63	4,66	5,51	3,87	0,29		0,58	-0,29	7,86

Table 12.6—SUN Oil Co. sales production forecast and cash flow calculation, where future operating cost (*) column includes applicable severance and ad valorem taxes amounts, and NCF indicates net cash flow.

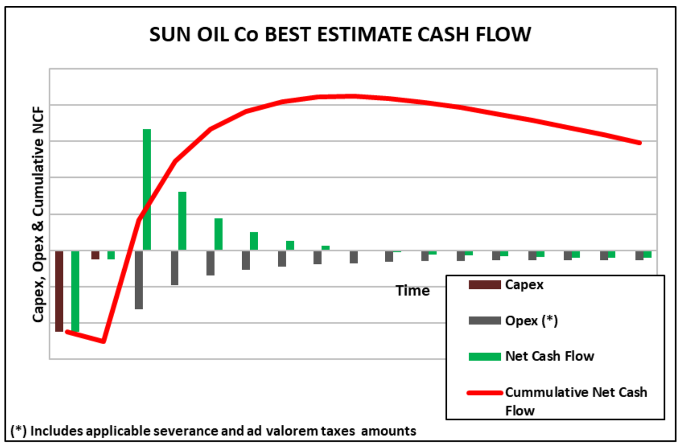


Fig. 12.14—SUN Oil Co. cash flow and economic limit for the best estimate, with royalties paid in kind, where NCF is net cash flow.

YEAR	1	2	3	4	5	6	7	8	9	2P RESERVES
Oil and Condensate (thousand STB)	0,00	0,00	191,34	99,33	59,96	39,69	27,53	19,62	14,40	451,86
Sales Gas (million CF)	0,00	0,00	134,62	69,89	42,18	27,93	19,37	13,81	10,13	317,93

Table 12.7—2P Reserves.

The 1P and 3P reserves are estimated similarly. In this example, royalties are paid in kind to the ABC Federal Government and are excluded from the contractor's reserves quantities.

12.6.3 Unitization Agreements. Petroleum accumulations straddling block contracts or license boundaries are common. Unitization is the process by which licensees of hydrocarbon leases or contracts pool their individual interest in return for an interest in the overall unit. Each participant involved in the unitization can have a different equity interest. **Fig. 12.15** shows an example of an accumulation that straddles block contracts.

Fig. 12.15—Accumulation straddling block contracts.

Unitization has its origins in the US, where hydrocarbon accumulations can extend across multiple privately owned land parcels or mineral rights boundaries/leases related to those lands. In the early days of the petroleum industry, the existing "rule of capture" doctrine acknowledged ownership of production by the landowner/mineral owner where the petroleum was produced, resulting in a rush to drill on adjacent spaces to prevent one's hydrocarbons from being drained from under one's property/ownership. This certainly had a profound effect on the pace of drilling in the US, including hydrocarbon drainage, production inefficiencies, and reservoir damage through overproduction. Subsequent development of US state-level legislation often required mineral rights owners to form a unit in petroleum development to promote "efficient and effective" production from the reservoir, avoid those harmful effects, and yield a fair outcome. Unitization is now applied throughout the world where similar circumstances prevail, while in some countries/areas, the rule of capture may still prevail. Generally, tracts to be unitized have proved the existence of the underlying petroleum resources, by drilling a well.

The act of forming this unit, i.e., unitization, is usually formalized by creating a unitization agreement (UA) or unit operating agreement between the mineral rights holders or mineral interest holders. This legal structure sets out the boundaries of the unit, describes the separate ownership by area ("tracts"), sets allocated ownership, and establishes how production operations are to be managed. The agreement typically contains clauses naming the party who will operate the unit (unit operator) and describing how hydrocarbon quantities and expenses will be shared among tracts making up the unit (termed tract participation or TP). Note that each tract may have multiple owners, and the TP would be apportioned according to ownership level in the original tract. Treatment of prior costs, provisions in the case of redetermination of TP, and other key elements of cooperation and dispute may also be addressed in the agreement.

Countries or states may have laws and regulations that set rules for the terms that should be followed by all parties, including "triggering" events, such as cash calls for development capital and required approvals for implementation. Unitization can also occur in accumulations that cross international borders, invoking use of international laws and agreements. Model contracts can also contain unitization clauses. Depending on the country and circumstances, more than one document may be needed to regulate the unit operation agreements

Arriving at the point of signing a UA or unit operating agreement may require significant data and technical study by the TPs, in addition to legal and regulatory activities, and the underlying uncertainties can lead to a long period of negotiations. Typically, an agreement will provide for an initial TP, to be followed by one or more redeterminations. As tracts may have different participant entities, a unit interest (for an ownership entity) is usually determined by multiplying the party's participating interest in each tract by that tract's interest (TP) in the unit.

Common parameters used for determining TP are: petroleum initially in place, hydrocarbon pore volume, estimated ultimate recovery, or net present value, but they can also include other factors, such as well productivity, well density, cumulative production, and/or surface acreage. The idea is to allocate the holdings in the unit by a reasonable facsimile of value or economic interest.

Reserves and resources entitlement under the PRMS is based on economic interest in the forecast production. The reserves and resources that are associated with each participant and party to the unitization are not necessarily just the product of the production forecast of the accumulation and determined TP (which shall represent the future split of production and expenses related to the unitized reservoir). Reserves and resources estimates will consider other factors, such as each tract's contract model, status, and expiration date. As for any other project, the entitled future production is subject to commerciality determination to be classified as reserves. Forecast prices, estimated development and operating costs, market infrastructure, and other factors may result in different commerciality considerations among participating entities in the unitized reservoir. Of course, each entity may have its own perception of uncertainties, which may result in different resources categorization among the participating entities. Additionally, the existence of other non-unitized reservoirs in a given tract would be appropriately considered in reserves estimates by those entities having an interest in them.

When estimating reserves and resources for a reservoir that may become unitized, an evaluator must also consider the unitization approval and effective dates because they affect the forecast, which may also be impacted by the venue regulatory framework, specific UA status and clauses, required outstanding approvals, history of similar unitizations, and any other document related to the unitization process. There may be a need for assumptions of entitlement before any agreement is signed or approved, and such an estimate of unit entitlement would be based on such considerations. Of course, entitlement of reserves and resources would be modified and adjusted to reflect actual unitized conditions when known.

Where costs have been incurred by one or more parties to the unitization prior to the effective date of unitization, the handling of those costs are typically subject to make-up provisions included in the UA. These costs may be recovered out of future production, or there may be an agreed-upon monetary settlement. In cases where cost reconciliation is received from future production, the entities on each side of the reconciliation may choose to report the future volume as a reduction (those that did not incur the pre-unitization costs) or an addition (those that incurred the pre-unitization costs and are being reimbursed) to their respective reserves or resources entitlement, if contracts, agreements, and regulatory framework permit. This scenario may include unitization of not-yet-contracted areas or a tract held by the government, whose costs are carried by other participants, which may be partly or wholly settled with future production to the contractor.

When a unitization or a redetermination results in adjustments to compensate for pre-event splits (including provisional unitization splits) that are changed, parties on each side of the agreement may receive or grant future production allocations to achieve balance between entities. In this case, the receiving entity must add reserves/resources entitlement in the appropriate amount. Accordingly, where part of an entity's future production is reduced to provide make-up volumes to other participants, that entity must reduce its reported entitlement reserves or resources by the amount by which the future production is reduced.

In certain cases, the tract that paid for past expenses may be under a PSC or similar agreement, and contracts, agreements, and regulatory framework may allow such expenses to be included as cost petroleum. Depending on contracts and regulation, care would be necessary to ensure that the entity did not receive double credit for booking cost petroleum (associated with the past costs) and then booking future production offsets. If the tract under a PSC or similar agreement did not pay for past expenses, attributed past expenses may be included as cost petroleum, depending on contracts and regulation.

12.6.3.1 Example: Reserves Estimates with Unitization of Accumulation in Two Concession Areas after a Unitization Agreement. SUN OIL Co. and MOON OIL Co. entered into an onshore concession contract with a local government to explore, develop, and produce hydrocarbons in Block 36. Each company has 50% interest in the block. After a 2-year exploration period, which included two exploratory wells and the acquisition of seismic data, they discovered oil in commercial quantities and that the accumulation extended to Block 37, recently leased from the local government by STAR OIL Co. (80% WI) and COMET OIL Co. (20% WI), as shown in **Fig. 12.16.** According to government regulations, the companies in Blocks 36 and 37 are responsible to pay cash payments termed royalties to the government, which have production tax characteristics. Those cash payments are calculated as 10% of all produced oil and gas, multiplied by a tax price established by the government. In this simplified example case, SUN OIL Co. oil and gas forecast sales prices are USD 50/STB and USD 8/MCF for all future years, and forecast royalty prices are USD 55/STB and USD 10/MCF for all future years.

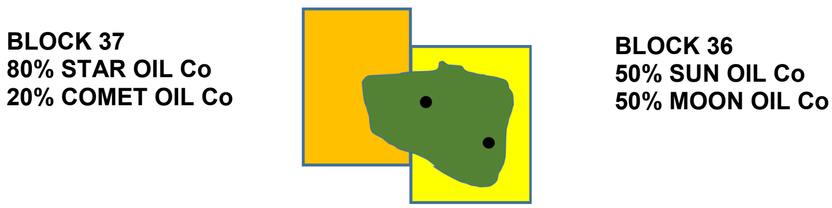


Fig. 12.16—Accumulation that extends across Block 36 and Block 37.

As the accumulation straddles the concession contract boundaries, after negotiation, all companies signed a UA in which they defined the TP based on estimated total petroleum initially in place from a P50 model of the accumulation in each lease area, with a possibility of future redetermination. The resulting TP was 70% (Block 36) and 30% (Block 37). Unit interests (UIs) were obtained by multiplying each company's WI in the block by the block TP, as shown in **Table 12.8.**

Block	Company	WI (%)	TP (%)	UI (%)
36	SUN OIL Co	50%	70%	35%
	MOON OIL Co	50%		35%
37	STAR OIL Co	80%	30%	24%
	COMET OIL Co	20%		6%
Total			**100%**	**100%**

Table 12.8—Tract participation and unit participation for the accumulation.

The UA included the development plan for the accumulation, which was approved by the local government entity. SUN OIL Co. was specified as the operator of the accumulation. The development plan included a project with drilling of two additional wells within the proved area, as shown in **Fig. 12.17,** which was approved by all four companies and attended to all commercial considerations.

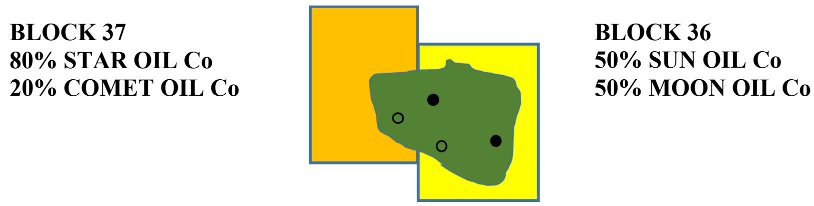


Fig. 12.17—Development wells in unitized accumulation.

Table 12.9 shows the SUN OIL Co. production forecast based on sales quantities for the low estimate case, with each company share according to the respective approved UIs. In this example, there are no royalties that diminish the reserves entitlement because the termed cash royalties were interpreted as production taxes. In the cases where royalties are payable or otherwise excluded from the contractor's entitlement, the split among participants of the unitized accumulation would probably be based on gross quantities (before deducting royalties), unless specified differently by unitization agreements.

	LOW ESTIMATE FORECAST									
	SALES QUANTITIES		SUN OIL Co (35%)		MOON OIL Co (35%)		STAR OIL Co (24%)		COMET OIL Co (6%)	
Year	Oil (thousand STB)	Sales Gas (million CF)	Oil (thousand STB)	Sales Gas (million CF)	Oil (thousand STB)	Sales Gas (million CF)	Oil (thousand STB)	Sales Gas (million CF)	Oil (thousand STB)	Sales Gas (million CF)
3										
4										
5	461,07	324,39	161,37	113,54	161,37	113,54	110,66	77,85	27,66	19,46
6	239,35	168,41	83,77	58,94	83,77	58,94	57,44	40,42	14,36	10,10
7	144,47	101,64	50,57	35,57	50,57	35,57	34,67	24,39	8,67	6,10
8	95,64	67,30	33,47	23,56	33,47	23,56	22,95	16,15	5,74	4,04
9	66,33	46,68	23,21	16,34	23,21	16,34	15,92	11,20	3,98	2,80
10	47,27	33,27	16,54	11,64	16,54	11,64	11,34	7,98	2,84	2,00
11	34,70	24,40	12,15	8,54	12,15	8,54	8,33	5,86	2,08	1,46
12	25,47	17,95	8,92	6,28	8,92	6,28	6,11	4,31	1,53	1,08
13	17,23	12,12	6,03	4,24	6,03	4,24	4,14	2,91	1,03	0,73
14	13,27	9,33	4,64	3,26	4,64	3,26	3,18	2,24	0,80	0,56
15	10,43	7,34	3,65	2,57	3,65	2,57	2,50	1,76	0,63	0,44

Table 12.9—SUN OIL Co. low estimate production forecast of the accumulation.

In general, in actual situations, each company will apply its own uncertainties for production forecasts in the low, best, and high cases and will consider them to classify and categorize reserves and resources. For example, this would mean that MOON OIL Co., STAR OIL Co., and COMET OIL Co. would estimate low, best, and high case forecasts differently from SUN OIL Co., and they would multiply them by the approved UI to obtain that company's low, best, and high case forecast share, resulting in different forecast quantities from those estimated by SUN OIL Co. as their forecast share. For example, MOON OIL Co.'s low estimate forecast will probably be different from the value shown as the MOON OIL Co. share column in Table 12.9. Each company will most likely use its own forecast to estimate reserves and resources and apply other commerciality constraints to its share (i.e., prices, royalty rates, contract constraints, etc.). According to the UA, companies will share costs based on their TP and UI, and costs incurred before the unitization agreement was effective will be settled with future sales production also based on their TP and UI, with a provision to limit this settlement to 25% of Block 37 contractor annual revenue. **Table 12.10** shows the SUN OIL Co. forecast of investment and operating costs for the low estimate case according to each company's UI.

	LOW ESTIMATE FORECAST		SUN OIL (35%)		MOON OIL (35%)		STAR OIL (24%)		COMET OIL (6%)	
Year	Investment (million USD)	Operating Cost (million USD)	Investment (million USD)	Operating Cost (million USD)	Investment (million USD)	Operating Cost (million USD)	Investment (million USD)	Operating Cost (million USD)	Investment (million USD)	Operating Cost (million USD)
3	9,00		3,15		3,15		2,16		0,54	
4	1,00		0,35		0,35		0,24		0,06	
5		6,53		2,29		2,29		1,57		0,39
6		3,87		1,36		1,36		0,93		0,23
7		2,73		0,96		0,96		0,66		0,16
8		2,15		0,75		0,75		0,52		0,13
9		1,80		0,63		0,63		0,43		0,11
10		1,57		0,55		0,55		0,38		0,09
11		1,42		0,50		0,50		0,34		0,08
12		1,31		0,46		0,46		0,31		0,08
13		1,19		0,42		0,42		0,28		0,07
14		1,16		0,41		0,41		0,28		0,07
15		1,13		0,39		0,39		0,27		0,07

Table 12.10—Low estimate SUN OIL Co. forecast investments and operating costs.

According to the UA, the Block 36 contractor (i.e., SUN OIL Co. and MOON OIL Co.) is entitled to extra produced oil and sales gas to settle past costs of USD 8 million, which they paid entirely. Because the Block 36 TP is 70%, its contractor will receive 30% of this amount (USD 2.4 million, representing Block 37 TP percentage in past costs) out of future sales production from the Block 37 contractors, which will be added to their Block 36 entitled resources. According to the UA, production costs and production taxes (including the cash payments termed royalties) related to the quantities used for settlement of past costs remain with the Block 37 contractors. **Table 12.11** shows Block 37 oil and gas sales production that will be used to settle past costs, according to the SUN OIL Co. low case forecast.

	LOW ESTIMATE									
	Block 37 (30% of accumulation)									
Year	Oil (thousand STB)	Sales Gas (million CF)	Oil Revenue (million USD)	Sales Gas Revenue (million USD)	Total Revenue (million USD)	Limit for Recovery (25% of Revenue)	Recovered Cost (million USD)	Unrecovered past cost (million USD)	Oil to settle past investment (thousand STB)	Sales Gas to settle past investment (million CF)
3								2,40		
4								2,40		
5	138,32	97,32	6,92	0,78	7,69	1,92	1,92	0,48	34,58	24,33
6	71,80	50,52	3,59	0,40	3,99	1,00	0,48		8,56	6,03
7	43,34	30,49	2,17	0,24	2,41	0,60				

Table 12.11—SUN OIL Co. low estimate of Block 37 production that will be used to settle costs incurred before the unitization agreement became effective.

Settlement will begin in year 5, when production starts. Past costs attributed to Block 37 contractors will be settled with production in years 5 and 6. In year 5, part of entitled Block 37 contractor sales production is estimated to be used to settle past costs, limited to 25% of annual Block 37 revenue (i.e., limited to 25% of 7.69 = USD 1.92 million). Therefore, SUN OIL Co. estimates that 25% of Block 37 sales quantities in year 5 (25% of 138.32 thousand STB = 34.58 thousand STB and 25% of 97.32 MMCF of gas = 24.33 MMCF) will be used to settle past costs. Since the total cost to be settled is USD 2.4 million, USD 0.48 million (USD 2.4 million – USD 1.92 million = USD 0.48 million) remains to be settled in future years. This amount may be estimated to be settled entirely in year 6, because it does not reach the settlement limit (25% of annual income of USD 3.99 million = USD 1.00 million, which is greater than USD 0.48 million).

Quantities used to settle past costs were estimated as a percentage of annual revenues that correspond to cost recovered (0.48/3.99), applied to sales quantities. Therefore, SUN OIL Co. estimates that 8.56 thousand STB of oil (71.80 × 0.48/3.99) and 6.03 MMCF of sales gas (50.52 × 0.48/3.99) in year 6 will be used by Block 37 to settle past costs. SUN OIL Co. and MOON OIL Co. are each entitled to 50% of oil and gas estimates shown in Table 12.11.

Table 12.12 shows SUN OIL Co.'s share of the sales production forecast for the low estimate case, as well as the related future cash flow using SUN OIL Co. forecast prices, including entitled production received to settle past costs. There are no royalties due (and no royalty interest quantities excluded from the contractor), as the termed royalty cash payments have production tax characteristics. SUN OIL Co. is responsible for such cash payments related to its entitled quantities, and it includes them as an expense in the cash flow. Production costs and production taxes (including the cash payments termed royalties) related to the quantities used for settlement of past costs are not expensed in the SUN OIL Co. cash flow, as they remain with the Block 37 contractors.

	SUN OIL Co LOW ESTIMATE											
	ENTITLED FROM UI (35%)		PRODUCTION ENTITLED FROM SETTLEMENT		TOTAL ENTITLEMENT		FUTURE CASH FLOW (million USD)					
Year	Oil (thousand STB)	Sales Gas (million CF)	Oil (thousand STB)	Sales Gas (million CF)	Oil (thousand STB)	Sales Gas (million CF)	Revenue	Investment	Operating Cost	Cash Payments termed Royalties & Ad Valorem Taxes	NCF	Cumulative NCF
3								3,15			-3,15	-3,15
4								0,35			-0,35	-3,50
5	161,37	113,54	17,29	12,16	178,66	125,70	9,94		2,29	1,02	6,63	3,13
6	83,77	58,94	4,28	3,01	88,05	61,95	4,90		1,36	0,53	3,01	6,14
7	50,57	35,57			50,57	35,57	2,81		0,96	0,32	1,54	7,68
8	33,47	23,56			33,47	23,56	1,86		0,75	0,21	0,90	8,58
9	23,21	16,34			23,21	16,34	1,29		0,63	0,15	0,52	9,09
10	16,54	11,64			16,54	11,64	0,92		0,55	0,11	0,27	9,36
11	12,15	8,54			12,15	8,54	0,68		0,50	0,08	0,10	9,46
12	8,92	6,28			8,92	6,28	0,50		0,46	0,06	-0,02	9,44
13	6,03	4,24			6,03	4,24	0,34		0,42	0,04	-0,12	9,33
14	4,64	3,26			4,64	3,26	0,26		0,41	0,03	-0,18	9,15
15	3,65	2,57			3,65	2,57	0,20		0,39	0,02	-0,21	8,93

Table 12.12—SUN OIL Co. share of sales production forecast and cash flow for the low estimate, where NCF is net cash flow.

SUN OIL Co. revenue is calculated by multiplying oil and gas prices by its total entitled sales production forecast (i.e., its UI share plus production received to settle past costs). The economic limit for 1P Reserves is in year 11, at the maximum undiscounted cumulative cash flow, considering incremental project costs. As SUN OIL Co. does not include gas consumed in operation in its reserves estimates, 1P Reserves are estimated by adding sales production forecast gas from year 5 to year 11, as shown in **Table 12.13.**

YEAR	3	4	5	6	7	8	9	10	11	1P RESERVES
Oil and Condensate (thousand STB)	0,00	0,00	178,66	88,05	50,57	33,47	23,21	16,54	12,15	402,66
Sales Gas (million CF)	0,00	0,00	125,70	61,95	35,57	23,56	16,34	11,64	8,54	283,31

Table 12.13—SUN OIL Co. 1P Reserves estimates.

SUN OIL Co. 2P and 3P Reserves are estimated similarly, considering best estimate and high estimate forecasts. MOON OIL Co. reserves entitlement will be estimated with a similar cash flow calculation, but it will probably use its own defined conditions (i.e., prices and costs) and other constraints for estimated quantities to settle past cost, commerciality determination, economic determination, and economic limit determination for the project, which might result in different reserves and resources quantities, even having the same UI as SUN OIL Co. Both companies may also consider different uncertainties for the low, best, and high cases, which would also result in different reserves and resources quantities for 1P, 2P, and 3P Reserves and 1C, 2C, and 3C Contingent Resources.

STAR OIL Co. and COMET OIL Co. will exclude forecast sales quantities used to settle past costs from their cash flows and reserves and resources entitlement. They may also have different contract models and their own defined conditions and uncertainties with which to estimate reserves and resources quantities for 1P, 2P, 3P, 1C, 2C, and 3C. In addition, their contract (Block 37 contract) may have different royalties, production taxes, or other conditions to consider for their entitled reserves and resources quantities. In an actual situation, Blocks 36 and 37 might also include other non-unitized reservoirs, which would be considered in the resources estimates. Each situation would need to be carefully analyzed to evaluate each contract model, the UA terms, the possibility to share costs with other accumulations or specific block-related issues, and each company's defined conditions and uncertainties for reserves and resources estimates.

12.6.4 Contract Extensions or Renewals. As described in the PRMS § 3.3.3.1, reserves cannot be claimed for those quantities that will be produced beyond the expiration date of the current production, concession, or license agreement unless there is reasonable expectation that an extension, a renewal, or a new contract will be granted. In the absence of such a reasonable expectation, estimated future production beyond the contract term may be classified as Contingent Resources, if the possibility exists that the terms of the agreement can be extended/renewed. This does not result in a split classification (PRMS § 2.2.0.4), because the Contingent Resources associated with the Reserves constitute a separate project in this context. As a separate project, a decision is likely to have to be made and approved. This may include decisions about a substantial bid amount to obtain/continue a concessionary arrangement and required investments that would be made, before or after the present contract expires, to produce beyond the present contract expiration date. When no extension or renewal of an existing agreement nor an assurance of a new agreement appears to be possible, estimated future production should be classified as unrecoverable resources by the contractor.

An additional uncertainty to be considered when future estimated quantities are being evaluated is whether it is reasonable to assume that the fiscal terms in a negotiated extension/renewal will be similar to existing terms. Differences in the agreed-upon terms could impact gross and net entitlement quantities.

Support for the reasonable expectation of extension or renewal would typically be based on the (1) intent of the interest holder and host government, (2) status of renewal negotiations, (3) historical treatment of similar transactions by the license-issuing jurisdiction, (4) legislation, and (5) the specific contract terms, which may also contain clauses about the possibility and requirements for contract extension or renewal. Reserves associated with production beyond the expiration date of the current agreement must comply with the other commerciality requirements of the PRMS § 2.1.2, commensurate with the project to produce those quantities.

Similar logic should be applied for gas sales agreements where market demand is not sufficient to support commerciality for all producible volumes. Reserves should not be claimed for estimated future production quantities that would be produced beyond those amounts specified in the current agreement or that do not have a reasonable expectation to be included in either contract renewals or future agreements.

12.6.4.1 Example: Considering Recovery Estimates After Contract Expiration Date. *A* contractor produces a field under a concession contract that is initially granted for 20 years, which will expire in 6 years. The concession contract has clauses specifying the requirements to extend the contract for 20 years from the original expiration date. The contractor has formally requested the extension and has already attended to its requirements. In similar requests, the local license-issuing jurisdiction has granted extension, without undue delay. There are no known contingencies that would prevent the contract extension.

The contractor's recoverable technical forecast of existing wells is expected to last 23 years from the effective date of the evaluation, and the project's economic limit will be reached in 16 years from the effective date (i.e., 10 years into the extension), if the extension is granted.

The contractor, under these circumstances, has a reasonable expectation that an extension will be granted, because there are no contingencies for the extension, and the local license-issuing jurisdiction historically granted the extension. The production forecast associated with the producing wells may be classified as Reserves, for 16 years (until the economic limit), if the other commerciality requirements of the PRMS § 2.1.2 are met. Production after the economic limit in year 16 may be classified as Contingent Resources (as noted previously in Section 12.5.1). **Fig 12.18** displays the contractor's resources classification for the field.

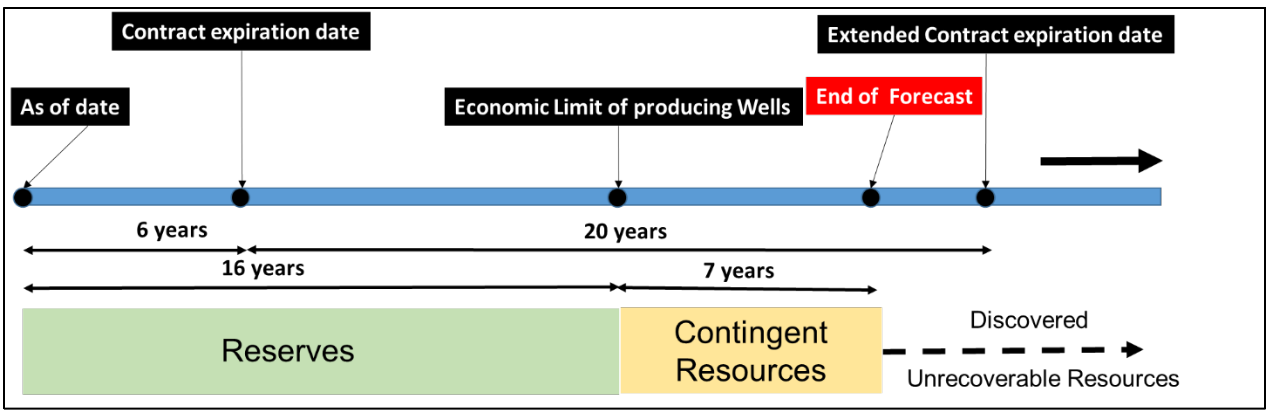


Fig. 12.18—Contractor's resource classification.

12.6.5 Appropriate Date on Which to Recognize Entitlement for Reserves Estimates in Specific Cases. There are situations where there is uncertainty about the appropriate date on which to consider and potentially recognize entitlement of reserves. For example, in situations where contracts or agreements are signed well in advance of the project's effective date, when should entitlement be applied? Farm-in and farmout agreements, unitization agreements, and other pending circumstances also may be unclear as to the particular date of entitlement application.

For reserves estimates, there must be evidence that legal, contractual, environmental, and government approvals are in place or will be forthcoming, together with solution of any social and economic concerns (see PRMS § 2.1.2). There must exist a reasonable expectation for all such approvals, which is a requirement for all activities to implement the project and begin production.

When contracts or agreements are signed before the effective date begins, and there are no further required approvals or circumstances that might prevent it from being effective at the signed terms and dates (e.g., environmental approvals), entitlement of reserves may be recognized when the contract is signed (if other commerciality requirements are met). The reserves estimated would include those quantities that will be produced from the contract effective date and term. When external approvals or specific circumstances are required to exist or come to pass, historical approvals and comparison with similar transactions may be considered to determine the reasonable expectation for entitlement recognition date. Required approvals or circumstances that might represent a meaningful possibility that the terms of the contract or agreement may change (circumstances not matching the terms signed or that might postpone the effective date significantly) may suggest caution in assuming the anticipated terms and dates will be applicable. In such a circumstance, it might be appropriate to wait for clearance of the approvals or circumstance milestones before recognizing the impact on reserves estimates.

This same logic may apply for farm-in and farmout arrangements. There is often a need for regulatory approvals after a farm-in or farmout contract is signed, which may prevent the transaction from actually occurring or may postpone the effective date significantly. In cases where such approvals or other circumstances are required, depending on historical similar transactions, it may be appropriate to wait for all necessary approvals and for the specific outstanding matters to be cleared up in order for the grantor to reduce its reserves and for the grantee to book reserves.

Similar issues may occur when estimating reserves for unitized accumulations where the TP is not yet finally agreed upon or approved. Depending on government regulation and circumstances, it is sometimes desirable (for more accurate depiction of future reserves) to estimate the TP or the effective date to begin the production split. In such cases, care should be taken to prevent recognizing significant (particularly Proved) reserves that might be subject to later reduction due to the actual terms and effective date of the unitization agreement once fixed by formal approval and agreement.

Judgement must also be applied when more than one related transaction involving reserves exists (e.g., pooling of assets). In such cases, the effects on reserves entitlement should represent the related transactions applied simultaneously.

12.7 Example Case

12.7.1 Reserves in a PSC. The following example illustrates the approach used to estimate reserves and resources under a PSC. In this example, the contractor develops and operates the field and is entitled to a share of production that is based on cost recovery and profit-share components. The contractor takes their share of product in kind. The contractor does not have ownership of the underlying resources being produced but does earn an economic interest by virtue of the exposure to technical, financial, and operational risks and is therefore able to recognize reserves and resources for the project under the PRMS. Due to the difficulty in predicting prices, this example uses a constant forecast oil price of USD 60/STB. Sensitivity cases of USD 10/STB above and below this price are also shown in the example. Although unlikely to represent the actual forecast prices in effect, they do provide a good illustration of how entitlement and contract terms respond to price changes.

12.7.1.1 Example Description. An oil field has a technically recoverable resource estimate of 500 million STB, of which 400 million STB are estimated to be produced during the PSC term, and, *for the purposes of this example*, the project is considered to be commercial, and all quantities are reflected in the Proved Reserves category during the PSC term, assuming a discovery. The contract provides for an initial exploration period, with the contract term lasting 20 years from the start of production. The general field data are summarized in **Table 12.14.**

The production forecast and full-life cost summary for the PSC term are shown in **Table 12.15.** The remaining 100 million STB are classified as Contingent Resources, assuming a discovery, related to a potential contract extension. In this simplified example, no additional drilling is required, and Probable and Possible Reserves are not shown.

Field Information Summary	
Field TRR	500 million STB
EUR during PSC term	400 million STB
Exploration Cost	USD 450 million
Drilling Cost	USD 600 million
Other Development Cost	USD 750 million
Fixed Operating Cost	USD 90 million/year (USD 1,800 million)
Variable Operating Cost	USD 4.55 / STB

Table 12.14—Example general field data, where TRR indicates technically recoverable resources, and EUR is estimated ultimate recovery.

Year	Annual Oil Production (million STB)	Exploration Cost (USD million)	Drilling Cost (USD million)	Other Devt Cost (USD million)	OP. Cost Fixed (USD million)	OP. Cost Variable (USD million)	Total Cost (USD million)
1	0	300	0	0	0	0	300
2	2,7	150	120	105	90	12	477
3	11,5	0	180	369	90	52	691
4	19,9	0	300	276	90	90	756
5	30,4	0	0	0	90	138	228
6	33,3	0	0	0	90	152	242
7	34,5	0	0	0	90	157	247
8	34,7	0	0	0	90	158	248
9	31,3	0	0	0	90	142	232
10	28,1	0	0	0	90	128	218
11	25,3	0	0	0	90	115	205
12	22,8	0	0	0	90	104	194
13	20,5	0	0	0	90	93	183
14	18,5	0	0	0	90	84	174
15	16,6	0	0	0	90	76	166
16	14,9	0	0	0	90	68	158
17	13,5	0	0	0	90	61	151
18	12,1	0	0	0	90	55	145
19	10,9	0	0	0	90	50	140
20	9,8	0	0	0	90	45	135
21	8,8	0	0	0	90	40	130
Total	400	450	600	750	1800	1820	5420

Table 12.15—Project production cost and cost schedule. Figures may not match due to rounding; Devt is development, and OP is operating.

Production startup is midyear in the second year of the project and builds to a peak rate of 95,000 BOPD (34.7 million STB annualized) in the eighth year.

12.7.1.2 PSC Terms. The example contract contains many common contractual terms affecting the industry today. These include royalty payments, limitations of revenue available for cost recovery, a fixed profit-share split, and income taxes. For simplicity, the example does not consider a variable profit share. It is a typical PSC in which the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers investments and operating expenses out of the gross production stream after royalty deduction and is entitled to a share of the remaining profit oil. The contractor receives payment in oil production and is exposed to both technical and market risks.

Fig. 12.19 shows the general terms of the contract, whereby taxes are paid by the contractor. The contract is for a 20-year production term with the possibility of an extension. The terms include a royalty payment in kind on gross production of 15%. Yearly cost recovery is limited to a maximum of 50% of the annual gross revenue after royalty deduction, with the remaining cost carried forward to be recovered in future years. The contractor's profit share is based on a simple split: 20% to the contractor and 80% to the host government.

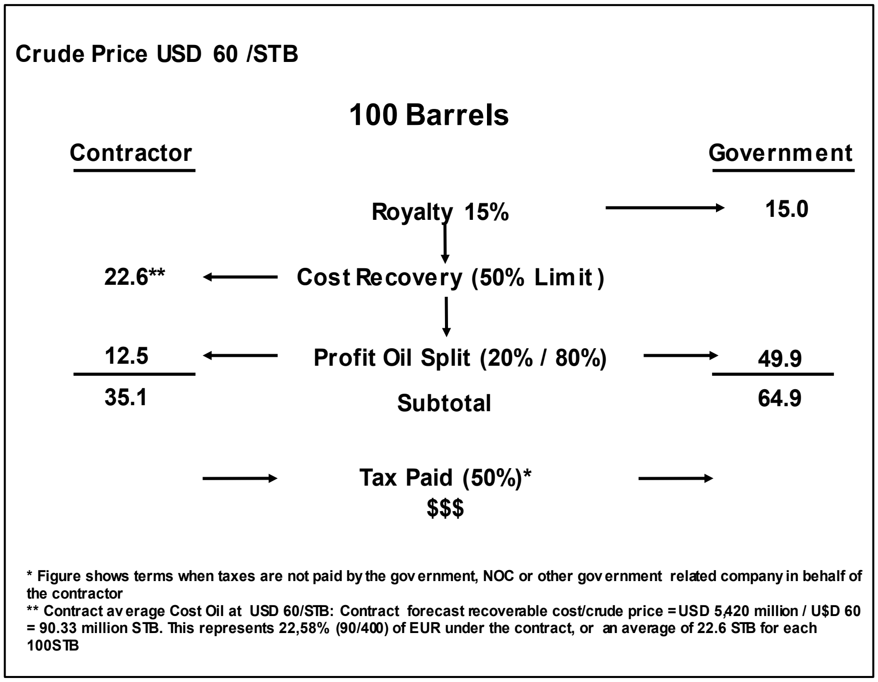


Fig. 12.19—Production sharing contract terms whereby taxes are paid by the contractor, where EUR is estimated ultimate recovery.

The contractor's share of reserves and resources will be estimated in the following sections, followed by sensitivity cases for the effects of price and alternative tax treatment on entitled reserves.

12.7.1.3 Contractor Entitlement and Reserves Estimates. *The* terms of a PSC determine the contractor's yearly entitlement or share of the project production based on the yearly cost recovery and profit split. Table 12.15 shows the forecast production, investment, and cost profiles for the project. The calculation of the contractor's entitlement for each year at the forecast price of USD 60/STB is shown in **Table 12.16.** Looking at year 8 as an example, the gross revenue from 34.7 million STB produced is USD 2,083 million. At a royalty rate of 15%, the government would receive as royalty 5.2 million STB valued at USD 312 million. The remaining USD 1,771 million would remain for cost recovery and profit split according to the terms of the contract. In this PSC, revenue available for cost recovery is limited to 50% after royalty amount, or USD 886 million. Costs and expenses for the year total USD 248 million (assumed to be fully recoverable under the agreement), and there are no costs carried forward from previous years. These costs are forecast to be fully recovered in the same period. In the case of unrecovered costs, they would be carried forward by the contractor for recovery in future years. The remaining revenue after royalty and cost recovery is shared by the contractor and government according to the contract profit split. In this case, the contractor's profit share is USD 305 million, or 20%. The contractor's total entitled revenue is the sum of the contractor's cost recovery and profit share.

Year	Total Revenue (USD million)	Net Revenue after Royalty (USD million)	Recoverable Costs (USD million)	Costs Carried Forward (USD million)	Contractor Recovered Costs (USD million)	Available for Profit Sharing (USD million)	Contractor Profit Share (USD million)	Contractor Cost + Profit Share (USD million)	Contractor Share %	Contractor Entitlement (million STB)
1	0	0	300	300	0	0	0	0	n/a	0
2	161	137	477	709	69	69	14	82	51	1
3	687	584	691	1.108	292	292	58	351	51	6
4	1.192	1.014	756	1.357	507	507	101	608	51	10
5	1.824	1.550	228	810	775	775	155	930	51	16
6	1.999	1.699	242	202	850	850	170	1.020	51	17
7	2.069	1.759	247	0	449	1.310	262	711	34	12
8	2.083	1.771	248	0	248	1.523	305	553	27	9
9	1.875	1.594	232	0	232	1.362	272	505	27	8
10	1.688	1.434	218	0	218	1.216	243	461	27	8
11	1.519	1.291	205	0	205	1.086	217	422	28	7
12	1.367	1.162	194	0	194	968	194	387	28	6
13	1.230	1.046	183	0	183	862	172	356	29	6
14	1.107	941	174	0	174	767	153	327	30	5
15	996	847	166	0	166	681	136	302	30	5
16	897	762	158	0	158	604	121	279	31	5
17	807	686	151	0	151	535	107	258	32	4
18	726	617	145	0	145	472	94	240	33	4
19	654	556	140	0	140	416	83	223	34	4
20	588	500	135	0	135	366	73	208	35	3
21	530	450	130	0	130	320	64	194	37	3
Total	24.000	20.400	5.420	4.486	5.420	14.981	2.996	8.416	35	140,27

Table 12.16—Project cost and profit-share schedule. Figures may not match due to rounding.

The estimated average contractor cost plus profit share value in year 8 is USD 553 million, about 27% of the project gross revenue. This 27% share is converted to an equivalent volume of the production of 9.2 million STB, representing the contactor's entitlement in year 8. Because the cost and revenue vary yearly, each estimated entitlement percentage applies only to the year in question. This calculation provides only the contractor's share of the annual production for the year in question. After discovery, as the project is commercial, and all example production forecast is categorized as Proved, the contractor's Proved Reserves are estimated by the summation of the estimated annual volume entitlements over the production forecast years of the project, up to the contract term limit (economic and technical limit would occur after that date). Table 12.16 shows the forecast entitlements from project initiation to the end of the contract term. They were estimated with the forecasted production, exploration, development, and operating expenses and schedules through the term of the agreement. After discovery and considering a commercial project, the contractor's Proved Reserves are estimated at 140 million STB, or 35% of the total project Proved Reserves of 400 million STB.

The contractor is obligated to pay income tax on its profits, which in the example case amounts to USD 152 million at the tax rate of 50% of its profit share in year 8 (50% of USD 553 million − USD 248 million). Income taxes were calculated as a percentage of yearly project revenues minus project costs. In many actual situations, income tax calculations will consider other deductions, percentages, or other data.

In this example, prices and profit splitting were held constant over the period, and the effect of the recovery of initial capital investments on the effective net entitlement interest can be seen. At the onset of production, entitlement (economic) interest is approximately 51% and declines over the next several years to a low of 27% in year 8. The entitlement interest then increases to 37% by the end of the term. This increase is due to the natural decline in the production rate and the need to have a greater portion of the production reimburse fixed operating costs. In general, PSC entitlement percentages are highest at the point of first production and tend to decrease as a project becomes cost current. Entitlements tend to increase as costs increase and prices decline; however, many agreements contain "*R*" terms and/or stepwise tranches that tend to reduce the profit share allocation to the contractor over time. These take many different forms, but they generally tend to be related to cumulative production, cumulative reimbursements, or higher production rates.

For the example entitlement calculation, price was considered to be constant during the year. In actual situations, the crude price may vary over the year, and the method for calculating the price for each settlement period is normally defined in the agreement.

In an actual field development, there will frequently exist low, best, and high cases with corresponding production forecasts. Entitlement volumes will be estimated for each, which will correspond to 1P, 2P, and 3P Reserves if entitled volumes are economic and the project satisfies commerciality requirements. Those 2P or 3P entitled volumes may be sourced from portions of the reservoir that are not considered Proved at the time of classification. Depending on technical information, those quantities may be included in 1P Reserves in later assessments.

12.7.1.4 Crude-Price Sensitivity. In a PSC, contractor reserves are sensitive to the assumed production schedule, price projections, and cost forecasts. Frequently, the most volatile of these factors is the price. **Table 12.17** demonstrates the inverse relationship between crude price and contractor reserves in this example. For a USD 10/STB increase in crude price, the contractor's reserves decrease from 140 to 130 million STB. (It may be noted that, although the reserves entitlement decreases as the price increases, the net production income per barrel also increases.) Such swings in reserves can be expected when prices are volatile. Several other commonly used financial metrics have also been included in Table 12.17 to illustrate how they also change with price. Subject to specific pricing requirements in the PSC agreement, the ability to use average prices over a year, as provided by the PRMS, can help to dampen price-related reserves changes. The contractor's actual ultimate recovery and resources will, however, be determined by prices over the project life.

	USD 50 Oil Price		USD 60 Oil Price		USD 70 Oil Price	
Parameter Measured	Normal Tax	TPOB	Normal Tax	TPOB	Normal Tax	TPOB
Reserves (million STB)	155	178	140	165	130	156
Cost of Finding & Dev. (USD/STB)	11.63	10.12	12.83	10.89	13.85	11.52
Profit/STB (USD/STB)	14.97	19.53	21.36	27.20	28.29	35.30
Production Costs (USD/STB)	23.40	20.35	25.81	21.91	27.86	23.18
Net Production Income (USD/STB)	7.48	13.02	10.68	18.13	14.14	23.53

Table 12.17—Examples of financial metrics, reserves sensitivity to oil prices, and taxes [normal tax or tax paid on behalf (TPOB)], where Dev is development.

12.7.1.5 Income Tax Paid on Behalf. In the normal case, as shown in Sections 12.7.1.2 to 12.7.1.4, the contractor is obligated to pay income tax out of their share of the project profit. In such cases, the contractor's tax obligation affects the project's economics but has no impact on the reserves estimates because reserves are calculated on a before-tax cash-flow basis. In some PSCs, however, the government or state-owned oil company agrees to pay tax on behalf of the contractor. If the tax payment is a purely financial arrangement, and the payments cannot be attributed to a portion of the government's production revenues, an economic interest would not exist; therefore, no additional reserves would be recognized by the contractor. In this case, the carried tax reserves will equal those obtained in the normal tax case shown in Table 12.17.

As mentioned in Section 12.6.1, if, under the terms of the contract, the contractor derives a benefit from and has an economic interest in the government's share of hydrocarbon volumes used to fund the tax payments, those volumes may be considered as the contractor's reserves. **Fig. 12.20** shows the general terms of the contract if taxes are paid by the host government on behalf of the contractor. Table 12.17 shows this impact on both the project financial indicators and the reserves. The contractor's cost recovery and profit share are computed in the standard fashion, but entitlement of reserves would now include the economic benefit related to the taxes paid on behalf of the contractor. With a tax-paid-on-behalf arrangement, the contractor's Proved Reserves (at USD 60/STB forecast price) would increase by 25 to 165 million STB. In an actual field development, 2P and 3P Reserves would also have estimates associated with cost recovery, profit share, and benefit related to the taxes paid on behalf of the contractor. In this example, all quantities are considered to be commercial up to the PSC contract limit.

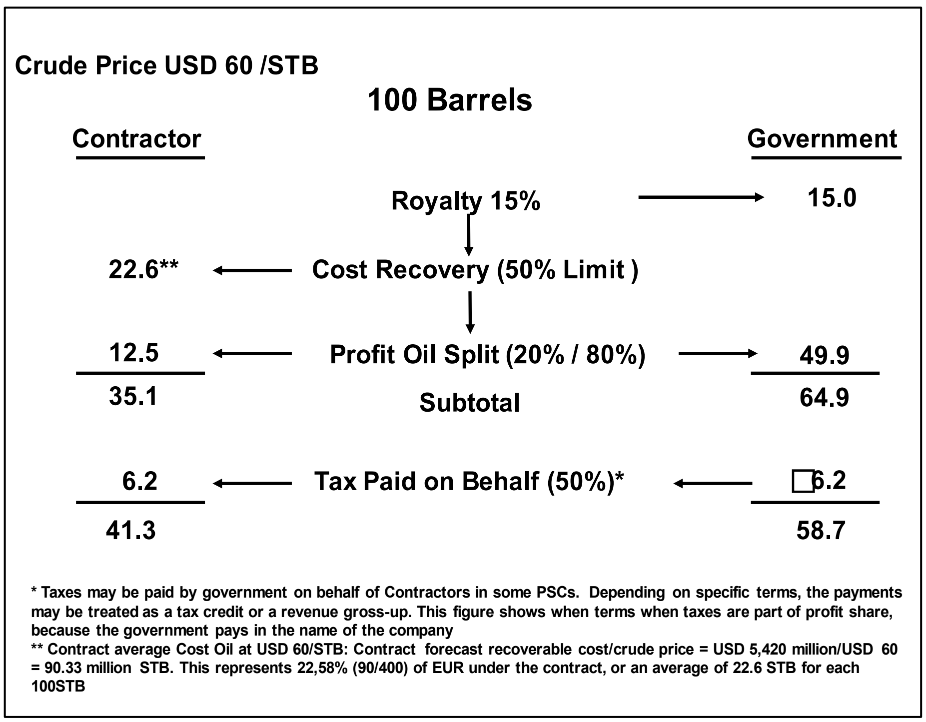


Fig. 12.20—PSC terms when taxes are paid by the host government on behalf of the contractor, where EUR is estimated ultimate recovery.

12.7.1.6 Common Procedure to Assess Reserves Sensitivity. The preceding reserves estimates illustrate the general approach that can be used for PSCs and revenue-sharing contracts at all levels of project maturity (risked-service contracts might use similar calculations). It accounts for varying yearly investment levels and the relative relationship between project costs and project revenue. In a mature project, with relatively stable prices and the relationship between project costs and project revenues relatively constant, some companies simplify the process by assuming that the reserves share is equal to an average entitlement percentage. In general, this approach is believed to be sufficiently accurate, and corrections would be applied when accounts were adjusted for actual production and realizations on the regular intervals prescribed in the agreement.

12.7.1.7 Assessing Other Classes and Categories of Reserves and Resources. In actual field development, a portion of the production forecast would likely be categorized in the Probable (and Possible) PRMS reserves category(ies), depending on supporting information and technical certainty. Each project would normally have Proved, Probable, and Possible Reserves components. For example, Probable (or Possible) Reserves may be estimated for better-than-expected recovery or perhaps for undrilled areas where technical certainty was not sufficient to classify the reserves as Proved. In this instance, modeling two cases, one for the Proved plus Probable flow streams and a separate model for the Proved-only case, would give the Probable Reserves entitlement by difference.

In this PSC example, 100 million STB were noted to be related to the potential extension of the original contract agreement. If significant additional new investments were required to produce this volume, and/or there was some doubt that the agreement would be extended, then the related volume would most likely be categorized as Contingent Resource in one or more of the 1C, 2C, or 3C scenarios, depending on the level of technical certainty. There may also be a question of whether the same or different terms would apply to the extension. Consequently, judgment must be used when estimating the entitlement interest that will be applied to determine the net share of the PRMS resources potentially available to the contractor.

In a different example scenario, if the 100 million STB were related to potentially higher recovery efficiency from the reservoir within the original term, and no additional debottlenecking or development investments were required, then the volume could be classified as Probable (and/or Possible) Reserves (assuming appropriate technical certainty). To determine the effective net interest for this Probable increment, a two-step process is commonly used. In the first step, the Proved flow stream is evaluated using the PSC model described in the preceding sections. In the second step, the forecast 2P (Proved plus Probable) flow stream and related costs are then evaluated with the PSC model, and the results from the Proved case are subtracted. This provides the entitlement and revenues related to the discrete Probable component. This approach can be used with multiple categories and in cases where additional investments or operating costs may also be required. It may also be used where there are multiple fields being developed within the same PSC ring fence.

12.8 Summary

Reserves and resources disclosures are not only a matter of forecast production and costs. Contractors must focus on their entitled resources, which are usually required for disclosure. Concessions, production-sharing, revenue-sharing, risked-service, and other related contracts offer the host country and the contractor alike considerable flexibility in tailoring agreement terms to best meet sovereign and corporate requirements, which can have a variety of competing and aligned factors. The entitlement of reserves and resources under the PRMS is based on economic interest and will depend on the host fiscal system and other contracts and agreements involved.

When considering projects, each fiscal system, contract, or agreement must be reviewed on a case-by-case basis to determine whether there is an opportunity to recognize reserves and resources for internal use, regulatory reporting, or public disclosure. Particular care should be taken to ensure that the contractual terms satisfy the company's business objectives and that the impact of alternative agreement structures is understood and considered.

The US Securities and Exchange Commission Section S-X, Rule 4-10b, "Successful Efforts Method" (US Securities and Exchange Commission 2011) and FASB ASC 932 Topic "Extractive Activities—Oil and Gas" (FASB 2010) provide guidelines and a useful framework for determining when a mineral (economic) interest in hydrocarbon reserves and resources exists. These guidelines may be used to supplement PRMS to help determine when an economic interest in hydrocarbons exists, allowing reserves and resources to be recognized and reported. However, the distinction between recognition and non-recognition of reserves and resources under many service-type contracts may not be clear and may be highly dependent on subtle aspects of contract structure and wording.

In some fiscal systems, such as concessions, it may be easier to determine the economic interest and the entitled reserves and resources, while it may be difficult in many other contracts. Cost-recovery terms in production-sharing, risked-service, and other related contracts provide a more complex calculation for economic interest and typically reduce the production entitlement (and hence reserves) obtained by a contractor in periods of high price and increase the volumes in periods of low price. While this ensures cost recovery, the effect on investment metrics may be counterintuitive. The treatment of taxes and royalties used can also have a very significant effect on the reserves and resources recognized and production reported from these contracts.

Given the complexity of these types of agreements, determination of the net company share of hydrocarbons recognized for each PRMS classification requires economic modeling of the flow streams with the related costs and investments for each cumulative PRMS categorization and/or classification (1P, 2P, 3P and 1C, 2C, 3C). The net amount for each discrete PRMS category can then be determined by difference from the model results (e.g., net Probable Reserves = 2P Reserves – 1P Reserves).

12.9 Acknowledgments

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Glossary

This Glossary provides further definition of terms used within the *Guidelines for Application of the PRMS* and the Chapter and subsections in which they appear (e.g., 12.4.2 refers to section 4.2 in Chapter 12). References in numerous chapters are identified as "General," while multiple references within a given chapter may be identified as "Ch. X—General."

TERM	USED IN THESE GUIDELINES	DEFINITION
1C	2.1	Denotes low estimate scenario of Contingent Resources.
2C	2.1	Denotes best estimate scenario of Contingent Resources.
3C	2.1	Denotes high estimate scenario of Contingent Resources.
1P	2.1	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	2.1	Denotes best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	2.1	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	2.1	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	2.1	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	2.1	Denotes the unrisked high estimate qualifying as Prospective Resources.
Abandonment, Decommissioning, and Restoration (ADR)	9.3.2	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as "ADR net of salvage."
Accumulation	General	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	8.1	The process of summing well, reservoir, or project-level estimates of resources 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.
Amplitude Variation with Offset/Angle (AVO/AVA)	3.4.1	The variation in the amplitude of a seismic reflection with angle of incidence or source-geophone distance(depends on changes in velocity, density, and Poisson's ratio). Often used as a hydrocarbon gas indicator because gas generally decreases Poisson's ratio and often increases amplitude with incident angle/offset, although other conditions can produce similar effects. (Source: SEG Wiki)

TERM	USED IN THESE GUIDELINES	DEFINITION
Analogous Reservoir	4.3	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., 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 insight and comparative data to assist in estimation of recoverable resources.
Approved for Development	2.7, 2.8	All necessary approvals have been obtained; capital funds have been committed, and implementation of the development project is ready to begin or is underway. A project maturity subclass that reflects the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Assessment	General	See Evaluation.
Barrels of Oil Equivalent (BOE)	11.10.1, 11.10.2	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
Basin-Centered Gas	10.2.1, 10.2.3	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas saturated reservoirs, and lack of a downdip water leg.
Best Estimate	2.1	With respect to resources categorization, 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	10.6.1, 10.6.2.1, 10.6.2.2	See Natural Bitumen.
Bright Spot	3.4.1	A spot with a local increase of amplitude associated with hydrocarbon accumulations. In its original implementation, the phrase referred to amplitudes of the Common Mid-Point (CMP) stack; modern implementations are pre-stack. These amplitude highs can be caused by an increase of reflection coefficient by gas in the pore space. It is used to identify the increase in amplitude rather than the presence of hydrocarbons, and it is usually greater in unconsolidated clastic rocks. Acoustic impedance is lower in sands than in shales, where pore space may be filled with water. As hydrocarbons are added to pore spaces, the velocity and density of the sand decreases. Due to this, the impedance contrast at the top of the sand increases, making the reflection stronger and more negative.
C1	2.1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.

TERM	USED IN THESE GUIDELINES	DEFINITION
C2	2.1	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	2.1	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Carried Interest	12.5.8	A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the preproduction costs of another party (the carried party) on a license in which both own a portion of the working interest.
Chance	8.1.1	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk) As used in Chapter 8 herein, "Chance" refers to the elements necessary to establish a hydrocarbon accumulation (e.g., reservoir seal, source, migration path).
Chance of Commerciality	2.6	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	2.6	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	2.6	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Coalbed Methane (CBM)	10.5	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC)].
Commercial	9.2, 9.5, 9.7	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met.
Committed Project	General	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared. (See also Final Investment Decision.)
Common Mid-Point (CMP)	3.4.2, 3.5.1, 3.5.3	Having the same mid-point between source and detector. The CMP method is a recording/processing method where each source is recorded at a number of geophone locations and each geophone location is used to record from a number of source locations.
Completion Interval	General	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.

TERM	USED IN THESE GUIDELINES	DEFINITION
Concession	9.3.6, 12.5.1, 12.6.2.1, 12.6.3.1	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity 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. (Also called a license.)
Conditions	2.9, 2.10, 9.2, 9.3.3, 9.3.4, 9.5, 9.6, 9.7, 9.10	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	9.3.4	A descriptor applied to the economic evaluation of resources estimates. Constant case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
Consumed in Operations (CiO)	9.5, 11.4	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)
Contingency	2.6, 2.7, 2.11	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Resources	2.3	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 owing to one or more contingencies.
Continuous-Type Deposit	10.2.1, 10.2.2, 10.2.3, 10.5.1, 10.6.1	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include “basin-centered” gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.
Conveyance	12.4.3, 12.5.11	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.
Correlation	8.1.1	A statistical measure by which the linear relationship between two variables is described and/or quantified (through the use of a correlation coefficient).
Correlation Coefficient	8.2.3	Numerical measure relating the degree of correlation between two variables, ranging from an inverse relationship (-1) to a direct relationship (+1). A value of (0) indicates that the two variables have no relationship (i.e., they are independent of each other).

TERM	USED IN THESE GUIDELINES	DEFINITION
Cost Recovery	12.5.2, 12.5.2.1, 12.5.4.1, 12.6.1, 12.7.1, 12.7.1.2, 12.7.1.3, 12.7.1.5	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 production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
Cumulative Production	2.10	The sum of petroleum quantities that have been produced at a given date. (See also Production.) Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
Current Economic Conditions	9.3.4	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.
Defined Conditions	2.10, 9.3.3, 9.3.5, 9.6	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Dependency	8.1.1, 8.2.4	A statistical measure of the causative effect of one variable upon another.
Depth Migration	3.5.3	A step in seismic processing in which reflections in seismic data are moved to their correct locations in space, including position relative to shotpoints, in areas where there are significant and rapid lateral or vertical changes in velocity that distort the time image. This requires an accurate knowledge of vertical and horizontal seismic velocity variations.
Deterministic Incremental Method	2.5, 4.1	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
Deterministic Method	2.5, 4.1	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponding to a given level of certainty.
Deterministic Scenario Method	2.5, 4.1	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
Developed Reserves	2.8	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non-Producing.

TERM	USED IN THESE GUIDELINES	DEFINITION
Developed Producing Reserves	2.8	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-producing Reserves	2.8	Developed Reserves that are either shut-in or behind-pipe.
Development Not Viable	2.7, 2.9	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	2.7, 2.9	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
Development Plan	2.2	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
Development on Hold	2.7, 2.9	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Unclarified	2.7, 2.9	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity. A project maturity sub-class of Contingent Resources.
Dim Spot	3.4.1	A local low amplitude seismic attribute anomaly that can indicate the presence of hydrocarbons and is therefore known as a direct hydrocarbon indicator. It’s caused by highly consolidated sands with a much greater acoustic impedance than the overlying shale. It primarily results from the decrease in acoustic impedance contrast when a hydrocarbon (with a low acoustic impedance) replaces the brine-saturated zone (with a high acoustic impedance) that underlies a shale (with the lowest acoustic impedance of the three), decreasing the reflection coefficient.
Discount Rate	9.3.5	The rate used in converting an undiscounted cash flow to a cash flow that reflects a present value to the entitled interest(s). The rate used will generally represent the entity’s weighted average cost of capital (WACC) or its minimum attractive rate of return (MARR).

TERM	USED IN THESE GUIDELINES	DEFINITION
Discovered/ Discovery	2.3	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. 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 commercial recovery. (See also Known Accumulation.)
Discovered Petroleum Initially-in-Place (PIIP)	General	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
Discovered Unrecoverable	2.3, 2.7	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Economic	9.2, 9.7	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	9.3.6, 12.3, 12.4.2, 12.4.2.1, 12.4.3	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which they must look for a return.
Economic Limit	9.3.3	Defined as the time when the maximum cumulative net cash flow (see Entitlement) occurs for a project.
Economic Limit Test (ELT)	9.2	The process of identifying the Economic Limit from a forecast of revenues and expenses attributable to an entity’s interests.
Economically Not Viable Contingent Resources	2.9	Those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.
Economically Viable Contingent Resources	2.9	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria.
Effective Date	General	Resource estimates of remaining quantities are “as of the given date” (Effective Date) of the evaluation. The evaluation must take into account all data related to the period before the “as of date.”
Entitlement	12.1	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	General	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.

TERM	USED IN THESE GUIDELINES	DEFINITION
Established Technology	2.3, 2.11	Methods of recovery or processing that have proved to be successful in commercial applications.
Estimated Ultimate Recovery (EUR)	2.11	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have already been produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
Evaluation	General	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. (Also called Assessment.)
Evaluator	General	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 its resources and attributed value estimates.
Farm-in, Farm-out	12.4.2	Farm-in and Farm-out typically refer to an arrangement in which the owner of a working interest (the farmor) assigns of all or part of the working interest (including exploration and/or production rights and obligations) to another party (the farmee) in return for agreed compensation which can be monetary, in-kind, or as relief from an obligation associated with the assigned working interest. The farmor may or may not retain any of a variety of types of interest.
Flat Spot	3.4.1, 3.4.2, 3.4.4	Represents a hydrocarbon contact seismic response where it is apparently flat. Such contact may be between gas and oil, oil and water, or gas and water. The hydrocarbon reservoir must be thicker than the vertical resolution in order to represent a flat spot. Flat spots are often difficult to find; the edge or base of channels, low angle faults, or processing artifacts can often be misconceived as flat spots. Flat spots may also be caused by low saturated gas in a reservoir.
Final Investment Decision (FID)	General	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Forecast Case	9.3.4	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas Balance	11.8.2	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner’s portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.

TERM	USED IN THESE GUIDELINES	DEFINITION
Gas Hydrates	10.1	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, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.
Geostatistical Methods	2.5	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
Gross Rock Volume (GRV)	3.3.1, 5.4	The total volume of rock within an evaluation interval, typically a specific formation, from top to base of said interval, including both reservoir and non-reservoir rock prior to the application of net pay cutoff criteria.
High Estimate (Resources)	2.1	With respect to resources 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.
Highest Known Hydrocarbons	4.1	The shallowest occurrence of a producible hydrocarbon accumulation as interpreted from some combination of well log, flow test, pressure measurement, and core data. Hydrocarbons may or may not extend above this depth. Modifiers are often added to specify the type of hydrocarbons (for instance, “highest known gas”).
History Match	6.4.3	The process of calibrating the underlying rock and fluid properties, geologic model, and resultant predicted performance of a numerical model to reasonably match the actual performance history (pressure depletion, physics of fluid flow, etc.) of a reservoir in terms of the fluid flow characteristics, geological framework, etc. Due to the number of variables involved, the history match of a reservoir is not usually a unique realization.
Improved Recovery (IR)	General	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.)
Justified for Development	2.7, 2.8	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/ contracts will be obtained. A project maturity sub-class of Reserves.

TERM	USED IN THESE GUIDELINES	DEFINITION
Kerogen	10.3.2, 10.6.1, 10.6.2.3	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	General	An accumulation that has been discovered.
Lease Fuel	11.4	Oil and/or gas used for field and processing plant operations. For consistency, quantities consumed as lease fuel should be treated as part of 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. [See also Consumed in Operations (CiO).]
Liquefied Natural Gas (LNG) Project	11.2	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.
Low/Best/High Estimates	2.1, 2.4, 2.5	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	2.1	With respect to resources categorization, this is 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.
Mean	8.1.1	The sum of a set of numerical values divided by the number of values in the set.
Median	8.1.1	That point in the distribution of an uncertainty parameter at which 50% of the possible outcomes are below and 50% of the outcomes are above the value at that point.
Migration	3.5.3	Process of moving dipping reflections to their true subsurface positions and collapses diffractions, thus increasing spatial resolution and yielding a seismic image of the subsurface. (See also Post-Stack Migration and Pre-Stack Migration.)
Mineral Interest	12.4.2, 12.4.3	See Economic Interest.
Mineral Lease	12.5.1	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (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).

TERM	USED IN THESE GUIDELINES	DEFINITION
Monte Carlo Simulation	General	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 quantities).
Multi-Scenario Method	7.1, 7.3.2, 7.4.2	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.
Natural Bitumen	10.6.1, 10.6.2.1, 10.6.2.2	The portion of petroleum that exists in the semi-solid 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 mPa·s (or 10,000 cp) 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 before normal refining.
Natural Gas Liquids (NGL)	11.2, 11.3, 11.9, 11.10, 11.10.2	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Cash Flow (NCF)	Ch.9–General	A cash flow is the calculation, at discrete intervals (typically reported on an annual basis but perhaps calculated on a monthly basis), of the cash inflow (e.g., revenue from product sales) and the cash outflow (e.g., operating costs, capital expenditures, taxes, etc.) attributable to a specific project. The NCF is the difference between the inflow and the outflow to the entity's interest. The NCF may be undiscounted or a discounted cash flow (DCF).
Net to Gross (NTG)	3.3.1, 5.4	The ratio of net reservoir rock to the gross rock volume, i.e., net pay divided by gross vertical thickness of the rock/formation under evaluation.
Net Pay	5.4	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Net Profits Interest	12.5.12	An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid.
Net Revenue Interest	9.5, 12.4.2	An entity's revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms.
Non-Hydrocarbon Gas	11.2, 11.5, 11.9	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.

TERM	USED IN THESE GUIDELINES	DEFINITION
Non-Sales	11.3	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non-hydrocarbons.
Oil Sands	10.6.2.2	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	10.1, 10.6.1, 10.6.3	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). (Often called kerogen shale.)
On Production	2.7, 2.8	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
Overlift/Underlift	11.8.1	Production entitlements received that vary from contractual terms resulting in overlift (producing over the entitled contract quantity) or underlift (producing below the entitled contract quantity) positions. This 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 upon by the parties.
Overriding Royalty Interest (ORRI)	9.3.6, 12.6.2	A revenue interest free of any cost obligation, created by the operating entity and/or working interest owner and paid by the operating entity and/or working interest owner out of revenue from the property. This differs from the Royalty Interest as ownership of the minerals is not the basis for this interest but rather another form of economic interest in the property.
P1	2.1	Denotes Proved Reserves. P1 is equal to 1P
P2	2.1	Denotes Probable Reserves.
P3	2.1	Denotes Possible Reserves.
P10	2.1, 2.4	Probabilistic resources estimate designation equivalent to “high estimate.”
P50	2.1, 2.4	Probabilistic resources estimate designation equivalent to “best estimate.”
P90	2.1, 2.4	Probabilistic resources estimate designation equivalent to “low estimate.”
Petroleum	General	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 of petroleum can be greater than 50%.
Petroleum Initially-in-Place	General	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.

TERM	USED IN THESE GUIDELINES	DEFINITION
Portfolio Effect	8.3.3	The stabilizing effect of having a population of individual outcomes. As the population of independent portfolio elements increases, the diversification effect of the larger population allows the aggregated result to approach the population's mean. Consequently, the aggregated portfolio's expected result has reduced variance (e.g., the P10:P90 ratio) as the population increases.
Possible Reserves	General	Possible Reserves are those additional reserves that analysis of geoscience and engineering data indicates 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.
Post-Stack Migration	3.4.2, 3.5.1	Migration applied on the Common Mid-Point stacking data.
Pre-Stack Migration	3.4.2, 3.5.1, 3.5.3	Migration before Common Mid-Point stacking is done to avoid the reflection-point smearing of dipping reflections and to accommodate strong lateral velocity gradients. It can also be used when the hyperbolic moveout assumption breaks down.
Probability	2.4, 2.5, 2.6, Ch. 7–General	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. PRMS 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.)
Probability Density Function (PDF)	8.3.2, 8.3.4	A probability density function (PDF), or density of a continuous random variable, is a function whose value at any given sample (or point) in the sample space (the set of possible values taken by the random variable) can be interpreted as providing a relative likelihood that the value of the random variable would equal that sample.
Probabilistic Method	2.4, 2.5, Ch. 7–General	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	General	An incremental category of estimated recoverable quantities 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	General	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as

TERM	USED IN THESE GUIDELINES	DEFINITION
		measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
Production Forecast	2.10, 9.2, 9.4.1, 9.5	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U, 2U, and 3U.
Production-Sharing Contract (PSC)	9.3.6, 12.2, 12.5.2, 12.5.2.1, 12.7	A contract between a contractor and a host government in which the contractor typically bears the 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 of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. [Also termed production-sharing agreement (PSA).]
Profit Split	12.5.2, 12.5.2.1, 12.7.1.3	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	2.1.1, 2.2; General	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	2.1.1	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prospective Resources	2.1, 2.2, 2.4, 2.6	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

TERM	USED IN THESE GUIDELINES	DEFINITION
Proved Reserves	General	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum that, 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.
Purchase Contract	12.5.10	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	12.5.4, 12.5.5	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. 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 contract's terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
Qualified Reserves Evaluator (QRE)	5.5.1, 5.5.2, 5.5.5, 6.4.2	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent, from an appropriate governmental authority or professional organization. (Modified from SPE 2019 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information.")
Rank	8.2.3	Rank is the probability position of an outcome across the full uncertainty range. Rank correlation, therefore, is the similarity between outcomes on the probability range for the uncertainties, not the actual magnitudes.
Raw Production	4.5.1.6, 11.1, 11.3, 11.5	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non-hydrocarbon gases, etc.).
Reasonable Certainty	General	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.

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Reasonable Expectation	2.2, 2.11, 9.7	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from Reasonable Certainty, which applies to resources quantity technical confidence, while Reasonable Expectation relates to commercial confidence.)
Recoverable Resources	General	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Recovery Efficiency	4.4.1.2, 4.4.1.3	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing. Current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Reference Point	11.2, 11.3	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
Reserves	General	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 (as of a given date) based on the development project(s) applied.
Reservoir	General	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	General	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation 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.)
Resources Categories	2.1.1, 2.4, 2.8, 2.10; General	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 and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.

TERM	USED IN THESE GUIDELINES	DEFINITION
Resources Classes	2.1.1, 2.4, 2.8, 2.10; General	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 likelihood of commerciality.
Revenue-Sharing Contract	12.5.3	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Reversionary Interest	12.5.8, 12.5.9	The right of future possession of an interest in a project when a specified condition has been met.
Risk	8.2.4, 8.6	The probability of loss or failure. Risk is not synonymous with uncertainty. 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	12.4.1, 12.5.4	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity'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 (RSC)	12.5.4, 12.5.4.1	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With an RSC, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty, Royalty Interest	9.3.6, 12.4.2, 12.6.2, 12.6.2.1	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at the discretion of the royalty owner. See also Overriding Royalty Interest (ORRI).
Sales	11.2, 11.3	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (Reference Point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
Seismic Inversion	3.5.1	Seismic inversion combines seismic and well data to predict rock properties (lithology, fluid content, porosity) across a survey. These rock properties can be used to identify hydrocarbon and reservoir. (SEG Wiki)

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Seismic Resolution	3.2.1, 3.3.1	Seismic resolution is a measure of minimum spatial or temporal separation between two reflection events so that they can yet still be distinguished and resolved separately. Two types of resolution are considered—vertical and lateral, both of which are governed by the signal bandwidth. The vertical resolution can be expressed as a fraction of the dominant wavelength, which is a function of wave velocity and the dominant frequency, for resolution criterion considered (criteria of Rayleigh – $\lambda/4$, Ricker – $\lambda/4$, or Widess – $\lambda/8$, where λ is the wavelength of dominant frequency). The lateral resolution is expressed by the Fresnel zone, a function of depth of the reflector, the velocity of the reflector and the dominant frequency. Migration improves the lateral resolution by decreasing the width of the Fresnel zone, thus separating features.
Shale Gas	10.3.1, 10.4.2, 10.4.5	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production.
Shale Oil	10.6.2.3	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production.
Split Classification	2.4, 9.3.4, 12.5.1	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as Split Classification. If there are differing commercial conditions, separate sub-classes should be defined.
Split Conditions	9.3.4	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves.
Stacking	3.4.2, 3.5.1, 3.5.3	Usually means Common Midpoint (CMP) stacking. It is a major process to enhance the signal-noise-ratio, reduce noise and improve seismic data quality. In multichannel seismic acquisition, the point on the surface halfway between the source and receiver that is shared by numerous source-receiver pairs. Traces from different shot records with a common reflection point, such as CMP data, are stacked to form a single trace during seismic processing. Such redundancy among source-receiver pairs enhances the quality of seismic data when the data are stacked.

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Sub-Commercial	2.1, 2.3	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. 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. Sub-commercial projects are classified as Contingent Resources.
Sunk Cost	9.6.2	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
Synthetic Crude Oil (SCO)	10.6.1, 10.6.2.3	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.
Synthetic Seismogram	3.4.1, 3.4.5, 3.5.2	A 1D synthetic seismogram is formed by simply convolving an embedded waveform with a reflectivity function. The embedded waveform is sometimes a theoretical waveform (such as a Ricker wavelet) and sometimes a waveform resulting from analysis of actual seismic data (the embedded wavelet, also called the equivalent wavelet). The reflectivity is usually that calculated for normal incidence from velocity (sonic) and density logs, but often only velocity changes are considered because density changes are unknown (or else some relationship between density and velocity is assumed). A synthetic seismogram is used to correlate with seismic at the well location.
Technical Forecast	2.10	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cutoff. (See also Technically Recoverable Resources.)
Technical Uncertainty	2.4	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Technically Recoverable Resources (TRR)	2.10, 2.11	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
Technology Under Development	2.3, 2.7, 2.10	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.

TERM	USED IN THESE GUIDELINES	DEFINITION
Tight Gas	10.2.1, 10.2.2, 10.2.5, 10.4.2, 10.4.6, 10.5.4	Gas that is trapped in pore space and fractures in very low-permeability rocks and/ or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
Tight Oil	10.2.1, 10.2.2, 10.2.5, 10.4.2, 10.4.6	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
Time Migration	3.5.3	A migration technique for processing seismic data in areas where lateral velocity changes are not too severe, but structures are complex. Time migration has the effect of moving dipping events on a surface seismic line from apparent locations to their true locations in time. The resulting image is shown in terms of travel time rather than depth and must then be converted to depth with an accurate velocity model to be compared to well logs.
Total Petroleum Initially-in-Place	General	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	2.1, 2.2, 2.4, Ch. 7–General	The range of possible outcomes in a series of estimates. For recoverable resources 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	Ch. 10–General	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called “continuous-type deposits”). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
Undeveloped Reserves	2.8, 2.11	Those 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 and completing a new well) is required to recomplete an existing well.
Undiscovered Petroleum Initially-in-Place	2.1	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Unitization	12.6.3, 12.6.3.1	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).

TERM	USED IN THESE GUIDELINES	DEFINITION
Unrecoverable Resources	2.2, 2.3, 2.7	Those quantities of discovered or undiscovered PIIP that are assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
Upgrader	11.2	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. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Volumetric Analysis	4.4.1, 4.4.2	This procedure uses reservoir rock and fluid properties to calculate PIIP and then estimate that portion that will be recovered by a specific development project. The volumetric estimate may be based on either probabilistic or deterministic approaches.
Well Abandonment	9.2, 9.3.2	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	General	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
Working Interest	12.4.2, 12.4.2.1	An entity’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.