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REQUEST FOR PUBLIC COMMENT

CANADIAN OIL AND GAS EVALUATION HANDBOOK (COGEH)
VOLUME 2

The Society of Petroleum Evaluation Engineers Calgary Chapter (SPEE Calgary Chapter) hereby notifies all interested parties that Volume 2 of the Canadian Oil and Gas Evaluation Handbook is now available in draft form for public review and comment. A copy of this draft COGEH Volume 2 ("Draft") entitled *Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves* can be accessed electronically via the following websites:

www.petsoc.org (Petroleum Society of CIM)

www.albertasecurities.com (Alberta Securities Commission)

www.speca.ca (Society of Petroleum Engineers, Canadian Section – link only)

Interested parties wishing to comment or propose changes to the Draft should clearly identify themselves with appropriate contact details and forward their specific comments, including the particular section, page and line number(s) to which their comments pertain, to the SPEE Calgary Chapter either by:

E-mail to: pegrey@greygroup.ca

Or Mail to: SPEE Calgary Chapter
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The deadline for submission of comments and/or proposed changes is May 31, 2004. The SPEE Calgary Chapter, through its COGEH Standing Committee, will review and consider all submissions and shall also retain full discretion to determine which proposed changes (in whole or in part), if any, are accepted and incorporated into the COGEH Volume 2, First Edition.

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CANADIAN

OIL AND GAS

EVALUATION HANDBOOK

First Edition

April 28, 2004

Volume 2

Detailed Guidelines for
Estimation and Classification
of Oil and Gas Resources and Reserves

Prepared by

Society of Petroleum Evaluation Engineers
(Calgary Chapter)

and

Canadian Institute of Mining, Metallurgy & Petroleum
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The Canadian Oil and Gas Evaluation Handbook, Volume 2 was prepared by the Calgary Chapter of the Society of Petroleum Evaluation Engineers (SPEE Calgary Chapter), the Petroleum Society of the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) and contributing authors (Co-authors). In addition, the SPEE Calgary Chapter, the Petroleum Society, and Co-authors prepared and published the Canadian Oil and Gas Evaluation Handbook, Volume 1 (ISBN0-9730695-0-3) (Volumes 1 and 2 together are here referred to as “the Handbook”). The SPEE Calgary Chapter, Petroleum Society, and Co-authors specifically disclaim any liability, loss, or risk, personal or otherwise, incurred as a consequence, directly or indirectly, of the use and application of any of the contents of the Handbook. The Handbook is intended primarily for use in Canada, and reflects recommended practice for evaluations and reporting of reserves information in Canada. It may also have application to other jurisdictions as a general guideline for reserves estimation. The SPEE Calgary Chapter, Petroleum Society, and Co-authors have made every effort to ensure the accuracy and reliability of the information contained in the Handbook and to qualify best practices for the conduct of reserves evaluations and reporting of reserves information. However, the SPEE Calgary Chapter, Petroleum Society, and Co-authors make no representation, warranty, or guarantee as to the validity, reliability, or acceptability of the contents of the Handbook, and disclaim any responsibility or liability for any loss or damage arising from the use of the Handbook for any purpose, including and without limitation any reports or filings, reserves evaluation results, conclusions, recommendations, or any decisions made as a consequence of the use of the Handbook.

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PREFACE (Volumes 1 & 2)

The First Edition of the Canadian Oil and Gas Evaluation Handbook (COGEH) currently consists of two complementary volumes, titled Reserves Definitions and Evaluation Practices and Procedures (Volume 1, published June 2002) and Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves (Volume 2, published June 2004), that provide a set of standards for the preparation of oil and gas reserves evaluations in Canada. These volumes are expected to be updated, amended, and/or expanded over time. The evaluation standards and guidelines set out in the COGEH Volumes 1 & 2 (the Handbook) are considered by the Calgary Chapter of the Society of Petroleum Evaluation Engineers (SPEE Calgary Chapter) to be the benchmark for Canadian oil and gas evaluation practice. Accordingly, in October 2003 the SPEE Calgary Chapter adopted the following official position regarding the use of the Handbook for purposes of preparing oil and gas reserves evaluations in Canada:

1. The Handbook is, by any reasonable current measure, the single most comprehensive set of technical standards available dealing with oil and gas reserves evaluation practice; and

2. The SPEE Calgary Chapter expects that all Canadian companies, whether public or private, will use the standards and guidelines set out in the Handbook when preparing, reporting, and disclosing their oil and gas reserves evaluation results.

Rules, regulations, or other legislative or regulatory provisions may permit deviation from the evaluation standards set out in the Handbook. Regardless of this, the SPEE Calgary Chapter expects that all evaluators involved in the preparation of oil and gas reserves evaluations for public disclosure in Canada will adhere to formally documented and comprehensive standards, practices, procedures, and guidelines that clearly meet or exceed those set out within the Handbook. Further, it is emphasized that the Handbook should be used and considered by evaluators in its entirety and that it is neither appropriate nor acceptable for an evaluator to use or exclude portions of the guidance on a selective basis unless it has valid, technically compelling reasons for doing so.

In the event that an evaluator is permitted to deviate from the Handbook in the preparation of a reserves evaluation intended for public disclosure in Canada, it is further expected that the evaluator shall disclose this fact in writing within its evaluation report, together with an explanation of the deviation.

SECTION 1

INTRODUCTION

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1.1 Introduction

Petroleum is found in many forms and in widely varying and complex geological environments. Petroleum resources and reserves are always estimated under conditions of uncertainty, which include incomplete and imprecise data. The objective of resources and reserves definitions is to provide a framework of nomenclature that permits reliable and consistent estimation and classification of petroleum quantities.

The objective of this Volume 2 of the *Canadian Oil and Gas Evaluation Handbook* (COGEH) is to provide additional guidelines for applying the reserves and resources definitions provided in COGEH Volume 1, in order to assist in achieving consistency in approach and in resulting estimates. Volume 2 includes guidelines and examples of recommended procedures for estimating oil and gas resources and reserves for a variety of situations. Even these expanded guidelines cannot provide a precise or unique approach to be taken for all complex situations and reserves estimation problems that will be encountered. The intent of Volume 2 is to provide guidance to evaluators on a wide array of reserves estimation scenarios requiring specific considerations or methodologies to be applied. This guidance will also form a basis for estimating and classifying resources and reserves in more complex situations.

Users of resources and reserves estimates must be aware that no amount of refining of definitions and guidelines will remove the conditions of uncertainty under which estimates are prepared. The degree of diligence applied to acquisition and scrutiny of data is influenced by the end use of the estimates, and this in itself could cause estimates to vary. The application of definitions and guidelines requires significant experience and objective judgement in determining the most appropriate estimation methods, performing a sound technical analysis, and classifying the final estimates. With the application of sound judgement and the guidance contained in this Volume 2, different qualified evaluators using the same information at the same time should produce reserves estimates that are not materially different.

This Volume 2 is intended for use by experienced evaluators. A good understanding of fundamental geoscientific and reservoir engineering principles and methods is essential to proper application of the guidelines provided. While basic reservoir analysis considerations will be identified to provide clarity, users of Volume 2 will be directed to additional reference material that sets out fundamental reserves estimation methods.

The definitions of reserves and resources allow for use of both deterministic and probabilistic methods. These guidelines will, therefore, address issues relating to both of these analytical approaches. However, reserves estimation and reporting continues to be dominated by deterministic methods. The primary focus of Volume 2 is the philosophy of classifying reserves estimates within a range of possible outcomes as proved, probable, and possible.

SECTION 2

RESOURCES CLASSIFICATIONS AND DEFINITIONS

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2.1 Introduction

Preparation by the COGEH committee of additional guidance for the estimation and classification of resources is ongoing and will be provided in this Section in updates of COGEH Volume 2. In the interim, evaluators preparing estimates of resources are directed to the material provided in COGEH Volume 1.

SECTION 3
DEFINITIONS OF RESERVES

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3.1 Introduction

3.1.1 Background — Development of Reserves Definitions

The Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum (CIM) Standing Committee on Reserves Definitions (the Committee) was formed in 1989 in recognition of the shortcomings of oil and gas reserves definitions existing at that time. In 1993, the Committee published reserves definitions, which also were included in the Petroleum Society's *Monograph 1, Determination of Oil and Gas Reserves*. The definitions addressed the use of both deterministic and probabilistic methods and included ranges of cumulative probability of exceedance for proved, probable, and possible reserves of 80+ percent, 40 to 80 percent, and 10 to 40 percent, respectively. After publication, the Committee continued to debate, review, and refine the definitions. This work included surveying industry practices and opinions. These definitions were not widely adopted, and the Canadian Securities Commissions' National Policy 2-B remained the basis for most reserves reporting in Canada.

The Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC) jointly published revised reserves definitions in 1997. Similar to the CIM definitions, the SPE/WPC definitions allowed for use of both deterministic and probabilistic methods. However, for probabilistic methods, the SPE/WPC definitions stipulated minimum cumulative probabilities of exceedance of 90, 50 and 10 percent (P_{90}, P_{50}, and P_{10}) for proved, proved + probable, and proved + probable + possible reserves, respectively. These probabilities were generally in keeping with the existing world standard.

In 1998, the Alberta Securities Commission (ASC), on behalf of the Canadian Securities Administrators (CSA), formed the Oil and Gas Securities Task Force (the Task Force) to review disclosure regulations, with reserves definitions being one item under review. The Task Force requested assistance from the Committee with definitions and guidelines to replace National Policy 2-B definitions for use in Canadian securities reporting. Discussions between the Task Force, reserves evaluators, the Committee, and the Calgary Chapter of the Society of Petroleum Evaluation Engineers (SPEE) lead to revised reserves definitions and guidelines. These were first published in draft form for industry comment in June 1999.

In keeping with the prior CIM definitions, the revised definitions again allowed for use of both deterministic and probabilistic methods. The Committee adopted the P_{90}, P_{50}, and P_{10} criteria in the SPE/WPC definitions for proved, proved + probable, and proved + probable + possible reserves, respectively. The general guidelines attempted to address the relationship between probabilistic and deterministic estimates. The summary guidelines attempted to clarify the level at which the probability targets were to be met.

After review of industry comments, the definitions were included in the CSA's National Instrument 51-101 (NI 51-101), which was published for public comment in January 2002. Following a review of feedback, the definitions were finalized in August 2002.

3.1.2 Introduction to Reserves Definitions

Oil and gas reserves estimation is inherently uncertain. The reserves categories of proved, probable, and possible have been established to reflect the degree of uncertainty and to indicate the probability of recovery.

The estimation and classification of reserves requires the application of professional judgement, combined with geological and engineering knowledge, to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of statistics and of the concepts of uncertainty, risk, probability, and of deterministic and probabilistic estimation methods, is required to correctly apply reserves definitions. These topics are discussed in greater detail within the guidelines that follow this section.

The reserves definitions and summary guidelines provided in COGEH Volume 1, Section 5 are repeated here for convenience and are subject to further clarification. Direct excerpts from the reserves definitions are italicized to distinguish the formal definitions from the additional clarification of this Volume 2.

The following definitions apply to estimates of both individual reserves entities and the aggregate of estimates for multiple reserves entities.

3.2 Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- *analysis of drilling, geological, geophysical, and engineering data;*
- *the use of established technology;*

- *specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.*

Reserves are a subset of resources—that portion of the original resource base that is discovered, remaining, and economically recoverable. Further clarification of the general requirements for classification of estimated recoverable quantities as reserves, rather than contingent or prospective resources, is provided in Section 5.

Reserves are classified according to the degree of certainty associated with the estimates. Sections 3.4 and 4 discuss the concepts of certainty and probability and the relationship between certainty and reserves estimates for the various categories.

In addition to the degree of certainty, there are other criteria that must be met for classifying reserves. These are summarized in the general guidelines in Volume 1, Section 5 and detailed in Section 6 of this Volume 2.

3.2.1 Proved Reserves

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

This brief definition shows proved reserves to be a "conservative" estimate of the remaining recoverable quantities.

3.2.2 Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves.

This definition shows the proved + probable estimate to be a "best estimate" of the remaining recoverable quantities. The proved + probable reserves estimate is the quantity that best represents the expected outcome with no optimism or conservatism, and as such is of key importance in reserves evaluation and reporting.

3.2.3 Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

This definition shows proved + probable + possible reserves to be an “optimistic” estimate of the remaining recoverable quantities.

3.3 Development and Production Status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories.

3.3.1 Developed Reserves

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

a. Developed Producing Reserves

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Reserves may also be classified as developed producing in the following cases:

- reserves associated with simple re-perforation of an existing well within a vertically contiguous producing zone where conventional operating practice involves progressive well recompletion to optimize depletion,
- reserves associated with a currently non-producing entity that is forecast with reasonable certainty to be producing as of the effective date of the reserves estimate,
- commonly, those gas reserves associated with increasing compression horsepower or restaging of compression. Reserves requiring an initial installation of compression are generally classified as undeveloped.

b. Developed Non-Producing Reserves

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Reserves classified as developed non-producing include reserves requiring a short well tie-in or production facilities, or behind-pipe reserves requiring recompletion, where capital requirements are small relative to the cost of a well. As a rough guide, costs should be less than 50% of the cost of drilling and casing a new well in order to be classified as developed.

3.3.2 Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Reserves classified as undeveloped include

- reserves associated with drilling,
- reserves requiring capital expenditures for tie-in or production facilities, or behind-pipe reserves requiring completion/recompletion and/or stimulation, where costs are significant relative to the cost of drilling a well. As a rough guide, reserves should be classified as undeveloped if costs are more than 50% of the cost of drilling and casing a new well.
- gas reserves requiring an initial installation of compression facilities, unless costs are small, in which case the associated reserves may be classified as developed non-producing.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

3.4 Levels of Certainty for Entity and Reported Reserves

The qualitative certainty levels contained in the definitions in Section 3.2 are applicable to individual Reserves Entities, which refers to the lowest level at which reserves calculations are performed, and to Reported Reserves, which refers to the highest level sum of individual entity estimates for which reserves estimates are *presented. Reported Reserves should target the following levels of certainty under a specific set of economic conditions:*

- *at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.*

- *at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable reserves.*

- *at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible reserves.*

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

The intent of including quantitative probability levels in the reserves definitions is to provide greater clarity of the uncertainty and risk associated with reserves estimates, for both evaluators and users of these estimates. The inclusion of probabilities is not intended to necessitate the use of probabilistic methods, but to allow for their use. It is also not intended that these definitions require radical new processes for reserves estimation. The probability targets for proved reserves are considered to be consistent with the spirit and intent of the predecessor definitions for securities reporting in Canada that were contained in Canadian National Policy 2-B (NP 2-B). The concepts that actual reserves will equal or exceed the reported proved reserves estimate at least nine times out of ten, and that the proved + probable estimate represents a realistic or best estimate are in keeping with the reasonable expectations of users of reserves estimates and of the public.

It is emphasized that the stated probability targets (i.e., P_{90}, P_{50}, and P_{10}) are minimum confidence levels. That these minimum probability levels be targeted at the aggregate reported level should not be interpreted as allowing lower certainty for entity level reserves estimates than implied in the NP 2-B definitions (or other definitions in use, including the SPC/WPC and U.S. Securities Exchange Commission definitions). It is not intended that evaluators adjust individual estimates of reserves within a portfolio in an attempt to meet a specific confidence level. Rather, application of the guidelines and procedures for reserves estimation and classification provided in COGEH Volumes 1 and 2 are intended to yield aggregate results that will meet or exceed these minimum confidence level targets.

The COGEH guidelines and constraints for deterministic estimates of proved reserves are consistent with SEC and SPE/WPC definitions and guidelines for proved reserves. Guidelines for probabilistic estimates of proved reserves are in keeping with procedures recommended in SPE/WPC guidelines and with best practices used worldwide.

Sections 4 through 6 provide standard approaches for evaluators preparing estimates of reserves using both deterministic and probabilistic methods. Clarification regarding certainty levels associated with reserves estimates and the impact of aggregation is provided in Section 4.

The concept that even deterministic estimates should target a minimum probability level has been perhaps the most widely discussed and controversial feature of the COGEH reserves definitions. It is expected that updates of COGEH Volume 2 will continue to provide additional clarification regarding reserves estimates and certainty levels.

SECTION 4

UNCERTAINTY AND STATISTICAL CONCEPTS

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4.1 Introduction

Reserves estimation has characteristics common to any measurement process that uses uncertain data. An understanding of statistical concepts and the associated terminology is essential to understanding the certainty associated with reserves definitions and categories. The inclusion of quantitative confidence levels with the COGEH reserves definitions has increased the understanding of statistical concepts by users of reserves data. As has been previously stated, the inclusion of probabilistic concepts in the reserves definitions was not intended to necessitate the use of probabilistic methods in evaluations, but rather to provide a greater clarity of the risks and uncertainty associated with reserves estimates.

Probabilistic methods have been used in the oil and gas industry for many years. The most common applications of probabilistic analyses in North America have been for internal use for portfolio management purposes, examination of acquisition and divestment opportunities, and analyses of significant fields with large uncertainties (typically in the delineation or early production stage). Since reserves definitions set out by North American securities regulators have not (prior to adoption of NI 51-101 in Canada) addressed the use of probabilistic methods, the reserves booking and disclosure process has almost exclusively relied on deterministic methods.

Many of the terms used to describe the level of certainty associated with reserves estimates are based on quantitative probabilistic estimation methods. However, it is an underlying principle in the COGEH guidelines that qualitative assessments of certainty are made whenever deterministic estimation methods are employed. Statistical principles also apply to deterministic estimates, because there is an inferred probability associated with each deterministic estimate. Notwithstanding that the reserves definitions include statistical concepts and make allowance for the use of probabilistic methods, it is expected that reserves estimation will continue to be dominated by deterministic estimates.

Inclusion of probabilities in the COGEH reserves definitions has caused great debate amongst evaluators. The following outlines two primary areas of debate with abbreviated clarification. Further commentary on these issues is provided later in this Section of Volume 2.

- *Reserves estimation will continue to be dominated by deterministic methods. Given that the probability associated with such estimates is unknown, how can one satisfy these quantitative probability targets?*

General COGEH guidelines stipulate that a deterministic estimate of proved + probable reserves is a realistic or “best estimate.” Proved and proved + probable + possible are, respectively, conservative and optimistic estimates of remaining reserves. Adherence to these basic principles and the additional guidelines provided in COGEH will yield results that will satisfy the probability targets.

- *Where are the probability targets to be achieved? The definitions indicate that the probability targets are to be met at the aggregate level reported (Reported Reserves). Is this intended to allow for different estimates for the same entity as a result of different grouping of entities (i.e., different companies) due to the impact of aggregation of estimates?*

When probabilistic methods are used, the guidelines provided in COGEH stipulate that the impact of aggregation must not be considered beyond the property (or field) level. That is, property total reserves estimates with appropriate confidence level for each reserves category (e.g., P_{90} for proved) are summed arithmetically with estimates for other properties to derive the reported total. Similarly, when deterministic estimates are made, each property must meet appropriate certainty level criteria (e.g., high certainty for proved reserves, that is, much greater likelihood of positive than negative revisions in the future) independently from the other properties within the portfolio evaluated. Since deterministic estimates of proved + probable reserves will approximate mean values, the probability associated with these estimates will not be materially affected by aggregation. The certainty requirements for proved reserves will be satisfied with a deterministic approach provided there are sufficient independent estimates in the summation. When Reported Reserves are dominated by estimates with significant uncertainty for a very small number of entities, particular attention may be required to achieve appropriate confidence levels for the aggregate.

A primary objective of reserves definitions and guidelines is to ensure that different qualified evaluators using the same information at the same time will produce reserves estimates that are not materially different. In the absence of bias, the range within which reserves estimates should fall depends on the quantity and quality of the data available, and the extent of the analysis of the data.

4.2 Uncertainty in Reserves Estimation

The reader is referred to COGEH Volume 1, Section 9, which provides an expanded discussion of uncertainty and probability and their impact on reserves evaluators and users of reserves information.

Reserves estimation always involves uncertainty. The degree of uncertainty in a reserves estimate is primarily a function of the quantity and quality of the data available, which is largely dependent on the level of delineation and extent of depletion of an accumulation. Generally, the range of estimates of reserves diminishes as an accumulation is developed and produced and more technical data are obtained.

The categories of proved, probable, and possible reserves have been established to reflect the level of uncertainty and to provide an indication of the probability of recovery. Because a single value estimate provides no indication of the degree of uncertainty, reserves estimates should be provided as a range. However, when uncertainty is very small, or when the estimated reserves are very small relative to the group of entities being evaluated, it is acceptable to record only a single estimate of reserves. In this case, the best estimate = 2P = 1P = 3P reserves. In all other cases, reserves should be recorded as a range.

4.2.1 Definitions of Terms Relating to Certainty

The concepts of “best estimate,” “confidence” or “confidence level,” “most likely,” “mean,” “expected value,” “probability,” etc. are important as they relate to reserves estimates. Certain of these expressions have definite meanings in mathematics and statistics while others do not. The following provides clarification of the meaning and usage of these terms in this Volume 2.

Best estimate is widely used in this Volume 2 to describe the value, derived by an evaluator using deterministic methods, that best represents the expected outcome with no optimism or conservatism. When a deterministic single best estimate of reserves is prepared, this estimate, subject to other appropriate constraints, represents proved + probable reserves.

Confidence or **confidence level** is the degree of certainty associated with an estimate. When used in relation to deterministic estimates, the term confidence level is a qualitative measure of the degree of certainty. Confidence level is also used in this Volume 2 in the context of a probabilistic analysis to indicate the probability of exceeding a particular value. For example, a P_{90} confidence level means that there is a 90 percent probability of equalling or exceeding the estimated value.

Expected value is synonymous with the arithmetic mean or average. It is the value obtained by dividing the sum of the values in a distribution by the number of values.

Maximum is the largest of a set of numbers or the highest quantity possible. In the deterministic reserves estimation process described in Volume 2, maximum refers to a practical maximum value, which is an evaluator's estimate of a reasonable maximum expectation (based on experience and judgement and on deterministic methods), rather than an absolute maximum.

Mean or arithmetic mean is synonymous with expected value.

Median is the value for which there is an equal probability that the outcome will be higher or lower. As noted above, the definition of and target for proved + probable reserves is the median (P_{50}).

Minimum is the least of a set of numbers or the lowest quantity possible. In the deterministic reserves estimation process described in Volume 2, minimum refers to a practical minimum value, which is an evaluator's estimate of a reasonable minimum expectation (based on experience and judgement and on deterministic methods), rather than an absolute minimum.

Mode is the most likely or most probable outcome. In statistics, the mode is the value that occurs most frequently.

Most likely is synonymous with mode as defined above.

Probability is the extent to which an event is likely to occur, expressed as the ratio of the number of favourable cases divided by the total number of cases.

Figure 4-1 illustrates many of the statistical terms.

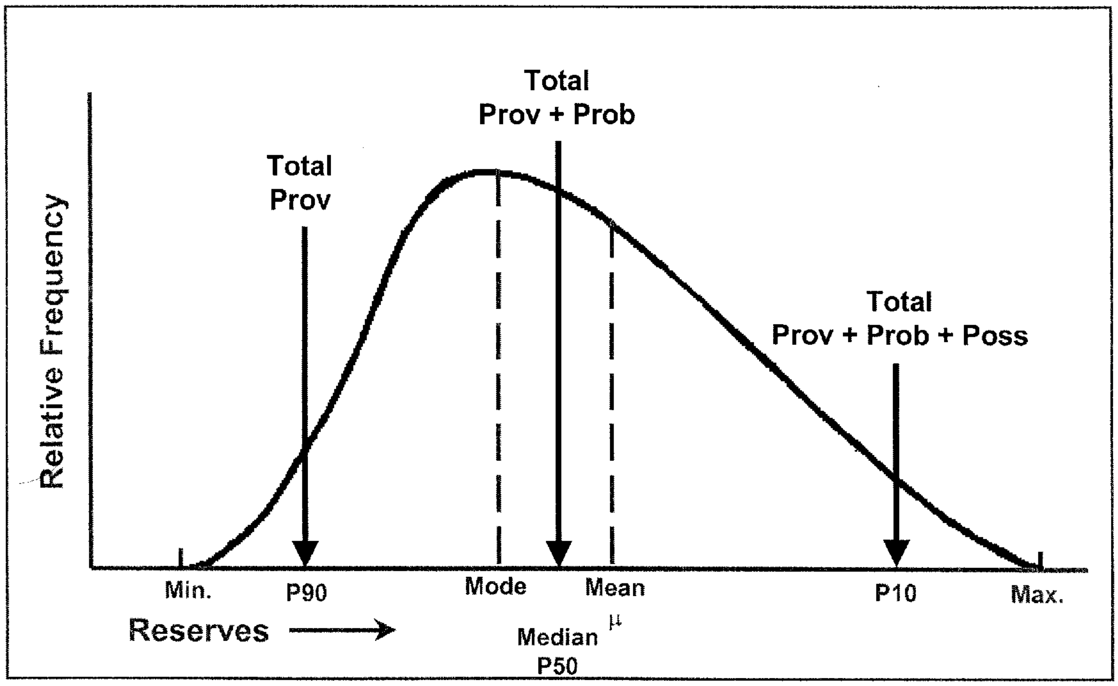

Figure 4-1 Terms Relating to Uncertainty.

4.2.2 Certainty Concepts in the Classification of Reserves

In a broad sense, reserves categories reflect the following expectations with regard to the associated estimates:

Reserves Category	Confidence Characterization
Proved (1P)	Conservative
Proved + Probable (2P)	Best Estimate
Proved + Probable + Possible (3P)	Optimistic

There are three important levels at which estimations are made and recorded for reserves management and reporting:

Entity Level: the lowest level at which reserves estimation is performed. For example, a reserves entity may be an individual well zone, a group of well zones, or a pool.

Property Level: In COGEH, "property" is a term used to describe a grouping of interests in oil and gas entities in a common geographic area (e.g., a field). Property groupings are defined primarily for asset management purposes to facilitate functions such as production and financial accounting and land, contract, and records management. A property will typically (but not always) consist of several reserves entities.

Reported Level: the highest level for which reserves estimates are presented for a specific reserves classification; the sum of all of the individual entity and property level reserves estimates.

The evaluation process begins with estimating reserves at the entity level for proved, proved + probable, and proved + probable + possible categories. After the entities are individually evaluated, they are aggregated to provide the total reserves estimates for properties and for the total of a company or other enterprise. Because the proved and the proved + probable + possible reserves estimates are conservative and optimistic estimates, respectively, the addition of these estimates results in further degrees of conservatism and optimism in the aggregation due to statistical considerations. These concepts will be explained in more detail in the following sections.

4.3 Deterministic and Probabilistic Methods

Reserves estimates may be prepared using either deterministic or probabilistic methods. The following is a brief description of these approaches and the relationship between the methods.

4.3.1 Deterministic Method

The deterministic method, the one most commonly employed in reserves estimation, involves the experience and judgement of an experienced evaluator in selecting a single value for each parameter in the reserves calculation. There are two deterministic approaches currently in use, referred to as risk-based and uncertainty-based (SPE 2001 NEED FULL REFERENCE). Both approaches are described below; however, the uncertainty-based approach is more consistent with the COGEH reserves definitions and guidelines. *The uncertainty-based approach is strongly recommended over the risk-based approach.*

a. Risk-Based Reserves Estimates

A single discrete value for each parameter is selected based on the evaluator's best estimate. No uncertainty is indicated in the resulting reserves estimates for each reserves entity; the entire quantity is classified according to the risk of that quantity not being produced. Low-risk reserves are classified as proved, moderate-risk reserves (including reserves not meeting specific criteria for classification as proved) as probable, and high-risk reserves as possible. In this approach, producing reserves entities commonly have only proved reserves identified. Probable or possible reserves are assigned only in instances of higher uncertainty, and when identified, these categories reflect the incremental development "wedges" with greater risk of recovery. This approach has been common for reserves estimation in North America due to U.S. SEC and Canadian NP 2-B reserves definitions and large numbers of mature reserves entities.

b. Uncertainty-Based Reserves Estimates

A discrete value for each parameter is selected based on the evaluator's determination of the value that is most appropriate for the corresponding reserves category. The resulting range of estimates for each reserves entity prepared for the various reserves categories reflects the associated degree of uncertainty. Proved reserves are those reserves having a high degree of confidence of recovery, proved + probable reserves are the best estimate recoverable quantities, and proved + probable + possible reserves capture the "upside" case. A single reserves estimate (2P = 1P = 3P) for an individual reserves entity is only acceptable when the uncertainty associated with an estimate is very small or when remaining reserves are not significant. This approach to deterministic estimates, which is the one most commonly used internationally, is effectively a scenario-based approach.

The uncertainty-based approach indicates the degree of uncertainty in estimates for all reserves entities and allows for tracking and reconciliation of estimates of various categories. This approach to reserves estimation, which recognizes a range of possible outcomes for all reserves entities, is generally consistent with the probabilistic method.

4.3.2 Probabilistic Method

Probabilistic analysis involves defining the full range of values for each unknown parameter. This method usually consists of employing computer software to perform repetitive calculations to generate the full range of possible outcomes and their associated probability of occurrence (e.g., Monte Carlo Simulation). Reserves estimates can be extracted directly from the probabilistic model as the value corresponding to the various confidence levels in the reserves definitions (i.e., 1P, 2P, and 3P at P_{90}, P_{50}, and P_{10}, respectively).

As with the deterministic method, estimation of the range and character of the unknown parameters in the probabilistic model requires objectivity and significant experience and judgement. Results from probabilistic analyses are not unique and are not necessarily more reliable than those from deterministic analyses.

The reserves definitions and guidelines require that when probabilistic models are used, dependencies between variables and individual estimates, and criteria that restrict the range of values allowed within the model, be properly accounted for. These issues and other issues relating to the aggregation of estimates are addressed in the following sections.

4.4 Aggregation of Reserves Estimates

Reserves estimates are prepared at the individual entity level, which may be a well zone, a group of well zones, or a pool. These reserves estimates are summed to obtain total estimates for properties (and often other groupings such as business unit, district, and country) and companies. The total reserves disclosed (Reported Reserves) are usually the aggregate of a number of properties, which in turn usually consist of a number of reserves entities.

4.4.1 Aggregating Probabilistic Estimates

When probabilistic techniques are used in reserves estimation, aggregation is usually performed within the probabilistic model. It is critical that such models appropriately include all dependencies between variables and components within the aggregation. Where dependencies and specific criteria contained in the guidelines have been treated appropriately (Section 4.8), reserves for the various categories are defined by the confidence levels set out in Section 3.4, subject to the considerations set out below.

Reserves estimates are used for a variety of purposes, including planning, reserves reconciliation, accounting, securities disclosure, and asset transactions. These uses will generally necessitate tabulations of reserves estimates at lower aggregation levels than the total Reported Reserves. Statistical aggregation of a tabulation of values, which does not result in a straightforward arithmetic addition, is not accepted for most reporting purposes. For these reasons, and due to the lack of general acceptance of probabilistic aggregation up to the company level, *reserves should not be aggregated probabilistically beyond the property (or field) level.*

Beyond the property (or field) level, discrete estimates for each reserves category resulting from separate probabilistic analyses must be summed arithmetically. As a result, Reported Reserves will meet or exceed the probability requirements in Section 3.4, regardless of dependencies between separate probabilistic analyses, and may be summed with deterministic estimates within each reserves category (i.e., 1P, 2P, 3P).

It is recognized that the foregoing approach can impose an additional measure of conservatism when proved reserves are derived from a number of independent probabilistic analyses, because there is a greater than 90 percent probability of achieving at least the arithmetic sum of independent P_{90} estimates. Nonetheless, this is considered to be an acceptable consequence, given the need for a discrete accounting of component proved estimates.

Conversely, this approach could cause the sum of proved + probable + possible reserves derived from a number of probabilistic analyses to fail to meet the P_{10} confidence level. Given the limited application for proved + probable + possible *aggregate total* Reported Reserves, this is also an acceptable consequence.

4.4.2 Aggregating Deterministic Estimates

When deterministic methods are used, Reported Reserves are simply the arithmetic sum of all estimates within each reserves category. Entity-level deterministic estimates have implicit associated probability levels. Consequently, fundamental principles of the Central Limit Theorem are applicable to deterministic estimates. Evaluators and users of reserves information must understand the effect of summation on the confidence levels associated with estimates. Arithmetic summation of independent estimates having confidence levels greater than P_{50} will result in a total with a higher certainty; arithmetic summation of estimates having confidence levels less than P_{50} will yield a total with a lower certainty.

The definitions and guidelines describe a conservative approach in the deterministic estimation of proved reserves. When a deterministic proved reserves estimate is the product of many individual uncertain parameters, it is not appropriate to select the most conservative value for each and every parameter; this would result in an unrealistically low value. Similarly, when the total reserves of a property consists of the sum of many individual independent entity estimates, it is not appropriate to apply a very conservative approach for each individual entity reserves estimate; this would result in an unrealistically low total property reserves. Application of these principles will provide results that are directionally consistent with a probabilistic approach. As with the probabilistic approach, a high level of certainty (i.e., much greater likelihood of positive than negative revision) must be met at the property level, and this property confidence level requirement is not dependent on the other properties within the total portfolio evaluated. The probability target of at least 90 percent for proved Reported Reserves will be satisfied with a deterministic approach provided there are sufficient independent high certainty estimates in the summation (see Sections 4.6 and 4.7).

Because proved + probable reserves prepared by deterministic methods, following the guidelines in this Volume 2, will yield results that approximate mean values, then the probability associated with proved + probable estimates will essentially be unaffected by aggregation.

Possible reserves estimates capture some of the upside reserves potential—they are an optimistic estimate of the reserves that could be recovered. Contrary to proved estimates, the likelihood of recovering the sum of all of the independent entity proved + probable + possible reserves decreases with the number of independent entity estimates in the summation. It is not appropriate to apply a very optimistic approach for each individual entity 3P reserves estimate—this would result in unrealistically high total property reserves.

4.4.3 Comparison of Deterministic and Probabilistic Estimates

The uncertainty-based deterministic approach to preparing reserves estimates is comparable to the probabilistic method. In the deterministic approach, however, only three scenarios (1P, 2P, and 3P) are prepared honouring the uncertainty in input parameters and/or prediction of future performance. The resulting range of reserves estimates reflects the degree of uncertainty. In the probabilistic method, the full ranges of input parameters are defined and results include the full range of possible outcomes. The deterministic results, therefore, represent a subset of the values determined using the probabilistic method.

As the COGEH reserves definitions allow for use of either a deterministic or probabilistic approach, there should, ideally, be no significant difference between reserves estimates prepared using either analytical method. In practice, differences will occur between the estimates resulting from the two methods, depending on the nature of the risks and uncertainties associated with the reserves evaluated. Due to different treatments of aggregation of component estimates in probabilistic and deterministic methods (statistical aggregation versus arithmetic summation, respectively), direct comparisons of probabilistic and deterministic estimates of proved reserves should only be made at the level of aggregation for which estimates are intended to be equivalent. It is intended that there should not be a material difference between aggregate results of estimates (Reported Reserves) prepared using deterministic or probabilistic methods or a combination of these. The guidelines provided, relating to the certainty associated with reserves estimates, requires that evaluators consider the probability associated with recovery of the estimated reserves even when the reserves estimates are derived deterministically (Section 4.7). Evaluators must in some cases apply constraints for certain reserves categories (a more deterministic approach; see Section 4.8) to the range of input parameters included in a probabilistic model.

It is reiterated that it is not intended that evaluators should adjust individual entity reserves estimates to attempt to meet the *specific* confidence levels in the definitions (e.g., a P_{90} confidence level for the aggregate reported proved reserves). The numeric confidence levels referred to in the definitions are *minimum* targets. The application of the COGEH guidelines for reserves estimation is intended to yield aggregate results that meet or exceed these probability levels. For example, guidelines relating to probabilistic estimates that preclude probabilistic aggregation beyond the property total level will cause aggregate proved reserves to have a greater than P_{90} confidence level if each property in a company's portfolio is evaluated probabilistically.

4.5 Meeting Certainty Requirements Using Deterministic Methods

This section reviews the significance of the Central Limit Theorem to reserves estimation and provides guidelines for estimating entity level reserves. A key factor in deterministic reserves evaluations impacting consistency is the selection of the discrete values within the range of possible outcomes as 1P, 2P, and 3P reserves. The following sections have intentionally used very elementary examples to illustrate concepts of uncertainty and aggregation. These fundamental concepts are extended to more practical oil and gas reserves estimation examples in Section 6.

4.5.1 Deterministic Estimates Considering Minimum, Best Estimate and Maximum Values

Selection and use of the most conservative parameters for calculating proved reserves may result in an unrealistically low estimate. Summing with other very conservative estimates to arrive at an aggregate further compounds this conservatism. Conversely, use of the most optimistic parameters for the proved + probable + possible reserves estimation may result in unreasonably high estimates.

In general, when reserves are estimated as the product of several parameters, the best estimate (i.e., neither conservative nor optimistic) should first be determined for all parameters. Appropriate constraints (e.g., limiting reserves to the lowest known hydrocarbons; restricting reservoir extent beyond well control, etc.), must be imposed on the portions of the subject reservoir that may be considered for the various reserves categories. Subject to the impact of imposing these constraints, one or two of the key parameters may then be varied from the best estimate to result in appropriate certainty levels for final estimates in each reserves category. This approach is discussed in greater detail, with illustrative examples, in Section 6.

In many cases, estimating minimum, best estimate, and maximum reserves can be straightforward, but the attribution of the appropriate proved and proved + probable + possible reserves estimates can be difficult. In such cases, the following is a recommended deterministic approach that will generally satisfy the certainty requirements of the COGEH reserves definitions:

- Determine best estimate reserves as those estimated reserves that are identified when a single value must be presented with no optimism or conservatism. This estimate is generally classified as a proved + probable reserves estimate. As noted in Section 4.2, when uncertainty is very small (and/or reserves very small), it is acceptable to record the best estimate value of reserves, which usually is the 2P estimate, as equal to 1P and 3P (i.e., best estimate = 2P = 1P = 3P).

- Determine the practical minimum and maximum reserves; that is, those values that the evaluator is highly confident will bracket the quantities that will actually be recovered. No firm minimum probability expectations are required for this approach. However, as a guide, the evaluator should target this interval to bracket the actual reserves at least 8 or 9 times out of 10 (i.e., roughly the P_{90} to P_{10} or P_{20} interval).

- In some cases, evaluators may prefer to determine the minimum and the maximum value before determining the best estimate reserves. The order of the determination of these values is unimportant; however, the determination of all three values is encouraged (whether or not all categories are reported) to assist in achieving consistency in reserves estimation.

- As a general guide, the proved estimate should usually fall within the range of 1/3 to 2/3 of the difference between the proved + probable estimate and the minimum (e.g., if proved + probable is 1000 and the minimum is 700, proved would usually lie between 800 and 900). The final estimate of proved reserves is subject to the judgement of the evaluator, the quality of data, the quality of fit of projections relative to actual historical performance, the quantity and quality of analogies, and the significance of the estimate in the property aggregate. *Issues relating to the impact of aggregation and portfolio effect should not extend beyond the evaluated property*. In certain cases, such as higher risk estimates that are critical to the overall reserves of an evaluated property, it may be appropriate to assign proved reserves at or near the minimum estimate. Depending on the nature of the uncertainties and available data, a probabilistic check may be warranted.

- Similarly, the proved + probable + possible reserves estimate should generally lie in the range of 1/3 to 2/3 of the difference between the proved + probable estimate and the maximum.

In some cases, proved reserves estimates are constrained by specific criteria limiting the assignment of proved reserves, for example, lowest known hydrocarbons. In such cases, the upper limit of the proved reserves estimate is the lesser of the reserves determined using the above approach without these constraints and the reserves determined applying the appropriate constraints along with the best estimates for all other parameters.

a. Confidence Levels Resulting from Application of Minimum, Best Estimate, and Maximum Guidelines

When a deterministic approach is used as described in the foregoing, the quantitative confidence levels associated with the best estimate, minimum, and maximum and the resulting reserves estimates are not known. Nonetheless, each of these values has an associated probability of occurrence and, therefore, basic principles of statistics apply. It is useful to examine approximate quantitative confidence levels associated with such estimates applying basic principles of statistics.

Table 4-1 provides an indication of the quantitative confidence levels associated with deterministic estimates prepared following general guidelines in Section 4.6.1 for a single estimate or the arithmetic sum of several (independent, equal size) estimates (i.e., similar to summing estimates for one or many reserves entities composing a property).

Table 4-1 Approximate Confidence Level of the Value at Mid-Point Between the Minimum or Maximum and Best Estimate

Confidence Level at Min or Max	Approx. confidence level midway between End-point and Best Estimate			
	Number of Entities in Aggregate			
	1 entity	2 entities	5 entities	10 entities
Min P_{90}; B.E. P_{50}	P_{74}	P_{83}	P_{94}	P_{98}
Max P_{10}; B.E. P_{50}	P_{26}	P_{17}	P_{6}	P_{1}

The following assumptions were made in a simple risk model used for the preparation of Table 4-1:

- The shape of the uncertainty distribution is a symmetrical triangle, with the best estimate at P_{50}.
- The deterministic selection of the minimum or maximum value corresponds to the various confidence levels in the leftmost column of the table.
- The table presents the associated confidence level for the value at the mid-point between the best estimate and the end-point value (e.g., if minimum is 600 and best estimate is 800, it is the confidence level for the value of 700)
- The confidence level is shown for various numbers of identical entities within the total; the assumption in the statistical aggregation is that entity estimates are fully independent.

The foregoing is an idealized situation. While actual uncertainty profiles would not be expected to meet the assumptions above, the key principles are that the best estimate should fall near to the median value and that the range selected as bracketing the minimum and maximum value is sufficiently wide to capture the significant majority of potential outcomes (i.e., P_{90} to P_{10} or greater range). If these *endpoints and the median are reasonably estimated*, factors such as the shape of the uncertainty distribution have only a small impact on the certainty level associated with resulting estimates. The range between the minimum and maximum reflects the degree of uncertainty and will generally be greatest in early time.

4.5.2 Simple Example Problem Involving Uncertainty

The following simple examples are provided to illustrate uncertainty concepts. Section 6 provides additional guidelines for reserves estimation, along with more practical examples.

a. Dice Problem

For this initial discussion, it is useful to simply address uncertainty concepts without reference to oil and gas reservoir issues.

Unlike most oil and gas situations, which involve complex natural heterogeneities, the possible outcomes of a die roll, the subject of this example, are clear and easily defined. Nonetheless, the selection of a discrete value for various qualitative certainty levels is not straightforward.

Outcomes for a die roll are simply as follows:

- Six discrete outcomes, 1, 2, 3, 4, 5, and 6,are possible.
- Each outcome has an equal probability of occurrence: 1/6 or 16.67 percent.
- The mean or "expected value" outcome is simply (1+2+3+4+5+6)/6 = 3.5 (In reviewing the example, the fact that 3.5 and other fractional outcomes are not possible outcomes of a single die roll is ignored).

Determining the proved + probable quantity under the COGEH definitions for this situation is straightforward: the P_{50} value of 3.5 is also equal to the mean in this case. This is clearly the mean or overall "best estimate," regardless of analytical method.

Determining a proved value is not so simple. First, consider the probabilistic approach.

If one were asked to provide a P_{90} value for a single die roll, the correct answer lies between 1 (100 percent probability of equalling or exceeding 1) and 2 (83 percent probability of equalling or exceeding 2, since only 1 of the 6 possible outcomes gives a lower result). The cumulative probability profile or "expectation curve" is expressed graphically in Figure 4-2.

The probabilistic method rigorously accounts for multiple opportunity situations; in this case, consider the roll of more than one die. When two or more dice are rolled, the average values change for a given probability on the expectation curve (excluding the mean, which in this case is also the median or P_{50}). For example, with two dice, the probability of an average result of 2 or more is 92 percent (only 3 out of 36 possible outcomes rolling two dice yields a total of less than 4). With three dice, an average result of 2 or greater is 97 percent (7 out of 216 outcomes achieve a total less than 6), etc. Figure 4-3 presents these results in terms of achieving an average outcome for 1-die to 25-dice rolls.

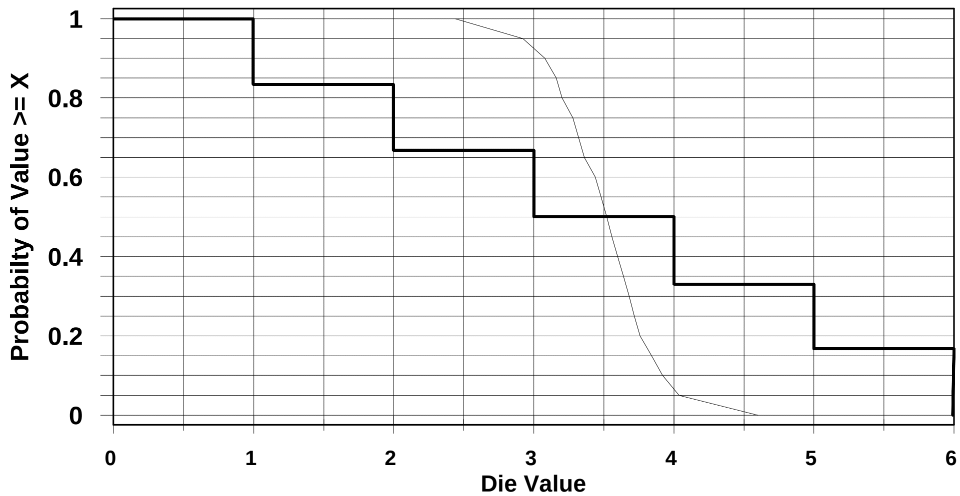

Figure 4-2 Cumulative probability profile for a single die roll.

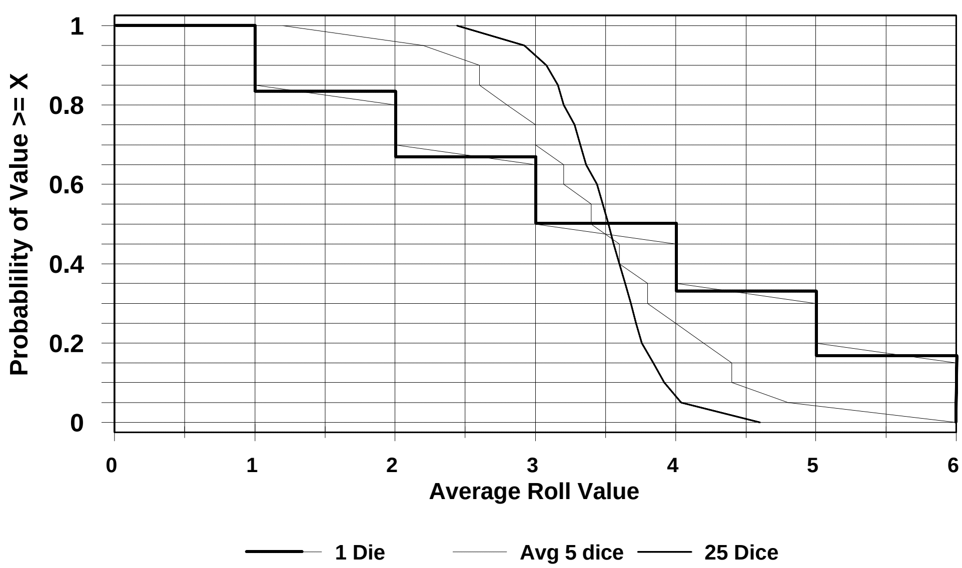

Figure 4-3 Cumulative probability profiles for multiple dice rolls.

In a probabilistic analysis, one would focus on the aggregate result of all of the die rolls. That is, if discrete 1P, 2P, and 3P values were required, these values would be selected from the aggregate P_{90}, P_{50}, and P_{10}, respectively. In an oil and gas situation, this is comparable to probabilistic aggregation of reserves estimates, which is permitted up to the total property (or field) level for the determination of total reserves. For example, for a group of five dice, the appropriate 1P, 2P, and 3P would be roughly 12.5, 17.5 and 22.5, respectively (i.e., five times 2.5, 3.5, and 4.5, respectively).

Now consider a deterministic approach to this problem. As stated previously, the expected value or best estimate is straightforward at 3.5 and this would be recorded as the proved + probable estimate.

Relating the approach in Section 4.5.2 to the foregoing dice example, the evaluator might select a value of 1 as the practical minimum (in this case, also the absolute minimum). With this value, a proved + probable "best estimate" value of 3.5, and the 1/3 to 2/3 difference guideline, the proved value is in the range of 1.83 to 2.67. Similarly, on the upside, a practical maximum of 6 results in a proved + probable + possible estimate of 4.33 to 5.17.

Consider now how the evaluator selects the final estimates within these ranges:

The quality of data and availability of analogies aren't relevant considerations in this case and the evaluator has good knowledge of the uncertainty. The primary consideration as to where in this range to assign proved reserves is the number of "opportunities" in the evaluated "property." If there were only a few opportunities, the evaluator should assign each a proved value near the low end of the proved range and the high end of the proved + probable + possible range (2 and 5, respectively). For a large number of opportunities, the opposite end of the range is appropriate.

For example, for a group of five dice, the appropriate 1P, 2P, and 3P would be roughly 2.5, 3.5, and 4.5 per die or 12.5, 17.5, and 22.5 in total, respectively, which corresponds to the probabilistic solution at the "property" level.

For the special case of only a single "opportunity" in the evaluated "property" where this "property" was critical to the overall portfolio being evaluated, the evaluator would need to consider that it would be more appropriate to place the deterministic proved estimate at or near the practical minimum.

b. A Simple Gas Material Balance Example

Consider this approach in a simple oil and gas example.

After a thorough analysis of a gas reservoir, the following is concluded:

Original Gas In Place

- minimum (no practical chance of being less): 90 Bcf
- best estimate: 100 Bcf
- maximum (no practical chance of exceeding): 110 Bcf

Recovery Factor

- minimum (considering liquid loading potential, etc.): 82 percent
- best estimate: 85 percent
- maximum (given optimal performance): 88 percent

Cumulative Production to Date

- 50 Bcf

The following discusses the philosophy of reserves assignments for the various reserves categories.

i. Deterministic Approach

Determination of the proved + probable case is straightforward in this example: proved + probable reserves are calculated as 100 x 85% - 50 = 35.0 Bcf.

The proved and proved + probable + possible reserves could be calculated deterministically by (1) using the minimum/maximum approach discussed above, or (2) selecting appropriate OGIP and recovery factors for each of these categories.

(1) The minimum and maximum for this approach are intended to be practical limits, so the product of two or more parameters using endpoints overstate the range of values. The minimum OGIP of 90 Bcf and a somewhat lower than best estimate recovery factor, say 84 percent, are appropriate for the minimum value calculation. Similarly, the maximum is derived using the maximum OGIP and an 86 percent recovery factor. This results in a range of minimum to best estimate reserves of 25.6 to 35.0 Bcf. Given no other information, proved reserves are estimated at about the midpoint of this range: 30 Bcf. A similar approach results in a proved + probable + possible reserves estimate of 40 Bcf.

(2) In this case, given the interpretation of the OGIP and recovery factor, most evaluators would simply assign appropriate parameters for each reserves category. For proved reserves, a somewhat lower than best estimate value for both the OGIP and recovery factor is appropriate. The OGIP of 95 Bcf and the recovery factor of 84 percent results in a proved reserves estimate of 29.8 Bcf. Similarly, proved + probable + possible reserves of 40.3 Bcf are estimated using an OGIP of 105 Bcf and a recovery factor of 86 percent. These results are in close agreement with the estimates derived using the minimum/maximum approach.

ii. ***Probabilistic Approach***

The following provides a probabilistic approach to this problem, which has the advantage of providing the evaluator with a clearer picture of the full range of uncertainty in the calculations.

In setting up the risk model, the phrase “no practical chance” was taken to mean a 5 percent probability, and the shape of the probability distribution was set as triangular. The risk analysis gave the results shown in Figure 4-4.

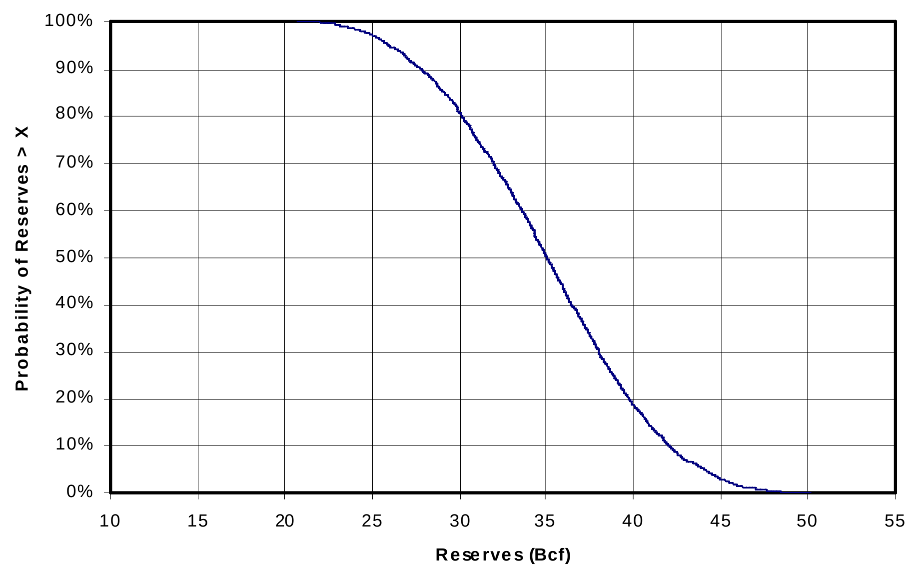

Figure 4-4 Cumulative probability profile for simple material balance example.

As expected, the P_{50} value is 35 Bcf, which is consistent with the deterministic proved + probable reserves. The P_{90} and P_{10} values, which correspond to COGEH-recommended proved and proved + probable + possible minimum probability levels, are 28 Bcf and 42 Bcf, respectively. If this entity is the entire evaluated property, these are the values that would be recorded for those reserves categories. If the property contained other entities, it would be acceptable to include those entities in a larger probabilistic model, aggregate the estimates up to the property total, and record total property reserves at the P_{90}, P_{50}, and P_{10} levels for the corresponding reserves categories.

The above probabilistic solution to this simple problem is not unique. The gas reserves probability distribution depends on interpretation of the phrase “no practical chance.” For example, had no practical chance had been interpreted as near zero probability, the P_{90} reserves would have increased to 30 Bcf, and P_{10} reserves decreased to about 40 Bcf. If no practical chance had been interpreted as 10 percent probability, the range would be 26 to 44 Bcf. The selection of a triangular frequency distribution for the variables also impacts the outcome to some extent.

4.6 Probabilistic Check of Deterministic Estimates

Where a very small number of entities dominate in the Reported Reserves, a probabilistic check of aggregate proved reserves is encouraged. If confidence levels of the reserves estimates for these key entities fall significantly below the probability targets defined in Section 3.4, then the aggregate Reported Reserves will likely fail to meet these certainty criteria. Given this outcome, an evaluator should review both the probabilistic and deterministic assessments for potential inconsistencies in logic and/or mathematical errors. If necessary, reserves estimates should be adjusted to satisfy the Reported Reserves certainty criteria.

4.7 Application of Guidelines to the Probabilistic Method

The guidelines provided in COGEH include specific limits to parameters for reserves estimation. For example, volumetric estimates are restricted by the lowest known hydrocarbons. These constraints are derived from other commonly used reserves definitions and guidelines (e.g., U.S. SEC) and existing standard industry practice, and have been included in COGEH because they are reasonable restrictions. Furthermore, imposition of these restrictions is necessary to promote compatibility with securities reporting regulations in jurisdictions outside of Canada. However, inclusion of these discrete limits in a risk simulation can conflict with standard probabilistic procedures, which require that input parameters honour the full range of technically valid potential values.

Regardless of analytical method, the restrictions contained in the guidelines must be adhered to. Two general approaches are acceptable when probabilistic methods are used in cases where imposition of these discrete restrictions significantly impacts reserves estimates:

- **Constrain the input parameters in the probabilistic model.** In this approach, the probabilistic model input is constrained to exclude values that do not meet reserves classification criteria. These constraints are usually only an issue for proved reserves and, therefore, this approach may be most applicable for individual entity analyses specifically to determine proved reserves. It is generally not appropriate to constrain the probabilistic model and then select the P_{90} value as the proved estimate, because the constraint can already impose a significant degree of conservatism on the outcome of the model. The P_{90} value of a constrained model could be very conservative. Depending on the degree of impact of the constraint on the calculated reserves, the proved value should lie between the P_{90} and mean value of the constrained probabilistic model.

- **Perform a deterministic check.** In this approach, a probabilistic model is prepared for an entire property (or field) using conventional probabilistic methods, i.e., allowing for the unconstrained full range of valid inputs to the model. Property totals are checked against deterministic estimates, which have included all appropriate constraints (e.g., testing requirements, LKH). Aggregate estimates prepared using probabilistic methods must not exceed those prepared using deterministic approach.

SECTION 5

GENERAL REQUIREMENTS

FOR CLASSIFICATION OF RESERVES

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5.1 Introduction

The general requirements for the classification of reserves are very important for evaluators and need to be applied consistently. The assignment of proved, probable, or possible reserves by an evaluator necessitates that all of the general requirements for classification of reserves have been carefully considered and, at a minimum, been satisfied. Quantities that do not meet the requirements for reserves should be classified as resources.

This section expands upon the guidelines provided in COGEH Volume 1, Sections 5.5.4 and 7.5.3 and adds two new requirements: ownership and the timing of production and development. The general requirements set out here must be carefully considered by the evaluator prior to the assignment of reserves to a well, pool, or field.

Reserves are defined as marketable quantities of oil, gas, and associated products and they reflect the prices for the product in the condition (upgraded or not upgraded, processed or unprocessed) in which they are sold. Reserves exclude any field or processing losses incurred prior to the point of sale (fuel, flare, shrinkage, etc.).

5.2 Ownership Considerations

The first requirement for assignment of reserves relates to the company's ownership in the subsurface mineral rights or the contractual right to exploit and produce. The company's ownership in the oil and gas reserves is usually defined through a working or royalty interest. This interest must permit the company to participate in exploration, exploitation, production, and sale of production, today and in the future.

Securities regulations require that a company have an ownership interest to report and disclose reserves. Therefore, evaluators should only assign reserves to lands in which the company has an interest.

An exception would be offset drainage, where the estimated reserves associated with interest wells exceeds the recoverable quantities underlying the interest lands. In assigning reserves related to offset drainage, an evaluator must reasonably consider the right and opportunity of the other owner(s) to exploit their lands and mitigate loss of reserves.

Ownership and related information are generally available to the evaluator through land records. The land records provide details of contractual obligations (burdens) pertaining to the working interest, such as lessor (Crown and freehold) or gross overriding royalties, net carried interests, net profits, or other encumbrances on production or income. The evaluator may also review revenue and expense statements, or other financial documents to verify the application of the contractual obligations as applied by the operator. Additional guidelines on this subject are provided in COGEH Volume 1, Section 4.5.

Internationally, ownership terms may be more complex and, therefore, the evaluator might need additional assistance. Note that participation by a company in a technical service contract might not meet the definition of ownership in reserves as defined by certain regulators.

Company gross reserves are defined as the working interest or net carried interest share of the reserves prior to the deduction of interests owned by others (burdens). Royalty interest reserves cannot be included in the company gross reserves. Internationally, for production sharing agreements or contracts, company interest reserves are calculated using either the company working interest or paying interest share of production.

The definition of company net reserves includes working, net carried, and royalty interest reserves after deduction of all applicable burdens. Internationally, for production sharing agreements or contracts, net company interest reserves are calculated as either the company working interest or paying interest share of production to cost recovery, plus the company profit interest share of production minus all applicable payments to others, excluding income taxes.

Net profits interests are generally (agreement specific) considered an interest in production income only, and not in production. Therefore, reserves (gross or net) are usually not assigned. However, company net reserves should be reduced for payment of a net profits interest to governments (right to take payment in kind), using the revenue interest method.

5.3 Drilling Requirements

The second requirement for assignment of reserves relates to drilling. Reserves may only be assigned to known accumulations that have been penetrated by a wellbore. The identification of a known accumulation must be consistent with the evaluator’s model for the trapping mechanism and be confirmed by drilling. Oil and gas quantities estimated to be recoverable from potential accumulations that have not been penetrated by a wellbore should be considered resources.

Reserves must not be assigned if the well(s) that penetrated the known accumulation is separated from the lands being evaluated by non-productive reservoir (i.e., absence of reservoir, structurally low, or uneconomic test results). An example is a situation where the geological and/or geophysical model indicated that the top of the reservoir was below the water contact between the productive well(s) and the lands to be evaluated. In this case, the potentially recoverable oil and gas quantities relate to an unproved structural model on the lands (undrilled at present) and should be classified as resources, not reserves.

Undrilled fault blocks cannot be assigned proved reserves in a formation, until penetrated and tested. The evaluator could assign probable or possible reserves to undrilled fault blocks in a structure, offsetting a commercially tested well, after considering factors such as reservoir quality, hydrocarbon migration path, seismic confirmation, fault seal, and results from drilling an adjacent fault block(s). Probable reserves may be attributed to offsetting fault blocks provided the formation is expected to be structurally higher and no reduction in reservoir quality is anticipated. If the formation in the offsetting fault block is expected to be structurally lower, the evaluator may at best assign possible reserves.

It is not necessary that a discovery or development well be capable of being used for production to assign reserves. However, the risk to re-drill a well capable of production should be considered by the evaluator in determining the reserves category.

5.4 Testing Requirements

The third requirement for assignment of reserves relates to testing. The wellbore must have penetrated the reservoir and a production test conducted. The evaluator must be reasonably certain that the test produced fluids from the reservoir to which reserves are being assigned.

The test must provide confirmation that the reservoir is capable of commercial production in order for proved reserves to be assigned to a new accumulation. Therefore, tests such as repeat formation tests (“RFT”) and modular dynamic tests (“MDT”) in themselves are not deemed to be adequate confirmation of a successful production test for the initial well in a new accumulation. Untested wells in a new accumulation (drilled, logged and/or cored, but not tested) may be assigned probable or possible reserves provided that offsetting known accumulations, with similar or reduced reservoir properties, were successfully tested or produced at commercial quantities.

There are two types of flow tests (drillstem and production) generally used in the industry. These tests are conducted to measure flow rates and reservoir properties and to collect a representative sample of the reservoir fluids.

Drillstem tests are designed to obtain a stabilized initial and final reservoir pressure, flow rates, and samples of the reservoir fluids. A drillstem test is typically conducted in open-hole conditions and, therefore, it is important that the packers seal the reservoir from external pressure and fluid influx. Packer failure can render the drillstem test invalid and require a re-test prior to reserves being assigned. The drillstem test involves opening and closing the valve in the tool for short periods of time to produce reservoir fluids and allow the pressure measurements. Drillstem test data can be analyzed to determine reservoir pressure and permeability and to estimate stabilized flow rates.

A closed chamber drillstem test measures downhole pressures and collects a small sample of the reservoir fluid in the drill string. Although production rate can be estimated based on the fluid recovery, the small quantity of reservoir fluids collected during a closed chamber test might not satisfy the requirement for evidence of economic productivity.

Production tests are performed on recently completed wells or on wells that have produced for a period of time. The test uses pressure recorders to continuously measure flowing and build-up pressures. The test also requires surface equipment to measure the flow rates of the well. The test design parameters may vary, but for the assignment of reserves, the evaluator should consider evidence of stabilized flow rate, delivery pressure, reservoir damage, drainage area, and boundary conditions.

The evaluator should analyze the well test to determine if results are satisfactory for the assignment of reserves. The confidence in drillstem and closed chamber test results is not as high as that associated with an extended production test. The well test result is important in classifying the reserves for a non-producing wellbore.

5.5 Regulatory Considerations

The fourth requirement for assignment of reserves relates to regulatory compliance. The company’s development plan will require applications that relate to drilling, completion, testing, processing facilities, and transportation infrastructure. Additional applications may also need to be submitted for public consultation on environmental, archaeological, and water management issues.

If the operator has not filed or received approval for all necessary development applications, the evaluator may still assign reserves, provided that development is not prohibited by government regulation (e.g., environmentally sensitive area). The reserves category used by the evaluator should reflect their level of confidence in the future approval of the outstanding applications.

In a partial ownership situation, where a pooling or other agreement is required to drill a well, the evaluator must have a reasonable expectation regarding the outcome of the agreement to assign reserves.

Reserves assignments related to reduced spacing, secondary or tertiary projects generally require regulatory approval for these types of applications. Additional development applications are usually required from regulatory agencies for the production, injection, or disposal of fluids related to these types of projects. The evaluator may assign proved reserves to a downspacing development provided that the company has received regulatory approval or the approval has a high probability of being granted based on offsetting analogous projects. Otherwise, the evaluator may consider the additional quantities associated with downspacing to be probable, possible or contingent resources, depending on the probability of the approval being granted.

The evaluator must also consider the existence of necessary infrastructure related to processing and transportation and of a market for sale of the reserves. If the company does not have an ownership interest in existing infrastructure, the evaluator may assign reserves if an agreement is realistic (available capacity or expansion capability). If the necessary infrastructure is not available, firm development plans are not in place or regulatory applications have not been filed, then the evaluator cannot assign reserves (e.g., northern Canada). These quantities would be classified as contingent resources.

Automatic renewal of licenses, permits, concessions, and commercial agreements cannot be assumed for proved reserves booking, unless there is a long and clear track record that shows that the renewal application and subsequent approval are a matter of course.

5.6 Timing of Production and Development

The fifth requirement for assignment of reserves relates to timing of production and development. This pertains to reserves with very long production forecasts, non-producing reserves near infrastructure, or significant reserves developments.

Production forecasts generated by curve fitting or matching techniques, reservoir simulation, or other engineering methods may project quantities beyond a 50-year timeframe. Evaluators understand that such production forecasts have increasing degrees of risk with time. The uncertainties in long-life production forecasts relate to the long-term reliability of the forecasts, whether the quantities will be recovered within the useful life of the field infrastructure, and economics. In addition, the net present value (discount rate greater than zero) of the forecast quantities after 50 years is negligible and immaterial to most stakeholders. Therefore, it is recommended that quantities be classified as contingent resources beyond a period of 50 years from the evaluation effective date. An evaluator may, however, consider a reasonable development scheme to allow these quantities to be recovered within a 50-year period (additional drilling, workovers, facility expansion, etc.).

Non-producing reserves that are near existing infrastructure and require minor capital should be developed within a two-year period. If these reserves have not been developed, the evaluator needs to review the technical and economic merit, and appropriateness, of the current reserves category. Exceptions to the guideline are non-producing reserves awaiting depletion of another producing zone in the same wellbore or reserves constrained by facility or market limitations.

If significant capital is required for field development or infrastructure construction (offshore, oilsands, etc.), then to be classified as proved reserves, a commitment to spending must occur within two years for smaller projects and three years for larger projects. To be classified as proved + probable reserves, a commitment to spending significant capital must occur within three years for smaller projects and five years for larger projects. An exception could be related to fields that are clearly commercial, but development is delayed for logistical reasons (facility constraints, gas contract or allowable limitations, etc.).

5.7 Economic Requirements

The sixth requirement for assignment of reserves relates to economics. Only those marketable quantities that are economically recoverable can be classified as reserves. The economic requirement is based solely on future costs and does not consider past (sunk) costs. Economic evaluation procedures and criteria, which address the technical, financial, and regulatory issues, are described in COGEH Volume 1 Section 7.

5.7.1 Forecast Prices and Costs

In practice, reserves should initially meet the economic requirement based on economic conditions that are generally accepted as being reasonable. The economic requirement must be applied successfully to all categories of reserves assigned. The evaluator must consider estimates of production, prices, all capital and operating (fixed and variable split) costs, regulatory approvals, and general and administrative costs incurred at the field. These costs should be developed with consideration for the confidence level of each reserves category (high, most likely, or low certainty). For example, future operating or capital cost reductions should not be considered for the proved category unless incorporated in a current field development plan and deemed feasible by the evaluator.

Revenue from third-party processing should not be used to significantly reduce operating expenses at the field. Processing revenue of less than 10 percent of field expenses may be used to reduce these costs if the revenue is expected to continue in the future.

Undeveloped reserves must have a sufficient rate of return to justify the level of capital expenditure associated with the project. The required rate of return is a function of the risk associated with the project. High-risk projects require a greater rate of return than low-risk projects. The minimum rate of return for low risk to moderate risk capital projects should be guided by the discount rates generally used for valuing oil and gas asset transactions. However, the rate of return for low risk capital projects cannot be less than the return on secure money market investments.

The evaluation of undeveloped reserves requires a plausible development plan, appropriate capital and operating costs, and abandonment and reclamation costs in order to properly assess economic viability. If a project is not economically viable for a proved reserves development, this does not preclude the booking of probable and/or possible reserves if a reasonable return on investment is achieved. However, the evaluator should not book stand-alone possible reserves unless the company is more likely than not to proceed with the required investment. An expected monetary value methodology will assist the evaluator in reaching an opinion on the merit and likelihood of the company proceeding with the required investment.

The economic requirement for a proved reserves assignment must not include projections of future drilling or infrastructure development by other companies that are not currently known. (e.g., stranded gas wells or oil wells).

5.7.2 Constant Prices and Costs

Securities commissions and other agencies commonly require that evaluations of reserves be prepared under a scenario of constant prices and costs. This requirement is usually based on the prices in effect on the last day of the fiscal year (e.g., December 31st) and the actual company costs for the fiscal year.

5.7.3 Booking Guideline

If both forecast and constant economic requirements are satisfied, then reserves should be reported.

If the reserves are economic for only the forecast prices and costs (e.g., uneconomic constant economics), the evaluator will generally report these reserves. However, should the economic requirement be successful for only the constant prices and costs (e.g., uneconomic forecast economics), the evaluator will generally not report these reserves. It is recommended that the evaluator consider the materiality of these reserves to the issuer when only one of two economic tests is met.

SECTION 6

PROCEDURES FOR ESTIMATION AND CLASSIFICATION OF RESERVES

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6.1 Introduction

The estimation and classification of reserves is predicated on data quantity and quality, applicable regulatory guidelines, current and forecast economic conditions, and the training and experience of the evaluator. For these reasons, the reserves estimate or classification may vary between evaluators using the same technical and financial data. The goal of this section is to promote consistency in reserves estimates and reserves classification by all evaluators. This material is intended to expand on the general guidelines contained in COGEH Volume 1, Sections 5.5.5 and 7.2

Evaluators are encouraged to consider all appropriate methods when estimating and classifying reserves. This section reviews reserves estimation procedures commonly used by evaluators—such as analogy, volumetrics, material balance, production decline, and reservoir simulation—and the integration of these methods. Also addressed are reserves estimation issues related to future drilling and planned enhanced recovery projects. The material provides an overview of the principles, estimation procedures, and classification recommendations, as well as examples to illustrate the recommended guidelines.

The guidelines contained in this section are intended to be a “best practices” reference for evaluators. The evaluator’s approach to reserves estimation or classification should only vary from the guidelines provided in this section when there is a compelling technical reason to do so. If this is the case, then a full explanation should be given.

6.1.1 Reserves Confidence Levels

The “best practices” guidelines in this section should not be interpreted by the evaluator in such a way as to contradict the requirements set out in Section 5 of COGEH Volume 1 or Section 3 of COGEH Volume 2.

a. Proved Reserves

i. Entity Level

The requirement for proved reserves at the entity level is a “conservative” estimate of the actual quantities that will be recovered. Although “conservative” is not statistically defined in COGEH Volume 1 or 2, a proved reserves estimate should be less than the proved + probable estimate. When the uncertainty is large, the degree of conservatism should be larger than if the uncertainty is small.

ii. Property Level

The requirement for proved reserves at the property level is a “high” degree of certainty that the actual quantities will be recovered. A high degree of certainty implies that there should be a much greater likelihood of positive compared to negative future annual proved revisions.

iii. Reported Level

The requirement for proved reserves at the reported level is at least a 90 percent probability that the actual quantities will be recovered.

b. Proved Plus Probable Reserves

The requirements also specify that the proved + probable reserves should be the best estimate at the entity, property, and reported levels and have at least a 50 percent probability that the actual quantities recovered will equal or exceed the estimated proved + probable reserves.

c. Proved Plus Probable Plus Possible Reserves

The requirements also specify that the proved + probable + possible reserves should be an optimistic estimate at the entity, property, and reported levels. It is expected that, at the reported level, the proved + probable + possible reserves will have at least a 10 percent probability that the actual quantities recovered will equal or exceed the estimate.

6.1.2 Reserves Validation—Reported Level

Reserves validation is a method of determining if reported level reserves were prepared in a manner consistent with the COGEH definitions. Each year the reported level technical revision for the proved reserves is expected to result in a positive adjustment, after accounting for reserves additions or reductions related to activities throughout the year (exploration discoveries, drilling extensions, infill drilling, improved recovery, acquisitions, dispositions, economic factors, and annual production). Should a negative proved adjustment occur, it is expected that the reserves will be revised to ensure compliance in future years. The proved + probable reserves at the reported level should remain relatively constant with time. The proved + probable + possible reserves should decrease with time.

6.2 Analogy Methods

Analogy methods are important to a reserves evaluator as a primary reserves estimation method when other methods are not considered reliable and for checking the results of other evaluation approaches.

The importance of using analogy methods with other reserves evaluation methods cannot be overstated. Consider an example of a single well gas pool where the volumetric estimate of the original gas in place is based on wellbore petrophysical parameters, the regulatory drilling spacing unit, and a theoretical recovery factor based on a low reservoir abandonment pressure. Even though the well could be capable of draining a very large area, comparison of areal extent with analogous pools in the area could show drainage areas significantly smaller than the regulatory well spacing indicates. Likewise, comparison of recovery factors with analogous pools could also show values significantly lower than indicated. A review of the areal extent and recovery factors in analogous pools in this case may prevent a potential overestimate of the gas reserves.

Because so many aspects of reserves estimation are based on limited or indirect information, it is important that the evaluator compare all of the reserves parameters to those in analogous reservoirs. In some cases, this could involve a quick check by the evaluator and a judgement, based on the evaluator's experience, that the parameter in question falls within an expected range of values. In other cases, it could involve a detailed statistical review. Where estimated values for the reserves under study are significantly different from those in analogous reservoirs without technical justification, adjustments should be made in the subject analysis.

It is important when relying on analogies to ensure that they are valid. Many aspects of the intended analogy should be compared: reservoir properties, fluid properties, presence of fluid contacts, productivity, etc. A valid analogy is one in which all of the characteristics that contribute to the reserves estimate are similar to the subject reservoir. As long as the key characteristics are not significantly inferior, appropriate adjustments should be made to reflect the differences. In some cases, there will simply not be any valid analogies; in those cases, a more conservative approach should be applied in reserves estimation.

The use of analogy methods as a primary reserves estimation method and as a supplement to other methods is described in more detail in Sections 6.2.1 and 6.2.2, respectively. Guidelines for their application are also provided.

6.2.1 Use of Analogies as a Primary Method

a. When Other Methods are Not Reliable

Reserves evaluators sometimes encounter situations where a well has no pressure data, wellbore data is unavailable or insufficient to allow for reliable volumetrically determined reserves estimates, and the well production exhibits no decline. In other situations, the volumetric data might be inconsistent with well productivity, for example, where a standard analysis of the volumetric data shows either unreasonably long or unreasonably short production life. In these instances, the evaluator must use analogies as a guide to estimating reserves. The evaluator typically reviews all the available reservoir and fluid characteristics and then applies judgement, based on experience, to estimate a range of reserves. The production rate is often used as the basis for the reserves estimates, and a reserves life index (remaining reserves divided by current production rates) is applied based on the observed reserves life indices of analogous wells.

The best estimate of reserves using analogies generally represents proved + probable reserves. Because there is usually significant uncertainty in the reserves estimates of this type, an additional level of conservatism must be applied to the proved reserves estimates.

b. Heavy Oil Cold Production

The high-permeability, unconsolidated sand, heavy oil reservoirs in eastern Alberta and southwestern Saskatchewan often have high sand production rates along with high and very stable oil production rates for a few years, followed by a steep decline thereafter. The sand production is believed to be due to a “wormhole effect” in the reservoir and it assists in reservoir recovery.

A common problem with these reservoirs is difficulty in applying either decline curve analysis or volumetric methods to estimate reserves, at least early in the production life. Although volumetric calculations of oil in place can be made, individual well recoveries of ultimate reserves are usually independent of the well’s net pay and correlate better to productivity, due to uncertainty in effective drainage areas.

Reserves estimation early in the well life commonly uses some multiple of the initial well productivity. This multiple is based on a statistical analysis of the reserves life indices of analogous older wells in the same field.

Proved + probable reserves estimates should usually be based on the average or median reserves life index determined for analogous wells. Proved reserves estimates should be reduced from the proved + probable estimates, in some cases significantly reduced, to reflect the greater uncertainty in using this method of analysis.

It is important to ensure that analogous wells used in this analysis are truly analogous. Different well spacing or significantly different oil or water production rates could require further adjustment to the values assigned.

c. Undeveloped Reserves Assigned for Infill Drilling

In mature reservoirs with successive programs of infill drilling on smaller and smaller well spacing, undeveloped reserves for further infill drilling are usually determined by statistically analyzing the recoverable reserves for each successive vintage of infill wells. This method is often applied to the shallow gas formations (Milk River and Medicine Hat) of southeastern Alberta and southwestern Saskatchewan, as well as many oil reservoirs (both light and heavy oil) developed on progressively smaller and smaller well spacing.

Usually the reserves for producing wells in these situations are estimated by decline analyses, and the declining trend of recovery for each year of infill drilling is extrapolated into the future to predict recoveries. Volumetric analysis checks should be conducted on a total field basis.

For this method of grouping wells by drilling date to yield reliable results, there should be several vintages of infill drilling with a consistent declining trend of initial production rates and recoverable reserves for each vintage.

It is important when analyzing the trend of recovery over time to assess how much of the recovery from future wells will be incremental and how much will be acceleration. If initial production rates and estimated reserves recovery are decreasing with each phase of drilling, then interference between wells is occurring and a significant portion of the recovery from the future infill wells will be acceleration.

The proved + probable reserves estimates should be based on the best estimate determined from the statistical review, considering only that portion of the recovery incremental to the older wells. The uncertainty in reserves estimates in these instances is primarily due to difficulties in estimating incremental recoveries versus production acceleration.

6.2.2 Use of Analogies for Specific Reserves Parameters

a. Areal Assignments

The most difficult reserves parameter to determine early in the life of an oil or gas well is commonly the areal extent of the reservoir. When estimating reserves for smaller single-well pools without the benefit of definitive seismic information, the area should be based on a review of analogous mature pools in the area. It is important when comparing analogous pools to consider that progressively smaller pools are encountered in a mature area. An analysis of the historical trend toward smaller and smaller single-well gas pools in Alberta and estimation of their areal extent were presented in a 1989 paper prepared by Andy Warren of the Alberta Energy Resources Conservation Board (Warren 1989).

b. Recovery Factors

Recovery factors early in the life of a reservoir are commonly based on analogies. Other information such as abandonment pressures or fluid displacement efficiencies must be considered, but the behaviour of analogous reservoirs is an important guide to recovery factors. Ideally, the analogous reservoirs should be located near the subject reservoir, but if unavailable, more distant analogies are acceptable. The key is that they are valid analogies.

c. Performance Characteristics

The forecast of future production performance for oil and gas reservoirs is often based on analogies. Reservoir and fluid characteristics help the evaluator predict future decline behaviour and trends in gas/oil, water/oil, or water/gas ratios. It is also important to consider the long-term production behaviour of nearby mature analogies.

For example, for a gas well declining at a consistent rate for several years, many evaluators extrapolate the decline trend to an economic limit. A review of nearby analogous wells could show that they initially declined in the same manner but experienced water loading in late life, causing truncation of production before reaching the expected economic limit. This behaviour in analogous wells must be considered in the reserves estimates and production forecasts for the subject reservoir.

6.3 Volumetric Methods

Volumetric methods are used to estimate oil and gas reserves or to check on estimates derived from material balance or decline analysis methods. Volumetric methods estimate

- the quantity of original oil and gas in place, using reservoir parameters determined from analysis of geophysical, geological, petrophysical, and reservoir engineering data;
- the economically recoverable quantities of oil, gas, and by-products.

Volumetric estimates of original gas and oil in place are subject to a degree of uncertainty commensurate with the type, amount, and quality of the data being used. In addition, recovery factors used to estimate reserves volumetrically are typically estimated from analogous pools, empirical formulae that consider viscosity, permeability, reservoir thickness, and drive mechanism, or “rules of thumb.” The inherent uncertainty in volumetric estimates can only be mitigated by acquiring additional or better reservoir and production data.

6.3.1 Data Used for Volumetric Methods

Three general types of data are used in volumetric methods: geophysical, geological, and reservoir engineering data. Following are guidelines for analyzing and applying these data in volumetric calculations.

a. Geophysical Data

Geophysical data are used to define the shape and size of the oil and gas bearing reservoir. The quality of the geophysical interpretation depends on the quantity and quality of the seismic data, the quality and quantity of supporting geological data, the interpretation method used, and the experience of the geophysicist.

Typically, the end result of geophysical mapping is a structure map of the top of the reservoir, which can be used to estimate the gross rock volume of the hydrocarbon bearing portion of the reservoir. Where sufficient reservoir data are available for calibration, reservoir quality may also be inferred from seismic attribute analysis. In some cases, direct oil and gas indicators are also interpreted and incorporated into the geophysical mapping.

Seismic interpretation has numerous pitfalls. Even with modern 3-D seismic interpretation, for example, time-to-depth conversion can result in significant uncertainty in the structural interpretation of field flanks, resulting in large uncertainty in the area of closure and, therefore, in the volumetric estimate of hydrocarbons in place. In addition, the reservoir might not be a seismic reflector, and its structure might have to be inferred by mapping another reflector either above or below it, resulting in uncertainty that must be recognized in the evaluation. It is imperative that a professional geophysicist with relevant experience interprets any geophysical data, or audits an interpretation of such data, used to support volumetric reserves estimates.

The estimation of reserves within a seismically defined pool must take into consideration all interpretational uncertainties. Whether in mature or frontier areas, reserves must not be automatically assigned to an entire seismically defined closure, even when productive wells have been drilled and fluid interfaces are reasonably known. This issue is discussed in Section 6.3.1.b.v, below.

In addition to its use in estimating in-place volumes of oil or gas, geophysical interpretation also provides critical information relating to estimation of recovery factors. The presence of compartmentalization, proximity to an aquifer, or cross-fault communication, for example, will impact ultimate recoveries and should be incorporated into recovery factor estimates.

b. Geological Data

Geological data used in volumetric reserves estimates are derived from wells that penetrate the reservoir, including wells that fall outside a pool boundary. Such data include well logs, drill cuttings, mud gas logs, conventional or special core analysis, and well test or completion results. Many sources describe the proper interpretation of such data, and interpretation will not be addressed here. It is crucial, however, that geological data be evaluated by an experienced geologist with an understanding of the uncertainties inherent in both the data and its interpretation, and the assumptions made during the interpretation.

In volumetric estimates, the geological data are used to establish the presence of both hydrocarbons and reservoir; to estimate net pay thickness, reservoir porosity and hydrocarbon saturation; to identify pool boundaries; and to either map the pool or provide an estimate of the appropriate drainage area for a single well assignment. In addition, the geological data provide critical input for the estimation of appropriate recovery factors, including porosity type and distribution, reservoir continuity and heterogeneity, and presence or absence of an associated aquifer.

i. Presence of Hydrocarbons

Evidence of hydrocarbons can come from many sources during the process of drilling and completing a well, including drilling mud shows, kicks, cuttings, cores, well log analysis, drillstem tests, swab reports, and production tests. While these sources are all evidence of the presence of hydrocarbons within the rock, the reserves definition clearly requires that the reservoir be capable of producing at commercial rates. In addition, the presence of hydrocarbons in a wellbore does not automatically mean that those hydrocarbons are present across a well spacing unit.

If well log analysis is the primary evidence of oil or gas in a well, commercial production must be established in the same reservoir in the same area before consideration can be given to the assignment of reserves to that well. Even then, if there remains some question as to the commercial productivity of the well, the reserves classification should be downgraded or no reserves attributed to the well without a test.

Hydrocarbon shows in drilling mud or from kicks, cuttings or cores must be supported by well log analysis at the very least, before consideration can be given to the assignment of reserves to a well. In such cases, the presence of hydrocarbons might have been demonstrated in the wellbore, but uncertainty regarding productivity will generally be too high to warrant the assignment of reserves.

The assignment of reserves based on well log analysis in the absence of a productive test is of particular importance in heavy oil sands in east-central Alberta. From log analysis, numerous Mannville sands in that area are unquestionably saturated with heavy oil; however, not all are capable of commercial production. Subtle variations in reservoir quality and oil viscosity, undetectable on well logs, can prevent the zone from producing at commercial rates. Therefore, other Mannville sands, even other productive sands within the same wellbore, cannot be used as analogies in such cases. This is but one example where reserves should not be assigned unless that particular zone has been satisfactorily tested in the well itself or in an adjacent well, and the quality of the reservoir in question is interpreted to be at least as good as the analogy.

In establishing the productive capability of a reservoir, there is a hierarchy of data based on an increasing radius of investigation: production data should take precedence over completion test results, which in turn should take precedence over drillstem test results, because the radius of investigation is progressively increasing. Such a hierarchy might seem obvious, but it is sometimes ignored. If a well was successfully tested but did not produce commercially upon completion, for example, proved reserves cannot be assigned, even though the operator might claim that a poor stimulation was to blame. Probable reserves could be assigned, at best, in such a case if convincing evidence was available to show that a more modern stimulation technique works in that reservoir in that area. However, the risk that the formation will be damaged beyond rehabilitation in that well must also be considered. In cases where a more definitive data source is overridden in the assignment of reserves, the exception must be properly documented.

ii. *Net Pay*

Usually, reservoir information is obtained from well logs and, ideally, sufficient core data are available to verify the well log interpretations, to develop porosity-permeability relationships, and to estimate cutoffs required to identify reservoir-quality rock and net pay within the zones of interest.

A reservoir rock is “any porous and permeable rock potentially capable of containing hydrocarbons within its pore system” (*Development Geology Reference Manual, AAPG Methods in Exploration Series No.10, AAPG, 1992,p. 286*). Pay, or net pay, is “that part of a reservoir unit from which hydrocarbons can be produced at economic rates given a specific production method” (*ibid*). Therefore, although the permeability of a rock might be sufficient to permit hydrocarbons to migrate into its pore system over geological time, the permeability might be too low to permit the production of those hydrocarbons at commercial rates.

The distinction between gross and net pay is made by applying cutoffs in the petrophysical analysis. The fundamental cutoff for determination of net pay is the in-situ relative permeability of the reservoir to the hydrocarbon of interest. Because relative permeability data are not usually acquired, ambient permeability measurements from conventional core analysis are used for this purpose. It must be recognized that there are several important inaccuracies associated with this substitution:

- Conventional permeability measurements are routinely conducted using air, not reservoir fluids.

- The measurements are conducted at ambient, rather than in-situ, conditions, without considering the compressibility of the rock or fluids.

When an ambient permeability cutoff is used, a water saturation or bulk water volume (porosity x water saturation) cutoff is also applied in order to reflect the limiting conditions at which the oil or gas can produce at an economic rate.

Often, however, even conventional permeability data are either unavailable or limited for a given reservoir, and a corresponding porosity cutoff is used instead. In such cases, the porosity cutoff must be based on a porosity-permeability correlation that has been calibrated to production from the same or a valid analogous reservoir.

Cutoffs vary with fluid type, porosity distribution, and recovery mechanism.

In identifying net pay, the data sources may be ranked into a hierarchy based on their relationship to the productive reservoir. Core data, for example, provide direct measurements of the permeability of the rock itself, and take precedence over indirect data sources such as well logs. Similarly, well logs that qualitatively indicate permeability, such as micrologs, take precedence over porosity logs, especially in cases where the porosity-permeability relationship is known, or suspected, to be tenuous due to diagenesis or fracturing. Exceptions, of course, are numerous: for example, the core might not be representative of the reservoir due to large vugs, or the well log might not be valid due to borehole caving. In cases where a more definitive data source is overridden in the assignment of reserves, however, the exception must be appropriately documented.

In volumetrically estimating reserves for single-well pools, the observed wellbore net pay thickness is often applied across a full or partial statutory spacing unit. This assumption must not be made without considering reservoir facies, extent, structure, post-depositional history, and the presence of fluid contacts. Such consideration often requires the review or evaluation of several offsetting wells. Examples are as follows:

- Lateral variation should be expected in fluvial channel fill reservoirs due to the cut-and-fill nature of their deposition. Therefore, offsetting wells within the same channel system should be reviewed for production and/or stratigraphic variability before wellbore net pay is assumed to be constant across an assigned drainage area.

- Highly permeable reservoirs, such as conglomerates or oolite shoals, could test at very high rates even if they are very thin and extend over small areas. In most situations, productivity has no direct relationship to reserves; sufficient geological evaluation must be conducted to estimate appropriate drainage areas.

- Even in extensive marine sands, net pay in a given well could be completely truncated by a fluid interface a short distance from the well, simply as a result of regional dip. A brief review of offsetting wells is usually sufficient to confirm regional structure and assess a drainage area appropriate for the wellbore net pay.

- The reservoir could have been exposed during its history and eroded. While evaluating the well, the geologist should routinely correlate reservoirs suspected of being eroded into adjacent wells to support the assumption of continuity across an assigned drainage area.

In some reservoirs, net pays and, therefore, reserves, are very difficult to estimate with confidence. Examples are fractured reservoirs, such as those that occur along the Alberta foothills, and laminated reservoirs, such as those that occur in southeastern Alberta. In fractured reservoirs, there could be no relationship between permeability and porosity because matrix porosity could be ineffective and productivity entirely fracture-dependent. In laminated sandstone reservoirs, the sand laminae could be too thin to be detected on well logs. In such cases, volumetric estimates usually carry a very high degree of uncertainty, and it is often preferable to forecast production and estimate reserves based on type-well production forecasts. Such forecasts should be developed from analogous wells and/or based on modelling of the well test results. The reserves category and estimates in such cases must reflect the degree of uncertainty associated with the available data.

iii. Porosity

In estimating reserves for single well pools, the assumption is usually made that the porosity is constant across the entire pool. This assumption might not be valid in many geological situations (e.g., in channel fill sands, where the porosity usually degrades upwards), and should be confirmed in every case by reviewing other wells in the same area.

In multi-well pools, it is common to estimate an average thickness-weighted porosity using all wells in the pool. In most cases, this is adequate. However, in pools that demonstrate reservoir heterogeneity, or in detailed geological models used as input for reservoir simulation, it might be appropriate to generate an iso-porosity map. The appropriateness of a simple average versus a detailed map to define porosity in multi-wells should be considered in every case before reserves are estimated.

Although the estimation of effective porosity will not be discussed here, two particular types of reservoirs are worthy of note: shaly sandstone reservoirs and fractured reservoirs.

Volumetric estimates of oil and gas contained within shaly sandstone reservoirs can carry significant uncertainty relating to the estimation of effective porosity. In such reservoirs, well log readings may be affected by thin beds and/or high clay content, and even core analyses could be inaccurate due to dehydration of the clay minerals if the core was not properly preserved and/or analyzed under humidity controlled conditions. In such cases, consideration should be given to estimating reserves by analogy if the effective reservoir volume cannot be confidently estimated.

Volumetric estimates of reserves in fractured reservoirs must also be made with caution. The matrix rock in such a reservoir could be porous but impermeable, and the reservoir could be entirely dependent on fractures for both storage and deliverability. In such reservoirs, there is likely to be a large disparity between net pays determined using standard permeability or porosity cutoffs, and volumetric estimates might correlate poorly to reserves estimated from material balance, decline analysis, or deliverability modelling. All available data must be used to estimate the quantities and classification of reserves assigned in such cases, rather than assuming the volumetric estimates are valid. It might be more appropriate to forecast production and estimate reserves based on type-well production forecasts, as discussed in the previous section addressing fractured reservoirs.

iv. Hydrocarbon Saturation

In assigning reserves to single well pools, the assumption is also made that the hydrocarbon saturation is constant across the entire area of the pool. It is good practice to consider the possibility that it might not be applicable. The most obvious exception to this assumption occurs in transition zones, where progressively more reservoir containing lower water saturation is present within the pay column updip of the interface.

In multi-well pools, it is common to estimate average porosity-thickness-weighted saturations using all wells in the pool. In most cases, this is adequate; however, in pools that demonstrate reservoir heterogeneity or in detailed geological models used as input for reservoir simulation, it might be appropriate to generate an iso-saturation map.

v. Pool Area/Drainage Area/Well Spacing Unit

The drainage area often has the greatest variability in the volumetric method. In the early stages of appraisal drilling of extensive reservoirs, volumetric reserves estimates are often made on an individual well basis using drainage areas equal to statutory spacing units: 640 acres for a gas well, 160 acres for a light oil well, and 40 acres for a heavy oil well. Caution should be exercised in assuming the well drainage area to be equal to the spacing unit, as it is not uncommon for wells to drain significantly smaller areas. Drainage area assignments should reflect analogous well performance, the perceived geological risk, the productivity of the zone being evaluated, and the potential for drainage by offsetting wells. Seismic data are often useful in estimating pool areas and in identifying any potential barriers to fluid flow, such as faults.

Geological factors affecting drainage area may be depositional or post-depositional. Identification of the depositional environment of the reservoir is very important in estimating an appropriate drainage area. Fluvial sands, for example, are notoriously variable and can cover from several acres to several sections, whereas marine sands can be regionally extensive, covering several townships. Post-depositional factors are also important and include structural movement, erosion, and diagenesis. These factors and variations are well known for the Western Canadian Sedimentary Basin and many examples could be cited. Suffice it to say that, in the assignment of reserves to a well, the importance of geological assessment of the depositional facies and post-depositional history of the reservoir being evaluated cannot be over-stressed.

In multi-well pools, geological mapping is required for volumetric reserves estimates. Reserves can be assigned to areas between wells if the wells can be demonstrated to be in the same pool. This is discussed in some detail in Section 6.7.

The estimation of oil and gas reserves in a seismically defined pool must take into account all interpretational uncertainties. In situations where the seismically defined closure significantly exceeds the expected drainage area of the existing wells, for example, the evaluator should consider whether

- the reservoir might be absent or ineffective within the mapped closure as a result of depositional facies variation, diagenetic heterogeneity, or erosion;
- the seismic interpretation might be subject to significant uncertainty as a result of issues such as time-to-depth conversion; or
- the mapped closure might be compartmentalized by stratigraphic variation, erosion, or sub-seismic faulting.

In such cases, the entire closure might be assigned proved, probable, and possible reserves, depending on the confidence level associated with the interpretation. As further drilling confirms both the structural interpretation and the reservoir continuity across the structure, probable and possible reserves should be progressively upgraded to the proved and probable categories, respectively. Caution in the classification of the reserves is warranted, because performance or pressure data might show the pool to be compartmentalized, requiring more wells and capital. Alternatively, further analysis might show the time-to-depth conversion to be incorrect on the flanks, resulting in a reduction in the area of the closure and the in-place oil and gas quantities.

In reservoirs where fluid contacts are unknown, volumetric calculation of proved reserves must be restricted to the lowest known structural elevation of the occurrence of hydrocarbons (LKH). The identification of fluid contacts may be based on well log interpretation, core analyses, test results or pressure-depth plots. Where a conclusive contact has not been defined in a reservoir (e.g., where a regional hydrostatic gradient established from other wells is used in a pressure-depth plot), sufficient verification must be conducted to justify the use of such data in the interpretation. If offsetting well control demonstrates reservoir continuity and provides a relevant highest known water elevation (HKW), sufficient pressure and fluid density data might be available to estimate the interface elevation. Failing this, probable reserves may be assigned to that portion of the pool down to an elevation midway between the LKH and the HKW. However, such an assignment will depend on both the vertical and lateral distances between the well control and the expected drainage area of the productive wells.

In assigning reserves updip of an oil well in a seismically defined closure, the possibility of a gas cap must also be considered. If PVT data for the oil are unavailable, correlations from analogous fields should be used to estimate whether an associated gas cap might be present. Failing this, acceptable industry correlations of oil gravity, reservoir pressure, and reservoir temperature should be employed to estimate the bubble-point pressure of the oil. Extrapolation of the reservoir pressure gradient to the structural crest should then show whether the reservoir pressure is below the bubble point on the crest of the structure. If such is the case, consideration should be given to the assignment of gas reserves in addition to oil reserves.

c. Reservoir Engineering Data

i. Fluid Analysis

Fluid analysis data are required to characterize the reservoir fluid. Fluid samples are usually collected from the reservoir early in the life of the field for laboratory PVT analysis. Reservoir fluids are usually divided into black oil, volatile oil, retrograde gas, and non-retrograde gas. If an analysis is not available, published correlations or an analysis of similar fluids from nearby properties may be used. Fluid properties such as formation volume factor, viscosity, solution gas/oil ratio, and density are used in volumetric calculations to relate reservoir hydrocarbon volumes to surface volumes, or in analytical equations and correlations to estimate recovery factors based on reservoir fluid type and drive mechanism.

ii. Formation Volume Factor

Laboratory PVT analysis of a hydrocarbon sample provides data on the oil and gas formation volume factors. If laboratory data are not available, the formation volume factor may be estimated with a reasonable degree of accuracy using empirical equations.

The volumetric calculation uses the initial oil or gas formation volume factor at the initial reservoir pressure and temperature. If no laboratory analysis is available, data from oil well tests at initial reservoir conditions may be used to estimate the bubble-point pressure and the initial formation volume factor using empirical correlations. These correlations have been developed to estimate the initial formation volume factor for two general cases:

- Saturated oil reservoir: initial reservoir pressure at bubble-point pressure;
- Undersaturated oil reservoir: initial reservoir pressure greater than bubble-point pressure.

The gas formation volume factor may be estimated from correlations, given the composition or specific gravity of the reservoir gas.

iii. Gas Compressibility Factor

The gas compressibility factor or gas deviation factor can be estimated from correlations, provided the critical temperature and critical pressure of the gas are known. The accuracy of the estimate depends on the quality of the gas analysis being used and how representative it is of the produced gas. Because a compressibility factor is only correct at the pressure and temperature used in the estimation, it is important to ensure that the reservoir pressure and temperature data are reliable. For gas containing significant amounts of non-hydrocarbon components, such as carbon dioxide, hydrogen sulphide, or nitrogen, appropriate corrections must be made in estimating the gas compressibility factor.

iv. Reservoir Pressure

Accurate measurement of initial reservoir pressure is extremely important in the estimation of oil or gas reserves. For an oil reservoir, comparison of initial pressure with bubble-point pressure can provide valuable information as to whether the reservoir is undersaturated or saturated. In addition, accurate initial formation pressure is very important for analysis of the reservoir drive mechanism and for subsequent material balance calculations. The duration of the shut-in period is critical in obtaining reliable pressure information. The lower the permeability of the reservoir and the higher the viscosities of the reservoir fluids, the longer will be the shut-in period.

v. Reservoir Temperature

It is important to obtain accurate reservoir temperature, because laboratory PVT data are obtained at reservoir temperature for an oil reservoir. In addition, accurate reservoir temperature is required for the volumetric estimation of the original gas in place (OGIP). It is desirable to determine the initial temperature versus depth profile of a producing well using a continuously recording subsurface temperature gauge under stabilized bottom-hole conditions, preferably with a static bottom-hole pressure measurement. Temperature measured during open-hole logging will tend to be lower than the normal formation temperature due to the cooling effect of the circulating drilling fluids. In a cased well, the measured temperature will tend to understate the true formation temperature if temperature equilibrium has not yet been reached in the wellbore.

For volumetric calculations, the reservoir temperature is estimated at the reservoir datum depth.

vi. Gas Shrinkage

In many fields, gas must be processed prior to sale to remove non-hydrocarbon components, such as hydrogen sulphide and carbon dioxide. Small amounts of non-hydrocarbon components can remain in the gas as long as the pipeline specifications are achieved. If the gas is rich in liquids (condensate), the liquids must also be removed. The quantity of liquids removed will depend on the processing facility and its efficiency. The removal of components from the wellhead (raw) gas stream will result in a reduction of the downstream (sales) gas volumes. In addition, some of the processed gas could be used as fuel gas to operate field equipment. These shrinkages must be accounted for in reserves estimates, which must reflect saleable gas volumes.

vii. Well Test Analysis

Well testing during the early life of a well can provide critical productivity, rock and fluid properties information, as follows:

- production rate;
- pressure and temperature measurements;
- fluid samples for PVT analysis;

- skin factor;
- formation characteristics (permeability, fractures, layering);
- influence of boundary conditions (faults, depletion).

A well-planned test that integrates as much open-hole logging and geological information as possible can capture critical formation fluid property data, transmissibility of the reservoir, and the radius of investigation during the infinite acting pseudo-steady-state and steady-state flow periods. The formation fluid property data and transmissibility provide valuable information for volumetric calculations.

viii. Extended Flow Tests

Extended well testing is used in evaluating marginal oil and gas reservoirs to determine their economic viability. The test, which can last weeks or months, provides engineering data for the estimation of oil and gas in place and the assessment of the nature and strength of the drive mechanism, before committing to a full-scale development. The data collected from the test are usually applied to a material balance equation to estimate oil and gas in place. As with other well tests, there are basic difficulties facing the engineer in interpreting the results. Unknowns, including aquifer strength, changes in oil and water formation volume factors with declining pressure, and the production contribution of lower permeability rock in a heterogeneous reservoir, can lead to either underestimation or overestimation of the oil and gas in place.

ix. Reservoir Drive Mechanisms

For oil reservoirs, there are five natural drive mechanisms: gravity segregation drive, fluid and rock expansion drive, solution gas drive, water drive, and gas cap drive. In general, the main drive mechanism for a field changes from one type to another during its producing life. For example, fluid and rock expansion could dominate at pressures above the bubble point and solution gas drive below bubble point. If conditions for a water drive are present, it will gain dominance with time.

For gas reservoirs, the typical drive mechanism is either pressure depletion or water drive. Once a volumetric estimate of oil or gas in place is made, the engineer must determine the drive mechanism(s) applicable to the reservoir, based on the limited geological, reservoir engineering, and production data. An understanding of the drive mechanism permits the engineer to estimate a range of recovery factors from the analysis of production data—by reservoir engineering computations, by analogy with producing pools in an analogous reservoir, or by a combination of these methods.

x. Reservoir Simulation Modelling

Reservoir simulation modelling is a computer simulation using complex mathematical formulations, numerical approximations, and reservoir descriptions to predict well and/or reservoir performance. Reservoir simulation can be a powerful tool to estimate reserves potential if significant production data are available for a history match. A history-matched model can provide a more reliable prediction of future performance than other engineering calculations or using observed recoveries in analogous pools.

On the other hand, the quantity and quality of geological, production, and pressure data available for a reservoir in the early stages of production could be very limited, introducing many uncertainties into a reservoir simulation. In addition, a short production history does not allow a history match to check if the input data are adequate for identifying the reservoir mechanisms responsible for the observed field behaviour. Therefore, the predicted recovery from the simulation must be cross-checked for consistency with other engineering calculations or observed recoveries in analogous pools. If the reserves assignment for a pool with a short production history is based on a predicted recovery from simulation, only a portion of the predicted recovery should be considered proved reserves, and the remaining portion may be considered probable or possible reserves. The transfer of portions of probable or possible reserves to proved reserves would occur as more production data become available and as the well performance substantiates the simulation prediction.

xi. Recovery Factor

Estimates of recovery factors are based on analysis of well production data, analogy with producing pools in analogous reservoirs, or empirical equations. Recovery factors are a function of the drive mechanism, the rock and fluid properties, and the development plan to be applied. Because a recovery factor must be estimated early in the producing life of a pool, usually with limited geological and engineering data, it carries a high degree of uncertainty. Therefore, the best estimate of the expected recovery factor should be used to estimate the proved + probable reserves.

The estimation of recovery factors in certain types of reservoir require extra caution:

- **Thin Pay Overlying Water**. Initially, high production rates with minimum water production may be observed in such pools. However, water production can increase rapidly after a brief period of production. A lower recovery factor should be assigned to such pools, compared to water-free reservoirs. In addition, as a general guide, 50 percent to 75 percent of the lower recovery factor should be used in estimation of proved reserves. Engineers must not be influenced to use a high recovery factor because of a very short reservoir life index based on the high initial rate.

- **Fractured Reservoirs.** Accurate estimation of volumetric reserves in naturally fractured reservoirs is difficult due to the presence of a dual-porosity system. The difficulty is attributed to the heterogeneity of the reservoir rock, with a wide variation in porosity, permeability, and water saturation between the fracture system and the matrix system. Defining the area of drainage presents yet another challenge. The drainage area in a naturally fractured reservoir is usually oriented along the open fracture systems, with significant areas included from nearby reservoir rock containing matrix porosity and permeability. Because of uncertainty in determining the drainage area and flow characteristics of dual-porosity systems, volumetric reserves estimates in fractured reservoirs are subject to substantial uncertainty. The estimates should be compared with observed recoveries from analogous reservoirs and refined with performance analysis as more production data become available.

- **Over-Pressured Reservoirs**. As pressure is depleted in an over-pressured sandstone, the reservoir evolves from being fluid-supported to being grain-supported, and permeability reduction can occur as a result of physical failure of the sand grains. In such cases, production rates and, likely, recovery factors can be drastically reduced. In addition, sand production could cause operational problems, further impacting production rates and, possibly, recovery factors. It is recommended that caution be exercised in assigning recovery factors to, and classifying reserves in, such reservoirs until the reservoir pressure approaches hydrostatic pressure and the long-term production characteristics of the pool are established.

Due to the high degree of uncertainty in reserves estimates in the early life of a well or a pool, only a portion of the "best estimate" reserves should be classified as proved. As cumulative production increases and more technical information becomes available, the uncertainty will decrease, resulting in a progressive transfer of probable reserves to proved reserves.

6.3.2 Guidelines for Reserves Assignments in Single-Well Pools

As noted in 6.2.2, drainage area estimates used in volumetric calculations in the early stages of a single-well discovery must be guided by local geological knowledge, such as the type of reservoir and its depositional environment, as well as any other data, such as seismic, which might provide an indication of the pool area. For example, a conventional gas spacing unit of 640 acres is not appropriate if geological information shows the reservoir to be a pinnacle reef that in analogous pools might cover less than 160 acres. Similarly, other depositional environments that result in narrow reservoirs or reservoirs with limited extent should be identified and used to control the areas assigned to single well pools. It is the responsibility of the evaluator to incorporate all available knowledge in the estimation of the most appropriate area assignment. Average wellbore parameters calculated for the well should be used in the volumetric estimates.

Three examples of single well assignments follow.

Example 1: Gas in a fluvial channel sand reservoir

Background

The well to be evaluated is the 10-26 well shown in Figure 6-1. The well has been on production for two years at a steady rate of 700 Mcf/d and the cumulative production is 500 MMcf. No decline analysis is possible and no bottom-hole pressure data are available. In the last month, the water/gas ratio increased to 15 bbl/MMcf from the historical average of 5 bbl/MMcf.

The geologist has identified the reservoir as a Basal Quartz sand and interpreted it to be a fluvial channel fill unit based on well log character. The reservoir is developed almost to the top of the channel and is interpreted to contain 20 ft of net gas pay overlying almost 50 ft of wet sand.

The pay zone has been correlated into the immediate offsets and is equivalent to

- a gas-bearing sand in the abandoned 4-26 well on the same section, also interpreted to be a channel fill unit;
- a gas-bearing sand in the producing 3-35 gas well, which could be either a channel edge facies or a regional marine sand, based on well log character.

Drainage Area

The nominal drainage area assignment for a gas-bearing channel fill sand reservoir in this area is 320 acres, which yields a volumetric OGIP of 3.0 Bcf. Before assigning this area to the well, however, the continuity of the pay zone into the offsetting wells must be investigated.

The results of the investigations were as follows:

- The gas zone in 4-26 had the same original gas-water contact as 10-26 but it is interpreted to be depleted based on the presence of original and secondary gas-water contacts on the well logs and on the completion results. The depletion is interpreted to have been caused by production of 1.0 Bcf from the same zone in the abandoned gas well at 10-23. Therefore, 4-26 is not interpreted to be in the same pool as 10-26.

- The 3-35 well has produced only 80 MMcf over two years and the rate has been steady at 50 Mcf/d for the last year. No pressure data are available to verify that the wells are in the same pool; however, it appears that 3-35 is starting to slug water, and a check of the structures shows the zone to be 10 ft higher than the porosity top in 10-26. Based on this information, the two wells are interpreted to be in separate pools.

The offsets have been satisfactorily reconciled and an assignment of 320 acres is considered reasonable for the 10-26 well.

Reserves

Given the presence of underlying water, the well rate, and concerns regarding the recent increase in the water/gas ratio, a range of recovery factors was used to assign the original recoverable raw gas reserves to different categories, as follows:

- proved: 3.0 * 50% = 1.5 Bcf RRG

- proved + probable: 3.0 * 60% = 1.8 Bcf RRG

- proved + probable + possible: 3.0 * 70% = 2.1 Bcf RRG

Offsetting Locations

No assignment of reserves to offsetting locations is justified, because well 10-23 was interpreted to be a single well pool based on the analysis of offset well information.

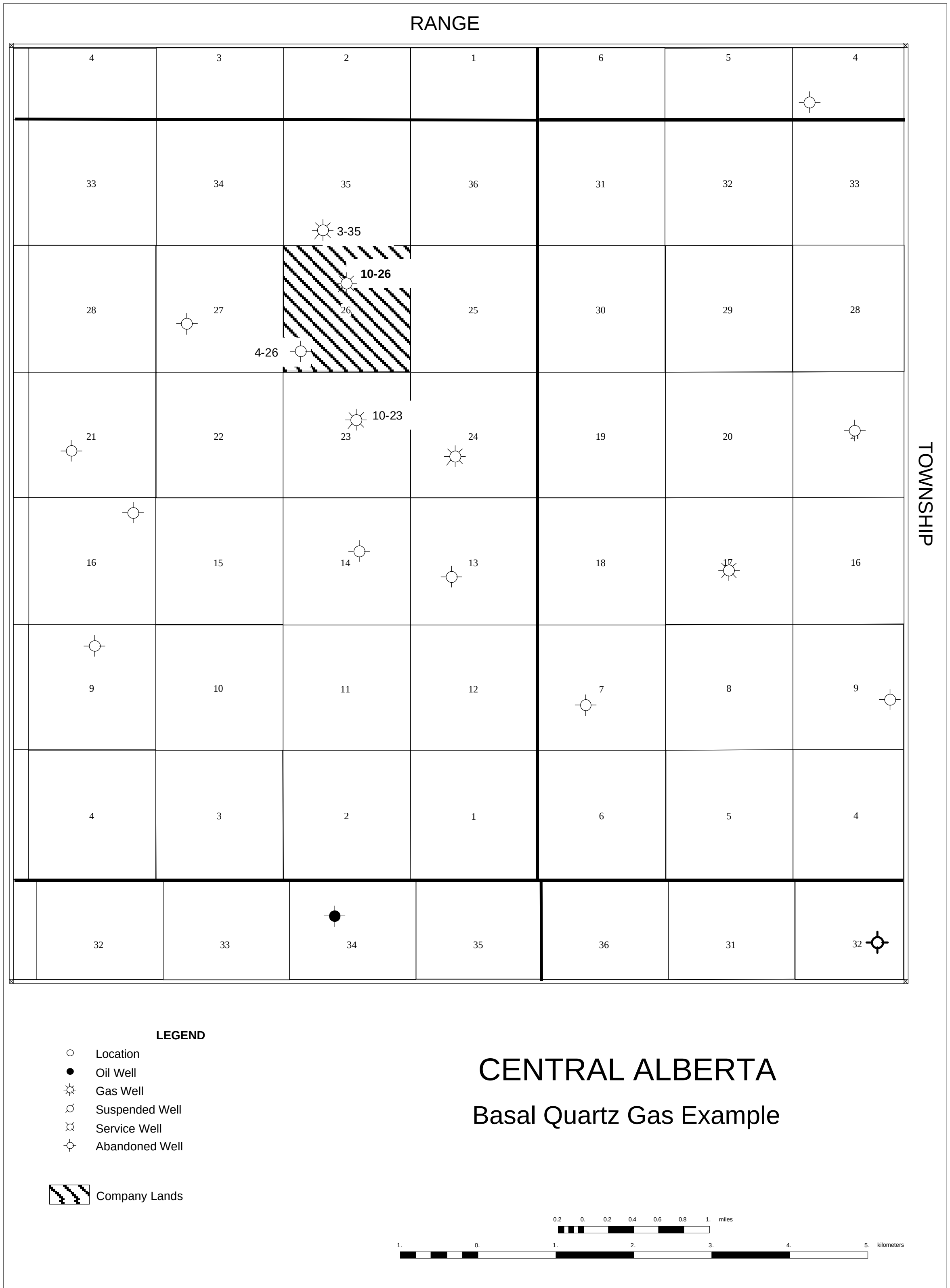
RANGE
TOWNSHIP
4 3 2 1 6 5 4
33 34 35 36 31 32 33
3-35
10-26
28 27 26 25 30 29 28
4-26
10-23
21 22 23 24 19 20 21
16 15 14 13 18 17 16
9 10 11 12 7 8 9
4 3 2 1 6 5 4
32 33 34 35 36 31 32
LEGEND
Location
Oil Well
Gas Well
Suspended Well
Service Well
Abandoned Well
Company Lands
CENTRAL ALBERTA
Basal Quartz Gas Example
miles
kilometers

Figure 1

Example 2: Heavy oil in a regional marine sand reservoir

Background

The well to be evaluated is the 9-3 well shown in Figure 6-2. The well produces heavy oil from a Sparky sand in east-central Alberta and has produced 40 Mstb since early 1997, at a steady rate of 40 bopd. The geologist has identified the producing zone as the regional marine sand of the Sparky member of the Mannville Group and has assigned 15 ft of oil pay in the well. The zone does not contain any underlying water in the wellbore. Original oil in place (OOIP) has been estimated at 1 MMstb per 40 acres.

The nearest offsets are approximately 800 m away:

- The 6-2 well was drilled and abandoned in 1980. It encountered an identical regional sand that was not tested but is interpreted to be oil-bearing based on well logs. Structurally, the zone is 5 ft higher than the 9-3 well.

- The 11-3 well was drilled and suspended in 1995. It also encountered an identical regional sand that was not tested and is interpreted to be oil-bearing based on well logs. Structurally, the zone is 5 ft lower then the 9-3 well, and no underlying water was interpreted within the zone on well logs.

Drainage Area

A drainage area of 40 acres was assigned to the well based on the normal development spacing for Mannville marine sands in this area.

Reserves

Based on the geological interpretation, the performance of the well, and recovery factors from analogous pools, the original recoverable oil reserves were assigned as follows:

- proved: 1.0 MMstb * 7% RF = 70 Mstb

- proved + probable: 1.0 MMstb * 8% RF = 80 Mstb

- proved + probable + possible: 1.0 MMstb * 9% RF = 90 Mstb

Offsetting Locations

No proved undeveloped or probable locations were assigned offsetting the well at this time because there are no immediate 40-acre offsets to the producing well. Both well 9-3 and offset 11-3 were operated by the same company. No attempt was made to recomplete into the heavy oil sand in well 11-3, even though the performance from well 9-3 was encouraging. In addition, there has been no follow-up delineation drilling in the five years since production began in 1997. Performance data in other

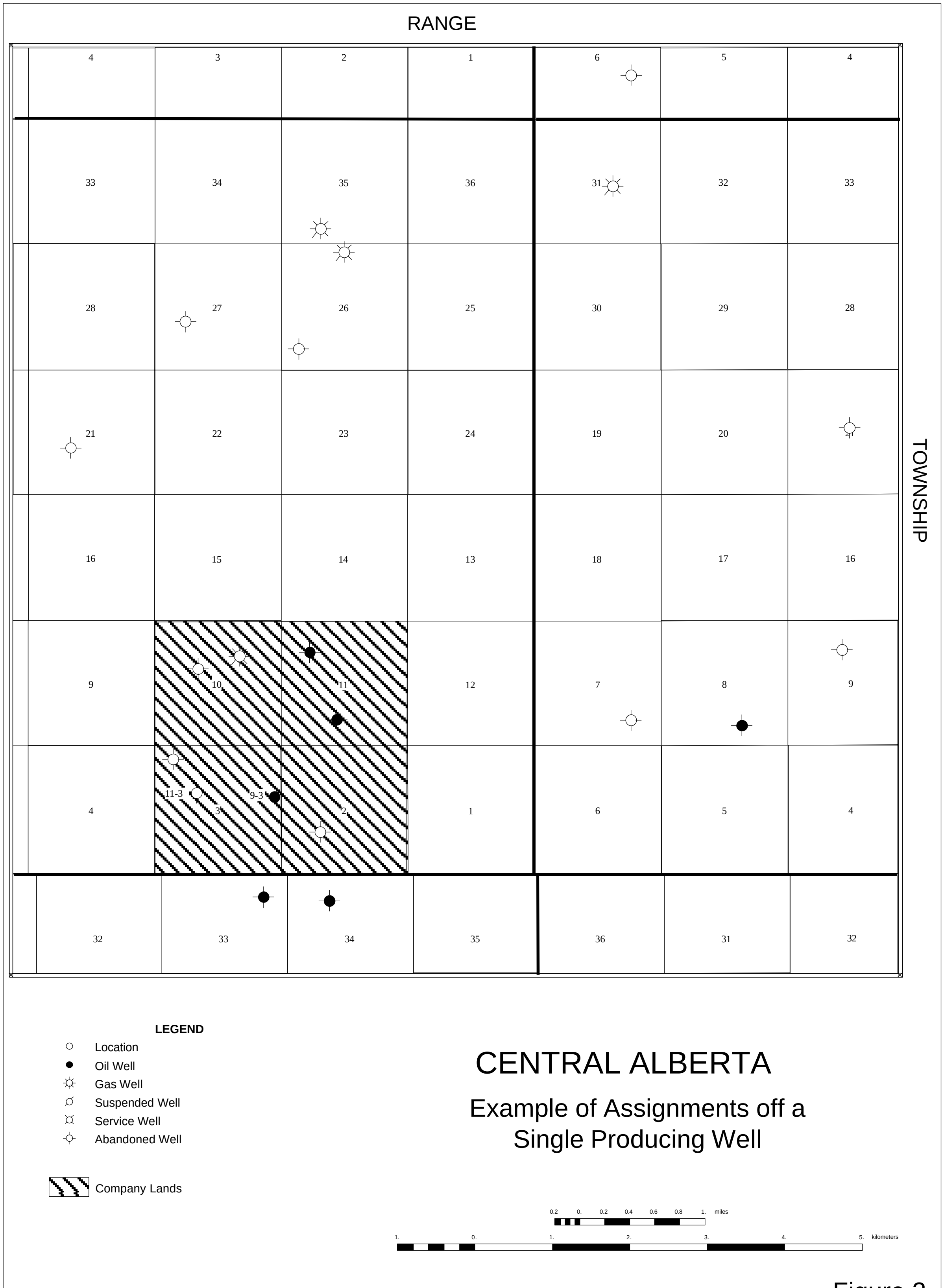
RANGE
TOWNSHIP
4 3 2 1 6 5 4
33 34 35 36 31 32 33
28 27 26 25 30 29 28
21 22 23 24 19 20 21
16 15 14 13 18 17 16
9 10 11 12 7 8 9
4 3 2 1 6 5 4
11-3
9-3
32 33 34 35 36 31 32
LEGEND
Location
Oil Well
Gas Well
Suspended Well
Service Well
Abandoned Well
Company Lands
CENTRAL ALBERTA
Example of Assignments off a Single Producing Well
miles
kilometers

Figure 2

analogous pools have shown that response to cold-production techniques varies from well to well, even though the wells are in the same reservoir and appear similar on well logs. Therefore, more development is required in this section to increase confidence before any proved or probable undeveloped reserves can be assigned to offsetting locations.

Example 3: Light oil in a shelf carbonate reservoir

Background

The well to be evaluated is the 16-27 well shown in Figure 6-3. The well produces 37°API oil from a dolomitized Nisku shelf carbonate reservoir in central Alberta. The well has produced 60 Mstb of oil and the rate has been constant at approximately 10 bopd for the last 6 years, precluding decline analysis. The watercut has been in excess of 98 percent for several years.

The geologist evaluated the well logs and core analysis and assigned 20 ft of oil pay, with no underlying water within the zone in the wellbore. The Nisku is separated from the underlying Leduc porosity by 30 ft of tight dolomite. The original oil in place is estimated to be 1.0 MMstb for a 160-acre spacing unit.

No seismic interpretation was available to assist in establishing a pool area. The offsetting 14-27 well logs were reviewed and the zone was interpreted to be tight.

The three nearest Nisku producers were also single well pools:

- The 6-35 well watered out after producing 5 Mstb oil.
- The 14-22 well watered out after producing 20 Mstb oil.
- The 6-22 well watered out after producing 10 Mstb oil.

A search for other Nisku producers in the same general area also showed a larger pool nearby, with individual well recoveries in excess of 400 Mstb. However, those wells produce from both the Nisku and the immediately underlying Leduc porosity, and the pool is under waterflood.

Drainage Area

Based on the performance of the well and its immediate offsets, the 16-27 well is assumed to be a single well pool with a drainage area of 160 acres.

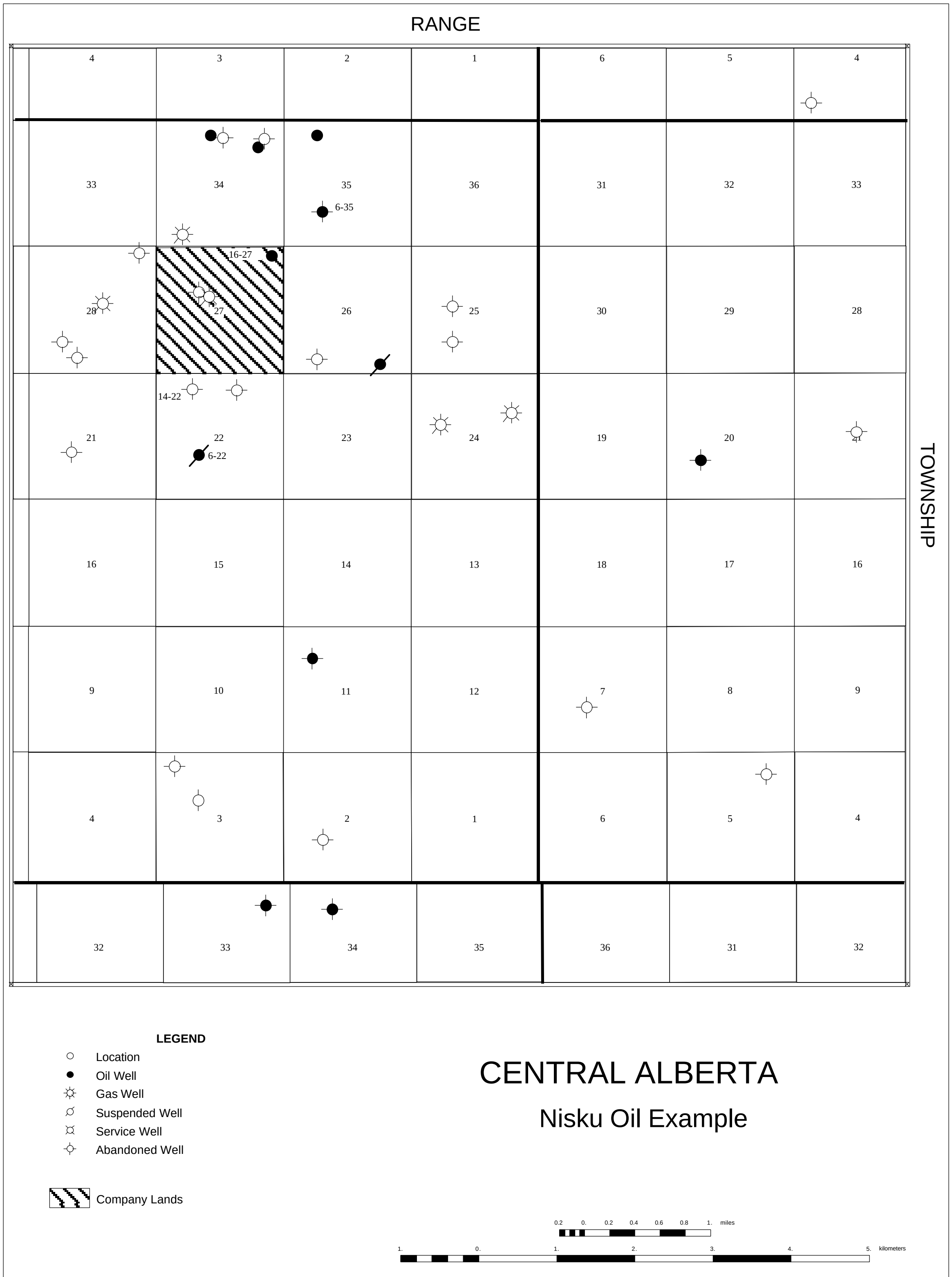
RANGE
TOWNSHIP
6-35
16-27
14-22
6-22
LEGEND
Location
Oil Well
Gas Well
Suspended Well
Service Well
Abandoned Well
Company Lands
CENTRAL ALBERTA
Nisku Oil Example
miles
kilometers

Figure 3

Reserves

Original recoverable oil reserves were assigned to the 16-27 well as follows:

- proved: 1.0 MMstb * 7% RF = 70 Mstb
- proved + probable: 1.0 MMstb * 8% RF = 80 Mstb
- proved + probable + possible: 1.0 MMstb * 9% RF = 90 Mstb

Offsetting Locations

No assignment of reserves to offsetting locations within the same section is justified. The zone is not porous in the offsetting spacing unit to the west, and the undrilled spacing unit to the south is offset by the obviously uneconomic well 14-22.

6.3.3 Guidelines for Reserves Assignments in Multi-Well Pools

If an oil or gas accumulation can be shown to be continuous through geological mapping, reserves may be assigned to undrilled locations within that pool. The reserves category assigned to each spacing unit within the pool will depend on the confidence with which the reserves can be estimated.

The producing wells within a pool provide the most relevant information for estimating drainage areas and recovery factors, as well as assigning reserves to undrilled locations within the pool. If the production of wells within the pool is not mature enough for such purposes, the performance of analogous wells and pools should be used, taking care to establish that such wells and pools are truly analogous.

In assigning reserves in any category within a pool, consideration must be given to all relevant factors, including, but not limited to geological control, reservoir quality, well performance, drainage area, underlying water, overlying gas, drive mechanism, addition of compression, artificial lift, potential for infill drilling and potential for enhanced recovery. Analogous pools can provide valuable information for analyzing the impact of such factors on reserves estimation and classification.

It is important to recognize that a proved entity should also be assigned probable reserves, such that the proved + probable recovery factor represents the most likely recoverable volume from that entity. A proved recovery factor should then be established, bearing in mind the requirement of high confidence in the reported pool reserves. A proved + probable + possible recovery factor may also be established based on improved recovery or field optimization, bearing in mind the requirement of low confidence in the reported pool reserves.

It is expected that the industry standard for volumetric reserves estimation will continue to be a single net pay isopach map representing the most likely estimate of the extent and configuration of a pool. In some cases, however, it may be appropriate to generate multiple maps, representing the maximum, most likely, and minimum pool configurations, in order to quantify the effects of particular uncertainties in the volumetric estimates. Alternatively, the most likely rock volume within a pool may be mathematically increased to reflect the possible rock volume for the purposes of assigning possible reserves. The preferred method of making such an adjustment is to use a probabilistic analysis . However, it may be acceptable to simply “gross up” the pool rock volume by a nominal amount based on observed variability of the volumetric parameters and uncertainty in the geological mapping. In using such a procedure, however, care must be taken to relate the calculated volume and pool area to the actual lands to ensure that any potential equity issues are addressed.

Generic examples illustrating the assignment of reserves within a multi-well gas pool and a multi-well oil pool are presented in the following discussion to illustrate the application of the guidelines discussed in this volume. For presentation purposes, it is customary to identify the reserves category for each spacing unit within a pool superimposed on a net pay isopach map of the pool. With the assignment of multiple reserves categories to spacing units within a pool, however, such a map may become confusing. To avoid such confusion in the following examples, the individual reserves categories are shown on separate maps.

Example 1: Multi-Well Gas Pool

A generic multi-well gas pool is illustrated in Figure 6-4A. The pool contains three gas wells producing from a shallow marine sandstone that has been interpreted from well control to be continuous across the mapped area. The updip limit of the pool is controlled by a facies change from sand to shale and the downdip limit is controlled by a gas-water interface, as shown on the map. The pool boundaries are estimated, having been interpolated from the existing well control, and are considered by the geologist to represent the most likely extent of the pool.

The individual reserves assignments within the pool are shown in Figure 6-4B.

From a comparison of well performance and volumetric calculations, the producing wells were each expected to drain the proved + probable reserves from at least a 640-acre spacing unit, and past work showed this to be true for analogous pools in this area. Thus, this spacing unit was honoured in assigning reserves within the pool.

The key to assigning reserves to the pool is the estimation of the most likely (proved + probable) recovery factor. In this example, the gas overlies water, and a most likely recovery factor of 65% was estimated using initial pressure, abandonment pressure and the expected impact of water influx. To reflect uncertainty concerning the impact of the underlying water on ultimate recovery, and bearing in mind the requirement for high confidence in the proved reserves, the proved recovery factor was estimated to be 50%. To acknowledge the possibility that the aquifer might be less active than is currently expected, a proved + probable + possible recovery factor of 75% was also estimated for the pool.

The statutory spacing units containing the producing wells (sections 17, 13 ,and 24) were thus assigned proved developed producing (PDP) reserves and probable developed (PBD) reserves as shown in Figure 4B. Probable developed reserves were also assigned to the partial spacing units downdip of the PDP lands (sections 8, 9, 16, and 12), because they will not be independently developed and are expected to be drained by the PDP wells.

Based on the estimated wellbore drainage area and the expectation of similar net pay and structural position from the geological mapping, the mapped lands within one spacing unit of the proved developed producing (PDP) lands were considered to contain proved undeveloped (PU) reserves. These lands (sections 18, 19, 14, and 23) were assigned the proved recovery factor established for the PDP wells. No PU reserves were assigned to the partial spacing units along the pool edges, based on uncertainties regarding either presence of reservoir (updip edge) or economic recovery (downdip edge close to underlying water).

The lands assigned PU reserves (sections 18, 19, 14, and 23) were also assigned probable undeveloped (PBU) reserves and the partial spacing units offsetting the PU lands (sections 7, 20, 30, 11, 25, and 26) were also assigned PBU reserves on the expectation of their drainage by existing and future wells. In addition, probable undeveloped (PBU) reserves were assigned to the mapped area within one spacing unit of the proved lands (sections 10, 15, 22, and 27), based on the geological mapping and the performance of the producing wells. These lands were assigned the proved + probable recovery factor established for the PDP reserves. The partial spacing units along the pool edges were expected to be drained by existing and future wells.

Each of the proved and probable reserves entities may also be assigned possible reserves. In this example, the entire pool was assigned possible reserves assuming the aquifer may be less active than currently expected. An ultimate recovery factor of 75% was estimated for this case and the reserves were assigned as possible developed (PosD) and possible undeveloped (PosU), as shown in Figure 4B. It should be noted that the pool volume could also have been increased to reflect the possibility of

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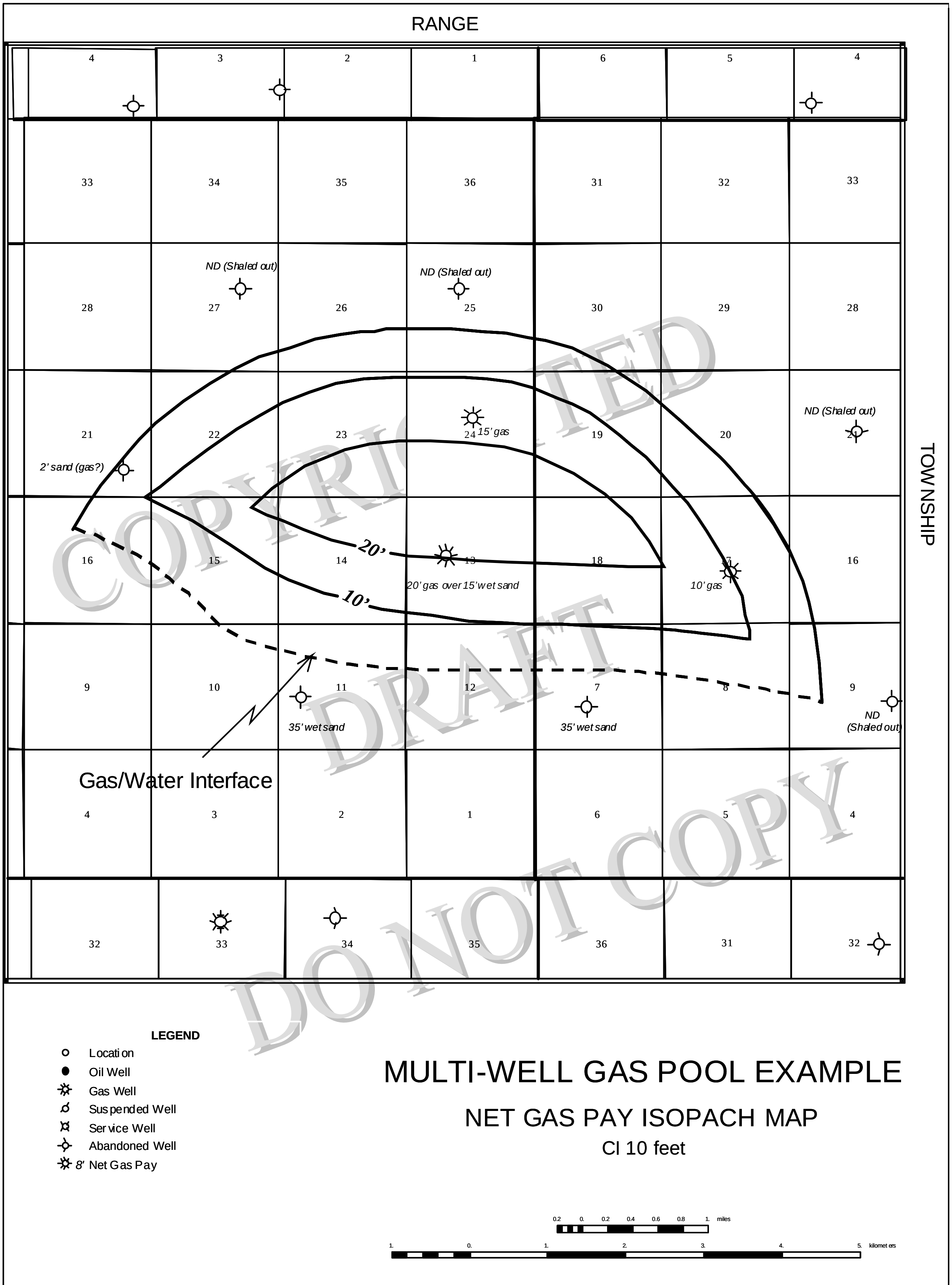

Figure 4A

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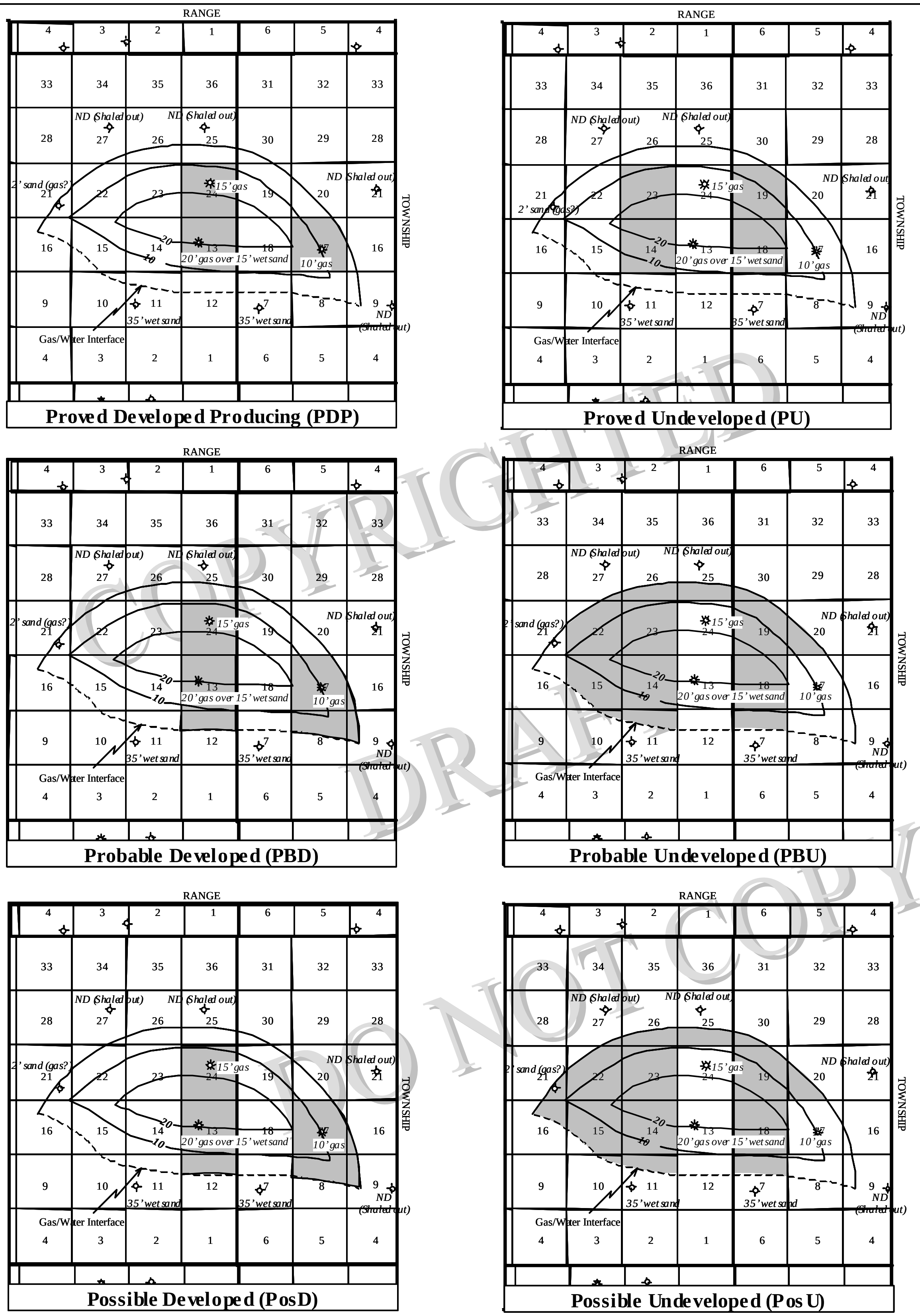

MULTI-WELL GAS POOL EXAMPLE RESERVES CLASSIFICATION Figure 4B encountering higher net pays, higher porosities or lower water saturations on the undrilled spacing units, or the likelihood that the pool area may be larger than currently expected.

Example 2: Multi-Well Oil Pool

A generic multi-well oil pool is illustrated in Figure 6-5A. The pool contains fourteen wells producing light gravity oil from a shallow marine sandstone that has been interpreted from well control to be continuous across the mapped area. The updip limit of the pool is controlled by a facies change from sand to shale and is reasonably well defined from well control. The downdip limit is controlled by an oil-water interface and its location is reasonably well defined from well control. The map is considered by the geologist to represent the most likely extent of the pool.

The pool is under primary production and the operator has no plans to implement an enhanced recovery scheme in the foreseeable future. Several analogous pools are being waterflooded, with mixed results.

The individual reserves assignments within the pool are shown in Figure 6-5B.

From a comparison of well performance and volumetric calculations, the producing wells were each expected to drain the proved + probable reserves from a 160-acre spacing unit; thus, this spacing unit was used to assign reserves to undrilled locations within the pool.

The key to assigning reserves to the pool is the estimation of the most likely (proved + probable) recovery factor. In this case, an appropriate recovery factor was estimated from a combination of production performance, analogous pool performance, and empirical correlations. A proved recovery factor was then estimated to reflect uncertainty concerning the impact of the underlying water on ultimate recovery, and bearing in mind the requirement of high confidence in the reported pool proved reserves. A proved + probable + possible recovery factor was also estimated based on the potential for enhanced recovery, bearing in mind the requirement of low confidence in the reported pool reserves.

The spacing units containing the producing wells were thus assigned proved developed producing (PDP) reserves and probable developed (PBD) reserves as shown in Figure 5B. PDP and PBD reserves were also assigned to several partial spacing units along the updip pool edge based on confidence in the geological mapping and the expectation that they would be drained by the existing wells.

Using the geological mapping and expected wellbore drainage area, the mapped lands within one spacing unit of each proved developed producing (PDP) well were considered to contain proved undeveloped (PU) reserves, with several exceptions. The exceptions were at both ends and along the downdip portion of the pool and were based on uncertainties regarding either the location of the pool edge or structure, resulting from sparse well control. The PU lands consist of one partial and seven full spacing units. The partial spacing unit lies at the updip edge of the pool, is defined by well control, and is expected to be drained by existing or future wells.

The lands assigned PU reserves were also assigned probable undeveloped (PBU) reserves. In addition, PBU reserves were assigned to one partial and five full spacing units at the eastern and western ends of the pool and along the downdip edge, based on consideration of expected net pay thickness, structural position relative to the oil-water contact and the presence of a producing well at a similar elevation in the pool. These lands all offset proved spacing units.

Each of the proved and probable reserves entities may also be assigned possible reserves. In this example, possible reserves were assigned to the entire pool based on the potential for enhanced recovery. Although the operator has no plans to waterflood the pool in the foreseeable future, several analogous pools are under waterflood, but with mixed results. The economic viability of developing the possible reserves was verified using the average incremental recovery factor established for analogous pools. Because the waterflood would require a significant capital expenditure, the possible reserves were classified as undeveloped (PosU). It should be noted that the pool volume could also have been increased to reflect the possibility of encountering higher net pays, higher porosities, or lower water saturations on the undrilled spacing units, or the likelihood that the pool area may be larger than currently expected.

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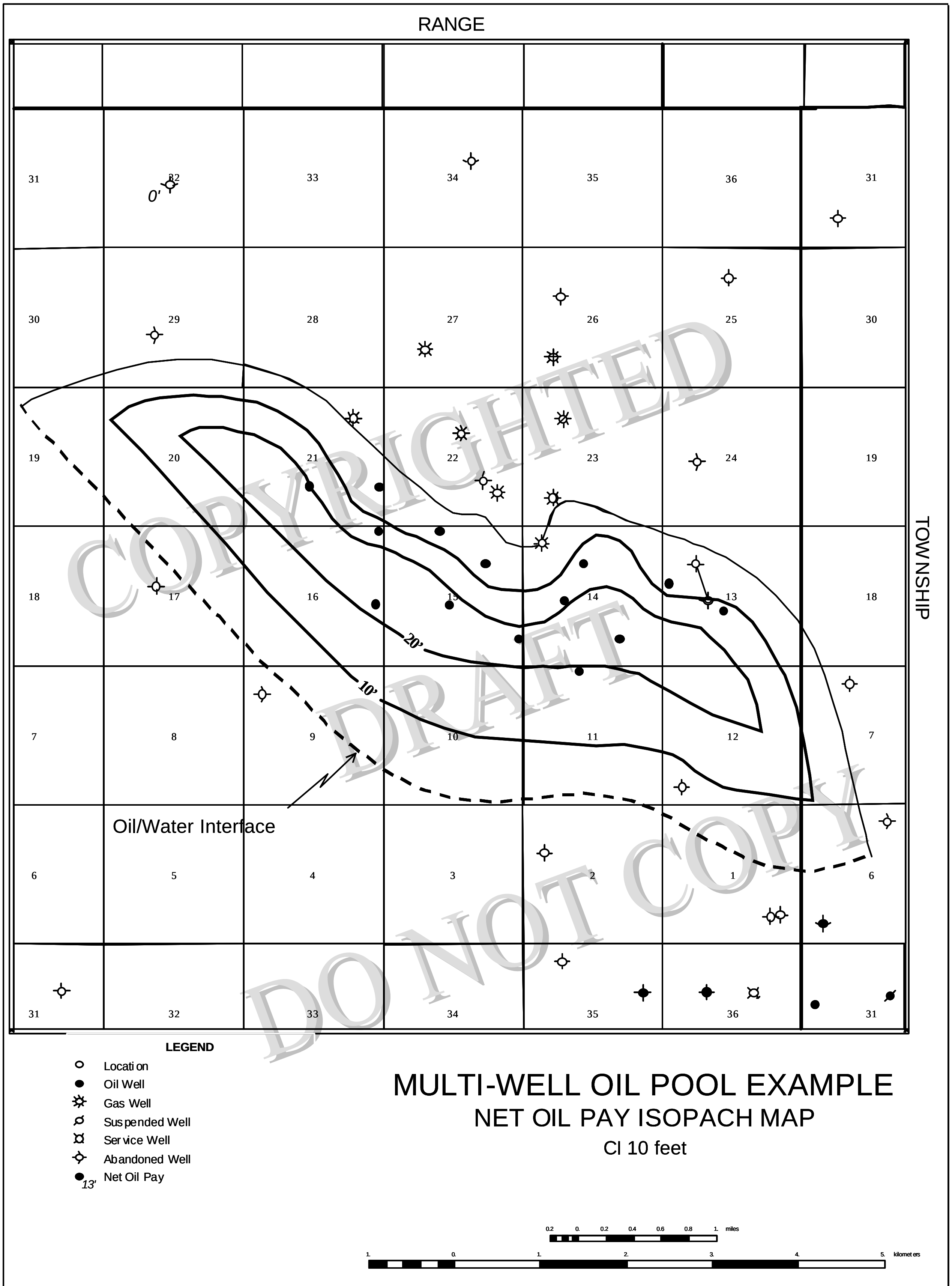

Figure 5A

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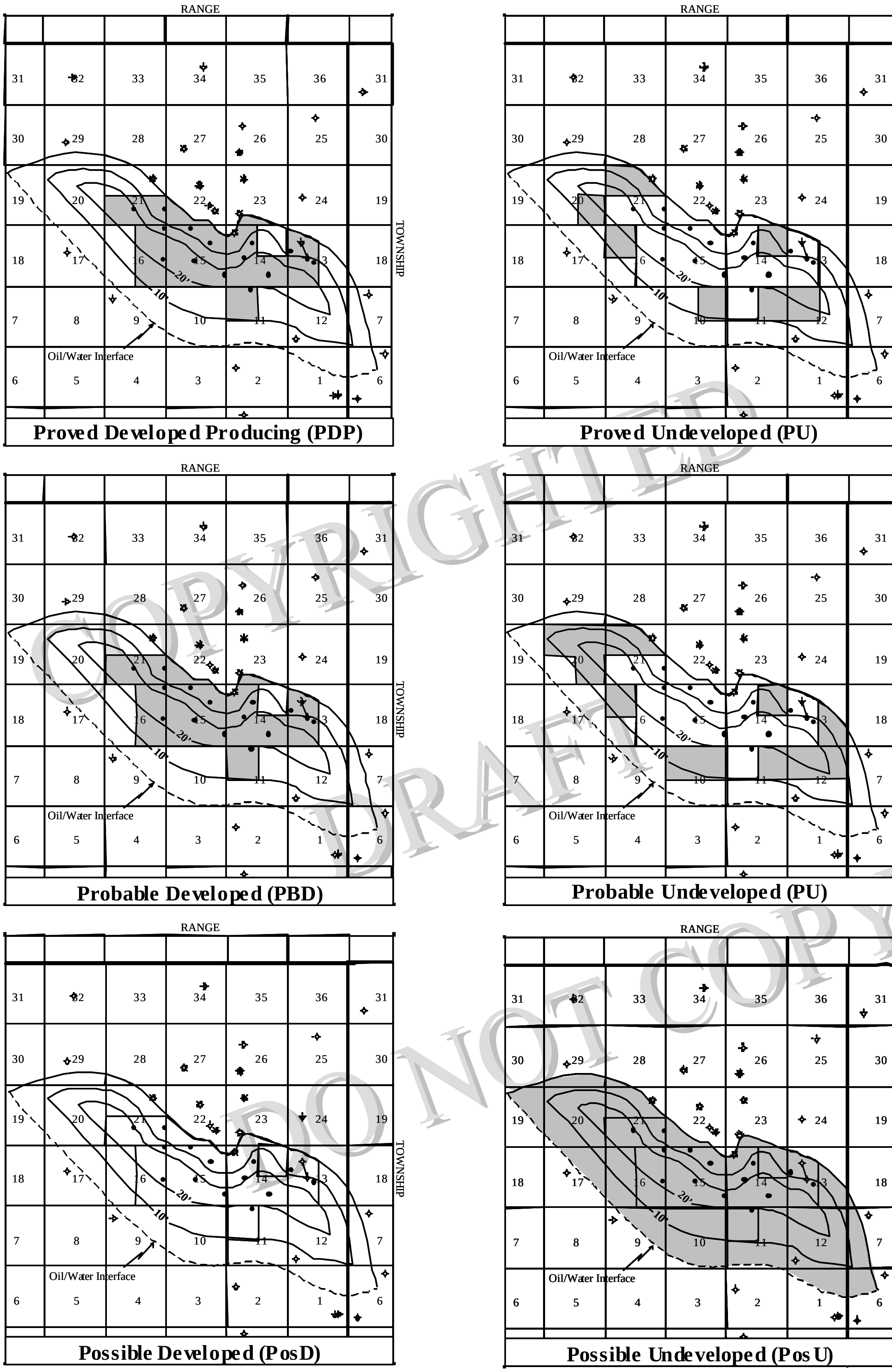


MULTI-WELL OIL POOL EXAMPLE RESERVES CLASSIFICATION Figure 5B

6.4 Material Balance Methods

Material balance methods of reserves estimation involve the analysis of pressure behaviour as reservoir fluids are withdrawn, and usually result in more reliable reserves estimates than those obtained using volumetric methods. Confident reserves estimates require a significant amount of reservoir fluid depletion, accurate reservoir pressures, knowledge of aquifer characteristics, and information on rock and fluid properties. In complex situations such as those involving water influx, multi-phase behaviour, and layered or low-permeability reservoirs, material balance estimates alone could provide erroneous results. In these cases, therefore, results must always be compared with those obtained using other methods.

The most common application of material balance methods is the use of P/Z versus cumulative gas production plots to determine original gas in place. This is only the first step in the determination of the gas reserves, and similar factors considered when using volumetric methods must be considered when using material balance methods to estimate recovery factors and recoverable reserves.

Material balance methods for oil reservoirs can be applied analytically, but are more often applied with a numerical reservoir simulator, with the reservoir properties varied to match the average reservoir pressure and fluid production history. Both fluids in place and future recoverable oil reserves can be estimated using these methods.

Use of material balance methods on gas reservoirs is discussed below. Their use on oil reservoirs is only briefly discussed, in Section 6.4.10.

6.4.1 General Considerations in the Use of Material Balance Methods for Gas Reservoirs

Rarely does an analysis of all of the geological and engineering data for a reservoir lead to a perfectly clear determination of the original fluids in place and recoverable reserves, and different analytical methods will often yield different results. Material balance methods are only one alternative and must not be relied upon without considering others. Only through an understanding of the reservoir and fluid properties and the limitations of material balance methods can the evaluator determine reliable estimates of original gas in place and recoverable reserves and understand the level of confidence that should be placed on the values determined.

Various factors must be considered in the application of material balance methods, some of which are discussed below.

6.4.2 Consideration of Reservoir Properties

a. Aquifers

An incorrect determination of original gas in place using material balance methods can occur when water from an underlying aquifer invades the gas-saturated portion of the reservoir. The size of the water zone relative to the size of the gas-saturated zone, the permeability of the gas and water zones, and the rate of and amount of production from the gas reservoir affect the degree of aquifer influx.

Upward curvature of the P/Z plot is often considered an indicator of an active aquifer. However, there are many reservoir situations, particularly in the case of a high-permeability aquifer or low gas withdrawal rates, where the P/Z line appears to be straight, yet significant water encroachment into the gas zone could be occurring. In some cases, the P/Z data points could follow a straight line, yet the gas column could be completely flooded out, with only a partial reduction in the reservoir pressure.

Recovery factors for gas reservoirs with a water drive may be significantly lower than those for reservoirs producing by gas expansion alone. The impact of water encroachment on recovery factor is related to the following factors:

- the volume of gas trapped by the encroaching aquifer,
- the higher pressure at which the reservoir is abandoned,
- the gas volume displaced by water influx.

Depending on aquifer “strength,” recovery factors for water drive reservoirs are commonly reduced by 30 to 50 percent of the recovery that would be expected without a water drive.

If aquifer pressure support is observed or considered likely, analytical material balance methods that take this into account (see, for example, Slider 1976), or a numerical reservoir simulator, should be used.

b. Reservoir Permeability

Reservoir pressure measurements in low-permeability reservoirs require either long buildup times or the application of pressure transient analysis methods to determine average reservoir pressures. An understanding of the reservoir permeability and the conditions under which the pressure data points were taken are essential to determine the reliance to be placed on the data points, especially if there is a poor correlation in pressure measurements over time.

c. Multi-Well Reservoirs

Material balance methods for multi-well pools should only be applied on a total pool basis and include all of the wells interpreted to be producing from the subject reservoir.

Pressure gradients often exist throughout large multi-well pools in medium to low permeability. In pools where multiple pressure readings are taken over a short period of time, these pressures should be appropriately averaged to determine the average pool pressure. Unless the pressure readings are reasonably well distributed throughout the pool, they should be weighted by the pore volume they appear to be draining.

Often material balance calculations for extensive pools include pressure readings from new wells. It must be recognized that new wells are usually drilled in the least depleted areas of a pool. Accordingly, the estimate of average reservoir pressure must account for the lower pressure areas of the pool (usually requiring averaging with pressure readings for older wells).

d. Multi-Layer Reservoirs

Reservoirs that contain multiple layers of differing permeability require very careful determination of average reservoir pressures. Pressure distributions can vary in each layer, and the correct determination of an average pressure for all the layers requires careful analysis of the data. Unless very detailed pressure transient analysis work is conducted, very long buildups are required to determine reliable average reservoir pressures. Caution must also be taken when estimating recovery factors in multi-layer reservoirs, because low-permeability layers may have significantly lower recovery factors than the high-permeability layers.

e. Naturally Fractured Reservoirs

Naturally fractured reservoirs usually consist of a high-volume, low-permeability matrix system and a low-volume, high-permeability fracture system. Pressures could build up rapidly when a well is shut in, but because of the presence of the low-permeability matrix, long pressure buildups or detailed pressure transient analyses are required in naturally fractured reservoirs to determine reliable average reservoir pressures.

6.4.3 Consideration of Fluid Properties

a. Dry Gas Reservoirs

Material balance P/Z plots for dry gas reservoirs do not require any special adjustments to the produced volumes prior to preparing the material balance plots.

b. Wet Gas Reservoirs

Use of material balance methods to determine the original gas in place for wet gas fluids could require a more sophisticated analysis than a simple P/Z plot. In these situations, significant volumes of natural gas liquids may be produced at the surface. Proper analysis of wet gas reservoirs requires the conversion of surface-produced volumes of gas and liquids to gas-equivalent volumes. This requires representative fluid samples, preferably early in the life of the reservoir, and accurate measurement of the PVT properties.

Although most gas reservoirs produce some natural gas liquids, if the produced liquids content is low (in the 10 to 40 bbl per MMcf range) and relatively constant over time, use of only wellhead gas volumes may be acceptable.

c. Retrograde Condensate Reservoirs

Use of material balance methods to determine the original gas in place for retrograde condensate reservoirs below the dew point is not possible using the simple P/Z plot if large volumes of liquids are produced due to the changing fluid composition during the decline in reservoir pressures. In these situations, a compositional reservoir simulator should be used, provided sufficient pressure decline and PVT data are available.

6.4.4 Consideration of Quality of Pressure Data

a. Types of Pressure Measurements

Pressure is the most important data in a material balance analysis and also the most susceptible to error. Reservoir pressures may be measured with downhole or surface gauges and may be single point or continuous transient measurements.

All pressure measurements should be referenced to either the midpoint of perforations in the case of a single well, or to a common reservoir datum in the case of multi-well pools. Bottom-hole pressures are more reliable than surface pressure measurements, because conversion of pressure readings from surface to bottom-hole conditions might be inaccurate if the presence of wellbore fluids is not properly taken into account.

Single point, or static gradient, pressure measurements are only reliable in material balance plots when the well has been shut in for a sufficiently long period of time. If reservoir pressures are still increasing at the time of pressure measurement, continuous pressure measurements over a period of several days must be taken and pressure transient analyses conducted to properly determine the estimated built-up pressure.

b. Number of Pressure Measurements

Although a determination of original gas in place can be made with as few as two pressure measurements, more confidence is obtained as more measurements are taken. In multi-well pools, more confidence is obtained by having multiple measurements of every well in the pool.

c. Correlation of the Pressure Data Points

The better the correlation of the data points in a straight line on the P/Z plot, the more confidence in the determination of the original gas in place. P/Z plots with a high degree of scatter should not be relied upon for an original gas in place determination, and other reserves determination methods should be used.

d. High-Permeability Reservoirs

Reservoir pressures build up quickly in high-permeability reservoirs; therefore, pressure measurements typically follow a consistent trend on a material balance plot. Pressure measurements that do not follow the trend should not be accepted without being reviewed.

e. Low-Permeability Reservoirs

Material balance plots for low-permeability, multi-layer, or naturally fractured reservoirs often have a significant scattering of the data points. In this situation, a more careful analysis of the pressure data should be conducted to ascertain which data points are the most representative of the average reservoir pressure. Usually, only pressure data based on pressure transient analyses or pressures taken from shut-in wells are reliable. Commonly, data points unadjusted through pressure transient analyses are excluded due to insufficient pressure buildup time. However, it is also possible to over-correct pressures in a pressure transient analysis, resulting in adjusted pressures that are too high.

6.4.5 Consideration of Degree of Pressure Depletion

Confidence in material balance calculations depends on the accuracy of the pressure measurements as well as the degree of pressure depletion. Earlier in the life of the property, pressure measurements must be very accurate, whereas later in the life of the property, errors in pressure measurements are more tolerable as the general trend will be well established.

Usually a minimum of 5 to 15 percent depletion is required for accurate estimates of the original gas in place, provided that the evaluator is reasonably certain there is no aquifer pressure support, the reservoir has high permeability, and there are high-quality, fully-built-up pressure data.

Pressure depletion as low as 5 percent may be acceptable in high-permeability reservoirs where several accurate pressure measurements follow a consistent trend on the P/Z plot and where there is little likelihood of aquifer support. It must be appreciated that with only a 5 percent pressure depletion, an error of +/- 1 percent in the reservoir pressure estimate will result in an error of -16 percent/+24 percent in the original gas in place estimate.

In situations with lower permeability reservoirs, where few pressure measurements exist and where there is uncertainty over aquifer support, as much as 25 percent or more depletion could be required for a reasonably confident estimate of the original gas in place.

In any case, the potential inaccuracies in material balance estimates should be weighed against the uncertainties in other reserves estimation methods. Even if material balance estimates are not considered to be accurate, they can provide a good basis for a directional adjustment to early life reserves estimates prepared with other methods such as volumetric calculations.

6.4.6 Guidelines for Determining Proved, Probable and Possible Reserves

a. Assess well groupings in multi-well pools.

For multi-well pools, review all available pressure and production data to determine which wells are producing from the same pool. This will usually start by grouping wells according to geologically defined pools, then confirming that each well is following the same pressure-time trend. The use of pressure versus time plots will help to determine similar pressure decline trends. It is important to ensure that the pressure data points are all corrected to a common datum depth and are properly built-up pressures.

b. Review reservoir and fluid properties.

Review the reservoir and fluid characteristics to determine if any of the following situations could be occurring:

- Pressure support from an aquifer.
- Low-permeability and/or multiple layers of varying permeability leading to incomplete pressure buildup.
- Pressure gradients occurring across a large or elongated pool.

c. Review inconsistent data points.

Where there is poor correlation of data points, determine how each pressure data point was obtained, and determine which data points are most representative of the average reservoir P/Z and which might need to be excluded from the analysis. Depending on the amount and accuracy of the data and numbers of wells, mathematical weighting of the pressure points by pore volume could provide a better estimate of the average reservoir pressure at a given point in time.

d. Determine OGIP for each reserves category.

If there is reasonable correlation of the data points, extrapolate the P/Z data to the cumulative production X-axis, either manually or with a linear regression best-fit line, to determine the original gas in place. This represents a proved + probable original gas in place estimate. If there are numerous data points, very good correlation of the data, and reasonable pressure depletion, the level of uncertainty will be relatively low, and proved and proved + probable + possible OGIP could be the same value. If there is more uncertainty in the OGIP estimate, the proved OGIP would typically be between 1/3 and 2/3 of the difference between the proved + probable estimate and a practical minimum OGIP estimate. Similarly the proved + probable + possible OGIP estimate would typically be between 1/3 and 2/3 of the difference between the proved + probable estimate and a practical maximum OGIP estimate.

e. Compare the OGIP to that found using other methods.

Compare the material balance OGIP to the OGIP determined using volumetric methods. In cases where the material balance OGIP is much higher than the volumetric OGIP, reconsider whether pressure support from an aquifer could be occurring, and reassess the OGIP.

f. Determine recovery factors and reserves.

Recovery factors should be based on methods similar to those described under volumetric methods in Section 6.3.1.c.xi. In a simple dry gas situation, recovery factor can be determined by estimating the minimum wellhead pressure that will yield an economic flow rate, and relating this pressure to static bottom-hole conditions and applying the following formula:

$$\text{Recovery Factor} = 1-(P/Z)_{\text{abandonment}}/(P/Z)_{\text{initial}}$$

Factors such as increasing water production or liquid loading in the later life of a pool, multi-layer, or low-permeability gas reservoirs complicate the estimation of recovery factor and commonly result in recoveries lower than the idealized situation.

Different recovery factors are usually applied to each reserves category , especially when there is some uncertainty in the analysis. The proved + probable recovery factor should be the best estimate considering all of the relevant factors. The proved recovery factor would typically be between 1/3 and 2/3 of the difference between the proved + probable estimate and a practical minimum recovery factor estimate. Similarly the proved + probable + possible recovery factor estimate would typically be between 1/3 and 2/3 of the difference between the proved + probable estimate and a practical maximum recovery factor estimate.

6.4.7 Special Situations

a. OGIP Calculations based on Initial Production Tests

Often gas in place estimates are based on pressure data taken before and after an initial production test, where the reservoir pressure depletion could be much less than one percent. An original gas in place estimate using these data is not considered reliable. It does, however, provide important information for future material balance estimates and can provide early indications of whether the reservoir size is limited.

b. Allocation of Reserves in Multi-Well Pools

In relatively mature multi-well pools with varying ownership, reserves must often be allocated to individual wells. When using material balance methods, the total pool gas in place is usually determined using the methods described above, and then the remaining reserves are allocated to individual wells based on their share of current and future production. The forecast production rates must be based on a reasonable expectation, considering likely operational changes and the possibility of future drilling, which will provide additional drainage points in the reservoir.

For example, in a situation where a pool has two producing wells and no further drilling is likely, the remaining reserves are usually allocated to each of the two wells according to their current production rates.

c. Drainage Outside Company Owned Lands

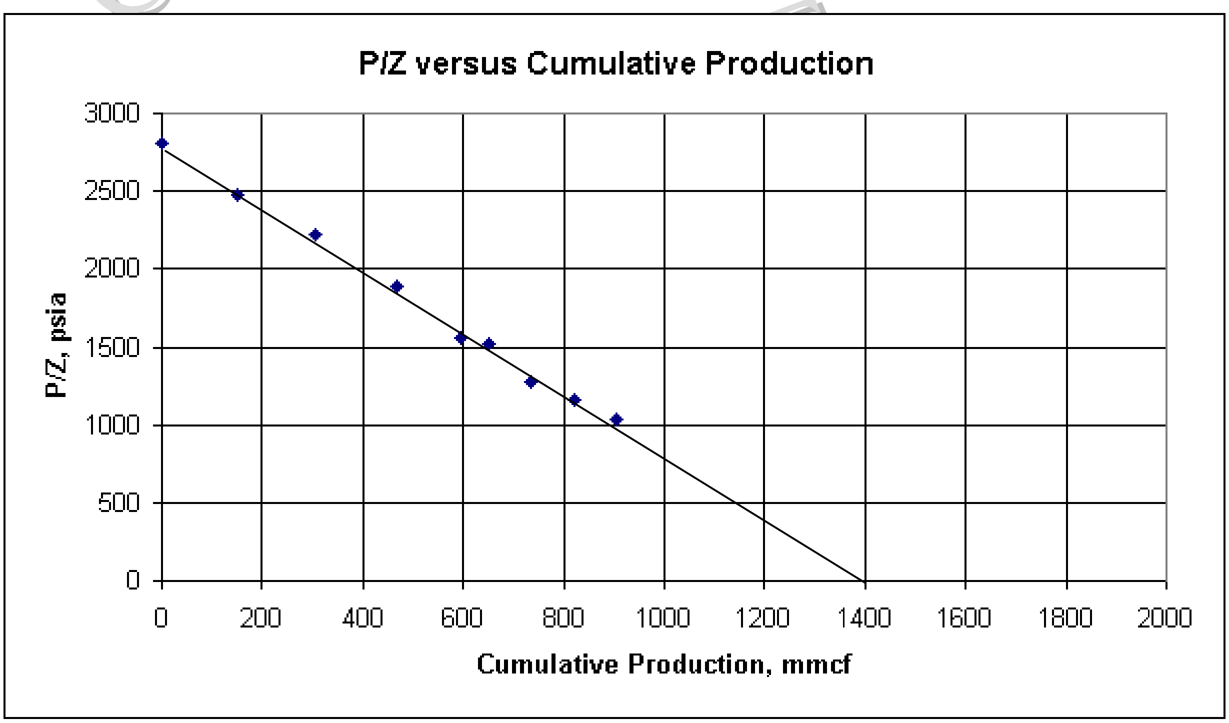
In cases where the original gas in place determined by material balance methods appears to extend outside company owned lands, consideration must be given to likely production from non-owned lands in the future, either from existing wells or future wells.

For example, a well is producing from a gas pool and has a reliable material balance plot. A comparison of the calculated original gas in place to geological data indicates that the pool likely covers an area larger than the well's spacing unit. If no other wells are to be drilled, then this well should recover all of the remaining pool's OGIP. However, barring any physical, economic, or regulatory restrictions to additional wells being drilled in the pool, the evaluator must consider the probability that additional wells will be drilled and remaining pool reserves will be shared with other wells. The actual reserves recovered by each well will depend upon the number of additional wells and how soon they will be drilled. The evaluator must apply reasonable judgement regarding how many wells will be drilled and their timelines. The evaluator should be guided by the assumption of prudent reservoir and business practices in the operation of the subject and competitor lands.

6.4.8 Examples

Material Balance Estimation of Reserves with Good Data Correlation – Single Well Pool

Date	Measured Pressure psia	Z-Factor frac.	P/Z psia	Cum. Prod. MMcf
85/05	2,350	0.838	2,804	-
86/08	2,100	0.848	2,477	150
89/01	1,900	0.858	2,215	305
92/03	1,634	0.868	1,883	467
94/05	1,368	0.878	1,559	597
96/10	1,347	0.887	1,518	650
98/03	1,163	0.907	1,282	736
99/12	1,069	0.917	1,166	820
00/03	956	0.927	1,031	904



Original Gas in Place Determination

1. Data Review:

    a) There are many data points and they have a good correlation.

    b) Geological data, the exhibited pressure data, and a review of analogous pools does not indicate the likelihood of aquifer support.

2. Proved + Probable OGIP Estimate: 1400 MMcf based on above P/Z versus Cumulative Production Line.

3. Proved OGIP Estimate: Same value as the proved + probable, due to high depletion, many data points, and very good correlation of data points.

4. Proved + Probable + Possible OGIP Estimate: Same value as the proved + probable, due to high depletion, many data points, and very good correlation of data points.

Reserves Determination

1. Data Review:

    a) The reservoir has good permeability and it is likely that economic rates can be supported down to reservoir pressures of 200 to 400 psia.

    b) A review of performance of analogous pools in the area indicates that water production is rarely a problem late in the life of each pool.

    c) Recovery factors of analogous pools are usually in the 86 to 94 percent range, with a median value of approximately 90 percent.

    d) Reserves based on decline curve methods are consistent with the pressure decline trend.

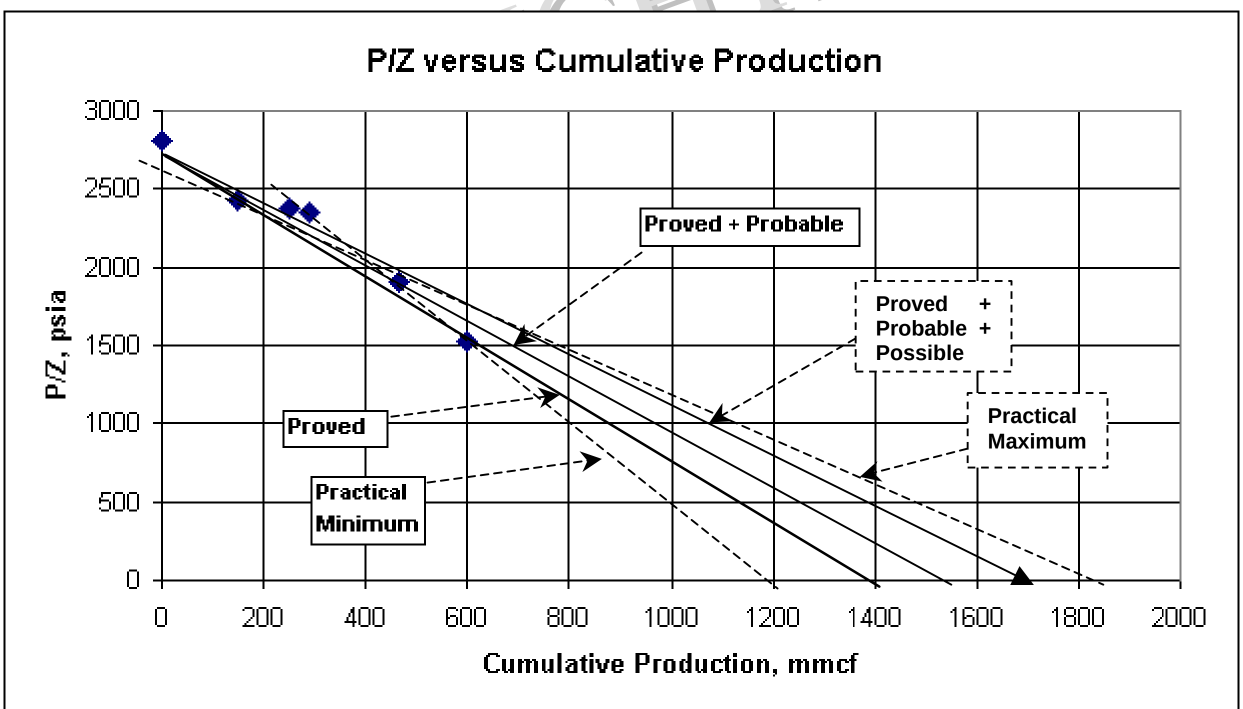
2. Proved + Probable Reserves Estimate: Based on a recovery factor of 90 percent.

3. Proved Reserves Estimate: Based on 1/2 of the difference between the practical minimum of 86 percent and the proved + probable estimate of 90 percent, for an 88 percent recovery factor.

4. Proved + Probable + Possible Reserves Estimate: Based on 1/2 of the difference between the practical maximum of 94 percent and the proved + probable estimate of 90 percent, for a 92 percent recovery factor.

Material Balance Estimation of Reserves with Moderate Data Scatter – Single Well Pool

Date	Measured Pressure psia	Z-Factor frac.	P/Z psia	Cum.Prod. MMcf
85/05	2,350	0.838	2,804	-
86/08	2,056	0.848	2,425	150
87/02	2,025	0.852	2,377	250
88/01	1,988	0.847	2,347	289
92/03	1,654	0.868	1,906	467
94/05	1,343	0.878	1,530	597



Original Gas in Place Determination

1. Data Review:

    a) There are a few data points, but they have a poor correlation.

    b) Geological data, the exhibited pressure data, and a review of analogous pools does not indicate the likelihood of aquifer support.

    c) Volumetric methods indicate a range in OGIP of 1,200 to 1,800 MMcf.

2. Proved + Probable OGIP Estimate: 1,550 MMcf.

3. Proved OGIP Estimate: 1,400 MMcf (approximately midway between the practical minimum and the proved + probable estimate).

4. Proved + Probable + Possible OGIP Estimate: 1,700 MMcf (approximately midway between the practical maximum and the proved + probable estimate).

Reserves Estimation

1. Data Review:

    a) The reservoir has low permeability, which is likely contributing to inconsistent pressure buildups and a poor correlation of data points.

    b) A review of performance of analogous pools in the area indicates that water wellbore loading could be a problem late in the life of each pool.

    c) Recovery factors of analogous pools are usually 55 to 85 percent, with a median value of approximately 70 percent.

    d) Reserves based on decline curve methods are consistent with the pressure decline trend.

2. Proved + Probable Reserves Estimate: Based on a recovery factor of 70 percent on an OGIP of 1,550 MMcf, resulting in an original recoverable reserves estimate of 1,085 MMcf.

3. Proved Reserves Estimate: Based on a 65 percent recovery factor and an OGIP of 1,400 MMcf, resulting in an original recoverable reserves estimate of 910 MMcf.

4. Proved + Probable + Possible Reserves Estimate: Based on a 75 percent recovery factor (approximately 1/3 of the difference between the proved + probable and the practical maximum estimate higher than the proved + probable estimate) and

an OGIP of 1,700 MMcf, resulting in an original recoverable reserves estimate of 1,275 MMcf.

6.4.9 General Considerations in the Use of Material Balance Methods for Oil Reservoirs

Use of material balance analysis methods for oil reservoirs, like non-associated gas reservoirs, is based on the premise that the reservoir pore volume changes in a predictable manner as the pressure declines when oil, gas and/or water are produced. It is, therefore, possible to equate the expansion of the reservoir fluids upon pressure drop to the reservoir voidage caused by the production of oil, gas, and water minus the water influx. The generalized equations can be applied to any type of gas or oil reservoir where the technique discussed above for gas reservoirs constitutes a special case.

The successful application of this technique requires an accurate history of the average reservoir pressure and produced volumes of various phases, as well as the PVT data for all the phases involved over the pressure range considered.

The most useful application of material balance concepts requires the concurrent use of fluid flow equations, therefore introducing the time dimension into the analysis. Although classical material balance techniques were used quite extensively in the past, they are now largely replaced by numerical reservoir simulators that are essentially multi-dimensional, multi-phase, and dynamic material balance programs.

6.5 Production Decline Methods

Production decline analysis refers to the analysis of declining production rates as reservoir fluids are withdrawn. Production declines occur mainly because of pressure depletion, displacement by another fluid (usually water), or a combination of these two. Reserves (economically recoverable by definition) are determined by extrapolation of production rate decline trends to an economic limit. The production trends derived are used to prepare production forecasts for economic evaluation purposes. Decline analysis is one of the most widely used reserves interpretation techniques. It is one of the most reliable methods of analyzing reserves of wells with sufficient production history, provided it is used properly. Misuse of the method can result in serious inaccuracies in reserves estimates. A recognizable decline trend must be apparent in order to perform decline analysis.

6.5.1 Types of Decline Analysis

There are two main types of decline interpretation techniques: curve fitting and type curve matching. Both methods can be used in depletion drive pools that are characterized by transient and pseudo-steady-state (PSS) flow regimes. Figure 6-6, following this page, illustrates the transient and PSS flow regimes on dimensionless scales. The transient period occurs prior to the drainage radius reaching boundary conditions, with PSS flow occurring thereafter.

Only curve fitting is applicable in pressure-supported pools such as waterfloods, miscible floods, and water drives. Pressure-supported decline behaviour is more complex than depletion behaviour, because it is characterized by multiple flow regimes. For example, a waterflooded pool initially produces under transient and PSS flow, then steady-state flow after commencement of water injection, and, finally, post water breakthrough flow behaviour.

a. Type Curve Matching

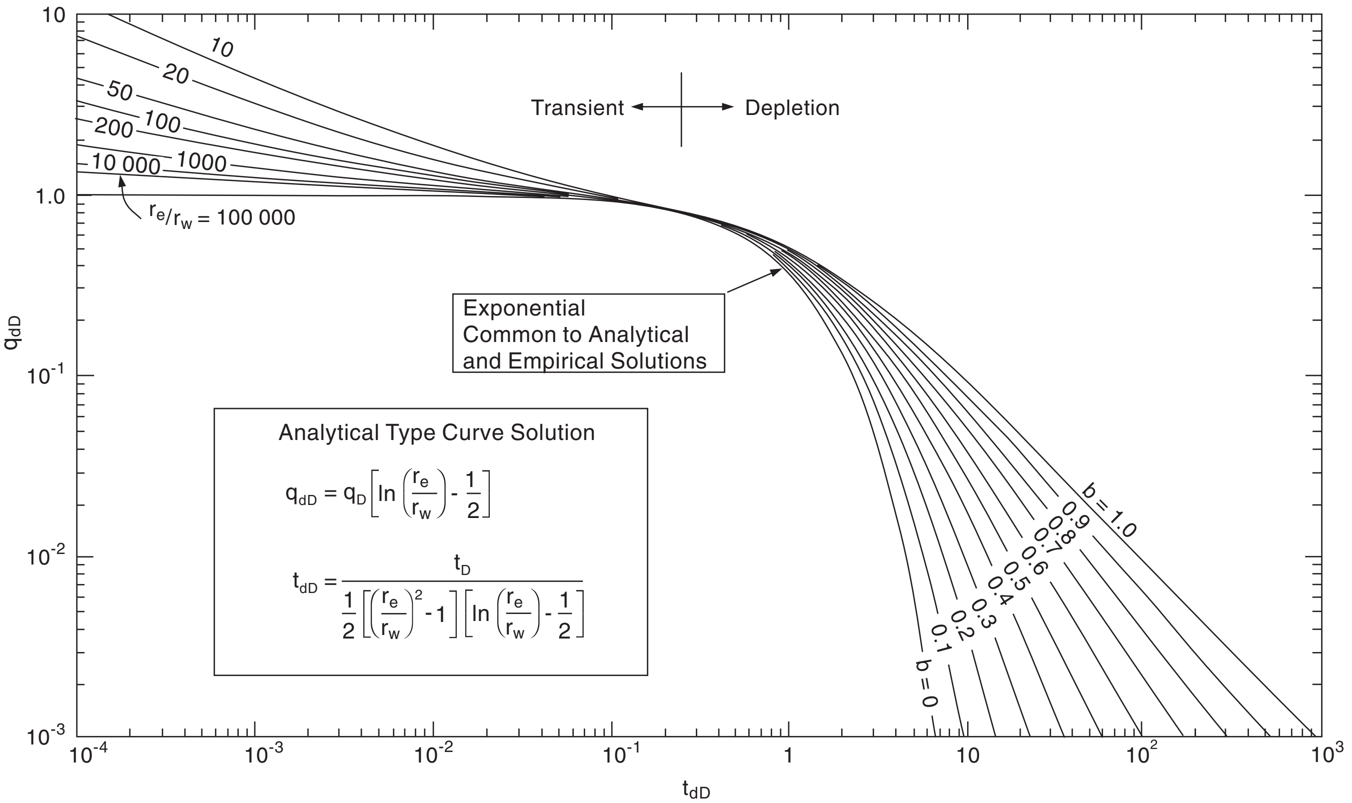
The type curve matching method was developed by M.J. Fetkovich (1973?) and consists of converting and plotting production data with dimensionless variables, then overlaying curves to obtain a type curve match (Figure 6-6). The match of the transient portion of the curve is used to characterize permeability and skin factor. The inflection point in the type curve is used to quantify drainage area. Finally, the matching of the Arps depletion stem in the PSS flow regime is used to quantify recoverable reserves. Computer software packages are available to assist in type curve analysis.

A key observation in this technique is that the transient decline behaviour does not relate to the PSS or depletion decline behaviour. This is an important consideration when dealing with low-permeability reservoirs that have long transient periods.

b. Curve Fitting

Curve fitting is usually the method implied when referring to decline analysis, and it is the most common method in use today. The curve fitting method refers to numerically fitting a curve through historical production data with the assumption that future production decline will be represented by this numerical relationship. The equation most commonly used was developed by Arps in 1944 (Arps 1945) to represent a constant flowing pressure solution to a well of fixed drainage radius.

$$q(t) = \frac{q_i}{(1+bD_i t)^{1/b}}$$



Source: After Fetkovich, 1980.

Where,

q_i = initial rate

$q(t)$ = rate at time t

b = decline exponent

D_i = initial decline

The best fit can be either exponential when b approaches 0, hyperbolic when b > 0, or harmonic when b = 1.

The best fit can be computer calculated or visual. Visual best fit exponential decline is based on a straight line arithmetic rate vs. cumulative production plot, or a straight line log of rate vs. time. Visual best fit harmonic decline is based on a straight line log rate vs. cumulative production plot. Visual best fit hyperbolic decline is derived by overlaying calculated profiles on rate vs. cumulative production plots.

Other decline methods in use today such as water/oil ratio, oil-cut trend analysis, and Blasingame type curve matching are variations of the above two methods.

6.5.2 Limitations of Methods

Decline methods have a number of theoretical limitations:

- Decline equations are only arithmetic approximations for future behaviour based on historic behaviour. Reservoir geometry, properties, and operating conditions could be such that no single relationship is valid for the remaining life of a well.
- Only the PSS phase of production history for depletion drive reservoirs can be analyzed with curve fitting methods. The transient period must be excluded from the curve fitting. For type curve matching, the entire history may be used.
- Constant wellbore pressure conditions must exist to reliably curve fit and type curve match. If these conditions are not met, there are methods of normalizing the data for more accurate results. If normalization is not performed, then the fit represents the case where the rate of pressure change continues at the same pace throughout the life of the well, which is not valid. Often, wellbore flowing pressure history is not available; therefore, engineers must use their knowledge and experience to determine which and how historical data should be curve fit.

  The normalization equation for a gas well is as follows:

$$\text{Normalized Rate} = \text{Measured Rate} \times \left(\left(P_{ts}^2 - P_{mlp}^2\right)/\left(P_{ts}^2 - P_{nlp}^2\right)\right)^n$$

Where,

P_{ts} = static wellhead pressure

P_{mlp} = measured line pressure

P_{nlp} = normalized line pressure

N = wellhead deliverability exponent

- Pressure-supported reservoirs can be analyzed with curve fitting, but not type curve matching. The fit is only representative for the duration of the flow regime; therefore, curve fitting should not be performed to determine reserves until injected fluid breakthrough trends are exhibited (post breakthrough regime).

- Harmonic decline behaviour should be used with caution, because it may not be clear how long the well will continue harmonic behaviour. Harmonic rate declines extrapolate to infinity at zero rate; therefore, at some point they must become exponential. The practical significance is whether this occurs prior to or after reaching economic limit.

- Future drilling affects current decline trends. The derived fits are only valid for the existing field development. Further field development such as infill drilling will change the decline behaviour of offset wells if interference occurs. The uncertainty lies in predicting when interference occurs.

6.5.3 Factors Affecting Decline Behaviour

There are certain factors that determine whether declines are steep, shallow, exponential, hyperbolic, or harmonic. These factors include rock and fluid properties, reservoir geometry, drive mechanisms, completion techniques, operating practices, and type of wellbore. Reservoir engineers must have an understanding of these factors prior to analyzing decline trends, in order to make a reliable assessment.

a. Rock and Fluid properties

i. Stratification

Reservoirs with a high degree of stratification or high permeability variation tend to decline along hyperbolic or harmonic trends, while homogeneous reservoirs tend to decline along exponential trends. This is a result of differential expansion of drainage radii in the layers and differential depletion of the layers (Fetkovich et al. 1996).

ii. Wettability

Strongly oil-wet rocks combined with low-gravity (high-viscosity) crude oils will exhibit hyperbolic or harmonic trends following water breakthrough, because of the shape of the fractional flow curve. Also, in oil-wet rocks, interfacial tension tends to bind the oil to the rock surface, causing oil to become increasingly difficult to recover as water saturation increases, which results in hyperbolic or harmonic trends. Strongly water-wet rocks combined with high-gravity (low-viscosity) crude oils tend to decline more exponentially.

iii. Relative Permeability

Masoner (1998) examined the effect of the shape of relative permeability relationships in secondary and tertiary recovery schemes on the Arps decline exponent. In general, more curvature in relative permeability curves results in higher decline exponents.

iv. Permeability

Low-permeability reservoirs have a long transition period, which is frequently super harmonic in nature, followed by shallow PSS decline trends. High-permeability reservoirs, if produced at capacity, have steeper decline trends compared to lower permeability reservoirs of similar volume. These steeper declines tend to be more exponential.

v. Fracturing

Fractured reservoirs can exhibit exponential to harmonic behaviour, depending on the contribution of the matrix to the dual porosity behaviour.

vi. Back Pressure Slope

Fetkovich et al. (1996) demonstrated that the theoretical values of the Arps decline exponent below bubble point are a function of the slope of the back-pressure curve. The decline exponent approaches zero for high-permeability, tubing-limited flow behaviour, where the back-pressure slope is 0.5, whereas the decline exponent is 0.33 (oil) and 0.5 (gas) for low-permeability reservoirs that are reservoir limited. Values greater than 0.5 can be demonstrated for layered no-cross-flow reservoirs.

b. Reservoir Geometry and Drive Mechanism

i. Vertical Displacement

Reservoirs with vertical displacement drive mechanisms usually exhibit non-declining behaviour prior to breakthrough of the displacing fluid, exponential decline after breakthrough of the displacement fluid as the oil and gas column thins, and hyperbolic decline behaviour when coning dominates the flow characteristics in late stage depletion of the reservoir. In the case of gas wells, the post breakthrough decline can be very steep. In these cases, prior to breakthrough, volumetric, analogy, and/or material balance methods that consider aquifer influx must be used to establish reserve estimates.

ii. Coning

For bottom-water drive oil reservoirs, coning behaviour usually results in hyperbolic decline trends. The decline tends to be more exponential for low viscosity and/or water-wet systems and more harmonic for high viscosity and/or oil wet systems.

iii. Horizontal Displacement

Decline behaviour in horizontal displacement drive mechanisms is a function of the rock and fluid properties of the reservoirs.

iv. Unconsolidated Heavy Oil Reservoirs

Unconsolidated sandstone solution-gas drive heavy oil reservoirs usually exhibit increasing productivity as the wellbore radius increases with sand production, a period of constant productivity as sand production reduces, then catastrophic decline behaviour due to wormhole collapse and/or foamy oil viscosity behaviour. Reserves analysis for these types of reservoirs must be based on volumetric or statistical reserves life index methods.

c. Completion and Operating Practices

i. Skin Factors

Skin factors affect decline performance by changing the productivity as well as the decline slope of wells. Positive skin factors are caused by wellbore damage, which decreases productivity. Negative skin factors are usually a result of wellbore stimulation, which increases productivity. In addition to productivity changes, negative skin factors result in more hyperbolic bending of production declines during the transient phase.

ii. Fluid Rate Changes

Total fluid (water plus oil) rate changes can be caused by changes in drawdown, over-injection, or under-injection. While total fluid rates are increasing, oil rate decline trends are dampened. Increasing or decreasing drawdown of a well violates the constant flowing pressure assumption of decline analysis and, therefore, will result in an unreliable decline fit.

iii. Workovers

Workovers on wells cause sudden increases in production rates. The future decline of a well after a workover is often difficult to predict. If the workover opens up previously unaccessed reservoir, the producing reserves of the well will now be the previously accessed reserves derived from decline analysis plus reserves associated with the new accessed reservoir, which can be estimated from volumetric analysis. If the workover simply removes wellbore damage, reserves can be estimated by examining decline trends prior to the wellbore damage. This procedure relies extensively on the judgement and experience of the evaluator in picking the correct trend. Workovers often result in a combination of both of the above results. Caution must be exercised in assessing results immediately after a workover, because production rates are likely in transient, not PSS, flow. In these cases, a review of the results of analogous workovers could be beneficial in assessing results.

iv. Infill Drilling

Infill drilling can affect decline behaviour of offset wells because of drainage interference; therefore, decline analysis is only valid for the current well configuration.

v. Regulatory Constraints

Regulatory constraints such as oil well allowables mask decline behaviour.

vi. Facility Constraints

Facility throughput limitations can also mask decline behaviour.

d. Type of Wellbore

i. Horizontal versus Vertical Wellbore

Decline behaviour of horizontal wells is different from that of vertical wells, though the decline interpretation techniques are similar.

ii. Coning Situations

Horizontal wells are often drilled to reduce drawdown, which masks early decline behaviour. Also, due to the geometry of the cone, decline profiles in horizontal wells after the transient period are usually less hyperbolic than vertical wells.

iii. Wellbore Contact

Horizontal wells are also drilled to increase wellbore contact with the reservoir. This causes higher initial production rates and steeper initial transient flow decline rates than those obtained by drilling vertical wells.

6.5.4 Guidelines for Individual Well Decline Analysis

In light of the numerous factors described above that affect decline trends, the following generalized guidelines are recommended when performing decline analysis.

a. Reservoir Properties Review

Understand the depletion mechanism and rock and fluid properties. This does not necessarily entail a detailed geological study, but rather a review of the log character to get a sense of the presence or absence of bottom water and the degree of stratification or variability. A review of the fluid analysis also establishes the gravity and viscosity of the oil being produced, or the quantity of liquids, in the case of a gas well.

b. Analogy Review

Review regional decline trends of more mature wells in the same zone with similar reservoir properties, especially for wells with little production history. The more similar the reservoir properties and the closer the location of the analogy to the well being analyzed, the more valid the analogy. It is important to review the late-time behaviour of analogies to verify if change in flow behaviour, such as liquid loading, occurs.

c. Transient Period Estimation

Estimate the length of the transient period. This will establish whether the well has sufficient history for use of the curve fitting technique. Exclude the transient period data when curve fitting, but include the transient period when type curve matching. For transient flow, only decline analogies or volumetric methods can be used to establish reserves. The estimation of the length of the transient period is not always straightforward. In high-permeability reservoirs, the period is usually short enough so as not to be a concern. In low-permeability reservoirs, this period can be lengthy and the transition to PSS can be unclear. There are two main ways to determine the transient period:

i. Buildup Analysis

If the buildup is still transient, the permeability calculated from the buildup can be used, along with an estimated drainage area, to calculate the time to PSS. If the well is in a defined pool, the drainage area can be reasonably well established; however, often the drainage area is not clearly defined. If the buildup shows boundary effects, the drainage areas are more clearly defined and the time to PSS more reliable. If boundaries are exhibited, then pressure buildup extrapolations and material balance analysis could also be performed.

ii. Type Curve Analysis

If Fetkovich type curve analysis is done, then the entire well history is used, with the inflection point of the dimensionless rate vs. time being the time to PSS. As a diagnostic indicator, log cumulative production vs. log producing time may be plotted, with the departure from straight line behaviour marking the start of PSS behaviour.

d. Final Rate Determination

Calculate the final rate to be used for decline analysis. This is usually either the economic limit or a value less than the economic limit when economic programs are used to determine the actual economic limit under different pricing scenarios. In the case of gas wells with water and/or oil and gas liquid production, it may be the physical lifting limit of the fluids in the wellbore. A review of water/gas ratio trends could be useful in establishing final rates at practical maximum water/gas ratio limits.

e. Operating Constraint Review

Use periods of constant operating constraints when fitting curves, or normalize data to reflect constant bottom-hole pressure conditions. For gas wells, review flowing wellhead pressure histories, if available, prior to establishing the decline matches.

f. Data Review

Select data that most closely represent stabilized conditions (i.e., calendar-day trends in low-permeability reservoirs and producing-day trends in high-permeability reservoirs.) Rate vs. cumulative production relationships must be used instead of log rate vs. time relationships to prevent inaccuracies caused by shut-in times.

g. Re-Initialization

Re-initialize declines after changes in drawdown, workovers, or stimulations. Initial production rates after these activities will be transient in nature and might not necessarily represent longer-term PSS trends.

h. Oil-Cut Analysis

Use oil-cut analysis when fluid rates are constant or increasing gradually. If fluid rates are increasing quickly, a transient flow period is introduced, which will not be representative of longer-term declines. In these cases, go back to periods of constant or gradually changing fluid rates to establish long-term trends. Use these extrapolations to estimate end-point reserves, and then adjust initial rates and exponents to match near-term behaviour.

i. Line-Pressure Adjustments

Account for increased reserves and rates from future line-pressure reductions for gas wells. This can be calculated from first principles based on the change in flowing pressure conditions relative to bottom-hole pressures. If line pressures have been reducing throughout the well's history, further adjustments might not be necessary, because historical curvature of the decline trend might already be caused by line pressure reductions. In these cases, normalization of data is the only rigorous method of determining reliable decline characteristics.

j. Interference Effects

The potential for interference effects must be considered when selecting long-term decline characteristics.

k. Production Forecasts

Production forecast trends should normally be consistent with historical trends. However, as a result of consideration of the influences described above, production forecast trends used for evaluation purposes may not always be consistent with historical data. For major property reporting purposes, explanations of these instances should be provided (COGEH Volume 1, Section 11.2.2).

6.5.5 Guidelines for Group Decline Analysis

Group decline analysis is usually performed to reduce evaluation time and smooth statistical variations and interference effects. The general guidelines for single-well analysis apply; however, some additional guidelines relating to group analysis are as follows.

a. Grouping

Wells should be grouped by common characteristics so as not to mix different profiles that do not, as a group, give the same numeric answer. Common grouping techniques in sequence of order include

- pool (so as not to mix unrelated reservoirs),
- pattern or drive mechanism (so as not to mix EOR versus primary profiles),
- geographic region (to allow for regional volumetric comparisons),
- producing versus shut-in (for existing wells),
- startup date (to prevent increasing well counts),
- productivity or water cut (to group wells of similar decline trend),
- common working interests,
- common group meters (in the case of shallow gas areas, where wells are infrequently tested and allocated production from the group meters).

b. Voidage Replacement

Decline trends in the case of EOR schemes should be matched during periods of stable voidage replacement. If the EOR scheme is not capable of maintaining voidage, then decline fits of recent rate trends are applicable.

c. Breakthrough Behaviour

Also for EOR schemes, decline forecasts are only reliable if they exhibit post breakthrough behaviour. If breakthrough has not been established, then volumetric or simulation methods must be used. If breakthrough is established in some of the geographic regions but not in others, then decline analysis should be used in the areas with breakthrough, and analogous recovery factors or decline profiles should be applied to determine reserves in the non-breakthrough areas.

6.5.6 Guidelines for Reserves Classification from Decline Analysis

If all the above factors are considered, a computer-generated best fit will give an initial guide as to the reserves assignment. The choice of best estimate case reserves, which represents the 2P reserves estimate, must be made after considering the quality of the fit, the uniqueness of the fit, the range of expected exponents, and the reasonableness of the reserves or life. Caution must be used, however, if relying on computer generated best fits, because there is always reservoir uncertainty and late-time behaviour, which may change decline rates and exponents in the future. A review of the decline behaviour of more mature analogous wells in the area is required to prevent inappropriate derivation of decline exponents. The choice of fit should match current decline behaviour and reasonably fit long-term trends. If decline characteristics have changed during the life of a well because of outside influences (interference from other wells, water breakthrough, damage, workovers, stimulations, etc.) it is not appropriate to match long-term trends.

If there is no material difference in the quality of a computer generated fit for a wide range of decline rates and exponents, then the evaluator must use judgement in picking the most reasonable decline rate and exponent based on his understanding of the reservoir characteristics and analogies. It is recommended that secondary methods, such as volumetrics and material balance, be considered for all significant entities with high exponents, poorly defined, or non-unique decline trends. For 2P determination, if very little information is available on analogies or reservoir characteristics, the decline analysis must be performed using the lowest exponent that reasonably fits the data.

It is also acceptable to visually fit curves to pick the most reasonable decline rate and exponent, using the best estimate exponent derived from analogies or reservoir characteristics.

After decline fits are derived for 2P reserves, proved reserves are estimated by either reducing the exponent, increasing the current decline rate, or selecting more conservative data points and refitting the data. Usually, depending on data scatter, a target reduction of between 1/3 and 2/3 of the difference between 2P and a reasonable minimum estimate meets acceptable proved confidence criteria. Wells with definitive decline trends may have little or no range between proved and 2P, whereas wells with more data scatter or less maturity may have a higher range.

Similarly, the exponent is increased, the current decline rate decreased, or more optimistic data points selected and the data refitted for 3P determination. A target increase of between 1/3 and 2/3 of the difference between 2P and a reasonable maximum estimate meets acceptable 3P confidence criteria.

If there is a good fit to the data in a 2P interpretation (i.e., less than a 10 percent difference between minimum and maximum interpretations of remaining reserves), the same value may be used for proved and 3P reserves determination, unless the entity is material to the property (i.e., greater than 10 percent), in which case a range of values should be incorporated.

6.5.7 Decline Examples

Following are a series of examples of decline interpretations using the guidelines described above for various types of reservoirs and drive mechanisms. A summary of the recommended interpretations is presented in Table 6-1.

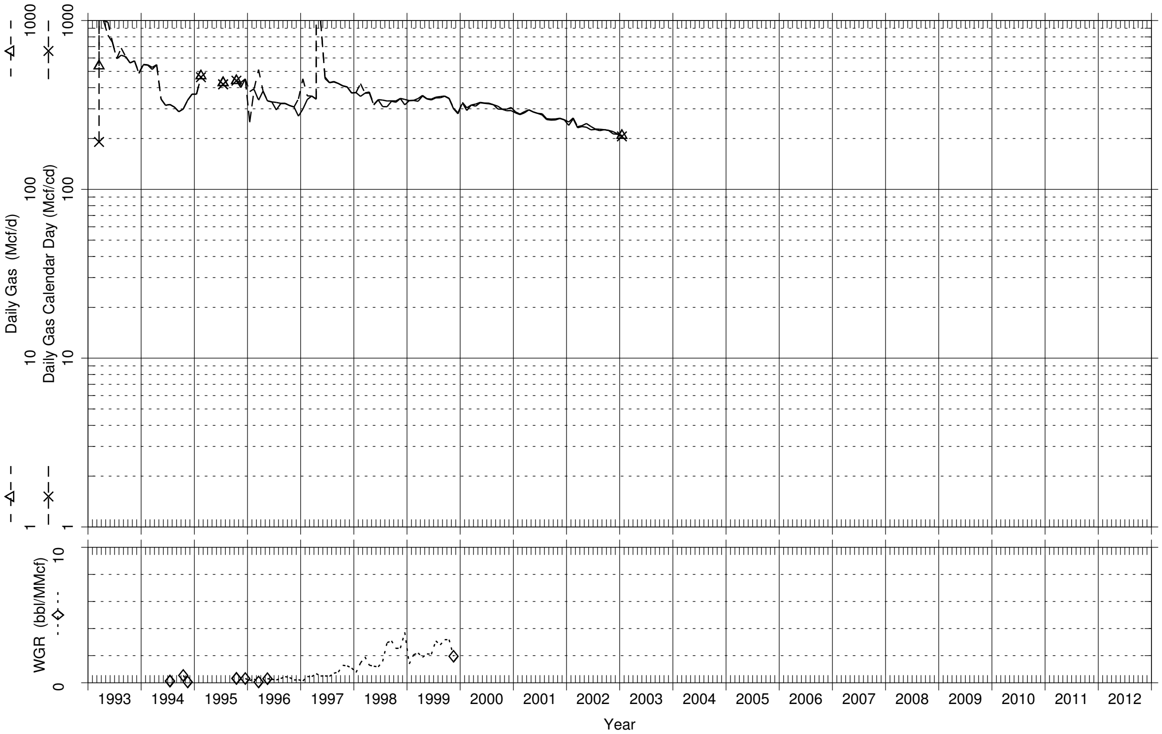
Gas Example A

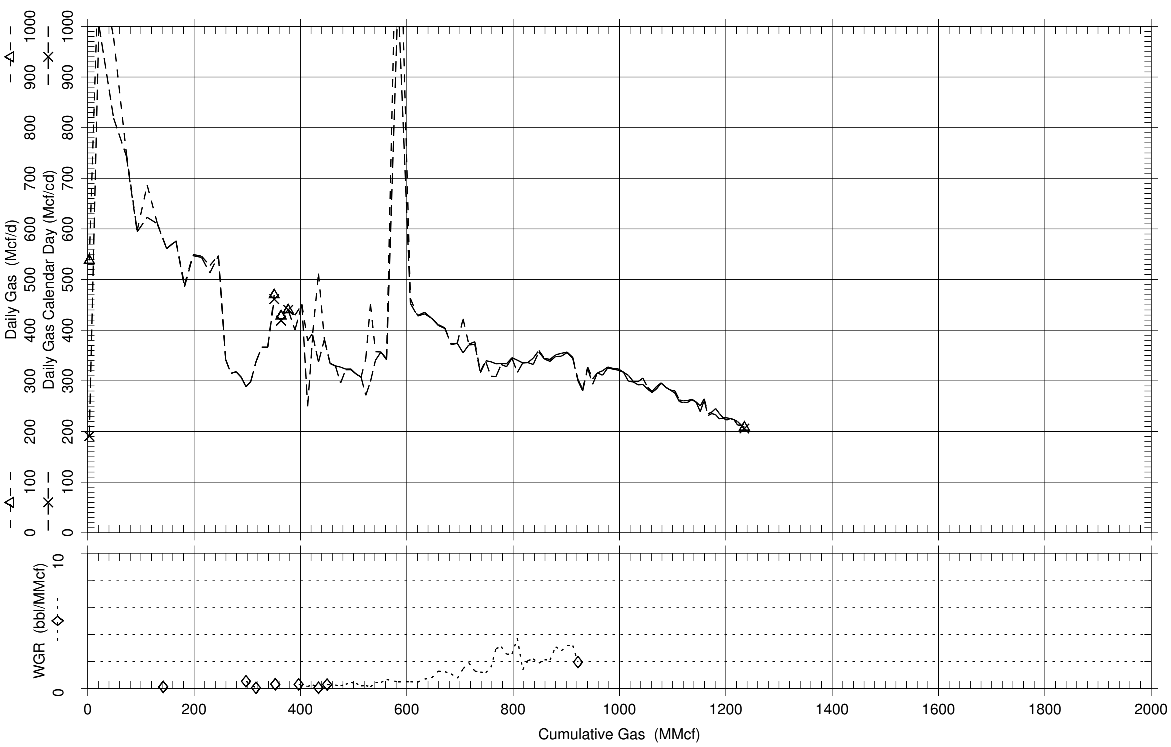
Gas Example A is a well in a moderate-permeability, unstratified gas reservoir now producing at terminal line-pressure conditions (Plot 1). Prior to year 2000, decline analysis could not be used on this well because production was not declining, probably because of reductions in line pressure. Best fit analysis for the period 1.0 Bcf to 1.23 Bcf yields a hyperbolic decline exponent of 0.3 and ultimate reserves of 1.52 Bcf (Plot 2, Line M). Because of the short duration of the actual decline period, best fit analysis must be used with caution, because results can be highly variable. Decline exponents must be chosen based on experience in the area and the characteristics of the reservoir. For this type of reservoir (unstratified, moderate permeability), exponential-type behaviour is expected, unless further line pressure reductions are anticipated.

Recommended best estimate reserves for 2P reserves determination (Plot 2) are based on a visual match, using exponential decline analysis and the average decline slope. Based on a 100 Mcfd final rate, calculated ultimate reserves for the 2P case are 1.48 Bcf (Line G). Prior to selecting proved and 3P reserves, reasonable minimum and maximum end points illustrated on Plot 2 are selected to understand the potential variability of the estimate. In this case, 1.44 Bcf minimum ultimate reserves are determined using a steeper exponential decline interpretation through more recent data and 1.52 Bcf maximum ultimate reserves are determined based on the best fit results. Recommended proved reserves interpretation is 1.46 Bcf (Plot 3, Line A) using exponential decline analysis and a reserves value halfway between the minimum and 2P values. Recommended 3P interpretation is 1.50 Bcf (Plot 3, Line P) using a hyperbolic exponent of 0.15 and a reserves value that is halfway between the 2P and maximum values. As described in the decline analysis guidelines, the selection of proved values between 1/3 and 2/3 of the distance between minimum and best estimate values is acceptable. Similarly, the selection of 3P values between 1/3 and 2/3 of the distance between maximum and best estimate values is acceptable.

In this example, a 100 Mcfd final rate is chosen, because of water lifting capacity rather than economic limit. A review of wells in the area indicates most wells cease production at a rate of 100 Mcfd. The reported water production on the plots is likely not meaningful because of lack of reliable measurement.

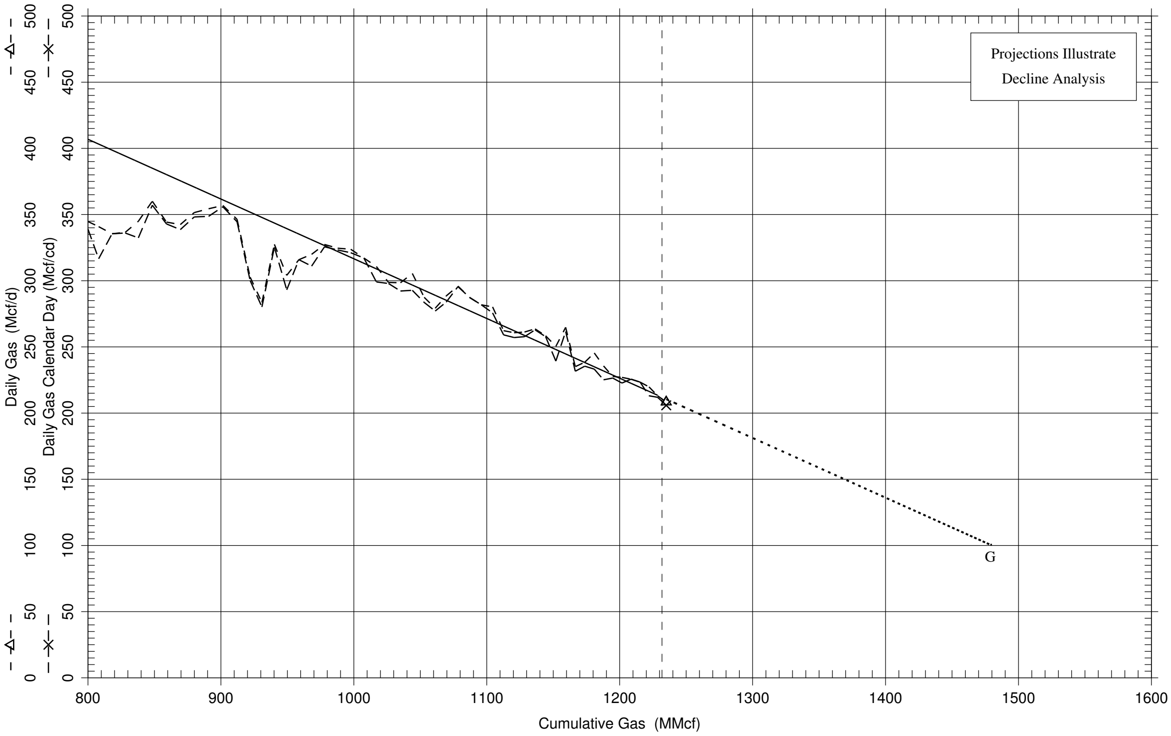
Historical Production
Gas Decline - Example A

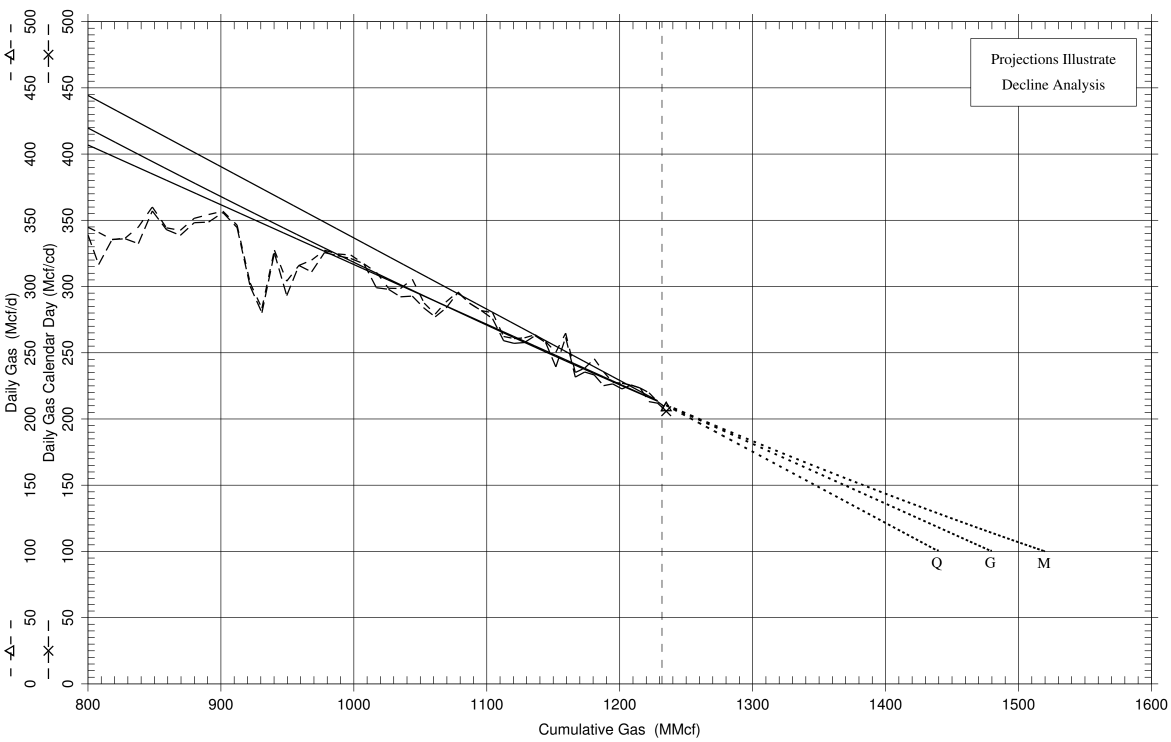




Status Summary		Cumulative Production		Average Production Rates (Last 12 months ending 2003/01/31)					
On Production date :	93/03/20	Gas :	1238.2 MMcf	Gas :	230.4 Mcf/d	226.3 Mcf/cd	WGR :	0.0 bbl/MMcf
Status date :	93/03/20	Oil :	0.0 Mbbl	Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
Status : FLOWING GAS		Water :	0.7 Mbbl	On Prod :	358.8 days		WC :	0.0 %

Historical and Forecast Production
Gas Decline - Example A





Decline Analysis Summary @ 2003/01/01

Reserves Classification		Raw Gas Reserves (MMcf) Ultimate	Cum Prd	Remain	Rates (mcf/d) Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	1480	1232	248	212	100	15.2%	0.00
Maximum Prd	M	1520	1232	288	212	100	14.2%	0.30
Minimum Prd	Q	1440	1232	208	212	100	17.8%	0.00

Average Production Rates (Last 12 months ending 2003/01/31)

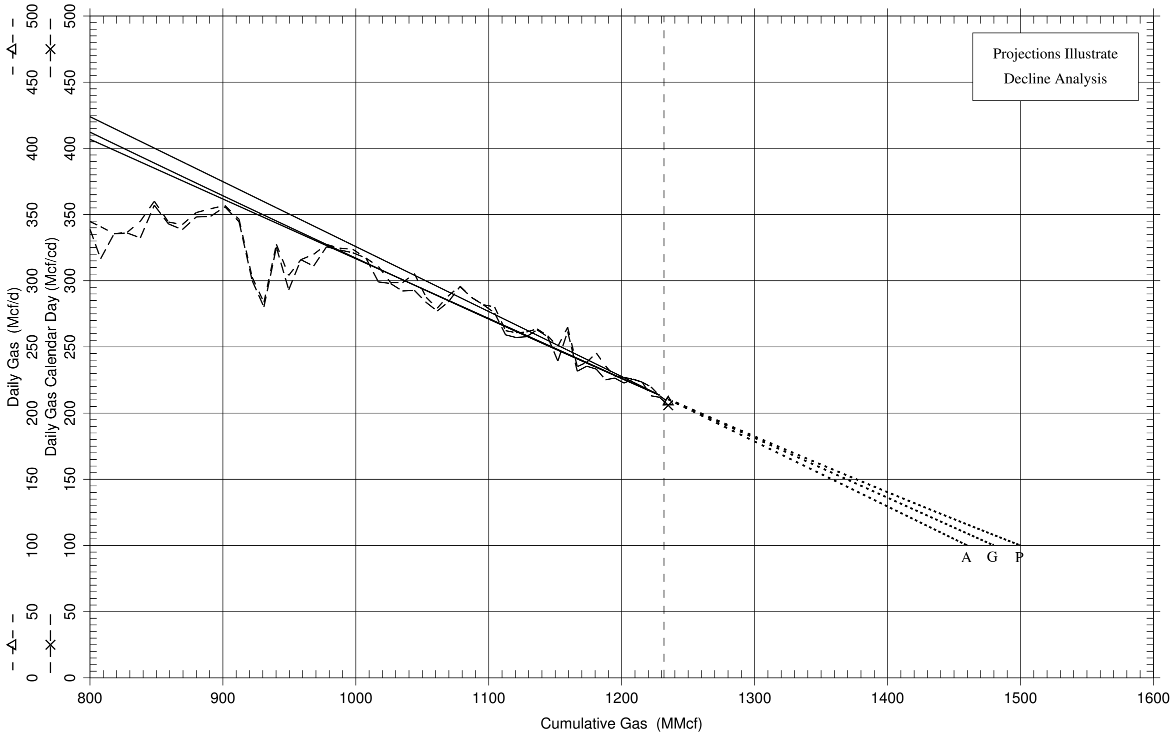
Gas :	230.4 Mcf/d	226.3 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	358.8 days		WC :	0.0 %

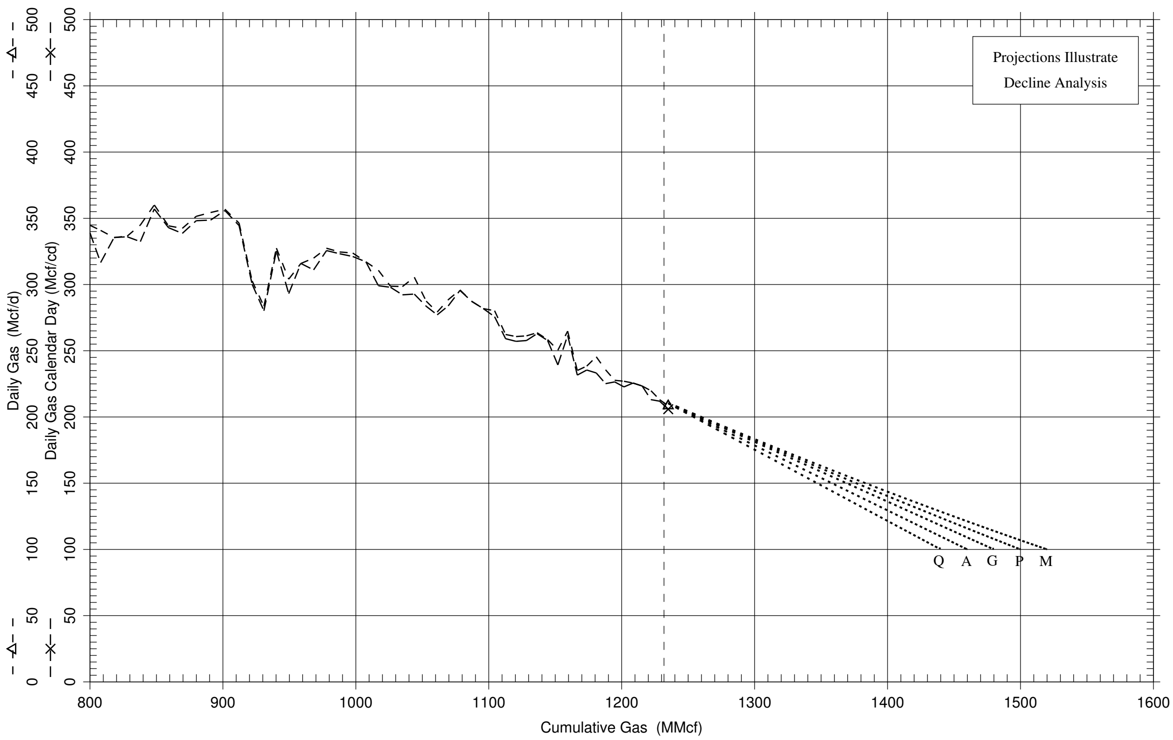
Cumulative Production

Oil : 0.0 Mbbl Gas : 1238.2 MMcf Water : 0.7 Mbbl

Plot 2

Historical and Forecast Production
Gas Decline - Example A





Decline Analysis Summary @ 2003/01/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv Prd	—— A	1460	1232	228	212	100	16.4%	0.00
Pv + Pb Prd	—— G	1480	1232	248	212	100	15.2%	0.00
Pv + Pb + Poss Prd	—— P	1500	1232	268	212	100	14.6%	0.15

Average Production Rates (Last 12 months ending 2003/01/31)

Gas :	230.4 Mcf/d	226.3 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	358.8 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	1238.2 MMcf	Water :	0.7 Mbbl

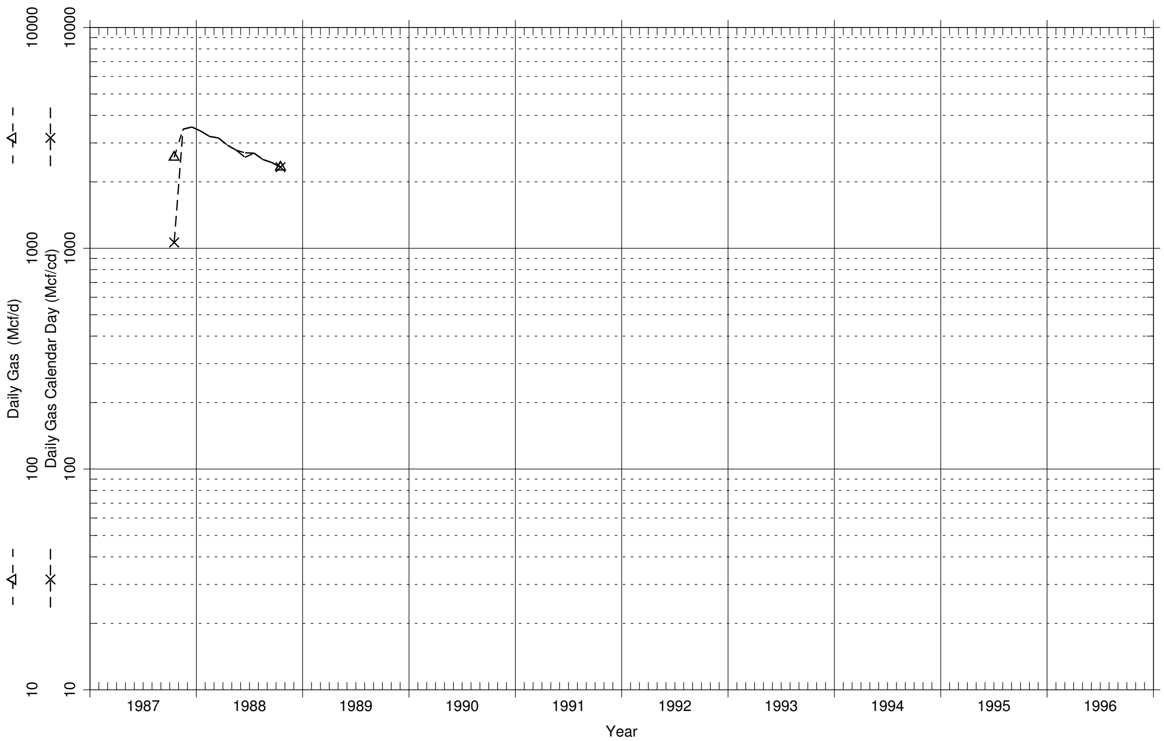
Gas Example B

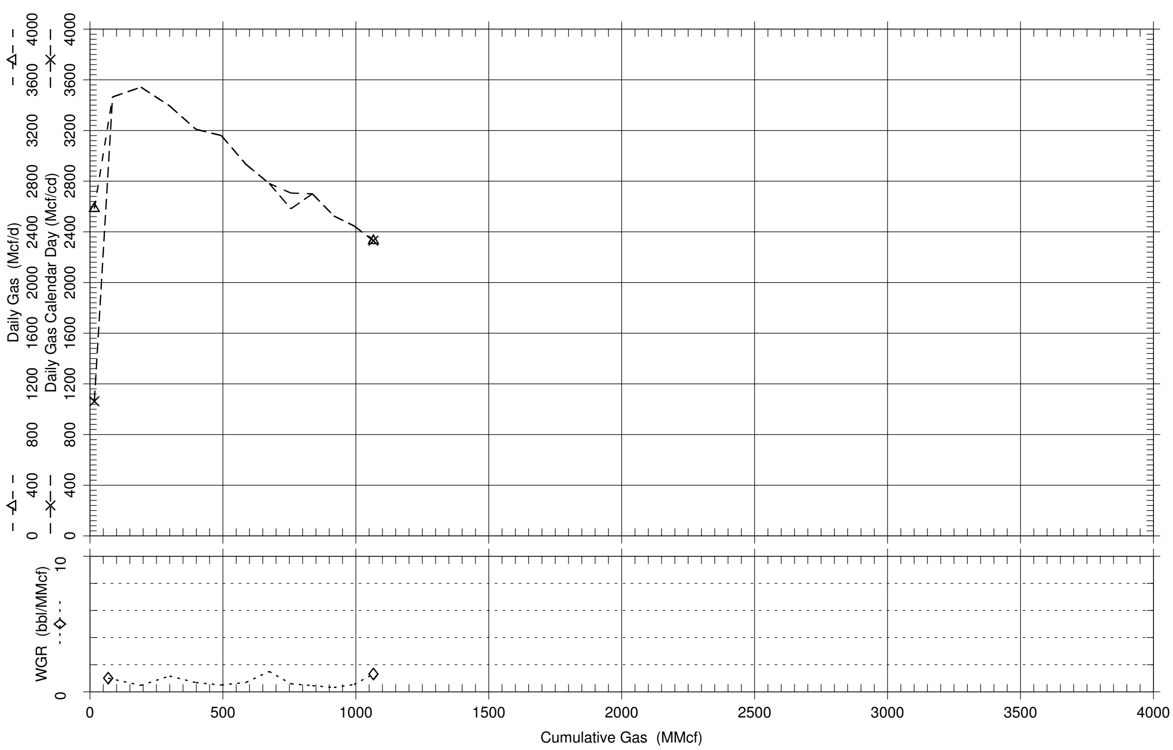
Gas Example B is a well in a moderate-permeability, unstratified gas reservoir in the early stage of depletion (Plot 4). Line pressure is approximately 300 psi, with future terminal line-pressure conditions expected to be 100 psi. This future line-pressure reduction is calculated to increase recovery by approximately 21 percent over extrapolations at current conditions. As this is a known moderate-permeability unstratified reservoir, decline behaviour is expected to be exponential under current line-pressure conditions, and slightly hyperbolic with future line-pressure reductions.

Recommended best estimate reserves for 2P reserves determination of 3.07 Bcf (Plot 5, Line G) are estimated by increasing the current minimum exponential forecast reserves of 2.53 Bcf (Line Q) by a factor of 1.21 to reflect recovery with additional line-pressure reduction. A hyperbolic decline exponent of 0.2 is selected to match this forecast end point at a 50 Mcfd final rate (liquid loading limit) with the current decline slope. Prior to selecting proved and 3P reserves, reasonable minimum and maximum end points illustrated on Plot 5 are selected to understand the potential variability of the estimate. In this case, 2.53 Bcf minimum ultimate reserves is determined using an exponential decline interpretation through recent data, while 4.10 Bcf maximum ultimate reserves is determined using an optimistic 0.5 decline exponent, to reflect the possibility of remote tighter gas contribution in addition to increases because of line-pressure reductions. Recommended proved reserves interpretation is 2.74 Bcf (Plot 6, Line A), using exponential decline analysis and a reserves value between the minimum and 2P values. Recommended 3P interpretation is 3.52 Bcf (Plot 6, Line P) using a hyperbolic exponent of 0.35 and a reserves value between the 2P and maximum values. As described in the decline analysis guidelines, the selection of proved values between 1/3 and 2/3 of the distance between minimum and best estimate values is acceptable. Similarly, the selection of values between 1/3 and 2/3 of the distance between maximum and best estimate values is acceptable.

Actual performance of the well resulted in cumulative production of 3.00 Bcf (Plot 7). As expected, hyperbolic bending was very slight due to moderate line-pressure reductions. In this particular case, the 2P estimate was slightly high; however, the proved estimate was exceeded.

Historical Production
Gas Decline - Example B





Status Summary

On Production date :	87/10/18
Status date :	87/10/18
Status : FLOWING GAS	

Cumulative Production

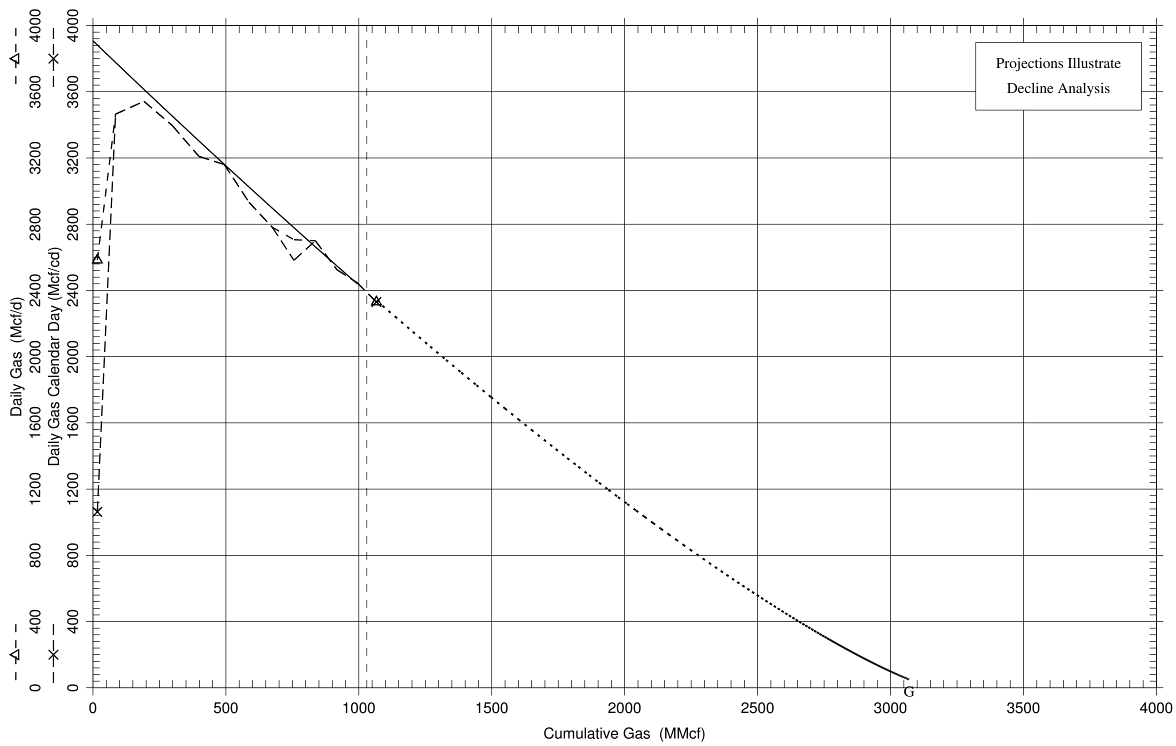
Gas :	1102.3	MMcf
Oil :	0.8	Mbbl
Water :	0.8	Mbbl

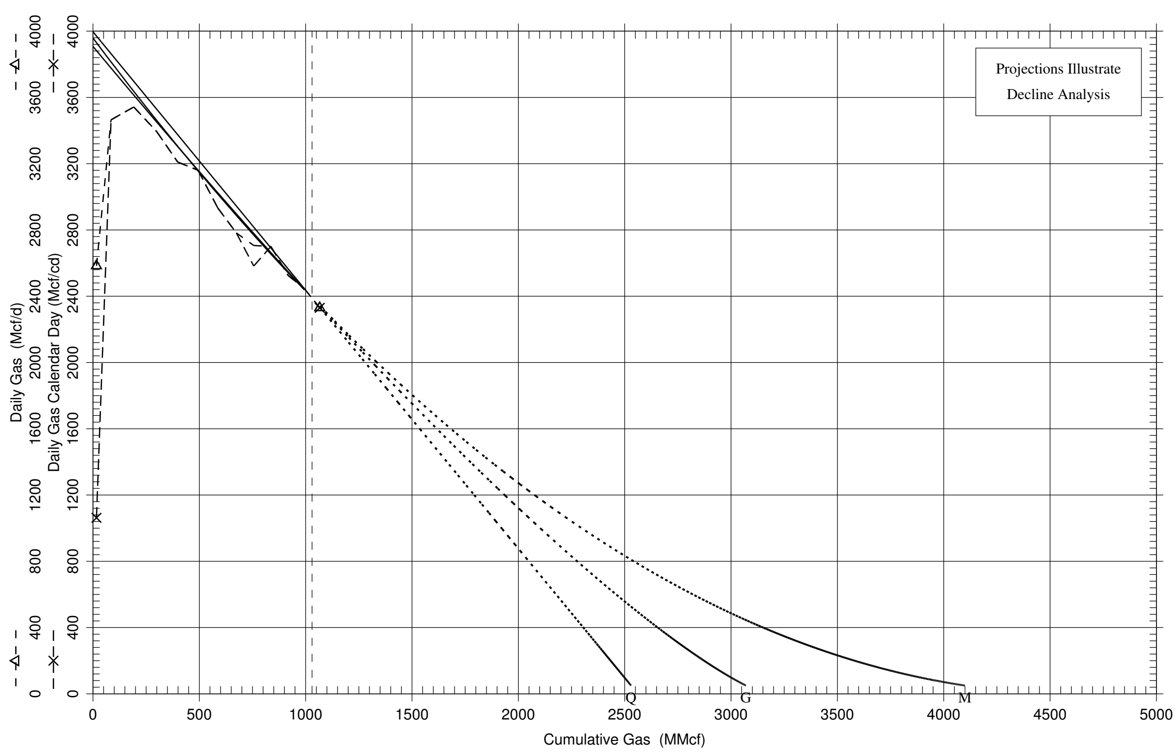
Average Production Rates (Last 12 months ending 1988/10/31)

Gas :	2932.9	Mcf/d	2922.5	Mcf/cd	WGR :	0.8	bbl/MMcf
Oil :	2.3	bbl/d	2.3	bbl/cd	GOR :	>99999.9	scf/stb
On Prod :	364.6	days			WC :	50.1	%

Plot 4

Historical and Forecast Production
Gas Decline - Example B





Decline Analysis Summary @ 1988/10/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv + Pb Prd	—— G	3070	1030	2040	2390	50	38.5%	0.20
Maximum Prd	—— M	4100	1030	3070	2390	50	35.3%	0.50
Minimum Prd	—— Q	2530	1030	1500	2390	50	43.4%	0.00

Average Production Rates (Last 12 months ending 1988/10/31)

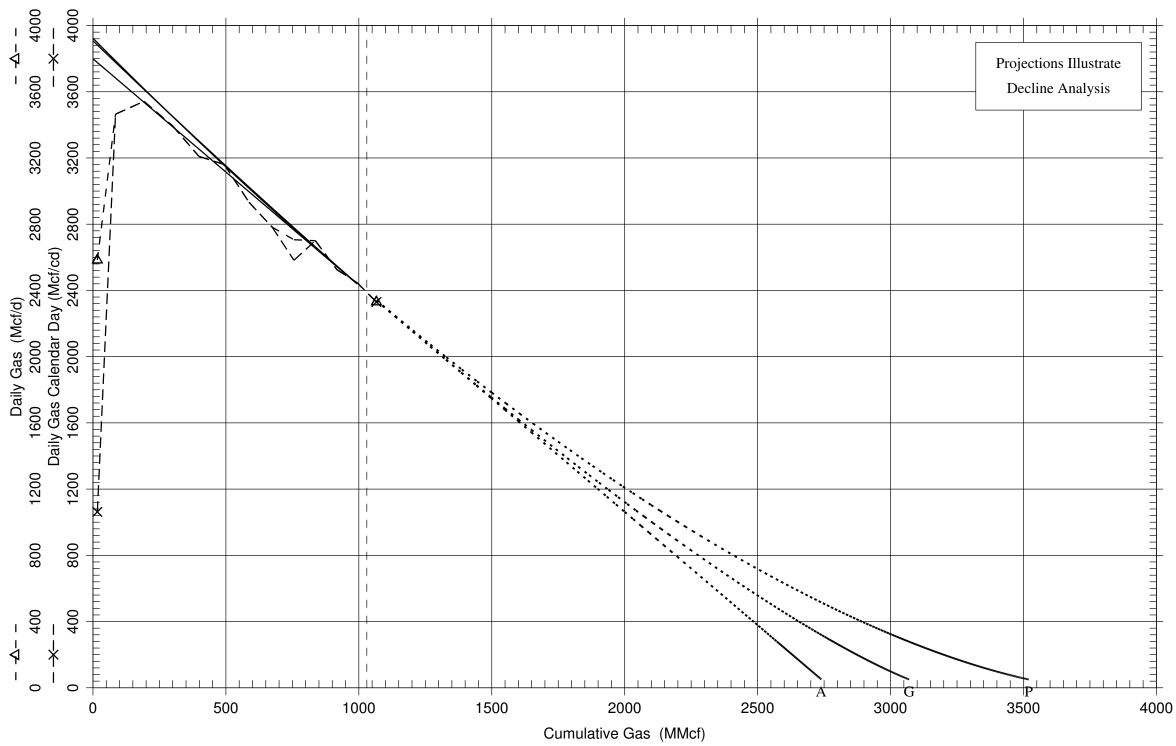
Gas :	2932.9	Mcf/d	2922.5	Mcf/cd	WGR :	0.8	bbl/MMcf
Oil :	2.3	bbl/d	2.3	bbl/cd	GOR :	>99999.9	scf/stb
On Prod :	364.6	days			WC :	50.1	%

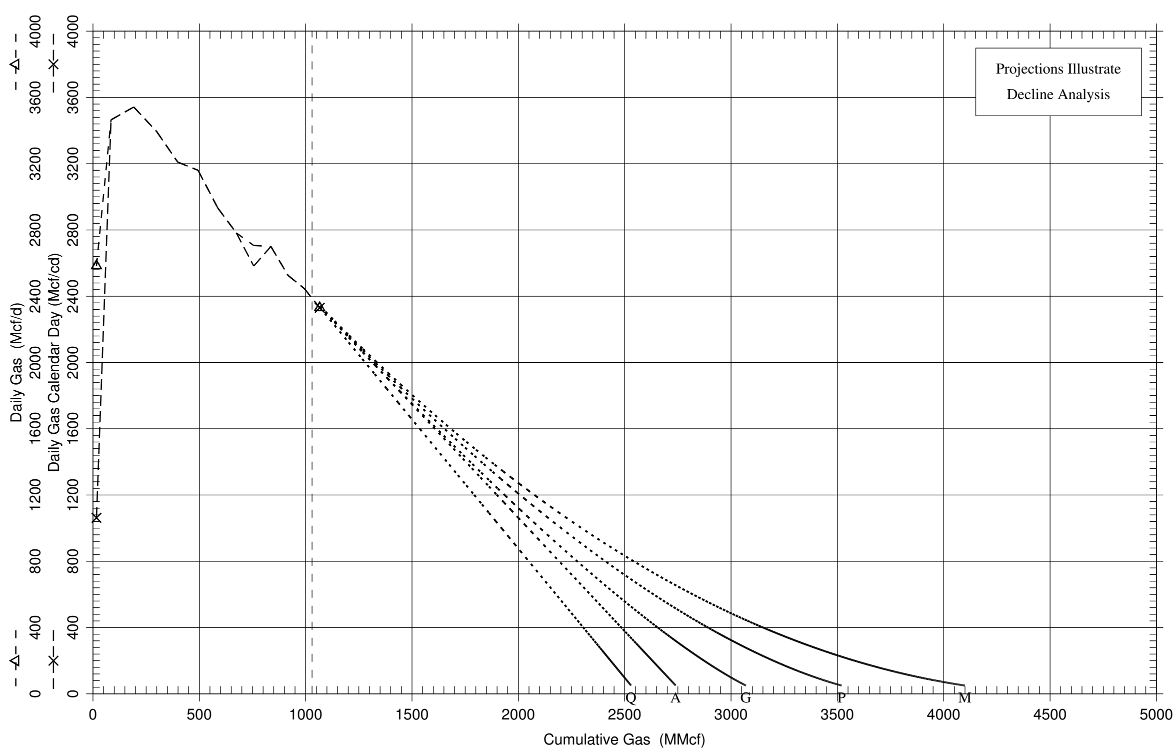
Cumulative Production

Oil :	0.8	Mbbl	Gas :	1102.3	MMcf	Water :	0.8 Mbbl

Plot 5

Historical and Forecast Production
Gas Decline - Example B





Decline Analysis Summary @ 1988/10/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv Prd	A	2740	1030	1710	2390	50	39.3%	0.00
Pv + Pb Prd	G	3070	1030	2040	2390	50	38.5%	0.20
Pv + Pb + Poss Prd	P	3520	1030	2490	2390	50	36.7%	0.35

Average Production Rates (Last 12 months ending 1988/10/31)

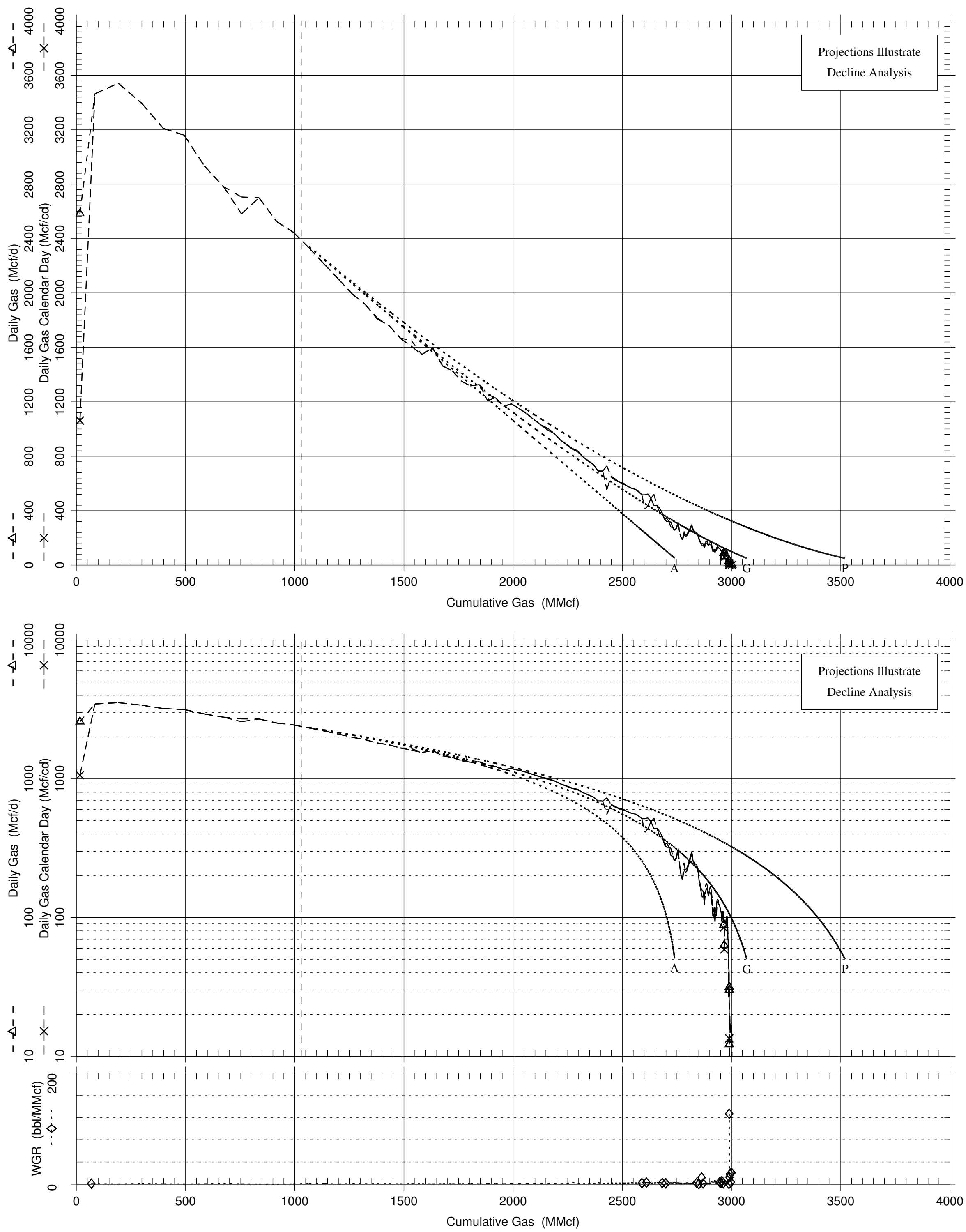
Gas :	2932.9	Mcf/d	2922.5	Mcf/cd	WGR :	0.8	bbl/MMcf
Oil :	2.3	bbl/d	2.3	bbl/cd	GOR :	>99999.9	scf/stb
On Prod :	364.6	days			WC :	50.1	%

Cumulative Production

Oil :	0.8	Mbbl	Gas :	1102.3	MMcf	Water :	0.8	Mbbl

Plot 6

Historical and Forecast Production
Gas Decline - Example B



Decline Analysis Summary @ 1988/10/01

Reserves Classification		Raw Gas Reserves (MMcf) Ultimate	Cum Prd	Remain	Rates (mcf/d) Initial	Final	Decline Initial	Expont
Pv Prd	A	2740	1030	1710	2390	50	39.3%	0.00
Pv + Pb Prd	G	3070	1030	2040	2390	50	38.5%	0.20
Pv + Pb + Poss Prd	P	3520	1030	2490	2390	50	36.7%	0.35

Average Production Rates (Last 12 months ending 2002/10/31)

Gas :	14.3 Mcf/d	13.9 Mcf/cd	WGR :	2.2 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	342.3 days		WC :	100.0 %

Cumulative Production

Oil :	1.9 Mbbl	Gas :	3001.8 MMcf	Water :	3.6 Mbbl

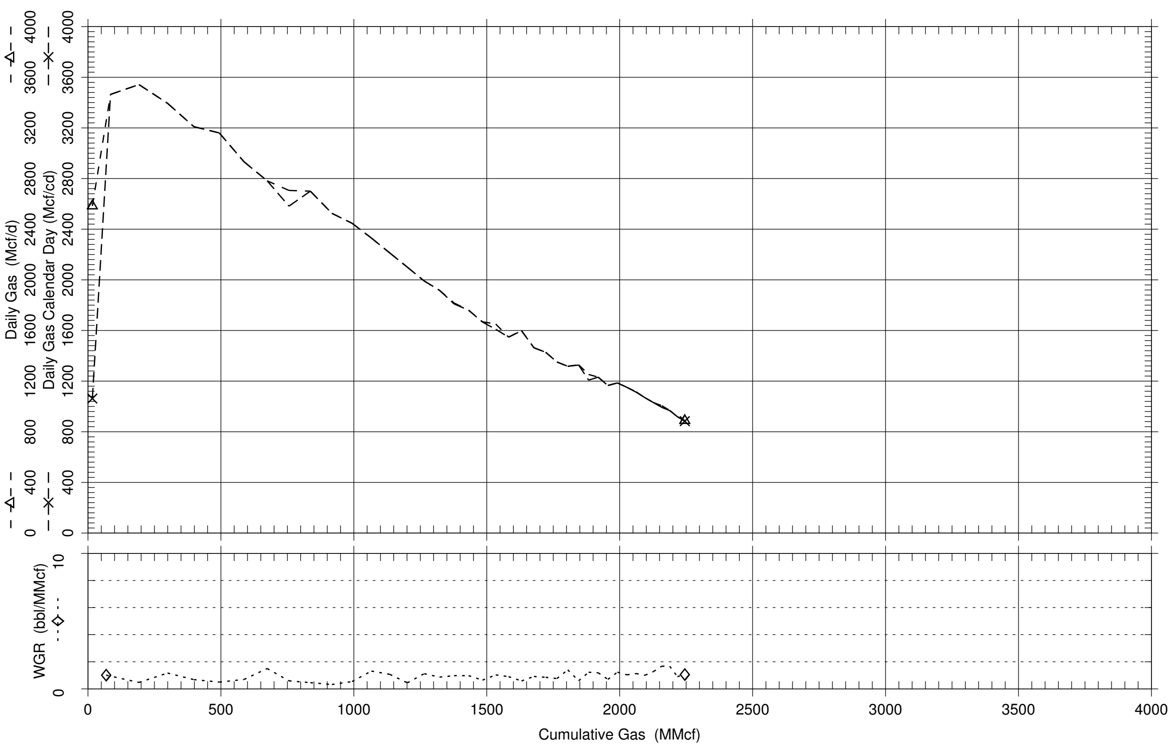
Plot 7

Gas Example C

Gas Example C is a well in a moderate-permeability, unstratified gas reservoir (Plot 8). It is the same example as Example B, except with more production history. No future line-pressure reductions are anticipated. Best fit analysis calculated for the period from 0.8 Bcf to 2.2 Bcf yields a hyperbolic exponent of 0.7 and ultimate reserves of 4.42 Bcf (Plot 9, Line M). This value should not be used for reserves determination, because line-pressure reductions over the fit period have caused the slope changes. As this is a known moderate-permeability unstratified reservoir with no expected additional line-pressure reductions, expected decline exponents should be low.

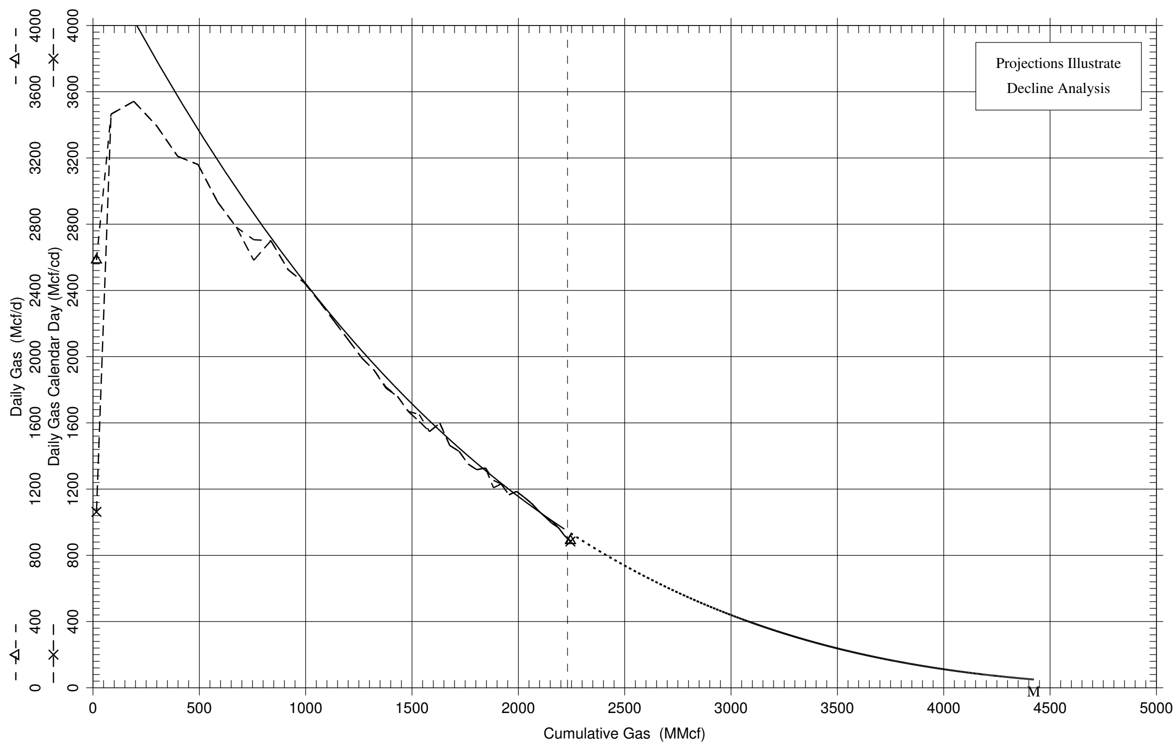
The recommended best estimate reserve for 2P reserves determination (Plot 10) is based on a visual match of current decline rate and exponential decline. Based on a 50 Mcfd final rate (liquid loading limit), calculated ultimate reserves for the 2P case are 2.96 Bcf (Line G). Prior to selecting proved and 3P reserves, reasonable minimum and maximum end points illustrated on Plot 10 are selected to understand the potential variability of the estimate. In this case, 2.90 Bcf minimum ultimate reserves are determined using an exponential decline interpretation through recent data, while 3.18 Bcf maximum ultimate reserves are determined using an optimistic 0.3 decline exponent. Recommended proved reserves determination is 2.93 Bcf (Plot 11, Line A), using exponential decline analysis and a reserves value between the minimum and 2P values. Recommended 3P determination is 3.03 Bcf (Plot 11, Line P), using a hyperbolic exponent of 0.15 and a reserves value between the 2P and maximum values. As described in the decline analysis guidelines, the selection of proved values between 1/3 and 2/3 of the distance between minimum and best estimate values is acceptable. Similarly, the selection of 3P values between 1/3 and 2/3 of the distance between maximum and best estimate values is acceptable. Due to the more extensive production history than the previous example, the differences between the reserves categories are reduced. Actual full-life well performance is illustrated on Plot 12.

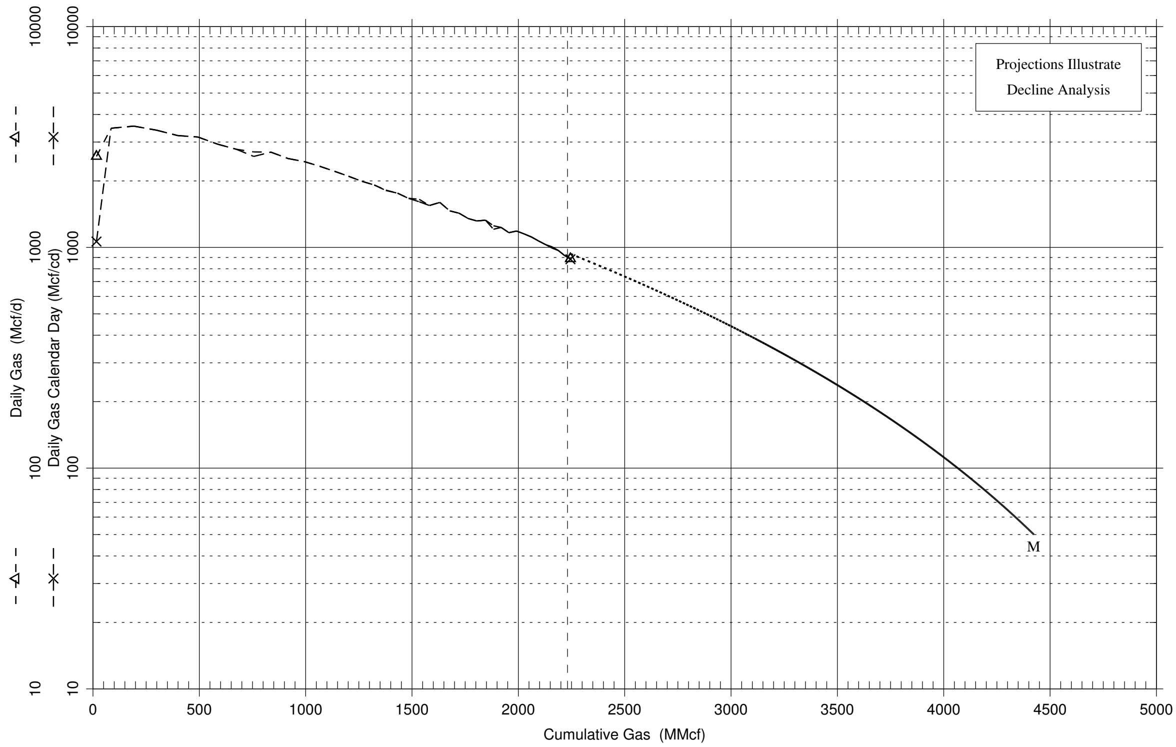
Historical Production
Gas Decline - Example C



Status Summary		Cumulative Production			Average Production Rates (Last 12 months ending 1991/01/31)								
On Production date :	87/10/18	Gas :	2258.6	MMcf	Gas :	1082.0	Mcf/d	1076.2	Mcf/cd	WGR :	1.2	bbl/MMcf
Status date :	87/10/18	Oil :	1.4	Mbbl	Oil :	0.5	bbl/d	0.5	bbl/cd	GOR :	>99999.9	scf/stb
Status : FLOWING GAS		Water :	2.0	Mbbl	On Prod :	363.2	days			WC :	73.6	%

Historical and Forecast Production
Gas Decline - Example C





Decline Analysis Summary @ 1991/01/01

Reserves Classification		Raw Gas Reserves (MMcf) Ultimate	Cum Prd	Remain	Rates (mcf/d) Initial	Final	Decline Initial	Expont
Maximum Prd	—— M	4424	2231	2193	946	50	24.3%	0.70

Average Production Rates (Last 12 months ending 1991/01/31)

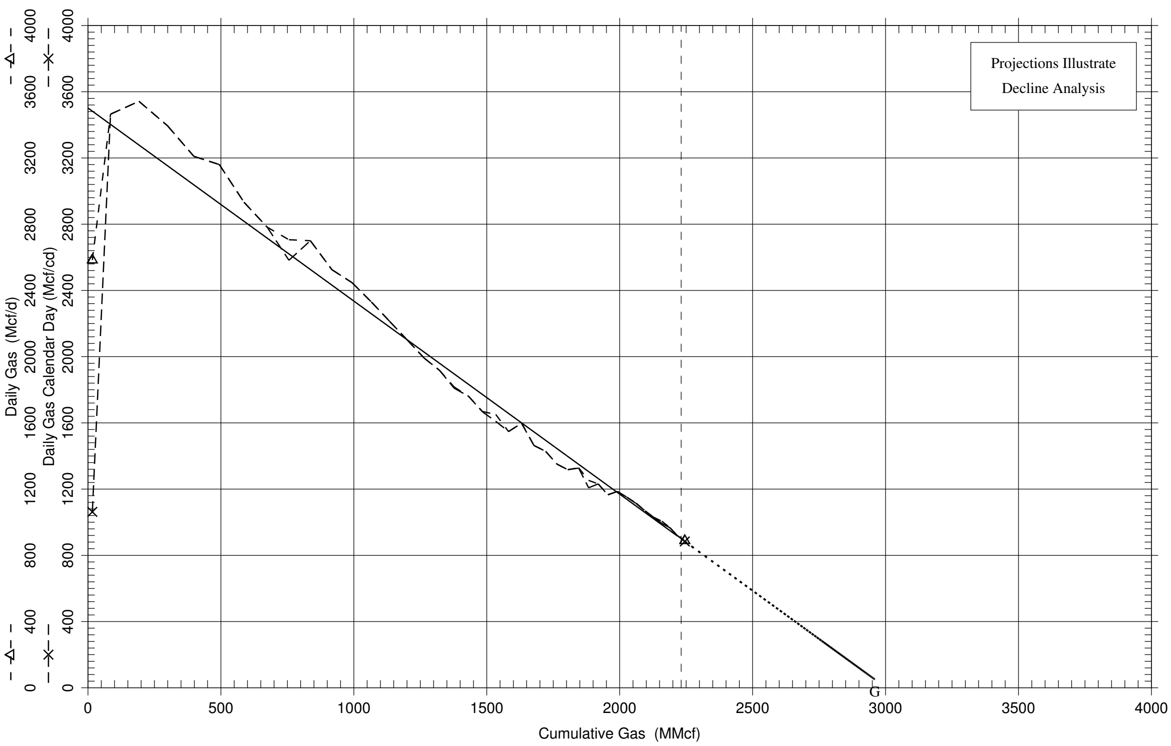
Gas :	1082.0	Mcf/d	1076.2	Mcf/cd	WGR :	1.2 bbl/MMcf
Oil :	0.5	bbl/d	0.5	bbl/cd	GOR :	>99999.9 scf/stb
On Prod :	363.2	days			WC :	73.6 %

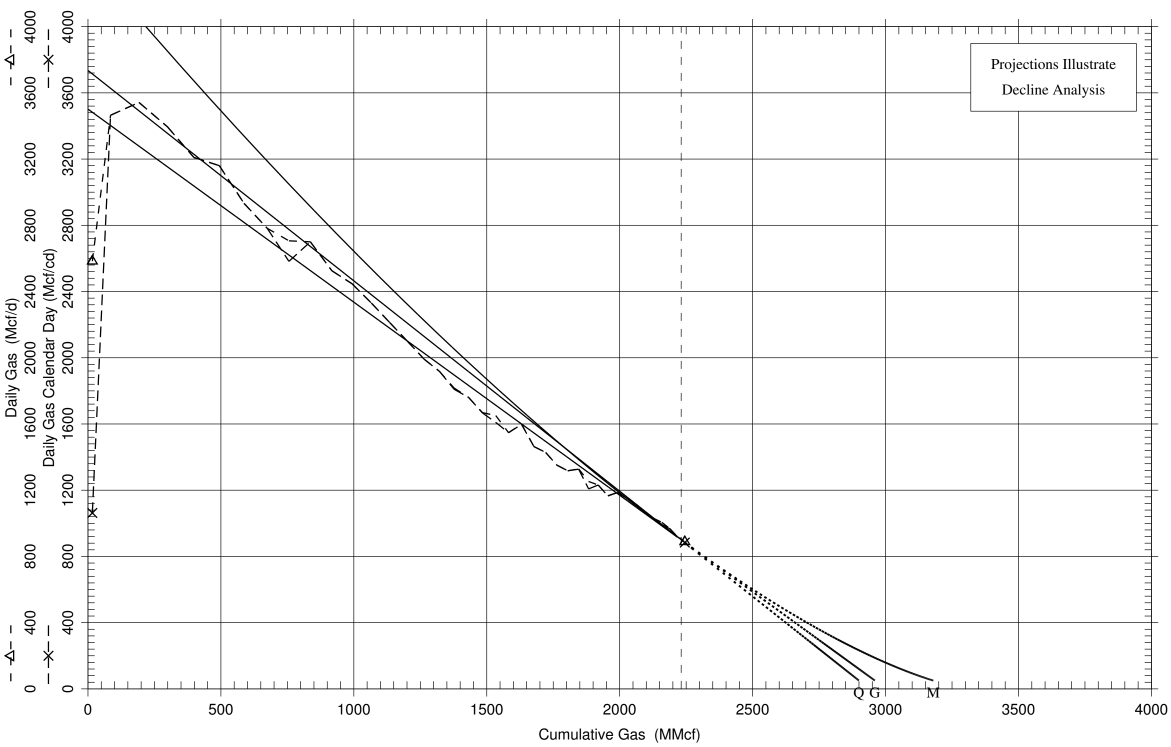
Cumulative Production

Oil : 1.4 Mbbl	Gas : 2258.6 MMcf	Water : 2.0 Mbbl	

Plot 9

Historical and Forecast Production
Gas Decline - Example C





Decline Analysis Summary @ 1991/01/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv + Pb Prd	G	2960	2231	729	900	50	34.7%	0.00
Maximum Prd	M	3180	2231	949	900	50	33.2%	0.30
Minimum Prd	Q	2900	2231	669	900	50	37.1%	0.00

Average Production Rates (Last 12 months ending 1991/01/31)

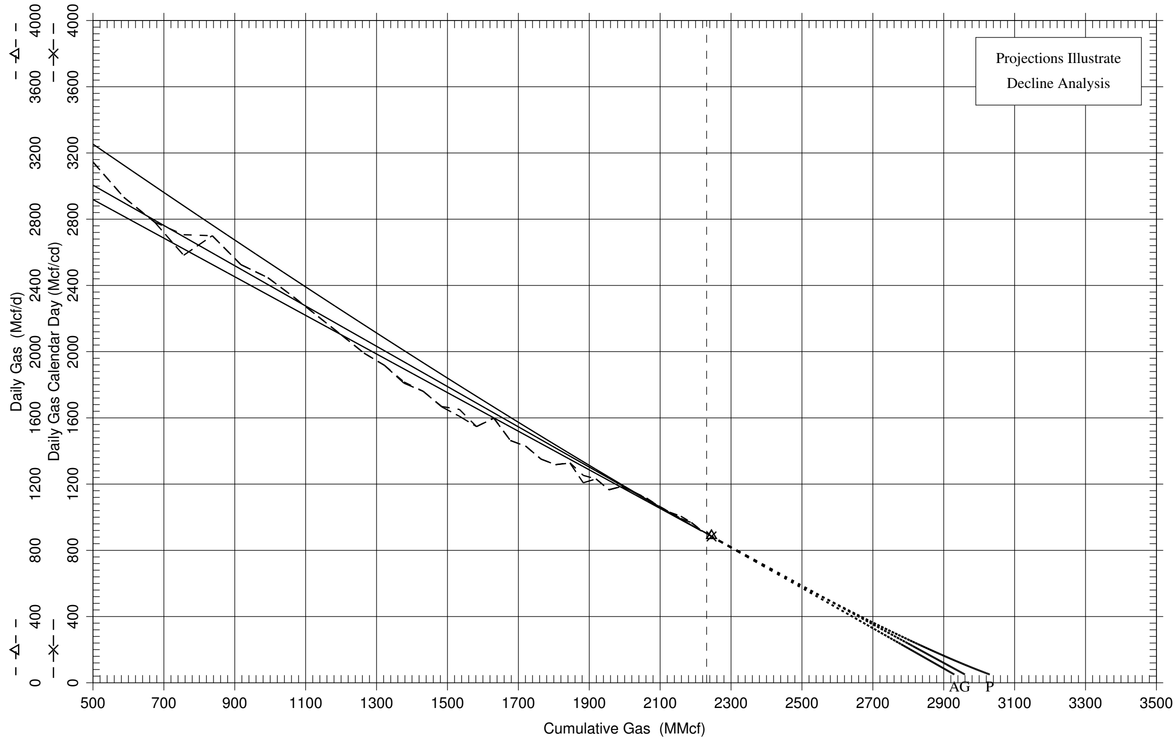
Gas :	1082.0	Mcf/d	1076.2	Mcf/cd	WGR :	1.2	bbl/MMcf
Oil :	0.5	bbl/d	0.5	bbl/cd	GOR :	>99999.9	scf/stb
On Prod :	363.2	days			WC :	73.6	%

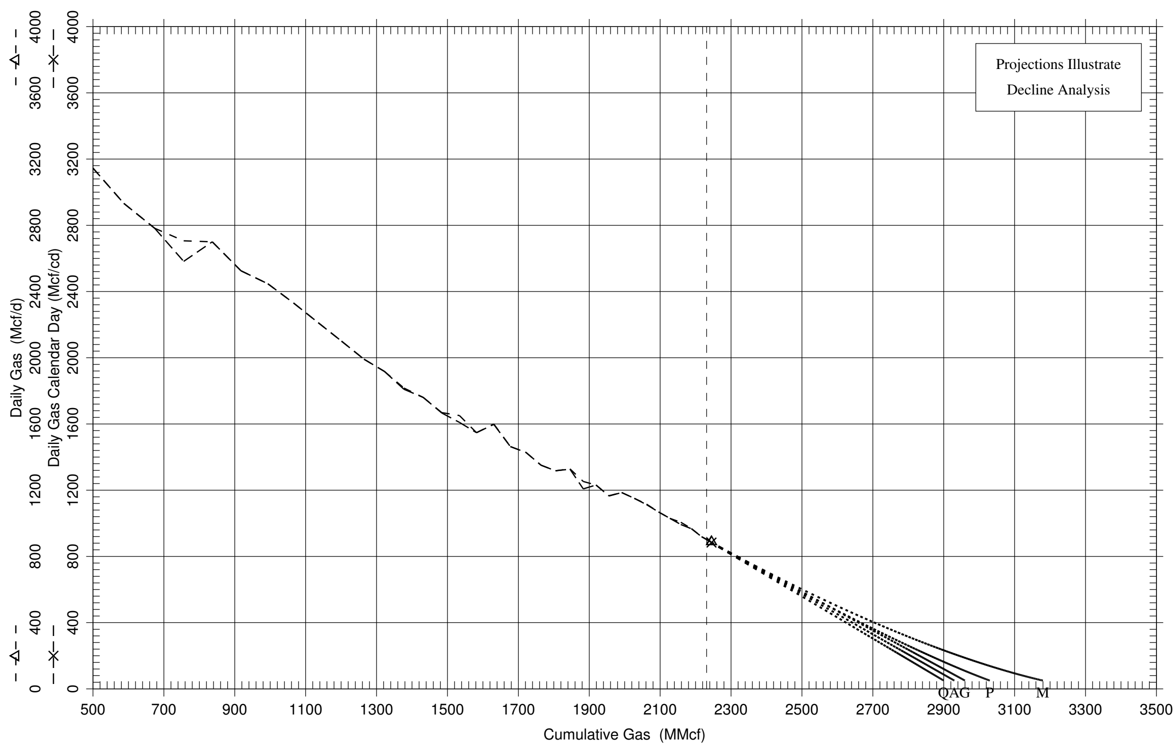
Cumulative Production

Oil :	1.4	Mbbl	Gas :	2258.6	MMcf	Water :	2.0	Mbbl

Plot 10

Historical and Forecast Production
Gas Decline - Example C





Decline Analysis Summary @ 1991/01/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv Prd	—— A	2930	2231	699	900	50	35.9%	0.00
Pv + Pb Prd	—— G	2960	2231	729	900	50	34.7%	0.00
Pv + Pb + Poss Prd	—— P	3030	2231	799	900	50	34.8%	0.15

Average Production Rates (Last 12 months ending 1991/01/31)

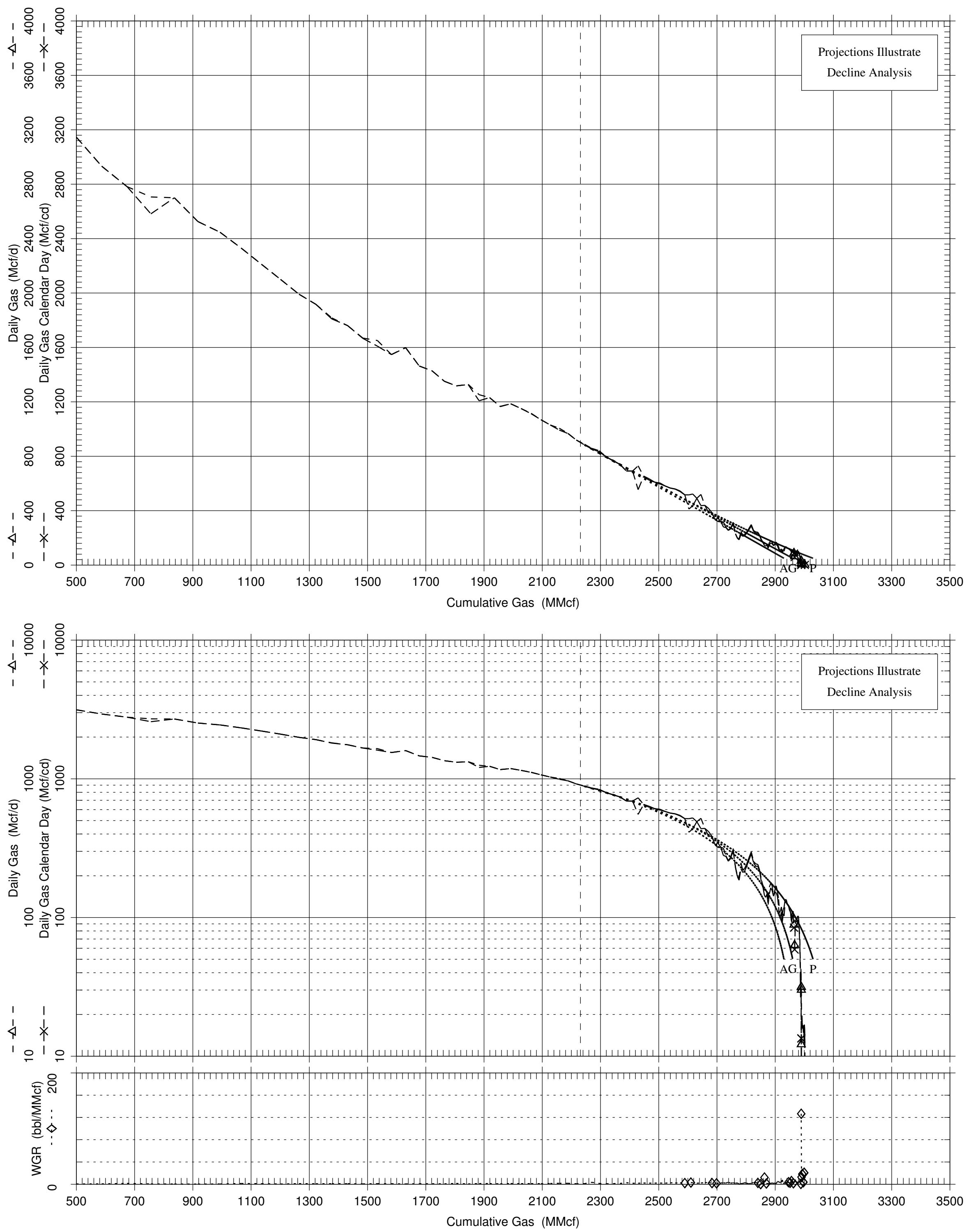
Gas :	1082.0	Mcf/d	1076.2	Mcf/cd	WGR :	1.2	bbl/MMcf
Oil :	0.5	bbl/d	0.5	bbl/cd	GOR :	>99999.9	scf/stb
On Prod :	363.2	days			WC :	73.6	%

Cumulative Production

Oil :	1.4 Mbbl	Gas :	2258.6 MMcf	Water :	2.0 Mbbl

Plot 11

Historical and Forecast Production
Gas Decline - Example C



Decline Analysis Summary @ 1991/01/01

Reserves Classification		Raw Gas Reserves (MMcf) Ultimate	Cum Prd	Remain	Rates (mcf/d) Initial	Final	Decline Initial	Expont
Pv Prd	—— A	2930	2231	699	900	50	35.9%	0.00
Pv + Pb Prd	—— G	2960	2231	729	900	50	34.7%	0.00
Pv + Pb + Poss Prd	—— P	3030	2231	799	900	50	34.8%	0.15

Average Production Rates (Last 12 months ending 2002/10/31)

Gas :	14.3 Mcf/d	13.9 Mcf/cd	WGR :	2.2 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	342.3 days		WC :	100.0 %

Cumulative Production

Oil :	1.9 Mbbl	Gas :	3001.8 MMcf	Water :	3.6 Mbbl

Plot 12

Gas Example D

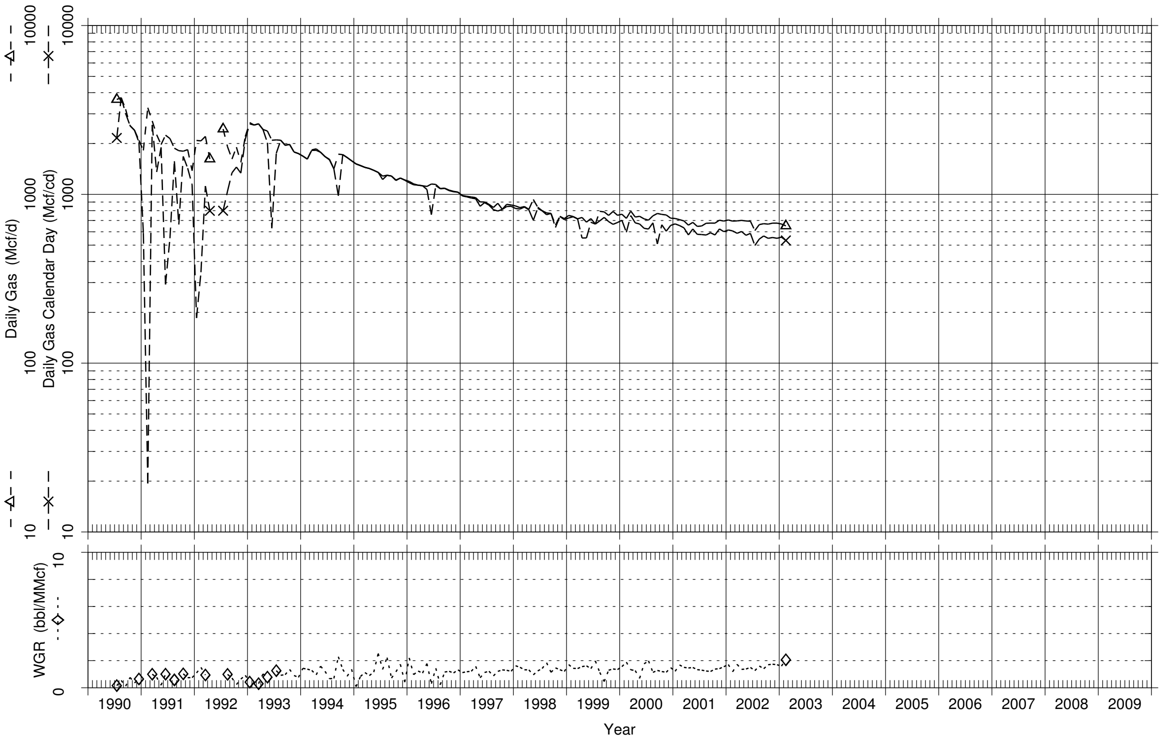
Gas Example D is a well in a low-permeability, highly stratified gas reservoir (Plot 13). Curve fitting was only performed after January 1, 1996 (3 Bcf cumulative production), when the well was calculated from pressure transient analysis to be in pseudo-steady-state flow. Best fit decline analysis results in a decline exponent of 1.35 and ultimate reserves of 15.2 Bcf, with a 216-year reserves life (Plot 14, Line M). Due to the stratified, low-permeability nature of the reservoir, decline behaviour is expected to be hyperbolic. The best fit exponent appears to be an unreasonably high exponent (over 1), possibly a result of line-pressure fluctuations occurring during the fit period, or a dual-permeability system not accurately represented by the Arps decline equation. In the absence of substantiation from volumetric data or more detailed reservoir modelling, use of this best fit exponent is not advised.

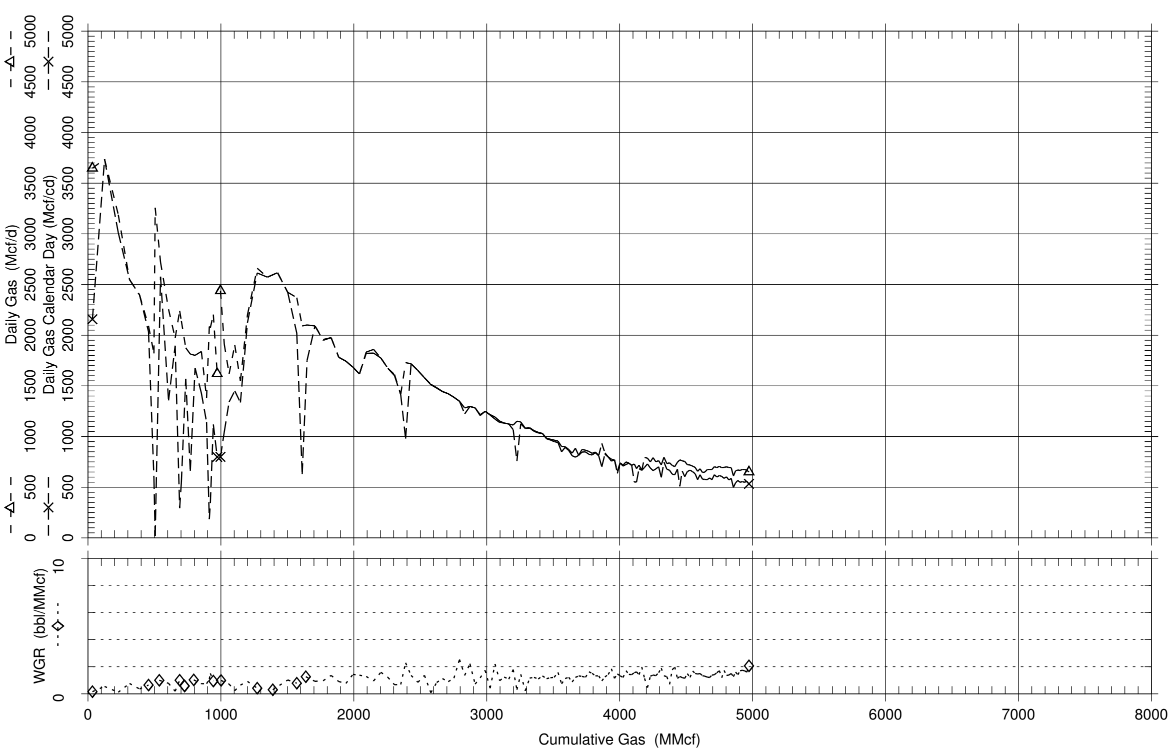
The recommended best estimate exponent for 2P reserves determination is the use of a reasonably high hyperbolic decline exponent that is less than 1. In this case, an exponent of 0.8 is selected based on a review of analogous wells in the area, which yields ultimate reserves of 9.6 Bcf with an 88-year reserves life (Line G). Prior to selecting proved and 3P reserves, reasonable minimum and maximum end points, illustrated on Plot 15, are selected to understand the potential variability of the estimate. In this case, 7.3 Bcf minimum ultimate reserves were determined using a hyperbolic decline exponent of 0.3, while 12.9 Bcf maximum ultimate reserves were determined using an optimistic 1.2 decline exponent. Decline curves calculated using exponents outside this range do not yield reasonable fits to the historical trend.

The recommended proved interpretation uses a 0.6 hyperbolic decline exponent, which yields ultimate reserves of 8.5 Bcf with a 62-year reserves life (Plot 16, Line A). The recommended 3P interpretation uses a harmonic decline exponent, which yields ultimate reserves of 11.0 Bcf with a 126-year reserves life (Plot 16, Line P).

Imposing a 50-year limit on reserves classification, as recommended previously in these guidelines, will reduce ultimate proved reserves to 8.3 Bcf, 2P reserves to 8.7 Bcf, and 3P reserves to 9.0 Bcf. In this case, the potential for downspacing should be reviewed in order to capture pool reserves in a meaningful time period.

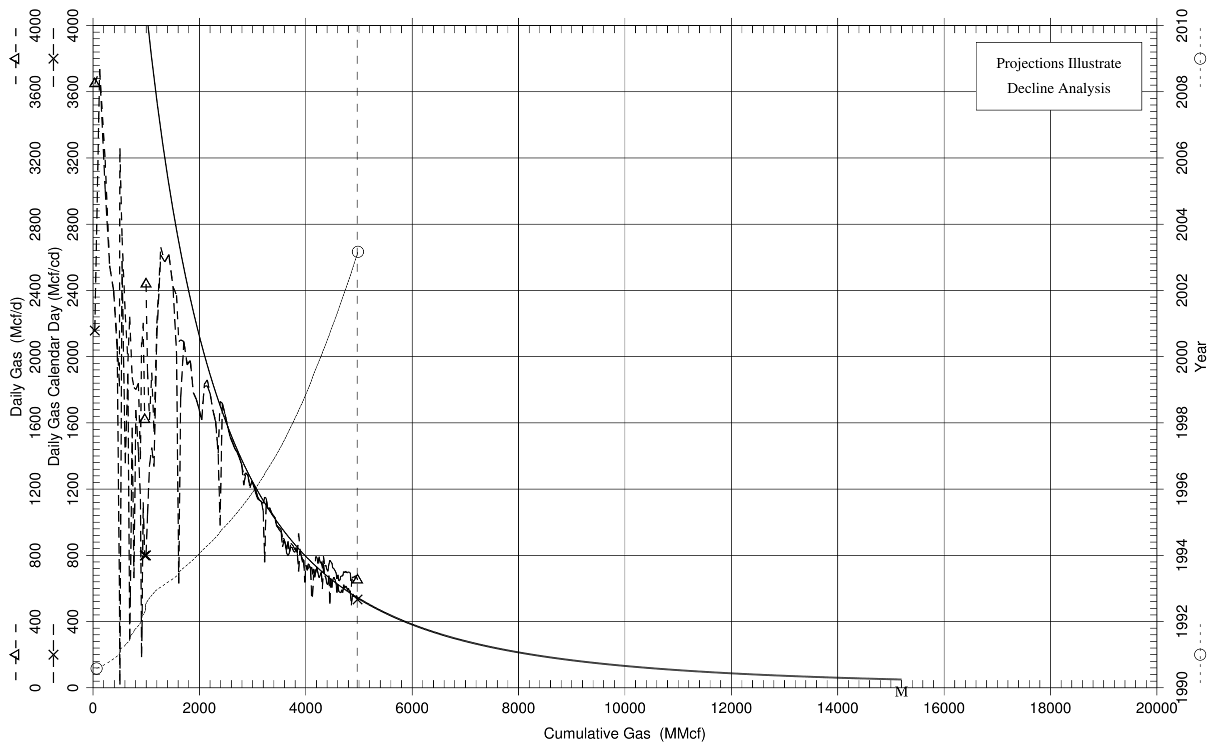
Historical Production
Gas Decline - Example D

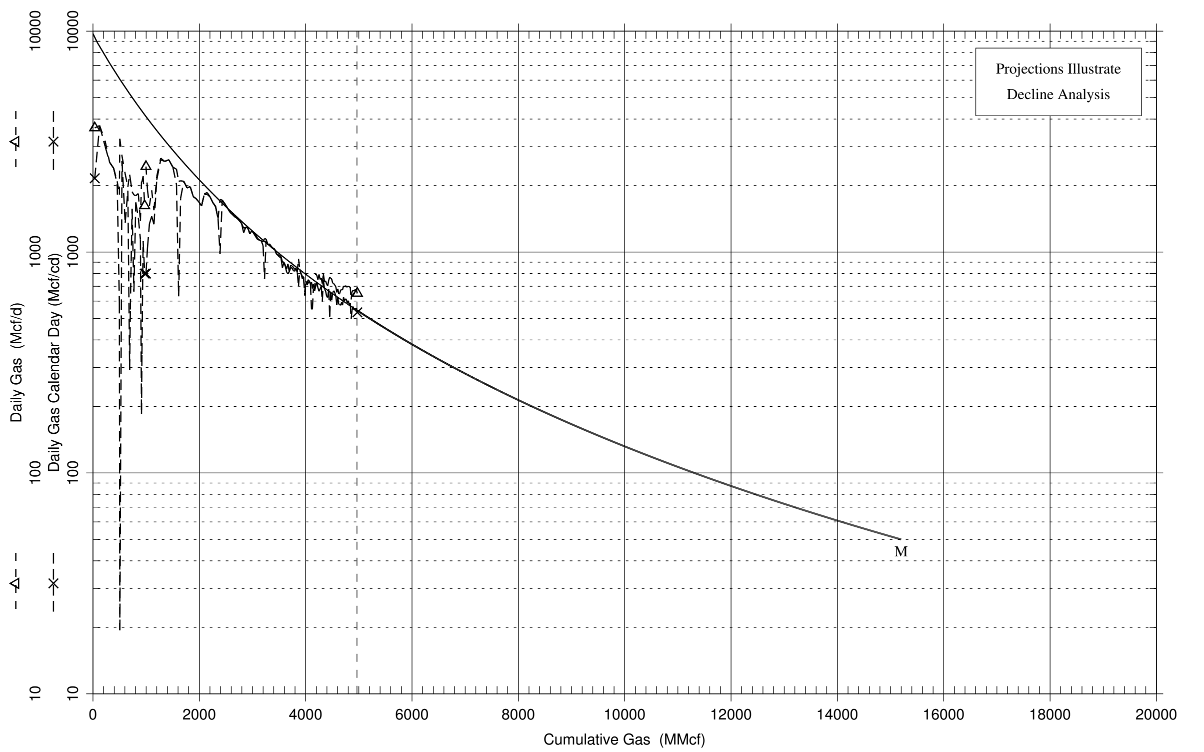




Status Summary		Cumulative Production			Average Production Rates (Last 12 months ending 2003/02/28)								
On Production date :	90/07/12	Gas :	4979.9	MMcf	Gas :	671.7	Mcf/d	558.4	Mcf/cd	WGR :	1.6	bbl/MMcf
Status date :	90/07/12	Oil :	0.0	Mbbl	Oil :	0.0	bbl/d	0.0	bbl/cd	GOR :	0.0	scf/stb
Status : FLOWING GAS		Water :	5.1	Mbbl	On Prod :	303.3	days			WC :	100.0	%

Historical and Forecast Production
Gas Decline - Example D





Decline Analysis Summary @ 2003/02/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Maximum Prd	M	15200	4965	10235	545	50	6.7%	1.35

Average Production Rates (Last 12 months ending 2003/02/28)

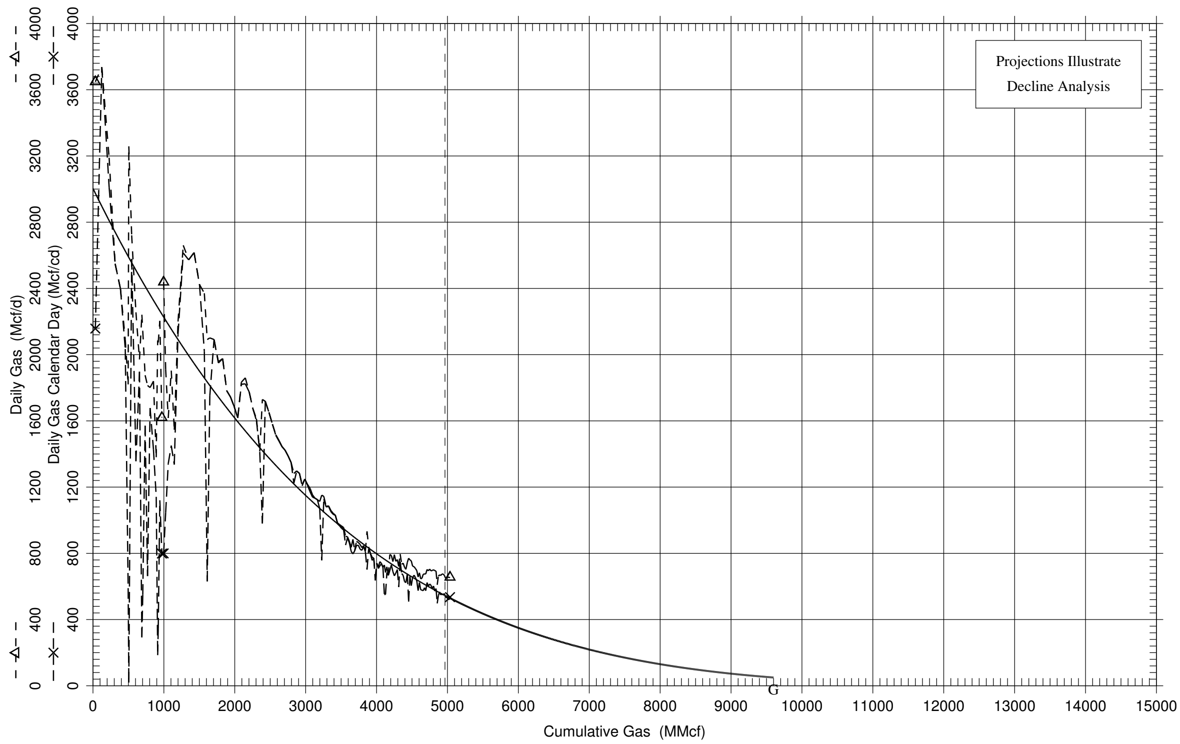
Gas :	671.7 Mcf/d	558.4 Mcf/cd	WGR :	1.6 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	303.3 days		WC :	100.0 %

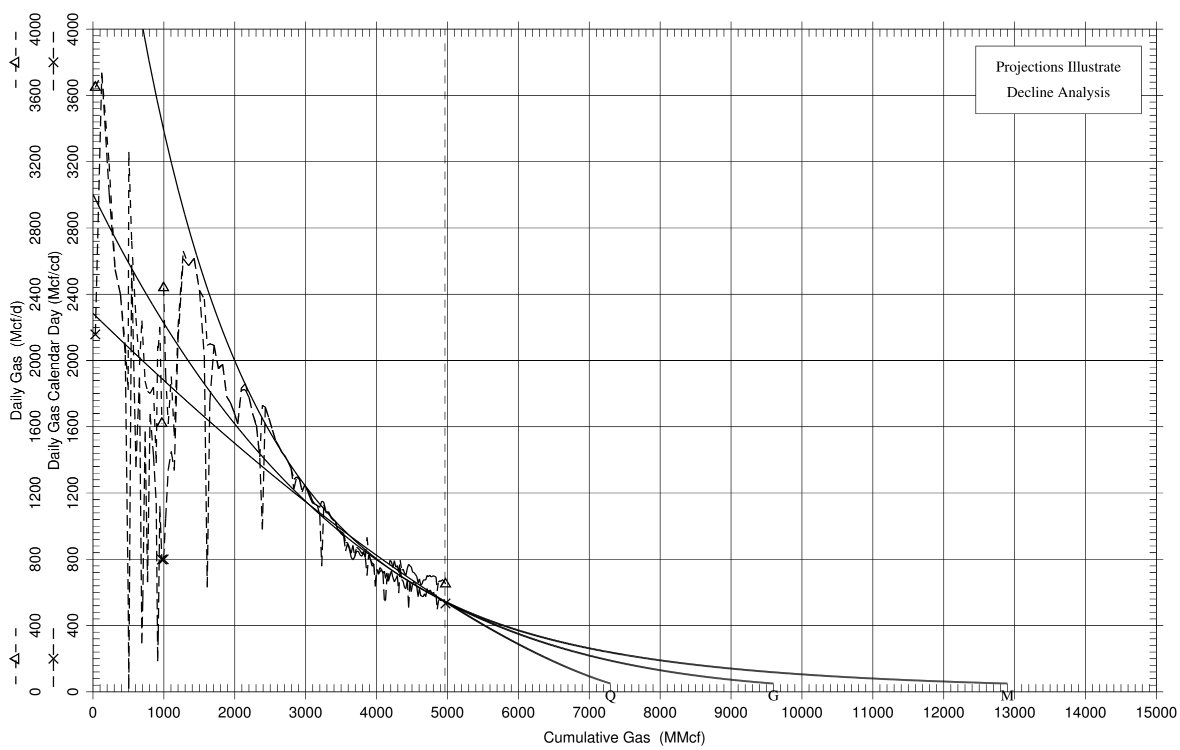
Cumulative Production

Oil :	0.0 Mbbl	Gas :	4979.9 MMcf	Water :	5.1 Mbbl

Plot 14

Historical and Forecast Production
Gas Decline - Example D





Decline Analysis Summary @ 2003/02/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv + Pb Prd	—— G	9600	4965	4635	545	50	7.6%	0.80
Maximum Prd	—— M	12900	4965	7935	545	50	7.1%	1.20
Minimum Prd	—— Q	7300	4965	2335	545	50	9.3%	0.30

Average Production Rates (Last 12 months ending 2003/02/28)

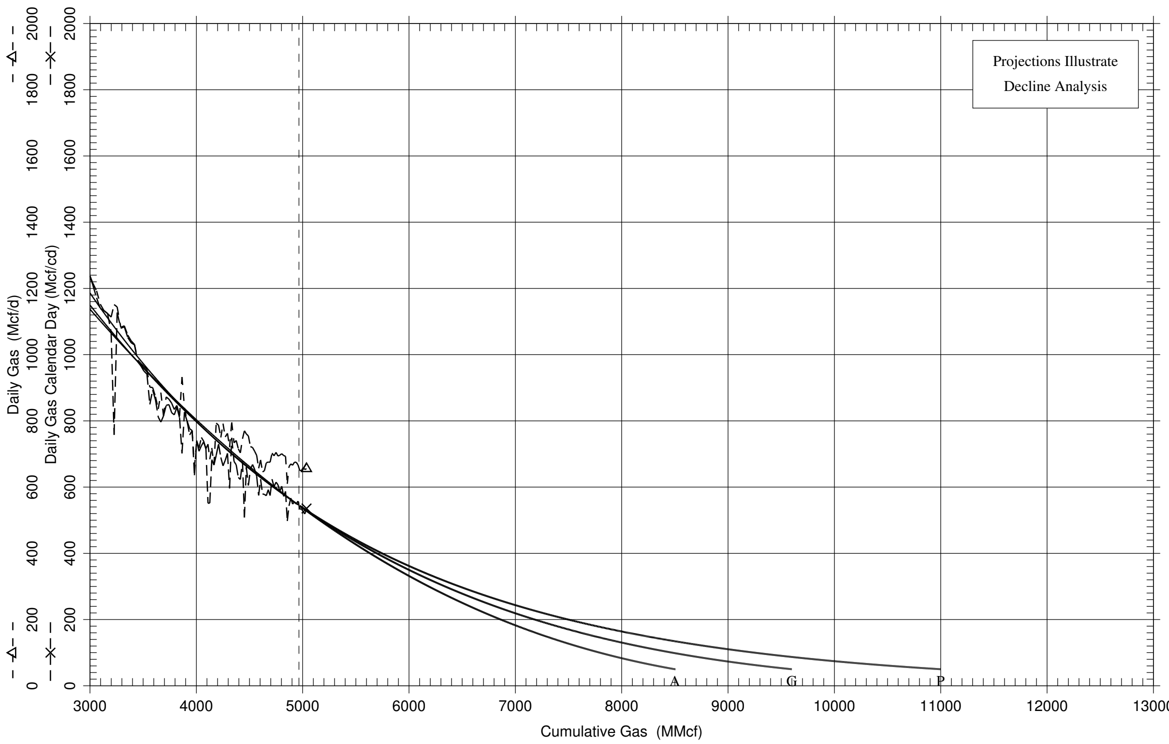
Gas :	671.7 Mcf/d	558.4 Mcf/cd	WGR :	1.6 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	303.3 days		WC :	100.0 %

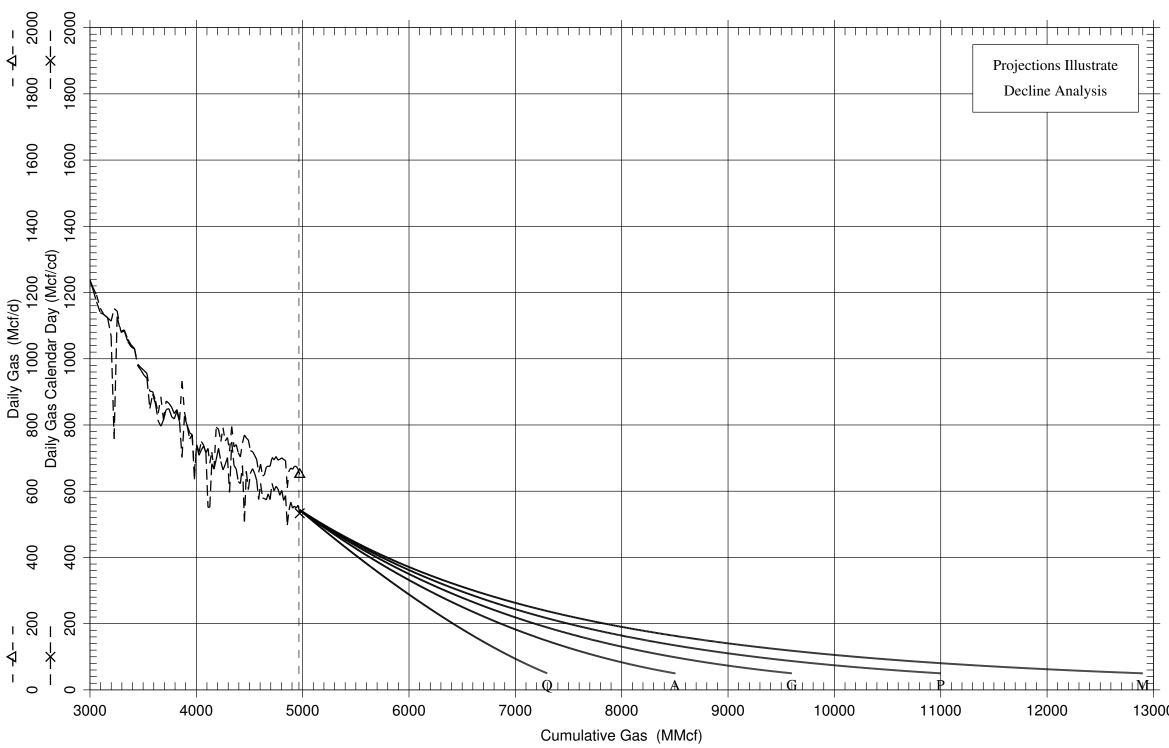
Cumulative Production

Oil : 0.0 Mbbl Gas : 4979.9 MMcf Water : 5.1 Mbbl

Plot 15

Historical and Forecast Production
Gas Decline - Example D





Decline Analysis Summary @ 2003/02/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv Prd	A	8500	4965	3535	545	50	8.1%	0.60
Pv + Pb Prd	G	9600	4965	4635	545	50	7.6%	0.80
Pv + Pb + Poss Prd	P	11000	4965	6035	545	50	7.3%	1.00

Average Production Rates (Last 12 months ending 2003/06/30)

Gas :	657.7 Mcf/d	538.9 Mcf/cd	WGR :	1.6 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	299.0 days		WC :	100.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	5044.4 MMcf	Water :	5.2 Mbbl

Gas Example E

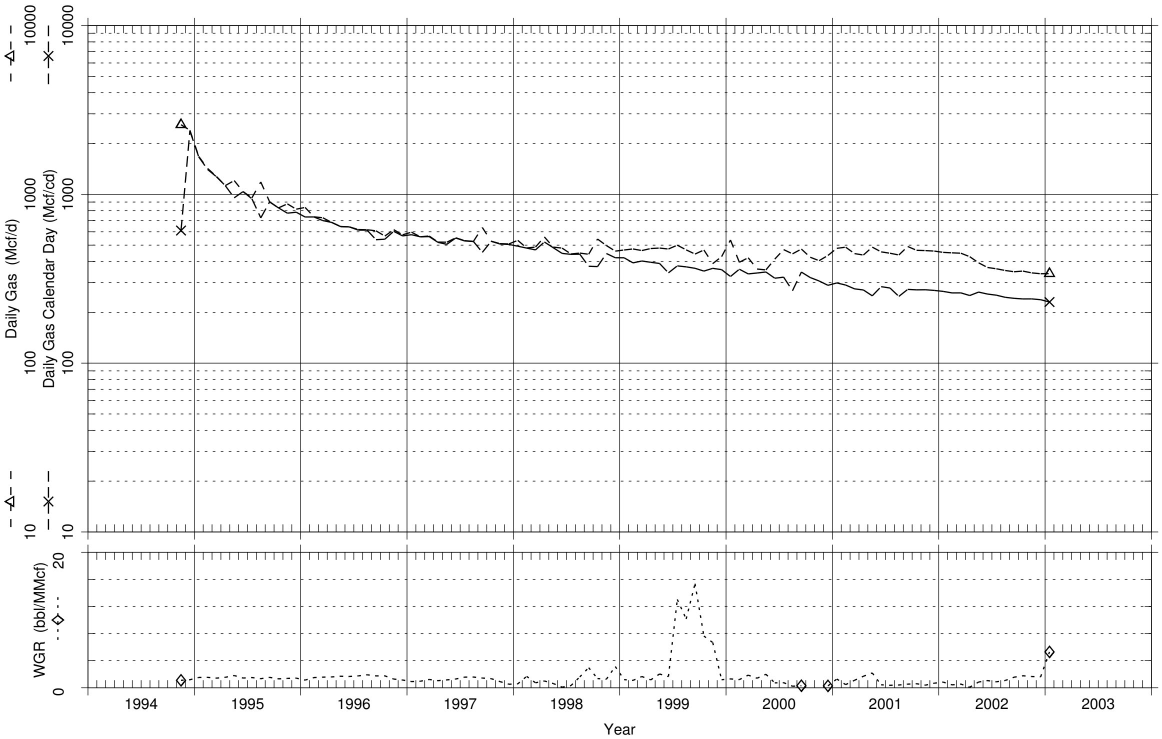
Gas Example E is a well in a low-permeability, moderately stratified gas reservoir (Plot 17). Curve fitting is only performed after cumulative production of 0.9 Bcf, when the well is determined from type curve analysis to be in pseudo-steady-state flow. Reasonable fits can be achieved using a range of hyperbolic exponents.

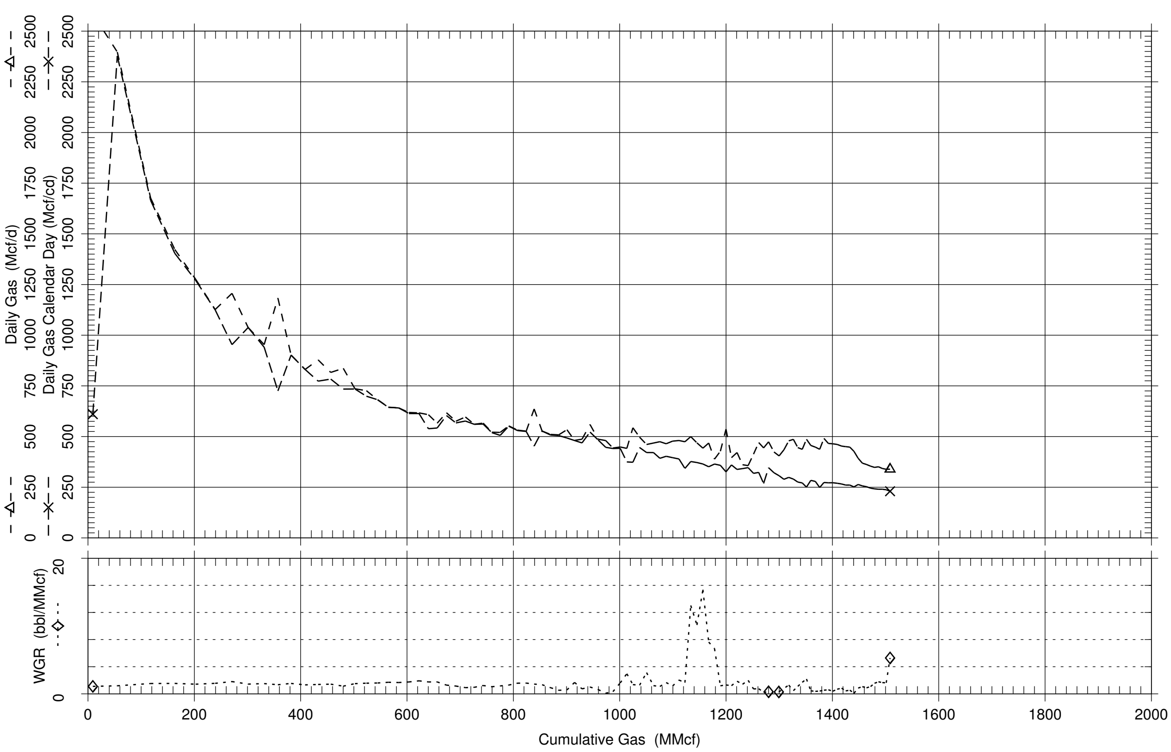
In this case, recommended best estimate interpretation for 2P reserves uses a 0.6 hyperbolic decline based on visual fitting of the data and a review of analogous wells in the area, which yields ultimate reserves of 2.36 Bcf (Plot 18, Line G). Prior to selecting proved and 3P reserves, reasonable minimum and maximum end points, illustrated on Plot 18, are selected to understand the potential variability of the estimate. In this case, 2.09 Bcf minimum ultimate reserves are determined using a hyperbolic decline exponent of 0.2, while 2.74 Bcf maximum ultimate reserves are determined using an optimistic harmonic analysis. Decline curves calculated using exponents outside this range do not yield reasonable fits to the historical trend.

The recommended proved interpretation uses a 0.4 hyperbolic decline exponent, which yields ultimate reserves of 2.19 Bcf (Plot 19, Line A). The recommended 3P interpretation uses a 0.8 hyperbolic decline exponent, which yields ultimate reserves of 2.54 Bcf (Plot 19, Line P).

Decline interpretation was performed on the calendar-day decline trends, as is the recommended practice for low-permeability reservoirs. The well was produced intermittently to prevent liquid loading.

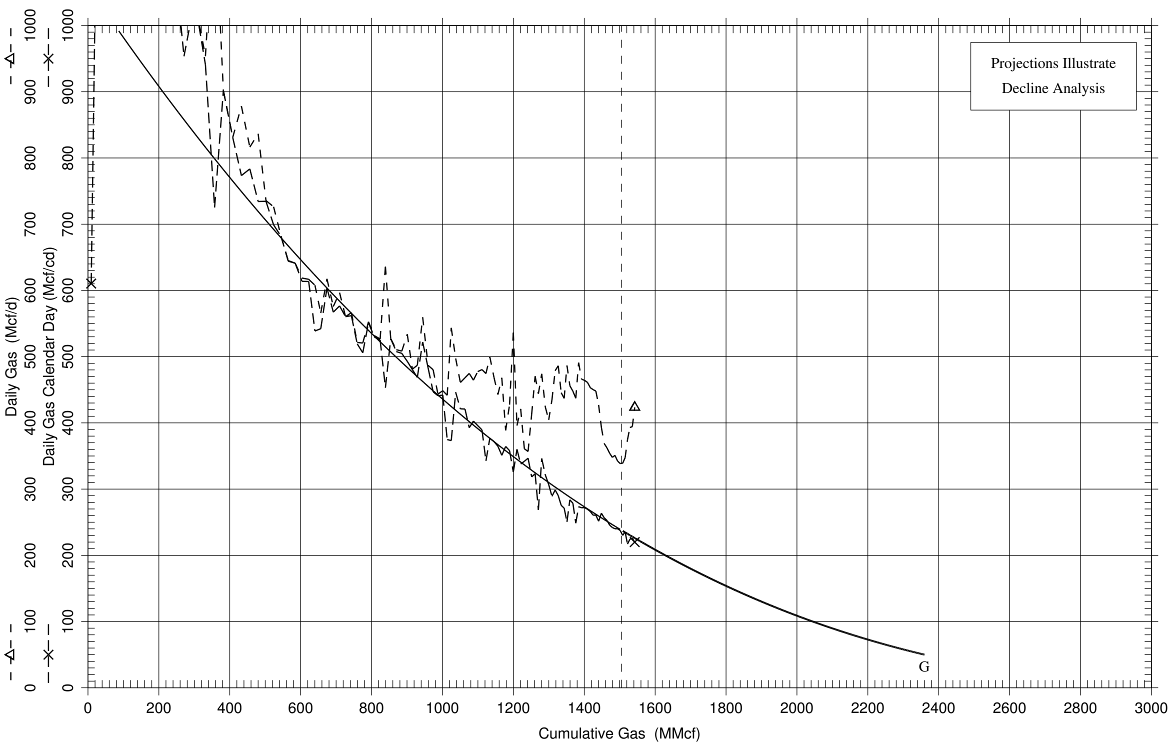
Historical Production
Gas Decline - Example E

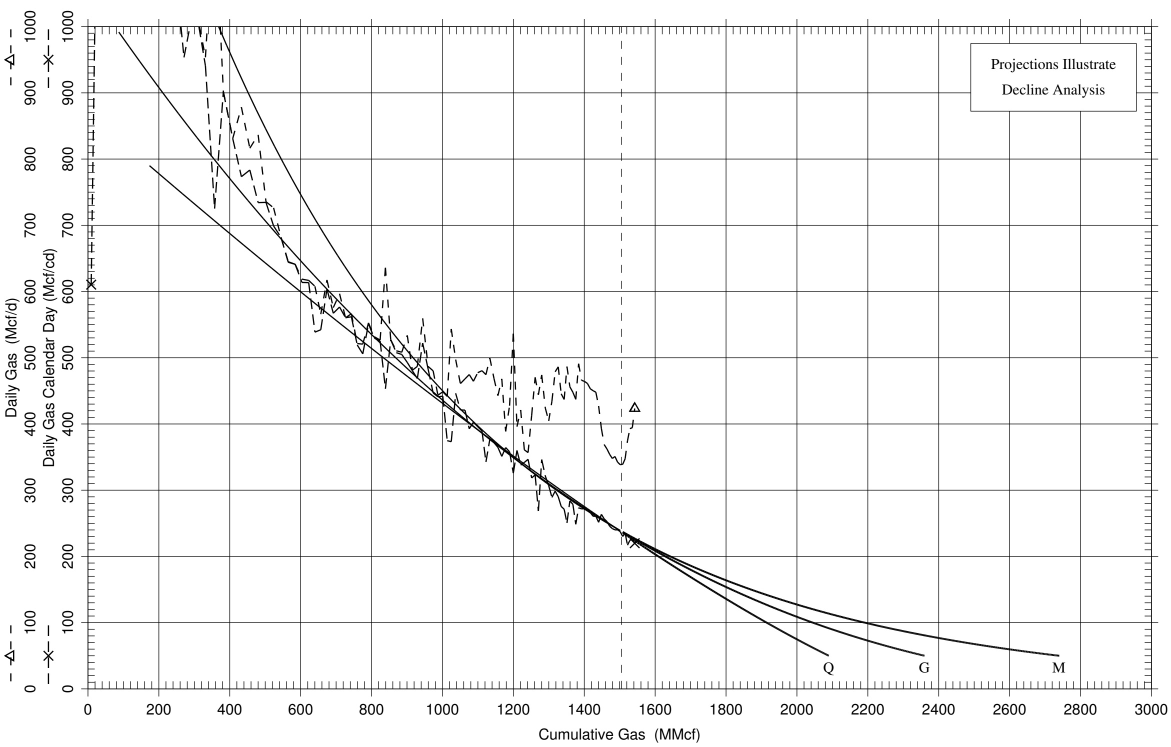




Status Summary		Cumulative Production			Average Production Rates (Last 12 months ending 2003/01/31)							
On Production date :	94/11/22	Gas :	1512.0	MMcf	Gas :	376.9	Mcf/d	248.4	Mcf/cd	WGR :	1.4	bbl/MMcf
Status date :	94/11/16	Oil :	0.0	Mbbl	Oil :	0.0	bbl/d	0.0	bbl/cd	GOR :	0.0	scf/stb
Status : FLOWING GAS		Water :	2.5	Mbbl	On Prod :	242.6	days			WC :	100.0	%

Historical and Forecast Production
Gas Decline - Example E





Decline Analysis Summary @ 2003/01/01

Reserves Classification		Raw Gas Reserves (MMcf) Ultimate	Cum Prd	Remain	Rates (mcf/d) Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	2360	1505	855	238	50	10.8%	0.60
Maximum Prd	M	2740	1505	1235	238	50	9.9%	1.00
Minimum Prd	Q	2090	1505	585	237	50	12.2%	0.20

Average Production Rates (Last 12 months ending 2003/06/30)

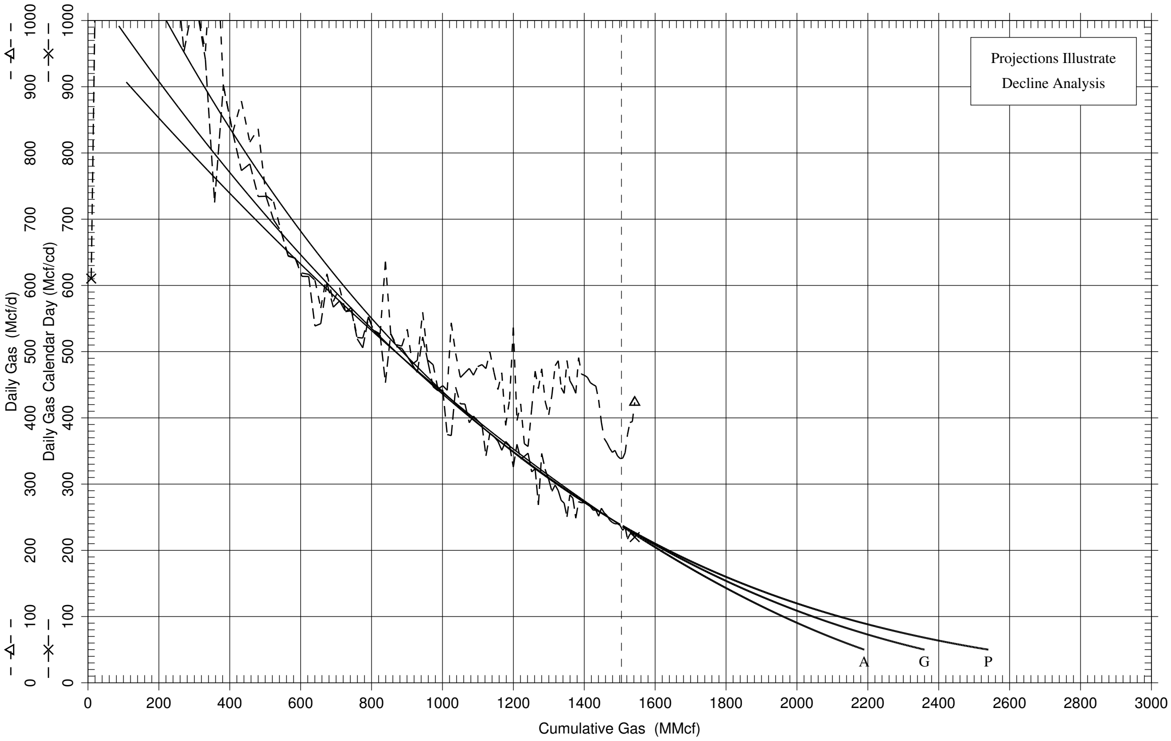
Gas :	364.0 Mcf/d	234.2 Mcf/cd	WGR :	1.8 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	236.4 days		WC :	100.0 %

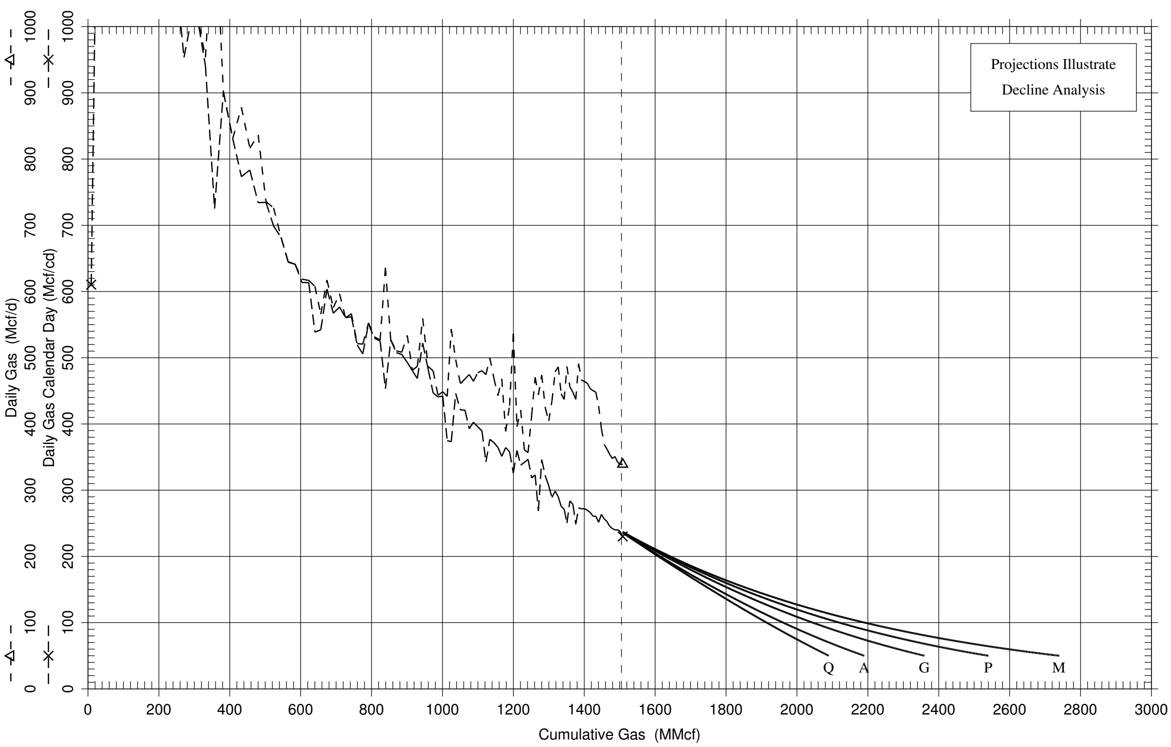
Cumulative Production

Oil :	0.0 Mbbl	Gas :	1545.7 MMcf	Water :	2.5 Mbbl

Plot 18

Historical and Forecast Production
Gas Decline - Example E





Decline Analysis Summary @ 2003/01/01

Reserves Classification		Raw Gas Reserves (MMcf)			Rates (mcf/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv Prd	—— A	2190	1505	685	237	50	11.7%	0.40
Pv + Pb Prd	—— G	2360	1505	855	238	50	10.8%	0.60
Pv + Pb + Poss Prd	—— P	2540	1505	1035	238	50	10.2%	0.80

Average Production Rates (Last 12 months ending 2003/06/30)

Gas :	364.0 Mcf/d	234.2 Mcf/cd	WGR :	1.8 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	236.4 days		WC :	100.0 %

Cumulative Production

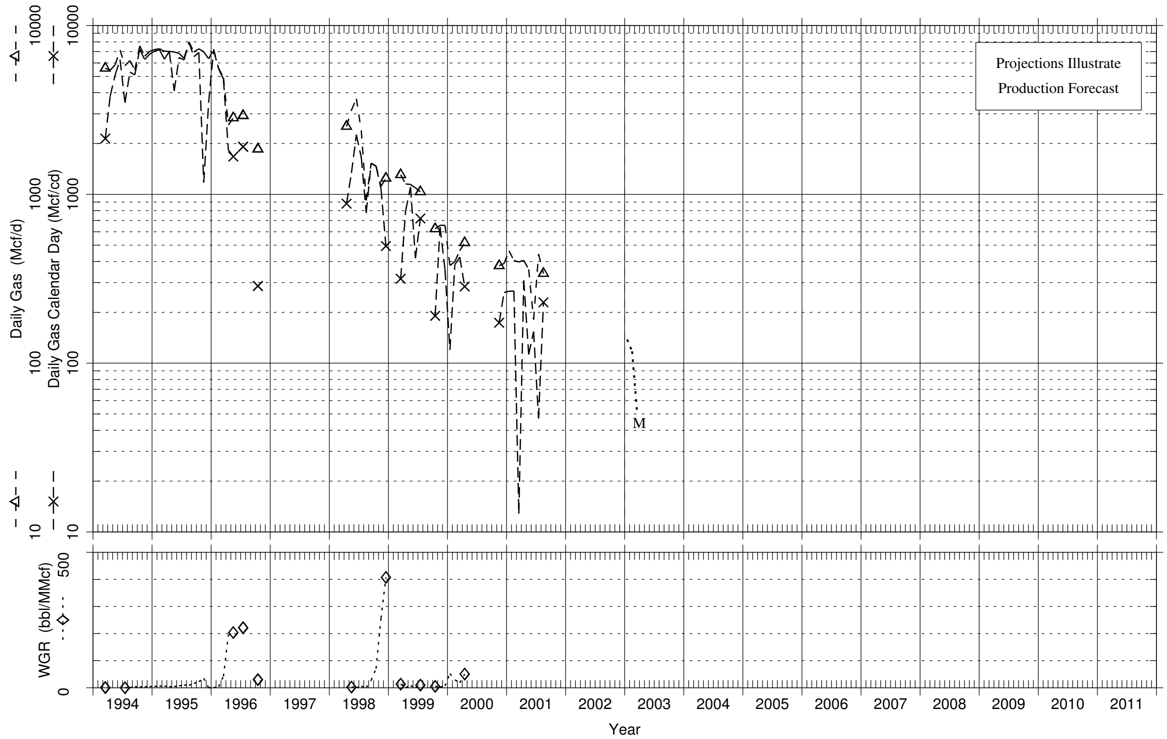
Oil :	0.0 Mbbl	Gas :	1545.7 MMcf	Water :	2.5 Mbbl

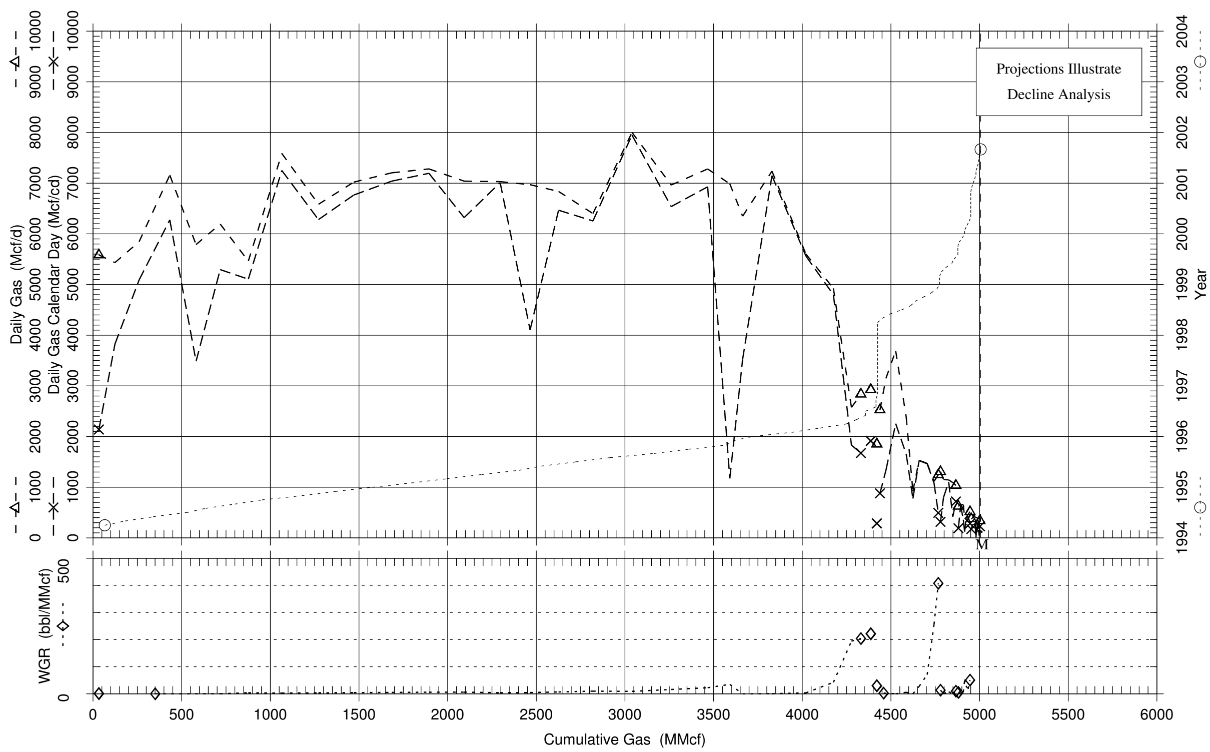
Plot 19

Gas Example F

Gas Example F is a well in a pool with an active water drive (Plot 20). Decline analysis cannot be used for most of the producing life of the pool, because pressure support suppresses the production decline. Production decline does not commence until the onset of water production, at which time decline is very steep. Volumetric or analogy methods must be used to analyze wells of this nature until the onset of production decline. Once production decline commences, volumetric data is of secondary importance.

Historical and Forecast Production
Gas Decline - Example F





Decline Analysis Summary @ 2003/01/01

Reserves Classification	Raw Gas Reserves (MMcf) Ultimate	Cum Prd	Remain	Rates (mcf/d) Initial	Final	Decline Initial	Expont
Maximum Prd —— M	5015	5006	9	150	100	86.3%	0.00

Average Production Rates (Last 12 months ending 2001/08/31)

Gas :	376.2 Mcf/d	183.5 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	154.3 days		WC :	0.0 %

Cumulative Production

Oil : 0.0 Mbbl Gas : 5005.8 MMcf Water : 85.9 Mbbl

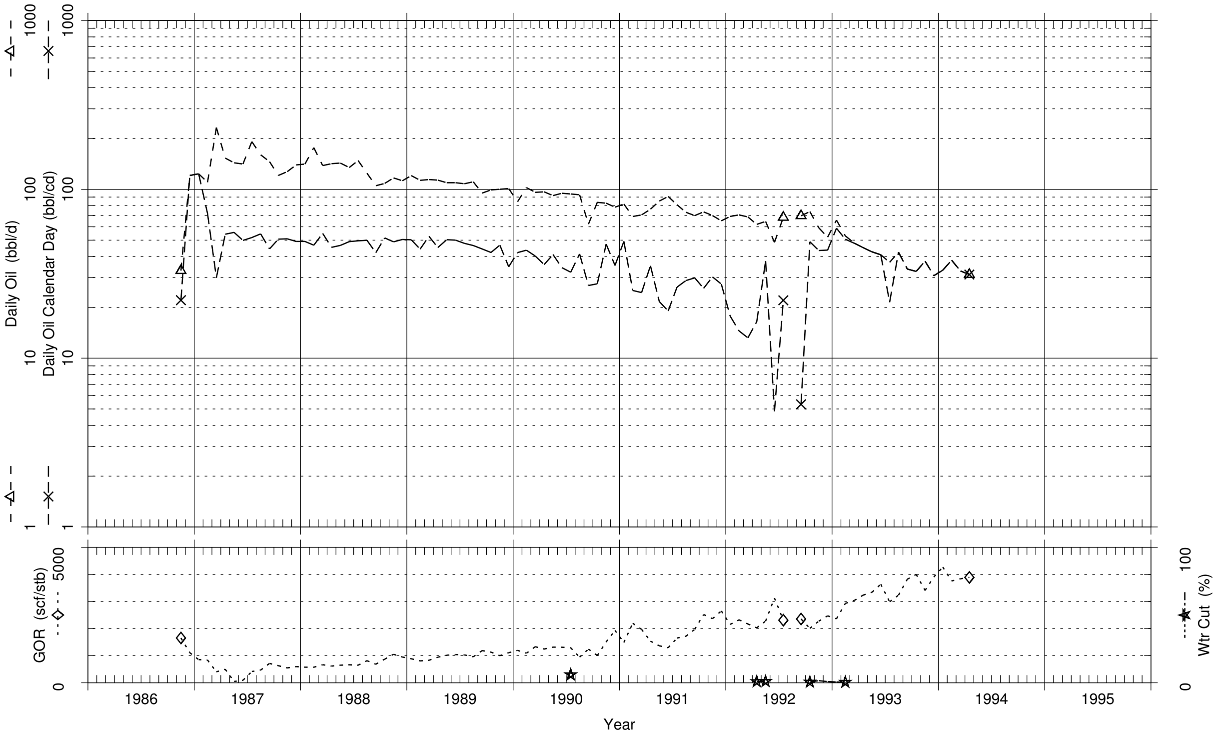
Plot 20

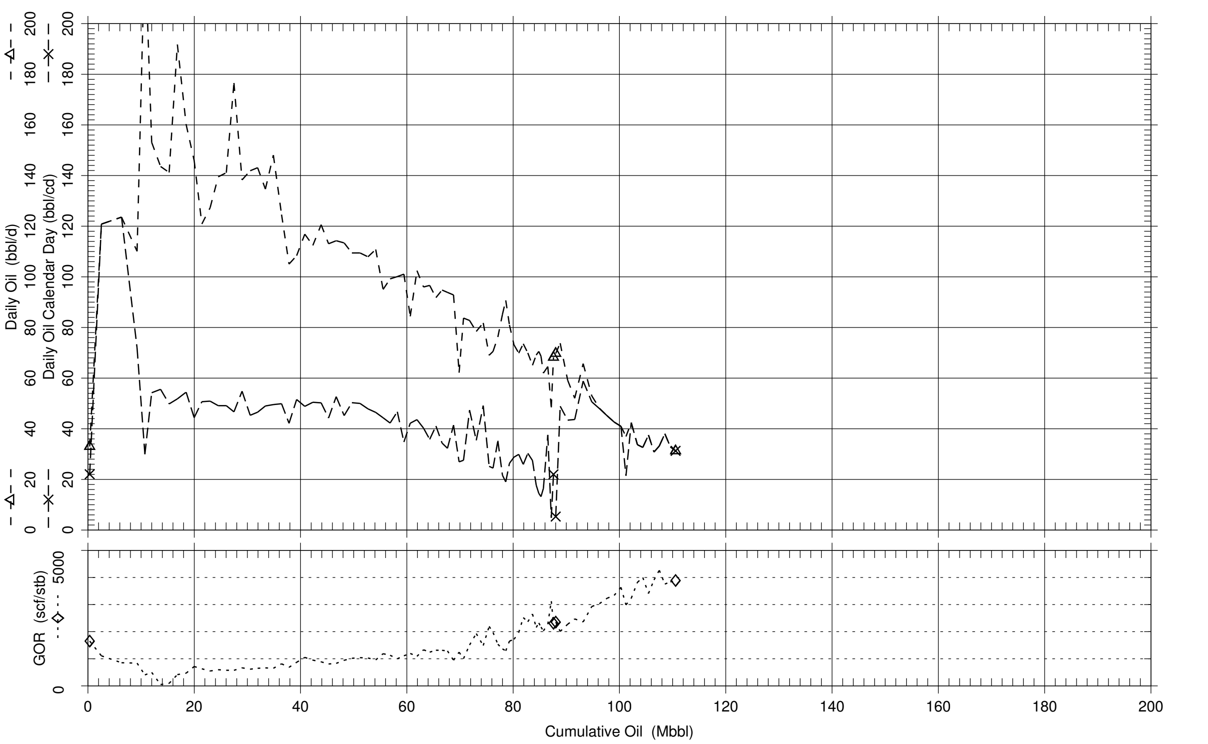
Oil Example A

Oil Example A is a well in a moderate-permeability, unstratified solution-gas drive oil pool with production history to April 1994, as illustrated on Plot 21. Production from the well was originally constrained by GOR penalty, which was removed in late 1992. Reasonable visual fits can be achieved using a range of hyperbolic exponents between 0 and 0.4. This range is in line with the range of decline exponents of 0 to 0.33 for single-layer oil reservoirs producing below bubble point, as derived by Fetkovich et al. (1996). The recommended best estimate interpretation for 2P reserves uses a 0.2 hyperbolic decline (midpoint of range) based on a review of other analogous wells in the area, which yields ultimate reserves of 137 Mstb (Plot 22, Line G). Minimum and maximum reserves of 130 Mstb and 145 Mstb are established using exponents of 0 and 0.4, respectively (Plot 22, Lines Q and M). The recommended proved interpretation uses a 0.1 hyperbolic decline exponent, which yields ultimate reserves of 133 Mstb (Plot 23, Line A), while the recommended 3P interpretation uses a 0.3 hyperbolic decline exponent, which yields ultimate reserves of 141 Mstb (Plot 23, Line P).

Actual results to mid 1997 exceeded the proved forecast and followed the 2P forecast. Results thereafter exceeded both forecasts because of a stimulation treatment performed on the well. Prior to actual results, the effect of a well stimulation is difficult to determine from curve-fit decline analysis alone. Type curve decline analysis is sometimes used to quantify wellbore damage and potential improvement.

Historical Production
Oil Decline Example A



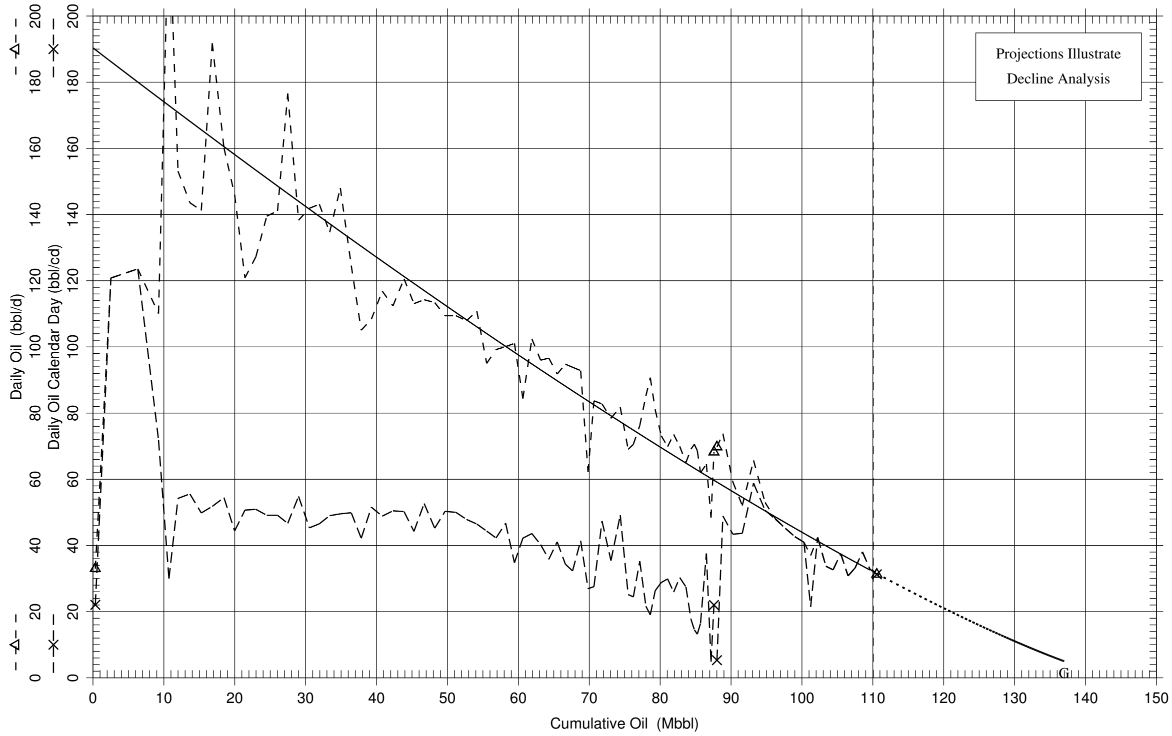


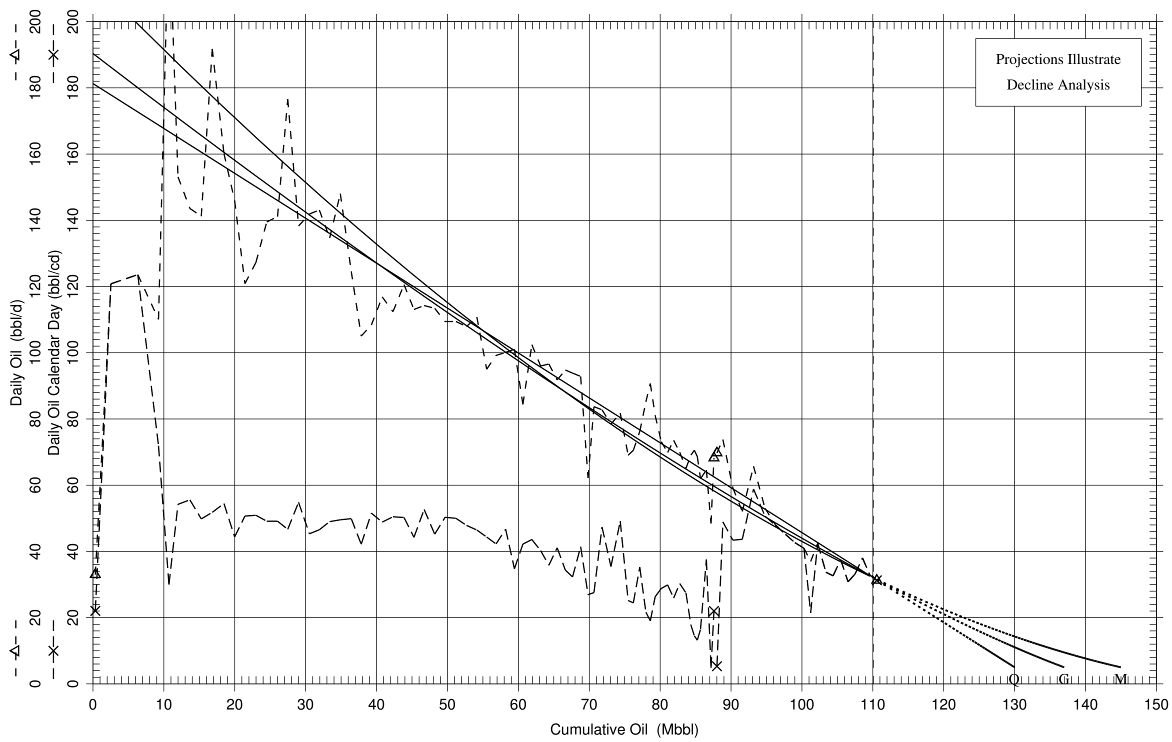
Status Summary	
On Production date :	86/11/09
Status date :	86/11/01
Status : PUMPING OIL	

Cumulative Production		
Gas :	166.2	MMcf
Oil :	111.0	Mbbl
Water :	0.1	Mbbl

Average Production Rates (Last 12 months ending 1994/04/30)								
Gas :	131.6	Mcf/d	127.7	Mcf/cd	WGR :	0.0	bbl/MMcf
Oil :	36.1	bbl/d	34.8	bbl/cd	GOR :	3669.7	scf/stb
On Prod :	352.0	days			WC :	0.0	%

Historical and Forecast Production
Oil Decline Example A





Decline Analysis Summary @ 1994/04/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Rates (bbl/d) Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	137	110	27	32	5	33.2%	0.20
Maximum Prd	M	145	110	35	32	5	29.5%	0.40
Minimum Prd	Q	130	110	20	32	5	39.0%	0.00

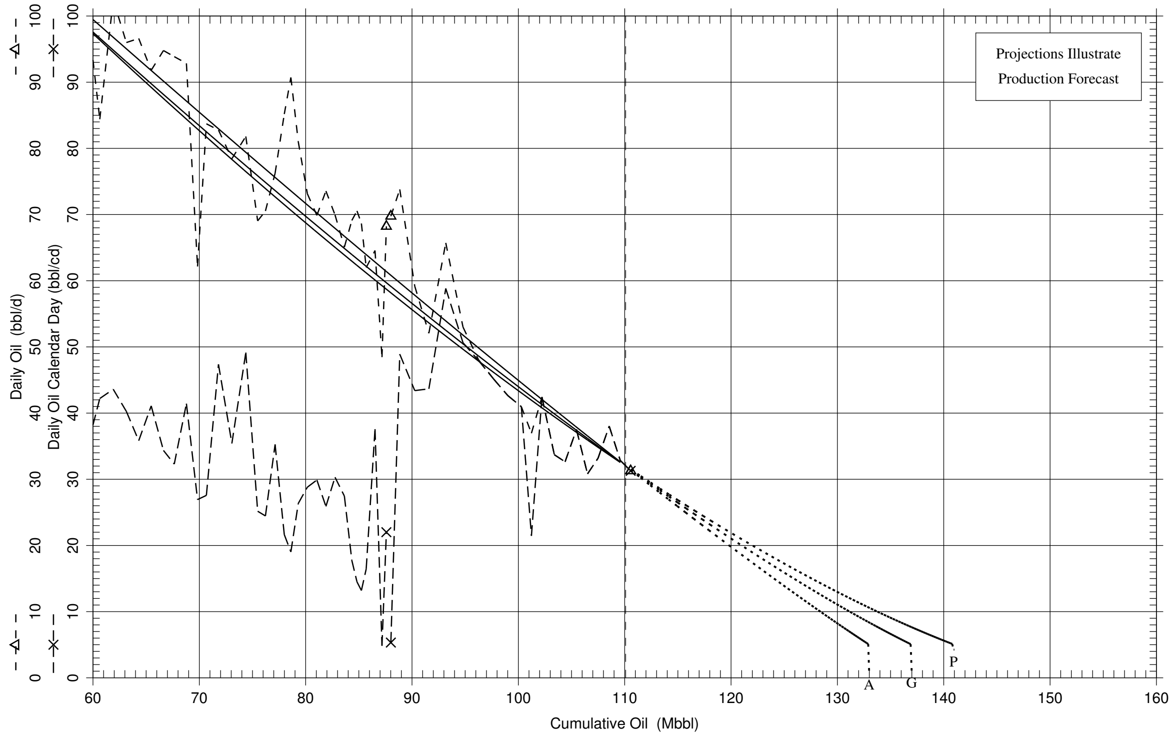
Average Production Rates (Last 12 months ending 1994/04/30)

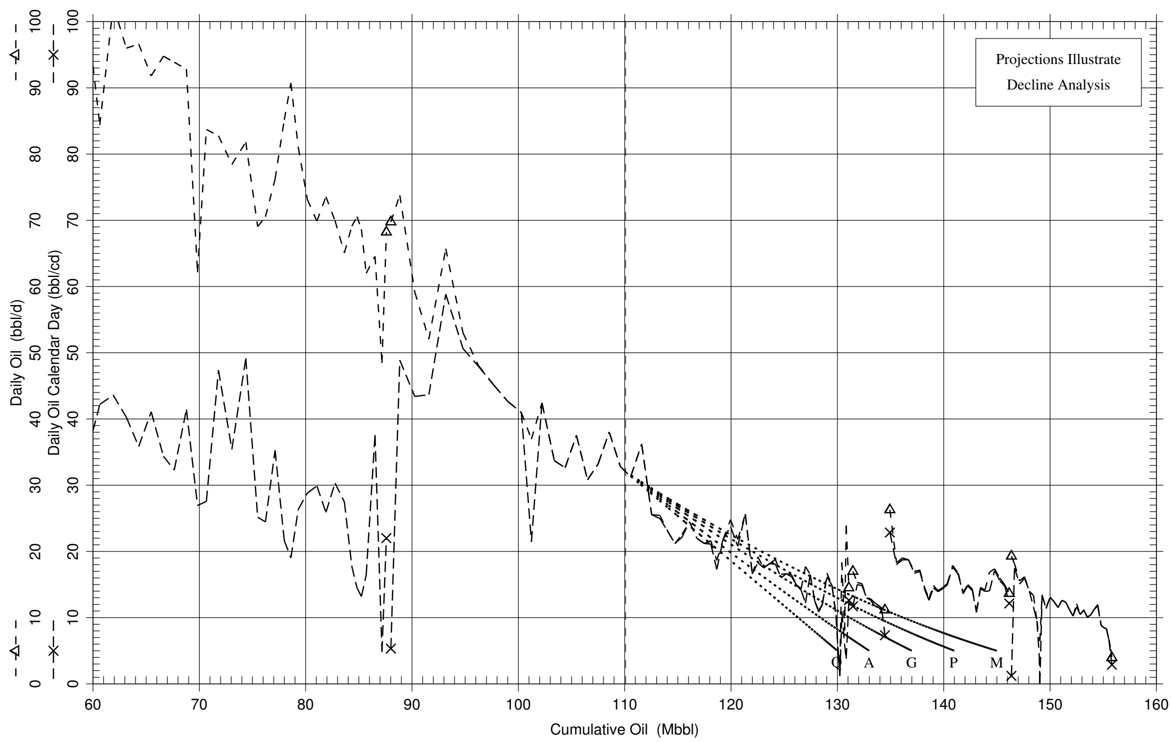
Gas :	131.6 Mcf/d	127.7 Mcf/cd	WGR :	0.0	bbl/MMcf
Oil :	36.1 bbl/d	34.8 bbl/cd	GOR :	3669.7	scf/stb
On Prod :	352.0 days		WC :	0.0	%

Cumulative Production

Oil :	111.0 Mbbl	Gas :	166.2 MMcf	Water :	0.1 Mbbl

Historical and Forecast Production
Oil Decline Example A





Reserves Summary @ 1994/04/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Reserves Method(s)
Pv Prd	—— A	133	110	23	Decline
Pv + Pb Prd	—— G	137	110	27	Decline
Pv + Pb + Poss Prd	—— P	141	110	31	Decline

Average Production Rates (Last 12 months ending 1994/04/30)

Gas :	131.6 Mcf/d	127.7 Mcf/cd	WGR :	0.0	bbl/MMcf
Oil :	36.1 bbl/d	34.8 bbl/cd	GOR :	3669.7	scf/stb
On Prod :	352.0 days		WC :	0.0	%

Cumulative Production

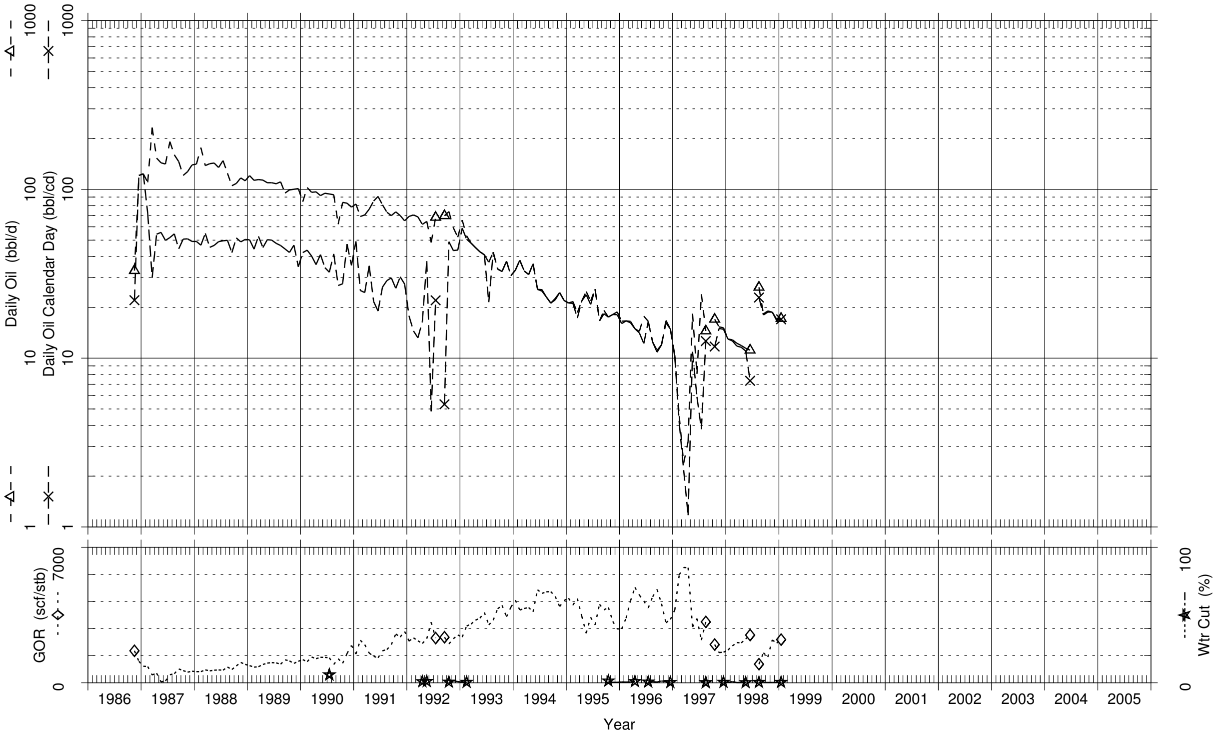
Oil :	111.0 Mbbl	Gas :	166.2 MMcf	Water :	0.1 Mbbl

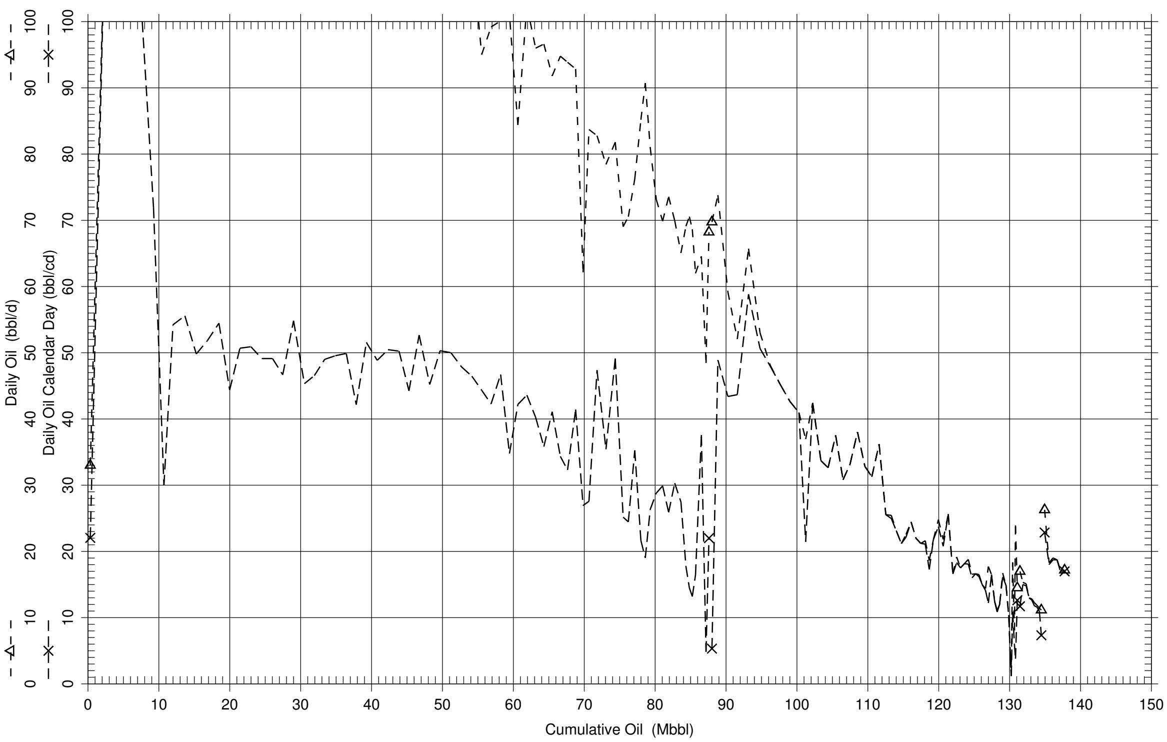
Oil Example B

Oil Example B is a well in a moderate-permeability, unstratified solution-gas drive oil pool with production history to January 1999, as illustrated on Plot 24 (Same as Example A, only later in life). A workover performed in mid 1998 on the well to remove wellbore damage successfully increased productivity. Because of the short duration of production decline after the workover, judgements must be made regarding expected future performance. The recommended best estimate interpretation for 2P reserves uses a 0.2 hyperbolic decline along with a match to previous producing day trends, as illustrated on Plot 25, Line G, and approximately parallels the latest pre-stimulation decline trend. This yields ultimate reserves of 153 Mstb. The interpretation assumes that the original producing day trend was undamaged and that the current post-stimulation behaviour will be restored to this trend. Minimum reserves of 142 Mstb (Plot 25, Line Q) were determined using the reserves forecast from the decline trend prior to the workover. This assumes no incremental reserves from the workover. Maximum reserves of 165 Mstb (Plot 25, Line M) are estimated using a higher decline exponent of 0.4 and a flatter decline trend. The recommended proved reserves assignment of 147 Mstb (Plot 26, Line A) is derived using a value midway between the minimum and 2P case. The recommended 3P reserves of 158 Mstb are estimated using a value midway between the 2P and maximum case (Plot 26, Line P).

Actual results to date depicted on Plot 26 exceed the 2P forecast and generally follow the maximum forecast. This illustrates the difficulty in predicting performance of new workovers. If production rate after a workover has not stabilized, performance predictions should be made using the expected stabilized rate.

Historical Production
Oil Decline - Example B



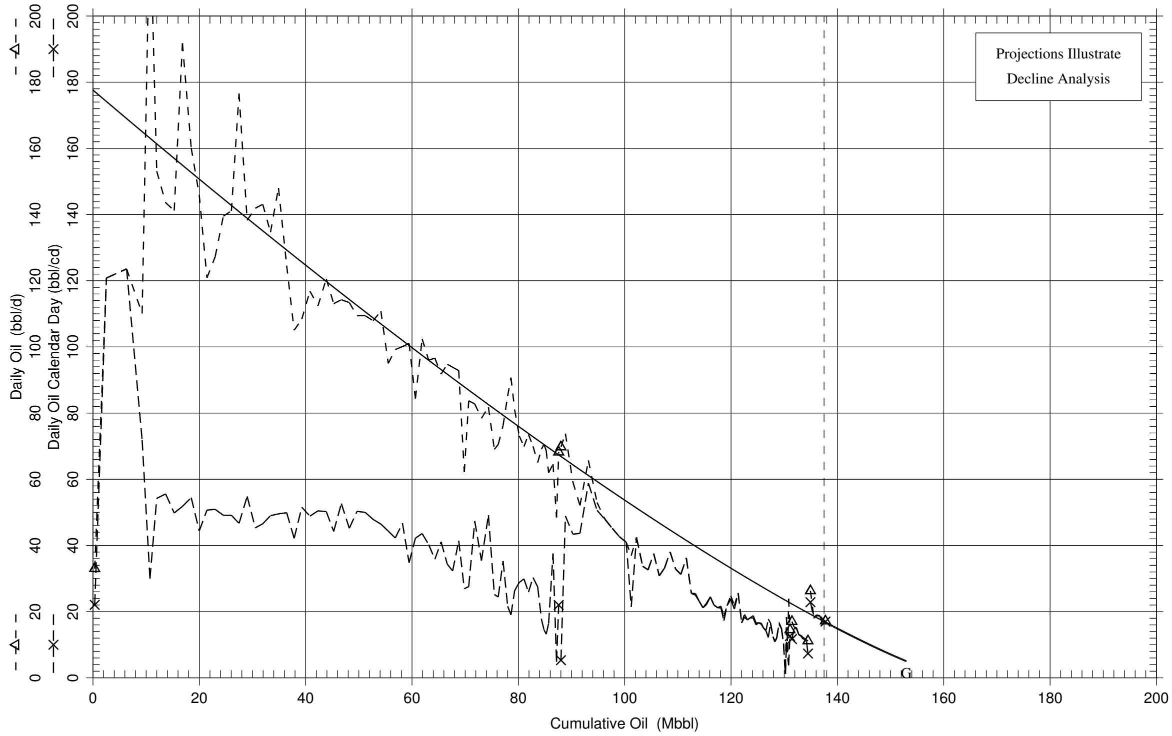


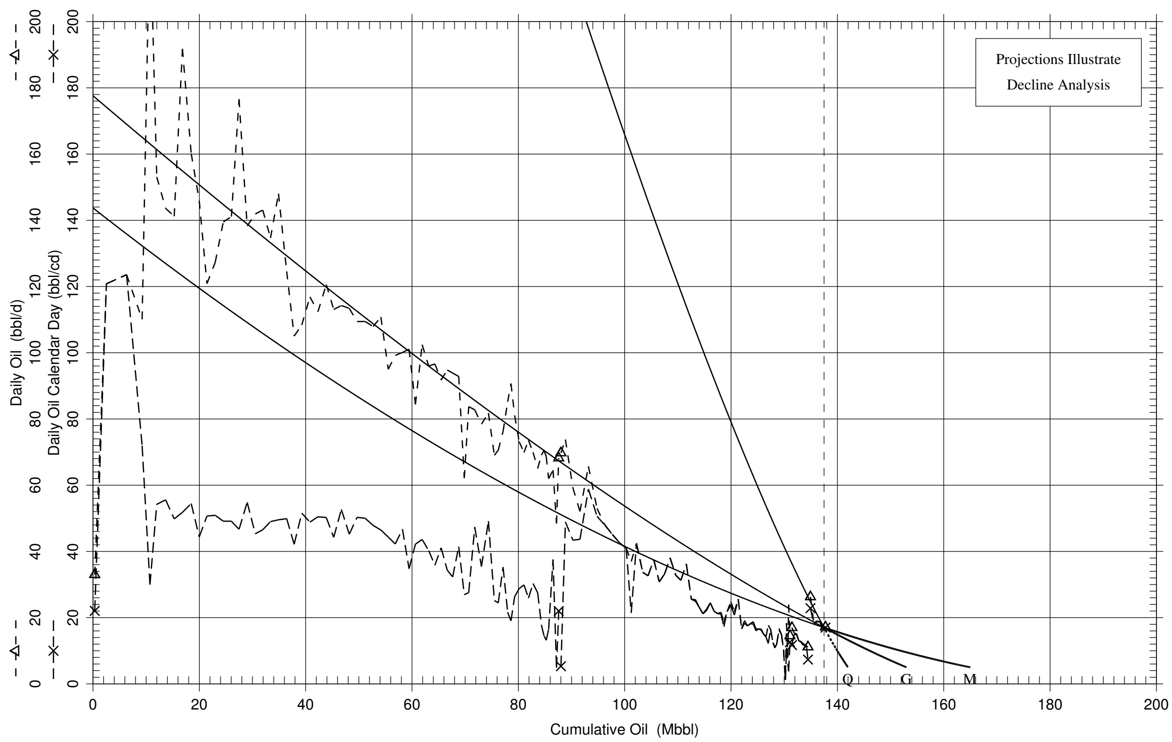
Status Summary	
On Production date :	86/11/09
Status date :	86/11/01
Status : PUMPING OIL	

Cumulative Production		
Gas :	256.7	MMcf
Oil :	138.0	Mbbl
Water :	0.2	Mbbl

Average Production Rates (Last 12 months ending 1999/01/31)							
Gas :	29.2	Mcf/d	27.6	Mcf/cd	WGR :	1.6	bbl/MMcf
Oil :	16.0	bbl/d	15.1	bbl/cd	GOR :	1823.6	scf/stb
On Prod :	314.5	days			WC :	0.3	%

Historical and Forecast Production
Oil Decline - Example B





Decline Analysis Summary @ 1999/01/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Rates (bbl/d) Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	153	137	16	17	5	26.1%	0.20
Maximum Prd	M	165	137	28	17	5	17.2%	0.40
Minimum Prd	Q	142	137	5	17	5	62.2%	0.20

Average Production Rates (Last 12 months ending 1999/01/31)

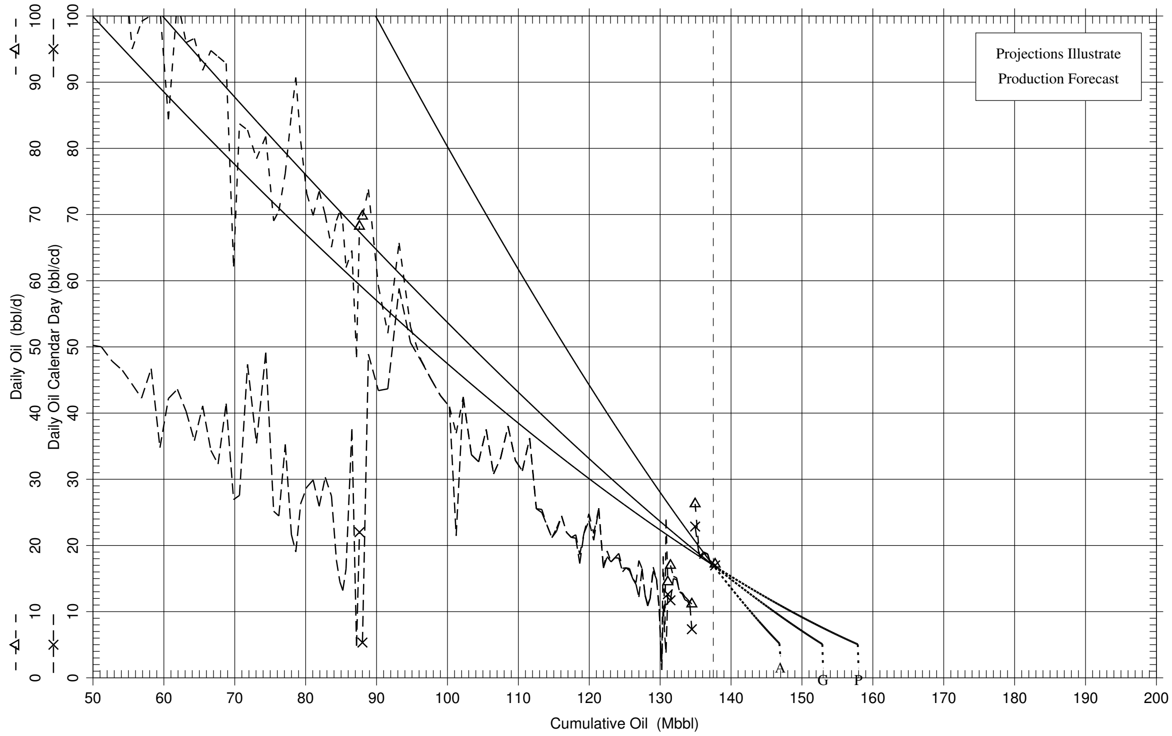
Gas :	29.2 Mcf/d	27.6 Mcf/cd	WGR :	1.6 bbl/MMcf
Oil :	16.0 bbl/d	15.1 bbl/cd	GOR :	1823.6 scf/stb
On Prod :	314.5 days		WC :	0.3 %

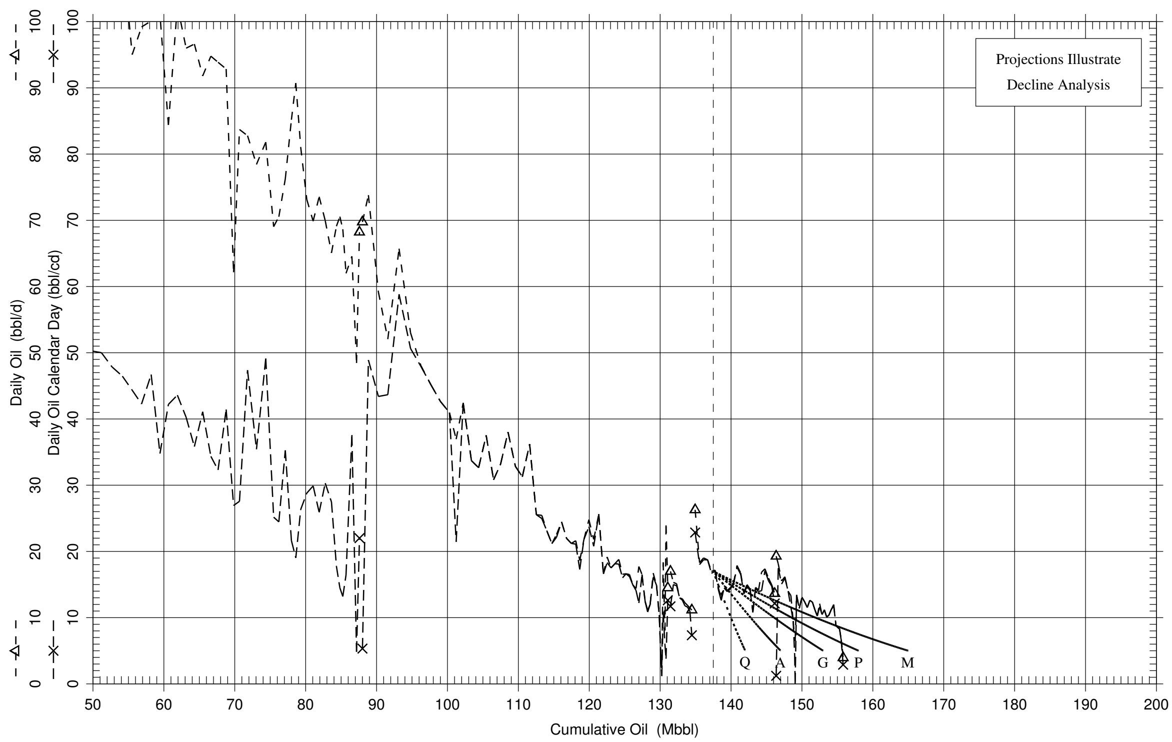
Cumulative Production

Oil :	138.0 Mbbl	Gas :	256.7 MMcf	Water :	0.2 Mbbl

Plot 25

Historical and Forecast Production
Oil Decline - Example B





Reserves Summary @ 1999/01/01

Reserves Classification		Ultimate	Cum Prd	Remain	Reserves Method(s)
		Reserves (Mbbl)			
Pv Prd	A	147	137	10	Decline
Pv + Pb Prd	G	153	137	16	Decline
Pv + Pb + Poss Prd	P	158	137	21	Decline

Average Production Rates (Last 12 months ending 1999/01/31)

Gas :	29.2	Mcf/d	27.6	Mcf/cd	WGR :	1.6	bbl/MMcf
Oil :	16.0	bbl/d	15.1	bbl/cd	GOR :	1823.6	scf/stb
On Prod :	314.5	days			WC :	0.3	%

Cumulative Production

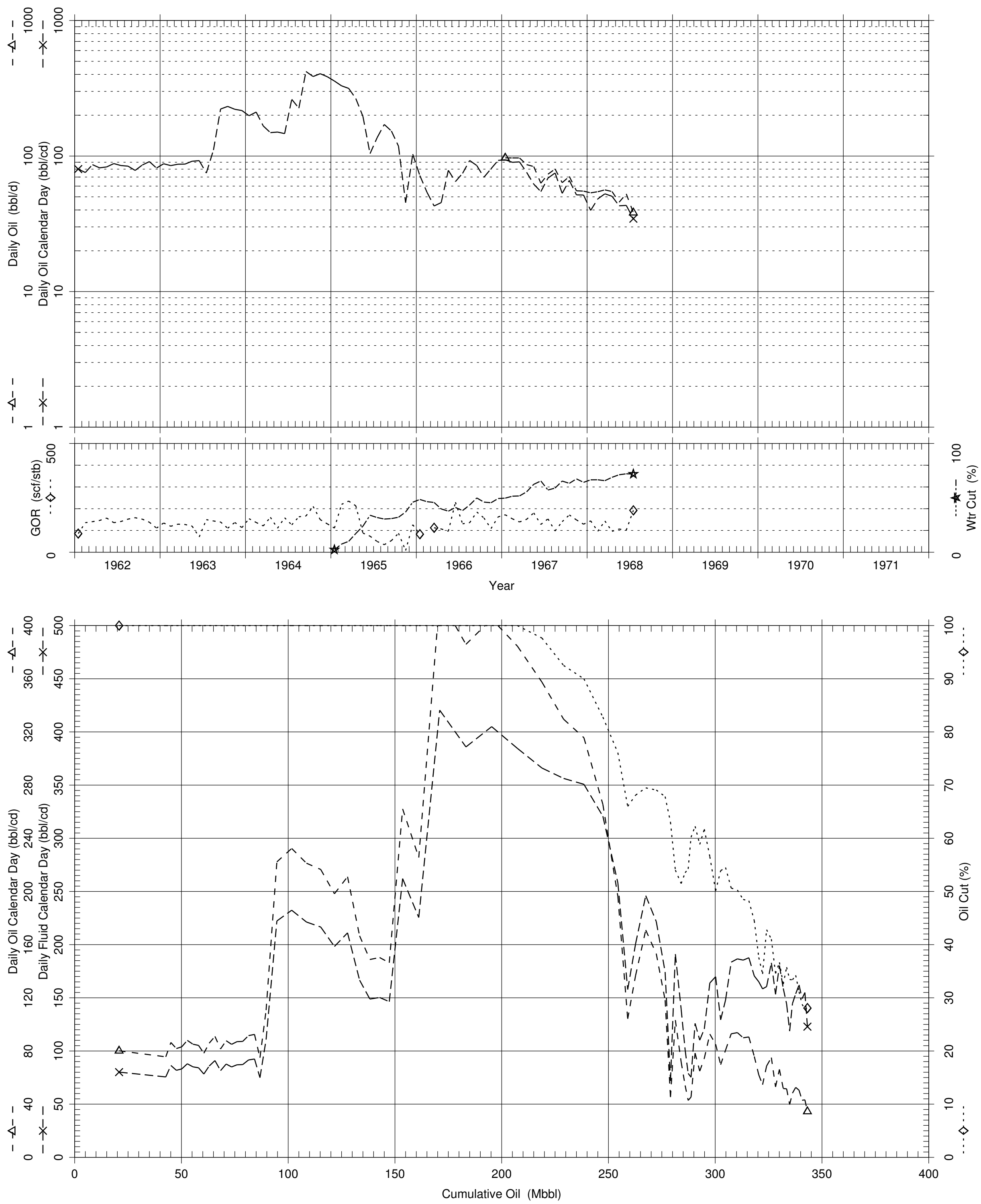
Oil :	138.0 Mbbl	Gas :	256.7 MMcf	Water :	0.2 Mbbl

Oil Example C

Oil Example C is a well in a moderate-permeability, unstratified, pattern waterflooded water-wet reservoir. Production history to July 1968 is depicted on Plot 27. As there does not appear to be any hyperbolic bending of the oil-rate or oil-cut curves, consistent with this type of reservoir, the recommended interpretation for 2P reserves uses an exponential decline, which yields ultimate reserves of 377 Mstb. Both oil-rate and oil-cut trends were examined in determining the estimate, as depicted on Plots 28 and 29, respectively, Line G. However, the oil-cut trends appear more consistent. An oil rate economic limit of 8 bopd is used (based on a review of operating costs), which corresponds to a 5.44 percent oil-cut limit. Minimum and maximum reserves of 364 Mstb and 388 Mstb, respectively, are estimated. The minimum estimate reflects current exponential oil-rate decline trends (Plot 28, Line Q), while the maximum reflects some hyperbolic bending on the oil-cut trend (Plot 29, Line M). The recommended proved reserves assignment of 371 Mstb (Plots 30 and 31, Line A) is derived using a value between the minimum and 2P case. Recommended 3P reserves of 381 Mstb are estimated using a value between the 2P and maximum case (Plots 30 and 31, Line P).

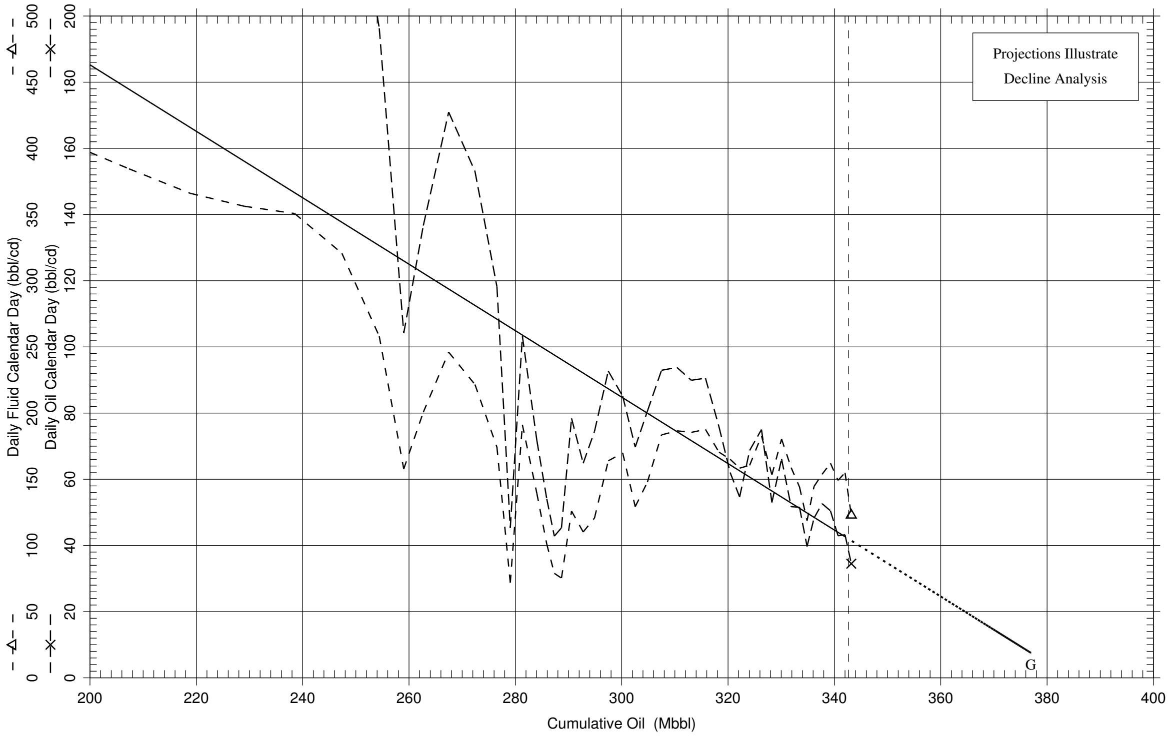
Actual performance of the well indicates ultimate recovery of 369 Mstb, though it appeared to have been produced to a higher final rate than that forecast (perhaps because of a higher economic limit at the time). Rates at the time of shut-in, however, were consistent with the forecast.

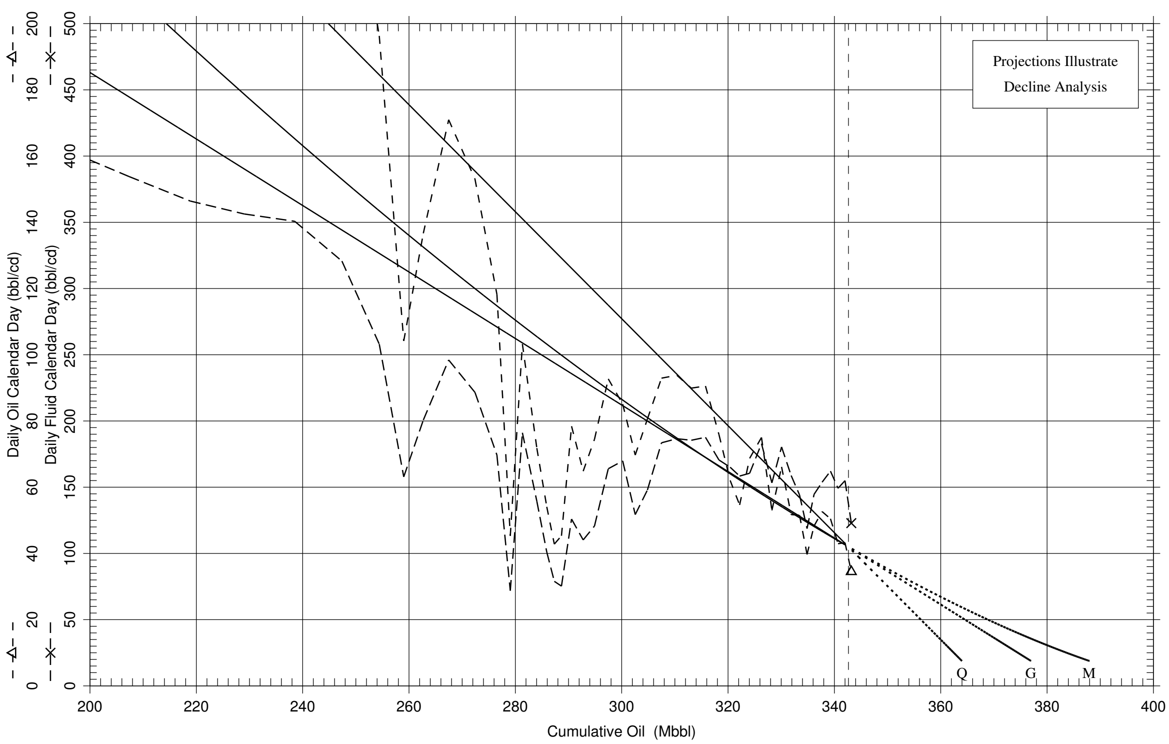
Historical Production
Oil Decline Example C



Status Summary		Cumulative Production			Average Production Rates (Last 12 months ending 1968/07/31)								
On Production date :	55/10/25	Gas :	72.8	MMcf	Gas :	7.3	Mcf/d	6.6	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Status date :	73/08/23	Oil :	343.7	Mbbl	Oil :	56.7	bbl/d	50.8	bbl/cd	GOR :	129.6	scf/stb
Status : ABANDONED OIL		Water :	97.7	Mbbl	On Prod :	327.2	days			WC :	66.6	%

Historical and Forecast Production
Oil Decline Example C





Decline Analysis Summary @ 1968/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Rates (bbl/d) Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	377	343	34	42	8	30.7%	0.00
Maximum Prd	M	388	343	45	42	8	27.5%	0.30
Minimum Prd	Q	364	343	21	42	8	44.6%	0.00

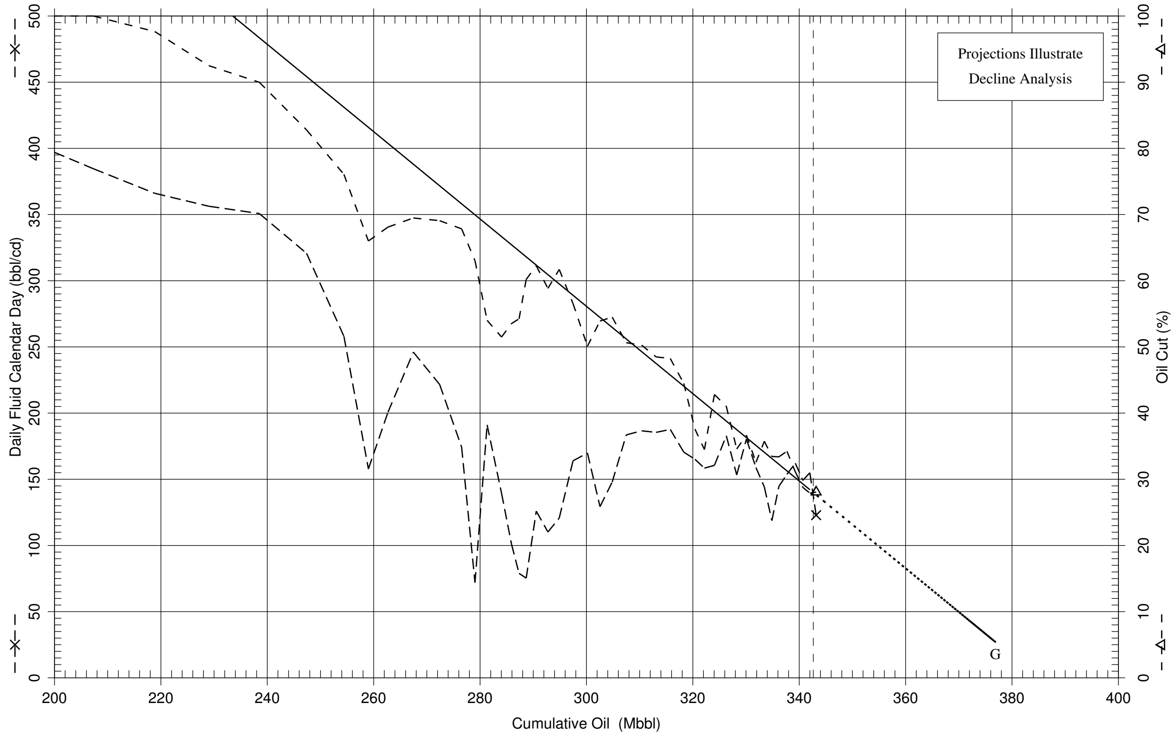
Average Production Rates (Last 12 months ending 1968/07/31)

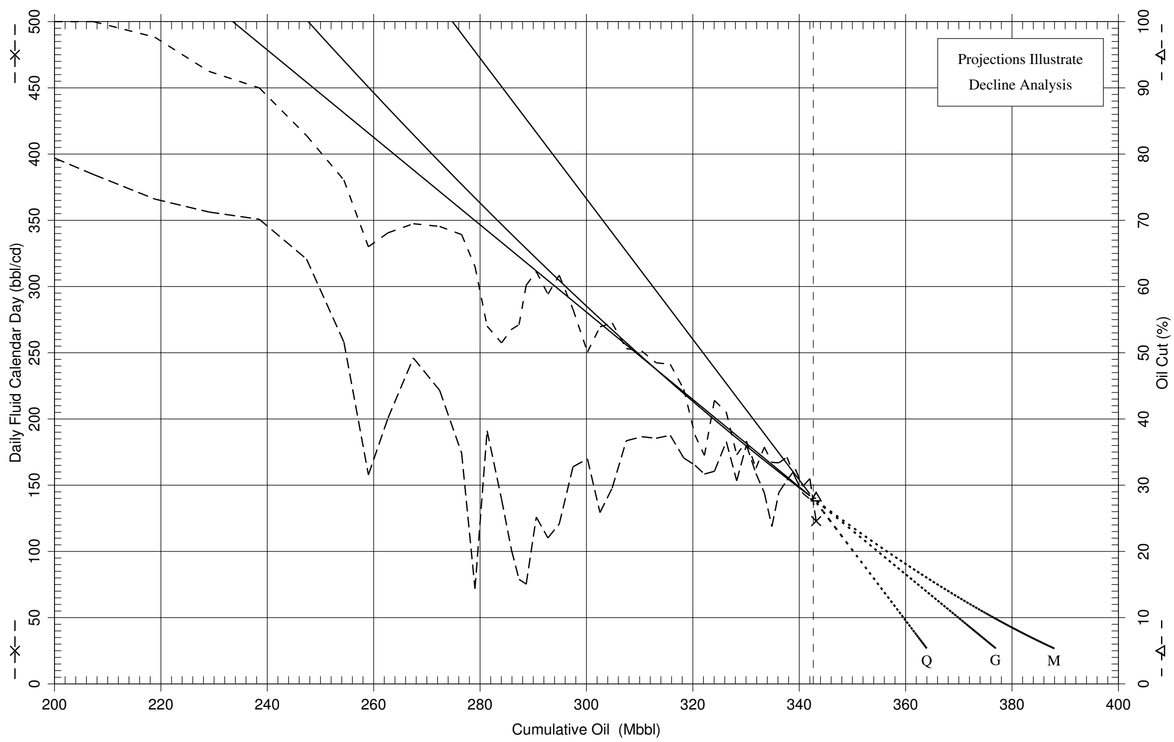
Gas :	7.3	Mcf/d	6.6	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	56.7	bbl/d	50.8	bbl/cd	GOR :	129.6	scf/stb
On Prod :	327.2	days			WC :	66.6	%

Cumulative Production

Oil :	343.7	Mbbl	Gas :	72.8	MMcf	Water :	97.7	Mbbl

Historical and Forecast Production
Oil Decline - Example C





Decline Analysis Summary @ 1968/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	377	343	34	28.00%	5.33%	30.3%	0.00
Maximum Prd	M	388	343	45	28.00%	5.33%	27.1%	0.30
Minimum Prd	Q	364	343	21	28.00%	5.33%	44.1%	0.00

Average Production Rates (Last 12 months ending 1968/07/31)

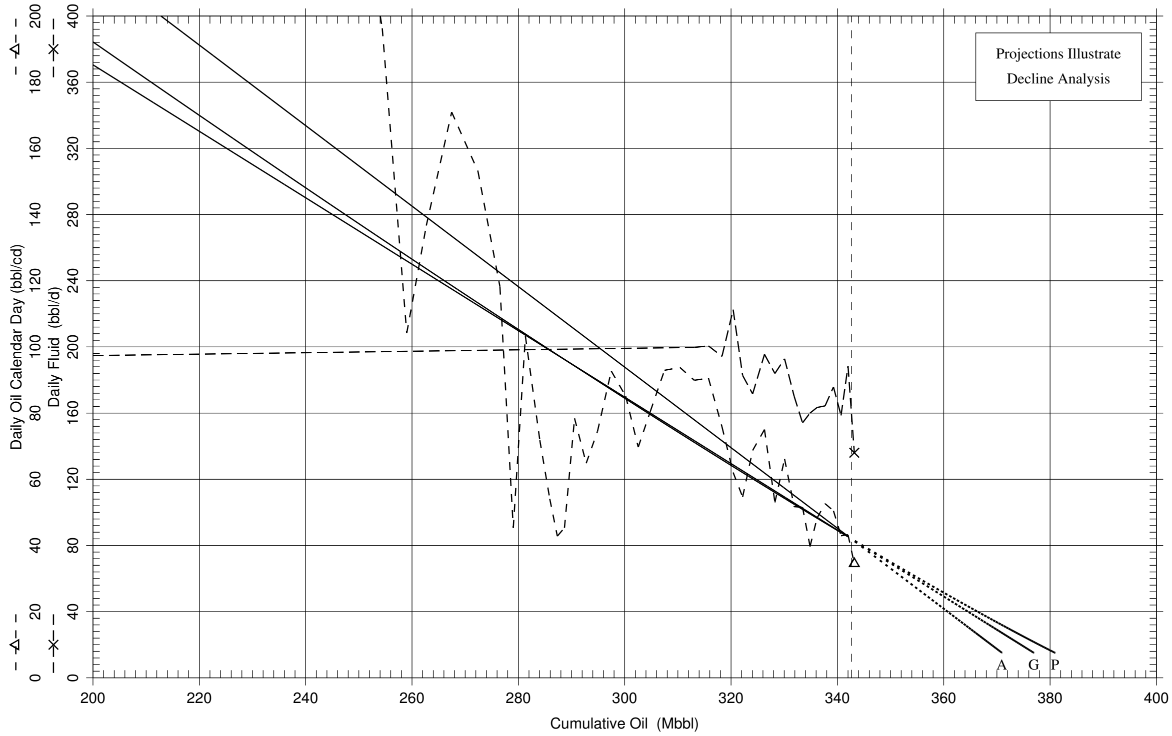
Gas :	7.3	Mcf/d	6.6	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	56.7	bbl/d	50.8	bbl/cd	GOR :	129.6	scf/stb
On Prod :	327.2	days			WC :	66.6	%

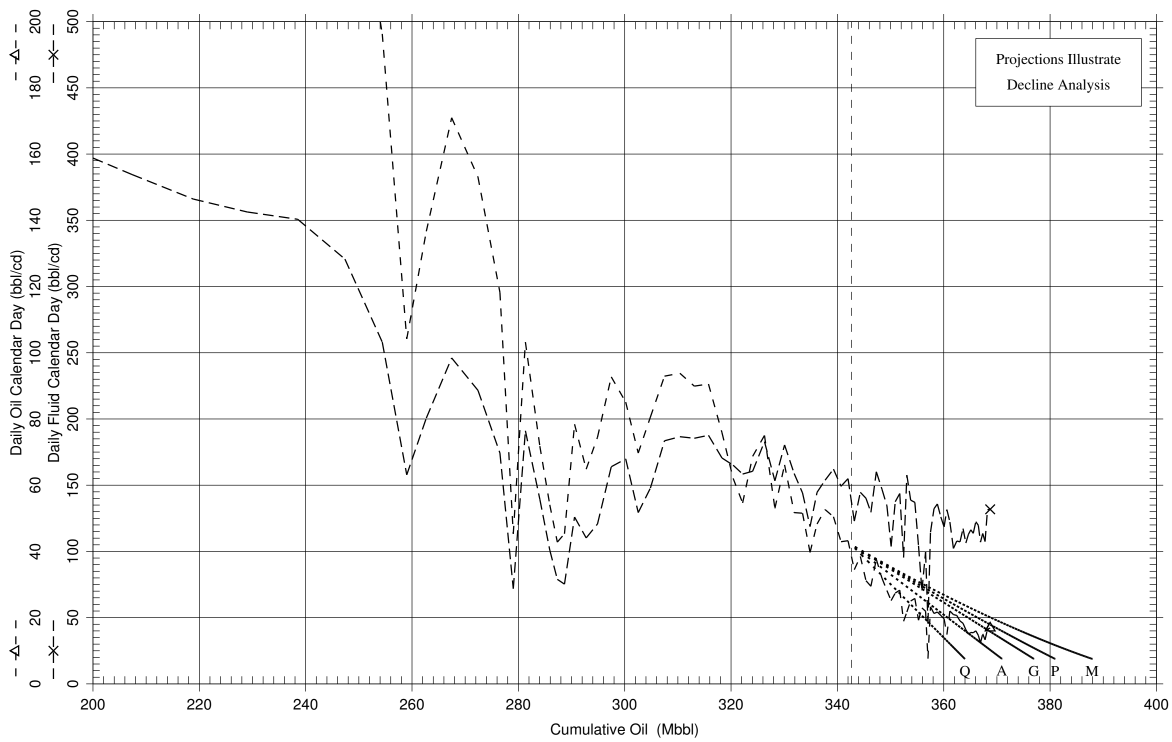
Cumulative Production

Oil :	343.7	Mbbl	Gas :	72.8	MMcf	Water :	97.7	Mbbl

Plot 29

Historical and Forecast Production
Oil Decline Example C





Decline Analysis Summary @ 1968/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Rates (bbl/d) Initial	Final	Decline Initial	Expont
Pv Prd	—— A	371	343	28	42	8	35.9%	0.00
Pv + Pb Prd	—— G	377	343	34	42	8	30.7%	0.00
Pv + Pb + Poss Prd	—— P	381	343	38	42	8	29.1%	0.10

Average Production Rates (Last 12 months ending 1968/07/31)

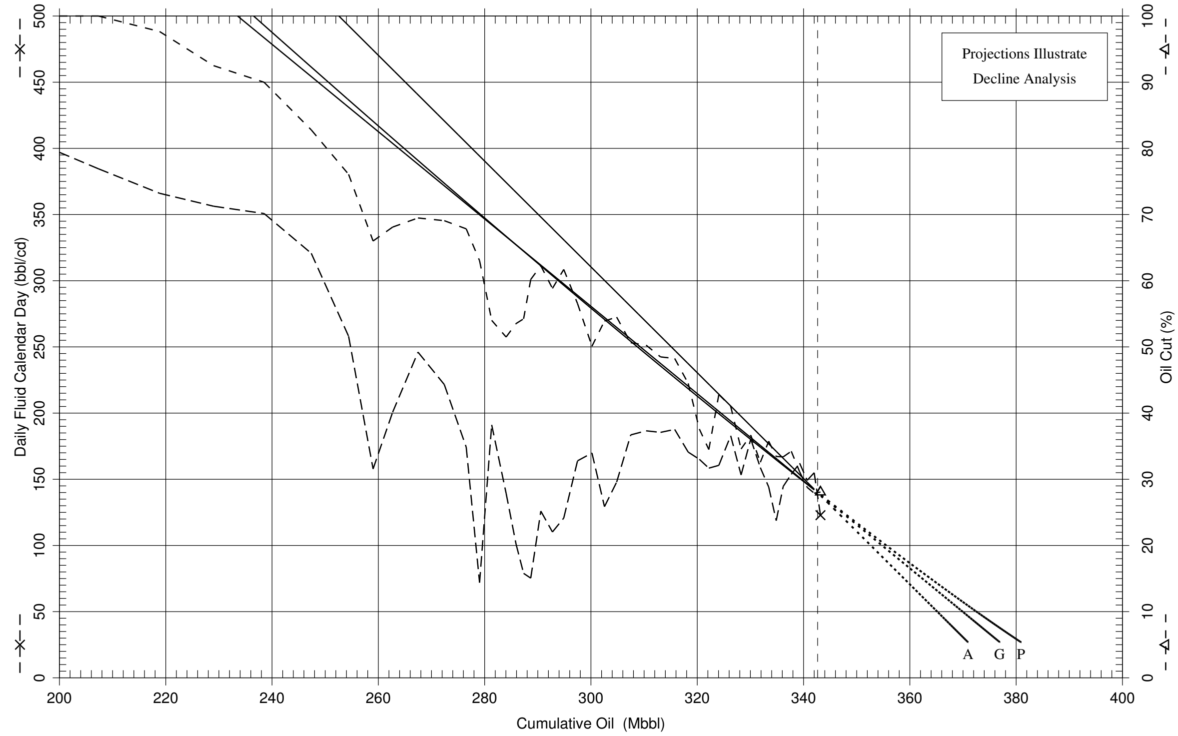
Gas :	7.3 Mcf/d	6.6 Mcf/cd	WGR :	>9999.9 bbl/MMcf
Oil :	56.7 bbl/d	50.8 bbl/cd	GOR :	129.6 scf/stb
On Prod :	327.2 days		WC :	66.6 %

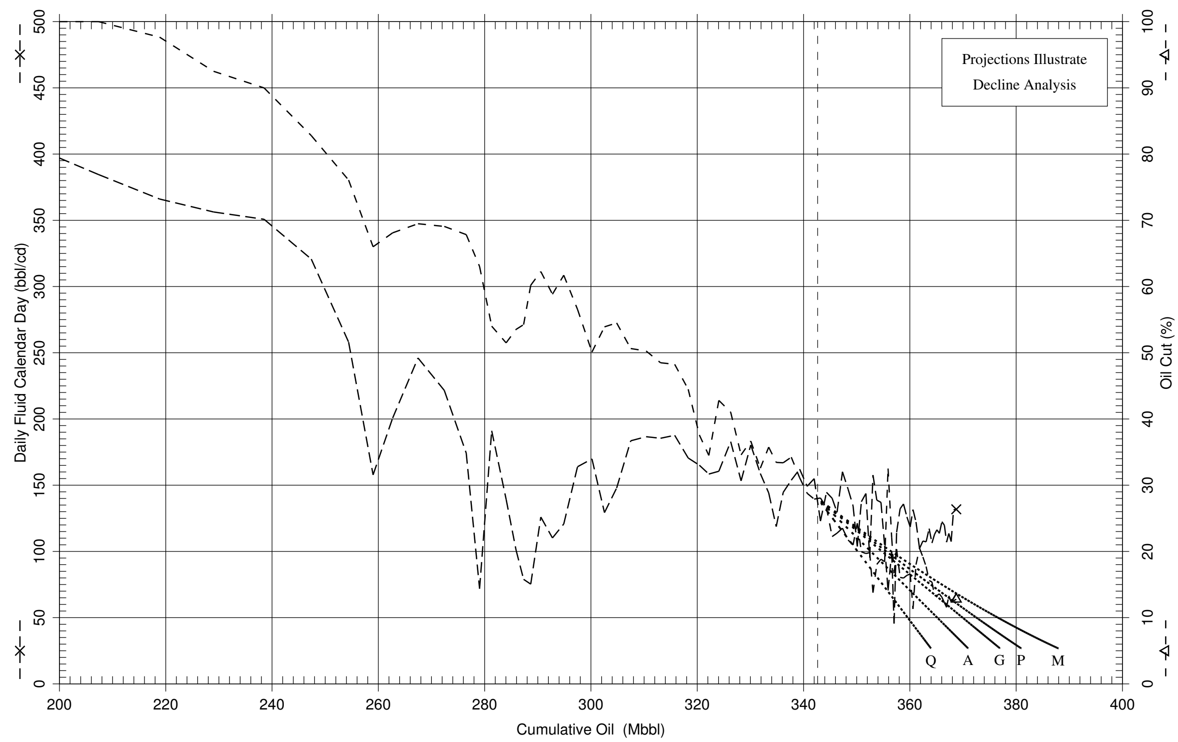
Cumulative Production

Oil :	343.7 Mbbl	Gas :	72.8 MMcf	Water :	97.7 Mbbl

Plot 30

Historical and Forecast Production
Oil Decline - Example C





Decline Analysis Summary @ 1968/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv Prd	A	371	343	28	28.00%	5.33%	35.4%	0.00
Pv + Pb Prd	G	377	343	34	28.00%	5.33%	30.3%	0.00
Pv + Pb + Poss Prd	P	381	343	38	28.00%	5.33%	28.7%	0.10

Average Production Rates (Last 12 months ending 1968/07/31)

Gas :	7.3	Mcf/d	6.6	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	56.7	bbl/d	50.8	bbl/cd	GOR :	129.6	scf/stb
On Prod :	327.2	days			WC :	66.6	%

Cumulative Production

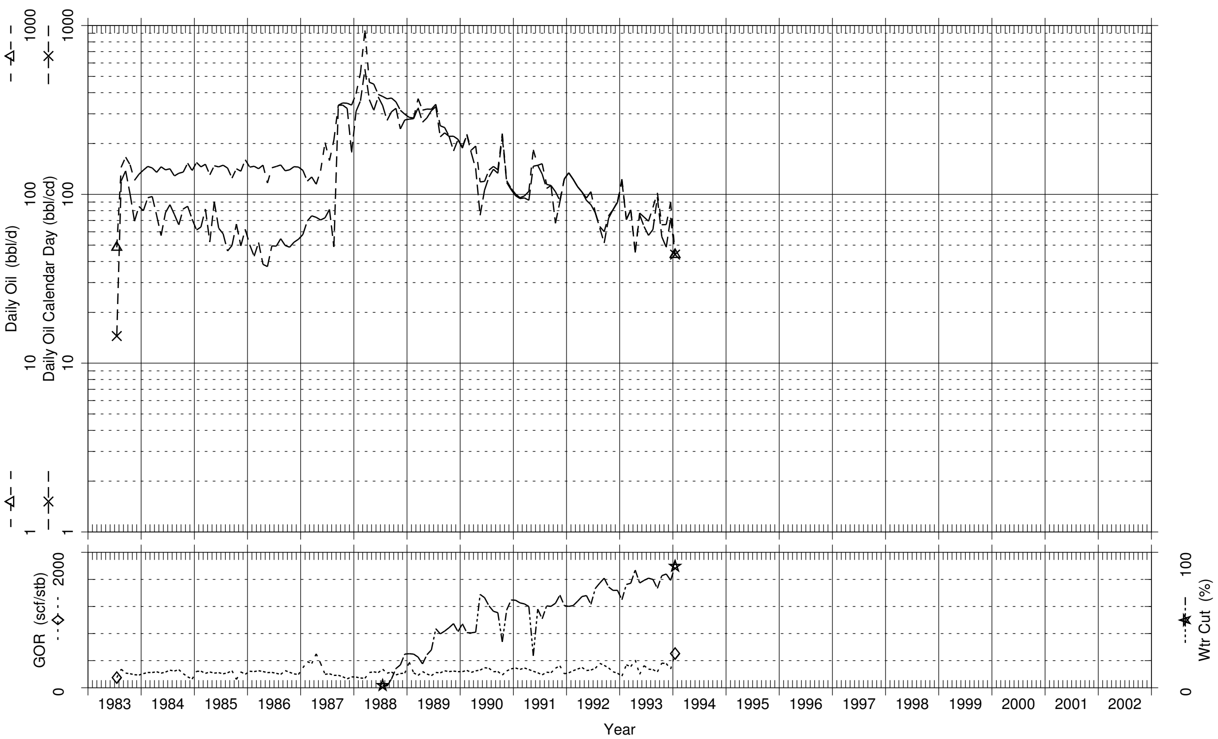
Oil :	343.7	Mbbl	Gas :	72.8	MMcf	Water :	97.7 Mbbl

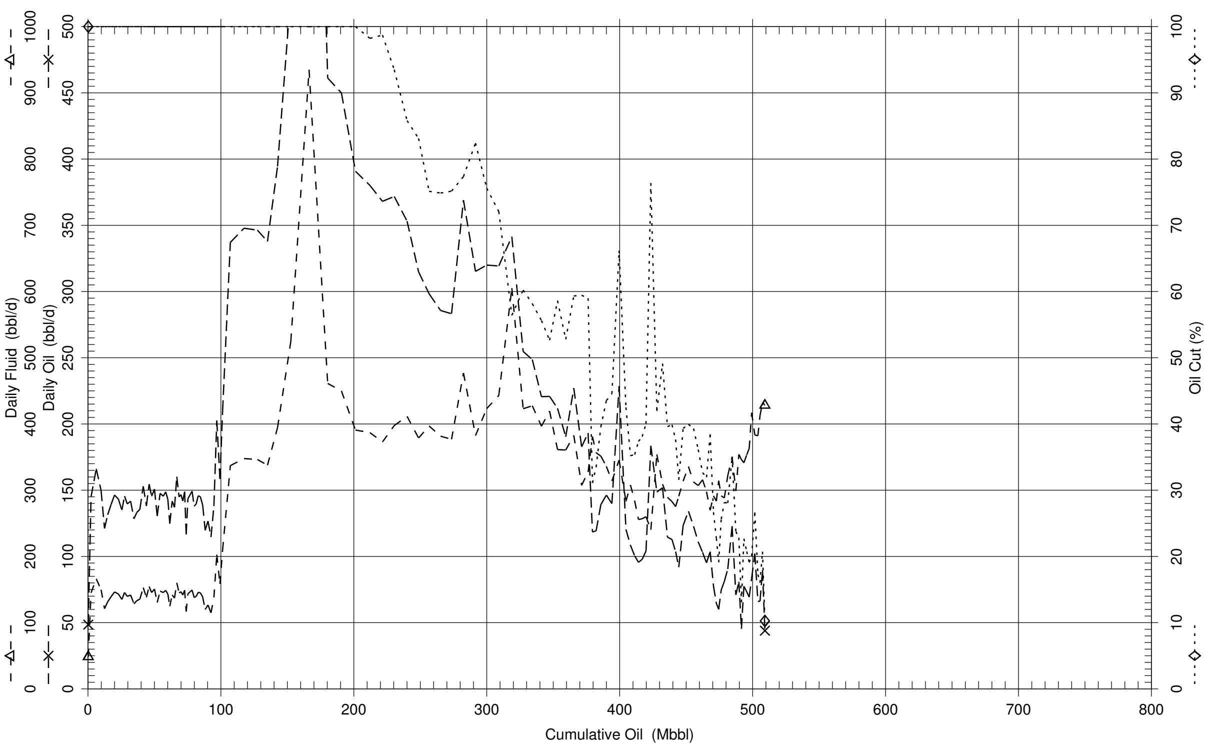
Oil Example D

Oil Example D is a well in a moderate-permeability, stratified, pattern waterflooded water-wet reservoir with production history to January 1, 1994, as illustrated on Plot 32. Based on the stratified nature of the reservoir, the recommended interpretation for 2P reserves uses a hyperbolic decline exponent of 0.4 (based on visual best fit and a review of analogous wells in the area), which yields ultimate reserves of 640 Mstb (Plot 33, Line G). A range of reasonable visual fits using exponential decline for minimum (Line Q) and a 0.6 exponent for maximum (Line M) are also illustrated on Plot 33. The recommended proved (Line A) and 3P (Line P) interpretations used exponents of 0.3 and 0.5, as depicted on Plot 34. Reserves estimated using these values are approximately 1/3 lower, and 1/3 higher, than the difference between the 2P and minimum and maximum, respectively.

Both oil-rate and oil-cut trends were considered in deriving the curve fits. Actual well performance after 1994 is illustrated on Plot 34. Performance is on trend to achieve the 2P reserves estimate.

Historical Production
Oil Decline Example D





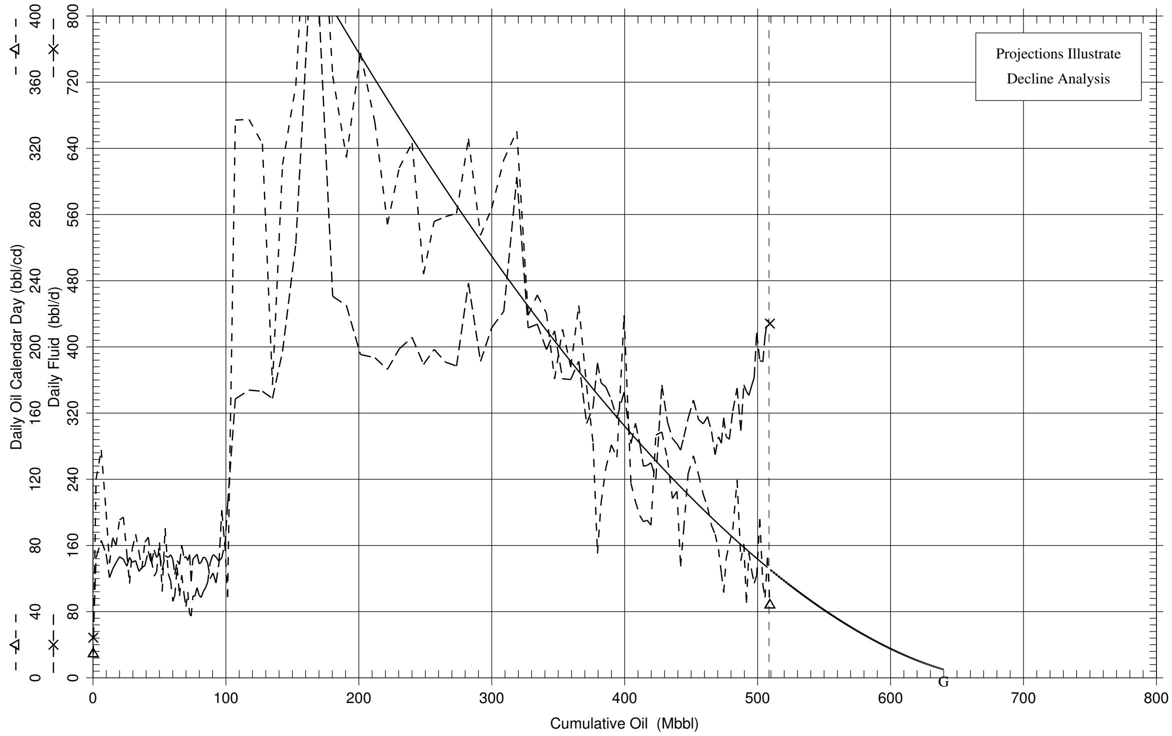
Status Summary	
On Production date :	83/07/21
Status date :	83/07/16
Status : PUMPING OIL	

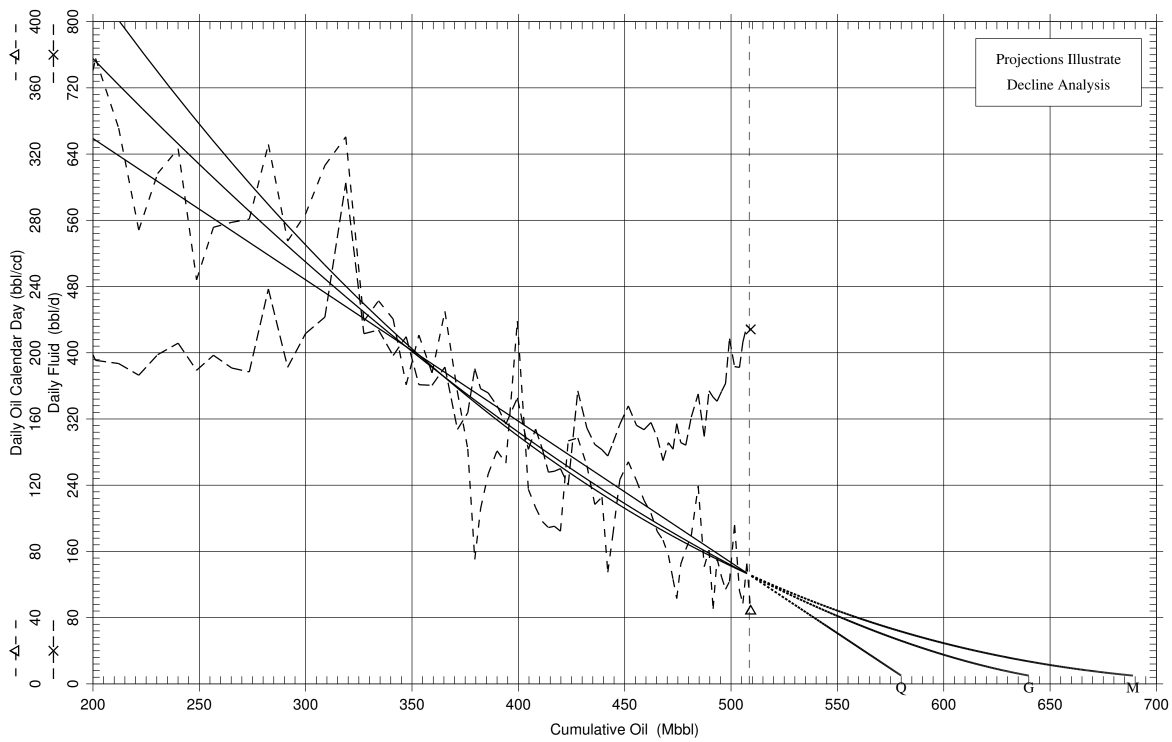
Cumulative Production		
Gas :	116.4	MMcf
Oil :	509.9	Mbbl
Water :	350.5	Mbbl

Average Production Rates (Last 12 months ending 1994/01/31)

Gas :	22.3 Mcf/d	19.9	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	72.4 bbl/d	64.4	bbl/cd	GOR :	308.4	scf/stb
On Prod :	326.7 days			WC :	80.8	%

Historical and Forecast Production
Oil Decline Example D





Decline Analysis Summary @ 1994/01/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Rates (bbl/d) Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	640	509	131	66	5	20.5%	0.40
Maximum Prd	M	689	509	180	66	5	18.3%	0.60
Minimum Prd	Q	580	509	71	66	5	26.8%	0.00

Average Production Rates (Last 12 months ending 1994/01/31)

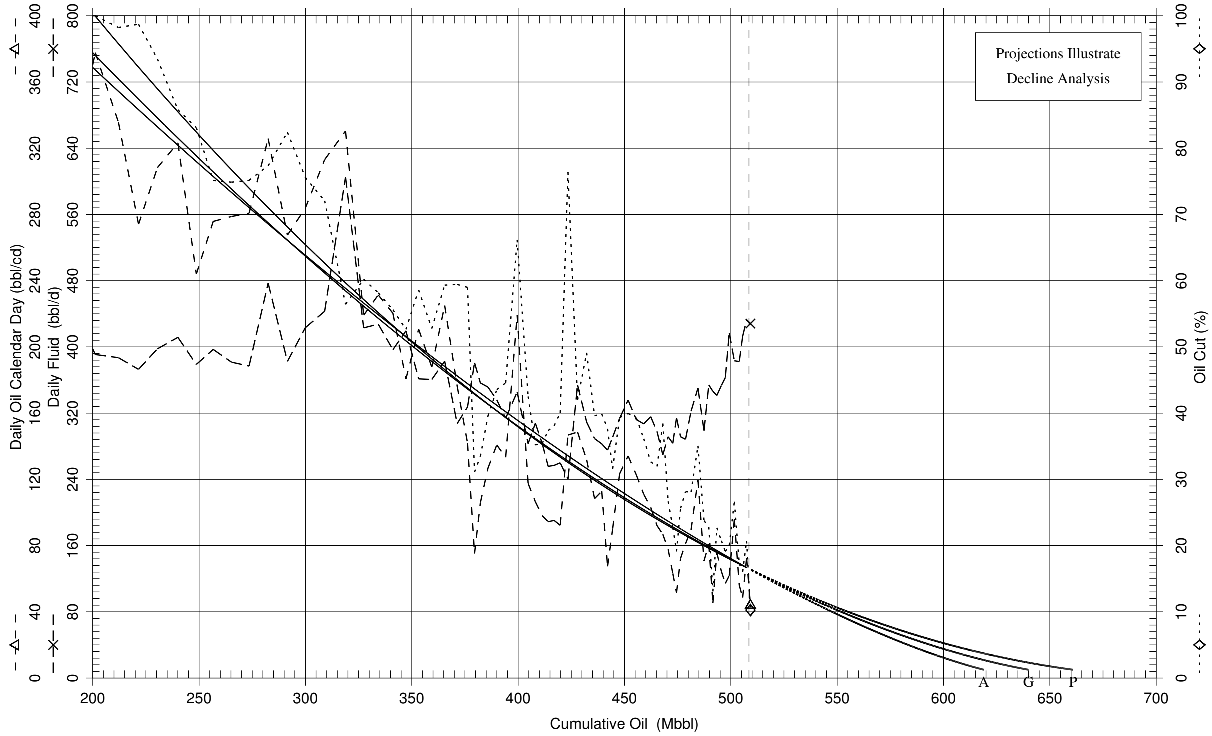
Gas :	22.3	Mcf/d	19.9	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	72.4	bbl/d	64.4	bbl/cd	GOR :	308.4	scf/stb
On Prod :	326.7	days			WC :	80.8	%

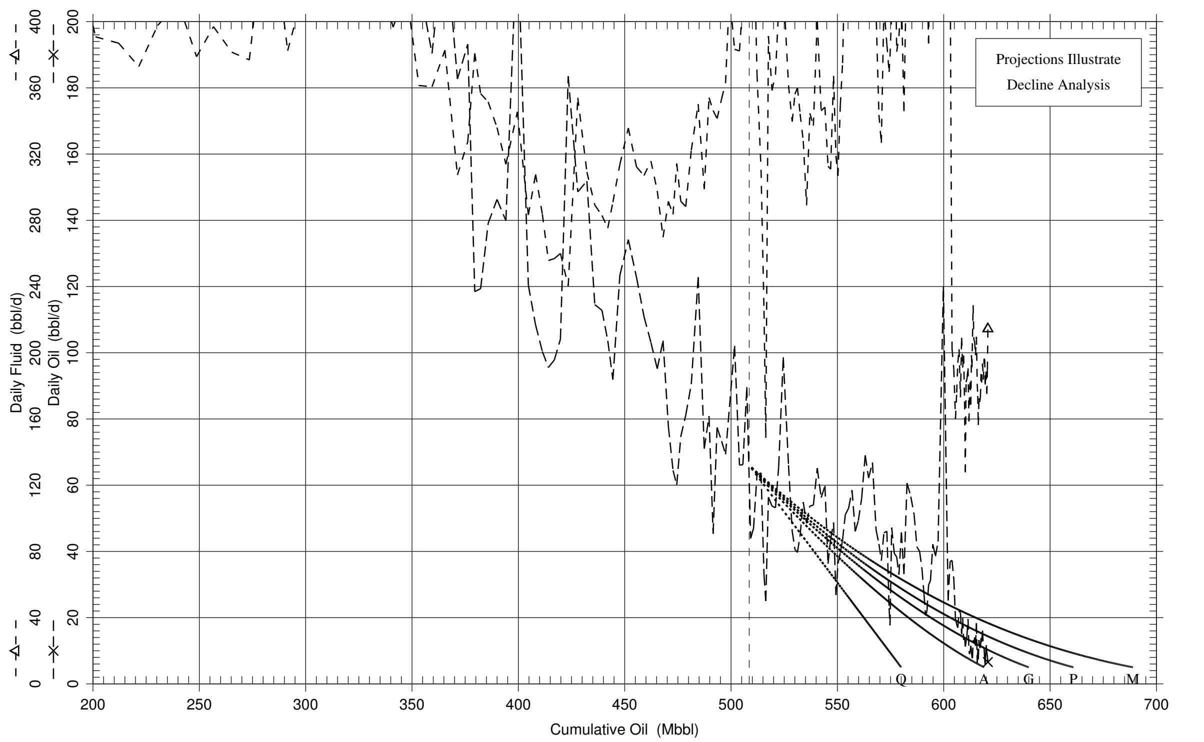
Cumulative Production

Oil :	509.9 Mbbl	Gas :	116.4 MMcf	Water :	350.5 Mbbl

Plot 33

Historical and Forecast Production
Oil Decline Example D





Decline Analysis Summary @ 1994/01/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Rates (bbl/d) Initial	Final	Decline Initial	Expont
Pv Prd	—— A	619	509	110	66	5	22.2%	0.30
Pv + Pb Prd	—— G	640	509	131	66	5	20.5%	0.40
Pv + Pb + Poss Prd	—— P	661	509	152	66	5	19.5%	0.50

Average Production Rates (Last 12 months ending 1994/01/31)

Gas :	22.3 Mcf/d	19.9 Mcf/cd	WGR :	>9999.9 bbl/MMcf
Oil :	72.4 bbl/d	64.4 bbl/cd	GOR :	308.4 scf/stb
On Prod :	326.7 days		WC :	80.8 %

Cumulative Production

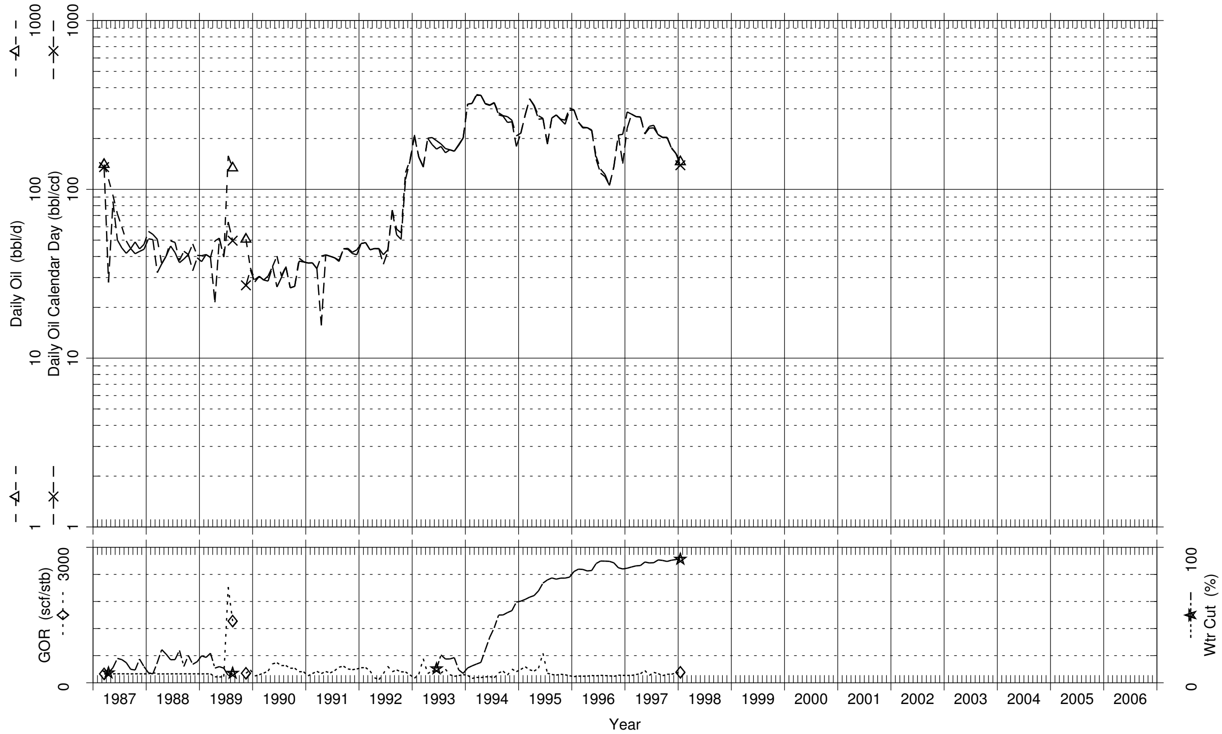
Oil :	509.9 Mbbl	Gas :	116.4 MMcf	Water :	350.5 Mbbl

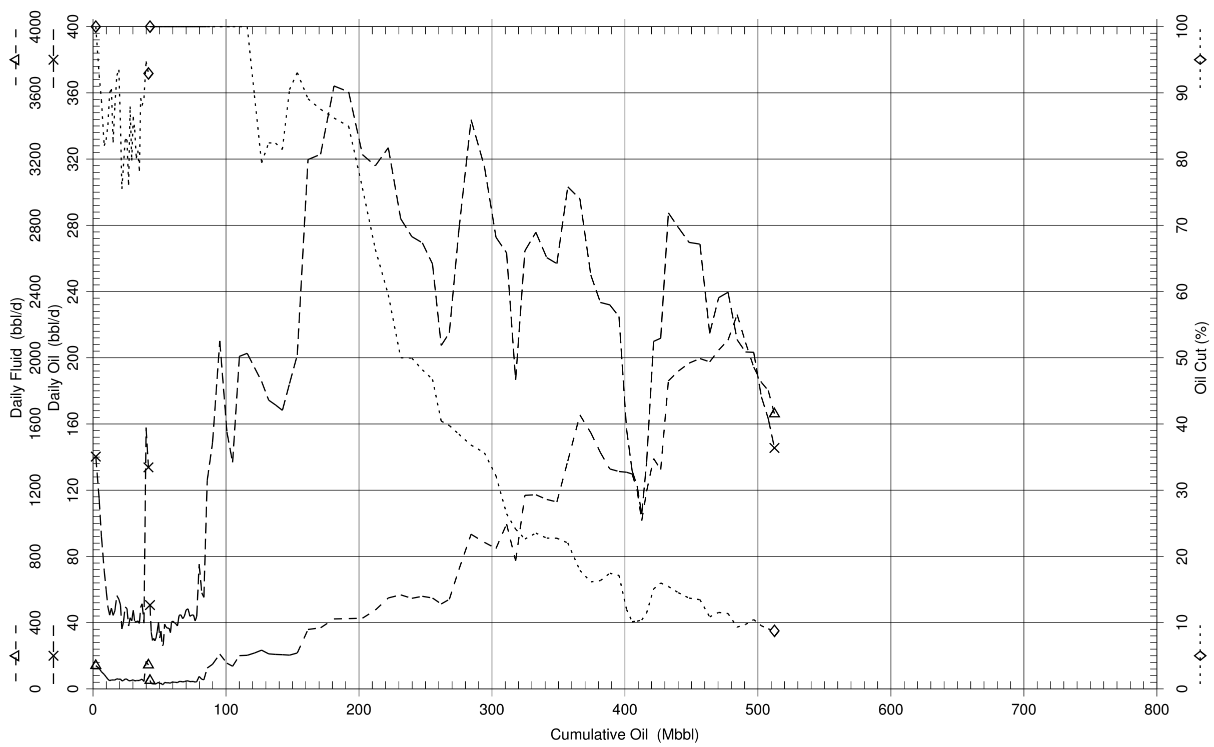
Oil Example E

Oil Example E is a well in a high-permeability, unstratified, bottom-water drive oil-wet reservoir with production history as illustrated on Plot 35. As fluid rates are continually increasing during the life of the well, oil-cut analysis is used for decline interpretation. An economic oil-cut limit of 0.7 percent is calculated from a review of operating costs and expected future fluid production rates. From visual curve fitting and a review of analogous wells in the area, the recommended best estimate interpretation for 2P reserves uses a hyperbolic decline exponent of 0.9, which yields ultimate reserves of 856 Mstb (Plot 36, Line G). Reasonable fits can be achieved using a range of hyperbolic exponents between 0.7 (minimum, Line Q) and 1.0 (maximum, Line M), as depicted on Plot 37. The recommended proved interpretation uses a hyperbolic exponent of 0.8, which yields ultimate reserves of 793 Mstb (Plot 38, Line A).The recommended 3P interpretation uses a hyperbolic exponent of 0.95, which yields ultimate reserves of 895 Mstb (Plot 38, Line P).

After the date of the decline analysis, a workover in 1999 improved oil-cut performance temporarily; however, actual performance is back to the original 2P oil-cut trend.

Historical Production
Oil Decline Example E



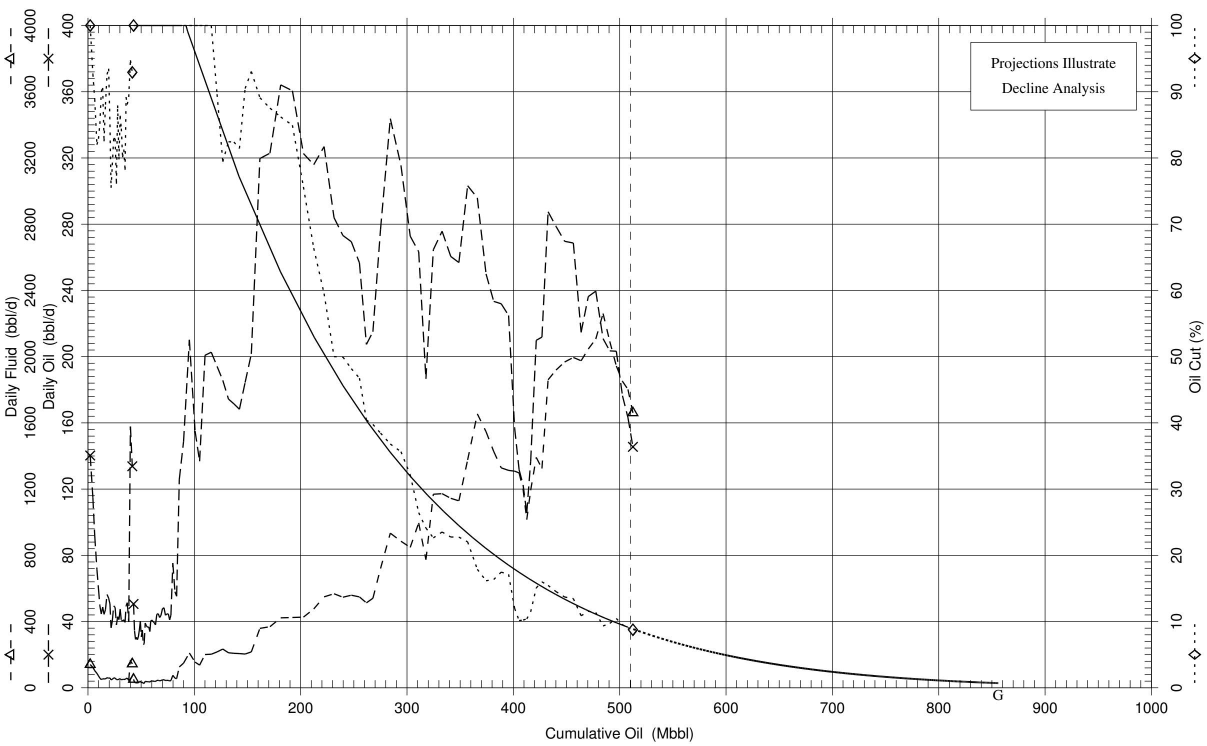


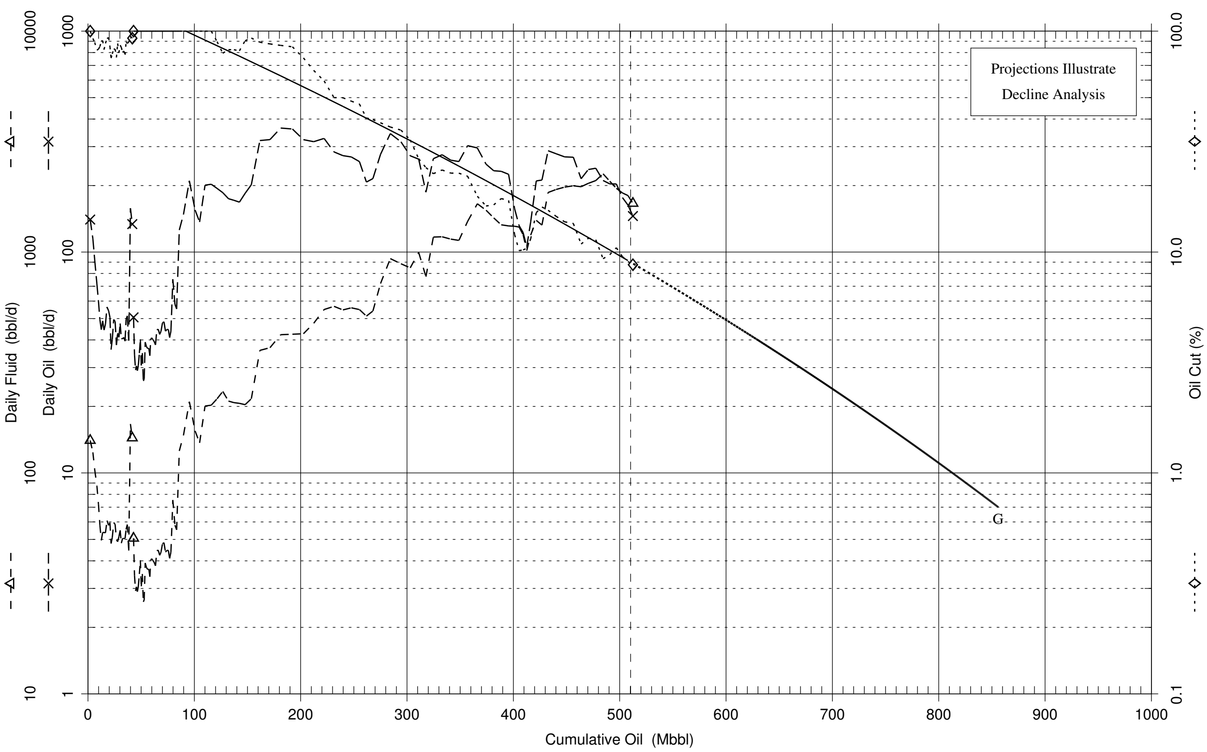
Status Summary	
On Production date :	87/03/01
Status date :	87/03/01
Status : PUMPING OIL	

Cumulative Production		
Gas :	111.7	MMcf
Oil :	514.6	Mbbl
Water :	1400.9	Mbbl

Average Production Rates (Last 12 months ending 1998/01/31)							
Gas :	43.0	Mcf/d	42.5	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	217.5	bbl/d	215.2	bbl/cd	GOR :	198.2	scf/stb
On Prod :	360.8	days			WC :	89.0	%

Historical and Forecast Production
Oil Decline Example E





Decline Analysis Summary @ 1998/01/01

Reserves Classification	Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv + Pb Prd —— G	856	510	346	9.00%	0.70%	28.2%	0.90

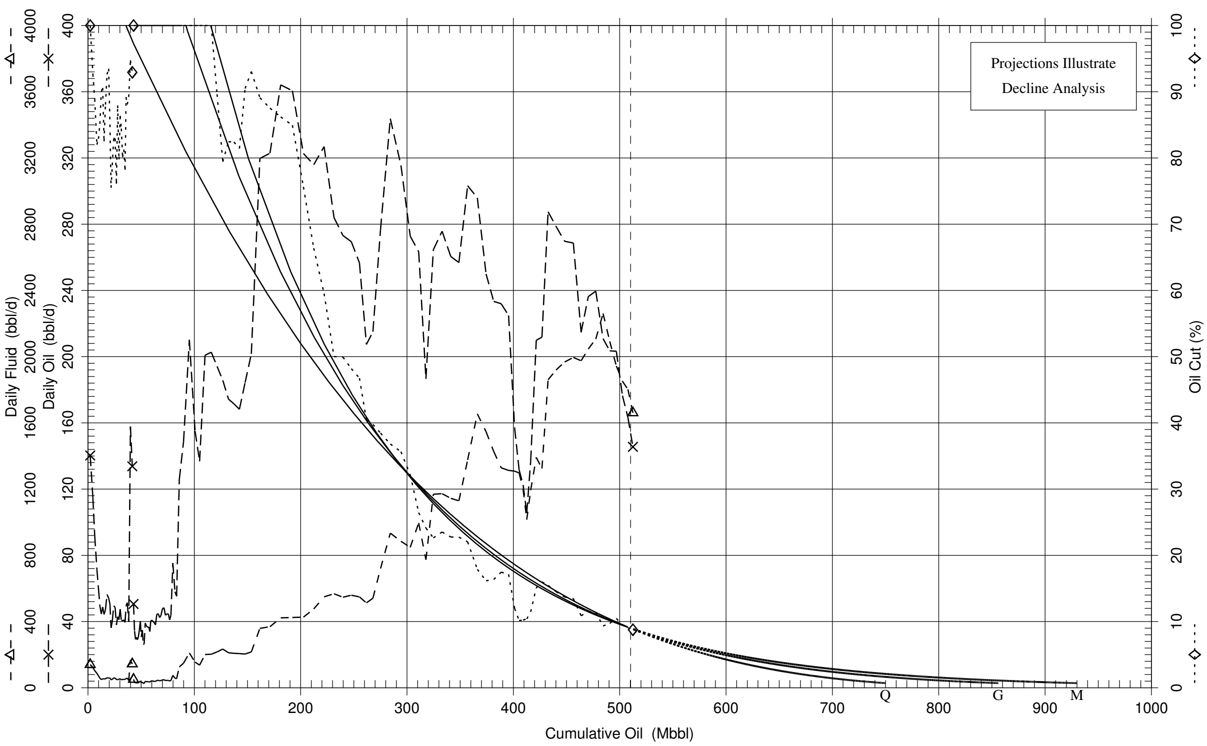
Average Production Rates (Last 12 months ending 1998/01/31)

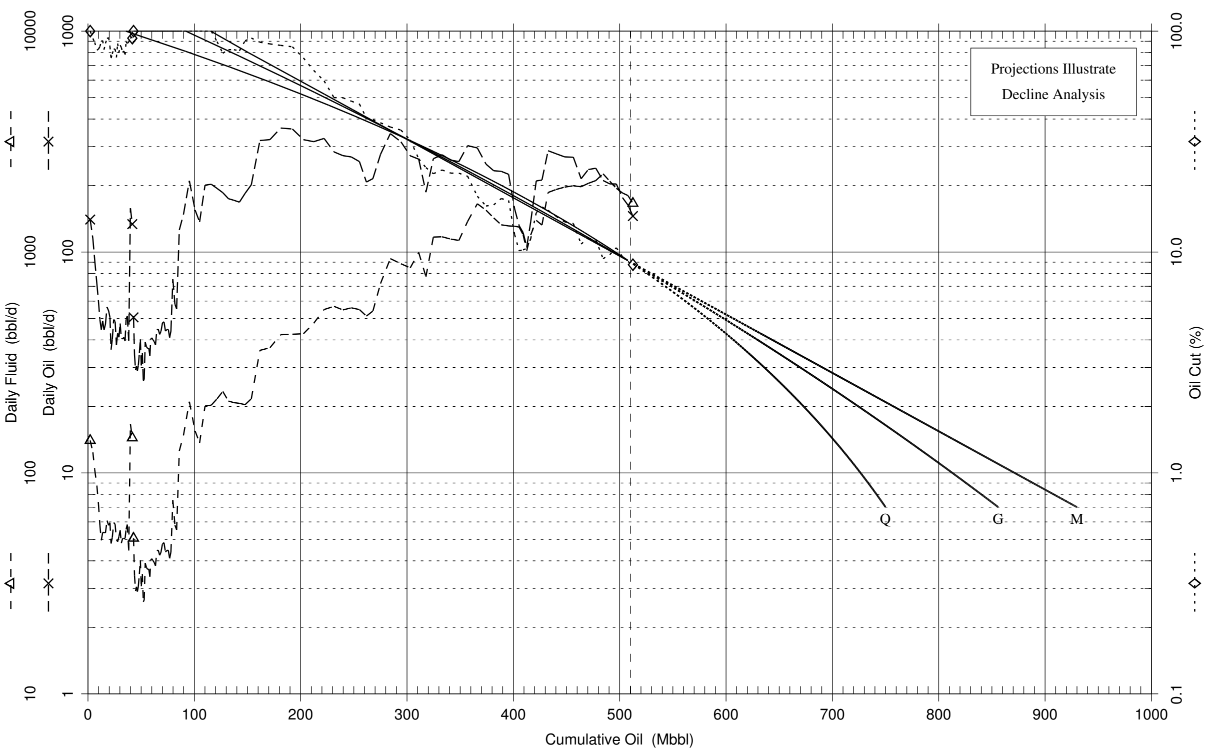
Gas :	43.0	Mcf/d	42.5	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	217.5	bbl/d	215.2	bbl/cd	GOR :	198.2	scf/stb
On Prod :	360.8	days			WC :	89.0	%

Cumulative Production

Oil : 514.6 Mbbl Gas : 111.7 MMcf Water : 1400.9 Mbbl

Historical and Forecast Production
Oil Decline Example E





Decline Analysis Summary @ 1998/01/01

Reserves Classification		Reserves (Mbbl)			Oil Cut %		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv + Pb Prd	G	856	510	346	9.00%	0.70%	28.2%	0.90
Maximum Prd	M	930	510	420	9.00%	0.70%	26.5%	1.00
Minimum Prd	Q	750	510	240	9.00%	0.70%	31.9%	0.70

Average Production Rates (Last 12 months ending 1998/01/31)

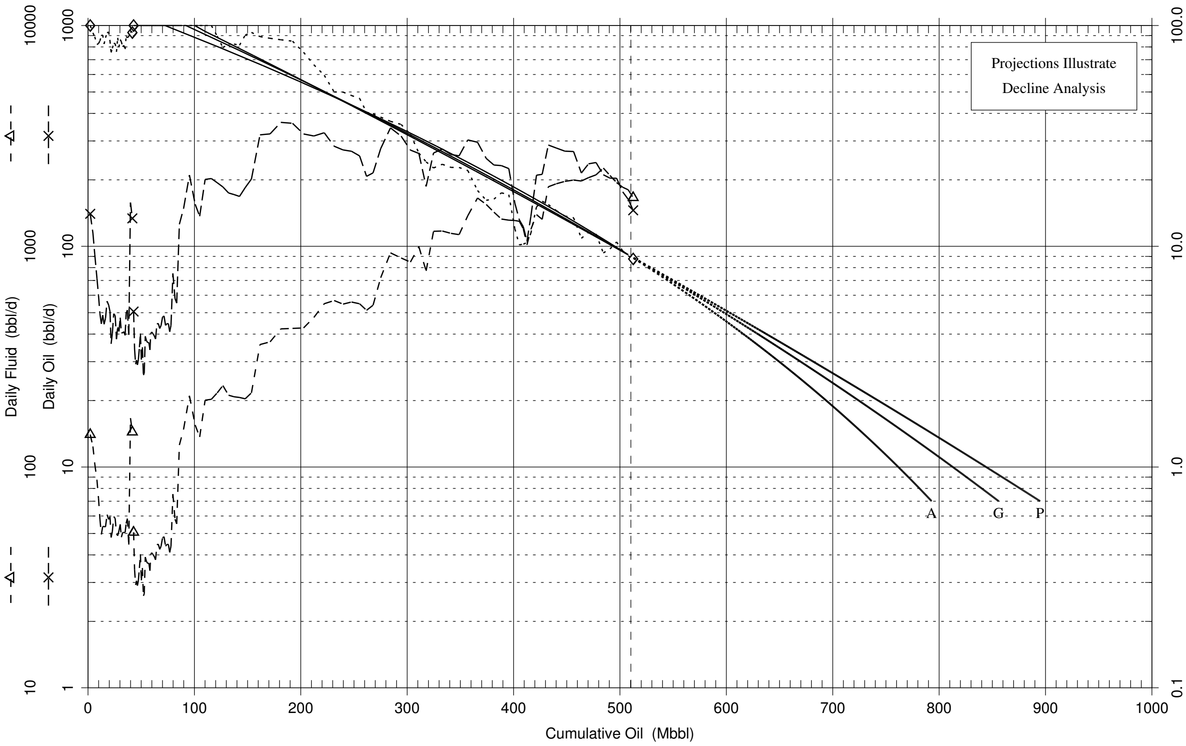
Gas :	43.0	Mcf/d	42.5	Mcf/cd	WGR :	>9999.9 bbl/MMcf
Oil :	217.5	bbl/d	215.2	bbl/cd	GOR :	198.2 scf/stb
On Prod :	360.8	days			WC :	89.0 %

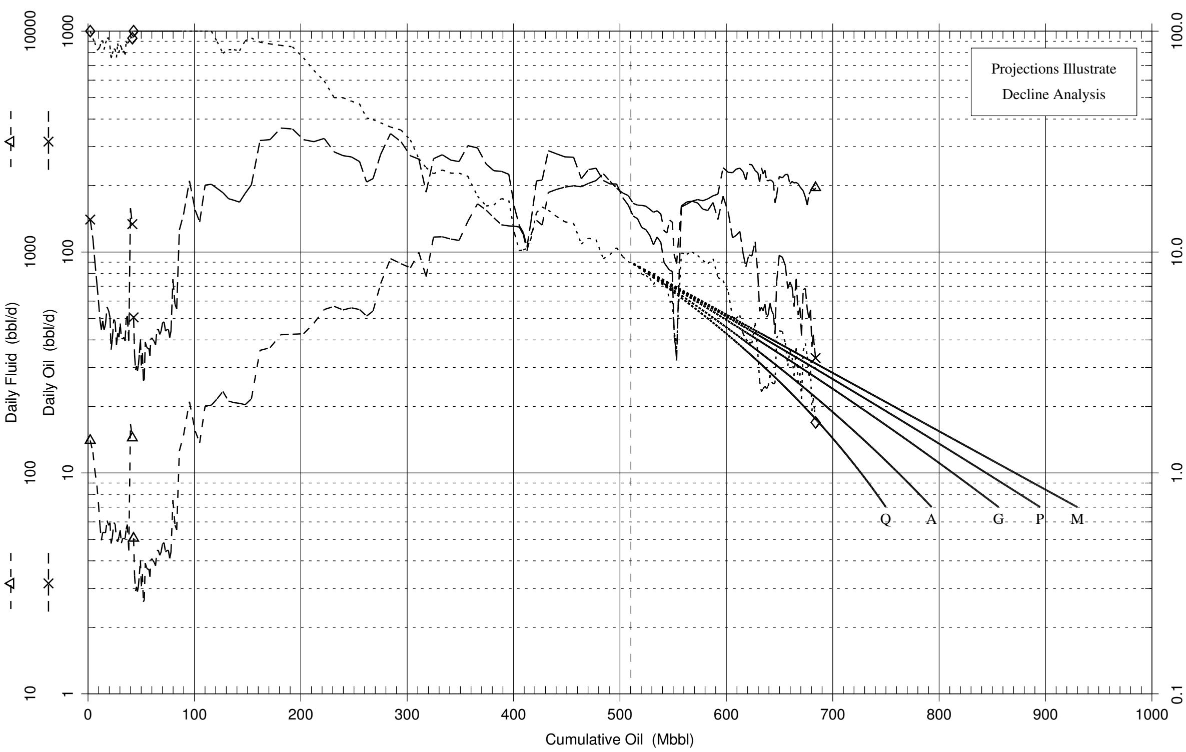
Cumulative Production

Oil : 514.6 Mbbl	Gas : 111.7 MMcf	Water : 1400.9 Mbbl	

Plot 37

Historical and Forecast Production
Oil Decline Example E





Decline Analysis Summary @ 1998/01/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv Prd	A	793	510	283	9.00%	0.70%	30.3%	0.80
Pv + Pb Prd	G	856	510	346	9.00%	0.70%	28.2%	0.90
Pv + Pb + Poss Prd	P	895	510	385	9.00%	0.70%	27.1%	0.95

Average Production Rates (Last 12 months ending 1998/01/31)

Gas :	43.0 Mcf/d	42.5 Mcf/cd	WGR :	>9999.9 bbl/MMcf
Oil :	217.5 bbl/d	215.2 bbl/cd	GOR :	198.2 scf/stb
On Prod :	360.8 days		WC :	89.0 %

Cumulative Production

Oil :	514.6 Mbbl	Gas :	111.7 MMcf	Water :	1400.9 Mbbl

Plot 38

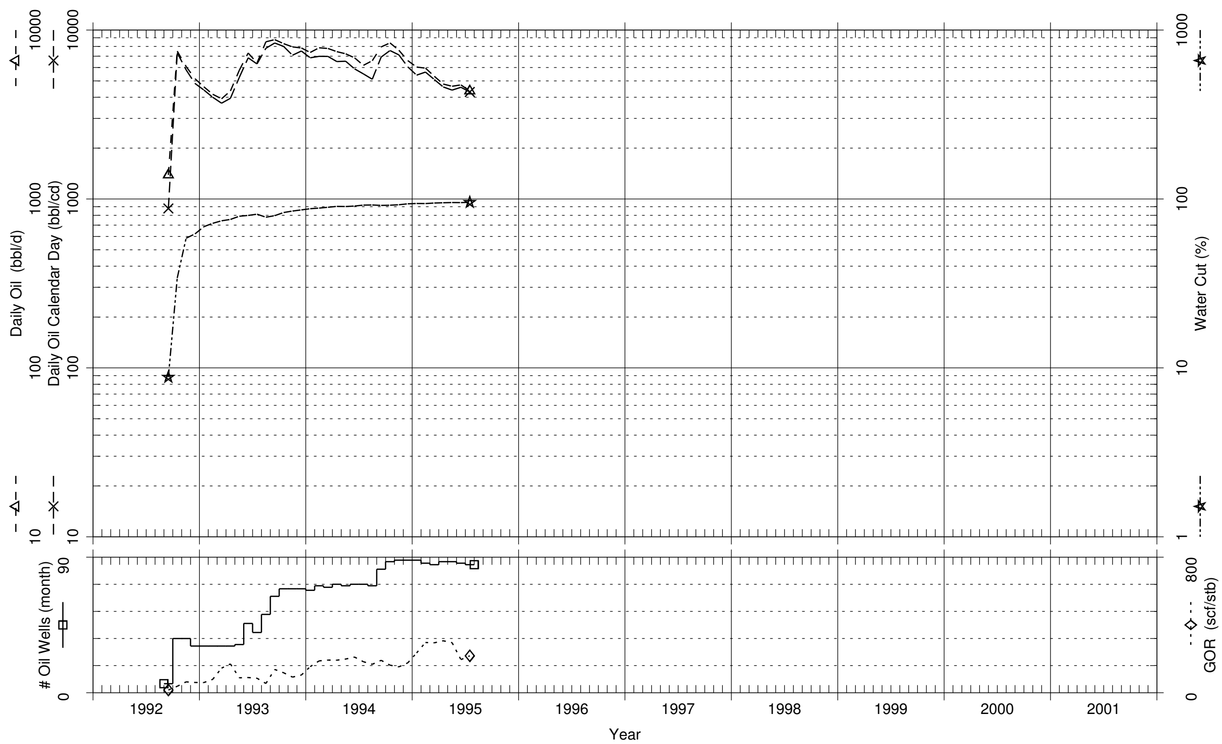
Oil Example F (Group Analysis)

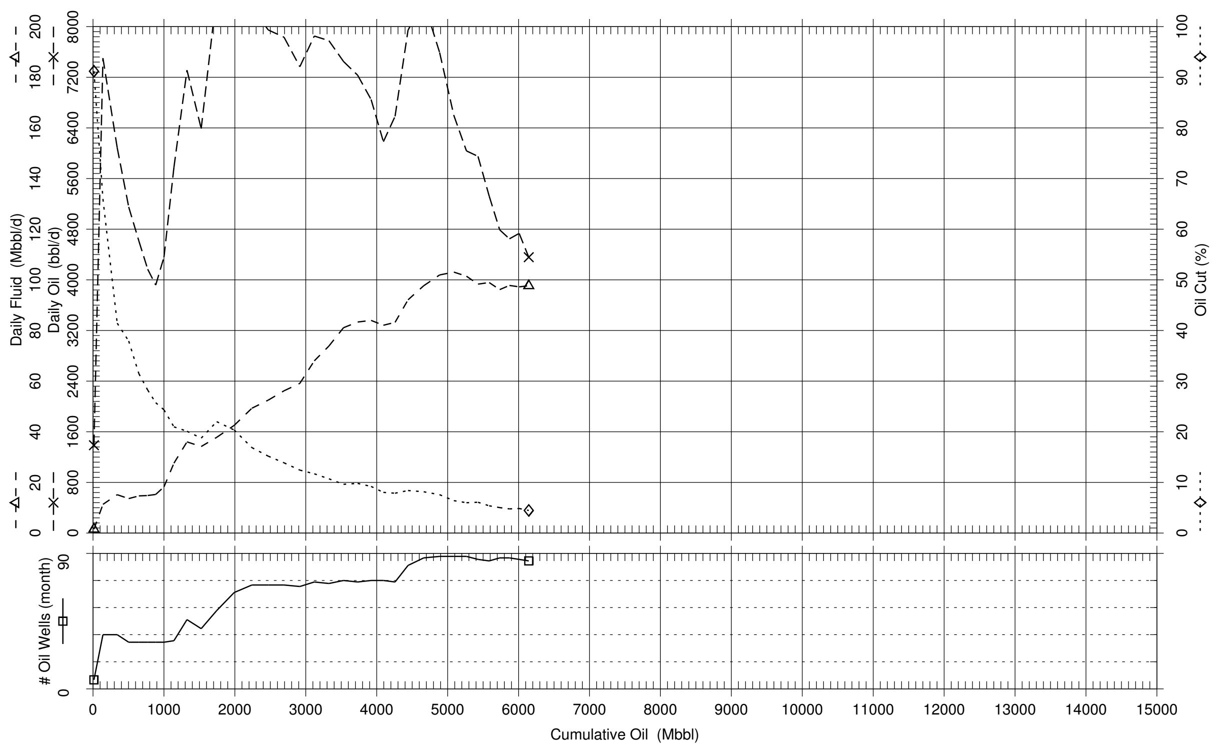
Oil Example F is a group of wells in a high-permeability unstratified bottom-water drive oil-wet reservoir. The group production plot to July 1995 is illustrated on Plot 39. Wells were added in 1992, 1993, and 1994. This continual addition of wells makes group decline interpretation more difficult, because the addition of new wells lowers the overall group oil cut and increases the overall group fluid rate. Decline analysis was, therefore, performed on each group of wells sorted by start-up date, using oil-cut trend analysis as illustrated on Plots 40 through 45. For each group, minimum (Line Q), best estimate (2P, Line G) and maximum (Line M) values are derived from visual curve fits using decline exponents of 0.6, 0.8, and 1.0, respectively, and a review of analogous pools in the area. Proved (Line A) and 3P (Line P) reserves are estimated using decline exponents of 0.7 and 0.9, respectively.

Analysis of each group uses oil-cut trend analysis, because the oil-rate trends are more sensitive to fluid rate changes. If available, decline analysis should be performed during periods of constant fluid rates so as to prevent any transient effects of additional drawdown. For periods of constant fluid production, the results of the two methods will coincide.

A review of performance for the pool since 1995 indicates the 2P forecast is a good match with actual production (Plot 46), with the proved forecast being slightly lower than actual performance. On a start-up group basis, actual performance is between the proved and 2P forecasts for the 1992 wells, coincident with the proved forecast for the 1993 wells, and above the 2P forecast for the 1994 wells. The underestimate of the 1994 wells and overestimate of the 1993 wells could be a result of interference between the well groups.

Historical Production
Oil Decline Example F (All Wells)





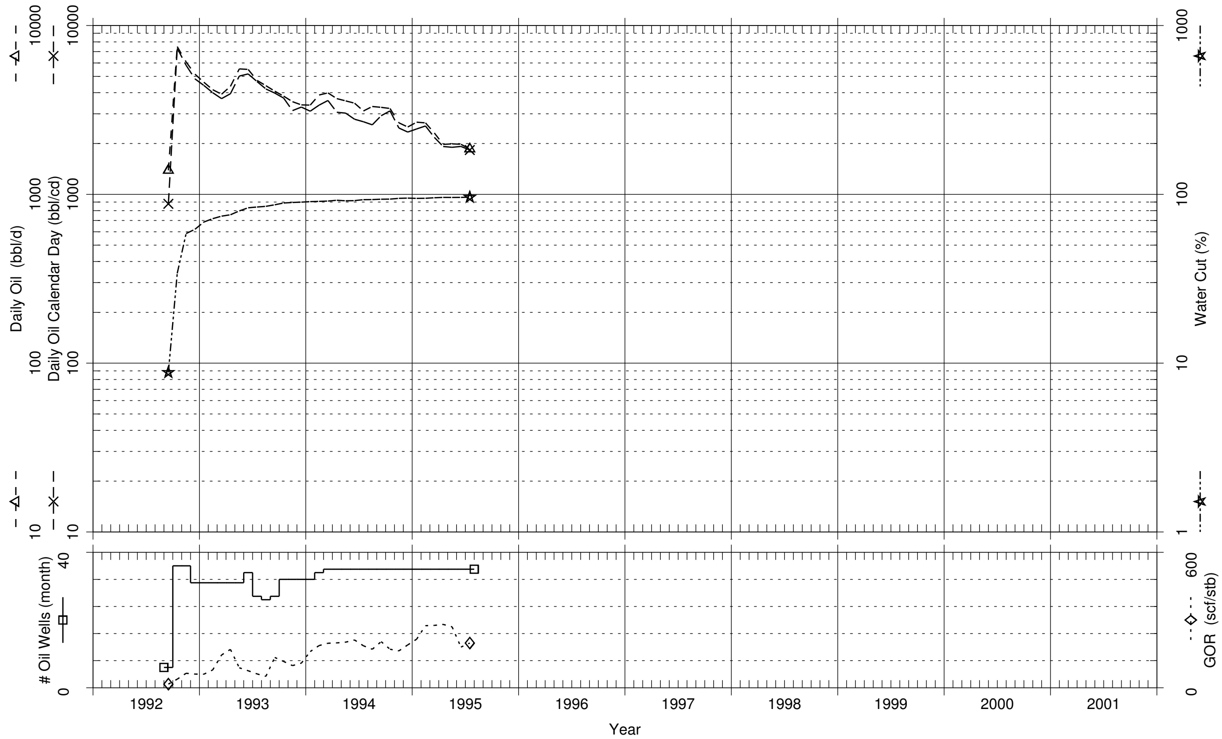
Cumulative Production

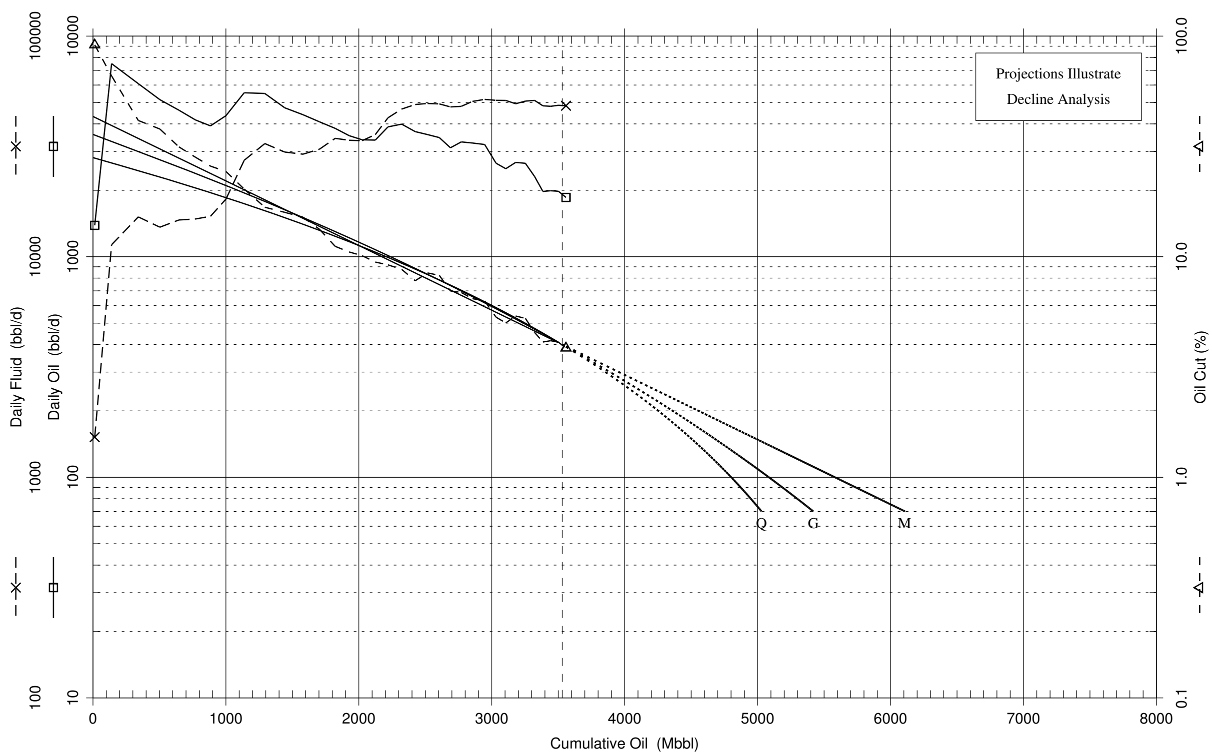
Gas :	952.5	MMcf
Oil :	6210.4	Mbbl
Water :	52879.5	Mbbl

Average Production Rates (Last 12 months ending 1995/07/31)

Gas :	1328.2	Mcf/d	1213.1	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	6078.9	bbl/d	5567.6	bbl/cd	GOR :	217.4	scf/stb
Avg Wells :	77.4				WC :	93.8	%

Historical and Forecast Production
EXAMPLE F 1992 WELLS





Decline Analysis Summary @ 1995/07/01

Reserves Classification		Reserves (Mbbl)			Oil Cut %		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv + Pb Prd	—— G	5420	3530	1890	4.00%	0.70%	35.9%	0.80
Maximum Prd	—— M	6110	3530	2580	4.00%	0.70%	31.7%	1.00
Minimum Prd	—— Q	5030	3530	1500	4.00%	0.70%	38.9%	0.60

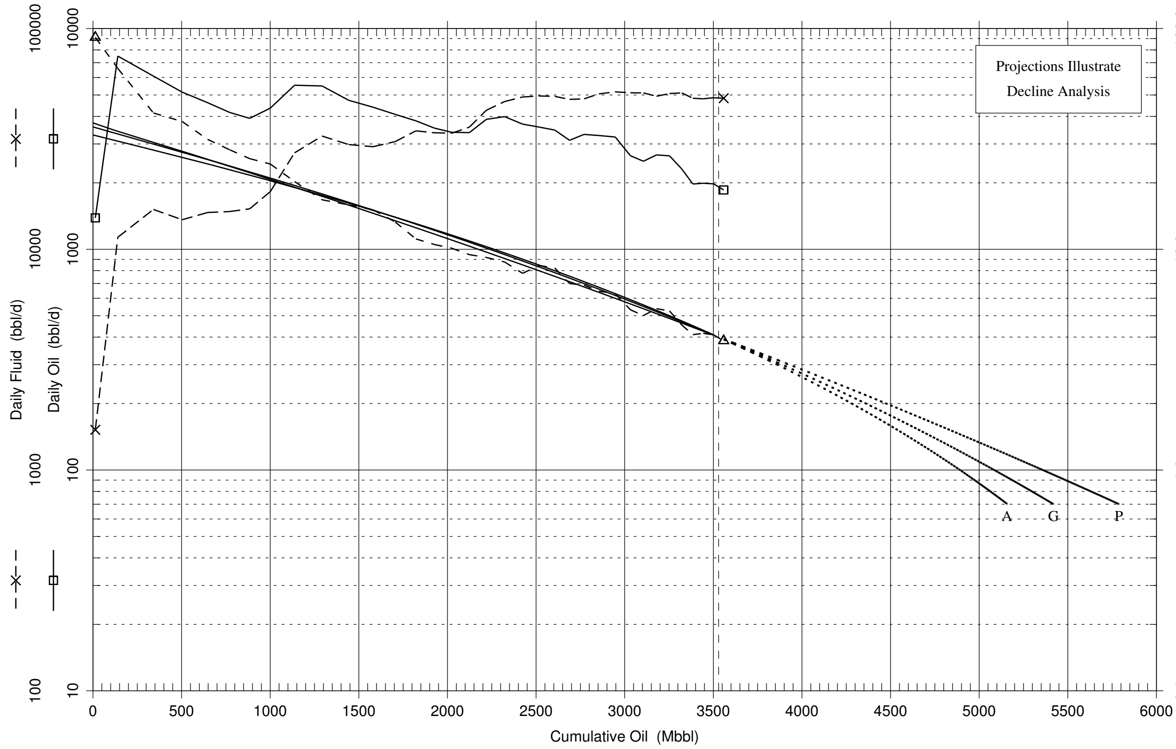
Average Production Rates (Last 12 months ending 1995/07/31)

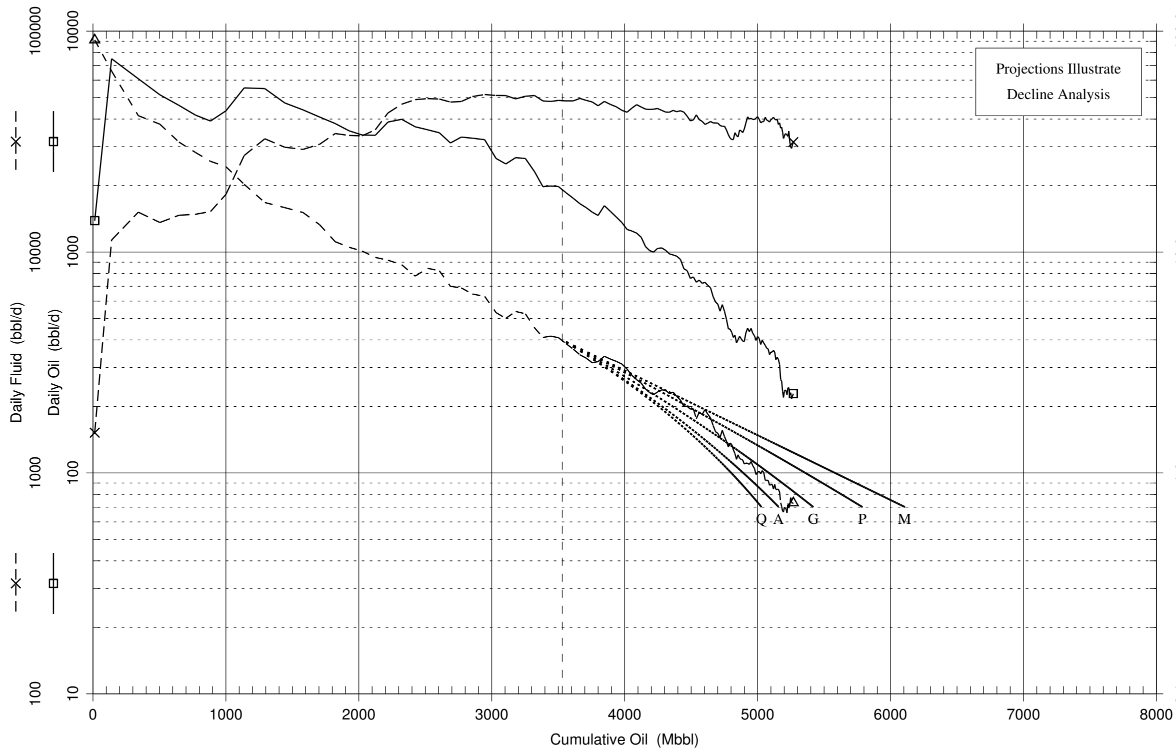
Gas :	538.9	Mcf/d	500.2	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	2534.3	bbl/d	2346.7	bbl/cd	GOR :	212.7	scf/stb
Avg Wells :	32.4				WC :	94.9	%

Cumulative Production

Oil :	3586.8	Mbbl	Gas :	481.5	MMcf	Water :	31328.2 Mbbl

Historical and Forecast Production
EXAMPLE F 1992 WELLS





Decline Analysis Summary @ 1995/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv Prd	—— A	5160	3530	1630	4.00%	0.70%	38.2%	0.70
Pv + Pb Prd	—— G	5420	3530	1890	4.00%	0.70%	35.9%	0.80
Pv + Pb + Poss Prd	—— P	5790	3530	2260	4.00%	0.70%	33.2%	0.90

Average Production Rates (Last 12 months ending 1995/07/31)

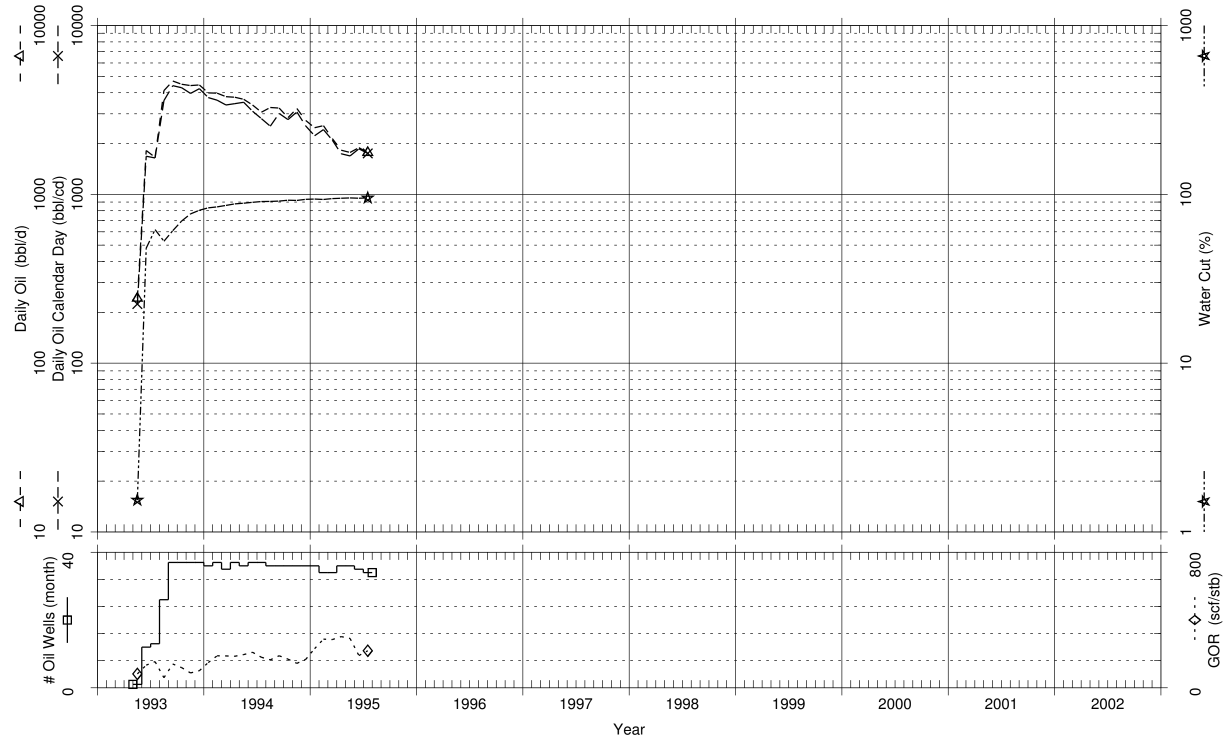
Gas :	538.9 Mcf/d	500.2 Mcf/cd		WGR :	>9999.9	bbl/MMcf
Oil :	2534.3 bbl/d	2346.7 bbl/cd		GOR :	212.7	scf/stb
Avg Wells :	32.4			WC :	94.9	%

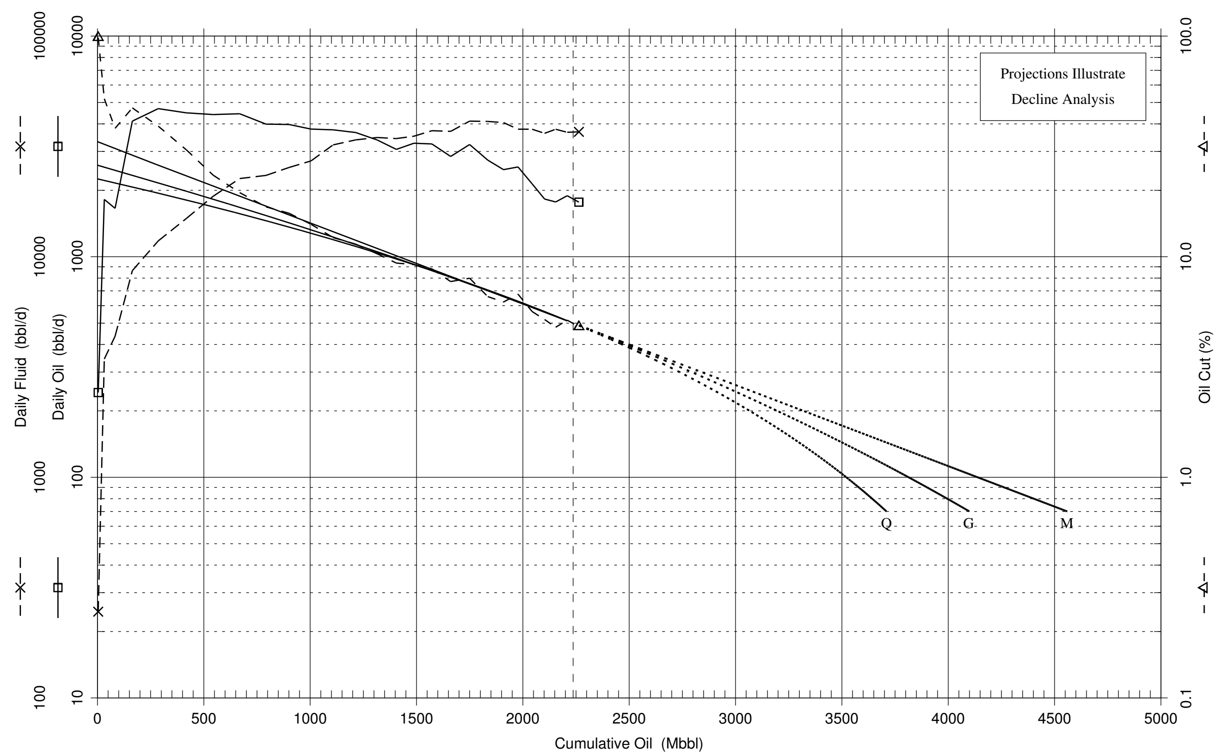
Cumulative Production

Oil : 3586.8 Mbbl Gas : 481.5 MMcf Water : 31328.2 Mbbl

Plot 41

Historical and Forecast Production
EXAMPLE F 1993 WELLS





Decline Analysis Summary @ 1995/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	4100	2236	1864	5.00%	0.70%	37.6%	0.80
Maximum Prd	M	4560	2236	2324	5.00%	0.70%	35.7%	1.00
Minimum Prd	Q	3710	2236	1474	5.00%	0.70%	40.4%	0.60

Average Production Rates (Last 12 months ending 1995/07/31)

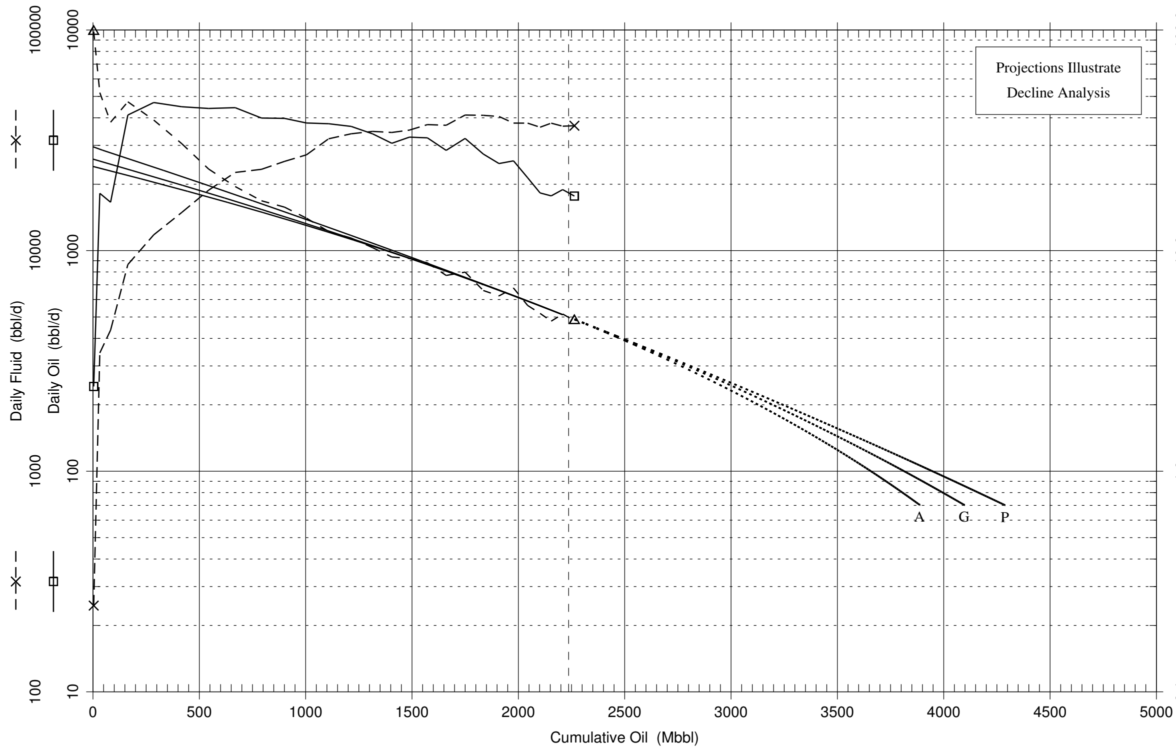
Gas :	529.0	Mcf/d	490.2	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	2479.0	bbl/d	2308.8	bbl/cd	GOR :	211.9	scf/stb
Avg Wells :	32.7				WC :	93.5	%

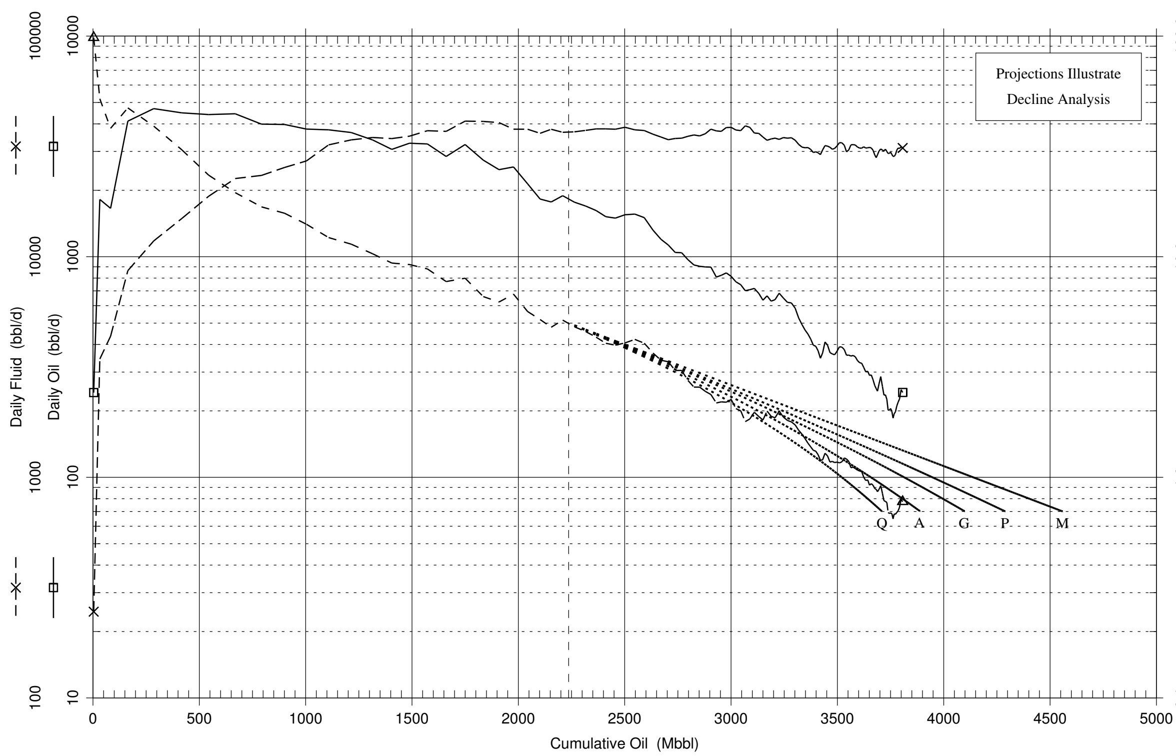
Cumulative Production

Oil : 2290.6 Mbbl Gas : 389.9 MMcf Water : 18754.7 Mbbl

Plot 42

Historical and Forecast Production
EXAMPLE F 1993 WELLS





Decline Analysis Summary @ 1995/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv Prd	A	3890	2236	1654	5.00%	0.70%	39.0%	0.70
Pv + Pb Prd	G	4100	2236	1864	5.00%	0.70%	37.6%	0.80
Pv + Pb + Poss Prd	P	4290	2236	2054	5.00%	0.70%	36.9%	0.90

Average Production Rates (Last 12 months ending 1995/07/31)

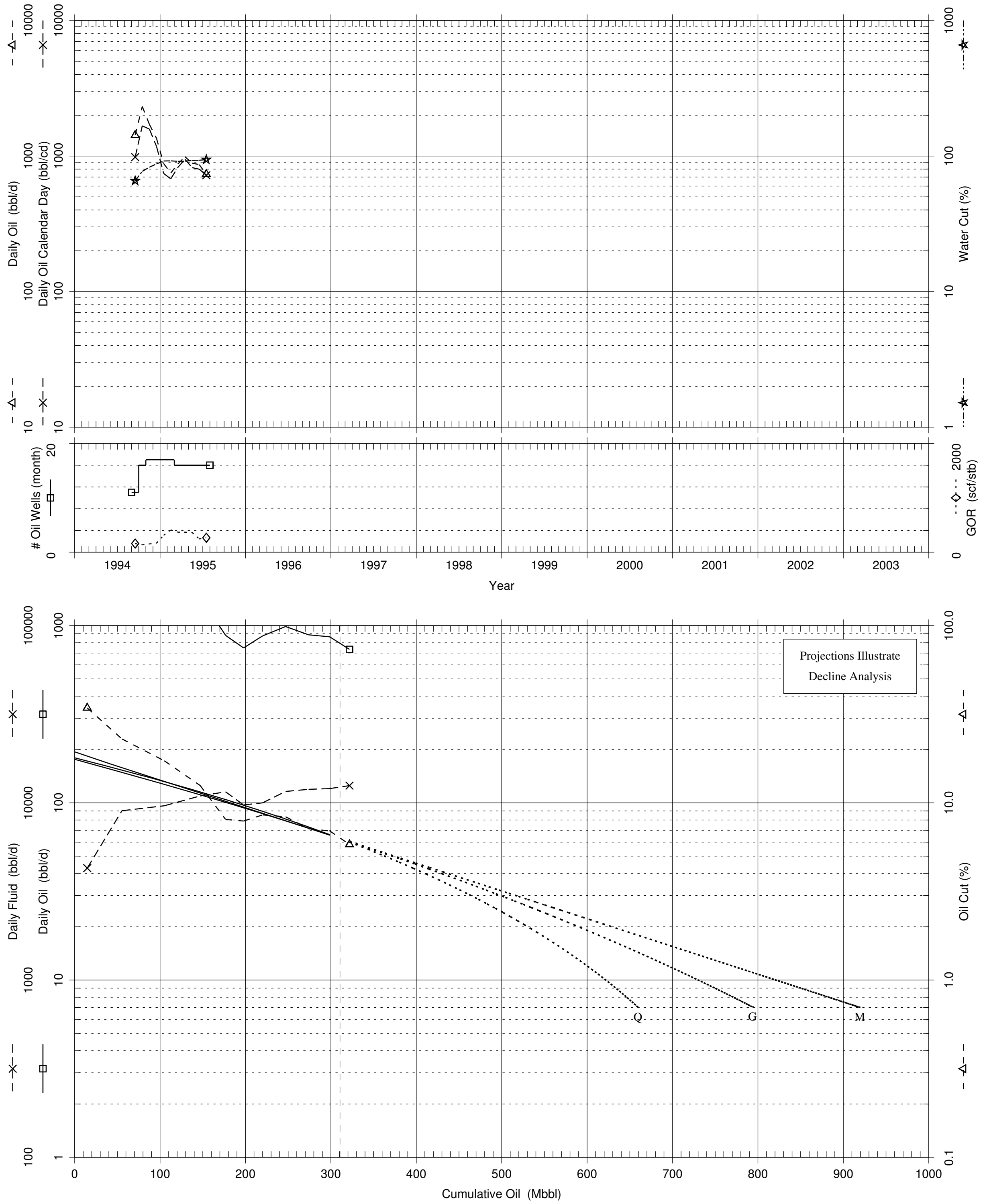
Gas :	529.0	Mcf/d	490.2	Mcf/cd	WGR :	>9999.9	bbl/MMcf
Oil :	2479.0	bbl/d	2308.8	bbl/cd	GOR :	211.9	scf/stb
Avg Wells :	32.7				WC :	93.5	%

Cumulative Production

Oil : 2290.6 Mbbl Gas : 389.9 MMcf Water : 18754.7 Mbbl

Plot 43

Historical and Forecast Production
EXAMPLE F 1994 WELLS



Reserves Classification		Ultimate	Cum Prd	Remain	Oil Cut % Initial	Oil Cut % Final	Decline Initial	Decline Expont
Pv + Pb Prd	G	795	311	484	6.30%	0.70%	52.4%	0.80
Maximum Prd	M	920	311	609	6.30%	0.70%	49.9%	1.00
Minimum Prd	Q	660	311	349	6.30%	0.70%	58.4%	0.60

Decline Analysis Summary @ 1995/07/01 — Reserves (Mbbl)

Average Production Rates (Last 12 months ending 1995/07/31)

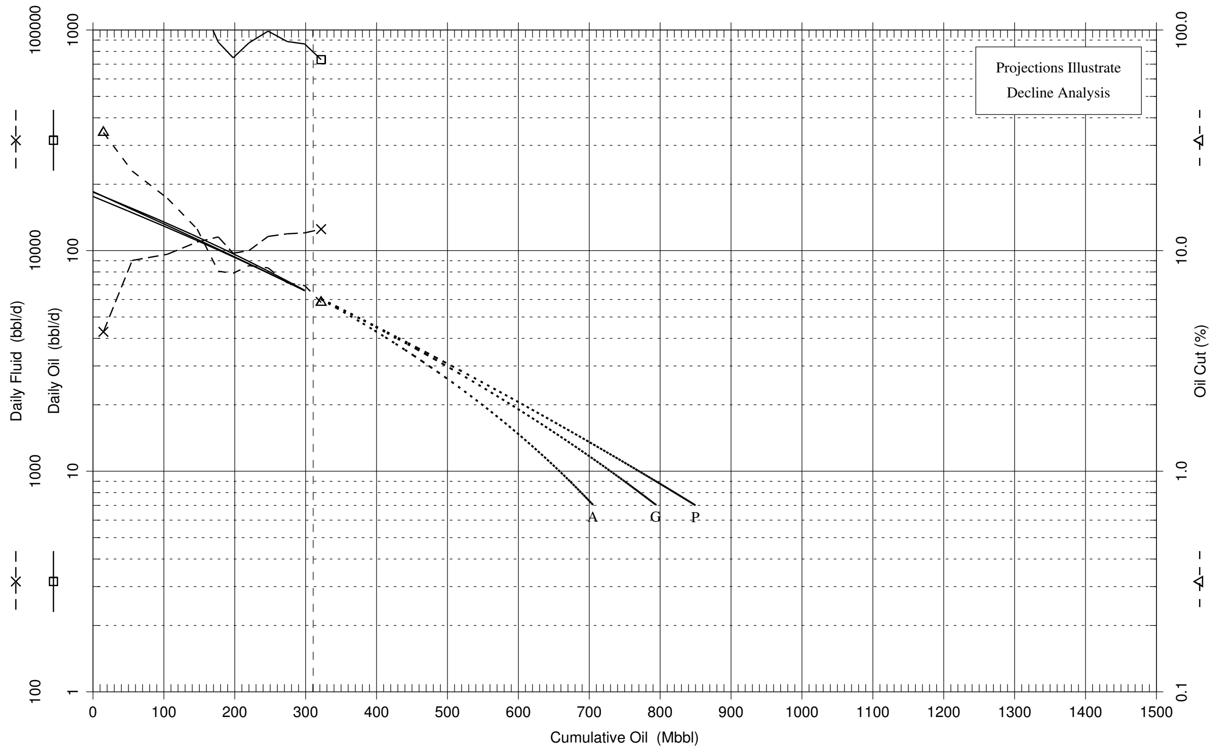
Gas :	283.9 Mcf/d	242.9 Mcf/cd	WGR :	>9999.9 bbl/MMcf
Oil :	1162.4 bbl/d	995.1 bbl/cd	GOR :	243.4 scf/stb
Avg Wells :	12.4		WC :	89.4 %

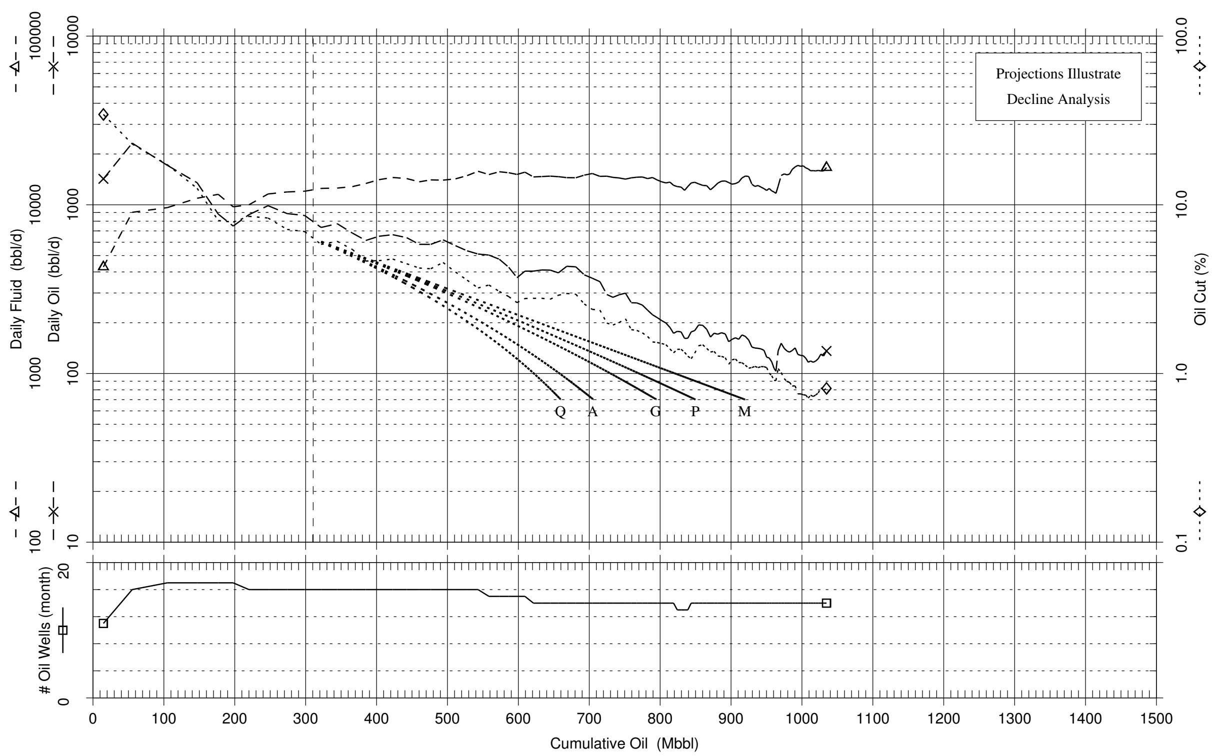
Cumulative Production

Oil : 333.0 Mbbl Gas : 81.1 MMcf Water : 2796.7 Mbbl

Plot 44

Historical and Forecast Production
EXAMPLE F 1994 WELLS





Decline Analysis Summary @ 1995/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Oil Cut % Initial	Final	Decline Initial	Expont
Pv Prd ——	A	706	311	395	6.30%	0.70%	56.3%	0.70
Pv + Pb Prd ——	G	795	311	484	6.30%	0.70%	52.4%	0.80
Pv + Pb + Poss Prd ——	P	850	311	539	6.30%	0.70%	51.2%	0.90

Average Production Rates (Last 12 months ending 1995/07/31)

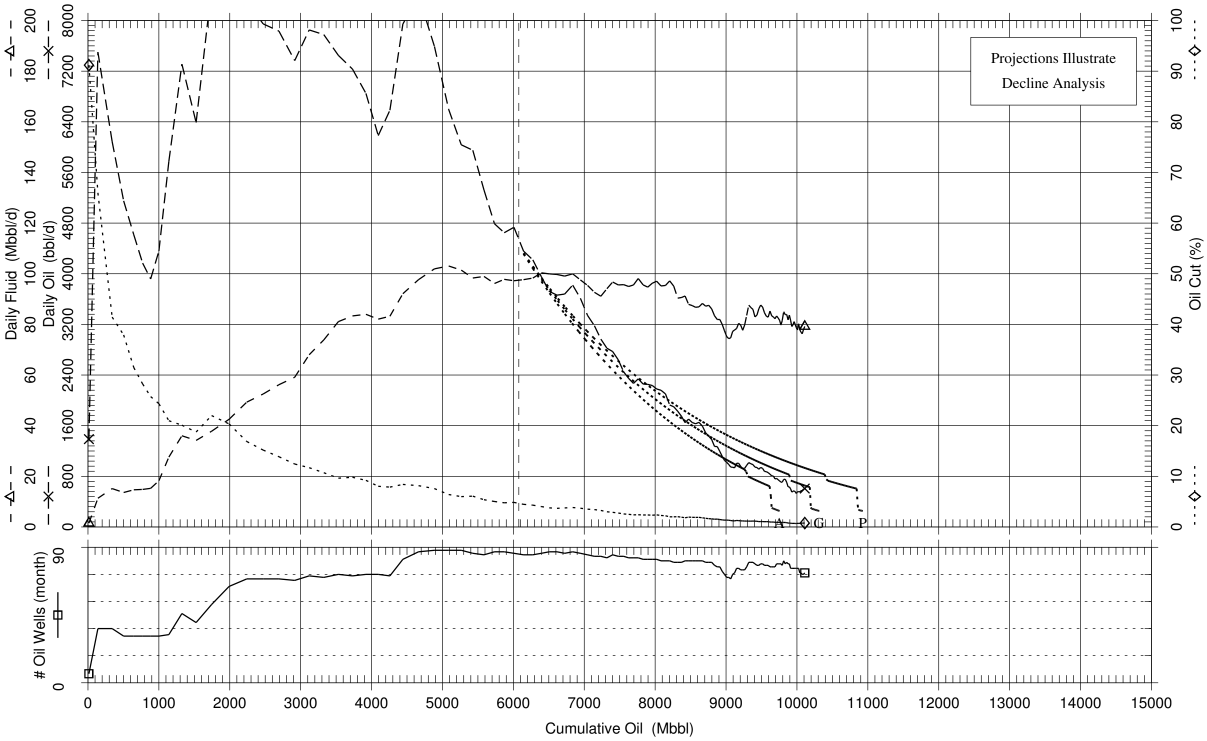
Gas :	283.9 Mcf/d	242.9 Mcf/cd	WGR :	>9999.9 bbl/MMcf
Oil :	1162.4 bbl/d	995.1 bbl/cd	GOR :	243.4 scf/stb
Avg Wells :	12.4		WC :	89.4 %

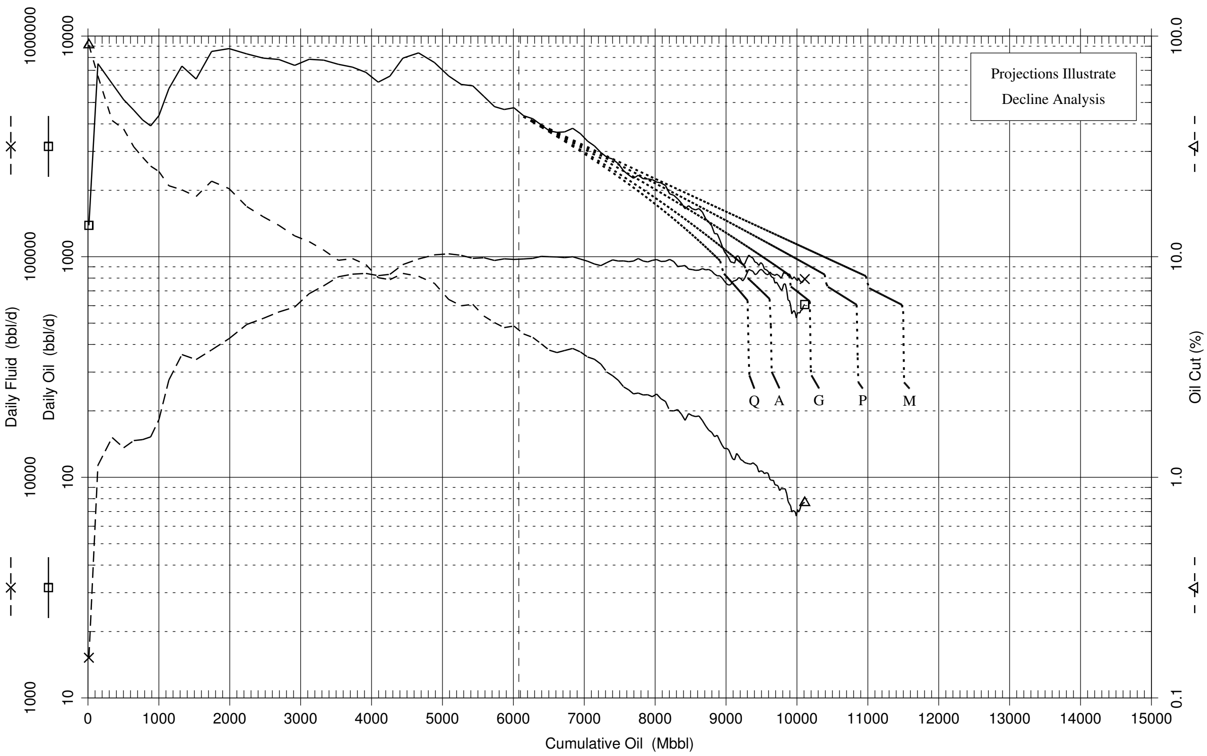
Cumulative Production

Oil : 333.0 Mbbl Gas : 81.1 MMcf Water : 2796.7 Mbbl

Plot 45

Historical and Forecast Production
Oil Decline Example F (All Wells)





Total Reserves Summary @ 1995/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
Pv Prd	—— A(R)	9756	6077	3679
Pv + Pb Prd	—— G(R)	10315	6077	4238
Pv + Pb + Poss Prd	—— P(R)	10930	6077	4853

Average Production Rates (Last 12 months ending 2003/01/31)

Gas :	365.4 Mcf/d	353.1 Mcf/cd	WGR :	>9999.9 bbl/MMcf
Oil :	565.8 bbl/d	546.3 bbl/cd	GOR :	646.8 scf/stb
Avg Wells :	71.8		WC :	99.3 %

Cumulative Production

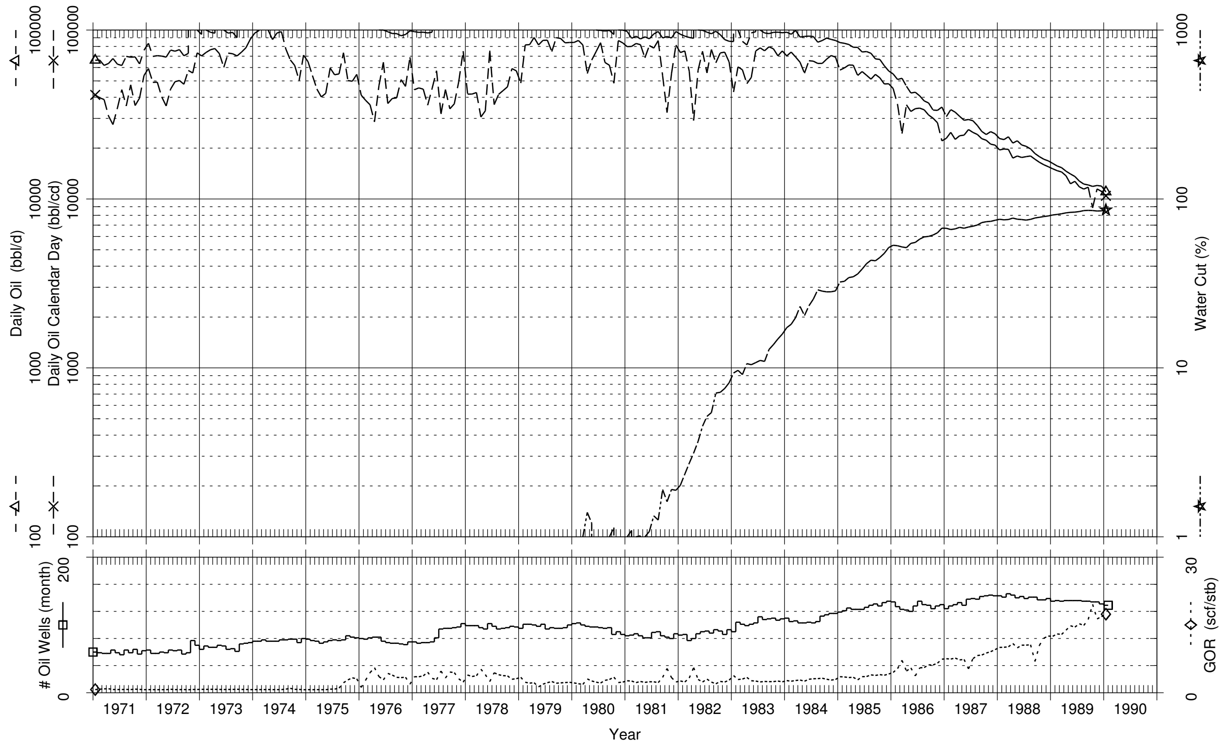
Oil : 10119.5 Mbbl Gas : 2352.4 MMcf Water : 276045.7 Mbbl

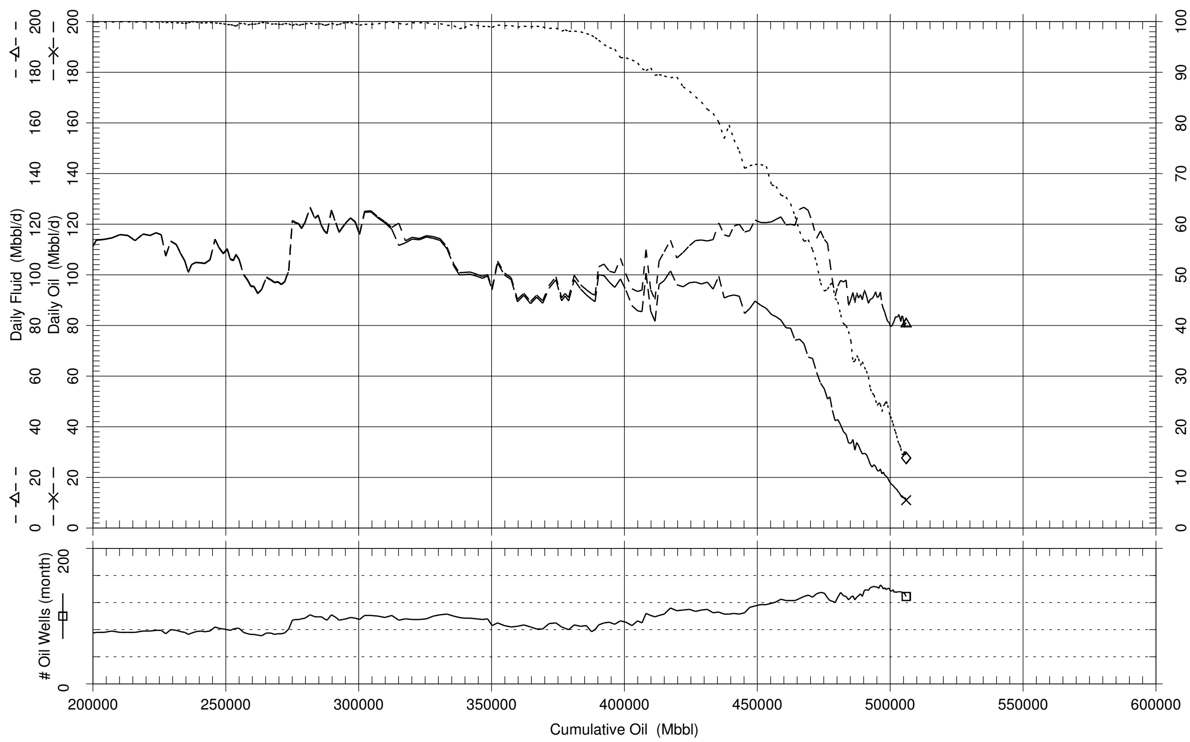
Oil Example G (Group Analysis)

Oil Example G is a bottom-water drive, thick, highly permeable, unstratified light oil reservoir with an overlying gas cap. The production history to January 1990 is illustrated on Plot 47. The recommended interpretation from visual curve fitting for 2P reserves uses a hyperbolic decline exponent of 0.2, which yields ultimate reserves of 519 MMstb (Plot 48, Line G). Reasonable visual fits can be achieved using hyperbolic exponents between 0 (minimum, Line Q) and 0.4 (maximum, Line M). Proved and 3P reserves are estimated using hyperbolic exponents of 0.1 (Line A) and 0.3 (Line P), respectively, as depicted on Plot 49.

Actual performance since the date of the decline analysis was initially along the proved forecast, then above the forecast due to a series of recompletion workovers to better target the remaining oil column. The stabilization of production rates that occurred as a result of the workovers is not predictable from decline analysis. Volumetric rationalization of oil-water and gas-water contact movements is required to identify and quantify the recompletion reserves opportunities.

Historical Production
OIL EXAMPLE G





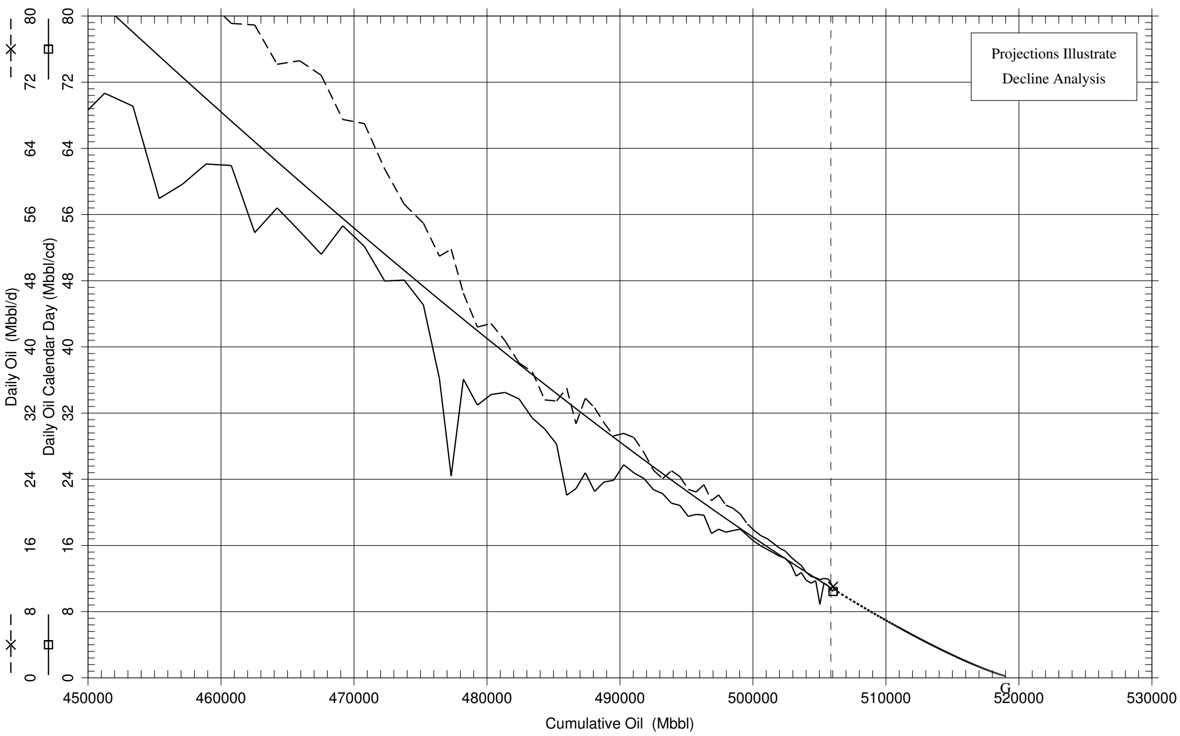
Cumulative Production

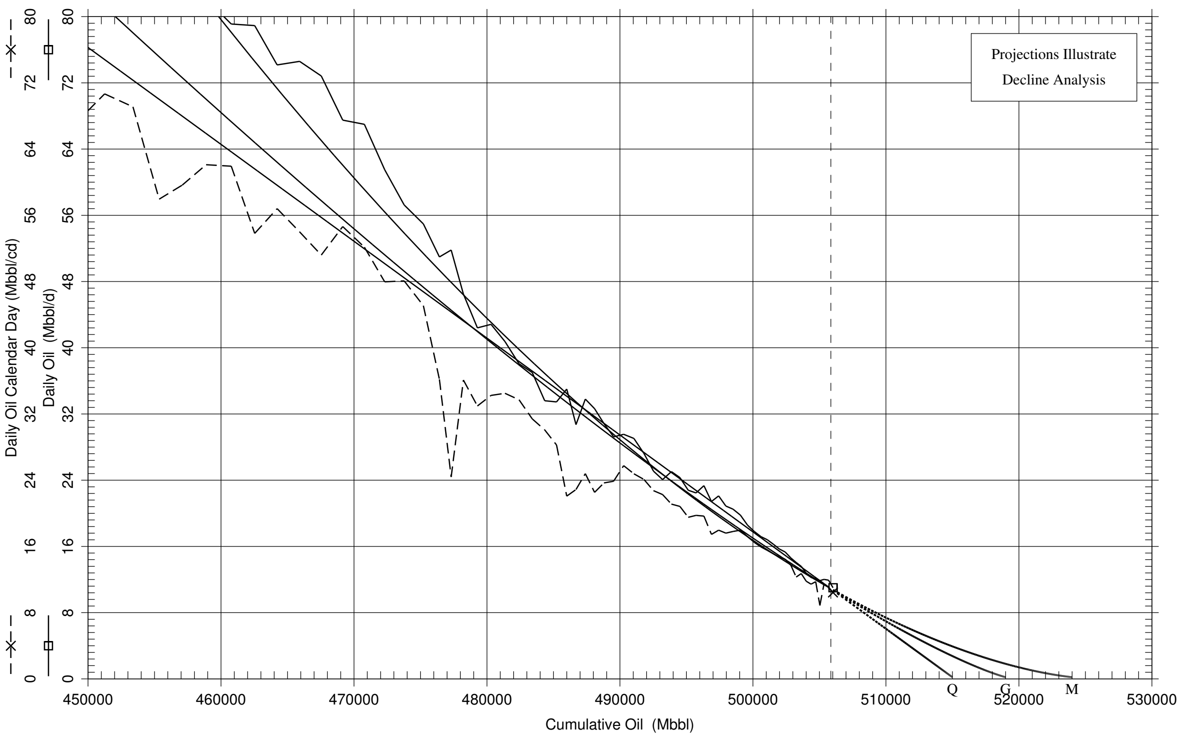
Gas :	1113604.1	MMcf
Oil :	506182.0	Mbbl
Water :	110068.9	Mbbl

Average Production Rates (Last 12 months ending 1990/01/31)

Gas :	205746.1	Mcf/d	183691.8	Mcf/cd	WGR :	346.3	bbl/MMcf
Oil :	13099.2	bbl/d	12060.5	bbl/cd	GOR :	15254.1	scf/stb
Avg Wells :	130.8				WC :	84.1	%

Historical and Forecast Production
OIL EXAMPLE G





Decline Analysis Summary @ 1990/01/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Prd	Remain	Rates (bbl/d) Initial	Final	Decline Initial	Expont
Pv + Pb Prd	G	519000	505858	13142	10900	200	29.6%	0.20
Maximum Prd	M	524000	505858	18142	10900	200	26.8%	0.40
Minimum Prd	Q	515000	505858	9142	10900	200	34.8%	0.00

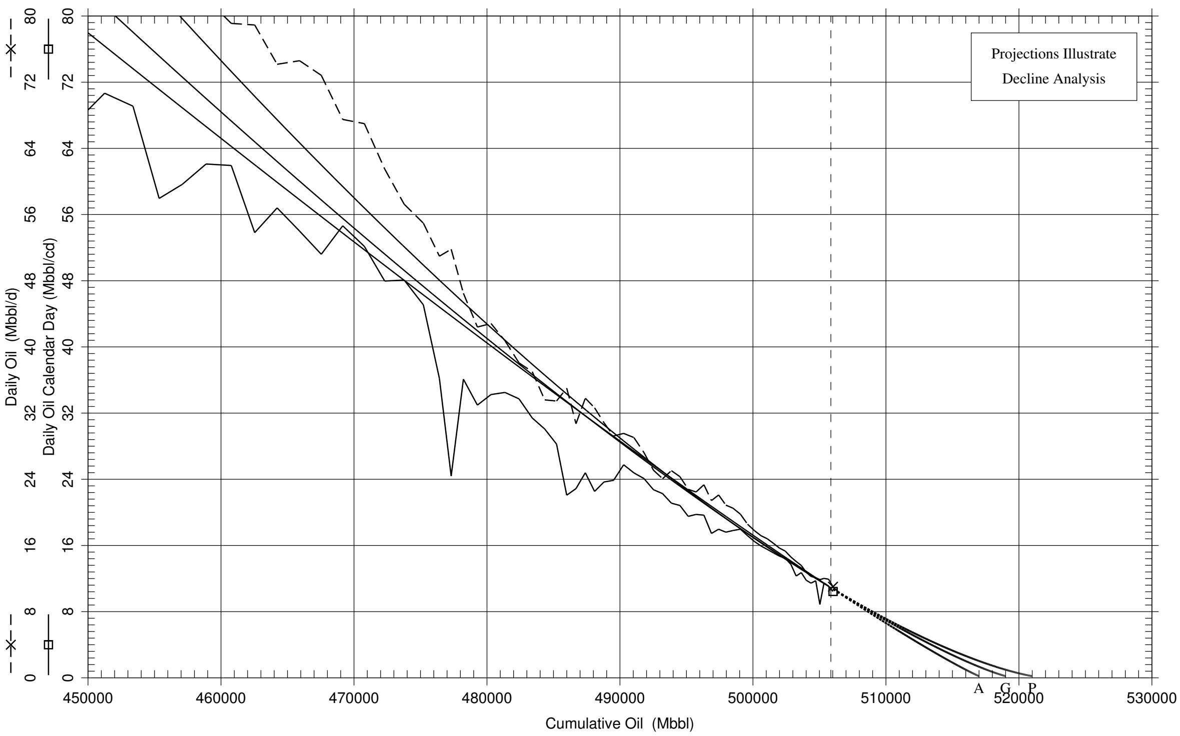
Average Production Rates (Last 12 months ending 1990/01/31)

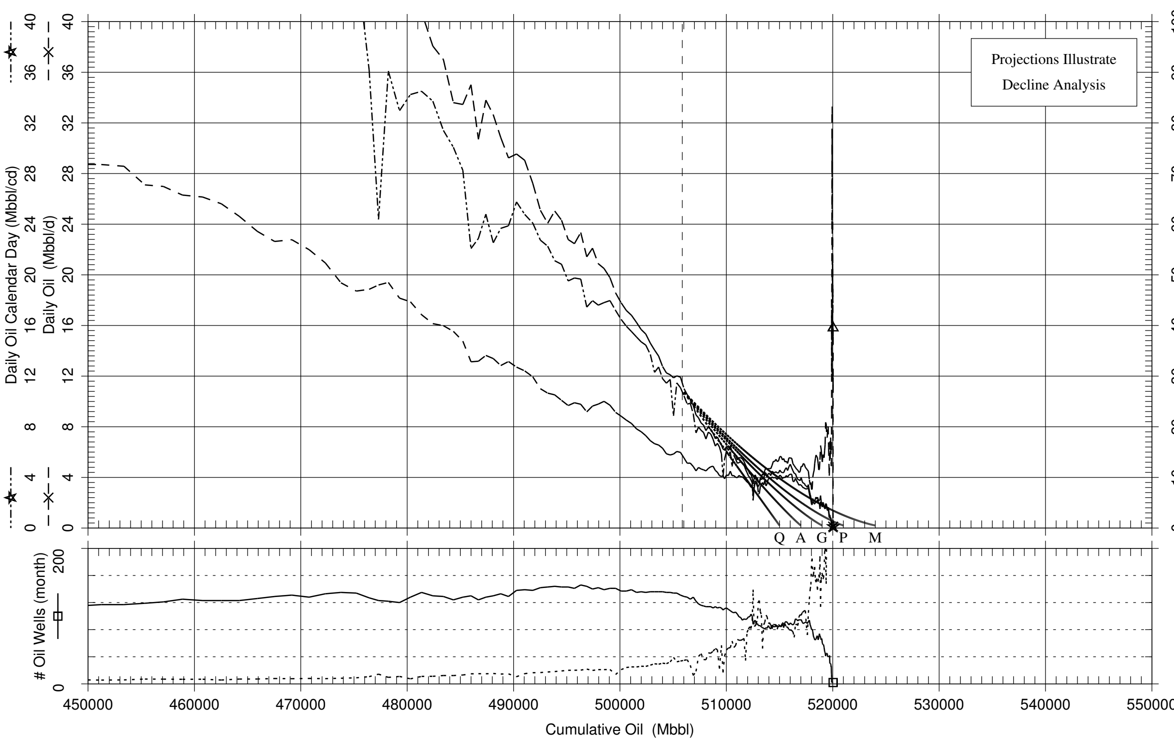
Gas :	205746.1 Mcf/d	183691.8 Mcf/cd	WGR :	346.3 bbl/MMcf
Oil :	13099.2 bbl/d	12060.5 bbl/cd	GOR :	15254.1 scf/stb
Avg Wells :	130.8		WC :	84.1 %

Cumulative Production

Oil : 506182.0 Mbbl Gas : 1113604.1 MMcf Water : 110068.9 Mbbl

Historical and Forecast Production
OIL EXAMPLE G





Decline Analysis Summary @ 1990/01/01

Reserves Classification		Reserves (Mbbl)			Rates (bbl/d)		Decline	
		Ultimate	Cum Prd	Remain	Initial	Final	Initial	Expont
Pv Prd	A	517000	505858	11142	10900	200	31.5%	0.10
Pv + Pb Prd	G	519000	505858	13142	10900	200	29.6%	0.20
Pv + Pb + Poss Prd	P	521000	505858	15142	10900	200	28.5%	0.30

Average Production Rates (Last 12 months ending 1990/01/31)

Gas :	205746.1	Mcf/d	183691.8	Mcf/cd	WGR :	346.3	bbl/MMcf
Oil :	13099.2	bbl/d	12060.5	bbl/cd	GOR :	15254.1	scf/stb
Avg Wells :	130.8				WC :	84.1	%

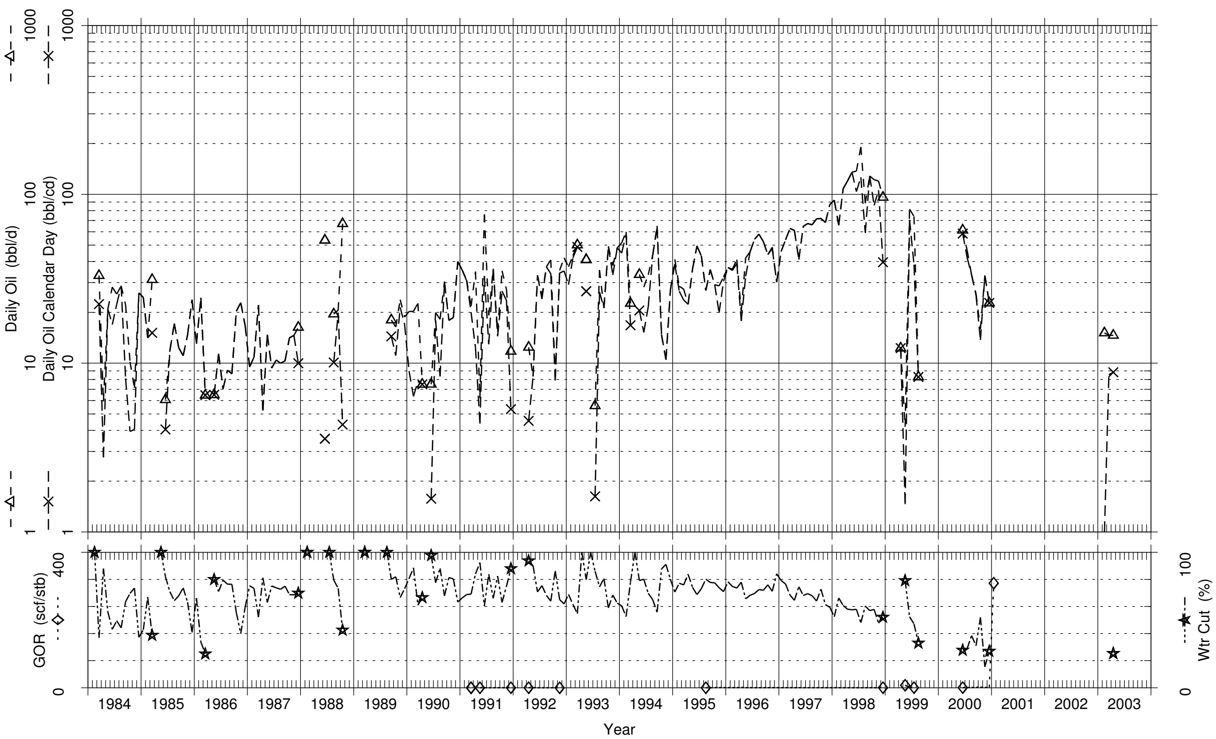
Cumulative Production

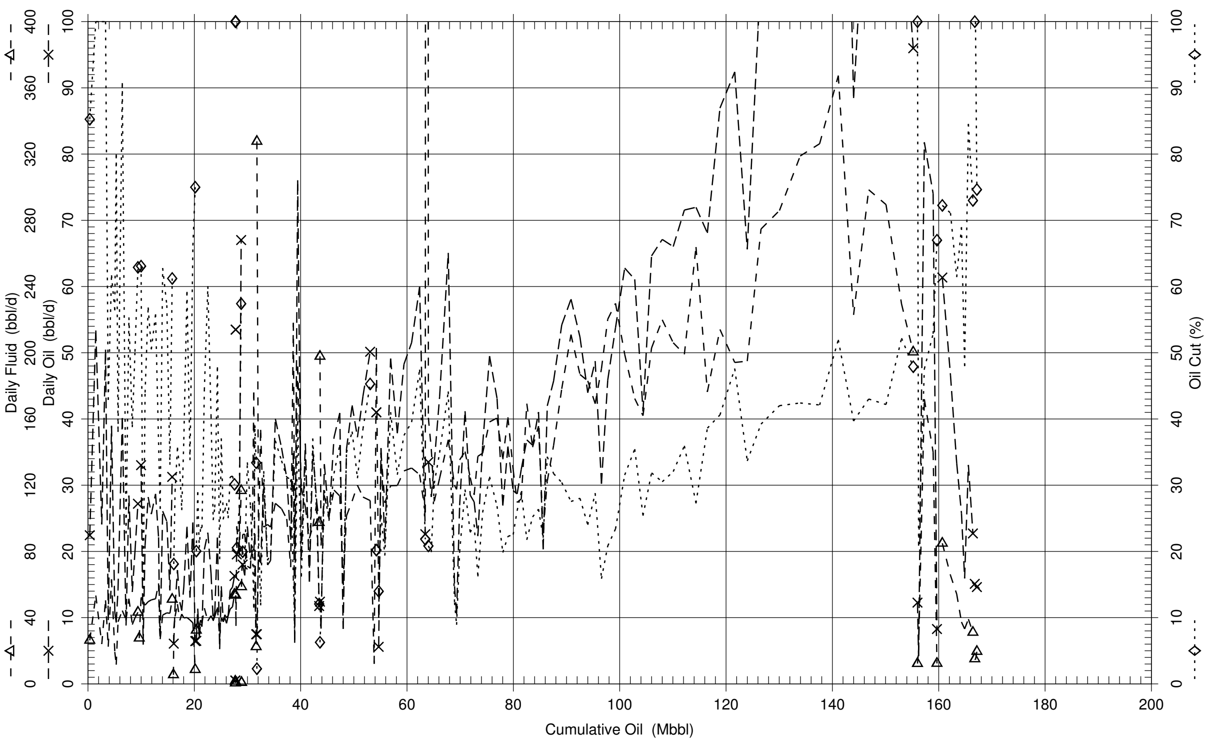
Oil : 506182.0 Mbbl Gas : 1113604.1 MMcf Water : 110068.9 Mbbl

Oil Example H

Oil Example H is a well in an unconsolidated, low GOR heavy oil well (Plot 50). Wells of this type cannot be analyzed from decline analysis and must be rationalized volumetrically using analogous recovery factors or performance analogies for reservoirs of this type. Production rates increase throughout the life of the well, because sand production continually increases the effective wellbore radius, and foamy oil behaviour with depressurization increases oil mobility. At some point, however, reservoir energy is lost, and/or the wellbore wormholes collapse, and the well ceases production.

Historical Production
Oil Decline Example H





Status Summary		Cumulative Production		Average Production Rates (Last 12 months ending 2003/04/30)			
On Production date :	82/08/08	Gas :	30.6 MMcf	Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR : 0.0 bbl/MMcf
Status date :	03/02/18	Oil :	167.3 Mbbl	Oil :	14.8 bbl/d	5.8 bbl/cd	GOR : 0.0 scf/stb
Status : OIL		Water :	338.0 Mbbl	On Prod :	36.3 days		WC : 14.5 %

Table 6-1 Decline Examples — Summary of Analysis

									Minimum	Proved	3P	Maximum
		Depletion at	Decline Exponents						% Less Than	% Less Than	% Greater Than	% Greater Than
Example	**Type of Reservoir**	**Analysis Date**	**Minimum**	**Proved**	**P+Pb**	**3P**	**Maximum**		**P+Pb**	**P+Pb**	**P+Pb**	**P+Pb**
Gas												
A	Unstratified - No Line Pressure Reductions	83%	0.0	0.0	0.0	0.15	0.3		16%	8%	8%	16%
B	Unstratified - Some Line Pressure Reductions	34%	0.0	0.0	0.2	0.35	0.5		26%	16%	22%	50%
C	Unstratified - No Line Pressure Reductions	72%	0.0	0.0	0.0	0.15	0.3		8%	4%	10%	30%
D	Highly Stratified	52%	0.3	0.6	0.8	1.00	1.2		50%	24%	30%	71%
E	Moderately Stratified	64%	0.2	0.4	0.6	0.80	1.0		32%	20%	21%	44%
F	Water Drive	100%	Use volumetrics prior to water breakthrough									
Oil												
A	Unstratified Solution Gas Drive	80%	0.0	0.1	0.2	0.30	0.4		26%	15%	15%	30%
B	Unstratified Solution Gas Drive - Stimulation	90%	0.2	0.2	0.2	0.30	0.4		69%	38%	31%	75%
C	Unstratified Waterflood - Water Wet	91%	0.0	0.0	0.0	0.10	0.3		38%	18%	12%	32%
D	Moderately Stratified Waterflood - Water/Oil Wet	80%	0.0	0.3	0.4	0.50	0.6		46%	16%	16%	37%
E	Bottom Water Coning - Oil Wet - Well	60%	0.7	0.8	0.9	0.95	1.0		31%	18%	11%	21%
F	Bottom Water Coning - Oil Wet - Groups	59%	0.7	0.8	0.9	0.95	1.0		22%	13%	15%	30%
G	Vertical Bottom Water & Gas Cap Drives - Group	97%	0.0	0.1	0.2	0.30	0.4		30%	15%	15%	38%
H	Heavy Oil - Cold Production	100%	Use volumetrics.									

6.6 Reservoir Simulation Methods

(IN PROGRESS)

6.7 Reserves Related to Future Drilling and Planned Enhanced Recovery Projects

Reserves assignments relating to planned drilling and enhanced recovery projects are classified as undeveloped. The classification of the reserves assignment as proved, probable or possible depends on both technical and implementation risk, the guidelines for which are discussed in this section.

6.7.1 Additional Reserves Related to Future Drilling

Undeveloped reserves may be assigned to either infill or delineation/step-out wells as described below. Reserves may not be assigned to planned exploratory wells penetrating undiscovered accumulations.

a. Drilling Spacing Unit

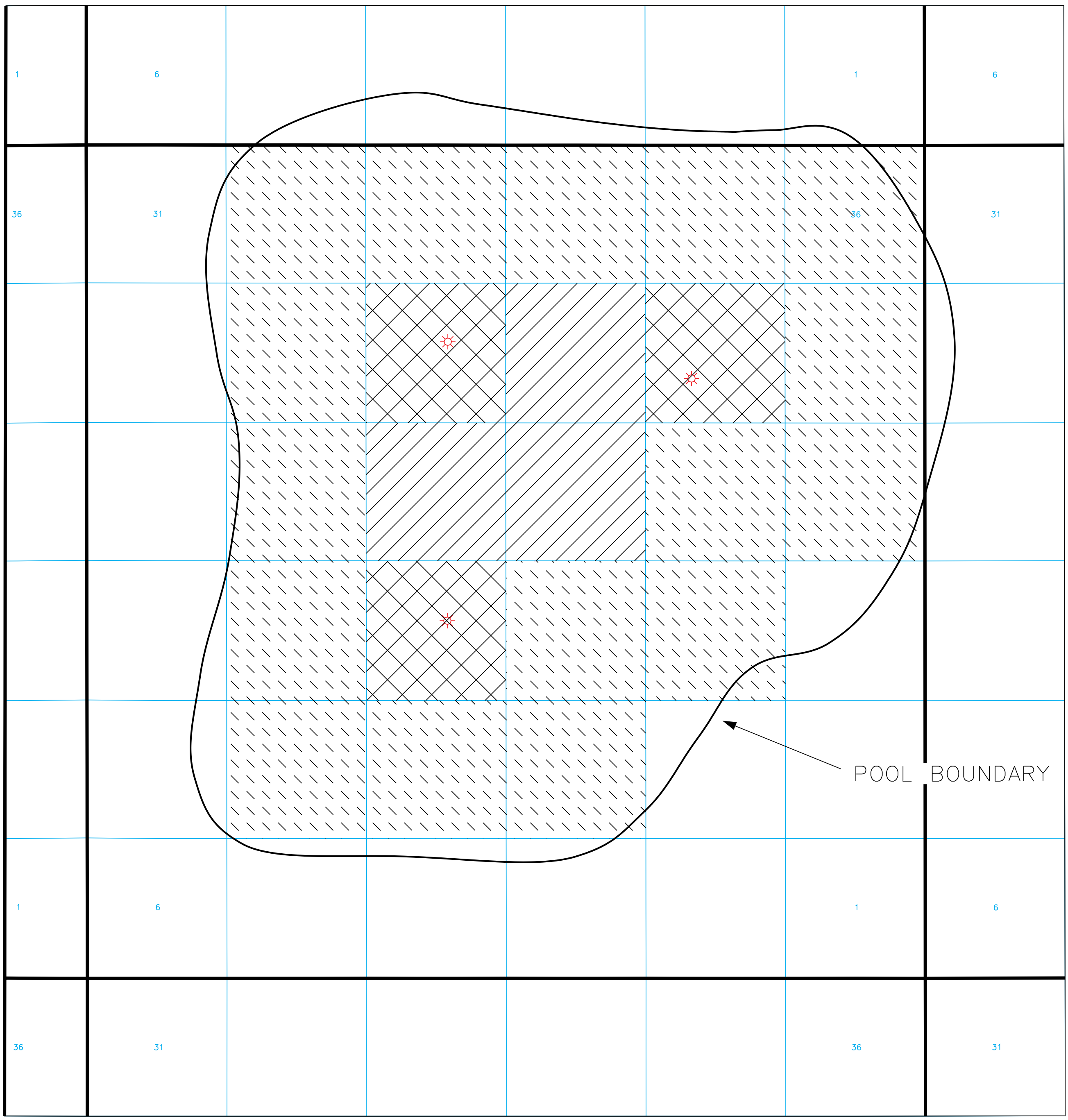
Drilling spacing unit (DSU) is the regulated drilling spacing size for an oil and gas accumulation. The spacing size might or might not coincide with the practical drainage area of a well. Usually a DSU is one section for gas and 1/4 section for oil. Gas DSUs are usually larger than oil DSUs, because the lower viscosity of gas allows for larger drainage area capability, not because gas pools are larger than oil pools. Reservoirs with high viscosity fluid or lower permeability rock will usually have smaller DSUs. DSUs are commonly used in North America, but not elsewhere. In reservoirs where DSUs are not established, the evaluator must use informed judgement as to a reasonable spacing unit size for developing the reservoir.

b. Infill Wells

Infill wells are wells drilled between two existing wells or within triangulation of three offset wells in a known common accumulation, as illustrated on Map 1. Infill wells are drilled to accelerate and/or improve recovery. In primary reservoirs, infill wells may be drilled if the practical drainage area of the existing wells is too small to effectively develop the pool in a timely manner. They may also be drilled to access pore volume not currently connected to existing wellbores. In EOR schemes, infill wells are drilled to improve sweep efficiency and/or pore volume connectivity.

Map 1

Infill / Delineation Example



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LEGEND:

- Drilled
- Infills
- Delineation

Reserves from infill wells may be proved, probable, or possible, depending on the amount and reliability of data and on the technical assessment. An assessment must be made of incremental versus accelerated recovery associated with the wells, and accounted for in the total pool reserves assignment. Where possible, the results of analogous infill drilling schemes should be reviewed to assist in the assessment. The best estimate of incremental recovery is classified as 2P. The initial proved increment is usually equal to the 2P value minus between 1/3 and 2/3 of the difference between the 2P and a reasonable minimum estimate. Similarly, the initial 3P increment is usually equal to the 2P value plus between 1/3 and 2/3 of the difference between the 2P and a reasonable maximum estimate. It is common practice to classify a reasonable portion of infill well reserves as proved. The proved increment should increase once drilling confirms actual productivity, pressure, and water cut.

c. Infill Analysis

Low-permeability, high-viscosity oil, and/or discontinuous reservoirs require denser drilling spacing than do high-permeability, low viscosity oil, and/or homogeneous reservoirs to effectively drain the reservoir. When reliable volumetric data are available, recovery factors from decline analysis of existing producing wells can be determined. Using analytical calculations or reservoir modelling, recovery factors for planned infill drilling can be calculated. These calculated incremental reserves for planned drilling are either 3P or 2P values. The portion classified as proved and probable depends on the reliability of the volumetric data and cutoff criteria.

Volumetric data are often unreliable in low-permeability reservoirs due to uncertainty in estimating effective pay. In these cases, the only reliable way of estimating incremental reserves for infill drilling is through analogies to other similar infill drilling projects that have quantifiable results. If volumetric data or analogies are not available or reliable, then incremental reserves from infill drilling should only be classified as possible.

d. Delineation or Step-Out Wells

Delineation or step-out wells are wells drilled in discovered pools that are not infill wells, as depicted on Map 1. Delineation wells are usually drilled to drain parts of the pool not currently being drained by existing wells and to substantiate pool mapping. Delineation drilling usually occurs in pools with primary recovery schemes, because enhanced recovery schemes are usually only implemented after the pool has been delineated. An exception to this is where new seismic data or reprocessing has redefined pool edges after implementation of an EOR scheme.

i. Classification

Reserves from delineation wells may be proved, probable, or possible, depending on geological confidence. For pools that are not fully delineated, there are usually halos of proved, probable and possible locations surrounding existing well control. The size and shape of these halos and the number of locations therein depend on the amount, quality, and reliability of the data and on the geological interpretation. An evaluator must decide, based on the available data, if the mapping of the pool represents 2P or 3P confidence levels. A suggested method of classifying drilling locations is to contour proved and probable limits on net pay mapping, with the limits defined as percentages of the distance between the pool edge and well control. The percentages selected depend on the evaluator's confidence in the mapping. The pore volumes of the proposed locations are those calculated from these undeveloped halos. Unless probabilistic methods are used, the best estimate pay cutoffs should be used in the mapping preparation.

ii. Qualifiers to Classification

Notwithstanding the above guidelines, only reserves of locations in spacing units directly or diagonally adjacent to currently drilled productive spacing units may be classified as proved, provided the evaluator has high certainty in the reservoir continuity and productivity at the locations. Locations beyond one spacing unit step-out are usually not classified as proved, unless compelling evidence of reservoir continuity, such as seismic data, pressure data, and well control, are available. Best estimate interpretations of reservoir mapping, properties, and recovery should be considered when classifying reserves as 2P. Usually, only wells that are an additional DSU step-out from proved locations are classified as probable, unless reasonable evidence of reservoir continuity is available. Delineation wells located in regions between best estimate and low certainty interpretations of reservoir mapping are classified as possible. It is up to the geological and engineering evaluators to classify the portions of the mapped reservoir as proved, probable, or possible. If best estimate mapping was prepared, there will be no possible locations within the mapped extent, because these will all be 2P locations. If 3P reserves are desired, either a halo of possible reservoir extent and reservoir parameters must be derived, or else 3P mapping must be prepared.

iii. Adjustments for Reservoir Quality

When estimating reserves of future drilling locations, evaluators must recognize the risks related to, and the recoverability of, oil and gas in place. In some types of reservoirs, permeability is lower closer to the edge of pools, which frequently lowers recovery factors. In other types of reservoirs, wells located closer to pool edges are closer to water contacts, which could also result in impeded recovery efficiency. In these types of reservoirs, reduced proved and 2P recovery factors should be assigned to delineation wells to reflect this behaviour.

e. Drilling Statistics

Historical drilling statistics are often reviewed as a guide to estimate reserves or resources for an area. Historical statistics include items such as success rates and median and average reserves per well. For undrilled accumulations, volumes derived on the basis of historical statistics must not be classified as reserves, because these are prospective resources, not reserves.

In certain types of pools that are mapped extensively (continuous deposits), reservoir quality is random and unpredictable. Drilling in these types of reservoirs results in successes and failures within the boundaries of the defined pool. In these types of deposits, in addition to conventional technical analysis of recoverable reserves, proved + probable reserves assignments for future drilling locations should consider the average reserves per well of past drilling, including successes and failures. The difference between the median and mean values should be considered when estimating 2P reserves. For proved reserves assignments, more conservative reserves per well should be assigned after considering the range in historical results of past drilling. Also, as a guide for multi-well programs, the number of proved locations should be limited to between 1/3 and 2/3 of the number of 2P locations, provided technical proved criteria are also met.

Similar to drilling statistics, historical statistics should also be reviewed when assessing reserves of workover programs.

f. Likelihood of Drilling

The likelihood that a well will be drilled is a consideration in classifying reserves. Future wells that an evaluator believes have a high probability of being drilled should be classified as proved, provided other proved certainty criteria are met. For probable reserves, a high probability of drilling is preferred, but a reasonable probability (more often than not) is acceptable provided further risking is applied as described below. For possible reserves, a lower probability is acceptable, but there should be at least a 50% probability the well will be drilled.

The timeline of drilling must reflect operator plans and potential access problems, and there must be no perceived impediments to approval. Locations that have uncertainty of being drilled because of potential regulatory constraints should not be classified as proved or probable.

Because, for most routine drilling programs, companies might only have firm plans for the upcoming fiscal year, the likelihood of drilling falls to the judgement of the evaluator. If the drilling locations being assessed by the evaluator are not in the company plans, the reasons for this should be examined prior to classifying reserves:

- If the operator has not yet completed an assessment of the locations and the evaluator strongly believes they are viable economic locations, then proved or probable reserves, depending on confidence levels, may be assigned, with the drilling scheduled for subsequent years.

- If the operator has examined the locations and believes they are not technically justified, then the evaluator should reassess the locations, because there could be some uncertainty in the success of the drilling program. If the evaluator, upon reconsideration, still believes in the merits of the drilling program and that it will eventually be undertaken, then proved or probable reserves, depending on the evaluator's confidence level, may still be assigned, with implementation delayed sufficiently in the future. These situations, where an evaluator assigns proved or probable reserves to locations the operator indicates will not be drilled, should be rare. In these cases, if the project is a multi-well program, a staged approach to classifying the locations as proved or probable could be warranted to confirm performance prior to classifying the remaining wells. If the operator is not planning to drill certain locations that the evaluator has assessed as technically possible, it is unreasonable to expect that the wells will be drilled. Therefore, no reserves should be assigned.

- If the drilling project economics are marginal, the evaluator should review evidence of commitment to the project prior to classifying reserves as proved, probable, or possible. As in the above situation, if the project is a multi-well program, a staged approach to classifying the locations as proved or probable could be warranted to confirm performance prior to classifying the remaining wells. Technically certain but marginally economic projects require evidence of company commitment before being classified as proved. Such evidence may be in the form of AFEs, budgets, or letters of intent from the company.

- If reserves have been previously assigned to drilling locations, but the drilling plans have been deferred, the evaluator should examine the reason for the deferral. If drilling economics are marginal, the deferral could indicate lack of company commitment and the reserves should be reclassified in a higher risk category. If the technical and/or economic merit is still viable, but the deferral is due to budget constraints, the reserves classification should not be changed. If technical or economic issues have changed, then the reserves classification should be reassessed to reflect the change. The production and economic forecasts will also change to reflect the new timeline.

For reserves classification, if technically probable well locations do not have a high probability, but have a reasonable probability, of being drilled, an allowance should be made in order to achieve a 50 percent probability that the estimate will be met or exceeded. This is illustrated in the situation where six well locations have probable reserves of 2 Bcf/well. The locations have been included in the operator's budget, but they have marginal economics and have not received approval for drilling. The evaluator believes there is only a 50/50 chance the wells will actually be drilled. In this situation, the P_{50} reserves are 6 Bcf (six wells x 2 Bcf/well x 50 percent chance of drilling). If the evaluator includes all six wells as probable, without an allowance, the probable reserves in the evaluation are 12 Bcf, which will not meet the definitional requirement for probable certainty of at least 50 percent. The recommendation in this situation is for the evaluator to schedule only the risked number of probable wells, which in this case are three, with the remainder classified as possible. For the situation where only one probable location is forecast with a 50/50 chance of being drilled, half the reserves and capital should be used in the analysis. (This is not the same situation where a well is forecast to be drilled with a 50 percent chance of success, in which case 100 percent of the capital and the risked reserves are used). When probable locations have a high certainty of being drilled, this further allowance is not necessary.

For wells that are technically possible locations but have less than a 50% likelihood of being drilled and placed onstream in a reasonable timeframe, no reserves should be assigned, because these are more suitably classified as contingent resources.

g. Time Constraints

Time constraints of drilling programs should not affect reserves classification decisions, as long as the certainty of their occurrence meets the appropriate reserves classification criteria, and provided there are technically and economically justified and logical reasons for delayed drilling (e.g., facility constraints, allowable constraints, capital budget constraints, orderly development). For drilling programs that are marginally economic, proved reserves should be limited to the extent to which the company has shown commitment. Marginally economic projects outside the time period committed by the company should be classified as probable or possible, depending on the levels of technical and implementation certainty. Because the likelihood of implementation has diminished for these uncommitted locations, only the risked portion of the drilling should be assigned probable reserves, as described in section f. above.

6.7.2 Examples of Future Drilling

Case A1

Background

A low-permeability shallow gas area was initially developed on 640-acre spacing. After a decade of history, the area is being considered for downspacing to 320-acre spacing. Due to the shale content of the sand, volumetric data are unreliable. Based on decline analysis, the existing wells drilled on 640-acre spacing are forecast to recover 1 Bcf/well of 2P reserves) and 0.9 Bcf/well of proved reserves. A number of 320-acre analagous infill drilling projects in the area have been reviewed. The analogous wells with similar productivity to the subject area demonstrated that downspacing increased incremental reserves per section by between 40 percent and 80 percent of the initial well, with the average being 60 percent. Downspacing approval has not been obtained, but is highly likely based on similar approvals in the area. What initial incremental reserves assignments should be made for the proposed subject infill drilling program?

Recommendation

- 2P incremental reserves: = 0.6 Bcf/section based on the average expectation of the analogy wells.

- 1P incremental reserves: 0.4 Bcf/section based on the low expectation of the analogy wells.

- 3P incremental reserves: 0.8 Bcf/section based on the high expectation of the analogy wells.

It is expected that the 0.4 Bcf value will likely increase to 0.5 Bcf upon verification of expected initial rates with actual tests, and eventually to 0.6 Bcf with additional performance support.

Case A2

Background

In Case A1, after additional performance, the 2P reserves of the first well in the section are established at 0.9 Bcf/well and the second well is established at 0.7 Bcf/well, for a total of 1.6 Bcf/section. Proved reserves are 0.1 Bcf less per well, for a total of 1.4 Bcf/section. The operator is now planning to drill two more wells per section so as to develop the area on 160-acre spacing. No other analogous areas have been developed on 160-acre spacing. To estimate the incremental reserves, the operator has conducted a modelling study using initial assumed reservoir parameters and adjusting them to match the results of both the first and second existing wells. The model indicates that incremental reserves of 0.6 Bcf per section will result from drilling the additional two wells per section. Modelling accuracy from sensitivity analysis is estimated at +/-0.2bcf. A minimum 0.5 Bcf per section is required for the project to be economic. Current drilling spacing approval is two wells per section. Application for downspacing has been made based on the results of the modelling work; however, approval has not been obtained. There may be issues with surface lease owners and offset mineral lease owners regarding the project, but these can likely be resolved. What initial incremental reserves assignments should be made for the proposed subject infill drilling program?

Recommendation

- 2P incremental reserves: 0.6 Bcf/section based on the modelling work and expectation of approval.

- 1P incremental reserves: nil because the high certainty incremental reserves value is not economic, there are no analogies, and there may be problems obtaining downspacing approval.

- 3P incremental reserves: 0.8 Bcf/section based on the modelling work.

If the evaluator's technical assessment was that the high-certainty reserves were 0.5 Bcf/section (i.e., economic) and that project approval was highly certain, then proved reserves of 0.5 Bcf/section may be assigned, despite the absence of analogies. In all cases, the technical assessment must conclude that the model is reliably set up and calibrated to reflect performance of both the initial and second phases of drilling.

Case B

Background

An unconsolidated sand heavy oil reservoir producing under cold production technology is developed on 40-acre spacing. Based on typical reserves life indices and performance of some wells that are near depletion, proved, 2P, and 3P recovery factors are estimated at 6 percent, 7 percent, and 8 percent, respectively. Other analogous pools in the area developed on 20-acre spacing usually recover 10 percent to 18 percent of OOIP, with an average of 15 percent. The operator is not planning any drilling, because of capital constraints; however, the evaluator believes that 20-

acre infill drilling is warranted. What recovery factors and development program should be assigned to the property?

Recommendation

- 2P Case: Assume development on 20-acre spacing, commencing in the future (but not within the first year). Estimated recovery factor = 14 percent based on analogy to other areas limited by existing 2P per-well recoveries.

- 1P Case: Assume development on 20-acre spacing, commencing in the future (but not within the first year). Estimated recovery factor = 10 percent (i.e., 4 percent incremental) based on analogy to the low end of recovery of other areas.

- 3P Case: Assume development on 20-acre spacing, commencing in the future (but not within the first year). Estimated recovery factor = 16 percent based on analogy to the high end of recovery of other areas limited by existing 3P per-well recoveries.

If there is a technical reason for infill drilling to be unsuccessful (such as pressure depletion, which could prevent foamy oil behaviour in the infill wells), then proved reserves must not be assigned. In this situation, the analogous reservoirs described above are not truly analogous due to different depletion histories; 2P reserves will only be assigned if the evaluator is convinced that this is not likely to be the case.

In this case, since the delay in development is a result of capital constraints and not due to marginal economics or technical concerns, timing does not affect the reserves classification. If the project were marginally economic, however, timing would affect the reserves classification. For small marginal projects, the operator must have plans to commence the project in two years.

Case C

Background

A light-oil pattern waterflood in a stratified reservoir is developed on 160-acre spacing. From decline analysis the wells are forecast to recover 23 percent and 25 percent of OOIP for the proved and 2P reserves cases, respectively. Water breakthrough is minimal. The operator is considering infill drilling a portion of the reservoir to 80-acre spacing. No infill wells have been drilled to date and there are no analogous pools upon which to base the success of such a scheme. A reservoir simulation study indicates a recovery factor of 27 percent on 160-acre spacing and 32 percent with infill drilling. However, results highly depend on relative permeability characteristics, which have been estimated in the simulation. What recovery factors and development program should be assigned to the property?

Recommendation

- 2P Case: Assume development on 80-acre spacing over the operator's planned development area. The recovery factor should be 30 percent over this area based on the 25 percent 2P producing recovery factor plus an incremental 5 percent recovery factor predicted by the model.

- 1P Case: No infill drilling reserves, pending results of the pilot program.

- 3P Case: Assume development on 80-acre spacing over the entire pool. Recovery factor should be 32 percent, as predicted by the model.

Case D

Background

Map 2 shows a seismically defined pool with three new producing gas wells and four dry holes. The seismic data were of high quality and, based on the most recent processing, accurately predict reservoir occurrence in all wells (including untested bypassed pay in two abandoned wells). The reservoir quality is such that the wells drain one section per well. Mapped OGIP is 2 Bcf per section for the three successful wells and three infill locations, and 1.5 Bcf per section for the remaining 16 delineation locations. (This is a simplistic assumption for the purpose of this example. In practice, an evaluator will use planimetering to more accurately assess gas in place.) Recovery factors of the drilled producing wells are 75 percent (proved), 85 percent (2P), and 90 percent (3P), the difference being the uncertainty of the effect of liquid loading late in the pool life. The operator is planning to drill three infill and 16 delineation locations within the mapped area. What reserves should be assigned in the non-producing categories?

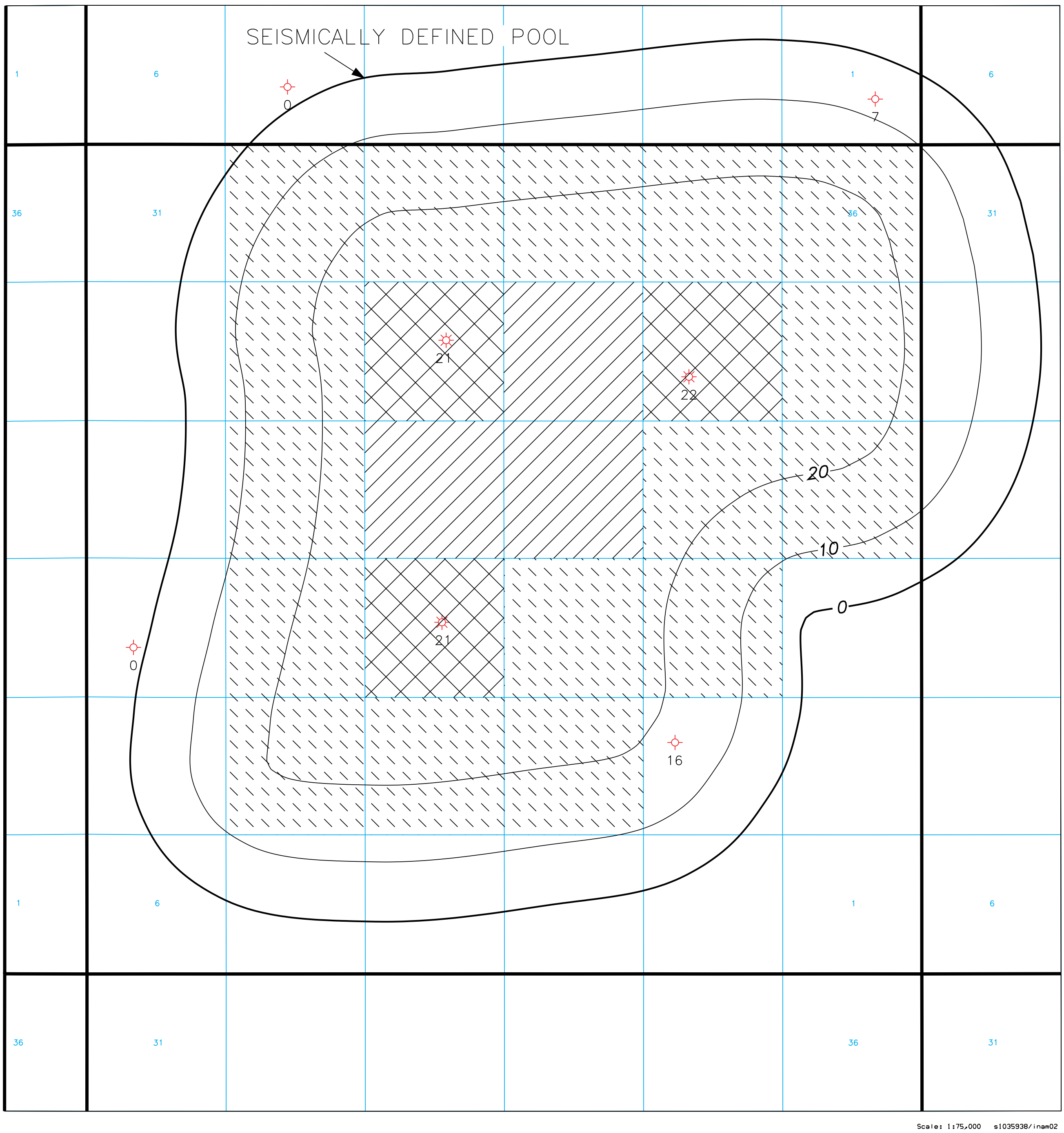
Recommendation

- 2P Case: The three infill locations should be assigned reserves of 1.70 Bcf/well (i.e., 85 percent of 2 Bcf OGIP). The 16 delineation locations should be assigned reserves of 1.275 Bcf/well (i.e., 85 percent of 1.5 Bcf OGIP).

- 1P Case: The three infill locations should be assigned reserves of 1.5 Bcf/well (i.e., 75 percent of 2 Bcf OGIP). Seven delineation locations (sections 10, 14, 15, 23, 25, 35, and 36) should be assigned reserves of 1.125 Bcf/well (i.e., 75 percent of 1.5 Bcf OGIP). The proved locations were

Map 2

Case D



LEGEND:

Drilled

Infills

Delineation

limited to the east portion of the pool, which had better (therefore reliable) well control near the pool edges for mapping purposes.

- 3P Case: The three infill locations should be assigned reserves of 1.80 well/well Bcf/well (i.e., 90 percent of 2 Bcf OGIP). The 16 delineation locations should be assigned reserves of 1.35 Bcf/well (i.e., 90 percent of 1.5 Bcf OGIP). If the operator was planning any additional locations outside the 16 shown on the map, but within the pool contours, these would be classified as possible, because of the increased risk of drilling near pool edges.

Case E

Background

Map 3 shows a geologically defined pool (i.e., no geophysical data) with three new producing gas wells and four dry holes. The mapping represents the possible extent of the gas in place. The reservoir quality is such that each well drains one section. Mapped OGIP averages 2 Bcf/section. Recovery factors of the drilled producing wells are 75 percent (proved), 85 percent (2P), and 87 percent (3P), the difference being the uncertainty in the effect of liquid loading late in the pool life. The operator has planned to drill all undrilled sections in the mapped area. What reserves should be assigned in the non-producing categories? The evaluator, based on his technical review of the data, has high confidence that wells drilled within 1/3 of the distance from existing wells to the mapped pool extent will be successful, and 50 percent confidence that wells drilled within 2/3 of the distance from existing wells to the mapped pool extent will be successful.

Recommendation

Draw 1/3 and 2/3 confidence limits to pool as shown on Map 4.

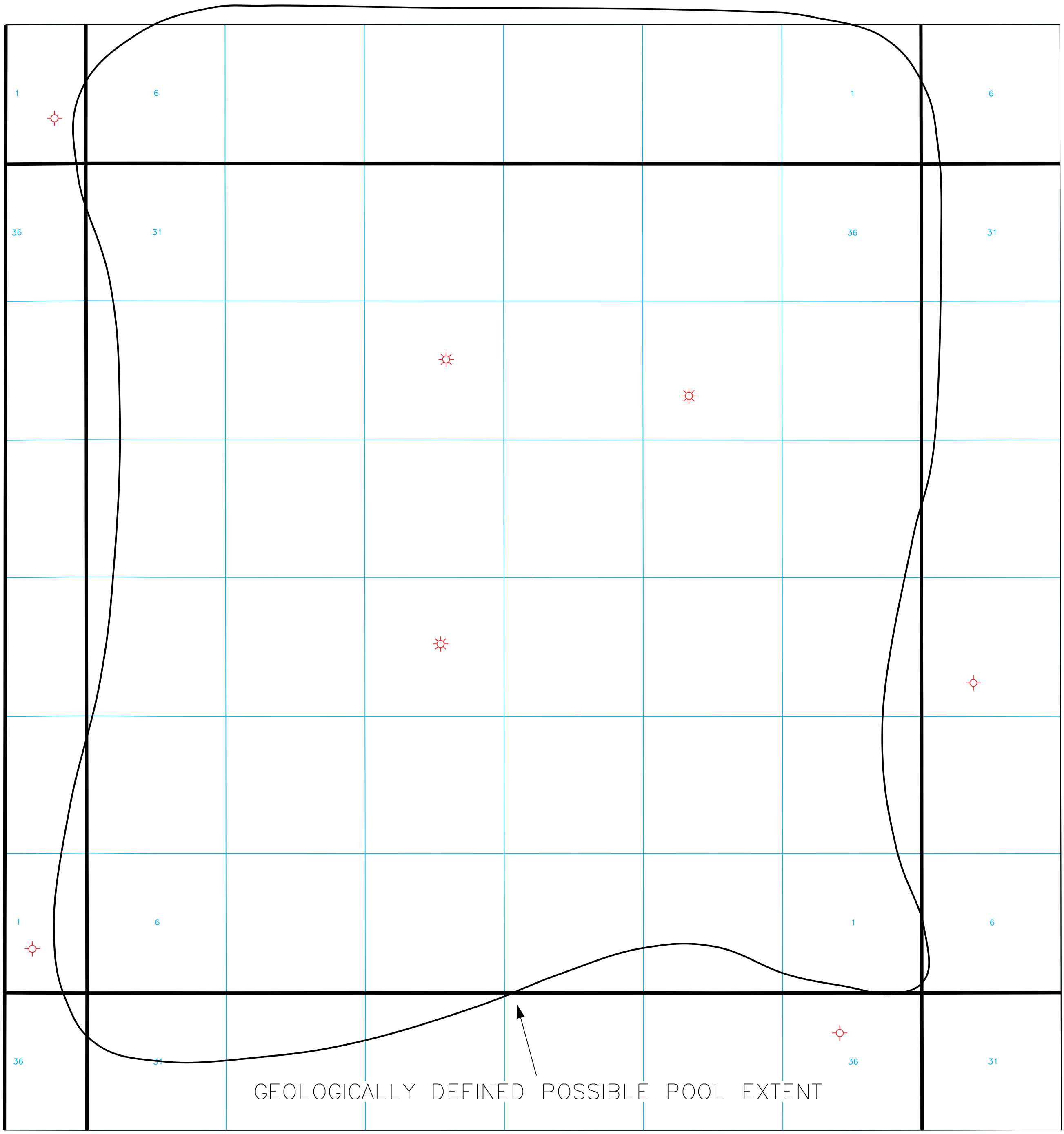
- 2P Case: The reservoir area within the 2/3 limit is approximately 22.5 sections (round down to 22 sections). Therefore, an additional 13 locations should be classified as probable (22 minus 3 existing minus 6 proved). All wells should be assigned reserves of 1.70 Bcf/well (i.e., 85 percent of 2 Bcf OGIP).

- 1P Case: The reservoir area within the 1/3 limit is approximately 9.5 sections (round down to 9 sections). Therefore, an additional six locations (nine minus existing three wells) should be assigned reserves of 1.5 Bcf/well (i.e., 75 percent of 2 Bcf OGIP).

- 3P Case: All proposed infill and delineation wells within the pool limit should be assigned reserves of 1.74 Bcf/well (i.e., 87 percent of 2 Bcf OGIP).

Map 3

Case E



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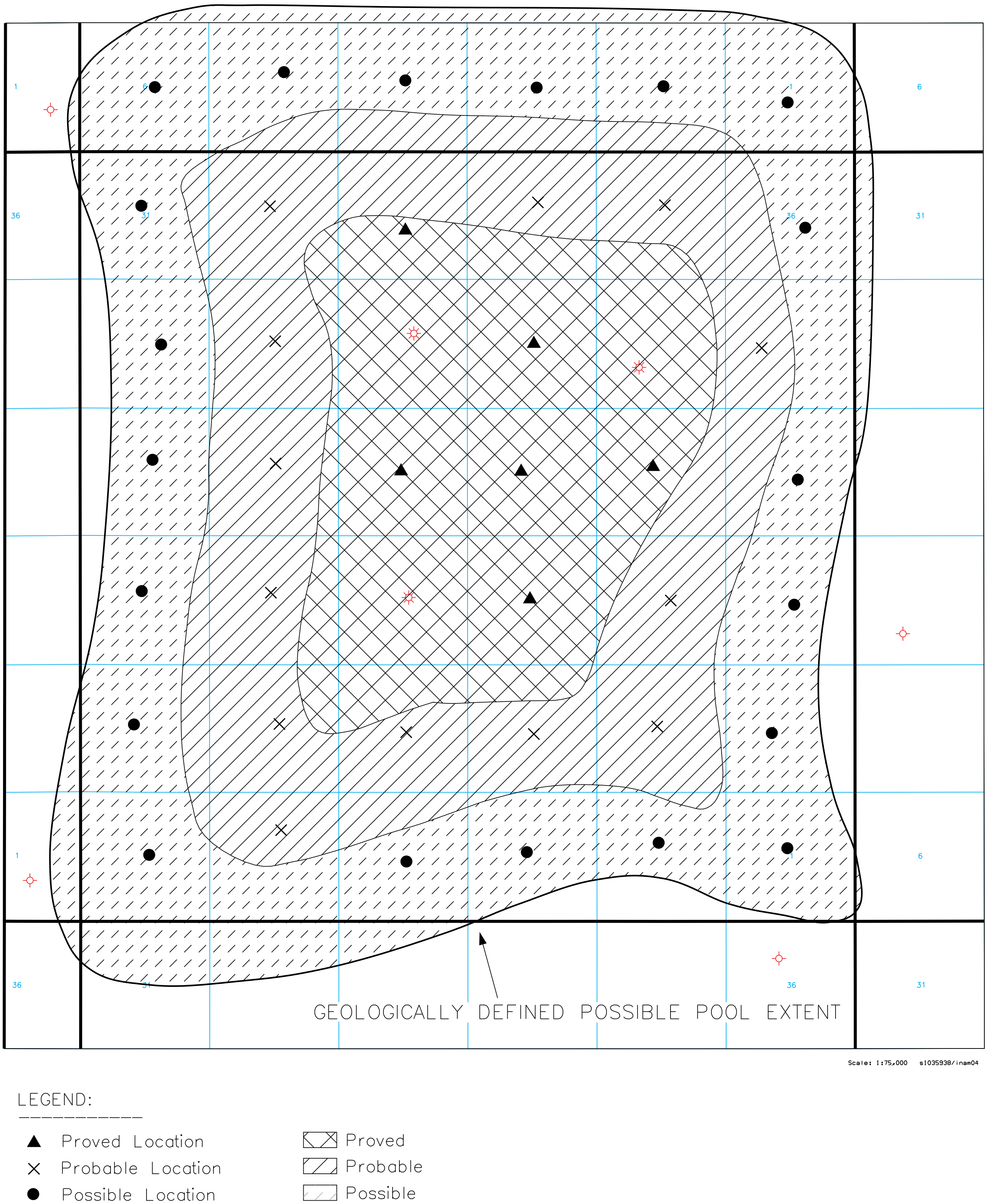
Map 4

Case E


GEOLOGICALLY DEFINED POSSIBLE POOL EXTENT
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LEGEND:
Proved Location
Probable Location
Possible Location
Proved
Probable
Possible

6.7.3 Reserves Related to Planned Enhanced Recovery Projects

Enhanced recovery includes all methods for supplementing natural reservoir forces and energy or increasing ultimate recovery from a reservoir. These methods include the following:

- Water Injection,
- Gas Injection,
- Miscible Fluid Displacement,
- Polymer Flooding,
- Microemulsion Flooding,
- Steam Injection,
- In-Situ Combustion.

a. Proved Criteria (1P)

Proved reserves may be assigned to planned enhanced recovery projects when the following criteria are met:

- Repeated commercial success of the enhanced recovery process has been demonstrated in reservoirs in the area with analogous rock and fluid properties or by an operational pilot scheme within the approval area.
- The project is highly likely to be carried out in the near future. This may be demonstrated by factors such as the commitment of project funding.
- Where required, either regulatory approvals have been obtained, or no regulatory impediments are expected, as clearly demonstrated by the approval of analogous projects.
- Suitable feasibility studies have been conducted.

Repeated commercial success has been demonstrated if there are at least three analogous operational projects known to be economically and technically successful, based on available data and public statements of the operators. The first commercial application of a process cannot rely on analogies and requires actual performance of a pilot or operational scheme upon which to justify a proved classification. For established conventional EOR processes such as waterfloods, one operational scheme in an area is sufficient to demonstrate economic and technical viability.

"Reservoirs in the area" refers to an oil and gas accumulation of similar geological age; depositional, diagenetic, and structural setting and history; and internal reservoir architecture in the same basin as the subject reservoir. There are no fixed distance criteria for the area as long as these criteria are met.

Analogous rock and fluid properties include the following properties, which affect the performance of an enhanced recovery scheme:

- porosity,
- porosity type (i.e., single or dual (fractured) systems),
- permeability,
- permeability orientation,
- permeability distribution,
- water saturation,
- oil gravity and viscosity,
- solution GOR,
- bubble point,
- relative permeability,
- well spacing,
- pressure,
- depth,
- thickness,
- continuity,
- stage of depletion,
- injected fluid properties (compatibility, mobility, relative permeability),

- reservoir architecture.

Measurement data on some of the analogous properties in the proposed scheme, such as relative permeability, might not be required if the analogous project is located close enough to infer the measurement. If data on critical properties have not been obtained on proposed projects in order to make proper analogy comparisons, or if the analogy is too distant from the proposed project, then proved reserves by analogy cannot be assigned. Properties need not be the same as or superior to the analogy, but engineering adjustments must be made to reflect the differences, provided the key properties are not materially inferior.

Pilot schemes are scaled-down non-commercial projects that must be scaled up to commercial application. Care must be taken to reliably scale up performance and costs. Phases of a pilot are injection, initial response, and breakthrough behaviour. A pilot needs to be into breakthrough behaviour in order to judge success of the scheme.

Likelihood of implementation influences reserves classification of a project. Part of this likelihood involves the processes of conducting studies, completing applications, and obtaining approvals. Items under the company's control include cost estimates, feasibility studies, implementation timelines, regulatory applications, environmental studies, capital budgets and unitization negotiations, as well as final approvals of AFEs and budgets. Items not under the company's control include unitization, environmental constraints, and regulatory approvals.

For proved reserves classification, the company must show commitment to implement the project. This pertains to all processes under the company's control. The degree of commitment required for reserves booking varies, depending on the nature and size of the EOR project. For small routine waterflood projects, processes such as budgeting, timeline preparation, and commencement of regulatory applications could be sufficient to show company commitment. For larger, non-routine EOR processes, final AFE and regulatory approvals could be required. The situations where proved EOR reserves are assigned without company commitment must be very rare.

To meet high certainty of implementation in the near future, a commitment to initial significant capital spending must be within the next three years for large projects and two years for small projects.

A suitable feasibility study incorporates analysis of both the geological and engineering aspects of the proposed scheme. A detailed geological definition is required, with sufficient well spacing and/or seismic control to characterize reservoir properties and geometry. The engineering analysis must address not only the reserves, but rate of production response, injection requirements (both source and rates), breakthrough behaviour, and cost of development. The study need not be a reservoir simulation; however, for complex reservoirs, a reservoir simulation may be the only practical method of predicting response. In routine EOR applications, the feasibility study could simply be a scaling of analogous projects.

Initially, only a portion of reserves can be classified as proved. Prior to implementation of a project, the best estimate reserves value is recommended a 2P classification. The initial proved increment is usually equal to the 2P value minus between 1/3 and 2/3 of the difference between the 2P and a reasonable minimum estimate. Similarly, the initial 3P increment is usually equal to the 2P value plus between 1/3 and 2/3 of the difference between the 2P and a reasonable maximum estimate. The portion of proved classification increases toward the best estimate value as injectivity is established, as response is exhibited, and as breakthrough trends are established.

EOR schemes are frequently implemented in a phased approach. If only minor capital compared to the initial project is required (i.e., less than 50 percent), then all proposed phases may be classified as proved, provided the expansion area is analogous to the initial phase. If significant capital (i.e., more than 50 percent of the initial project) is required for future phases, then the future phases are treated using the same criteria as the initial phase.

b. Proved + Probable Criteria (2P)

Proved + probable reserves may be assigned when a planned enhanced recovery project does not meet the requirements for classification as proved. However, the following criteria are met:

- The project can be shown to be practically and technically reasonable.
- Commercial success of the enhanced recovery process has been demonstrated in reservoirs with analogous rock and fluid properties but not necessarily in the area of the reservoir.
- It is reasonably certain that the project will be implemented.

Practical and reasonable tests are judged from the results of feasibility studies. These studies are similar to those described for the proved criteria, though the degree of geological control to define the reservoir may be less.

Reservoir properties of a proposed project should be similar to those of the analogous project, with adjustments made for any differences.

Reasonably certain implementation refers, in the case of small routine waterflood projects, to evidence such as planning, budgeting and timeline preparation. For larger, non-routine EOR processes, final regulatory and AFE approvals could be required. Also, to meet reasonable certainty of implementation, commitment to initial significant capital spending must be within 5 years for large projects and 3 years for small projects.

Best estimate estimates of reserves must be used for 2P reserves bookings.

When the first phase of an EOR project is classified as 2P, and if only minor capital compared to the initial phase is required (i.e., less than 50 percent), all future phased expansions within existing approval or expansion areas may be classified as 2P, provided there is no perceived technical, economic or regulatory impediment to these phased expansions proceeding. If significant capital (i.e., more than 50 percent of the initial project) is required for future phases, then the future phases are treated using the same criteria as the initial phase.

As mentioned in the infill drilling discussion, if technically probable EOR projects do not have a high probability of being implemented, but have a reasonable probability (more often than not), further risking must be applied to achieve a 50 percent probability that the estimate will be met or exceeded (see Section 6.7.1.f for the procedure).

c. Proved + Probable + Possible Criteria (3P)

Proved + probable + possible reserves may be assigned when a planned enhanced recovery project does not meet the requirements for classification as proved or probable; however, the following criteria are met:

- The project can be shown to be practically and technically reasonable.
- Commercial success of the enhanced recovery process has been demonstrated in reservoirs with analogous rock and fluid properties, but there remains some doubt that the process will be successful in the subject reservoir.
- It is reasonable that the project will be implemented.

Practically and technically reasonable requirements are met if theoretical calculations show economically recoverable reserves are achievable.

Acceptable uncertainty relating to possible reserves may include a process not being tested in the same geological horizon or certain rock or fluid properties being dissimilar to a commercial analogy.

Reasonable implementation criteria are met if technical analysis indicates the project is economically worth pursuing, even if the company does not have firm plans to proceed. As a guide, the evaluator should believe there is at least an equal chance of the project proceeding as not. Projects with a low chance of being implemented should not be classified as reserves, but as contingent resources.

6.7.4 Planned EOR Examples

Case G

Background

A new oil pool has been discovered and delineated. Relative permeability tests indicate the reservoir is amenable to waterflood. The operator is planning on installing a waterflood scheme and has conducted a reservoir simulation study. There have been no other waterflood schemes attempted in this horizon in the area, because reservoir continuity and formation plugging due to water susceptibility are potential issues. There have been waterfloods implemented in other horizons in the area. The simulation study, using reasonable economic limits, predicts primary recovery of 10 percent of OOIP and waterflood recovery of 30 percent of OOIP. Decline analysis and analogies to other pools in the area in the same horizon indicate proved and 2P primary recovery factors of 8 percent and 9 percent, respectively. Initially the plan is to implement a pilot scheme over 20 percent of the reservoir, which will be expanded to the entire reservoir pending the results of the pilot scheme. What recovery factors should be assigned for the total proved and total 2P categories and over what portion of the reservoir at this time?

Recommendation

- 2P Case: Assign a 25 percent waterflood recovery factor over 20 percent of the reservoir (pilot area) and 9 percent primary recovery factor over 80 percent of the reservoir (non-pilot area). The 25 percent factor is 80 percent of the simulation results, to account for probable simulation inaccuracy. (The simulation appears to overestimate primary reserves and there is no actual breakthrough behaviour to simulate actual relative permeability characteristics.) Waterflood reserves are not assigned to the non-pilot area, because the pool-wide waterflood implementation is contingent upon the success of the pilot. If the main perceived risk of the waterflood was that of injectivity, then probable waterflood reserves using a 25 percent recovery factor could be assigned to the entire pool once the pilot demonstrated injectivity.

- 1P Case: Assign a primary recovery factor of 8 percent for the entire pool. Because there are no analogies available in the same horizon, proved waterflood reserves cannot be assigned. Initial proved waterflood reserves assignment will occur once production response is known, and could be applied to the entire pool at a value warranted by the degree and stage of response. A recommended initial proved recovery factor will likely be between 15 and 20 percent of OOIP, which represents primary plus 1/3 to 2/3 of the difference between 2P waterflood and primary recovery factors.

- 3P Case: Assign a 30 percent recovery factor over the entire reservoir, based on the simulation results. There is no evidence as yet to suggest that this value is a maximum recovery factor, thus the use of the value for 3P classification.

Case H

Background

A horizontal CO_2 miscible flood scheme is proposed for an oil unit currently under pattern waterflood. A pilot CO_2 scheme has been implemented, and early performance exceeds that predicted by a reservoir simulation study of the pilot area. This study predicted incremental reserves of 15 percent. The operator is planning two stages of expansion. The first stage, to be implemented over the next three years, is in high-quality areas of the reservoir analogous to the pilot area. The second stage, to be implemented within the next five years, is in lower quality areas. Simulation studies have not been conducted over the first and second stages; however, analytical studies indicate recovery in the first stage should be identical to the pilot area, whereas recovery in the second stage should be 80 percent that of the pilot area. What reserves and categories should be assigned to the various phases at this point in time?

Recommendation

- 2P Case: 15 percent incremental reserves over the pilot area plus Stage 1, and 12 percent incremental over Stage 2 based on the simulation results.

- 1P Case: 9 percent incremental reserves over the pilot area plus Stage 1. No CO_2 reserves over Stage 2. An initial incremental EOR reserves estimate midway between the 2P estimate and a perceived minimum incremental recovery factor of 3 percent was assigned. This compares to the recommended range of between 1/3 to 2/3 of the difference between 2P and minimum estimates. The middle of the range was selected because of the superior performance of the pilot compared to the simulation, factored down by the complexity of this type of process (i.e., tertiary versus secondary). Proved reserves were not assigned to Stage 2 because of the long lead time of implementation and the lower quality in this area of the reservoir, which has not been tested.

- 3P: 16 percent incremental reserves over the pilot area plus Stage 1, and 13 percent incremental reserves over Stage 2. These values are slightly higher than the simulation results, because performance is superior to simulation. Updated simulation work would assist in calibrating reserves assignments for the various categories.

6.8 Integration of Reserves Estimation Methods

Throughout the life of an oil and gas well, a variety of reserves estimation methods may be used. Usually reserves are estimated volumetrically or by analogy early in the life of a well, and as production and pressure data are obtained, decline curve, material balance, and reservoir simulation methods may be used.

A schematic diagram of the time frame for which the main reserves estimation methods are considered reliable is presented in Figure 6-7.

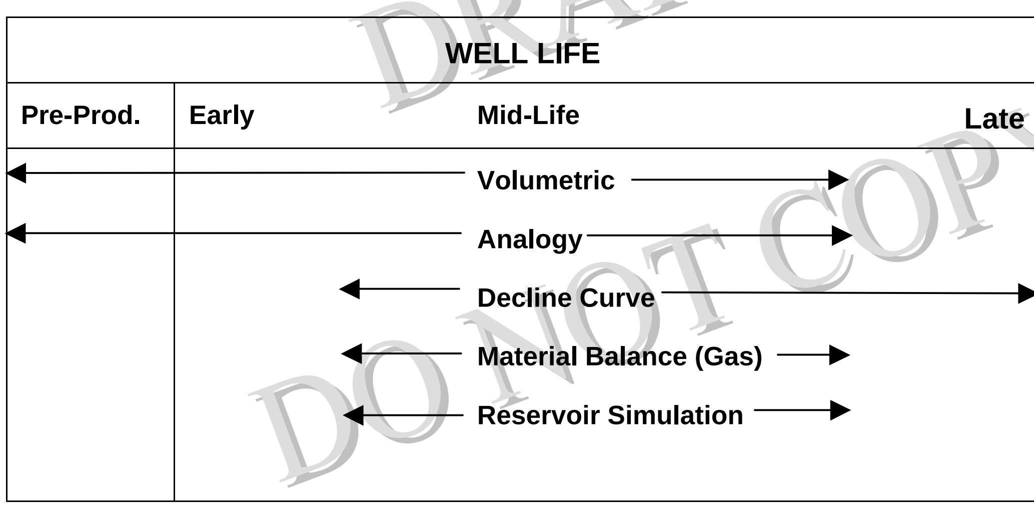

Figure 6-7 Reliability of Reserves Estimation Methods with Time.

As can be seen in the schematic above, multiple reserves estimation methods may be applied at any point throughout the life of a well. It is important that the evaluator attempt to determine reserves estimates using all of the methods that would be considered reliable at the time the estimate is made (except perhaps a reservoir simulation, because of the complexity and cost of such an analysis). In the case of material properties, more than one method should be used to determine reserves.

Different methods often yield different reserves estimates, which the evaluator should attempt to reconcile. In some cases, the reconciliation is obvious; for example, when comparing a decline curve estimate based on a consistent decline trend to a volumetric estimate for a single well pool. In this case, more reliance would be placed on the decline curve estimate if the areal extent required to arrive at a similar estimate determined by decline methods was within an expected range of values. On the other hand, if the areal extent would have to be significantly larger than the acreage owned by the company to arrive at the decline curve estimated reserves, possibly indicating the well is draining non-owned lands, a reserves estimate somewhat less than the decline curve estimate should be applied to allow for additional drilling that may capture some of the reserves currently being drained by the subject well.

Other sections of this Volume 2 have provided detailed guidelines regarding the conditions under which each reserves estimation method is reliable, and on the proper application of each method. A brief summary of the requirements for reliable estimates using each method is presented below.

a. Volumetric Methods

- Usually the only methods available prior to significant production.
- Most reliable in multi-well pools that have good well control and well-defined reservoir properties.
- Tend to be less reliable in single-well pools.
- Reserves should be consistent with demonstrated productivity and analogous pools.

b. Analogy Methods

- Usually the primary estimation method when all other methods are considered less reliable.
- Reserves estimated using other methods should always be compared to reserves estimates for analogous reserves to ensure they are within an expected range.

c. Decline Curve Methods

- Considered the most reliable reserves estimation method, provided a consistent decline trend has been established and operating conditions are constant.

- Production decline trends are not reliable in cases where reservoir or fluid characteristics indicate that increasing gas/oil, water/oil, or water/gas ratios will occur in later life, until those trends are well established.

- Production decline trends are not reliable in an oil reservoir under water drive or waterflood, until water-cut trends are well established.

- Most reliable reserves estimation method late in the life of a reservoir.

d. Material Balance Methods for Gas Reservoirs

- Usually requires at least 5 to 15 percent pressure decline.

- Most reliable in high-permeability reservoirs and when there are many high-quality data points and consistent pressure decline.

- If aquifer pressure support is present, it must be accounted for.

- Less reliable early in the life of low-permeability reservoirs where it is difficult to determine average reservoir pressures, in cases with few data points, and in cases with poor correlation of pressure data points.

e. Reservoir Simulation

- Requires a sound geological model, a properly gridded reservoir model, and good quality petrophysical PVT and pressure data.

- Requires a significant volume of production and pressure decline and a good history match of past performance.

- Less reliable in water drive reservoirs or oil reservoirs being waterflooded, until significant water breakthrough has occurred.

SECTION 7

VALIDATION AND RECONCILIATION OF RESERVES AND VALUE ESTIMATES

TABLE OF CONTENTS

7.1 Introduction

Because of the uncertainty in estimating oil and gas reserves, the actual reserves recovered from a reservoir will not be known until production reaches the economic limit and the reservoir is abandoned. Even then, future improvements in technology and economics could allow the reservoir to be redeveloped and additional reserves produced.

In an evaluation of reserves, the evaluator must prepare estimates of the remaining oil and gas reserves for individual reservoirs, usually on an annual basis, according to the definitions and guidelines specified in COGEH. Those estimates will vary in the future because of production, capital investments, changing economic conditions, and further technical data. On a corporate level, acquisitions, dispositions, and new discoveries will also affect the overall reserves of a company from one evaluation to the next.

The process of identifying and categorizing the reasons for changes in reserves estimates from one evaluation to the next is called a reserves reconciliation. The primary reasons for conducting a reserves reconciliation are to track reserves changes and to understand the reasons for those changes. A secondary reason is to verify that past reserves estimates met the definitions and guidelines specified in COGEH.

A discussion of reserves reconciliation and validation of previous reserves estimates is presented in this section. Reconciliations of net present values of oil and gas reserves are also presented. Submissions of these reconciliations to securities regulators could require different reserves change categories and reconciliation procedures than those presented below. However, the guidelines presented below can be adapted to most Canadian and American requirements.

7.2 Reserves Validation

Validation that past crude oil and natural gas reserves estimates meet the reserves definitions and guidelines in COGEH is discussed in COGEH Volume 1, Section 5.5.6. This procedure involves the tracking of technical reserves revisions over time for each of the proved, proved + probable, and proved + probable + possible reserves categories. This procedure only validates past reserves estimates and does not necessarily ensure that current estimates are consistent with the definitions.

Because of the uncertainty in estimating oil and gas reserves, some entity reserves estimates will have positive revisions with successive evaluations (increase in estimates), while others will have negative revisions (decrease in estimates). Proved reserves estimates are intended to be conservative; therefore, positive revisions should occur in significantly more entities than negative revisions, and the overall revisions on an aggregate basis for a large number of entities should be positive.

Conversely, negative revisions should occur in significantly more entities than positive revisions for the proved + probable + possible reserves, and the overall revisions for a large number of entities from year to year should be negative. The proved + probable reserves estimates should have equal numbers of both positive and negative revisions, with the effect that on an aggregate basis these total estimates should remain constant. These guidelines apply only to the technical revisions and not to changes that could occur as a result of capital expenditures or changing economic factors.

Table 7-1 summarizes the technical revisions that should be expected for each reserves category.

Table 7-1 Reserves Revisions by Category

Reserves Category	Entity Level	Reported Level
Proved	Positive reserves revisions should occur in significantly more of the entities than negative revisions.	Negative reserves revisions should seldom occur at this level.
Proved + Probable	Positive reserves revisions should equal negative reserves revisions.	Only minor positive or minor negative revisions should occur at this level.
Proved + Probable + Possible	Negative reserves revisions should occur in significantly more of the entities than positive revisions.	Positive reserves revisions should seldom occur at this level.

The process of validation of the reserves estimates should ideally be conducted over a period of several years. For example, the definitions for proved reserves at the reported level require that there be at least a 90 percent probability that the actual quantities recovered be equal to or exceed the estimated proved reserves. There still remains a 10 percent probability that the actual quantity recovered will be less. A negative revision in the aggregate proved reserves in one particular year is cause for concern. However, it is expected that the revisions in the following years will be positive.

Materiality of the reserves revisions should also be considered. On a proved reserves basis there should be significantly more positive entity revisions than negative.

However, a large number of very small negative entity revisions could be significantly offset by a few very large positive entity revisions. On a reported level, the expectation is that a multi-year average of the aggregate proved reserves revisions will be positive.

As an example of the validation process, consider the reserves reconciliation in Table 7-2. A validation of the reserves adds up all the technical revisions over the four-year period. The proved technical revisions over the four-year period total 40 Mbbl, while the proved + probable technical revisions are zero. Both of these values are in the range expected overall.

7.3 Reserves Reconciliations

7.3.1 Introduction

Reserves reconciliations should be undertaken to identify and categorize the changes in reserves estimates between the previous and current reserves evaluations.

Canadian securities regulations require reserves reconciliations to be conducted on a net reserves basis (after deducting royalties owned by others, but including royalties owned) for public reporting purposes. It is recommended that the reconciliation be prepared using the reserves estimates from the forecast prices and cost evaluation. However, the constant prices and costs evaluation may also be used for regulatory reporting purposes.

Reconciliations of reserves in Canada on a Company net reserves basis are more complex than on a Company gross reserves basis due to price and rate sensitive royalties. Various royalty incentive programs can also cause the net Company reserves to change without a change in the gross Company reserves. A discussion of the treatment of these effects is provided later in this section.

The reconciliation may be prepared by the evaluator on a property-by-property basis, and then aggregated to arrive at a reported level reconciliation. The reconciliation should be prepared for the total proved, probable, and total proved + probable reserves categories, and should be separately prepared by country.

7.3.2 Product Types

Separate reserves reconciliations should be prepared for each of the following product types:

- light and medium oil (combined),

- heavy oil,
- natural gas,
- natural gas liquids,
- bitumen,
- synthetic oil,
- non-conventional oil and gas (including coalbed methane, hydrates, etc.)

A reconciliation of bitumen reserves could be combined with heavy oil if the bitumen quantities are relatively minor. Likewise, a reconciliation of synthetic oil reserves could be combined with light and medium oil if the synthetic reserves are not significant.

The Canadian regulations allow solution gas and natural gas liquids reserves to be excluded from the reserves reconciliation, because they are usually not significant compared to the oil and total natural gas quantities. Even so, evaluators may want to capture all reserves changes.

7.3.3 Reserves Change Categories

In performing a reserves reconciliation, the following categories of reserves changes should be considered:

a. **Opening Balance:** Company net reserves that were recorded as the closing balance of the previous reconciliation.

b. **Exploration Discoveries:** Additions to reserves in reservoirs where no reserves were previously booked. Any positive or negative reserves changes to an entity after the initial assignment should be recorded as a technical revision.

c. **Drilling Extensions:** Additions to reserves resulting from capital expenditures for step-out drilling in previously discovered reservoirs. Any positive or negative reserves changes to an entity after the initial assignment should be recorded as a technical revision, except as noted in Section 7.3.4a.

d. **Infill Drilling:** Additions to reserves resulting from capital expenditures for infill drilling in previously discovered reservoirs that were not drilled as part of an enhanced recovery schemes. Any positive or negative reserves changes to an entity after the initial assignment should be recorded as a technical revision, except as noted in Section 7.3.4a.

e. **Improved Recovery:** Additions to reserves resulting from capital expenditures associated with the installation of improved recovery schemes (secondary or tertiary projects such as waterfloods, miscible injection, SAGD, etc.). This may include both injection wells and infill production wells associated with the improved recovery project. Any positive or negative reserves changes to an entity after the initial assignment should be recorded as a technical revision, except as noted in Section 7.3.4a.

Reserves added as a result of capital expenditures not specifically for drilling or enhanced recovery projects, such as for compression and improved gathering systems, are also included in this category.

f. **Technical Revisions:** Positive or negative reserves revisions to a reserves entity resulting from new technical data or revised interpretations on previously assigned reserves. Positive technical revisions are usually associated with better reservoir performance and negative revisions with poorer reservoir performance.

g. **Acquisitions:** Positive additions to reserves estimates as a result of purchasing oil and gas properties or increasing an interest in currently owned properties. The reserves additions are recorded at the closing date of the acquisition (after adjustment for any reserves changes between the end of the reporting period and the closing date of the acquisition).

h. **Dispositions:** Reductions in reserve estimates as a result of selling all or a portion of an interest in oil and gas properties. The reserves reductions are recorded at the closing date of the disposition (after adjustment for any reserves changes between the start of the reporting period and the closing date of the disposition).

i. **Economic Factors:** Changes to reserves between the current and previous reporting periods resulting from different price forecasts, inflation rates, and regulatory changes. These changes could affect not only the life of the reservoirs but also royalty rates and reversionary interests. These changes may be positive or negative. The common method to estimate these changes is to re-run the old evaluation, using the current evaluation's price forecast or fiscal terms, and compare the differences in net reserves.

j. **Production:** Reductions in the reserves estimates due to production during the time period being reconciled. These quantities may include estimated production for recent periods when actual sales quantities are not available.

k. **Closing Balance:** Company net reserves at the end of the time period being reconciled.

7.3.4 Discussion of Special Reserves Change Situations

a. **Changes in Reserves Category from Probable to Proved.** If all of the reserves assigned to an exploration discovery, a drilling extension, infill drilling, or an improved recovery project are initially classified as probable, they may be classified as a proved addition, in the same reserves change category, in the year when the reserves are transferred to proved (with a corresponding negative probable addition). For multi-phased improved recovery projects, the reclassification of phases from probable to proved would result in a proved addition for that phase in the same reserves change category in the year when the reserves are transferred. Any subsequent changes to the proved or probable reserves assignment should be recorded as a technical revision.

b. **Changes in Development Status:** Changes to the production status, between proved producing, proved non-producing, proved undeveloped, etc. are not usually included in the reserves reconciliation. Evaluators may choose to create sub-categories for the transfer of reserves between different production statuses, but only the total proved, probable, and total proved + probable categories are normally reported.

c. **Changes due to Different Operating and Capital Cost Assumptions:** Changes resulting from different operating and capital cost assumptions should be included in the technical revision category. An exception may be capital expenditures to reduce operating costs, such as the installation of a battery to reduce trucking costs. Reserves additions in this case are classified as improved recovery.

d. **Errors in Interests and Encumbrances:** Changes to reserves resulting from the correction of an incorrect company interest or royalty payable are usually categorized as technical revisions. Changes to government royalty formulas are usually included in the economic factors category.

In practice, precisely identifying all of the individual changes that occur to a reserves portfolio from one year to the next is difficult, if not impossible. The evaluator should attempt to identify the most material changes, and then group the remaining minor changes into the technical revisions category so that the annual reconciliation balances.

7.3.5 Example Reserves Reconciliation

The following example illustrates a typical reserves reconciliation. It is based on a new company that participates for a 50 percent working interest in an exploration well and considers typical reserves changes over the first four years. Table 7-2 shows the reconciliation of those changes.

Summary of Changes in Year 1

1. Opening balance nil.

2. An exploration well was successfully drilled, logged, and tested. It was volumetrically estimated to have 50 Mbbl of net recoverable proved reserves and 50 Mbbl of net recoverable probable reserves. This addition is recorded as an exploration discovery.

Summary of Changes in Year 2

1. The well started production in early January and 20 Mbbl of net probable reserves were transferred from the probable to the proved category. This change is recorded as a technical revision, positive in the proved category and negative in the probable category (no change in the proved + probable category).

2. An extension well is drilled and 60 Mbbl of net recoverable proved reserves and 40 Mbbl of net recoverable probable reserves are assigned.

3. Company net share of production during the year was 10 Mbbl.

Summary of Changes in Year 3

1. Company net share of production during the year was 20 Mbbl.

2. Other nearby reservoirs were successfully waterflooded, so a feasibility study was conducted. The study was favourable, so 50 Mbbl of net probable reserves were assigned.

3. At the end of the year, a technical revision was made, based on good production performance, to transfer 20 Mbbl of net probable reserves to the proved category.

Table 7-2 Sample Reserves Reconciliation
Company Net Reserves (Mbbl)
Light and Medium Crude Oil

	Proved	Probable	Proved + Probable
January 1, Year 1	0	0	0
Exploration Discoveries	50	50	100
Drilling Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Technical Revisions	-		
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	-	-	-
January 1, Year 2	50	50	100
Exploration Discoveries	-	-	-
Drilling Extensions	60	40	100
Improved Recovery	-	-	-
Infill Drilling	-	-	-
Technical Revisions	20	(20)	
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(10)	-	(10)
January 1, Year 3	120	70	190
Exploration Discoveries	-	-	-
Drilling Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	50	50
Technical Revisions	20	(20)	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(20)	-	(20)
January 1, Year 4	120	100	220
Exploration Discoveries	-	-	-
Drilling Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	40	(40)	-
Technical Revisions	-	-	-
Acquisitions	-	-	-
Dispositions		-	-
Economic Factors	(11)	(13)	(24)
Production	(20)	-	(20)
January 1, Year 5	129	47	176

Summary of Changes in Year 4

1. The waterflood was initiated and 40 Mbbl of net probable reserves were transferred from probable to proved. Because this is the first booking for the improved recovery reserves for this project in the proved category, the transfer was recorded as a proved improved recovery addition and a negative probable improved recovery addition.

2. Company net share of production during the year was 20 Mbbl.

3. Government royalty formulas were changed at the end of the year, resulting in an effective drop of 10 percent of the Company's share of net reserves.

7.4 Net Present Values Reconciliations

7.4.1 Introduction

The Canadian securities regulations also require a reconciliation of net present values for reporting purposes. This reconciliation is only required for proved reserves net present values at a 10 percent discount rate before income taxes, using constant prices and costs.

A net present value reconciliation is more complex than a reserves reconciliation because of numerous changes that can occur in economic and technical factors, many of which are dependent on each other.

Reconciliation should be presented as shown in Table 7-3.

7.4.2 Net Present Value Change Categories

A summary of the categories of changes that should be considered in a net present value reconciliation, and the recommended procedure to determine those values, is presented below:

a. **Oil and Gas Sales During the Period.** This category is based on the actual gross revenues minus royalties minus production costs for the reporting period. This value is determined on a before-tax basis.

b. **Changes Due to Prices.** This category is based on the net present value before taxes of the difference between

1. the net revenue forecast (gross revenues minus royalties and production costs) at the beginning of the period, and

2. the net revenue forecast at the beginning of the period, recalculated using the actual prices for the reporting period, and the December 31 prices after the reporting period. Changes to royalty and production cost assumptions should also be included in this recalculated revenue forecast, though in practice only significant changes are included.

c. **Actual Development Costs During the Period.** This category is based on the actual development costs for the reporting period. Exploration and acquisition costs should be excluded.

d. **Changes in Future Development Costs.** This category is based on the net present value of the difference between

1. the forecast of future development costs at the beginning of the period, and,

2. the actual development costs for the period plus the forecast development costs at the end of the period.

e. **Changes Resulting from Extensions, Infill Drilling and Improved Recovery.** This category includes the net present value before taxes of all reserves changes due to extensions, infill drilling, and improved recovery. This value should be calculated at the end of the period and determined using the end of the period constant prices and costs.

f. **Changes Resulting from Discoveries.** This category includes the net present value before income taxes of all reserves changes due to discoveries. This value should be calculated at the end of the period and determined using the end of the period constant prices and costs.

g. **Changes Resulting from Acquisitions of Reserves.** This category includes the net present value before income taxes of all reserves changes due to acquisitions of reserves. This value should be calculated at the end of the period and determined using the end of the period constant prices and costs.

h. **Changes Resulting from Dispositions of Reserves.** This category includes the net present value before taxes of all reserves changes due to dispositions of reserves. This value should be determined using the net revenue forecast for the disposed properties that was calculated at the start of the period but adjusted to an effective date of the disposition.

i. **Accretion of Discount.** The additional net present value before tax of the previous year's revenue forecast, determined by discounting to the end of the current period rather than the start of the period. It is usually calculated as 10 percent of the beginning of the period net present value.

j. **Other Significant Factors.** Any other significant factors resulting in a change to the net present values before tax and not accounted for above should be listed separately.

k. **Net Changes in Income Tax.** This category is calculated as the difference between the net present value of the estimated income taxes at the start of the period and the net present value of the actual taxes during the period plus the forecast taxes at the end of the period.

l. **Changes Resulting from Technical Reserves Revisions Plus Effects of Timing.** Because it is difficult to calculate the effect on the net present value on all technical reserves revisions, and the effect of changes to the timing of development, this category should be calculated after accounting for all other changes, by subtracting the previous year net present value after tax and all of the changes estimated above from the current year net present value after tax.

Table 7-3 Reconciliation of Changes in Net Present Values of Future Net Revenue Discounted at 10% Per Year

Proved Reserves

Period And Factor	2003 (M$)	2002 (M$)
Estimated Net Present Value After Tax of Future Net Revenue at Beginning of Period	xxx	xxx
Oil and Gas Sales During the Period Net of Royalties and Production Costs (1)	xx	xx
Changes Due to Prices (2)	xx	xx
Actual Development Costs During the Period (1)	xx	xx
Changes In Future Development Costs (2)	xx	xx
Changes Resulting from Extensions, Infill Drilling and Improved Recovery (2)	xx	xx
Changes Resulting from Discoveries (2)	xx	xx
Changes Resulting from Acquisitions of Reserves (2)	xx	xx
Changes Resulting from Dispositions of Reserves (2)	xx	xx
Accretion of Discount (3)	xx	xx
Other Significant Factors (2)	xx	xx
Net Changes in Income Taxes (4)	xx	xx
Changes Resulting from Technical Reserves Revisions Plus Effects of Timing (2)	xx	xx
Estimated Net Present Value After Tax of Future Net Revenue at End of Period	xxx	xxx

(1) Undiscounted before income taxes

(2) Discounted before income taxes

(3) 10 percent of beginning of year net present value before income taxes

(4) Discounted

APPENDIX A — Glossary

Accelerated production. The recovery of the reserves of a pool at a faster rate than a base production scenario with no recovery of incremental reserves.

Accumulation. An individual body of petroleum in a reservoir

Acidizing. A method of well stimulation using acid (to increase productivity); conducted mostly in carbonates.

Acoustic log. A measurement of the interval transit time of compressional seismic waves in rocks near the wellbore of a liquid-filled borehole; used chiefly for estimating porosity and lithology; also referred to as sonic log.

Aggregate /Aggregation - The sum total of, or the process of totalling, individual estimates in a collection of separate estimates.

Analogous fields. Fields having similar properties that are at a more advanced stage of development or production history than the field of specific interest, and that may provide concepts or patterns to assist in the interpretation of more limited data.

Anhydrite. A granular, white or light-colored evaporite mineral ($CaSO_4$), often found together with rock salt.

Annulus. The space around the tubing in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

Aquifer. A stratum below the surface of the earth capable of producing water.

Arithmetic mean. The average obtained by dividing the sum of a distribution by the number of its addends.

Asphaltene. Any of the dark solid constituents of crude oils and other bitumens that are soluble in carbon disulphide but insoluble in paraffin naphthas.

Beta model. A numerical simulator used to model black oil systems; also referred to as black oil model.

Bias. A systematic deviation from the actual value or distribution; a combination of two effects: displacement bias and variability bias.

Bitumen. Refer to Crude bitumen.

Black oil model. Refer to Beta model.

Black oil. Refers to a system in which the volume of fluid is primarily a function of reservoir pressure and constant temperature. A system that is not a black oil system includes compositional variables.

Bottom water. Sand layers at the bottom of a formation which contain mobile water that appreciably affects reservoir performance; water in strata underlying an oil- or gas-bearing formation.

Bottom-hole pressure. The pressure in a well at a point opposite the producing formation as recorded by a bottom-hole pressure recorder.

Bottom-hole temperature. The temperature in a well at a point opposite the producing formation.

Bubble point. In a solution of two or more components, the pressure at which the first bubbles of gas appear; same as saturation pressure.

Bulk density. Density of the combined pore volume and rock volume; measured, for example, by a density log.

Bulk volume. Total volume of a formation including the pore volume and the rock volume.

Butanes. In addition to its normal scientific meaning of C_4H_{10} (a mixture of two gaseous paraffins, normal butane and isobutane), a mixture mainly of butanes that ordinarily may contain some propane or pentanes.

Capillarity. The effect of surface attraction forces among oil, gas, water, and rock in retaining fluid saturations within the pore structure of a porous medium. Refer to Capillary pressure.

Capillary pressure. A force per unit area resulting from surface forces at the interface between two immiscible fluids.

Carbon dioxide flooding. A recovery process in which carbon dioxide is injected into an oil reservoir to improve recovery.

Carbonates. Sedimentary rocks primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite), which form many petroleum reservoirs.

Cementation. The process of precipitation or growth of a binding material around grains or fragments of rock.

Chase gas. Gas used to displace another phase in an enhanced recovery process.

Chemical flooding. A recovery process in which chemicals added to water are injected into an oil reservoir to improve recovery.

Choke. An orifice installed in a line to restrict the flow and control the rate of production.

Clastics. Sedimentary rocks composed of fragments of pre-existing rocks; sandstone is a clastic rock.

Clay lattice. A three-dimensional pattern of clay parts in space.

Compaction. A decrease in volume of sediments as a result of compressive stress, usually resulting from continued depositional loading by accumulation of overlying sediments.

Completion interval. The portion of the wellbore that has been perforated or is open to the formation.

Compressibility. The rate of change in volume of rock and fluids with decrease in pressure. Compressibility is a major contributor to recovery efficiency and a cornerstone of reservoir performance.

Condensate. A mixture of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities, or at the inlet of a processing plant before the gas is processed.

Conductivity. A property of an electrical conductor defined as the electrical current per unit area divided by the voltage drop per unit length.

Confidence level. The qualitative degree of certainty associated with an estimated value.

Conformance efficiency. The fraction of total reservoir volume that is contacted by injected fluid as a result of discontinuities in the reservoir; also referred to as continuity factor.

Conglomerate. A sedimentary rock composed of coarse-grained rock fragments, pebbles or cobbles cemented together in a fine-grained matrix.

Coning. A cone of gas or water that forms in the reservoir due to pressure drawdown at the perforations.

Connate water. The original water of deposition trapped in the interstices of the reservoir rock.

Conventional crude oil. Crude oil that, at a particular time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.

Conventional natural gas. Natural gas that occurs in a normal, porous, permeable reservoir rock and that, at a particular time, can be technically and economically produced using normal production practices.

Cricondentherm. Maximum temperature at which two phases (for example, liquid and vapour) can exist.

Critical gas saturation. Saturation at which free gas in a reservoir becomes mobile.

Critical pressure. The pressure required to condense a gas at the critical temperature, above which, regardless of pressure, the gas cannot be liquefied.

Critical temperature. That temperature above which a substance can exist only in the gaseous state, no matter what pressure is exerted.

Crude bitumen or bitumen. A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. Its viscosity is greater than 10 000 mPa-s (cp) measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis. Crude bitumen may contain sulphur and other non-hydrocarbon compounds.

Crude oil or Oil. A mixture, consisting mainly of pentanes and heavier hydrocarbons, that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non- hydrocarbons, but does not include liquids obtained from the processing of natural gas. Classes of crude oil are often reported on the basis of density, sometimes with different meanings. Acceptable ranges are as follows:

- Light: less than 870 kg/m^3 (greater than 31.1^0 API)
- Medium: 870 to 920 kg/m^3 (31.1 to 22.3^0 API)
- Heavy: 920 to 1000 kg/m^3 (22.3 to 10^0 API)
- Extra-heavy: greater than 1000 kg/m^3 (less than 10^0 API)

D'Arcy's Law. The basic law of fluid flow through a porous medium that expresses how easily a fluid of a certain viscosity flows through a rock under a pressure gradient.

Decision tree. A graphical summary of the possible outcomes and probabilities of the events that comprise a project.

Density log. A radioactivity log for open-hole surveying that responds to variations in the specific gravity of formations; an excellent porosity -measuring device, especially for shaly sands. It is a contact log (i.e., a detector held against the wall of the hole). The tool emits neutrons and then measures the secondary gamma radiation that is scattered back to the detector.

Density. The ratio of the mass of an object to its volume.

Depletion. The reduction, or exhaustion of a well or pool's commercial volumes of crude oil or natural gas and related substances by production.

Depositional environment. The conditions under which sediments were laid down.

detecting device and examined under ultraviolet light to detect the presence of oil or gas. Often carried out in a portable laboratory set up at the well.

Deterministic method. A method of estimating an uncertain outcome whereby discrete values are used for each parameter in a calculation.

Differential liberation. The liberation of gas from oil as pressure is reduced wherein the evolved gas is separated from its associated oil; usually the physical model related to transport of oil and gas through the formation during the majority of the primary depletion life.

Dip. The angle at which a stratum is inclined from the horizontal.

Discounted cash flow. Future cash converted to present conditions using an appropriate discount rate.

Displacement bias. A shift of the whole frequency distribution curve to higher or lower values.

Displacement efficiency. The fraction of initial oil saturation that is displaceable by a given injection fluid.

Displacement process. The process by which oil is displaced by water, gas, or another fluid.

Disposal well. A well used for the disposal of salt water. The water is pumped into a subsurface formation sealed off from other formations by impervious strata of rock.

Dolomite ($CaMg(CO_3)_2$). A common rock-forming mineral.

Dolomitization. The process whereby limestone is altered to dolomite by the substitution of magnesium carbonate for a portion of the original calcium carbonate.

Drainage area. The area of a pool contributing oil or gas to a well.

Drillstem test. The procedure used to gather data on a formation to determine its potential productivity before installing casing in a well. In the drillstem testing tool are a packer, valves or ports that may be opened and closed from the surface, a sample chamber and a pressure-recording device. The tool is lowered in the wellbore on a string of drill pipe and the packer set, isolating the formation to be tested from the formations above and below and supporting the fluid column above the packer. A port on the tool is opened to allow the trapped pressure below the packer to bleed off into the drill pipe, gradually exposing the formation to atmospheric pressure and allowing the well to produce to the surface, where the well fluids may be sampled and inspected. From a record of the pressure readings, a number of facts about the formation may be inferred.

Effective Date. The effective date, also referred to as the "As of Date," serves two purposed in an oil and gas reserves evaluation:

(1) It is the cut-off date for all geological, engineering, and financial data after which no new information can be included in the evaluation.

(2) It is the date to which all future net revenue or other cash flow forecasts are discounted to determine present worth values.

Efflux. Quantities of hydrocarbons, water or other fluids that leave a reservoir or zone of interest via permeable formation boundaries.

Electrical conductivity. Used for estimating reservoir properties; reciprocal of electrical resistivity. Refer to Conductivity.

Electrical resistivity. The reciprocal of electrical conductivity; used for estimating properties such as water saturation and fracture porosity. It is one of the most useeful measurements in boreholegeophysics.

Enhanced recovery. See recovery.

Entity. In the context of a "reserves entity", entity refers to the distinct item for which a reserves calculation is performed prior to aggregation; an entity may, for example, consist of a well-zone, a group of wells or a pool.

Established reserves. Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that is interpreted, from geological, geophysical or similar information, to exist with reasonable certainty. This is a term that has been used historically in Canada, particularly by regulatory agencies, and typically comprises proved reserves plus one-half probable reserves.

Established technology. Methods that have been proven to be successful in commercial applications.

Ethane. In addition to its normal scientific meaning of C_2H_6 (a colourless, odourless gas of the alkane series), a mixture mainly of ethane that may contain some methane or propane.

Evaporite. Deposits of mineral salts from sea water or salt lakes due to evaporation of the water.

Expectation. The mean of all possible outcomes of an event.

Facies. Part of a bed of sedimentary rock of similar depositional environment, composition, appearance and properties.

Fault plane. A surface along which faulting has occurred.

Fault. A break in subsurface strata. Often strata on one side of the fault line have been displaced (upward, downward, or laterally) relative to their original position.

Field. A defined geographical area consisting of one or more pools.

Fines migration. The dislocation and movement of fine particles within a reservoir. Fines migration can cause damage or impair permeability by blocking pore throats.

Flash liberation. The liberation of gas from oil as pressure is reduced wherein the evolved gas remains in contact with the liquid phase.

Flow test. A test of the ability of a well to produce fluids usually at a constant rate.

Fluid contact - The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturation. Because of capillary and other phenomena, fluid-saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.

Fluid saturation. The portion of porosity in a reservoir that is occupied by a fluid.

Fluid viscosity. Internal friction of a fluid, caused by molecular interactions, that makes it resist a tendency to flow.

Fold. A flexure of rock strata into arches and troughs, produced by earth movements.

Formation heterogeneity. Variation both laterally and vertically of properties such as porosity, permeability, and formation thickness.

Formation imaging. Logs that generate images (or "pictures") of the borehole from various sources including sonic and resistivity devices.

Formation pressure. The pressure in a formation at a defined depth.

Formation temperature. The temperature at a given point within a formation. Temperature usually increases with depth.

Formation volume. The volume of fluid, at formation pressure and temperature, that results in one barrel of stock tank oil.

Fractional flow. Phase flow rate as a fraction of total flow rate.

Fracturing. A stimulation to increase productivity that results in the formation of a fracture in the wellbore area; conducted mostly in clastics.

Free-water level. The level or depth at which capillary pressure is equal to zero and which, in rocks of variable pore structure, is the only truly level reference line between hydrocarbons and water.

Friable. Describes a substance that is easily rubbed, crumbled, or pulverized into powder.

Gamma ray detector. A device that is capable of sensing and measuring the amount of gamma particles emitted by certain radioactive substances.

Gas chromatography. The process of separating constituents of a mixture by permitting a solution of the mixture to flow through a column of adsorbent on which the different substances are selectively separated into distinct bands or spots.

Gas compressibility factor. A factor used to correct the Ideal Gas Law (pv = nRT) to actual measurements.

Gas. Refer to Natural gas.

Gas-oil ratio. The ratio of gas in solution to the oil volume in which it is dissolved, usually expressed in cubic feet of gas per barrel of liquid at 101.325 kPa (14.65 psia) and 15.6ºC (60ºF).

Genetic sand unit. Formation consisting of sands from the same origin.

Geostatistics. A specific statistical technique (based on the statistics of regionalized variables) that uses the position as well as the magnitude of a parameter; classical statistics does not generally use position. Other spatial statistics methods also exist.

Gravity drainage. The movement of oil in a reservoir toward a wellbore resulting from the force of gravity.

Gravity override. Preferential movement of one fluid over another due to density differences.

Gross pay. The gross economically productive thickness of a formation containing hydrocarbons.

Gross swept volume. The reservoir rock volume that is swept by injected fluid.

Heavy or extra-heavy crude oils, as defined by the density ranges given, but with viscosities greater than 10 000 mPa·s measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis, would generally be classified as crude bitumen.

Heavy or extra-heavy crude oils, as defined by the density ranges given, with viscosities greater than 10 000 mPa-s measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis, would generally be classified as crude bitumen.

Heterogeneity. A lack of uniformity in formation properties such as permeability, porosity and thickness.

Homogeneity. Uniformity of reservoir properties in all directions.

Horizontal sweep efficiency. The areal fraction of a pattern contacted by the injected fluid; also referred to as areal sweep efficiency.

Horizontal waterflood scheme. The injection of water in a pattern of wells with oil production from wells completed between injectors.

Hybrid sand unit. A formation with sands from different origins.

Hydrate. A hydrocarbon and water compound that forms under reduced pressure and temperature in gathering, compression, and transmission facilities for gas; flakes of hydrate resemble snow or ice and impede fluid flow.

Hydrocarbon pore volume. The pore volume in a reservoir containing hydrocarbons; the product of hydrocarbon-filled thickness, porosity, and hydrocarbon saturation usually expressed for a unit area. May be represented on a contour map as a type of volumetric map.

Hydrocarbons. Solid, liquid or gas made up of compounds of carbon and hydrogen in varying proportions.

Hydrocarbons in place. The total quantity of hydrocarbons estimated to be contained in an accumulation, at a given time.

Hydrodynamic flow. The motion and action of water and other liquids in the subsurface.

Hydrodynamic trap. An oil or gas reservoir trapped by surrounding water movement; usually leads to tilted water-oil contacts.

Hydrodynamics. The study of the motion of a fluid and of the interactions of the fluid with its boundaries, especially in the incompressible ideal (frictionless) case.

Hydrostatic head. The pressure exerted by a body of water at rest.

Hysteresis. A change in process path in successive experimental tests.

Ideal Gas Law. The volume occupied by an ideal gas depends only upon temperature, pressure, and the number of molecules (moles) present ($pv = nRT$).

Imbibition. The increase in saturation of the wetting phase in a porous medium with time.

Improved recovery. See recovery.

In situ recovery. A term that is used, when referring to oil sands, for the process of recovering crude bitumen from oil sands other than by surface mining.

Incremental reserves. The additional quantities of crude oil, natural gas and related substances that can be recovered by an enhancement to production conditions.

Infill well(s). A well (or wells) that is drilled within a known accumulation.

Influx. Quantities of hydrocarbons, water or other fluids that enter a reservoir or a designated portion of a reservoir through permeable formation boundaries.

Initial reserves. A term often used to refer to reserves prior to deduction of any production. Alternatively, initial reserves can be described as the sum of remaining reserves and cumulative production at the time of the estimate.

Initial volumes in place. The gross volume of crude oil, natural gas and related substances estimated, at a particular time, to be initially contained in a reservoir before any volume has been produced and without regard for the extent to which such volumes will be recovered.

Injection. The pumping of fluids into the reservoir via wellbores, for wellbore conditioning or stimulation or for improved recovery operations.

Intercalation. Insertion of a bed or stratum of one material between layers of another material.

Interfacial tension. The force per unit length existing at the interface between two immiscible fluids.

Interference effects. The change in a well's production and recovery caused by the operation of other wells within a common reservoir.

Irreducible water saturation. The minimum water saturation that can be obtained in a reservoir under normal operations.

Isochrone. A line on a chart connecting all points having the same time of occurrence of particular phenomena or of a particular value of a quantity.

Isolating packers. Devices used for isolating an interval in a well.

Isopach map. A geological map of subsurface strata showing contours of the thickness of a given formation underlying an area; one type of volumetric map.

Isotherm. A line connecting points of equal temperature.

Isothermal. Having constant temperature; at constant temperature.

J function. A dimensionless grouping of the physical properties of a rock and its saturating fluids proposed by Leverett.

Kerogen. A solid bituminous substance occurring in certain shales that decomposes to oil and natural gas when heated.

Klinkenberg. Mathematical correction of laboratory air permeability measurements (made on formation material) into equivalent liquid permeability values, necessitated by gas slippage in pores.

Known accumulation. An accumulation that has been penetrated by a well. In general, the well must have demonstrated the existence of hydrocarbons by flow testing in order for the accumulation to be classified as "known". However, where log and/or core data exist and there is a good analogy to a nearby and geologically comparable known accumulation, this may suffice.

Laterolog. A resistivity measuring device using electrodes in which a current is forced through the formation in a sheet of predetermined thickness, so that the measurement involves a limited vertical extent.

Liquefied petroleum gases. A term commonly used to refer to hydrocarbon mixtures consisting predominantly of propane and butanes. In Canada, ethane is also frequently included.

Lithification. The conversion of unconsolidated deposits into solid rock by compaction and cementing together of the individual rock grains.

Lithology. The description of the physical character of a rock as determined by eye or with a low-power magnifier; based on color, structures, mineralogic components, and grain size.

LKH (lowest known hydrocarbon). The lowest structural elevation of hydrocarbons in a well or pool that has been confirmed by well logs, testing or pressure analysis.

Marketable natural gas. Natural gas that meets specifications for its sale, whether it occurs naturally or results from the processing of raw natural gas. Field and plant fuel losses to the point of the sale must be excluded from the marketable quantity. The heating value of marketable natural gas may vary considerably, depending upon its composition, and therefore quantities are usually expressed not only in volumes, but also in terms of energy content. Reserves are always reported as marketable quantities.

Material balance method. Engineering methods of analysing project performance based on mass-balance concepts, wherein expansion of in-situ rock and fluids is related to influx-efflux and production-injection streams. Material balance methods are commonly used to determine fluids in-place or predict production performance.

Matrix. The continuous, fine-grained material in which large grains of a sediment or sedimentary rock are embedded.

Mean. The most commonly used measure of central tendency; the average value of repeated trials. The mean represents the most probable value of an estimate of reserve volume or value.

Median. A measure of central tendency; the middle value or the arithmetic mean of the two middle values of a list of numbers, for a list containing an odd or even number of members, respectively. Geometrically, the value that divides a histogram or frequency distribution into two parts of equal area; also the 50 percent probability level on a cumulative distribution function or expectation curve.

Methane. In addition to its normal scientific meaning of CH_4 (a light, odourless, colourless gaseous hydrocarbon), a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium or carbon dioxide.

Micellar flooding. The addition of surfactants to injected water to reduce interfacial tension.

Micro-fractures. Fractures not easily seen by the naked eye; might be seen in thin sections. They usually feed macro-fractures.

Microlog. A wellbore resistivity log recorded with electrodes mounted at short distances from each other in the face of a rubber-padded microresistivity sonde and with different depths of investigation. Comparison of the two curves identifies mudcake which indirectly identifies the presence of permeable formation.

Microporosity. Porosity that is visible only at high magnification and that is generally not effective.

Miscibility. The tendency or capacity of two or more liquids to form a uniform blend, that is, to dissolve in each other; degrees are total miscibility, partial miscibility, and immiscibility.

Miscible flooding. A recovery process in which a fluid (a "solvent") that is capable of dissolving into the crude oil it contacts is injected into an oil reservoir to improve recovery.

Mobility ratio. The ratio of the mobility of the displacing phase behind the flood front to the displaced phase ahead of the flood front.

Mobility. The ratio of the permeability of a given phase to the viscosity of that phase. Phase mobility is an indication of how easily that phase moves in the reservoir.

Mode. A measure of central tendency; the most commonly occurring value of a set of numbers.

Mole. An amount of substance of a system which contains as many elementary units as there are atoms of carbon in 0.012 kilogram of the pure nuclide carbon-12; the elementary unit must be specified and may be an atom, a molecule, an ion, an electron, a photon, or even a specified group of such units.

Morphology. The observation of the form of lands.

Mudcake. The residue that forms on the wall of the borehole as the drilling mud loses filtrate into porous and permeable formations; also called well cake or filter cake.

Mud-gas log. The recording of information derived from examination and analysis of formation cuttings made by the bit and mud circulated out of the hole. A portion of the mud is diverted through a gas-

Multi-phase behaviour. The equilibrium relationships between at least two fluids such as water, crude oil, or natural gas and related substances either in pools or above ground in gas-oil production facilities.

Multi-well pools. Pools which contain more than one well.

Natural fracture. A discontinuity in rock caused by diastrophism, deep erosion of the overburden, or volume shrinkage. Examples would include shales that lose water, the cooling of igneous rock, and the desiccation of sedimentary rock.

Natural gas liquids. Those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of nonhydrocarbons.

Natural gas or gas. A mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

Net present value. The value obtained when all cash flow streams, including the investment, are discounted to the present and totalled.

Neutron log. A radioactive device that emits high energy neutrons and records a curve which responds primarily to the amount of hydrogen in the formation. Thus, in clean formation where the pores are filled with water or oil, the neutron log measures the amount of liquid-filled porosity.

Nonconventional crude oil. Crude oil that is not classified as conventional crude oil. An example would be kerogen contained in oil shale deposits. Bitumen is also generally included in the non-conventional crude oil category as a matter of practice, although some wells may produce at commercial rates without steam injection. Also referred to as unconventional crude oil.

Nonconventional natural gas. Natural gas that is not classified as conventional natural gas. An example would be coal-bed methane. Also referred to as unconventional natural gas.

Nuclear magnetism inject log. A tool that uses a pulsed nuclear magnetic resonance analyzed to determine fluid content, total and free fluid porosity, and permeability.

Oil sands. Deposits of sand or sandstone or other sedimentary rocks that contain crude bitumen.

Oolite. A spherical to ellipsoidal body, 0.25 to 2.00 mm in diameter, which may or may not have a nucleus, and has concentric or radial structure or both; usually calcareous, but may be hematitic or of other composition.

Operating conditions. The conditions (eg. temperature, pressure and rates) under which a well or pool is being depleted.

Pentanes plus. A mixture mainly of pentanes and heavier hydrocarbons, which ordinarily may contain some butanes, and which is obtained from the processing of raw gas condensate or crude oil.

Permeability. Property of a porous medium relating to the capacity of the medium to transmit fluids.

Permeameter. A device for measuring permeability by measuring the flow of fluid through a sample across which there is a pressure drop.

Petroleum. A naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase.

Phase behaviour. The equilibrium relationships between water, liquid hydrocarbons, and dissolved or free gas, either in reservoirs or as separated aboveground in gas-oil production facilities.

Pilot. A small-scale test or trial operation that is used to assess the suitability of a method for commercial application.

Polymer flooding. The addition of polymers to injected water to improve mobility ratios and increase oil recovery.

Pool. An individual and separate accumulation of petroleum in a reservoir.

Pore volume. The pores in a rock considered collectively; the product of porous thickness times porosity. May be represented on a contour map, a type of volumetric map.

Porosimetry. The measurement of the porosity of reservoir rock s.

Porosity. The ratio of the aggregate volume of interstices in a rock to its total volume. It is usually stated as a percentage.

Pressure depletion. Pressure decline in a reservoir due to oil or gas production.

Pressure transient analysis. The estimation of reservoir properties from measurements of flow, buildup and drawdown pressures.

Primary recovery.- See recovery.

Probabilistic method. A method of estimating an uncertain outcome whereby a range of values is used for each parameter in a calculation. Results are generally expressed as a range with an associated probability of occurrence.

Probability. The extent to which an event is likely to occur, measured by the ratio of the favourable cases to the whole number of cases possible.

Production decline analysis. Analytical methods that use historical production data to estimate the future production and/or reserves for an entity.

Production tests. Tests conducted to determine the productivity of a given reservoir.

Propane. In addition to its normal scientific meaning of C_3H_8 (a heavy, colourless hydrocarbon of the paraffin series), a mixture mainly of propane that ordinarily may contain some ethane or butanes.

Pseudo-critical and pseudo-reduced properties (temperature and pressure). Properties of pure hydrocarbons are often the same when expressed in terms of their reduced properties. The same reduced-state relationships often apply to multicomponent systems if "pseudo" critical temperatures and pressures are used rather than the true critical properties of the systems. The ratios of the temperature and pressure of interest to the pseudo-critical temperature and pressure are called the pseudo-reduced temperature and pressure respectively.

Pulsed neutron log. A special cased-hole logging tool that uses radioactivity reaction time to obtain measurements of water saturation, residual oil saturation, and fluid contents in the formation outside the casing of an oil well.

PVT data. Information describing the physical inter-relationship of pressure, volume, and temperature of reservoir fluids and various production and injection streams.

Pyrobitumen. Any of various dark-colored, relatively hard, nonvolatile hydrocarbon substances often associated with mineral matter, which decompose upon heating to yield bitumens.

Pyrolysis. The breaking apart of complex molecules into simpler units by the use of heat, as in obtaining gasoline from heavy oil.

Raw natural gas. Natural gas as it is produced from the reservoir prior to processing. It is gaseous at the conditions under which its volume is measured or estimated and may include varying amounts of heavier hydrocarbons (that may liquefy at atmospheric conditions) and water vapour. May also contain sulphur and other nonhydrocarbon compounds. Raw natural gas is generally not suitable for end use.

Recovery factor - The fraction of petroleum-in-place that is estimated to be recoverable from a pool.

Recovery*:*

Enhanced recovery. A term that, in Canada, is equivalent to improved recovery.

Improved recovery. The extraction of additional crude oil, natural gas and related substances from reservoirs through a production process other than natural depletion. Includes both secondary and tertiary recovery processes such as pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids.

Primary recovery. The extraction of crude oil, natural gas and related substances from reservoirs utilizing only the natural energy available in the reservoirs.

Secondary recovery. The extraction of additional crude oil, natural gas and related substances from reservoirs through pressure maintenance schemes such as waterflooding or gas injection.

Tertiary recovery. The extraction of additional crude oil, natural gas and related substances from reservoirs using recovery methods other than primary or secondary recovery. A tertiary process can be implemented without a preceding primary or secondary recovery scheme.

Related substances. In the context of this document, those substances that are either separate products or are by-products of crude oil, natural gas and crude bitumen.

Remaining reserves. Initial reserves less cumulative production at the time of the estimate.

Reservoir. A porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

Reservoir continuity. No interruption of a reservoir by faults, facies changes, or any other type of heterogeneity.

Residual oil saturation. Following a recovery process, the oil saturation at which oil will no longer flow in a normal immiscible water-oil system.

Resin. Any of a class of solid or semisolid organic products of natural or synthetic origin with no definite melting point, generally of high molecular weight; most resins are polymers.

Resistivity log. The measurement of subsurface electrical resistivity accomplished either by sending current into the formation and measuring the ease of electrical flow or by inducing an electrical current into the formation and measuring how large it is.

Resistivity. The electrical resistance offered to the passage of current; the inverse of conductivity.

Risk. The probability of loss or failure.

Rock volume. The volume of rock contained within a specified area.

Salt dome intrusive. A subsurface mound or dome of salt.

Sandwich loss. The volume of oil remaining unswept at the top of a reservoir after water flooding or at the bottom of the reservoir after gas or miscible flooding.

Saturated oil. Oil that contains all the gas that is capable of dissolving given the compositions of that oil and gas at the particular temperature and pressure.

Saturation pressure. Also known as bubble-point pressure; the pressure at which the first bubble of gas comes out of solution.

Saturation. Refer to Fluid Saturation.

Secondary recovery. See recovery.

Seismic. The measurement of the response to energy waves travelling through rock layers. The energy waves may be created by earthquakes, explosives or by dropping or vibrating a heavy weight. Some energy is reflected whenever the waves cross an interface of rock layers of distinctly different properties. Measurements can be made at the surface of travel time, which may be related to depth, and wave amplitude variations, which may relate to changes in rock properties (porosity, etc.).

Separator. An oilfield vessel or series of vessels in which pressure is reduced so that the dissolved gas associated with reservoir oil is flashed off or removed as a separate phase. Also known as gas separator, oilfield separator, oil-gas separator, and oil separator.

Shrinkage factor. The reciprocal of the formation volume factor expressed as barrels of stock tank oil per barrel of reservoir oil.

Shrinkage. The decrease in volume of a liquid phase caused by the release of solution gas or by the thermal contraction of the liquid; the reciprocal of formation volume factor.

Shut in. When used in reference to a reserves entity, “shut in” implies that the entity is capable of production but is not currently producing.

Solution gas. Natural gas that is dissolved in crude oil in the reservoir at original reservoir conditions and that is normally produced with the crude oil; also known as dissolved gas. Solvent flooding. Refer to Miscible flooding.

Sonic log. A device that measures the time required for a sound wave to travel through a definite length of formation. Refer to Acoustic log.

Sour gas. Natural gas that contains corrosive, sulphur-bearing compounds such as hydrogen sulphide, sulphur dioxide, and mercaptans.

Specific gravity. The ratio of the density of a material to the density of some standard material, such as water at a specified temperature, 4ºC or 60ºF or (for gases) air at standard conditions of pressure and temperature.

Spontaneous potential. A recording of the difference between the electrical potential of a movable electrode in the borehole and the electrical potential of a fixed surface electrode.

Stabilized flow - The steady-state or pseudo steady-state flow conditions that exist when a well has been produced at a constant rate for a sufficient time such that pressure and rate distributions throughout a pool do not change with time or change at a uniform rate throughout the pool. The stabilized flow period is always preceded by a period of transient flow.

Static gradient. Pressure measured in a wellbore at various depths while a well is shut in.

Statistics. The science of collecting, analyzing, presenting, and interpreting data .

Stock tank cubic metre. One cubic metre of oil at standard temperature and atmospheric pressure.

Stratification. A structure produced by deposition of sediments in beds or layers (strata), laminae, lenses, wedges, and other essentially tabular units.

Stratigraphic trap. A type of reservoir capable of holding oil or gas, in which the trap is formed by a change in the characteristics of the formation, which could be loss of porosity and permeability or a break in its continuity.

Stratum - A sheet-like body or layer of sedimentary rock, visually separable from other layers above and below; a bed. It has been defined as a stratigraphic unit that may be composed of a number of beds.

Stringer. A narrow vein or irregular filament of mineral traversing a rock mass of different materials.

Structural trap. A type of reservoir containing oil and/or gas, formed by deformation of the earth's crust that seals off the oil and gas accumulation in the reservoir, forming a trap. Anticlines, salt domes, and faulting of different kinds form structural traps.

Structure map. A map showing contour lines drawn through points of equal elevation on a stratum, key bed, or horizon, in order to depict the attitude of the rocks.

Sulphur. As used in the petroleum industry, the elemental sulphur recovered by conversion of hydrogen sulphide and other sulphur compounds extracted from crude oil, natural gas or crude bitumen.

Surface loss. The quantity of natural gas removed at field processing plants as a result of the recovery of liquids and related products and the removal of nonhydrocarbon compounds, plus the gas used for fuel; also referred to as shrinkage.

Surfactant. A soluble compound that reduces the surface tension of liquids, or reduces interfacial tension between two liquids or a liquid and a solid.

Sweep efficiency. The volume swept by a displacing fluid divided by the total volume being flooded.

Sweet gas. A petroleum natural gas containing no corrosive components, such as hydrogen sulphide, sulphur dioxide, and mercaptans.

Synthetic crude oil. A mixture of hydrocarbons derived by upgrading crude bitumen from oil sands, and kerogen from oil shales or other substances such as coal. May contain sulphur or other nonhydrocarbon compounds and has many similarities to crude oil.

Tertiary recovery - See recovery.

Thermal conductivity. The heat flow across a surface per unit area per unit time, divided by the negative of the rate of change of temperature with distance in a direction perpendicular to the surface.

Tilts. Blocks that have received a marked tilt in regions of block faulting. Regional tilts occur on the margins of basins of subsidence in the earth's crust.

Tool resolution. The precision of a tool to investigate a given property.

Transient flow. The unsteady state or non-stabilized flow period prior to steady state or pseudo steady state flow. The duration of the transient flow period will vary depending on rock and fluid properties.

Transition zone. The interval directly above the free water level in a reservoir where capillary effects result in significant changes in water and hydrocarbon saturation s in response to pore structure variations and elevation.

Transmissibility. The ability of a reservoir to conduct fluids spatially in response to pressure differentials. Depends upon permeability and formation flow geometry. Production potential depends heavily upon reservoir transmissibility.

Trap. A mass of porous, permeable rock that is sealed on top and down both flanks by nonporous, impermeable rock that prevents the free migration of hydrocarbons and concentrates them in a limited space. Uncertainty. The spectrum of possible outcomes of an evaluation.

Ultimate potential recovery. A term sometimes used to refer to an estimate at a particular time of the initial reserves that will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area, the known technology, and the anticipated economic conditions. It includes cumulative production; remaining proved, probable and possible reserves; and future additions to reserves through extensions and revisions to existing pools and the discovery of new pools. It may also be described as initial reserves plus those other resources that may be recoverable in the future.

Uncertainty. The range of possible outcomes of an estimate.

Unconformity. Lack of continuity in deposition between rock strata in contact with one another corresponding to a gap in the stratigraphic record; the surface of contact between rock beds in which there is a discontinuity in the ages of the rocks.

Unconsolidated sand. A sand formation in which individual grains are not cemented together. If an unconsolidated sandstone produces oil or gas, it will produce sand if not controlled or corrected.

Undersaturated oil reservoir. A reservoir that is above the bubble-point pressure.

Undersaturated oil. Oil that is capable of absorbing more gas than is present in the reservoir. Undersaturated oil typically displays relatively low compressibility and hence a rapid pressure decline with production.

Unitization. A term denoting the joint operation of separately owned producing leases in a pool or reservoir.

Upgrading. The process of converting crude bitumen or heavy crude oil into synthetic crude oil.

Utilization rate. In an enhanced oil recovery process, the amount of gas or fluid injected per incremental oil recovered.

Variability bias. An alteration in the shape of a frequency distribution curve.

Verification. The process of establishing the validity of an event or result.

Vertical sweep efficiency. The vertical fraction of reservoir swept by injected fluid.

Vertical waterflood scheme. The injection of water at wells completed at the bottom of the formation; oil production is from wells completed at the top of the formation.

Vesicle. A cavity in lava formed by entrapment of a gas bubble during solidification.

Viscous fingering. Faster advance of a displacing phase as compared to the displaced phase due to an unfavorable mobility ratio.

Voidage replacement ratio. The quotient of voidage replacement divided by reservoir voidage.

Voidage replacement. The volume at reservoir conditions of fluids injected into a producing pool to offset fluid withdrawals during depletion.

Voidage. The reservoir volume of hydrocarbons and water removed from the formation via wellbores during a term of producing operations.

Volumetric estimation. An estimate of hydrocarbon or water volume based on a combination of geological maps and other data which in total must account for the reservoir area, thickness, porosity, hydrocarbon and water saturation.

Volumetric mapping. A contour map of a parameter or combination of parameters that relate to reservoir volume.

Vugs. Pore spaces that are larger than would be expected from the normal fitting together of the grains that compose the rock framework. Vugs are often formed during dolomitization.

Water channelling. Preferential movement of water towards a wellbore due to unfavourable mobility ratio and pressure drawdown at the wellbore or due to the presence of higher permeability streaks.

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Water influx. The movement of water into crude oil or natural gas pools as a result of production.

Water injector. A well in which water has been injected into an underground stratum to increase reservoir pressure.

Water saturation. Portion of the pore volume occupied by water.

Waterflooding. An improved recovery process in which water is injected into a reservoir to increase oil recovery.

Weighted-mean. The number obtained by multiplying each value of x by the probability (or probability density) of x and then summing (or integrating) over the range of x.

Well density. The intensity of drilling in a given area.

Wellbore. The hole drilled by the bit.

Wetting phase. The liquid phase (oil, gas or water) that "wets" reservoir rock.

APPENDIX B — REFERENCES

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