RESERVES AND RESOURCES TRACKING

A Dissertation

by

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Submitted to the Office of Graduate and Professional Studies of

Texas A&M University

in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

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May 2020

Major Subject: Petroleum Engineering

ABSTRACT

In this work, we develop a robust methodology for hydrocarbon inventory management by creating visual representations describing how volumes move from Prospective Resources to Reserves. This helps engineers visualize how volumes move for a given project, and also provides a visual description of the definitions in the Petroleum Resources Management System (PRMS) document, which is dense and can be difficult to understand.

We propose methods to understand and quantify expected Reserves and Resources other than Reserves (ROTR) assets at any future time, incorporating the uncertainties that cause a change between the different Reserves and ROTR categories. We also develop a methodology to simulate the progression of hydrocarbons through the value chain based on actual events or specific planning strategies. The model will work in resources volumes, but we will incorporate conversions allowing us to quantify these volumes in units of energy or mass. The results from the proposed model are acceptable for decision making, can reduce analysis time, and may reduce the need for traditional evaluation methods. Furthermore, we incorporate the chance of commerciality (COC) to show the impact through the development of a project. This is a novel approach that shows the mathematical impact of the COC on Reserves and ROTR volumes.

We then propose a methodology that aims to help engineers understand the spatial and time relationship of hydrocarbons. The results from this work show the impact of well spacing on Reserves, and discuss the time to move through different sub-classes which can be used to determine the return on investment. Finally, we discuss model accuracy through time by

comparing a truncated dataset to a full dataset estimation results. Ideally, we want our initial estimates with the truncated dataset to be accurate. By comparing the amount of hydrocarbon booked as Reserves from the truncated dataset to the amount booked from the full dataset, we see the accuracy of the model through time. We aim to increase the accuracy of early-time estimates to reduce the need to re-run the model, and to have a better understanding of the actual Reserves for the future of the project.

DEDICATION

This dissertation is dedicated to my parents, Vivi Fissekidou and George Moridis.

Yes Mama, you were right.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. John Lee, my committee co-chair, Dr. Thomas Blasingame, and my committee members, Dr. Marcelo Laprea, and Dr. Zenon Medina-Cetina, for their guidance and support throughout the course of this research.

I would also like to thank my friends, colleagues, SPE student chapter, and the department faculty and staff for making my time at Texas A&M University a great experience. In particular, I would like to thank Dr. Valerie Jochen, Dr. Jerome Schubert, and Dr. Heitor Lima for whom I taught during my Ph.D. program.

Finally, I would like to thank my parents, George Moridis and Vivi Fissekidou, and my siblings, Iris-Eleni Moridis and Julius-Maximos Moridis, for their love, support and encouragement throughout this process.

CONTRIBUTORS AND FUNDING SOURCES

Contributors

This work was supervised by a dissertation committee consisting of Professor Dr. W. John Lee [advisor], Dr. Thomas A. Blasingame [co-advisor], and Dr. Marcelo Laprea of the Department of Petroleum Engineering, and Professor Zenon Medina-Cetina of the Department of Civil Engineering.

The workflows for Chapter 3 were made with the help of Ms. Morgan Quist of the Department of Petroleum Engineering who graduated in 2018 with her Master's of Science degree. A portion of the work in Chapter 6 was done with the help of Dr. Valerie Jochen.

All other work conducted for the dissertation was completed by the student independently, under the advisement of Dr. W. John Lee and Dr. Thomas Blasingame of the Department of Petroleum Engineering.

Funding Sources

This work was made possible in part by Mr. Wayne Sim at Aucerna, who provided an unrestricted gift to the TAMU foundation for Dr. W. John Lee's use. Dr. Lee funded this research with Mr. Sim's gift.

Its contents are solely the responsibility of the authors and do not necessarily represent the official views of Wayne Sim, or Aucerna.

NOMENCLATURE

A&D	=	Acquisitions and Divestitures
b-factor	=	Hyperbolic Exponent Factor
bbl	=	Barrel
BDF	=	Boundary Dominated Flow
bopd	=	Barrels of oil per day
C_K	=	Coefficient of the Gaussian Quadrature
CAPEX	=	Capital Expenditures
CDF	=	Cumulative Distribution Function
COC	=	Chance of Commerciality
COGEH	=	Canadian Oil and Gas Evaluation Handbook
D	=	Initial Nominal Decline Rate, 1/unit time
DCA	=	Decline Curve Analysis
EDF	=	Excess Distribution Function
EL	=	Economic Limit
EMV	=	Expected Monetary Value
EUR	=	Estimated Ultimate Recovery
$E[X^k]$	=	Expected Value of X, Moments of the Distribution
ft	=	Feet
$f(x_i)$	=	Probability Density Function
$F(x_i)$	=	Cumulative Distribution Function
gal	=	Gallons
GoM	=	Gulf of Mexico

GQ	=	Gaussian Quadrature
$G(x_i)$	=	Excess Distribution Function
<g(x)>	=	Expected Value of Function $g(x)$
k	=	Permeability, md
kg	=	Kilograms
kWh	=	Kilowatt-hours
lbs	=	Pounds
MB	=	Material Balance
MBT	=	Material Balance Time
MBTU	=	Million British Thermal Units
Mbbl	=	Thousand barrels
MCS	=	Monte Carlo Simulation
MFHW	=	Multi-Fractured Horizontal Well
O/GIP	=	Oil/Gas In Place
OPEX	=	Operating Expenses
p_i	=	Probabilities of the Gaussian Quadrature
PD	=	Proved Developed
PDF	=	Probability Density Function
PDP	=	Proved Developed Producing
PDNP	=	Proved Developed Not Producing
PIIP	=	Petroleum Initially-In-Place
PRMS	=	Petroleum Resources Management System
PUD	=	Proved Undeveloped

P1	=	Proved Reserves
P2	=	Probable Reserves
P3	=	Possible Reserves
P10	=	There is 10% probability that the actual reserves are greater than the P10 quantile
P50	=	There is 50% probability that the actual reserves are greater than the P50 quantile
P90	=	There is 90% probability that the actual reserves are greater than the P90 quantile
Q	=	Cumulative production, volume
q	=	Flow Rate, volume/unit time
q_i	=	Initial Instantaneous Flow Rate, volume/unit time
RE	=	Recovery efficiency (fraction)
ROTR	=	Resources Other Than Reserves
RTA	=	Rate Transient Analysis
SAGD	=	Steam Assisted Gravity Drainage
SEC	=	Securities and Exchange Commission
SM	=	Swanson's Mean
SPE	=	Society of Petroleum Engineers
SPEE	=	Society of Petroleum Evaluation Engineers
S_w	=	Water Saturation, fraction
t	=	Time
w_i	=	Weights of the Gaussian Quadrature

x = Lognormally distributed discrete random variables

x_f = Fracture Half-Length

$<x>$ = Expected Value of x

y = Lognormally distributed discrete random variables

1C = Low estimate of Contingent Resources

2C = Best estimate of Contingent Resources

3C = High estimate of Contingent Resources

1P = Proved Reserves

2P = Proved + Probable Reserves

3P = Proved + Probable + Possible Reserves

1U = Low estimate of Prospective Resources

2U = Best estimate of Prospective Resources

3U = High estimate of Prospective Resources

α = Weight of the Gaussian Quadrature

α = 1P Ratio of resources

β = 2P Ratio of resources

γ = 3P Ratio of resources

μ = Mean of the distribution

$\pi(x)$ = Polynomial Function of the Gaussian Quadrature

σ = Standard deviation of the distribution

σ^2 = Variance of the distribution

ϕ = Porosity, fraction

$\omega(x)$ = Weighting function of the Gaussian Quadrature

Ξ = Function of the mathematical relationship of the 1P, 2P, and 3P ratios resources with COC included

Ω = Function of the mathematical relationship of the 1P, 2P, and 3P ratios of resources

TABLE OF CONTENTS

Page

LIST OF FIGURES

Page

LIST OF TABLES

Page

1. INTRODUCTION AND RESEARCH OBJECTIVES

The last few years have seen a fundamental business model shift in the upstream oil and gas industry — from one enjoying healthy margins to one driven by marginal economics. The current perception is that prosperity in this new era demands a much more manufacturing-oriented perspective, using lessons learned in other industries in oil and gas workflows. The great crew change is largely complete, leaving the industry significantly "younger," in terms of age, social and environmental values, workstyles, and perhaps most importantly—experience.

Key lessons learned in the downstream oil and gas industry over the last thirty years include organizational workflow, manufacturing efficiency and understanding, as well as management and control of inventory. This research will develop a methodology to provide the upstream oil and gas industry with a robust approach to hydrocarbon inventory management.

Public markets, investors, and banks have provided the catalyst for oil and gas operators to develop practices and models to understand and quantify their Reserves and Resources other than Reserves (ROTR) assets at a particular time each year. This includes understanding and incorporating uncertainties. Today, this process is largely disconnected from planning and is focused on accounting for the state of the Reserves balance at year end rather than proactively engineering a particular set of outcomes. To excel in a margin/cost driven environment, companies require a broader perspective of the hydrocarbon value chain, merging the planning and reserves processes.

The Petroleum Resources Management System (PRMS) is a resources classification framework that characterizes Reserves and Resources other than Reserves (ROTR) in a three-by-three matrix in which the *x*-axis represents the technical uncertainty of the volumes in a given classification (such as Reserves), and the *y*-axis represents uncertainty (in different categories) in the commercial viability in the different classifications. The PRMS matrix is presented in **Fig. 1**.

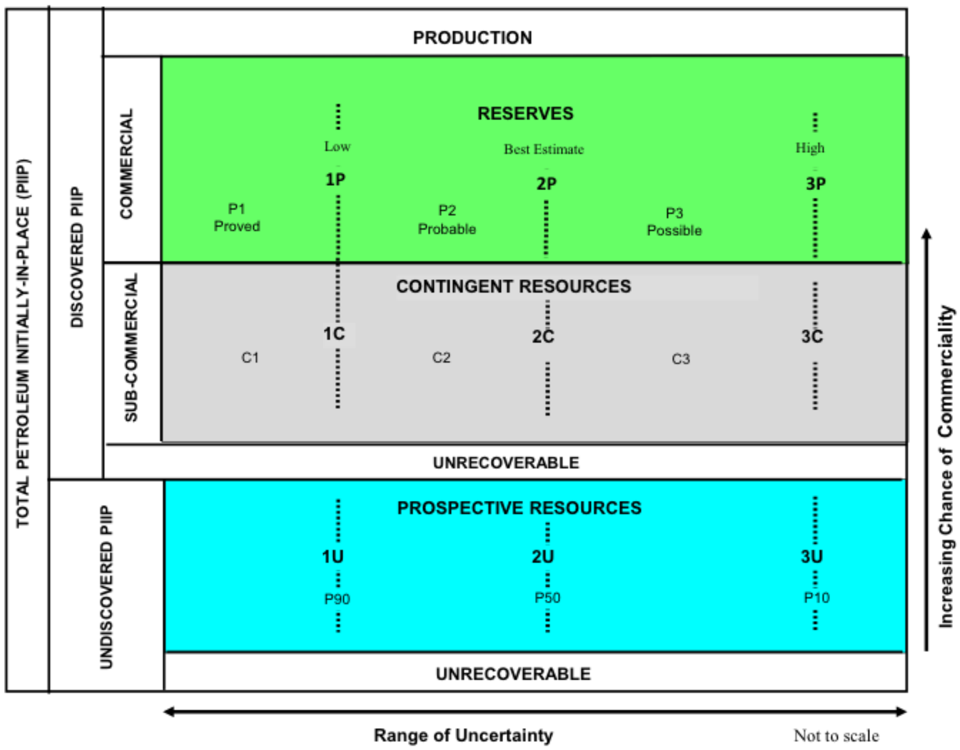

Figure 1 — The PRMS resources classification system which defines the major recover-able resources classes: Production, Reserves, Contingent Resources, Prospective Resources, and Unrecoverable hydrocarbons (reprinted from PRMS, p. 5).

We use the PRMS definitions of Reserves and ROTR to better understand how the volumes are related, and to help us understand where to place different volumes. This document is used extensively throughout this work, and we present a thorough list of definitions in **Chapter 2.**

This work is separated into four tasks, and is presented in **Chapters 3-6** of this dissertation:

- Task 1 (Chapter 3): Define and derive the correct order of movements and estimate Reserves in unconventional reservoirs
- Task 2 (Chapter 4): Describe the elements of the PRMS matrix as discrete though a cumulative distribution function (CDF)
- Task 3 (Chapter 5): Develop and define the functional relationships across the vertical elements of the PRMS matrix
- Task4 (Chapter 6): Understanding the continuity of volumes through time

To perform this work, we used a data set provided by University Lands to Texas A&M University that contains 38 wells in the Midland Basin, TX. **Table 1** shows the wells and their associated blocks. The wells have been renamed for confidentiality purposes.

Block	Rename	Block	Rename	Block	Rename
Univ 03-14	Well 1	Univ 03-19	Well 15	Univ 03-31	Well 29
	Well 2		Well 16		Well 30
	Well 3		Well 17	Univ 03-32	Well 31
	Well 4		Well 18		Well 32
	Well 5		Well 19	Univ 03-33	Well 33
	Well 6		Well 20		Well 34
	Well 7		Well 21		Well 35
	Well 8		Well 22		Well 36
	Well 9		Well 23		Well 37
	Well 10		Well 24		Well 38
	Well 11		Well 25		
	Well 12		Well 26		
	Well 13		Well 27		
	Well 14		Well 28		

Table 1—The 38 wells in the dataset from the Midland Basin (TX), with the well names sanitized. These five blocks of wells are presented in **Fig. 2** to provide a visual understanding of spatial relationships.

The spatial relationship of the wells at the surface is presented in **Fig. 2.** The dataset provided did not include location information, so we supplemented with latitude and longitude data extracted from Enverus DrillingInfo.

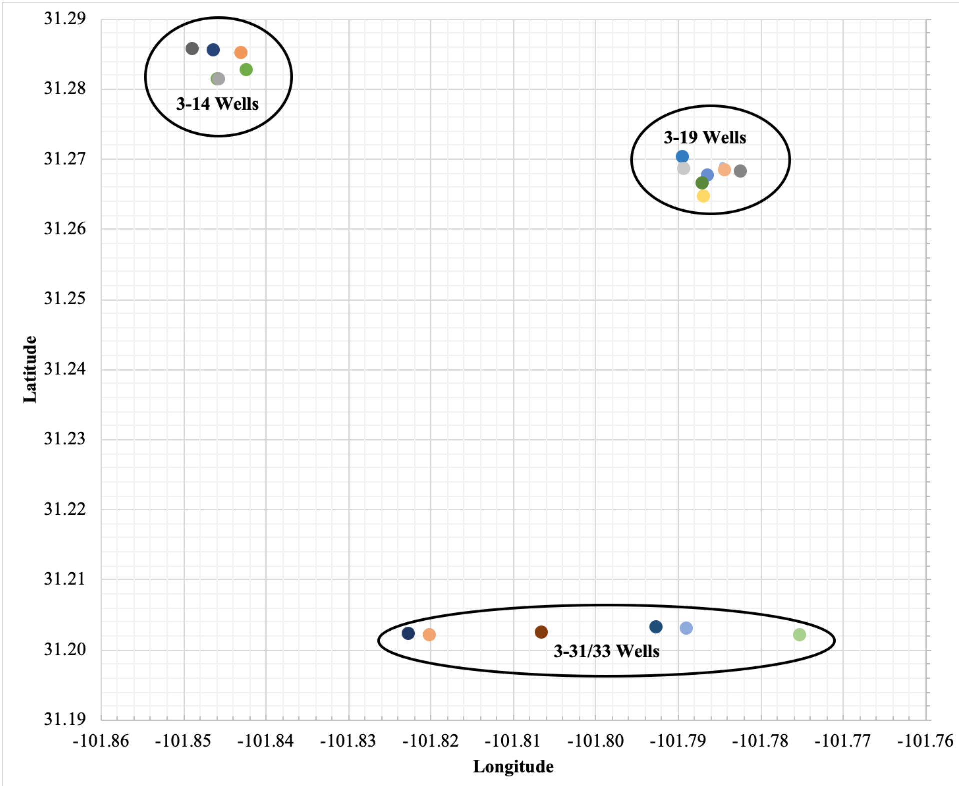

Figure 2 — Well locations of the 38 wells in the Midland Basin, TX presented in on a latitude vs. longitude plot. The 3-14 and 3-19 blocks each have 14 wells, and the 3-31/33 blocks have 10 wells.

Appendix A provides more detailed maps that show the specific surface well locations of each block.

The overall objectives of this work are:

- Develop a robust methodology for hydrocarbon inventory management.
- Develop practices and models to understand and quantify expected Reserves and resources ROTR assets at any future time, incorporating the uncertainties that cause a change between the different Reserves and ROTR categories.

- Develop a methodology and associated algorithms to accurately simulate the progression of hydrocarbons through the value chain based on actual events or specific planning strategies. The model will work in resources volumes, but we will incorporate conversions allowing us to quantify these volumes in units of energy or mass.

1.1 Task 1 – Define And Derive The Proper Order Of Movements from Prospective Resources, to Contingent Resources, to Reserves

In this chapter, we progress resource volumes from undiscovered toward Reserves. We do this by starting with suggested procedures to reclassify Prospective Resources as Contingent Resources upon discovery. We provide post-discovery guidance on development and commerciality for the project maturity sub-classes within the Contingent Resources classification. We explain that "established technologies" must be technically and economically viable before they can be used for development decisions. And finally, we examine requirements to remove contingencies so that the volumes can be reclassified properly as Reserves.

For movement of resources toward Reserves , we suggest that there is no linear path to define the movement from Prospective to Contingent Resources, though there are certain criteria which must be met for a given project. Certain contingencies, such as price of oil and available technologies, dominate the classification of resource volumes.

We begin with the updated PRMS and the Canadian Oil and Gas Engineering Handbook (COGEH) documents (2018). We then define the three steps that are necessary to move through Prospective Resources before we can begin moving into the sub-classes of Contingent Resources. We define the movement for Prospective Resources to become discovered, making these Prospective Resources become Contingent Resources. We define the progression, following discovery, in chance of development and commerciality in the project maturity sub-classes within the Contingent Resources classification. We define the criteria for a technology to become "established" and explain that these technologies must be technically reliable and economic before they can be used for development decisions. Lastly, we define the contingencies and the movement through each contingency for the volumes to become Reserves.

The objective of the first task is to propose systematic procedures for classification of ROTR volumes. We describe how the volumes are classified and categorized and how those volumes move between Reserves and ROTR as more information becomes available.

1.2 Task 2 – Describe the elements of the PRMS matrix as discrete through a cumulative distribution function (CDF)

Production data are lognormally distributed, regardless of basin type, and thus are not compatible with Swanson's Mean (SM) concept. The Gaussian Quadrature (GQ) algorithm provides a methodology to estimate the weights of the Reserves that lie within the 1P, 2P, and 3P categories. The GQ is a numerical integration method that uses discrete random variables and a distribution that matches the original data. For this work, we associate the lognormal CDF with a set of discrete random variables that replace the production data, and determine the associated probabilities. The production data for both conventional and unconventional fields are lognormally distributed, thus we expect that this methodology can be implemented in any field.

Using the provided dataset, we performed probabilistic decline curve analysis (DCA) using the Arps Hyperbolic model (1945) and Monte Carlo simulation (MCS) to obtain a probability distribution of the P90, P50, and P10 volumes. We considered this information to be our "truth case," to which we compared ratios of different Reserves categories from the GQ and SM methodologies. We also performed probabilistic rate transient analysis (RTA) using the IHS *Harmony* software to obtain the P90, P50, and P10 volumes, and calculated the relative weights of each Reserves category. Once we completed these first two steps, we implemented a 3-, 5-, and 10-point GQ to obtain the weights, percentiles, and ratios of each category for the 38 well. We analyzed the GQ results by calculating the percentage differences between the probabilistic DCA, RTA, and GQ results.

The objective of the second task of this research is to develop a methodology to estimate the fraction of Reserves assigned to each Reserves category (1P, 2P, and 3P) of the PRMS resources classification matrix using a CDF. Previous published work has often used SM as the basis for allocating Reserves to individual categories. We found that this method, which relates the Reserves categories through a CDF for a normal distribution, is an inaccurate means to determine the relationship of the Reserves categories with asymmetric distributions, and our work identified a better method, the gaussian quadrature.

1.3 Task 3 – Develop and define the functional relationships across the vertical elements of the PRMS matrix

In this task, we aim to provide planners with a methodology that will allow evaluators to progress resources from classifications with lower COC to classes with higher chances of commerciality (top sub-classes of Reserves) and also to progress resources from categories with large uncertainty to categories with less uncertainty of eventual recovery. This is important to entities of all sizes for planning purposes because companies should track their resources regardless of project stage or size. Our methodology provides continuous tracking of volumes when moving from Prospective Resources to Contingent Resources to Reserves throughout the life of the project, and allows for more accurate Reserves reporting.

We begin this work with the relationship between the Reserves categories in the PRMS matrix, modeled using the GQ, which are the results of Task 2 presented in **Chapter 4**. Using the GQ results, we develop functional relationships across the vertical elements of the PRMS matrix by simulating event-variant movement across categories. Resources move on a time basis, and the rate of movement differs for different classes and categories. We implement the COC presented by Etherington *et al.* (2010) to develop relationships between the vertical elements of the PRMS matrix using the GQ weights; however this value can also be user-defined. Etherington's values are used purely as an example to produce results for this work.

1.4 Task 4 – Understanding the Continuity of Volumes Through Time

The first objective of this task is to determine the volume of hydrocarbon that can be moved from ROTR to Reserves, or from Proved Undeveloped Reserves (PUD) to Proved

Developed Producing (PDP) Reserves based on well placement. The second objective is to create a model that incorporates the production history and forecasted estimated ultimate recovery (EUR), in this case by implementing two-segment decline curve analysis (DCA).

To accomplish this task, we first understand how well spacing can impact the recovery of wells. We performed a literature review of sensitivity analyses done in the Wolfcamp A (the reservoir that our wells are producing) which helped determine the spatial well relationships that may trigger movements in certain regulatory frameworks. A successful well may promote the offsetting 2P wells to PUD wells. We incorporate the methodology in SPEE Monograph 3 (2013) for estimating PUD volumes beyond immediate offset locations that can be used to estimate the Reserves and possibly Contingent Resources in some situations. The question we aim to answer is: *How do we move the PUDs to PDPs?*

In the second part of this work, we create a model which includes the production history and the forecasted EURs. As time moves forward, continuity and consistency must be maintained across the model. Assume the following scenario: we plan to move a volume "x" from 1C Contingent Resources to1P Reserves, but we can only book $0.7x$ as 1P Reserves. The model must reflect the fraction of the volume x that was actually moved and how it depends on, for example, commodity price contingencies. The remaining $0.3x$ volume that was not classified as Reserves must be accounted in the model. The continuity of the model through time will track the volumes, and it needs to be able to do so consistently.

2. DEFINITION OF CONCEPTS

2.1 Petroleum Resources Management System (PRMS)

The Petroleum Resources Management System (PRMS) has defined different volumes of petroleum into the categories of Reserves, Contingent Resources, and Prospective Resources. They have created a resources classification table that presents how these volumes are related, presented in **Fig. 1**.

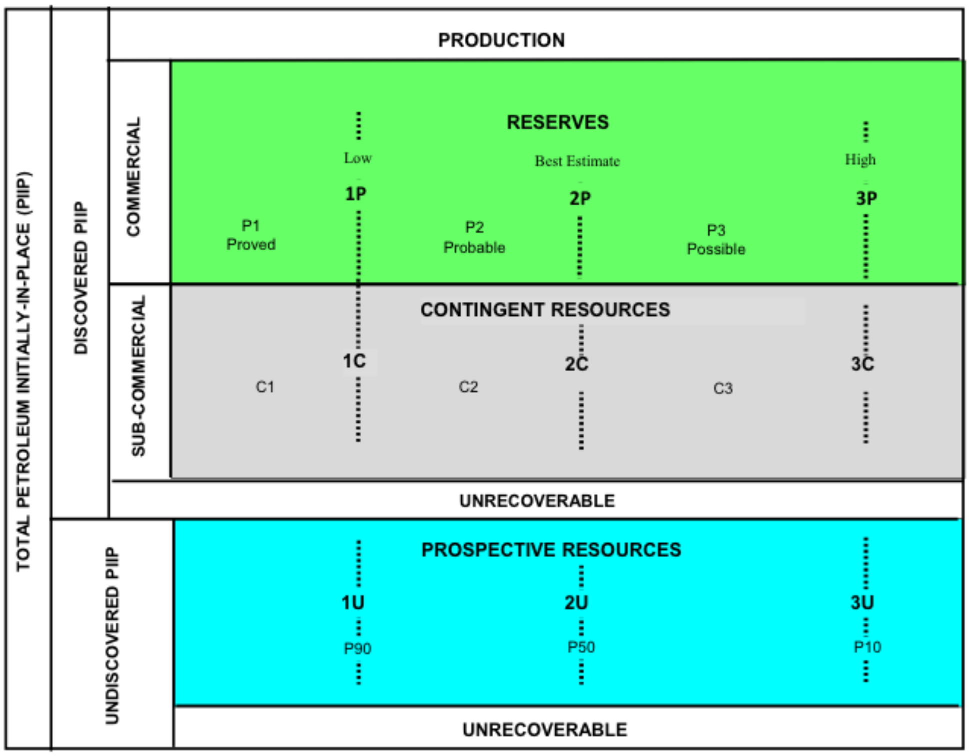

Figure 1 — The PRMS resources classification system which defines the major recover-able resources classes: Production, Reserves, Contingent Resources, Prospective Resources, and Unrecoverable hydrocarbons (reprinted from PRMS, p. 5).

The *x*-axis of this matrix indicates the *Range of Uncertainty*, which is the "range of estimated quantities potentially recoverable from an accumulation" (PRMS, p. 5). It is read from right to left, where the highest uncertainty is at the right end of the matrix, and the lowest uncertainty is at the left end of the matrix.

The right *y*-axis is defined as the *Chance of Commerciality*, "that is the chance that the project that will be developed and reach commercial producing status" (SPE PRMS, p. 2). This is defined mathematically as

$$\textit{Chance of Commerciality} = \textit{Chance of Discovery} \times \textit{Chance of Development} \quad \textbf{(1)}$$

The left *y*-axis represents the total petroleum initially-in-place (PIIP), which is what is estimated to exist in the given accumulation. It is then divided by class:

- Reserves = Commercially discovered PIIP
- Contingent Resources = Sub-commercially discovered PIIP
- Prospective Resources = Undiscovered PIIP

Reserves, Contingent Resources, and Prospective Resources are defined in **Sections 2.2**, **2.3**, and **2.4**, respectively.

PRMS uses these terms *classify* and *categorize* when placing resources into inventory. As **Fig. 3** indicates, classification depends on the chance of commerciality, and categorization depends on the certainty of recovery.

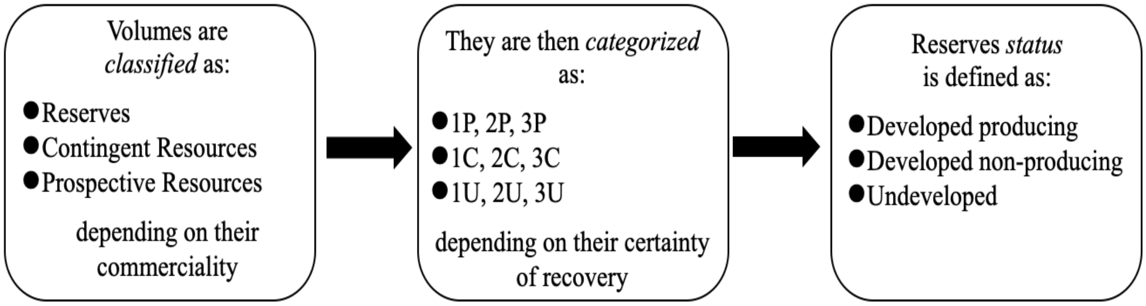

Figure 3 — The Resources ordering workflow from *classification*, to *categorization,* to Reserves *status*. This workflow identifies *class*, *category*, and *status* within the PRMS matrix (reprinted with permission from Moridis *et al.* 2019, SPE 195298).

We can then sub-classify resources within a given class based on the differences in their chance of commerciality.

Fig. 4 is a visual representation of the PRMS classification matrix, which includes categories, classes, and sub-classes.

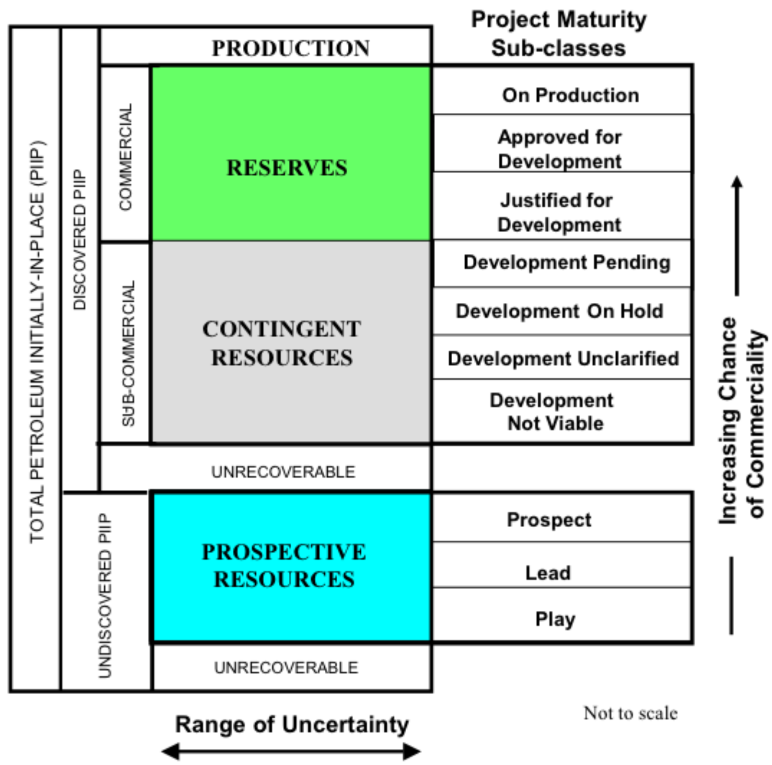

Figure 4 — The PRMS classification matrix, complete with project maturity sub-classes. This figure is a visual representation of the sub-classes for each Resources class. Each sub-class depends on the chance of commerciality (reprinted from PRMS, p. 11).

The definitions of the sub-classes for Reserves, Contingent Resources, and Prospective Resources are presented in the subsequent sections.

2.2 Reserves

Reserves are defined as "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions" (PRMS, p. 24). They must satisfy four criteria:

- Discovered
- Recoverable

- Commercial
- Remaining based on the development project applied

The Reserves are separated into three categories:

- Proved Reserves, defined as "those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate" (PRMS, p. 10-11).
- Probable Reserves, defined as "those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate" (PRMS, p. 11).
- Possible Reserves, defined as "those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent

to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate" (PRMS, p. 11).

To summarize:

- 1P = Proved Reserves (90% probability that <u>actual</u> reserves > the P90 quantile (*i.e.,* P90)).
- 2P = Proved + Probable Reserves (50% probability that <u>actual</u> reserves > the P50 quantile (*i.e.,* P50)).
- 3P = Proved + Probable + Possible Reserves = 10% probability that <u>actual</u> reserves > the P10 quantile (*i.e.,* P10).

The incremental volumes are:

- P2 = Probable Reserves = 2P-1P
- P3 = Possible Reserves = 3P-2P

Furthermore, "to be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame" (SPE PRMS, p. 24). The term "reasonable time frame" is ambiguous, however PRMS states that five years is the recommended benchmark. However, each project differs, therefore this "reasonable time frame" depends on a case-by-case basis. A longer time frame would be necessary, for example, when the "development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests" (PRMS, p. 24).

Reserves statuses can be defined, providing finer granularity characterization. For example, 1P Reserves contain PDP, PDNP and PUDs.

The four reserves statuses that make up the 1P category are:

- PDP = Proved Developed Producing
- PDNP = Proved Developed Not Producing
- PD = Proved Developed
- PUD = Proved Undeveloped

These statuses also apply to each Reserves category, and can be described as:

$$1P=PDP+PDNP+PD+PU \tag{2}$$

$$2P=2PDP+2PDNP+2PD+2PU \tag{3}$$

$$3P=3PDP+3PDNP+3PD+3PU \tag{4}$$

The same process can be implemented on the two incremental volumes, P2 and P3:

$$P2=P2DP+P2DNP+P2D+P2U \quad \text{.......} \quad (5)$$

$$P3=P3DP+P3DNP+P3D+P3U \quad \text{.......} \quad (6)$$

The Reserves sub-classes are defined in **Table 2.**

Class	Sub-Class	Definition	PRMS
Reserves	On Production	A development project currently producing or capable of producing	p. 31
	Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready or is under way	p. 31
	Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained	p. 32

Table 2—Definitions of the sub-classes of Reserves from PRMS (2018) to supplement Fig. 2 (reprinted from PRMS, p. 31-32).

The sub-classes of Reserves (On Production, Approved for Development, Justified for Development) are related to progressing a project "though final approvals to implementation" and "initiation of production and product sales" (PRMS, p. 11).

2.3 Contingent Resources

Contingent Resources are defined as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. These may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status" (PRMS, p. 25).

Contingent Resources are separated into three categories:

- 1C = the low estimate scenario of Contingent Resources
- 2C = the best estimate scenario of Contingent Resources
- 3C = the high estimate scenario of Contingent Resources

The Contingent Resources sub-classes are defined in **Table 3.**

Class	Sub-Class	Definition	PRMS
Contingent Resources	Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future	p. 32
	Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay	p. 32
	Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information	p. 32
	Development Not Viable	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay	p. 32

Table 3—Definitions of the sub-classes of Contingent Resources from PRMS (2018) to supplement Fig. 2 (reprinted from PRMS, p. 32).

The sub-classes of Contingent Resources (Development Pending, Development on Hold, Development Unclarified, and Development Not Viable) can be related to gathering and analyzing data and to clarify the maturity of the project. These sub-classes mainly focus on contingencies that may prevent a project from being classified as Reserves.

2.4 Prospective Resources

Prospective Resources are defined as "those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration" (PRMS, p. 25).

Prospective Resources are separated into three categories:

- 1U = the low estimate scenario of Prospective Resources
- 2U = the best estimate scenario of Prospective Resources
- 3U = the high estimate scenario of Prospective Resources

The Prospective Resources sub-classes are defined in **Table 4.**

Class	Sub-Class	Definition	PRMS
Prospective Resources	Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects	p. 46
	Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect	p. 44
	Prospect	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target	p. 47

Table 4—Definitions of the sub-classes of Contingent Resources from PRMS (2018) to supplement Fig. 2 (reprinted from PRMS, p. 44-47).

The sub-classes of Prospective Resources (Play, Lead, Prospect) are those which can move a project closer to a decision to proceed with exploration drilling. To progress through Prospective Resources, we focus in on Plays, and try to identify more Leads. Ultimately, we want to obtain Prospects. This differs from the decision-making process through Contingent Resources and Reserves that only requires additional data and/or studies that are used to better understand the project

3. DEFINE AND DERIVE THE PROPER ORDER TO MOVEMENTS FROM PROSPECTIVE RESOURCES, TO CONTINGENT RESOURCES, TO RESERVES (AND BACK)*

3.1 Introduction

In this chapter, we aim to describe the proper order of movements from Prospective Resources (PR), to Contingent Resources (CR), to Reserves. These movements are based on changing uncertainty and commerciality, and do not necessarily move directly from one class or one category to another through the PRMS matrix (Fig. 1). Because this movement is not linear, we identify what can cause change and what the change means when classifying Reserves and Resources other than Reserves (ROTR). This includes developing a workflow for event-based triggers that drive movements through the matrix and cause reclassification. We used the most current Reserves and ROTR definitions presented in the updated PRMS (2018) and COGEH documents (2018) that are summarized in **Chapter 2**.

Our proposed workflow is as follows:

- We first describe the three steps that are necessary to move through the three sub-classes of Prospective Resources, defined in **Section 2.1.4**, before we can begin moving into the sub-classes of Contingent Resources, defined in **Section 2.1.3**. We

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then describe the criteria for Prospective Resources to become discovered, moving these volumes to Contingent Resources.

- We describe the progression, following discovery and classification as Contingent Resources, in chance of development and commerciality within the project maturity sub-classes of Contingent Resources.
- We describe the criteria for a technology to become established (as defined by PRMS and COGEH), and explain that these technologies must be technically reliable and economic before they can be used for development decisions.
- Finally, we describe the contingencies and the movement through each contingency for the volumes to move to Reserves.

3.2 Discussions Of Workflows For Reserves Classification

The question we aim to answer in this work is:

How do we progress through the ROTR categories?

To answer this question, we have divided our methodology into four steps. First, we define the movements for undiscovered Resources to become discovered. Second, we define progression in chance of development and commerciality within project maturity sub-classes within the Contingent Resources classification. Third, we describe the elements of the pilot and field testing stage of a technology, and the criteria required for the technology to progress further to become an *established technology*. Established technology is defined more explicitly in **Section 3.2.3**. Fourth, we define the different contingencies and the movement through each contingency. This may not be the order of movement for each project, but it does include all contingencies.

3.3 Define Movements For Undiscovered Resources To Become Discovered

We determine how to move the volumes from undiscovered to discovered, meaning that we are moving volumes from Prospective to Contingent Resources. These movements are described in the updated COGEH document (2018), and we present them as a workflow in **Fig. 5**. The elements in the discovery process are numbered from one to three in Fig. 5. The green nodes signify that the criteria for the volumes to be considered to be discovered have been met. The orange nodes signify that the volumes do not meet the necessary criteria, so we must obtain more information to go through the workflow again or the resources will remain undiscovered until the criterion is met.

Recall that Prospective Resources are undiscovered petroleum volumes, whose subclasses are Play, Lead, and Prospect. These three subclasses move a project closer to a decision to proceed with exploration drilling. We first focus on the play, (a large area, initially with large sections of unleased acreage). From there, we aim to identify more prospective areas, known as Leads, and ultimately obtain leases and identify specific drilling locations, known as Prospects.

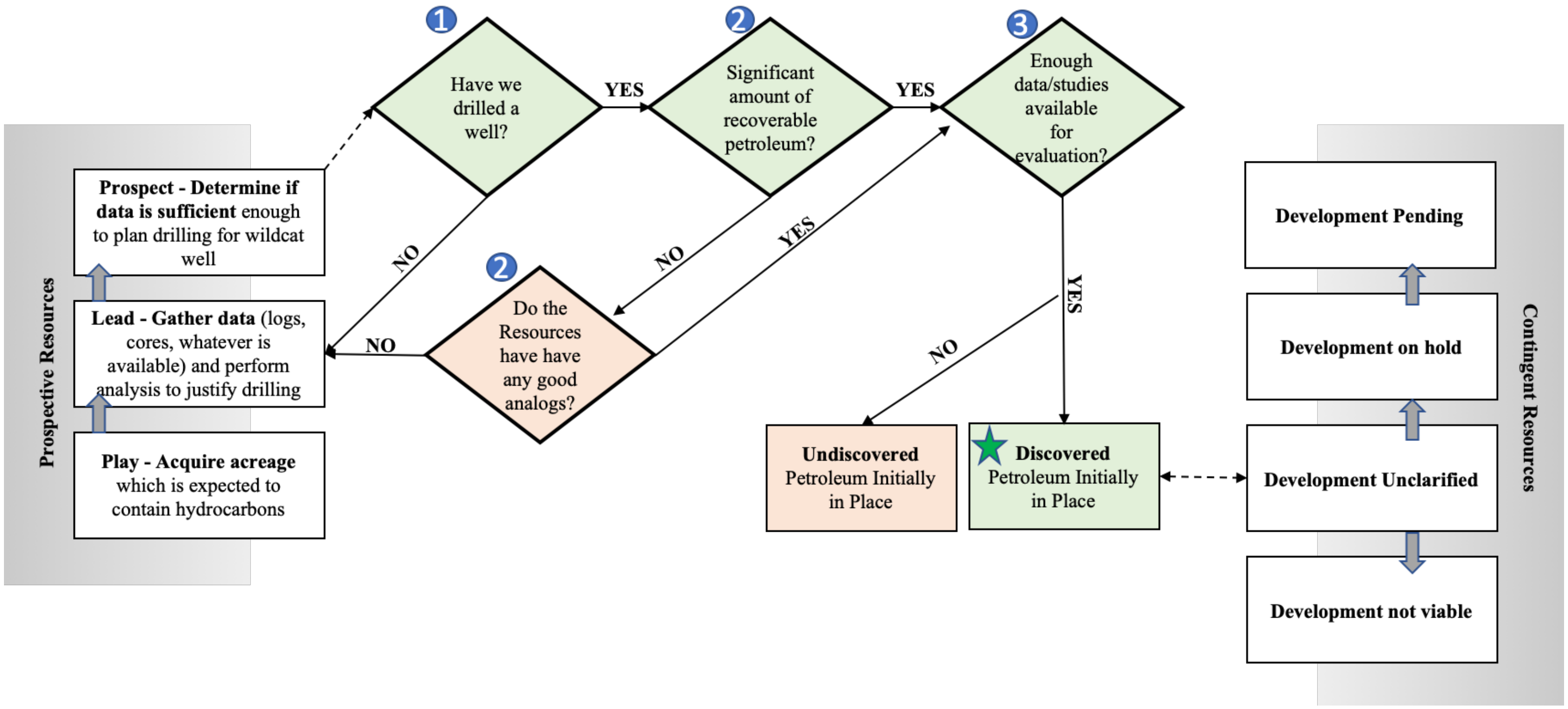

Figure 5 — A visual representation of a process that can be used to move from "undiscovered Resources" to "discovered." The PR sub-classes are presented on the left side of the figure to show how the undiscovered Resources are characterized as chance of discovery increases. Each step in the discovery process is labeled (1-3), eventually reaching a point where we determine whether the resources are undiscovered or discovered. We include also the CR sub-classes on the right side of the figure to reference where the discovered volumes land within the Contingent Resources class, and how they progress to other classifications (reprinted with permission from Moridis *et al.* 2019, SPE 195298).

Once we have reached the Prospect stage, we proceed to either drill a well or we do not. If we drill, then we can proceed with the workflow but until we drill, we have Prospective Resources. After we drill a well, we move to green node 2 and ask whether there is a significant amount of recoverable petroleum to justify evaluation of a project to recover the petroleum.

1. No (orange node 2), and the Resources have no good analogs, but we have identified specific drilling locations, the sub-class remains Prospect, and we can go through the workflow again.
2. No (orange node 2), but analogs support further investigation, so we move to green node 3.
3. Yes, and move to green node 3.

At green node 3, we ask if there are enough data and enough studies so that we can properly evaluate the acreage. The two possible outcomes at this node are:

1. No, and the Resources volume remains undiscovered.
2. Yes, the Resources volume is discovered, and are now sub-classified as "development unclarified" Contingent Resources.

Now that the Resources volume is discovered, the volume can move through the Contingent Resources sub-classes. The first, and most favorable option is for the volume to move from "development unclarified" to "development on hold", and ultimately "development pending." This will allow the volume to then move to Reserves once all the contingencies have been resolved. However, it is also possible that the volume moves down a sub-class to "development not viable".

Now that we have progressed through the workflow and met the necessary criteria to reclassify the Resources as discovered, we can now progress through the project maturity sub-classes of the Contingent Resources classification.

3.4 Define The Progression In Chance Of Development and Commerciality Within Project Maturity Sub-Classes Within The Contingent Resources Classification

In this step, we define the progression of the criteria that must be met and the work which must be performed within each sub-class of the Contingent Resources classification, and how the outcome of those decisions affect the chance of development for given Resources. The flowchart for this work is presented in **Fig. 6**.

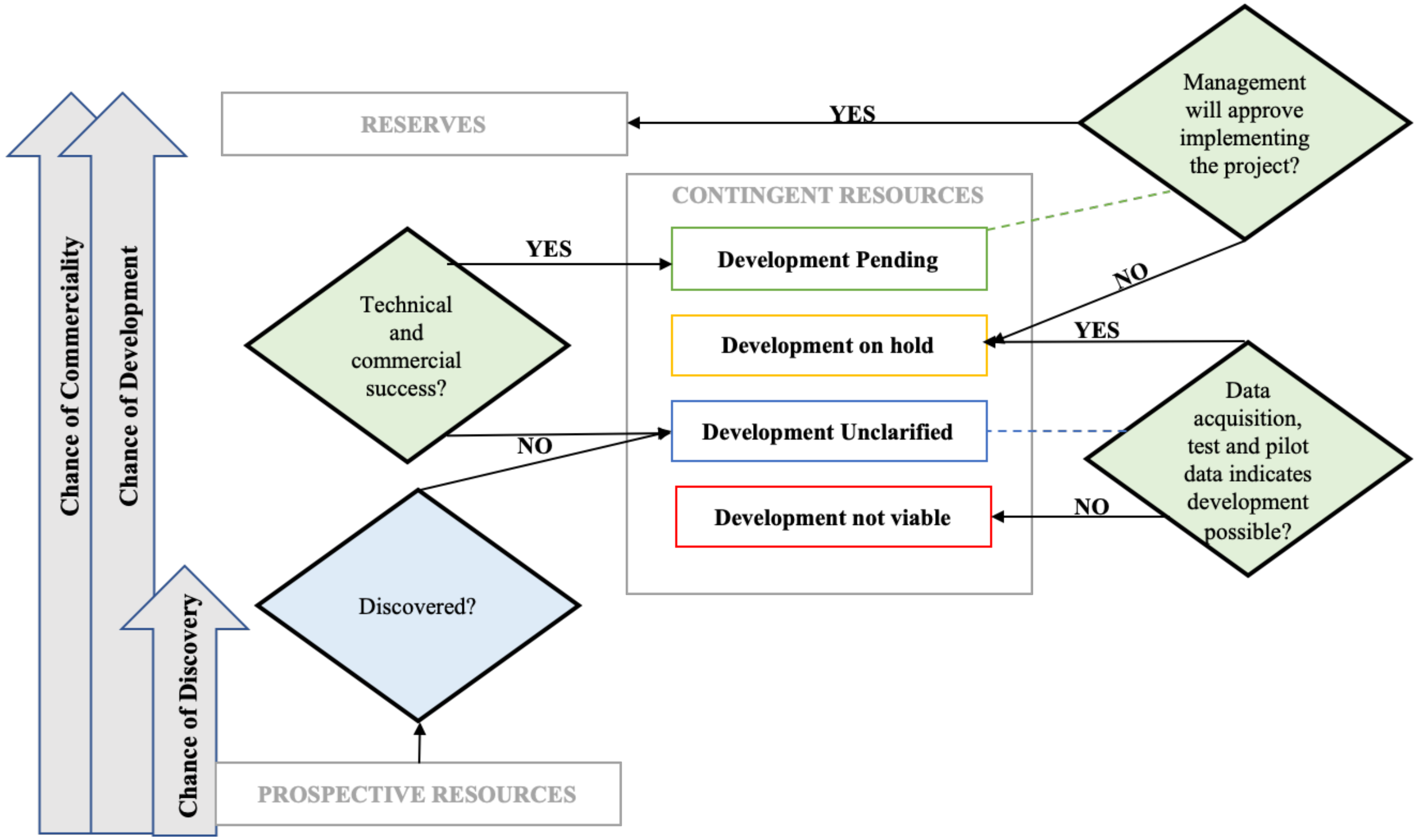

Figure 6 — A visual representation of progression of the chance of development/commerciality within the project maturity sub-classes of the Contingent Resources classification. This graphic shows the decisions that are made and the work done with each sub-class and how the outcome of those decisions affect the chance of development for given Resources (reprinted with permission from Moridis *et al.* 2019, SPE 195298).

This workflow begins where Fig. 5 concluded: the Prospective Resources are discovered, and have progressed to the "development unclarified" sub-class of Contingent Resources, presented with the blue node in Fig. 6. Note that if the Resources continue to be undiscovered, these remain Prospective Resources. We move to the green node, which asks if data acquisition, test and pilot data indicates if development is possible. There are two possible outcomes at this node:

1. No, and the Resources move to the "development not viable" sub-class in the Contingent Resources class
2. Yes, and the Resources move to the "development on hold" sub-class in the Contingent Resources class

As the chance of commerciality and development increase, we move to the green node on the left-hand side of the workflow, which asks if there is technical and commercial success. There are two possible outcomes at this node:

1. No (technical and commercial success <u>are not</u> achieved), and the Resources are sub-classified as "development unclarified" in the Contingent Resources class, which moves to the same node as in the first step of this analysis, which asks if development is possible. There are two possible outcomes at this node:
    i. No (development <u>is not</u> possible), and the Resources move to the "development not viable" sub-class in the Contingent Resources class
    ii. Yes (development <u>is</u> possible), and the Resources move to the "development on hold" sub-class in the Contingent Resources class

2. Yes (technical and commercial success <u>are</u> achieved), and the Resources are sub-classified as "development pending" in the Contingent Resources class because there is reasonable expectation of technical and commercial success, and moves to the final green node of the workflow

Once the Resources have been sub-classified as "development pending", the chance of development and commerciality have increased. We move to the top green node on the right-hand side of the workflow which asks if we can validate whether there is a good chance that management will approve implementing the project. Chance of commercial success was already considered good to have moved to the development pending subclass, as seen in the previous node. There are two possible outcomes at this node:

1. No (project <u>does not</u> receive management approval to proceed), and the Resources are sub-classified as "development on hold" in the Contingent Resources class
2. Yes (project <u>does</u> receive management approval to proceed), and the Resources are now classified as Reserves

As we progress through the steps to move through the Contingent Resources sub-classes, the chances of development and commerciality increase, moving the volumes towards Reserves. We will establish the necessary steps and contingencies that must be met for the volumes to be moved from Contingent Resources to Reserves in **Section 3.2.4**, but before we can do that we examine the role that technology plays in determining Reserves. The following section describes the elements of pilot and field testing stage of a technology, and the criteria that is required to progress that technology to "established technology" status.

3.5 Describe The Elements Of A Pilot and Field Testing Stage Of A Technology, And The Criteria Required For The Technology To Progress Further To Become An "Established Technology"

Technology is one of the main contingencies that must be met before ROTR can be classified as Reserves. *Established technology* is defined as "methods of recovery or processing that have proved to be successful in commercial applications" (PRMS, p. 42). *Technology under development* is defined as the "technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (*e.g.*, a test project/pilot) to indicate that the technology may reasonably be expected to be available to commercial application" (PRMS, p. 51).

Quite often, the petroleum recovery process has not yet been determined for a given project at the time of the evaluation process. If neither existing technology nor technology currently under development can be used to evaluate the Resources, then the volumes must be classified as unrecoverable. The technology to recover volumes must exist to classify the volumes as commercial or sub-commercial, and these projects must be technically feasible.

We present the development process of a given technology, and how a given the development stage of a given technology affects how Resources are classified. Conversely, we discuss how the classification of a resource is impacted by a given technology's development stage.

The technology development process is shown in **Fig. 7**. If we consider the use of a new technology we can refer to this as "experimental technology". Experimental technology must prove that it can repeatedly produce successful results, and do so economically. If the failure rate of the technology is low, it may then be considered to be "established technology" if it can prove to be reliable, and economic, throughout the stages of its development.

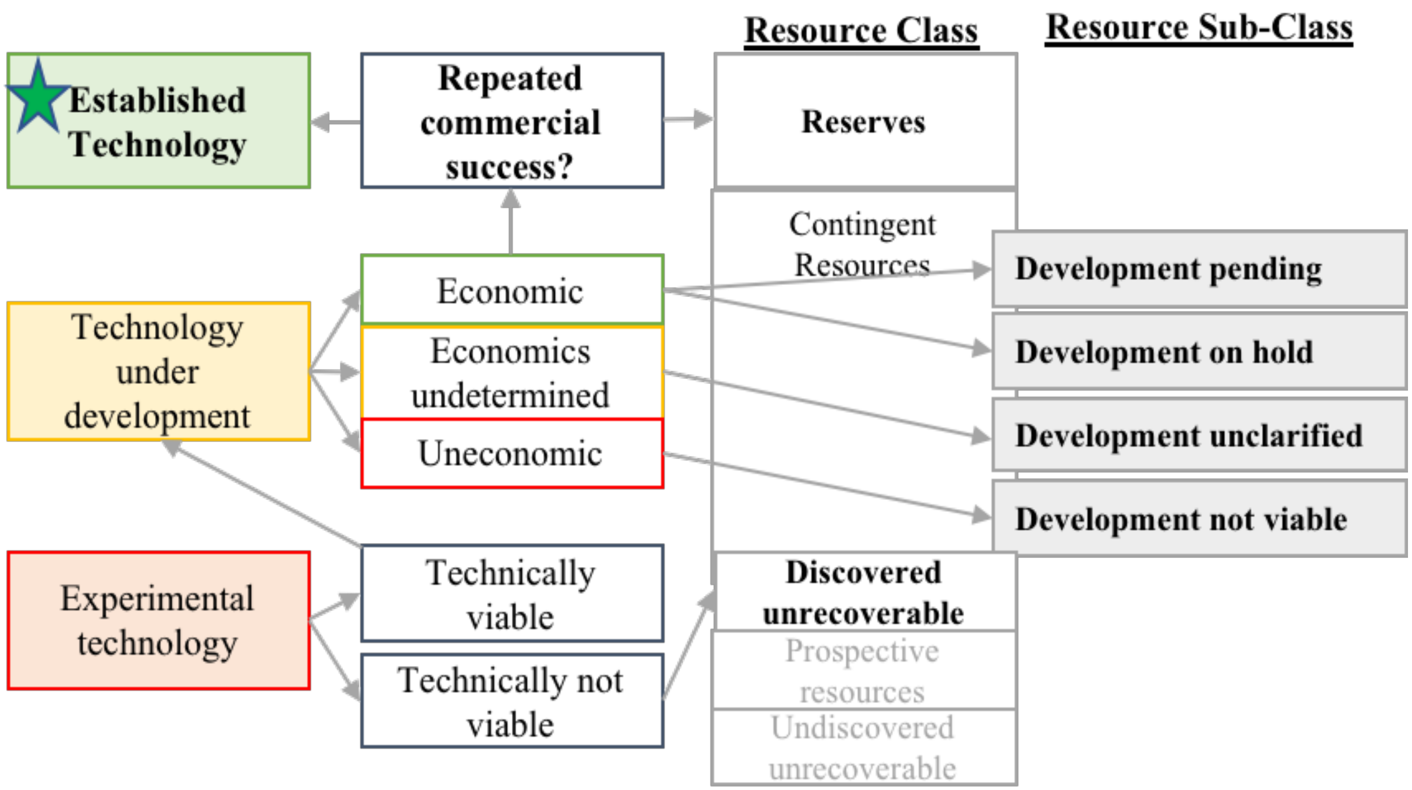

Figure 7 — Visual representation of the elements of a pilot/field testing stage of a technology, and the criteria required to progress further to becoming an "established technology." The technology being tested needs to be both *technically reliable* and *economic* before it can be used to make development decisions (reprinted with permission from Moridis *et al.* 2019, SPE 195298).

We begin with an "experimental technology," shown in the red node on the left-hand side of the diagram, which has two possible outcomes:

1. Technically not viable — so the volumes are "discovered unrecoverable" (defined as "discovered petroleum in place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned" (PRMS, p. 41)
2. Technically viable — leads to the next node of technology under development (yellow)

Once we have established that the technology is under development, there are three possible outcomes:

1. Uneconomic, which is classified as Contingent Resources, and sub-classified as "development not viable"
2. Economics undetermined, which is classified as Contingent Resources, and sub-classified as "development unclarified"
3. Economic, which is classified as Contingent Resources, and can be sub-classified as either "development on hold" or "development pending," depending on its commerciality

Now that the proposed technology has proved to be economic, we must establish that it has had repeated commercial success. Once this is established, it becomes an established technology, and the Resources evaluated can now be classified as Reserves.

For a technology to become an "established technology," it must succeed in both laboratory testing and field testing. The laboratory testing is usually performed at a smaller scale as the technology is still in its theoretical stage. The field (or pilot) testing is done at a much larger scale once the laboratory testing has proved that the technology is repeatedly successful and economic. When the technology is finally proved useful and reliable at an "appropriately large" scale, it can be used to make decisions regarding commercial development. As previously presented, Fig. 7 focuses on the field testing stage. **Fig. 8** presents how both the laboratory and the field testing impact the technology's movement to becoming established.

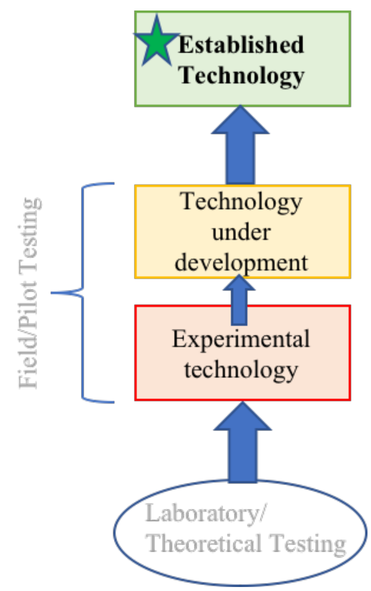

Figure 8 — This figure illustrates the testing stages for a new technology to become established. We begin with laboratory testing. Once it has been proven successful at a small scale, we move into the second phase—the field testing stage. This stage is separated into two parts, the experimental technology phase, followed by the technology under development phase (as shown in Fig. 7). (reprinted with permission from Moridis *et al.*, 2019, SPE 195298).

COGEH (2018) states that "technology testing will usually proceed in steps, gradually increasing in scope until the desired information has been acquired, but may be halted at any stage if the results suggest that it is unlikely to lead to a commercial process" (COGEH, 2018).

This step of our workflow focuses solely on the technology contingency, which is one of the main criteria that must be met before Contingent Resources volumes can be classified as Reserves. If the technology contingency is the only contingency for a given project, once that technology is established, the volumes for that project can be classified as Reserves. In the next step, we explore other contingencies that must be overcome to classify the volumes as Reserves.

3.6 Define The Different Contingencies And The Movement Through Each Contingency

How we manage uncertainty is unknown, but we do know that we have to categorize movement from Contingent Resources to Reserves, which depends on the type of contingency. We can overcome multiple contingencies in one event, and the order in which they are overcome will have an impact, so we must establish the proper order of movements. The optimal order differs from case to case, but there are certain contingencies, specifically price and technology (presented in **Section 3.2.3**), that will dominate the process. Those contingencies that must be met before moving to Reserves are shown in **Fig. 9.**

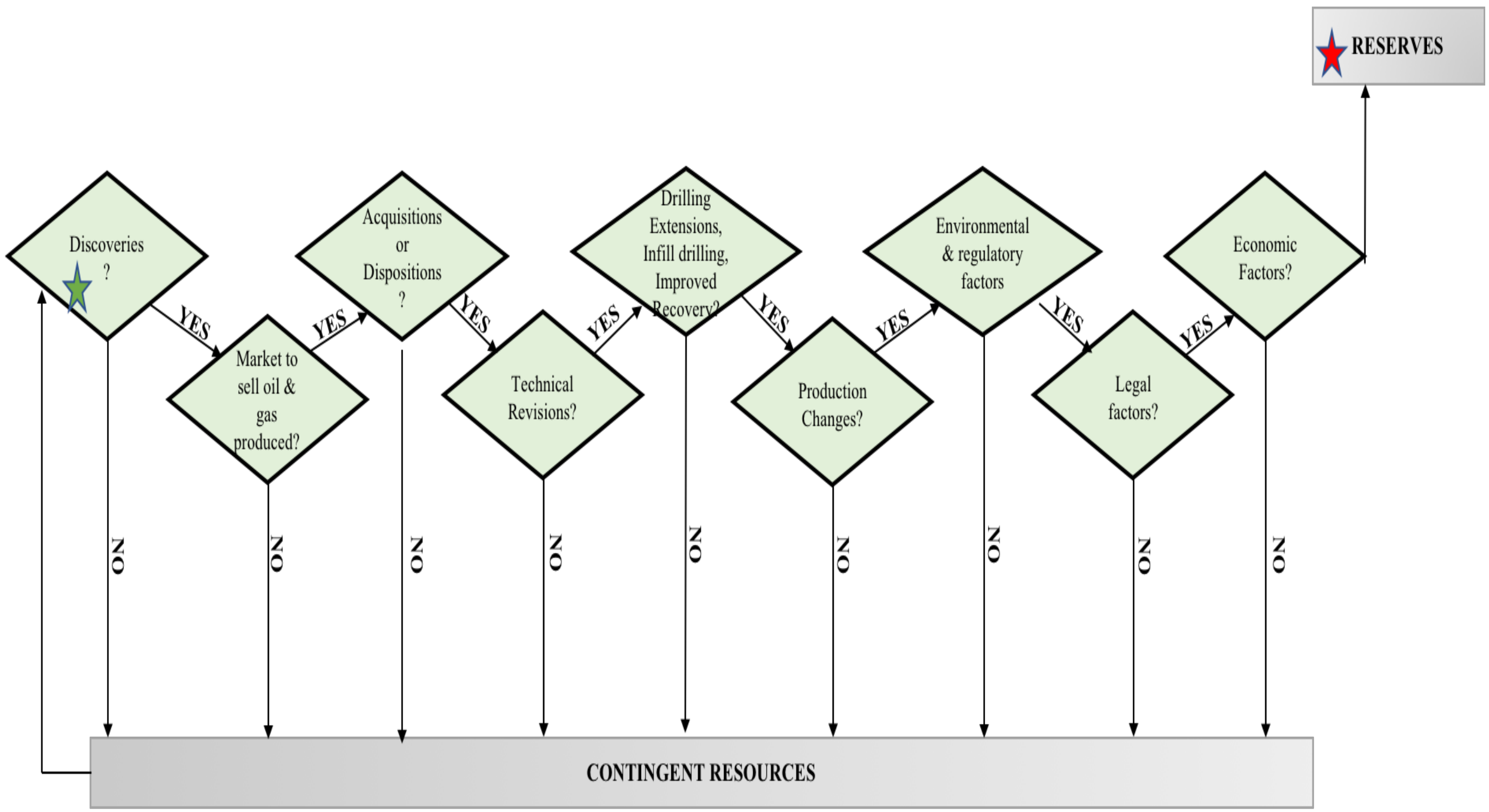

Figure 9 — This graphic illustrates the different contingencies and the movement path through each contingency. This specific "path map" may not represent the exact order of movement for any given project, but it does present all the contingencies identified in the PRMS and COGEH documents (2018). However, the economic contingency must be resolved for any project, as do the technical and production contingencies (reprinted with permission from Moridis *et al.*, 2019, SPE 195298).

We will refer to volumes moving from Contingent Resources to Reserves as a *promotion*, and volumes moving from Reserves to Contingent Resources a *demotion*. Several factors can cause a promotion or a demotion between classes, between Reserves and ROTR. These contingencies can be overcome in groups or one-by-one. The main contingencies to overcome are:

- **Economic** conditions are arguably the most significant factor influencing the commerciality of a project. If there is a decrease in commodity price, a project may no longer be economic, therefore no longer commercial. This causes a *demotion* of volumes. Similarly, when the commodity price increases, this may result in a *promotion* of volumes. Changes to Reserves between current and past reporting periods resulting from different price forecasts, but also due to inflation rates and regulatory changes may also cause promotion or demotion of Reserves and ROTR volumes. These changes can be observed when comparing an old evaluation to the same evaluation but at the current, revised economic conditions; differences in net Reserves are the incremental volumes which need to be re-classified and re-inventoried.
- **Production** may not cause a direct promotion or demotion between classes of recovery estimates. The volumes that are produced need to be removed from the volumes previously being tracked as Reserves. This includes any expected or estimated production to be realized in the reporting period of interest. As new data become available, recovery estimates should be refined. Not only can data acquisition help form better predictions of future performance and change the production profile and

recovery estimates of a project, but data acquisition can also result in re-classifying or re-sub-classifying a particular project within PRMS.

- **Drilling extensions** result in additions to Reserves from capital expenditures for step-out drilling in previously discovered reservoirs.
- **Infill drilling** results in additions to Reserves from capital expenditures for infill drilling in previously discovered reservoirs that were not drilled as part of an enhanced recovery scheme.
- **Improved recovery** results in additions to Reserves from capital expenditures for improved recovery projects (secondary or tertiary projects such as waterfloods, miscible injection, steam-assisted gravity drainage (SAGD), etc.). This may include both injection wells and infill production wells associated with the improved recovery project. Reserves added as a result of capital expenditures not for drilling or enhanced recovery projects, but for projects to improve existing gathering facilities, are also considered to be an Extensions or Improved Recoveries.
- **Technical revisions:** As new data are acquired, and/or as interpretations of Reserves or ROTR volumes are revised, either the volume itself or how the volume is classified could be impacted.
- **Discoveries:** Additions to Reserves or ROTR volumes in reservoirs where no volumes were previously booked are considered to be discoveries. Once these volumes go through the proper screening to become discovered volumes, they can then move through the contingencies to be classified as Reserves.
- **Acquisitions:** Any properties or volumes acquired need to be appropriately recorded and classified as part of inventory.

- **Dispositions:** Any properties or volumes sold need to be appropriately recorded, and removed from inventory.

Other requirements for commerciality include funding being made available, management approving the project, and that the project has reasonable time-frame for development.

As previously discussed, the economic contingency is the most important. If this contingency cannot be met, none of the other contingencies matter. For example, if the price of oil or gas decreases and it is no longer economic to produce the field, the volumes are now Contingent Resources and no longer Reserves. Similarly, if the price increases unexpectedly and it is now possible to produce the volumes economically, the volumes are moved from Contingent Resources to Reserves. The second essential contingency is technology (as discussed in **Section 3.5**). The third contingency that is of importance is the production contingency. Production may not cause a direct promotion or demotion between classes of recovery estimates; however, produced volumes do directly impact the quantity of volumes inventoried.

3.7 Summary of Key Points

The follow key points of this work are derived from the observations of these workflows:

- There are several steps necessary for volumes to become discovered, but until a well is drilled, all resources volumes remain undiscovered (Prospective Resources)
- Once resources volumes are discovered, they becomes classified as Contingent Resources and sub-classified as Development Unclarified

- As we move through Contingent Resources sub-classes, the chances of development and of commerciality increase, moving the resources volumes towards Reserves
- Technology is one of the main contingencies that must be met for volumes to be classified as Reserves, and for a technology to become established, it must have repeated commercial success
- All the contingencies must be met for the resources volumes to be classified as Reserves
- The economic contingency is the most important because no volumes will be classified as Reserves if it is not economic to proceed with the project

4. DESCRIBE THE ELEMENTS OF THE PRMS MATRIX AS DISCRETE THROUGH A CUMULATIVE DISTRIBUTION FUNCTION (CDF)*

4.1 Introduction

In this chapter, we aim to estimate the fraction of Reserves assigned to each Reserves category (1P, 2P, 3P) of the PRMS matrix. We do this by using a cumulative distribution function (CDF) and discretizing the function at certain points, which provides 1P, 2P, and 3P estimates, from which the ratios of each Reserves category are calculated.

Previous published work (Hurst *et al.,* 2000; Cronquist, 2001) has often used Swanson's Mean (SM) as the basis for allocating Reserves to individual categories, but we found that this method, which relates the Reserves categories through a CDF for a normal distribution, is an inaccurate means to determine the relationship of the Reserves categories with asymmetric distributions, and our work identified a better method (Bickel *et al*., 2011), the Gaussian Quadrature (GQ).

Production data are lognormally distributed, regardless of basin type, and thus are not compatible with the SM concept. The GQ algorithm provides a methodology to estimate the fraction of Reserves that lie within the 1P, 2P, and 3P categories — known as their *weights*. GQ is a numerical integration method that uses discrete random variables and a distribution

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that matches the original data. For this work, we associate the lognormal CDF with a set of discrete random variables that replace the production data, and determine the associated probabilities. We then calculate the ratio of the Reserves that lie in the three Reserves categories. The production data for both conventional and unconventional fields are lognormally distributed, thus we expect that this methodology can be implemented in any field.

Using the 38 wells from the dataset provided by University Lands to Texas A&M University, we performed probabilistic decline curve analysis (DCA) using the Arps Hyperbolic model (1945) and Monte Carlo simulation (MCS) to obtain a probability distribution of the 1P, 2P, and 3P volumes. We considered this information to be our "truth case," to which we compared relative weights of different Reserves categories from the GQ and SM methodologies. We also performed probabilistic rate transient analysis (RTA) using the IHS *Harmony* software to obtain the 1P, 2P, and 3P volumes, and calculated the relative weights of each Reserves category. Once we completed these first two steps, we implemented a 3-point GQ to obtain the weights and percentiles for each well. We analyzed the GQ results by calculating the percentage differences between the probabilistic DCA, RTA, and GQ results.

The probabilistic DCA results indicated that the SM method is an *inaccurate* method for estimating the relative weights of each Reserves category. Our results show that the GQ method was able to capture an accurate representation of the Reserves weights, we note that we assumed an expected lognormal CDF for Reserves. We believe that 1C, 2C, 3C, and 1U, 2U, and 3U Contingent Resources (CR) and Prospective Resources (PR) are distributed in a similar way (*i.e.*, as a lognormal CDF) but have greater variance.

Based on our results, we see that the ratios of each Reserves category, calculated using the GQ are approximately those of the probabilistic DCA results. We conclude that the GQ method is accurate and can be used to approximate the relationship between the relative weights of resources in PRMS categories, which means it can be used for decision making purposes. This relationship will aid entities in reporting Reserves of different categories to regulatory agencies because it can be recreated for any field, play, or region. These distributions of Reserves and ROTR are important for planning and for resource inventorying. The GQ method provides a measure of confidence in our prediction of the Reserves weights because of the relatively smaller percentage differences between the probabilistic DCA and GQ weights than those implied by the SM method. For reference, our proposed methodology can be implemented in both conventional and unconventional reservoirs.

We develop relationships between each row of the PRMS matrix (Fig. 1) in the form of a CDF. We began by defining a relationship between the 1P, 2P, and 3P Reserves by examining the SM method, which is regarded by some to assume a lognormal distribution of the variables, but which actually assumes a symmetrical normal distribution. The SM method is defined in **Eq. 7**.

$$SM = 0.3\times P90 + 0.4\times P50 + 0.3\times P10 \quad \textbf{(7)}$$

However; we have determined that applying the GQ method to a true lognormal distribution may be a better approach to determine the relationships between the volumes in each column of the PRMS matrix. In this determination, we assume that the Reserves and ROTR can all be described by a lognormal distribution.

4.2 The Lognormal Distribution

The lognormal distribution characterizes data sets in which the logarithms of a data in a given set are distributed normally, with highly skewed distributions. The distribution is unbounded in one, positive direction, and has a significant fraction of the data near the mode with a finite probability of large values of data far from the mode. Finally, this distribution is expected when data are result of multiplication of several parameters (Lee, 2016).

The lognormal distribution is often used to characterize parameters in probabilistic resource assessments, including porosity, net pay, permeability (k), oil/gas in place (O/GIP), recovery efficiency (RE), which is correlated to porosity (ϕ), water saturation (S_w), permeability, net-gross pay ratio, net pay, initial well potential, which is correlated with porosity, permeability, net pay, and reserves and ROTR estimates, which are calculated based off a product of many variables.

The lognormal distribution is bounded between 0 and infinity, denoted as $x \in (0,+\infty)$. The full lognormal probability density function (PDF) is expressed in **Eq. 8**.

$$f(x) = \frac{1}{x}\frac{1}{\sigma\sqrt{2\pi}}\exp\left[\frac{-(\ln x - \mu)^2}{2\sigma^2}\right] \quad \textbf{(8)}$$

The full lognormal cumulative distribution function (CDF) is expressed in **Eq. 9** as:

$$F(x) = \frac{1}{2} erfc\left[\frac{-\ln x - \mu}{\sigma\sqrt{2}}\right] \quad \textbf{(9)}$$

The distributions given by Eqs. 9 and 10 are graphically presented using a PDF and CDF as shown in **Fig. 10** and **Fig. 11**, respectively.

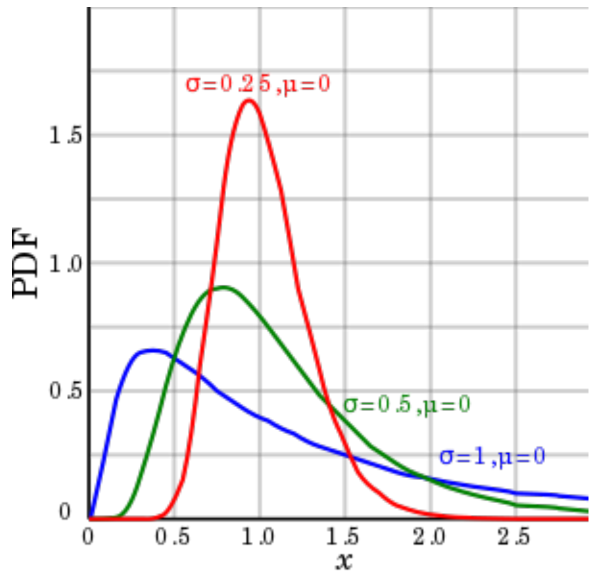

Figure 10 — PDF of three lognormal distributions with mean (μ) = 0 and different standard deviations (σ). The blue and green lognormal distributions are skewed to the right. The red curve is also slightly skewed but this is not as evident as with the two other lognormal distributions (reprinted from Wikipedia, Log-normal distribution, 2017).

In Fig. 10, the *y*-axis represents the probability that a given value will occur in terms of a percentage, to analyze the PDF curve.

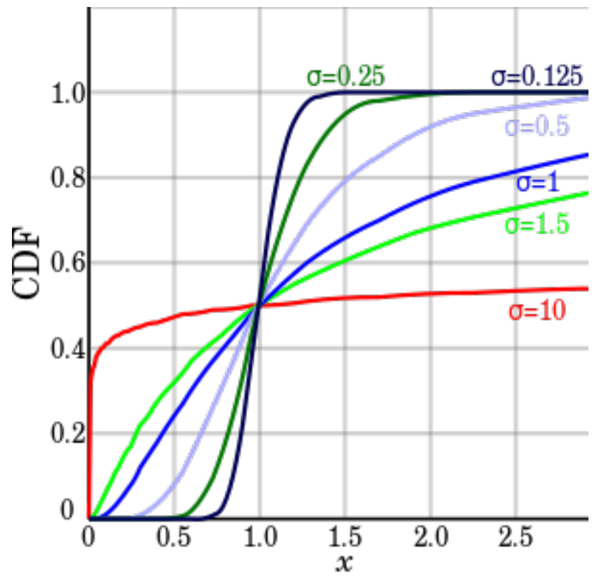

Figure 11 — CDF of lognormal distributions with μ=0 and various values of standard deviation. From this graph, we can determine the probability that the value of the parameter is less than or equal to a certain value (reprinted from Wikipedia, Log-normal distribution, 2017).

In Fig. 11, The *y*-axis represents the cumulative probability that the value of the parameter is greater than or equal to a certain value in terms of a percentage associated with the CDF. Fig. 11 shows the conventional CDF curve, however in the oil and gas industry, we use the inverse of the CDF curve to obtain the P90, P50, and P10 results of the value we are analyzing. We refer to this value as the excessive distribution function (EDF) which we present and discuss in the subsequent section.

4.3 Swanson's Mean And The Gaussian Quadrature

There is high uncertainty related to determining Reserves because the parameters needed to calculate those volumes also hold a high level of uncertainty. To address this uncertainty, probabilistic analyses, such as Monte Carlo Simulation (MCS), is often implemented, from which we can calculate the PDF and CDF that yield a range of Reserves volumes, as previously discussed. We assume that Reserves and ROTR follow a lognormal distribution because they are the results of a multiplication as a set of parameters, the midpoint of the distribution represents the most likely Reserves case, but not the true median. Furthermore, it is difficult to determine the "prospects smaller than the 90th percentile or larger than the 10th percentile" (Hurst *et al* 2000). To overcome this, Swanson presented the 30-40-30 rule, also known as Swanson's Mean (SM), which creates a relationship between the three Reserves categories.

SM is often used in the petroleum industry to evaluate possible Reserves ranges. It is done "to approximate the mean of the lognormal distribution" (Cronquist 2001), which is important because we will implement the lognormal distribution for the Reserves and ROTR. As previously stated, this holds true because the volumes are a result of multiplying several parameters, yielding a lognormal distribution.

SM has also been used to "quantify expected outcomes from drilling prospects analogous to nearby developed areas." (Cronquist, 2001). This methodology is used as part of the risk assessment of hydrocarbon exploration (Hurst *et al.,* 2000) and is defined in **Eq. 11**.

$$SM=0.3P90+0.4P50+0.3P10 \quad \textbf{(10)}$$

It is used to define the Reserves distribution curve, giving three probabilities to the specific percentiles. SM states that:

- The medium (50th percentile ≡ median, P50) — half the Reserves are larger than, half smaller;

- The maximum (10th percentile, P90 on a forward CDF), which only 10% were larger than;
- The minimum (90th percentile, P10 on a forward CDF), which 90% were larger than." (Hurst *et al* 2000)

The 30-40-30 probabilities were proposed "based on the proportions of the total range 0-100% appropriate to each" (Hurst *et al.*, 2000). Hurst *et al.* is referring to the inverse CDF, or the EDF as we have previously defined it. The range from P50 to P90 is the same as the range from P50 to P10, which is 40% (0.4), which is then halved. One half is assigned to P50, and the other half is assigned to P90. The same methodology is applied for the P10 as well. Therefore, this means that "50-70% = 0.2 of total range assigned to P50 and 70-90% = 0.2 of total range assigned to P90)" (Hurst *et al.,* 2000). Therefore, the P50 has a total probability of 0.2+0.2 = 0.4. In continuation, 0.1 is assigned to the tail end from 90%-100%, with the 0.2 from the halved value of P50, giving P90 a total probability of 0.3. The methodology for P10 is the same, giving it a probability of 0.3.

From the literature, it is stated that SM is a reasonable approximation "to the true mean of a lognormal distribution, provided the distribution is not too highly skewed. For progressively more skewed distributions, SM approaches the median value of the distribution" (Cronquist 2001). However, Cronquist also states that "quantification of expected outcomes with only the estimated mean values of reserve distributions ignores the full range of potential Reserve outcomes."

Bickel *et al.* (2011) agree with Cronquist (2001) that SM is an inaccurate representation, arguing that the results yield highly under-estimated Reserves probabilities. Furthermore, the authors state that the SM inaccurately approximates "the variance of many distributions." **Fig. 12** illustrates the error associated with SM when implemented on a lognormal distribution. From this figure, we see that SM underestimates the mean by approximately 45% in this example. However, it is also evident that the variance is underestimated by 80% and the skewness by 100% for skewed distributions (lognormal)

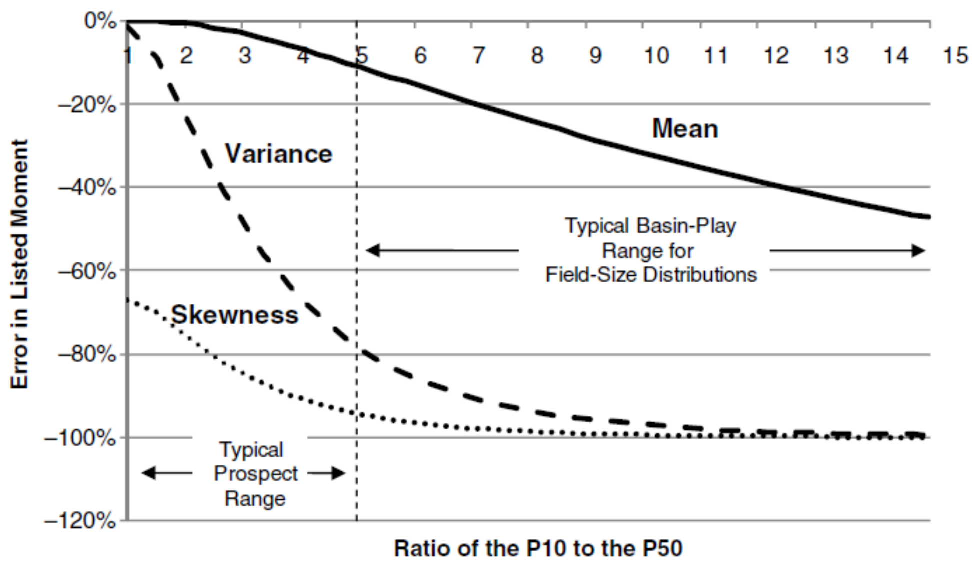

Figure 12 — Plot of the error of SM estimate of the mean, variance, and skewness for a lognormal distribution, against the ratio of the P10 to the P50, which Megill (1977) intended to be a measure of skewness (reprinted from Bickel *et al* 2011, p.133).

Bickel *et al.* (2011) illustrate that there are several methods that are better choices than SM, specifically focusing on the GQ, by implementing the lognormal PDF and CDF of the given data set. This approach "provides both an organizing framework for understanding the objective of discretization and a computational method for determining the best approximation" (Bickel *et al* 2011). However, what differentiates the Bickel *et al* (2011) approach, is that they "provide the percentiles of the excess distribution function (EDF), also called the complementary CDF, which is used more frequently than the CDF in oil and gas settings." The relationships between the EDF and CDF are presented in **Eq. 11**.

$$\alpha \equiv G(x_i) \times 100 = [1 - F(x_i)] \times 100 \qquad \textbf{(11)}$$

where,

α = The percentiles,

$G(x_i)$ = The EDF, and

$F(x_i)$ = The CDF, defined in Eq. 7.

The EDF is the inverse of the CDF, as presented in Eq. 11, and is the convention used in the oil and gas industry. We will refer to the inverse CDF curves as EDF throughout the rest of this manuscript.

Bickel *et al* (2011) implement the above methodology on the uniform, normal, and exponential distributions, on a 2-, 3-, and 4-point GQ. Their presented results show a more accurate percentage value for each probability, meaning that the same methodology can be implemented onto the lognormal distribution.

We use the following notation through this work, where x and y are the discrete random variables lognormally distributed that were built using the scaled mean and standard deviation of the production data of each well. This notation follows the notation presented by Miller and Rice (1983).

$f(x)$ = PDF of the lognormal distribution, presented in Eq. 9

$F(x) \leq \int_0^{\infty} f(x)dx$ = CDF of the lognormal distribution, presented in Eq. 10

$\langle x \rangle = E\left[X^N\right] = \int_0^{\infty} xf(x)dx$ = the expected value of x

$\langle g(x) \rangle = \int_0^{\infty} g(x)f(x)dx$ = the expected value of the function $g(x)$

The GQ method is a numerical integration method that determines "the discrete approximations of probability distributions that are much more accurate than those based on intervals. This approach approximates the integral of the product of function *g(x)* and the weighting function *ω(x)* at several values of *x*, and computing a weighted sum of the results" (Miller and Rice, 1983):

$$\int_a^b g(x)\omega(x)dx \cong \sum_{i=1}^{N} w_i g(x_i) \quad \textbf{(12)}$$

where,

$\omega(x)$	=	weighting function
p_i	=	probabilities
w_i	=	weights

To establish the "correspondence between the numerical integration formula and a discrete approximation of the probability distribution, we associate the distribution, *f(x)*, with the weighting function and the probabilities, with the weights. We approximate *g(x)* by a polynomial, and choose x_i and p_i (or w_i) to provide an adequate approximation for each term of the polynomial. Thus, we want to find a set of values and probabilities such that" (Miller and Rice, 1983):

$$\langle x^k \rangle = \int_{-\infty}^{+\infty} x^k f(x)dx = \sum_{i=1}^{N} p_i x_i^{\,k}, \text{for } k = 0,1,2,\ldots \quad \textbf{(13)}$$

A discrete approximation with N probability-value pairs can match the first (2N-1) moments exactly by finding p_i and x_i that satisfy the following equations:

$$\begin{aligned}
&p_1 + p_2 + p_3 + ... + p_N = \langle x^0 \rangle = 1 \\
&p_1 x_1 + p_2 x_2 + p_3 x_3 + ... + p_N x_N = \langle x \rangle \\
&p_1 x^2{}_1 + p_2 x^2{}_2 + p_3 x^2{}_3 + ... + p_N x^2{}_N = \langle x^2 \rangle, \\
&\vdots \\
&p_1 x^{2N-1}{}_1 + p_2 x^{2N-1}{}_2 + p_3 x^{2N-1}{}_3 + ... + p_N x^{2N-1}{}_N = \langle x^{2N-1} \rangle
\end{aligned} \qquad \text{……………..…………}\textbf{(14)}$$

There is a well-known method (Miller and Rice, 1983) for solving these equations. First, define the polynomial:

$$\pi(x) = (x - x_1)(x - x_2)\ldots(x - x_N) = \sum_{k=0}^{N} C_k x^k \quad \text{………....……………………..…….}\textbf{(15)}$$

It follows from this definition that C_N =1 and $p(x_i)$ for i = 1, 2, …, N. take the first N equations. By multiplying the first equation by C_0, the next by C_1, etc.., and the adding them together we get:

$$\sum_{i=1}^{N} p_i \pi(x_i) = 0 = \sum_{k=0}^{N} C_K \langle x^k \rangle \quad \text{……….…………..……………………..…..…….}\textbf{(16)}$$

Now, taking the second through (N+1)st equations, we multiply by the coefficients of the polynomial again and add to get:

$$\begin{aligned}
&\langle x^0 \rangle C_0 + \langle x \rangle C_1 + \langle x^2 \rangle C_2 + \ldots + \langle x^{N-1} \rangle C_{N-1} = -\langle x^N \rangle, \\
&\langle x \rangle C_0 + \langle x^2 \rangle C_1 + \langle x^3 \rangle C_2 + \ldots + \langle x^N \rangle C_{N-1} = -\langle x^{N+1} \rangle, \\
&\langle x^2 \rangle C_0 + \langle x^3 \rangle C_1 + \langle x^4 \rangle C_2 + \ldots + \langle x^{N+1} \rangle C_{N-1} = -\langle x^{N+2} \rangle, \\
&\vdots \\
&\langle x^{N-1} \rangle C_0 + \langle x^N \rangle C_1 + \langle x^{N+1} \rangle C_2 + \ldots + \langle x^{2N-2} \rangle C_{N-1} = -\langle x^{2N-1} \rangle
\end{aligned} \qquad \text{………....…..…}\textbf{(17)}$$

These equations are then solved for the coefficients of the polynomial, and then the x_i are determined by finding the zeroes of polynomial. Then the p_i can be determined by substituting x_i into the original set of equations for the moments of the approximate distribution (Miller and Rice, 1983).

For this work, we want to evaluate the GQ of the lognormal distribution, where the $f(x)$ is the PDF of the lognormal distribution, as previously defined in Eq. 9. The PDF of the lognormal distribution is evaluated on a set of coordinates other than [-1,1]. To account for this, we transform the lognormal PDF from a range [a,b] to the GQ coordinates [-1,1], as presented in **Eq. 18**.

$$\int_a^b f(x)\,dx = \frac{b-a}{2}\int_{-1}^{+1} f\left(\frac{b-a}{2}x+\frac{b+a}{2}\right)dx \quad \text{(18)}$$

To transform the coordinates from [0, +∞] to [-1,1]. We introduce a variable, t, as a coordinate transformation variable, presented in **Eq. 19**.

$$t = \frac{b-a}{2}x+\frac{b+a}{2} \quad \text{(19)}$$

which is the general formula for coordinates [a,b]. Therefore, we can set up the function with the general coordinates as presented in **Eq. 20**.

$$\int_a^b f(x)\,dx \cong \frac{b-a}{2}\sum_{i=1}^{N} c_i f\left[\frac{b-a}{2}x_i+\frac{b+a}{2}\right] \quad \text{(20)}$$

From Eq. 20, we can define what coordinates we would like to set for the lognormal distribution. It has previously been discussed that the lognormal distribution is bound by

$x \in (0,+\infty)$ meaning the *a*-coordinate will be set to 0 for this work. The *b*-coordinate will be defined by the user. With these conditions set, Eq. 15 can be further reduced to **Eq. 21.**

$$\int_0^b f(x)dx \cong \frac{b}{2}\sum_{i=1}^{N} c_i f\left[\frac{b}{2}x_i + \frac{b}{2}\right] \qquad \textbf{(21)}$$

We use this transformation within the summation system of equations to determine the weights and probabilities of the lognormal distribution. We then calculate the ratios of each Reserves category to understand the relationship between the three categories.

4.4 Methodology, Results, And Discussion

To demonstrate and validate the GQ methodology, we analyzed 38 wells in the Midland Basin, TX. We first implemented the GQ using a random, lognormally distributed dataset built using the mean and standard deviation of each well's production data. The mean and standard deviation were both scaled to aid in building these distributions.

We then aim to understand the relationship between the categories of the CR and PR (1C, 2C, 3C, and 1U, 2U, and 3U, respectively). To do this, we assume that CR and PR have the same mean as Reserves, but an increased standard deviation to account for the uncertainty of these volumes. We built two arbitrary, theoretical cases for CR, the first with 20 per cent higher standard deviation, and the second with 50 per cent higher standard deviation. Similarly, we built two arbitrary, theoretical cases for PR, one with 90 per cent higher standard deviation, and the second with 100 per cent higher standard deviation than that of the production data.

We first implement a probabilistic DCA to determine the P90, P50, and P10 (1P, 2P, and 3P, respectively) of the estimated ultimate recovery (EUR), by implementing the triangular distribution on the *b*-factor and decline parameters. Once we obtain the results, we calculate the ratio of Reserves in each category to create a relationship between the three volumes. We then perform probabilistic RTA to determine the P90, P50, and P10 (1P, 2P, and 3P) using the IHS *Harmony* software. We again determined the ratios of Reserves in each category. These first two steps were done to determine a relationship between the volumes, and are used to validate the GQ results. We finally implemented a 3-point, 5-point, and 10-point GQ on the production data by using a lognormal distribution built by using the mean and standard deviation of the production data.

4.4.1 Probabilistic Decline Curve Analysis (DCA)

We performed probabilistic DCA using the Arps Hyperbolic model, presented in **Eq. 22**, and MCS to obtain 1P, 2P, and 3P volumes, and calculated the relative ratio of each Reserves category.

$$q(t) = \frac{q_i}{(1 + bD_i t)^{1/b}} \quad \textbf{(22)}$$

where,

q_i	=	initial production rate
b	=	hyperbolic decline constant
D_i	=	initial nominal decline rate
t	=	time

To implement the MCS, we modeled the *b*-factor and initial decline rate, D_i, using PDF's with triangular distributions, as presented by Wright (2015). The PDF and CDF of the triangular distribution are presented in **Figs. 13** and **14**.

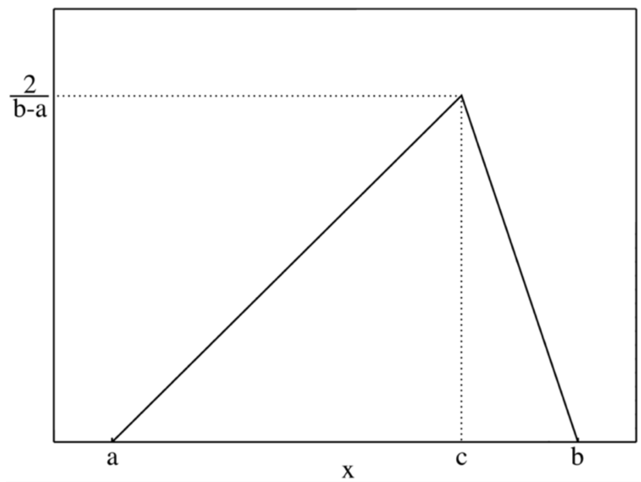

Figure 13 — PDF of a triangular distribution, where the minimum (*a*), maximum (*b*) and the most likely value (*c*) are indicated on the x-axis. The bounds of the parameter *x* are clearly defined by the minimum and maximum (reprinted from Wikipedia, Triangular distribution, 2017).

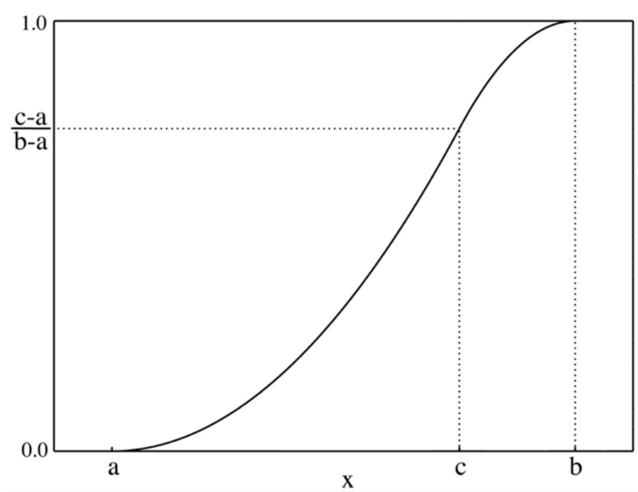

Figure 14 — CDF of the triangular distribution. The inflection point occurs at the most likely value (c). The minimum cumulative probability (at (a)) is 0 and the maximum cumulative probability (at (b)) is 1. The cumulative probability of the most likely value of X is (c-a)/(b-a), where the inflection point occurs (reprinted from Wikipedia, Triangular distribution, 2017).

In Fig. 13 and Fig. 14, *a* represents the minimum value, *b* represents the maximum value, and *c* represents the most likely (ML) value. We calculated the *m*-value using the *c* value obtained from the deterministic work, presented in **Eq. 23**.

$$m = \frac{c-a}{b-a} \quad \text{………………………………………………………….…..} \mathbf{(\ 23)}$$

In this analysis, we assume that the b-factor is bound by $b \in \left[0.1-2\right]$, and the decline rate is bound by $D \in \left[0.0005-0.1\right]$.

The *b*-factor and the decline rate D_i are highly correlated parameters. To run the MCS, we assume that no correlation exists between these two parameters to obtain a probabilistic distribution on each. We assume this because we want to model each parameter separately, and we bound the two parameters by values that we believe to be representative of unconventional reservoirs. We obtained the 1P, 2P, and 3P Reserves volumes for each of the 38 wells by plotting a CDF obtained for each well from the MCS analysis and making the 0.9, 0.5, 0.1 samplings as shown in **Fig.15** for Well 6.

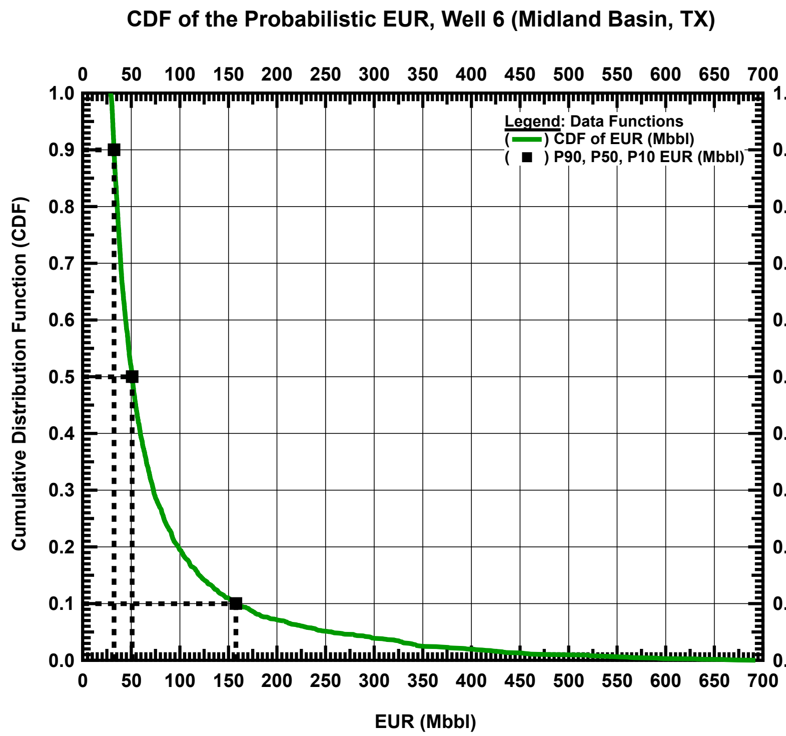

Figure 15 — CDF of the EUR of Well 6 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 32.14 Mbbls, the 2P (P50) is 50.8 Mbbls, and the 3P (P10) is 157.66 Mbbls.

We repeat this process for the remaining 37 wells and have a set of 1P, 2P, and 3P results for each well, presented in **Appendix B**. We consider the results of this portion of work to give our "truth case" because implementing a probabilistic DCA is a method to quantify the uncertainty associated with unconventional reservoirs.

We assign the variable Ω to define the relationship of the ratios of the three categories through the rest of this work. The subscript identifies which method is used to obtain these ratios and if it is a set of results for Well 6 or for the mean of the 38 wells. The general equation is presented in **Eq. 24.**

$$\Omega_{Method\_Well} = (\alpha \times 1P) + (\beta \times 2P) + (\gamma \times 3P) \text{ ....} \textbf{(24)}$$

where,

Ω	=	Variable to represent the equation of ratios of the three resources categories
α	=	1P ratio result
β	=	2P ratio result
γ	=	3P ratio result

We summed the Reserves volumes and calculated the ratios of each category, shown in **Eq. 25**, and repeated the process for the 2P and 3P weights.

$$\alpha = \frac{1P}{1P + 2P + 3P} \text{ ....} \textbf{(25)}$$

The results from Fig. 15 and the ratios of the three categories are presented in **Table 5,** and the results are defined mathematically in **Eq. 26**.

1P (Mbbl)	**2P (Mbbl)**	**3P (Mbbl)**	**1P Ratio (α)**	**2P Ratio (β)**	**3P Ratio (γ)**
30	50	165	0.12	0.20	0.67

Table 5—Probabilistic DCA results and weights of the 1P, 2P, and 3P ratio results, calculated from Eq. 14, of Well 6.

$$\Omega_{DCA\_Well6} = (0.12 \times 1P) + (0.20 \times 2P) + (0.67 \times 3P) \text{ ....} \textbf{(26)}$$

The mean values of all 38 wells of the probabilistic DCA analysis results are presented in **Eq. 27.**

$$\Omega_{DCA\_Mean} = (0.11 \times 1P) + (0.21 \times 2P) + (0.68 \times 3P) \text{ ....} \textbf{(27)}$$

Using Eqs. 24, 25, 26, and 27 we obtain the ratios of the 1P, 2P, and 3P Reserves volumes of the total Reserves. We see that these results do not resemble the SM weight distribution

(Eq. 18). As expected, the highest weight is in the 3P category because the production data is lognormally distributed and these results show the skewness of the production data.

We determine the uncertainty of the results of these wells by calculating the P10/P90 ratio. This uncertainty is dependent on the available data and the accuracy of the model, and a higher ratio means a higher uncertainty. We want this ratio to fall between 4 and 8 because this is the “ideal” range (SPEE, 2013). The P10/P90 ratio for Well 6 is equal to 6, and the P10/P90 ratio of the average of the wells is equal to 7. **Fig. 16** presents the full range of the P10/P90 results for the 38 wells, with the minimum and maximum values highlighted.

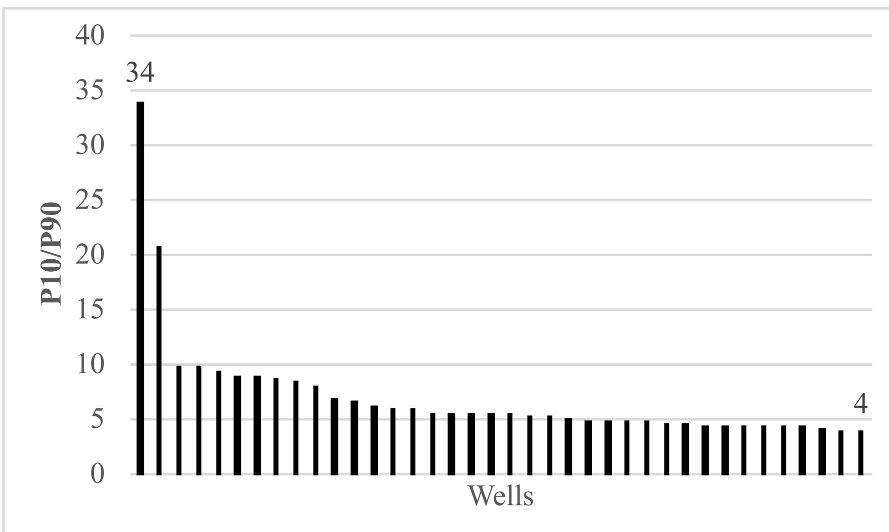

Figure 16 — The P10/P90 ratios for the probabilistic DCA results. We see two outliers with results that are 34 and 21, but the remaining wells have P10/P90 values that are as expected.

We see from Fig. 16 that there are only two, very high, outliers, and that the remaining 36 wells have a P10/P90 ratio that falls between 10 and 4. We consider the results of the probabilistic DCA to be accurate from these results, and this reinforces that the probabilistic DCA is the truth case.

4.4.2 Probabilistic Rate Transient Analysis (RTA)

We then performed probabilistic RTA using IHS *Harmony* to obtain the 1P, 2P, and 3P volumes, and calculated the relative ratios of each Reserves category (as done for the probabilistic DCA case). To run the probabilistic RTA in *Harmony*, we first built a multi-fracture horizontal well (MFHW) "composite" model. We forecasted the production rate and pressure for each well and saved the results. We then built a probabilistic analysis for each well from the forecasted pressure and production rate results. We used the same ranges for the *b*-factor and the initial decline rate as we did for the probabilistic DCA. The rest of the parameters that we input into the probabilistic RTA are presented in **Table 6,** and we used the distribution of each parameter as presented in Wright's (2015) textbook. As with probabilistic DCA, we found the P90, P50, and P10 Reserves volumes and determined the weight of each using Eq. 25.

Parameter	Value	Distribution
Number of fracture, n_f	27	Constant
Porosity, ϕ, percent	10	Triangular
Net Pay, h, ft	200	Triangular
Permeability, k, md	0.001	Lognormal
Fracture half-length, x_f, ft	200	Triangular

Table 6—Input parameters for the probabilistic RTA in IHS *Harmony*

The results of the probabilistic RTA for Well 6 and the weights of the three categories are presented in **Table 7,** and the results are defined in **Eq. 28**.

1P (Mbbl)	2P (Mbbl)	3P (Mbbl)	1P Ratio (α)	2P Ratio (β)	3P Ratio (γ)
197	223	259	0.29	0.33	0.38

Table 7—Probabilistic RTA results and weights of the 1P, 2P, and 3P ratio results, calculated from Eq. 14, of Well 6.

$$\Omega_{RTA\_Well6} = \left(0.29 \times 1P\right) + \left(0.33 \times 2P\right) + \left(0.38 \times 3P\right) \quad \textbf{(28)}$$

The mean weights for the 1P, 2P, and 3P fractions obtained using RTA methods are presented in **Eq. 29**.

$$\Omega_{RTA\_Mean} = \left(0.28 \times 1P\right) + \left(0.33 \times 2P\right) + \left(0.39 \times 3P\right) \quad \textbf{(29)}$$

The RTA results are intermediate between the weights given for the SM method and those obtained from our probabilistic DCA work. The results of the probabilistic RTA of the remaining 37 wells are presented in **Appendix C** and are compared to the results of the probabilistic DCA. Similar to our DCA results, the relative weights for each category increase with the increasing uncertainty of volumes in a given category, which is what intuition suggests for a skewed distribution. However, we also see a very similar Reserves ratios between the three categories, which is not what we expect.

We determine the uncertainty of the results of these wells by calculating the P10/P90 ratio. As previously discussed, this uncertainty is dependent on the available data and the accuracy of the model, and a higher ratio means a higher uncertainty. The P10/P90 ratio for Well 6 is equal to 1, and the P10/P90 ratio of the average of the wells is equal to 2. These results indicate that there is no variation between the P10 and P90 Reserves estimations, that the estimated volumes are the same. **Fig. 19** presents the full range of the P10/P90 results for the 38 wells, with the minimum and maximum values highlighted.

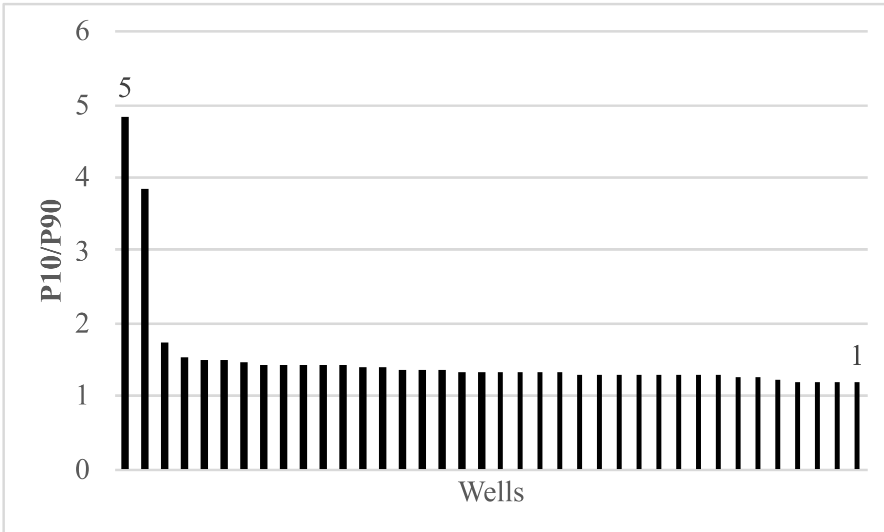

Figure 17 — The P10/P90 ratios for the probabilistic RTA results. We see that these results range only from 5 to 1.

We see from Fig. 19 that the P10/P90 ratio from the probabilistic RTA fall only between 5 and 1, and the majority of the results are less than 2. These results indicate that there are not great differences between the P10 and P90 Reserves estimates based on the probabilistic RTA analysis, meaning that there is not much longevity of these wells.

We make no further use of the quantitative results from probabilistic RTA calculations obtained using IHS *Harmony* because the documentation does not sufficiently clarify the assumptions used in computational algorithm. Furthermore, the P10/P90 ratios are all very close to 1, meaning that there is little difference in the calculated volumes of the three categories. We do expect higher variation, as we saw in the probabilistic DCA P10/P90 ratios. In contrast, using from our DCA work, we know precisely the implementation of the computational algorithm. Qualitatively, the RTA results from IHS *Harmony* confirm those from DCA (increasing Reserves ratios for each category with increasing uncertainty, unlike the SM method).

4.4.3 The Gaussian Quadrature

Once we completed the first two steps, we implemented a 3-point, 5-point, and 10-point GQ to obtain the weights, percentiles, and ratios for the 1P, 2P, and 3P Reserves categories of each well. We then performed the same analysis to determine the 1C, 2C, and 2C ratios, and the 1U, 2U, 3U ratios. To account for the uncertainty of these volumes, we increased the standard deviation, and present two theoretical cases for each. The GQ method provides an organizing framework for understanding the objective of discretization and a computational method for determining the best approximation of the Reserves ratios. We implemented a 3-point GQ model based on the work from Bickel *et al.* (2010), but also present the results of the 5-point and 10-point to see if we can obtain more accuracy with an increased number of nodes.

4.4.3.1 Building the Distribution for the Gaussian Quadrature

We first determine the mean (μ) and standard deviation (σ) of the production data of each well. These values were very high due to the nature of production data, so we scaled them to smaller values to be more manageable when building a random lognormal distribution, by using **Eq. 30** and **Eq. 31**.

$$\mu_{scaled} = \ln\left(\frac{\mu^2}{\sqrt{\mu^2+\sigma^2}}\right) \quad \text{(30)}$$

$$\sigma_{scaled} = \sqrt{\ln\left(\frac{\mu^2 + \sigma^2}{\mu^2}\right)} \qquad \textbf{(31)}$$

We also determine the variance, skewness, and kurtosis of each well's production data. *Skewness* is defined as the "measure of asymmetry of the probability distribution of a real-valued random variable about its mean" (Wikipedia, Skewness, 2020). *Kurtosis* is defined as "the measure of tailedness of the probability distribution of a real-valued random variable. Like skewness, kurtosis describes the shape of a probability distribution, and, like skewness, there are different ways of quantifying it for a theoretical distribution and corresponding ways of estimating it from a sample population" (Wikipedia, Kurtosis, 2020).

These four parameters are also the first four central moments of the distribution, and we will see if they match our estimates in the subsequent sections. *Moments* are "specific quantitative measures of the shape of the function" (Wikipedia, Moment (mathematics), 2020). The moments of the lognormal distribution are defined by the relationship in **Eq. 32**.

$$\mathrm{E}\left(X^n\right) = \exp\left(n\mu + \frac{1}{2}n^2\sigma^2\right), n \in N \qquad \textbf{(32)}$$

The results of the well's production data mean, standard deviation, variance, skewness, and kurtosis, along with the scaled mean and standard deviation are presented in **Table 8**.

	Characteristics of Production Data					Scaled Results		
Well	**Mean**	**Standard Deviation**	**Variance**	**Skewness**	**Kurtosis**	**Mean**	**Standard Deviation**	**Variance**
6	173	148	22,004	3	7	4.87	0.74	0.55

Table 8—The mean, standard deviation, variance, skewness, and kurtosis of the Well 6 production data, and the calculated scaled results of the mean, standard deviation, and variance.

We then created a synthetic lognormal distribution based on the scaled mean and scaled standard deviation of the production data, and determined the first four central moments, presented in **Table 9**.

	4 Moments of Synthetic Lognormal Distribution from Production			
Well	**E[X]=Mean**	**E[X2]=Variance**	**E[X3]=Skewness**	**E[X4]=Kurtosis**
6	169	17,380	1.99	6.35

Table 9—The mean, variance, skewness, and kurtosis of the synthetic lognormal distribution created using Well 6 production data's scaled mean and standard deviation. These four parameters are also the first four central moments of this distribution.

We calculated the percent difference between the actual and synthetic datasets, presented in **Table 10.** We see that the first moment, the mean, is well captured by the synthetic dataset with only 2.2% difference between the actual and estimated distributions. We see that the variance and skewness, the second and third moments, respectively, had approximately 20% difference between the actual and estimated distribution, and the kurtosis, fourth moment, had 14% difference. We can consider these results to be acceptable.

	% Difference (Prod Data vs. Synthetic Lognormal Distr.)			
Well	**E[X]=Mean**	**E[X2]=Variance**	**E[X3]=Skewness**	**E[X4]=Kurtosis**
6	2.21%	23%	26%	14%

Table 10—The percent difference between the actual and synthetic moments.

We also notice that this well's synthetic lognormal distribution's first four moments have a higher percent different than the rest of the wells. Overall we notice that the synthetic distributions we built to implement with the GQ are accurate when compared to the production data. The full set of results for the 38 wells is presented in **Appendix D**.

We plot the CDF, EDF, and PDF based on the lognormal distribution, presented in **Fig. 18** and **Fig. 19**, respectively.

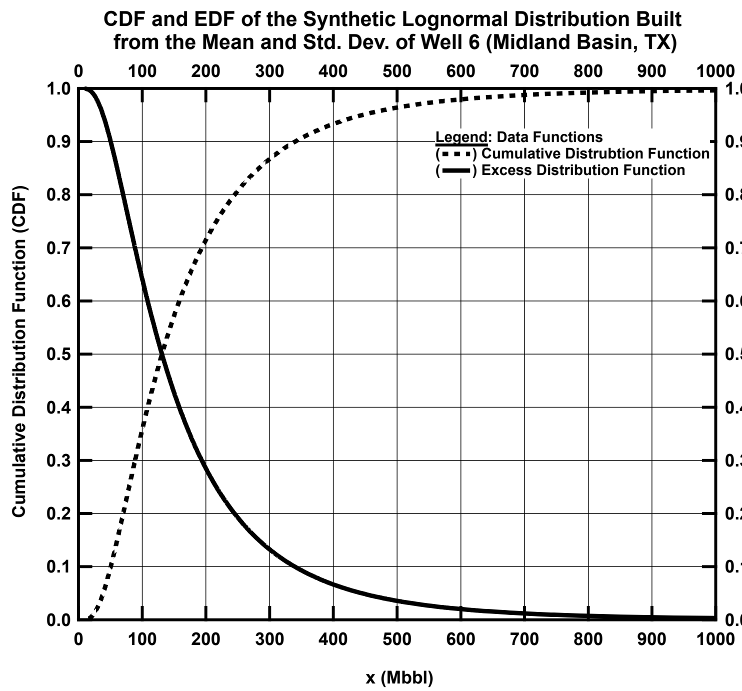

Figure 18 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 6.

As previously discussed, the EDF (solid black curve) is the inverse of the CDF (dashed black curve) and is the standard convention in the oil and gas industry. We show the CDF to prove graphically that the EDF is its inverse.

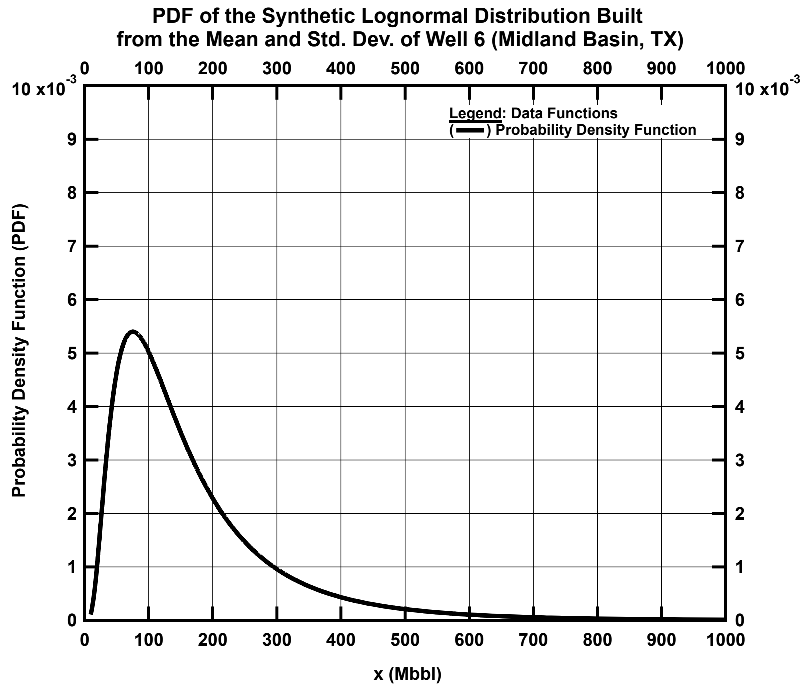

Figure 19 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 6.

The EDF is the inverse of the CDF, as presented in Eq. 12. In this work we do consider that the EDF is referred to as the inverse CDF, and presented by Fig. 15 in the probabilistic DCA results, and in Fig. 16. We use this convention because according to PRMS, P90 is the "low" estimate, P50 is the "best" estimate, and P10 is the "high" estimate.

We then transformed the GQ from the standard [a,b] coordinates to the lognormal [0, ∞] coordinates. The *a*- and *b*-coordinates are user defined, and can range from [0,+∞], as these are the boundaries of the lognormal distribution.

4.4.3.2 The 3-point, 5-point, and 10-point Gaussian Quadrature Reserves

4.4.3.2.1 Methodology to Implement the Gaussian Quadrature

We ran the 3-point GQ and found that the weights are 0.17, 0.67, 0.17. This translates to the

P83, P67, and P17 results, and the respective percentiles are the volumes at these three weights. We notice that these three weights to do not correspond to P90, P50, and P10 as we were able to determine from the CDF of the probabilistic DCA results. This is because the GQ discretizes the distribution into three points and reports the equivalent oil volume at those three points. For the purpose of this work, we will call the P83 the 1P Reserves, the P67 the 2P Reserves, and P17 as the 3P Reserves. Similarly, when we discuss Contingent and Prospective Resources, these three represent the 1C, 2C, 3C, and 1U, 2U, and 3U, respectively. Again, this notation is not technically correct, but these three results are the "low", "best", and "high" Reserves, and for simplicity and continuity from the probabilistic DCA and RTA results, we will maintain this notation.

Similarly to the 3-point GQ, when we ran the 5-point GQ, we found that the weights are 0.01, 0.22, 0.53, 0.22, 0.01. This translates to the P99, P78, P53, P22, and P1 results, and the respective percentiles are the volumes at these five weights. We assume that the P78, P53, and P22 correspond to the P90, P50, and P10, respectively. Finally, we ran the 10-point GQ and found that the weights are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0. This translates to the P100, P99, P98, P86, P66, P34, P14, P2, P1, P0 results, and the respective percentiles are the volumes at these ten weights. We assume that the P86, P66, and P14 correspond to the P90, P50, and P10, respectively. The calculated GQ weights are the same for all the cases using the 3-, 5-, and 10-point GQ, but the percentiles are dependent on the mean and standard deviation of the lognormal distribution, and the ratios are dependent on the percentiles. We present the results of the three cases in the following sections.

4.4.3.2.2 Results of the 3-, 5-, and 10-point Gaussian Quadrature

3-point GQ Results

The ratios are calculated using the same equation presented in Eq. 25, the weights, percentiles, and ratio results for Well 6 are presented in **Table 11**, and are defined mathematically in **Eq. 33**.

3-point	Weights	Percentiles	Ratios
P83	0.17	36	6%
P67	0.67	131	20%
P17	0.17	470	74%

Table 11—The weights, percentiles, and ratios of Well 6 by implementing the 3-point gaussian quadrature.

$$\Omega_{\text{3-pt GQ\_Well6}} = \left(0.06 \times 1P\right) + \left(0.2 \times 2P\right) + \left(0.74 \times 3P\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\text{(33)}$$

We perform the same analysis on the mean results of the 38 wells for the 3-point GQ and probabilistic DCA. The results of the average of the 38 wells of the 3-point GQ are defined mathematically in **Eq. 34**.

$$\Omega_{\text{3-pt GQ\_Mean}} = \left(0.07 \times 1P\right) + \left(0.21 \times 2P\right) + \left(0.72 \times 3P\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\text{(34)}$$

We estimate the P10/P90 ratio as an expression of uncertainty, but we do not have these percentiles from the GQ results, so we calculate the P17/P83 ratio as the uncertainty expression. The P17/P83 ratio for Well 6 is equal to 13, and the P83/P17 ratio of the average of the wells is equal to 10. **Fig. 20** presents the full range of the P83/P17 results for the 38 wells, with the minimum and maximum values highlighted.

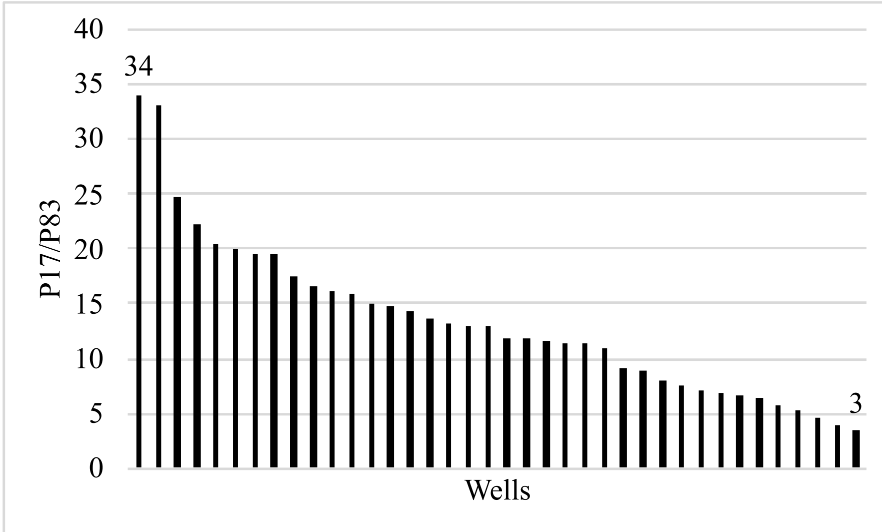

Figure 20 — P17/P83 ratios of the Reserves of the 38 wells in the Midland Basin, TX dataset. We see the maximum results is 34 and the minimum is 3.

In Fig. 20 we see that there are two outliers at the maximum, which are significantly higher than the other results. We notice that the remaining values follow a steady decrease in the P17/P83 ratio. These results are interesting because we see a higher uncertainty in the GQ results when compared with the probabilistic DCA results.

<u>5-point GQ Results</u>

The weights, percentiles, and ratio results for Well 6 are presented in **Table 12**, and are defined mathematically in **Eq. 35**.

5-point	Weights	Percentiles	Ratios
P99	0.01	16	1%
P78	0.22	48	3%
P53	0.53	131	8%
P22	0.22	356	22%
P1	0.01	1081	66%

Table 12—The weights, percentiles, and ratios of the Well 6 by implementing the 5-point Gaussian Quadrature.

$$\Omega_{\text{5-pt GQ\_Well6}} = (0.01 \times P99) + (0.03 \times P78) + (0.08 \times P53) + (0.22 \times P22) + (0.66 \times P1) \quad \text{.................................} \ \mathbf{(35)}$$

The results of the average of the 38 wells of the 5-point GQ are defined mathematically **Eq. 36**

$$\Omega_{\text{5-pt GQ\_Mean}} = (0.02 \times P99) + (0.04 \times P78) + (0.09 \times P53) + (0.22 \times P22) + (0.64 \times P1) \quad \text{.................................} \ \mathbf{(36)}$$

We see that the majority of the Reserves fall in the tail end of the distribution, where the P22 and P1 percentiles have the highest Reserves ratios. This is expected because the lognormal distribution is asymmetric, however the three chosen percentiles results would be inconsistent with the 3-point GQ and probabilistic DCA results.

We calculate the P22/P78 ratio as the uncertainty expression of the 5-point GQ. The P22/P78 ratio for Well 6 is equal to 8, and the P22/P78 ratio of the average of the wells is equal to 6. **Fig. 21** presents the full range of the P83/P17 results for the 38 wells, with the minimum and maximum values highlighted.

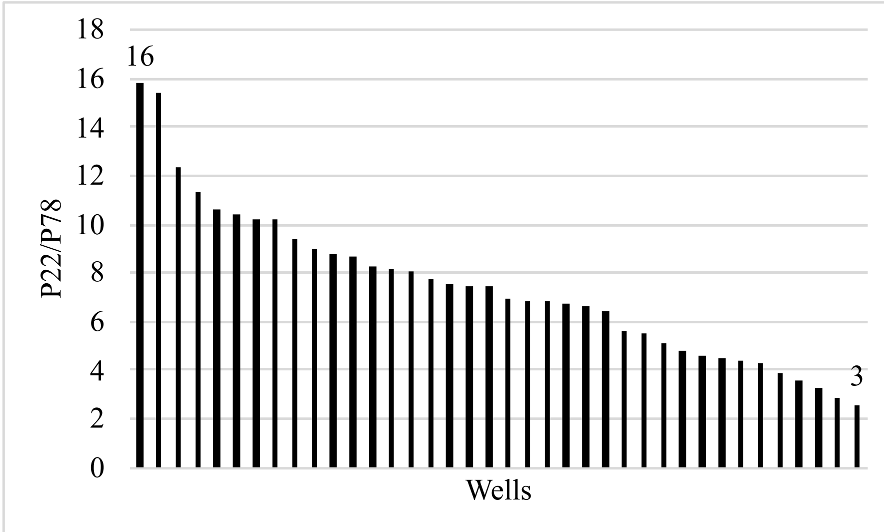

Figure 21 — P22/P76 ratios of the Reserves of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 16 and the minimum is 3.

In Fig. 21 we see that there are two outliers at the maximum, with an approximate value of 16, and they are higher than the other results. We notice that the remaining values follow a steady decrease in the P22/P78 ratio. We see values are lower than those of the P17/P83 ratio, which may be explained by the fact that the range from P78 to P22 is less than the range from P17 to P83. It can also be explained by the 5-point GQ having less uncertainty in the volume and ratio estimates than the 3-point GQ results.

<u>10-point GQ Results</u>

The weights, percentiles, and ratio results for Well 6 are presented in **Table 13**, and are defined mathematically in **Eq. 37**.

10-point	Weights	Percentiles	Ratios
P100	4.3E-06	4	0.0%
P99	7.6E-04	9	0.1%
P98	1.9E-02	21	0.3%
P86	1.4E-01	44	0.5%
P66	3.4E-01	91	1.1%
P34	3.4E-01	187	2.3%
P14	1.4E-01	386	4.7%
P2	1.9E-02	821	10.0%
P1	7.6E-04	1849	22.6%
P0	4.3E-06	4758	58.2%

Table 13—The weights, percentiles, and ratios of the Well 6 by implementing the 10-point Gaussian Quadrature.

$$\begin{aligned}\Omega_{\text{10-pt GQ\_Well6}} = &\left(0\times P100\right)+\left(0.001\times P99\right)+\left(0.003\times P98\right)+\left(0.005\times P86\right)+\\ &\left(0.011\times P66\right)+\left(0.023\times P34\right)+\left(0.047\times P14\right)+\left(0.12\times P2\right)+\\ &\left(0.23\times P1\right)+\left(0.58\times P0\right)\end{aligned} \quad \text{.....}\mathbf{(37)}$$

The results of the average of the 38 wells of the 10-point GQ are defined mathematically in **Eq. 38.**

$$\begin{aligned}\Omega_{\text{10-pt GQ\_Mean}} = &\left(0.001\times P100\right)+\left(0.003\times P99\right)+\left(0.005\times P98\right)+\left(0.01\times P86\right)+\\ &\left(0.02\times P66\right)+\left(0.03\times P34\right)+\left(0.05\times P14\right)+\left(0.1\times P2\right)+\\ &\left(0.22\times P1\right)+\left(0.56\times P0\right)\end{aligned} \quad \text{.}\mathbf{(38)}$$

Again we see that the majority of the Reserves fall in the tail end of the distribution, where the P14 through P0 percentiles have the highest Reserves ratio. This trend is similar to the one presented for the 5-point GQ results.

We calculate the P14/P86 ratio as the uncertainty expression of the 10-point GQ. The P14/P86 ratio for Well 6 is equal to 9, and the P14/P86 ratio of the average of the wells is equal to 7. **Fig. 22** presents the full range of the P14/P86 results for the 38 wells, with the minimum and maximum values highlighted.

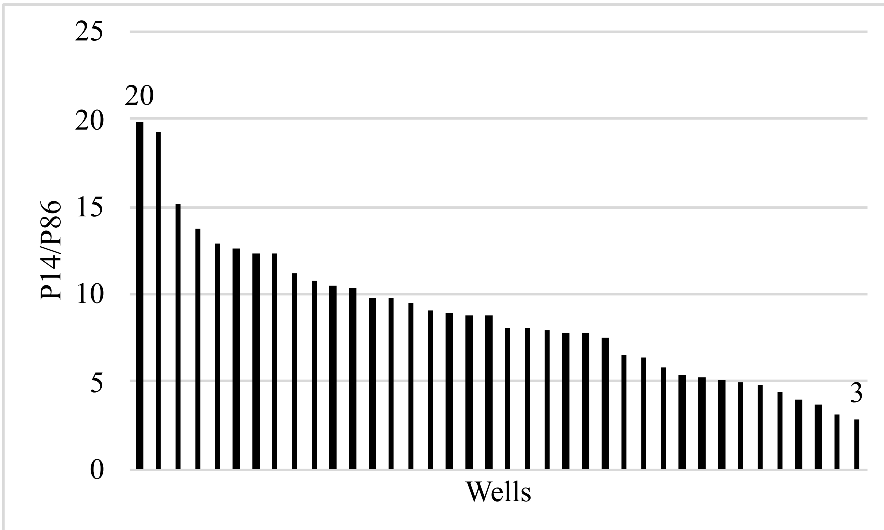

Figure 22 — P14/P86 ratios of the Reserves of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 16 and the minimum is 3.

In Fig. 22 we see that there are two outliers at the maximum, with an approximate value of 20, and they are higher than the other results. We notice that the remaining values follow a steady decrease in the P14/P86 ratio. These uncertainty ratio results show less uncertainty than the 3-point GQ ratios, which may be due an improved estimate of volumes and Reserves categories ratio estimates. However, we do not see a significant improvement in the uncertainty, meaning that we can implement the 3-point GQ with confidence.

The results of this work will aid entities in reporting Reserves and in their internal reporting processes. The Securities and Exchange Commission (SEC) only requires that 1P Reserves be reported for any publicly traded company, while 2P and 3P Reserves *may* be reported if the company desires. Obtaining accurate hydrocarbon estimates in unconventional reservoirs is particularly difficult, and probabilistic methods are used to quantify the uncertainty. However probabilistic DCA is not included in any software and is time consuming as it is done one well at a time. Implementing the GQ can help the engineers obtain the estimates for these wells effectively, and relatively quickly. This saves the engineer time on their analysis because they can run all the wells they are analyzing at once with the proposed algorithms. Furthermore, most entities choose not to report the 2P and 3P Reserves, but knowing these volumes is necessary to understand how the volumes will be promoted to 1P Reserves. Being able to model the relationships of the three Reserves categories simultaneously provides an understanding of their relationships, and does so quickly.

The full set of Reserves results for the remaining 37 wells of the 3-point, 5-point, and 10-point GQ are presented in **Appendix E.**

4.4.3.3 The 3-point, 5-point, and 10-point Gaussian Quadrature of Contingent and Prospective Resources

CR and PR have a higher uncertainty than Reserves, and so it is difficult to estimate these volumes. To account for this uncertainty, we increase the standard deviation of the production data and present theoretical cases. The two CR cases are: one with 20 per cent increase on the standard deviation, and one with 50 per cent increase on the standard deviation. The two PR cases are: one with 90 per cent increase on the standard deviation, and one with 100 per cent increase on the standard deviation.

These are arbitrary cases, and the uncertainties of the CR and the PR are user defined. These cases show a range of the possible outcomes for CR and PR. We calculate the increased standard deviation of the production data, then scaled the mean and standard deviation as presented in Eq. 30 and Eq. 31, respectively. The methodology is identical to that of the Reserves cases and we only present the results of the CR and PR cases.

4.4.3.3.1 Contingent Resources: 20 per cent increase on standard deviation

<u>3-point GQ</u>

The weights, percentiles, and ratio results for Well 6 are presented in **Table 14**, and are defined mathematically in **Eq. 39**.

3-point	Weights	Percentiles	Ratios
P83	0.17	35	6%
P67	0.67	120	21%
P17	0.17	416	73%

Table 14—The weights, percentiles, and ratios of the 3-point GQ of the Contingent Resources of Well 6, with a 20 per cent increase in the standard deviation.

$$\Omega_{\text{3-pt GQ\_Well6\_CR 20\%}} = \left(0.06\times 1C\right)+\left(0.21\times 2C\right)+\left(0.73\times 3C\right) \qquad \textbf{(39)}$$

The mean results for the 3-point GQ are defined mathematically in **Eq. 40**.

$$\Omega_{\text{3-pt GQ\_Mean\_CR 20\%}} = \left(0.08\times 1C\right)+\left(0.22\times 2C\right)+\left(0.7\times 3C\right) \qquad \textbf{(40)}$$

The P17/P83 ratio for Well 6 is equal to 12, and the P83/P17 ratio of the average of the wells is equal to 8. The ratios of this case are similar to those of the Reserves, and we see that the P17/P83 results are less than those of the Reserves. We would expect that the CR would be more uncertain, and so we would expect that the P17/P83 would be higher. These results imply that if the standard deviation of the Contingent Resources is 20 per cent higher than the original distribution, we can expect the ratios of the three categories will be approximately those of the Reserves.

Fig. 23 presents the full range of the P17/P83 results for the 38 wells, with the minimum and maximum values highlighted.

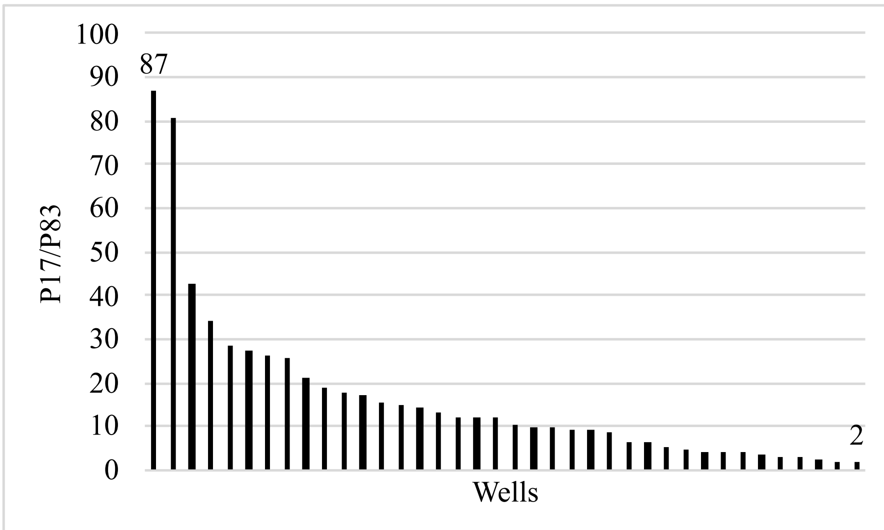

Figure 23 — P17/P83 ratios of the Contingent Resources with 20 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 87 and the minimum is 2.

In Fig. 23 we see that there are two outliers at the maximum, with values equal to 87 and 80. These are very high P17/P83 results, but we see that the subsequent results for the remaining wells are also very high. This can be attributed to the increase in the standard deviation which yield higher percentile results.

<u>5-point GQ</u>

The results for Well 6 are presented in **Table 15**, and are defined mathematically in **Eq. 41**.

5-point	Weights	Percentiles	Ratios
P99	0.01	15	1%
P78	0.22	45	3%
P53	0.53	120	8%
P22	0.22	317	22%
P1	0.01	932	65%

Table 15—The weights, percentiles, and ratios of the 5-point GQ of the Contingent Resources of Well 6, with a 20 per cent increase in the standard deviation.

$$\Omega_{\text{5-pt GQ\_Well6\_CR 20\%}} = (0.01 \times P99) + (0.03 \times P78) + (0.08 \times P53) + (0.22 \times P22) + (0.65 \times P1) \quad \text{.....................(41)}$$

The mean results of the 38 wells for the 5-point GQ are defined mathematically in **Eq. 42**.

$$\Omega_{\text{5-pt GQ\_Mean\_CR 20\%}} = (0.02 \times P99) + (0.05 \times P78) + (0.1 \times P53) + (0.22 \times P22) + (0.62 \times P1) \quad \text{.....................(42)}$$

The P22/P78 ratio for Well 6 is equal to 7, and the P22/P78 ratio of the average of the wells is equal to 5. These results are very similar to those of the Reserves. **Fig. 24** presents the full range of the P22/P78 results for the 38 wells, with the minimum and maximum values highlighted.

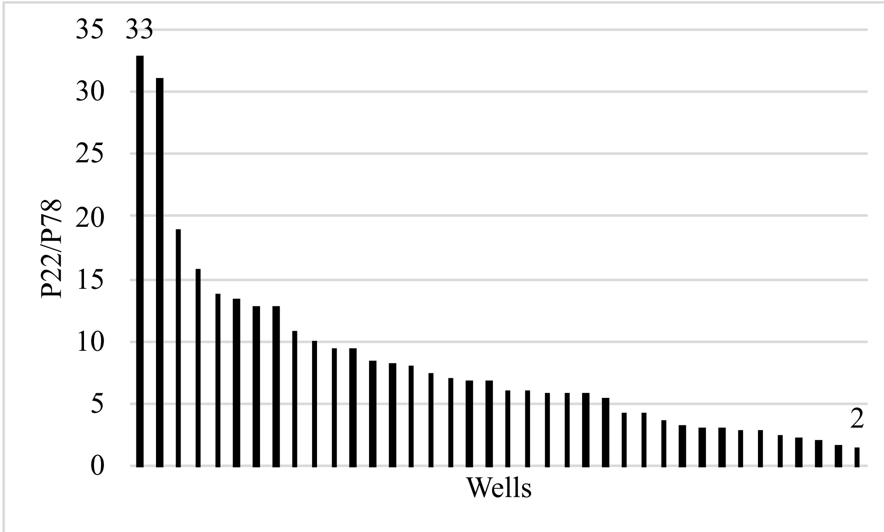

Figure 24 — P22/P78 ratios of the Contingent Resources with 20 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 33 and the minimum is 2.

In Fig. 24 we see that the results range from 33 to 2. These values are less than the P17/P83 and we account for the smaller ratio because the range is less than the range from P17 to P83. We note that the majority of these wells have a P22/P78 ratio less than 10.

10-point GQ

The results for Well 6 are presented in **Table 16**, and are defined mathematically in **Eq. 43**.

10-point	Weights	Percentiles	Ratios
P100	4.3E-06	4	0.1%
P99	7.6E-04	9	0.1%
P98	0.02	20	0.3%
P86	0.14	42	0.6%
P66	0.34	85	1.2%
P34	0.34	170	2.5%
P14	0.14	343	5.0%
P2	0.02	713	10%
P0	7.6E-04	1568	23%
P	4.3E-06	3921	57%

Table 16—The weights, percentiles, and ratios of the 10-point GQ of the Contingent Resources of Well 6, with a 20 per cent increase in the standard deviation.

$$\Omega_{\text{10-pt GQ\_Well6\_CR 20\%}} = (0.001\times P100)+(0.001\times P99)+(0.003\times P98)+ (0.006\times P86)+(0.012\times P66)+(0.025\times P34)+(0.05\times P14)+ (0.1\times P2)+(0.23\times P1)+(0.57\times P0) \qquad \text{.............}\mathbf{(43)}$$

The mean results of the 38 wells for the 10-point GQ are defined mathematically in **Eq. 44**.

$$\Omega_{\text{10-pt GQ\_Mean\_CR 20\%}} = (0.004\times P100)+(0.007\times P99)+(0.01\times P98)+ (0.014\times P86)+(0.022\times P66)+(0.035\times P34)+(0.058\times P14)+ (0.1\times P2)+(0.21\times P1)+(0.53\times P0) \qquad \text{..............}\mathbf{(44)}$$

The P14/P86 ratio for Well 6 is equal to 8, and the P14/P86 ratio of the average of the wells is equal to 6. Again these results are similar to those of the Reserves, and are better than the results of the 3-point GQ case with 20 per cent higher standard deviation. **Fig. 25** presents the full range of the P14/P86 results for the 38 wells, with the minimum and maximum values highlighted.

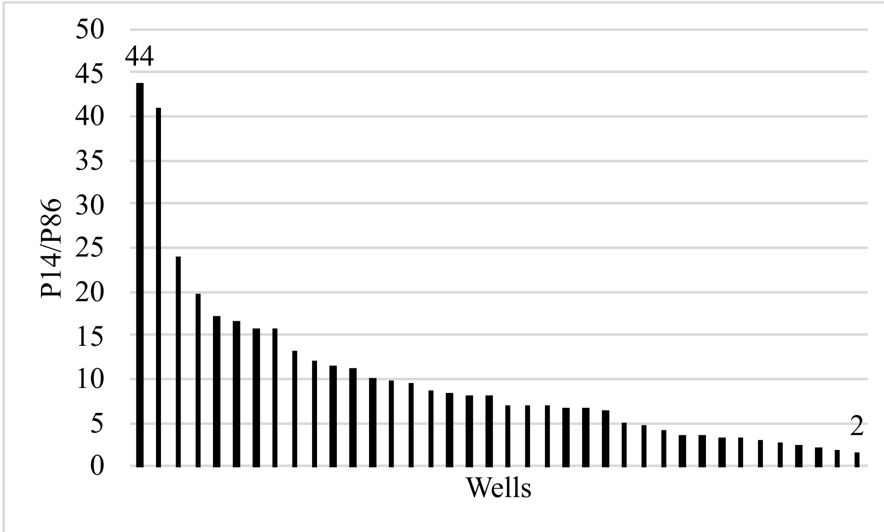

Figure 25 — P14/P86 ratios of the Contingent Resources with 20 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum result is 44 and the minimum is 2.

In Fig. 25 we see that the uncertainty ranges from 44 to 2. This range of P14/P86 is higher than the range of the 5-point GQ case with the 20 per cent increase on the standard deviation.

4.4.3.3.2 Contingent Resources: 50 per cent increase on standard deviation

3-point GQ

The results are presented in **Table 17**, and are defined mathematically in **Eq. 45**.

3-point	Weights	Percentiles	Ratios
P83	0.17	20	3%
P67	0.67	106	15%
P17	0.17	568	82%

Table 17—The weights, percentiles, and ratios of the 3-point GQ of the Contingent Resources of Well 6, with a 50 per cent increase in the standard deviation.

$$\Omega_{\text{3-pt GQ\_Well6\_CR 50\%}} = \left(0.03 \times 1C\right) + \left(0.15 \times 2C\right) + \left(0.82 \times 3C\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\mathbf{(45)}$$

The mean results are defined mathematically in **Eq. 46**.

$$\Omega_{\text{3-pt GQ\_Mean\_CR 50\%}} = (0.05 \times 1C) + (0.17 \times 2C) + (0.78 \times 3C) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \textbf{(46)}$$

The P17/P83 ratio for Well 6 is equal to 29, and the P17/P83 ratio of the average of the wells is equal to 17, presented in **Fig. 26**, which are significantly higher than the P17/P83 ratio with 20 per cent increase. These P17/P83 results are what we expected initially; due to the increased uncertainty, the volumes shift to the tail end of the distribution. This case can be described as the extreme case of the CR.

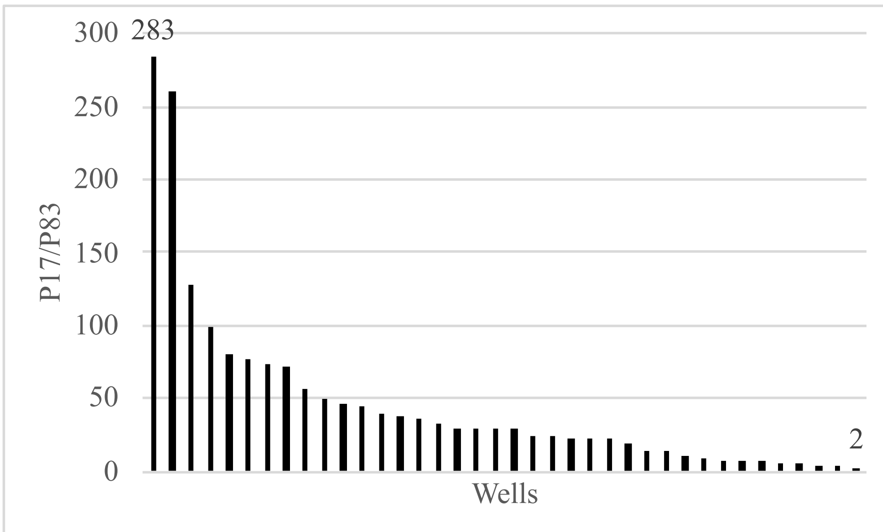

Figure 26 — P17/P83 ratios of the Contingent Resources with 50 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 283 and the minimum is 2.

In Fig. 26 we see that the results are significantly higher than those of the CR with the 20 per cent increase in standard deviation, and also those of the 3-point GQ Reserves results. We expect the uncertainty ratio to increase as we increase the uncertainty of the dataset.

5-point GQ

The results are presented in **Table 18**, and are defined mathematically in **Eq. 47**.

5-point	Weights	Percentiles	Ratios
P99	0.01	7	0%
P78	0.22	28	1%
P53	0.53	106	5%
P22	0.22	394	18%
P1	0.01	1692	76%

Table 18—The weights, percentiles, and ratios of the 5-point GQ of the Contingent Resources of Well 6, with a 50 per cent increase in the standard deviation.

$$\Omega_{\text{5-pt GQ\_Well6\_CR 50\%}} = \left(0 \times P99\right) + \left(0.01 \times P78\right) + \left(0.05 \times P53\right) + \left(0.18 \times P22\right) + \left(0.76 \times P1\right) \quad \text{..........................}\textbf{(47)}$$

The results of the mean of the wells are defined mathematically in **Eq. 48**.

$$\Omega_{\text{5-pt GQ\_Mean\_CR 50\%}} = \left(0.01 \times P99\right) + \left(0.03 \times P78\right) + \left(0.06 \times P53\right) + \left(0.18 \times P22\right) + \left(0.71 \times P1\right) \quad \text{....................}\textbf{(48)}$$

The P22/P78 ratio for Well 6 is equal to 14, and the P22/P78 ratio of the average of the wells is equal to 9. We see that these values are significantly higher than those with the 20 per cent increase, which is consistent with our expectations. The ratios of the 38 wells are presented in **Fig. 27**.

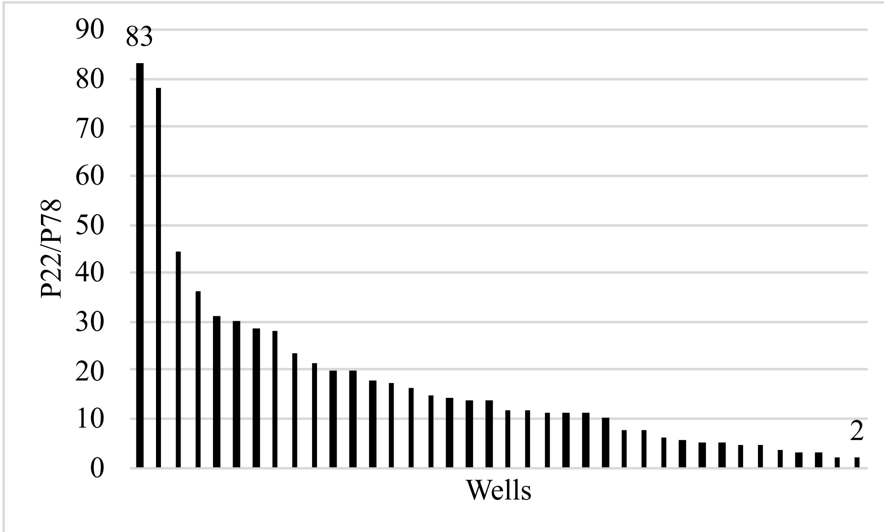

Figure 27 — P22/P78 ratios of the Contingent Resources with 50 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 83 and the minimum is 2.

In Fig. 27 we see that the results range from 83 to 2. This range of P22/P78 is significantly higher than the range of the previous CR case. We account for the higher range because of the higher increase in the standard deviation.

The 5-point percentiles and ratios decrease until the last weight, and we see a higher percentile and ratio in the P1 category. We notice that the P22/P78 ratios are significantly lower than the P17/P83 ratios, and is because we are taking a smaller range and taking the ratio of those values. We suspect that if the 5-point GQ provided weights closer to P90 and P10, the range would be larger.

<u>10-point GQ</u>

The ratios are calculated using the same equation presented in Eq. 25, the results for Well 6 are presented in **Table 19**, and are defined mathematically in **Eq. 49**.

10-point	Weights	Percentiles	Ratios
P100	4.3E-06	1	0.0%
P99	7.6E-04	3	0.0%
P98	0.02	9	0.1%
P86	0.14	25	0.1%
P66	0.34	66	0.4%
P34	0.34	169	1.0%
P14	0.14	439	3%
P2	0.02	1178	7%
P0	7.6E-04	3420	20%
P	4.3E-06	11820	69%

Table 19—The weights, percentiles, and ratios of the 10-point GQ of the Contingent Resources of Well 6, with a 50 per cent increase in the standard deviation.

$$\Omega_{\text{10-pt GQ\_Well6\_CR 50\%}} = \left(0\times P100\right)+\left(0\times P99\right)+\left(0.001\times P98\right)+ \left(0.001\times P86\right)+\left(0.004\times P66\right)+\left(0.01\times P34\right)+\left(0.03\times P14\right)+ \left(0.7\times P2\right)+\left(0.2\times P1\right)+\left(0.69\times P0\right) \quad \textbf{(49)}$$

The average 10-point GQ results are defined mathematically in **Eq. 50**.

$$\Omega_{\text{10-pt GQ\_Mean\_CR 50\%}} = \left(0.002\times P100\right)+\left(0.003\times P99\right)+\left(0.004\times P98\right)+ \left(0.007\times P86\right)+\left(0.012\times P66\right)+\left(0.02\times P34\right)+\left(0.038\times P14\right)+ \left(0.079\times P2\right)+\left(0.19\times P1\right)+\left(0.64\times P0\right) \quad \textbf{(50)}$$

The P14/P86 ratio for Well 6 is equal to 17, and the P14/P86 ratio of the average of the wells is equal to 11. **Fig. 28** presents the full range of the P14/P86 results for the 38 wells, with the minimum and maximum values highlighted.

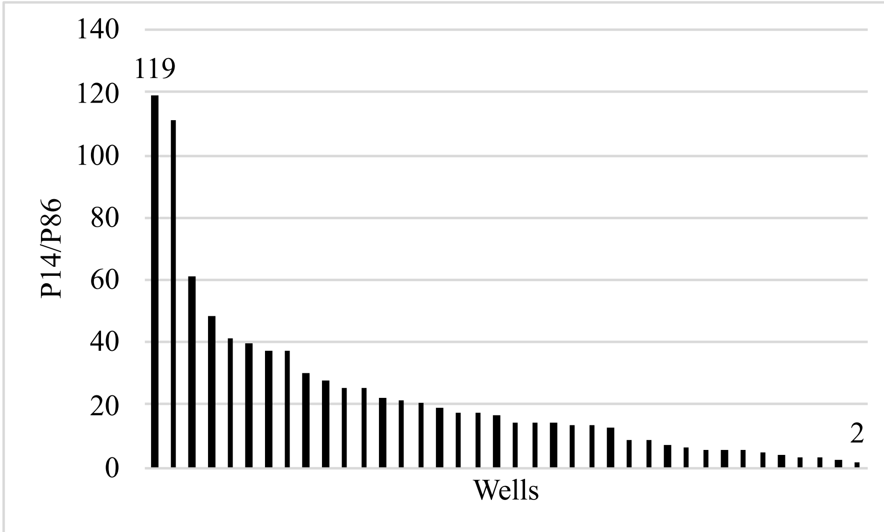

Figure 28 — P14/P86 ratios of the Contingent Resources with 50 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 119 and the minimum is 2.

In Fig. 28 we see that the results range from 119 to 2, which is a significantly larger range than the case with 20 per cent increase on the standard deviation (Fig. 27). These results are as expected because of the increase in uncertainty on the standard deviation.

4.4.3.3.3 Comparing the 20 and 50 per cent Model Results

Table 20 shows a direct comparison of the results of the two cases for Well 6, and **Table 21** shows the direct comparison for the cases of the mean values. These tables allow for easier comparison of the results.

WELL 6		20% Increase			50% Increase		
3-point	Weights	Percentiles	Ratios	P17/P83	Percentiles	Ratios	P17/P83
P83	0.17	35	6%	12	20	3%	29
P67	0.67	120	21%		106	15%	
P17	0.17	416	73%		568	82%	

Table 20—Comparison of the weights, percentiles, and ratios of the 3-point GQ of the Contingent Resources of Well 6, with the 20- and 50 per cent increase in the standard deviation.

Mean		20% Increase			50% Increase		
3-point	Weights	Percentiles	Ratios	P17/P83	Percentiles	Ratios	P17/P83
P83	0.17	49	8%	8	33	5%	17
P67	0.67	127	22%		114	17%	
P17	0.17	411	70%		561	78%	

Table 21—Comparison of the weights, percentiles, and ratios of the 3-point GQ of the Contingent Resources of the mean of the 38 wells, with the 20- and 50 per cent increase in the standard deviation.

The P83 and P67 percentiles and ratios decrease and the P17 percentile and ratio increase. Similarly we see that the P17/P83 ratios increase with the increase in standard deviation. These results are as expected, we see a greater shift to the tail end of the lognormal with the increased standard deviation, which is also represented in the P17/P83 ratio.

Table 22 shows a direct comparison of the results of the two cases for Well 6, and **Table 23** shows the direct comparison for the cases of the mean values. These tables allow for easier comparison of the results.

WELL 6		20% Increase			50% Increase		
5-point	Weights	Percentiles	Ratios	P22/P78	Percentiles	Ratios	P22/P78
P99	0.01	15	1%	7	7	0%	14
P78	0.22	45	3%		28	1%	
P53	0.53	120	8%		106	5%	
P22	0.22	317	22%		394	18%	
P1	0.01	932	65%		1,692	76%	

Table 22—Comparison of the weights, percentiles, and ratios of the 5-point GQ of the Contingent Resources of Well 6, with the 20- and 50 per cent increase in the standard deviation.

Mean		20% Increase			50% Increase		
5-point	Weights	Percentiles	Ratios	P22/P78	Percentiles	Ratios	P22/P78
P99	0.01	29	2%	5	17	1%	9
P78	0.22	59	5%		42	3%	
P53	0.53	127	10%		114	6%	
P22	0.22	312	22%		384	18%	
P1	0.01	1,012	62%		1,927	71%	

Table 23—Comparison of the weights, percentiles, and ratios of the 5-point GQ of the Contingent Resources of the mean of the 38 wells, with the 20- and 50 per cent increase in the standard deviation.

Similarly to the trend of the 3-point GQ, the 5-point percentiles and ratios decrease until the last weight, and we see a higher percentile and ratio in the P1 category. We notice that the P22/P78 ratios are significantly lower than the P17/P83 ratios, and is because we are taking a smaller range and taking the ratio of those values

Table 24 shows a direct comparison of the results of the two cases for Well 6, and **Table 25** shows the direct comparison for the cases of the mean values. These tables allow for easier comparison of the results.

WELL 6		20% Increase			50% Increase		
10-point	Weights	Percentiles	Ratios	P22/P78	Percentiles	Ratios	P22/P78
P100	4.3E-06	4	0.1%	8	1	0.01%	17
P99	7.6E-04	9	0.1%		3	0.02%	
P98	0.02	20	0.3%		9	0.06%	
P86	0.14	42	0.6%		25	0.15%	
P66	0.34	85	1.2%		66	0.39%	
P34	0.34	170	2.5%		169	0.99%	
P14	0.14	343	5%		439	3%	
P2	0.02	713	10%		1,178	7%	
P1	7.6E-04	1,568	23%		3,420	20%	
P0	4.3E-06	3,921	57%		11,820	69%	

Table 24—Comparison of the weights, percentiles, and ratios of the 10-point GQ of the Contingent Resources of Well 6, with the 20- and 50 per cent increase in the standard deviation.

Mean		20% Increase			50% Increase		
10-point	Weights	Percentiles	Ratios	P22/P78	Percentiles	Ratios	P22/P78
P100	4.3E-06	13	0.4%	8	6	0.2%	11
P99	7.6E-04	21	0.7%		11	0.3%	
P98	0.02	34	1%		21	0.4%	
P86	0.14	56	1%		39	0.7%	
P66	0.34	95	2%		78	1%	
P34	0.34	172	3%		172	2%	
P14	0.14	338	6%		429	4%	
P2	0.02	742	11%		1,259	8%	
P1	7.6E-04	1,916	21%		4,618	19%	
P0	4.3E-06	6,544	53%		24,546	64%	

Table 25—Comparison of the weights, percentiles, and ratios of the 10-point GQ of the Contingent Resources of the mean of the 38 wells, with the 20- and 50 per cent increase in the standard deviation.

Similarly to the trend of the 3- and 5-point GQ, the 10-point percentiles and ratios decrease until the last few weights, and we see a higher percentiles and ratios. We notice that the P14/P86 ratios are similar to those of the 5-point P22/P78 results.

The full set of CR results for the remaining 37 wells of the 3-point, 5-point, and 10-point GQ are presented in **Appendix F.**

4.4.3.3.4 Prospective Resources: 90 per cent increase on standard deviation

3-point GQ

The weights, percentiles, and ratio results for Well 6 are presented in **Table 26**, and are defined in **Eq. 51**.

3-point	Weights	Percentiles	Ratio
P83	0.17	10	1%
P67	0.67	90	10%
P17	0.17	841	89%

Table 26—The weights, percentiles, and ratios of the 3-point GQ of the Prospective Resources of Well 6, with a 90 per cent increase in the standard deviation.

$$\Omega_{\text{3-pt GQ\_Well6\_PR 90\%}} = \left(0.01\times 1U\right)+\left(0.1\times 2U\right)+\left(0.89\times 3U\right) \qquad \textbf{(51)}$$

The mean results of the 38 wells for the 3-point GQ are presented in **Eq. 52**.

$$\Omega_{\text{3-pt GQ\_Mean\_PR 90\%}} = \left(0.03\times 1U\right)+\left(0.12\times 2U\right)+\left(0.85\times 3U\right) \qquad \textbf{(52)}$$

The P17/P83 ratio for Well 6 is equal to 87, and the P83/P17 ratio of the average of the wells is equal to 43. These values are very high, and indicate a large uncertainty in the PR volumes. **Fig. 29** presents the full range of the P17/P83 results for the 38 wells, with the minimum and maximum values highlighted.

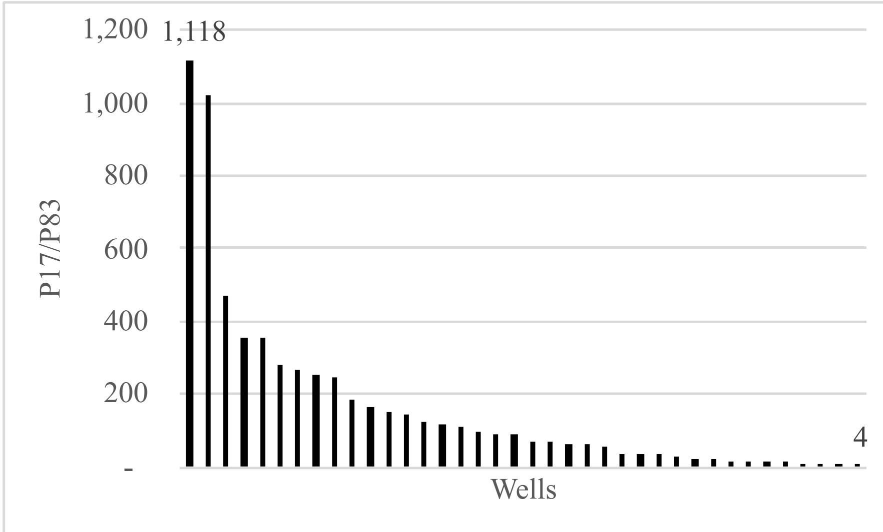

Figure 29 — P17/P83 ratios of the Prospective Resources with 90 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 1,118 and the minimum is 4.

In Fig. 29 we see that the results range from 1,118 to 4, showing a very large range of uncertainty. Because we do not have data to determine the Prospective Resources volumes and we cannot know what the 1U, 2U, and 3U results are, we can say that this range of uncertainties is appropriate for this case of PR.

5-point GQ

The results for Well 6 are presented in **Table 27**, and are defined mathematically in **Eq. 53**.

5-point	Weights	Percentiles	Ratio
P99	0.01	2	0.1%
P78	0.22	16	0.4%
P53	0.53	90	2%
P22	0.22	518	12%
P1	0.01	3,587	85%

Table 27—The weights, percentiles, and ratios of the 5-point GQ of the Contingent Resources of Well 6, with a 20 per cent increase in the standard deviation.

$$\Omega_{\text{5-pt GQ\_Well6\_PR 90\%}} = (0.001 \times P99) + (0.004 \times P78) + (0.02 \times P53) + (0.12 \times P22) + (0.85 \times P1) \quad \text{(53)}$$

The mean results of the 38 wells for the 5-point GQ are presented in **Eq. 54**.

$$\Omega_{\text{5-pt GQ\_Mean\_PR 90\%}} = (0.005 \times P99) + (0.01 \times P78) + (0.04 \times P53) + (0.14 \times P22) + (0.8 \times P1) \quad \text{(54)}$$

The P22/P78 ratio for Well 6 is equal to 33, and the P22/P78 ratio of the average of the wells is equal to 19. These results are significantly lower than those of the 3-point GQ. **Fig. 30** presents the full range of the P22/P78 results for the 38 wells, with the minimum and maximum values highlighted.

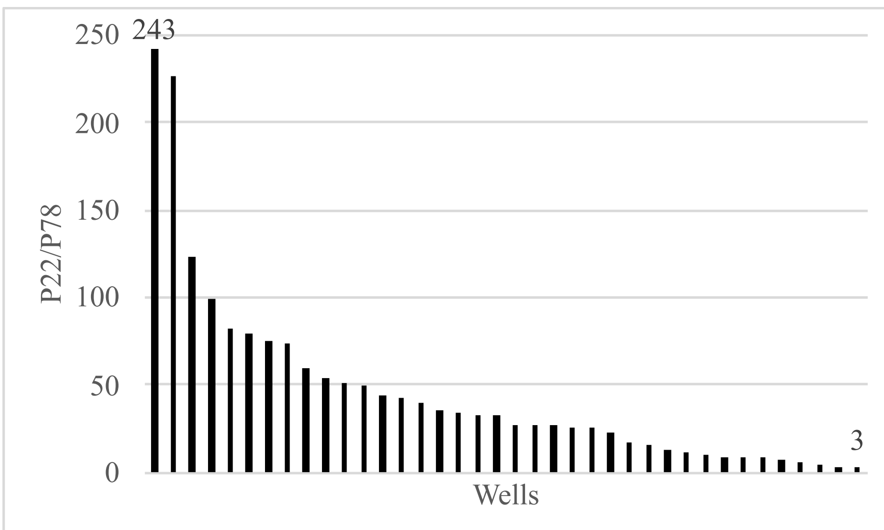

Figure 30 — P22/P78 ratios of the Prospective Resources with 90 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 243 and the minimum is 3.

We see that the P22/P78 ratios have a lower range than the 3-point GQ P17/P83 results, but we see that again there are very high results for this uncertainty ratio.

10-point GQ

The results for Well 6 are presented in **Table 28**, and are defined in **Eq. 55**.

10-point	Weights	Percentiles	Ratio
P100	4.3E-06	0	0.00%
P99	7.6E-04	1	0.00%
P98	0.02	4	0.01%
P86	0.14	14	0.02%
P66	0.34	48	0.1%
P34	0.34	168	0.3%
P14	0.14	597	1%
P2	0.02	2218	4%
P1	7.6E-04	9135	15%
P0	4.3E-06	47447	80%

Table 28—The weights, percentiles, and ratios of the 10-point GQ of the Prospective Resources of Well 6, with a 90 per cent increase in the standard deviation.

$$\Omega_{\text{10-pt GQ\_Well6\_PR 90\%}} = (0\times P100)+(0\times P99)+(0.0001\times P98)+ (0.0002\times P86)+(0.001\times P66)+(0.003\times P34)+(0.01\times P14)+ (0.04\times P2)+(0.15\times P1)+(0.8\times P0) \quad \textbf{(55)}$$

We perform the same analysis on the mean results of the 38 wells for the 5-point GQ and the results are presented in **Eq. 56**.

$$\Omega_{\text{10-pt GQ\_Mean\_PR 90\%}} = (0\times P100)+(0.001\times P99)+(0.002\times P98)+ (0.003\times P86)+(0.005\times P66)+(0.01\times P34)+(0.02\times P14)+ (0.05\times P2)+(0.16\times P1)+(0.75\times P0) \quad \textbf{(56)}$$

The P14/P86 ratio for Well 6 is equal to 44, and the P14/P86 ratio of the average of the wells is equal to 24. **Fig. 31** presents the full range of the P14/P86 results for the 38 wells, with the minimum and maximum values highlighted.

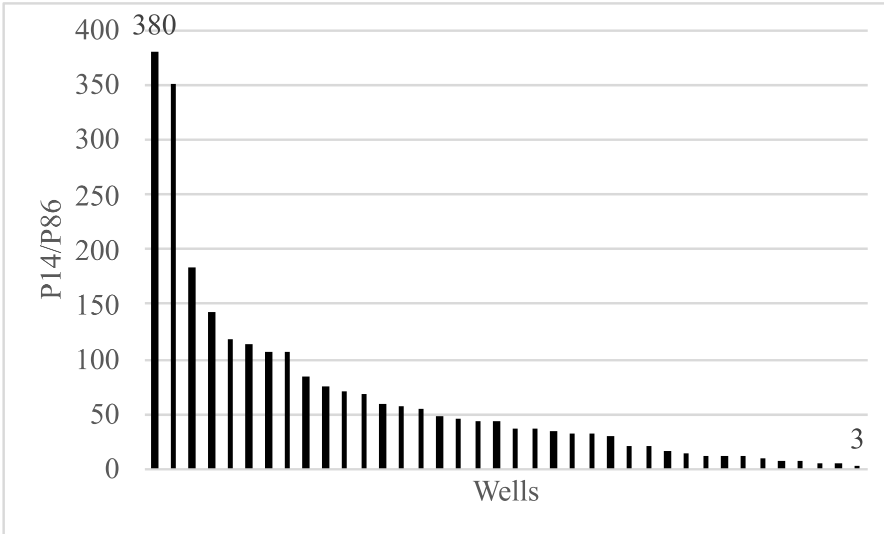

Figure 31 — P14/P86 ratios of the Prospective Resources with 90 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 380 and the minimum is 3.

From Fig. 31, we see that the range of the P14/P86 ratio is between 380 and 3. This range is less than the 3-point GQ results but higher than the 5-point results. As previously discussed, the volumes of the PR are unknown and this large range of uncertainty results can be considered accurate.

4.4.3.3.5 Prospective Resources: 100 per cent increase on standard deviation

<u>3-point GQ</u>

The results for Well 6 are presented in **Table 29**, and are defined in **Eq. 57**.

3-point	Weights	Percentiles	Ratio
P83	0.17	8	1%
P67	0.67	87	9%
P17	0.17	923	91%

Table 29—The weights, percentiles, and ratios of the 3-point GQ of the Contingent Resources of Well 6, with a 100 per cent increase in the standard deviation.

$$\Omega_{\text{3-pt GQ\_Well6\_PR 100\%}} = \left(0.01\times 1U\right)+\left(0.09\times 2U\right)+\left(0.91\times 3U\right)\text{..........................}\mathbf{(57)}$$

The mean results of the 38 wells for the 3-point GQ and the results are presented in **Eq. 58**.

$$\Omega_{\text{3-pt GQ\_Mean\_PR 100\%}} = \left(0.02\times 1U\right)+\left(0.11\times 2U\right)+\left(0.87\times 3U\right)\text{..........................}\mathbf{(58)}$$

The P17/P83 ratio for Well 6 is equal to 113, and the P83/P17 ratio of the average of the wells is equal to 53. These values are very high, and indicate a large uncertainty in the PR. The results of this PR case are what we expected. We see that due to the uncertainty, the increased standard deviation shifts the volumes of hydrocarbon to the tail end of the distribution. We also see that the uncertainty of Well 6 is 113, and the uncertainty of the average of the wells is 53, meaning that these results are more uncertain than the previous ones with the 100 per cent increase of the standard deviation.

Fig. 32 presents the full range of the P17/P83 results for the 38 wells, with the minimum and maximum values highlighted.

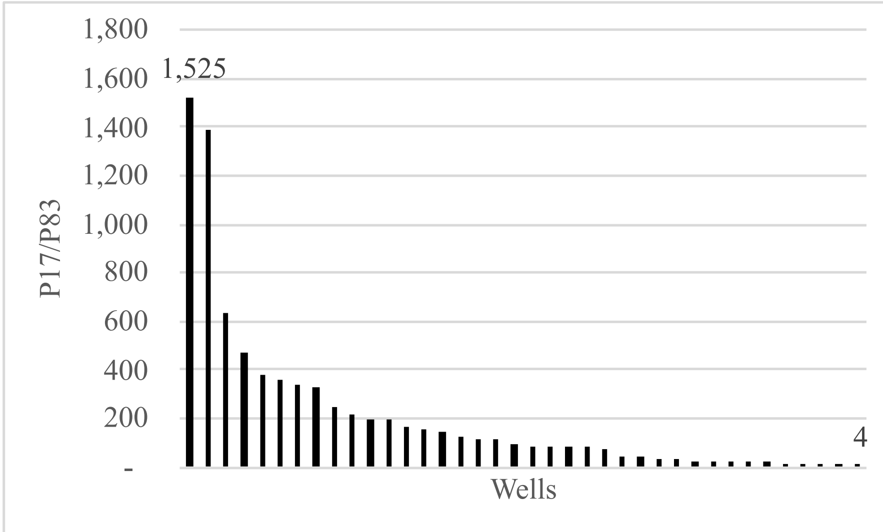

Figure 32 — P17/P83 ratios of the Prospective Resources with 100 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 1,525 and the minimum is 4.

We see that this range is very high, meaning that there is significant uncertainty in the P17, P67, and P83 values.

5-point GQ

The ratios are calculated using the same equation presented in Eq. 25, the results for Well 6 are presented in **Table 30**, and are defined in **Eq. 59**.

5-point	Weights	Percentiles	Ratio
P99	0.01	2	0%
P78	0.22	14	0.3%
P53	0.53	87	2%
P22	0.22	552	11%
P1	0.01	4284	87%

Table 30—The weights, percentiles, and ratios of the 5-point GQ of the Contingent Resources of Well 6, with a 50 per cent increase in the standard deviation.

$$\Omega_{\text{5-pt GQ\_Well6\_PR 100\%}} = (0 \times P99) + (0.003 \times P78) + (0.02 \times P53) + (0.11 \times P22) + (0.87 \times P1) \quad \text{.....................}\textbf{(59)}$$

The mean results of the 38 wells for the 5-point GQ are presented in **Eq. 60**.

$$\Omega_{\text{5-pt GQ\_Mean\_PR 100\%}} = (0 \times P99) + (0.01 \times P78) + (0.03 \times P53) + (0.13 \times P22) + (0.82 \times P1) \quad \text{.....................}\textbf{(60)}$$

The P22/P78 ratio for Well 6 is equal to 40, and the P22/P78 ratio of the average of the wells is equal to 22. As expected, these values are higher than those of the 90 per cent higher case. **Fig. 33** presents the full range of the P22/P78 results for the 38 wells, with the minimum and maximum values highlighted.

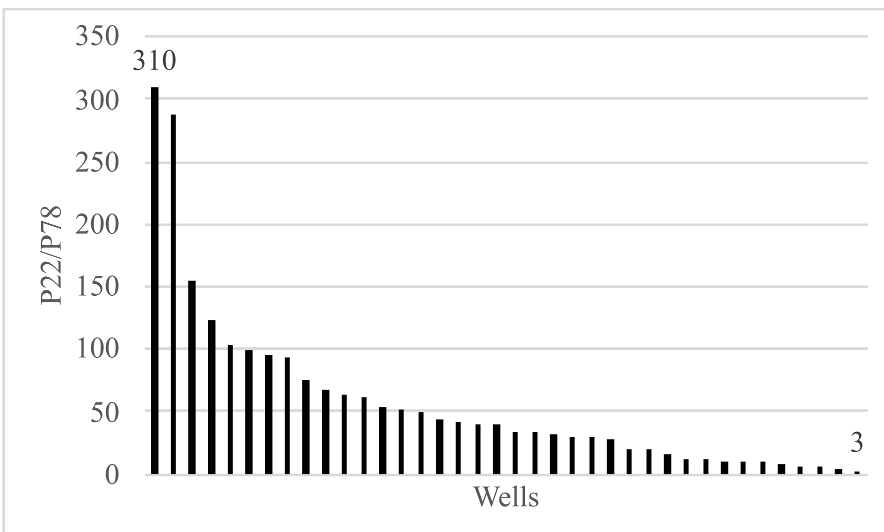

Figure 33 — P22/P78 ratios of the Prospective Resources with 100 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 310 and the minimum is 3.

From Fig. 33, we see that the range is slightly higher than that of the previous case (Fig. 33), however this increase is expected because of the increase in standard deviation.

10-point GQ

The ratios are calculated using the same equation presented in Eq. 25, the results for Well 6 are presented in **Table 31**, and are defined in **Eq. 61**.

10-point	Weights	Percentiles	Ratio
P100	4.3E-06	0	0%
P99	7.6E-04	1	0%
P98	0.02	3	0%
P86	0.14	12	0%
P66	0.34	45	0.1%
P34	0.34	168	0.2%
P14	0.14	642	0.8%
P2	0.02	2,576	3%
P1	7.6E-04	11,523	14%
P0	4.3E-06	65,903	81%

Table 31—The weights, percentiles, and ratios of the 10-point GQ of the Contingent Resources of Well 6, with a 100 per cent increase in the standard deviation.

$$\Omega_{\text{10-pt GQ\_Well6\_PR 100\%}} = (0\times P100)+(0\times P99)+(0\times P98)+(0\times P86)+ (0.001\times P66)+(0.002\times P34)+(0.008\times P14)+(0.032\times P2)+ (0.14\times P1)+(0.82\times P0) \quad \text{..................}\mathbf{(61)}$$

The mean results of the 38 wells for the 5-point GQ are presented in **Eq. 62**.

$$\Omega_{\text{10-pt GQ\_Mean\_PR 100\%}} = (0\times P100)+(0.001\times P99)+(0.001\times P98)+ (0.002\times P86)+(0.004\times P66)+(0.008\times P34)+(0.02\times P14)+ (0.05\times P2)+(0.15\times P1)+(0.77\times P0) \quad \text{..................}\mathbf{(62)}$$

The P14/P86 ratio for Well 6 is equal to 55, and the P14/P86 ratio of the average of the wells is equal to 29. **Fig. 34** presents the full range of the P14/P86 results for the 38 wells, with the minimum and maximum values highlighted.

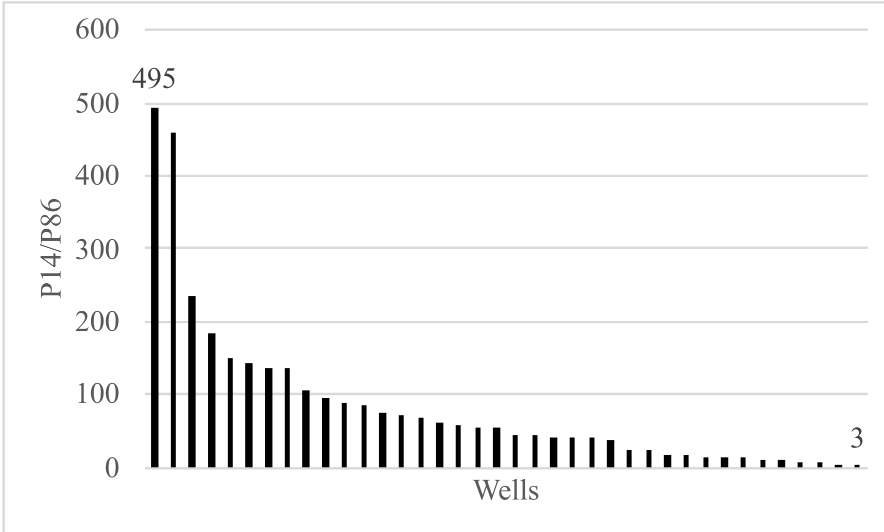

Figure 34 — P14/P86 ratios of the Prospective Resources with 100 per cent increase on the standard deviation, of the 38 wells in the Midland Basin, TX dataset. We see the maximum results if 495 and the minimum is 3.

From Fig. 34, we see that the range is higher than the previous case (Fig. 35) which is as expected because of the increase in standard deviation.

4.4.3.3.6 Comparing the 90 and 100 per cent Model Results

Table 32 shows a direct comparison of the results of the two cases for Well 6, and **Table 33** shows the direct comparison for the cases of the mean values. These tables allow for easier comparison of the results.

WELL 6		**90% Increase**			**100% Increase**		
3-point	**Weights**	**Percentiles**	**Ratio**	**P17/P83**	**Percentiles**	**Ratio**	**P17/P83**
P83	0.17	10	1%	87	8	1%	113
P67	0.67	90	10%		87	9%	
P17	0.17	841	89%		923	91%	

Table 32—Comparison of the weights, percentiles, and ratios of the 3-point GQ of the Prospective Resources of Well 6, with the 90- and 100 per cent increase in the standard deviation.

Mean		90% Increase			100% Increase		
3-point	Weights	Percentiles	Ratio	P17/P83	Percentiles	Ratio	P17/P83
P83	0.17	19	3%	43	17	2%	53
P67	0.67	99	12%		96	11%	
P17	0.17	830	85%		911	87%	

Table 33—Comparison of the weights, percentiles, and ratios of the 3-point GQ of the Prospective Resources of the mean of the 38 wells, with the 90- and 100 per cent increase in the standard deviation.

We see that the P83 and P67 percentiles and ratios decrease and the P17 percentile and ratio increase. Similarly we see that the P17/P83 ratios increase with the increase in standard deviation. These results are as expected, we see a greater shift to the tail end of the lognormal with the increased standard deviation, which is also represented in the P17/P83 ratio.

Table 34 shows a direct comparison of the results of the two cases for Well 6, and **Table 35** shows the direct comparison for the cases of the mean values. These tables allow for easier comparison of the results.

WELL 6		90% Increase			100% Increase		
5-point	Weights	Percentiles	Ratio	P22/P78	Percentiles	Ratio	P22/P78
P99	0.01	2	0.1%	33	2	0.0%	40
P78	0.22	16	0.4%		14	0.3%	
P53	0.53	90	2%		87	2%	
P22	0.22	518	12%		552	11%	
P1	0.01	3,587	85%		4,284	87%	

Table 34—Comparison of the weights, percentiles, and ratios of the 5-point GQ of the Prospective Resources of Well 6, with the 90- and 100 per cent increase in the standard deviation.

Mean		90% Increase			100% Increase		
5-point	Weights	Percentiles	Ratio	P22/P78	Percentiles	Ratio	P22/P78
P99	0.01	8	0.5%	19	7	0.4%	22
P78	0.22	27	1.3%		24	1.1%	
P53	0.53	99	4%		96	3%	
P22	0.22	501	14%		533	13%	
P1	0.01	4,307	80%		5,201	82%	

Table 35—Comparison of the weights, percentiles, and ratios of the 5-point GQ of the Prospective Resources of the mean of the 38 wells, with the 90- and 100 per cent increase in the standard deviation.

Similarly to the trend of the 3-point GQ, the 5-point percentiles and ratios decrease until the last weight, and we see a higher percentile and ratio in the P1 category. We notice that the P22/P78 ratios are significantly lower than the P17/P83 ratios, and is because we are taking a smaller range and taking the ratio of those values. We suspect that if the 5-point GQ provided weights closer to P90 and P10, the uncertainty ratio would be larger.

Table 36 shows a direct comparison of the results of the two cases for Well 6, and **Table 37** shows the direct comparison for the cases of the mean values. These tables allow for easier comparison of the results.

WELL 6		90% Increase			100% Increase		
10-point	Weights	Percentiles	Ratio	P14/P86	Percentiles	Ratio	P14/P86
P100	4.3E-06	0	0%	44	0	0%	55
P99	7.6E-04	1	0%		1	0%	
P98	0.02	4	0%		3	0%	
P86	0.14	14	0%		12	0%	
P66	0.34	48	0.1%		45	0%	
P34	0.34	168	0.3%		168	0%	
P14	0.14	597	1%		642	1%	
P2	0.02	2,218	4%		2,576	3%	
P1	7.6E-04	9,135	15%		11,523	14%	
P0	4.3E-06	47,447	80%		65,903	81%	

Table 36—Comparison of the weights, percentiles, and ratios of the 10-point GQ of the Prospective Resources of Well 6, with the 90- and 100 per cent increase in the standard deviation.

Mean		90% Increase			100% Increase		
10-point	Weights	Percentiles	Ratio	P14/P86	Percentiles	Ratio	P14/P86
P100	4.3E-06	2	0.0%	24	2	0.0%	29
P99	7.6E-04	5	0.1%		4	0.1%	
P98	0.02	11	0.2%		9	0.1%	
P86	0.14	24	0.3%		22	0.2%	
P66	0.34	60	0.5%		56	0.4%	
P34	0.34	171	1.0%		171	1%	
P14	0.14	580	2%		623	2%	
P2	0.02	2,443	5%		2,856	5%	
P1	7.6E-04	13,713	16%		17,674	15%	
P0	4.3E-06	122,586	75%		177,725	77%	

Table 37—Comparison of the weights, percentiles, and ratios of the 10-point GQ of the Prospective Resources of the mean of the 38 wells, with the 90- and 100 per cent increase in the standard deviation.

Similarly to the trend of the 3-point GQ, the 10-point percentiles and ratios decrease until the last weight, and we see a higher percentile and ratio in the P1 category. In this case, we see that the estimated P100, P99, P98, P86 percentile values are miniscule for both the cases and yield almost zero when calculating the ratios. This is particularly apparent for Well 6 with the 100 per cent increase on the standard deviation.

As expected, we see that the P14/P86 ratio increases with the increased uncertainty on the standard deviation. We notice particularly high ratios for Well 6, though they are not as large as the 3-point P17/P83 results.

The results of this work will aid entities in their internal reporting of ROTR because the PR and CR volumes are relatively unknown. Though we may know the area of the reservoir being analyzed, there is significant uncertainty in understanding the amount of hydrocarbon in the subsurface. By implementing the GQ, we can obtain volume estimates of the three categories of both PR and CR, and we can understand their relationship to each other by calculating the ratio of hydrocarbon that fall in each category. Not only have we understood how volumes from PR to CR from the flowcharts in Chapter 3, but now we can incorporate hydrocarbon volumes into the flowcharts.

The full set of the PR results for the remaining 37 wells of the 3-point, 5-point, and 10-point GQ are presented in **Appendix G.**

4.4.4 Validating the Gaussian Quadrature Results

We validate the Reserves results of the three cases of the GQ because we can compare these results to models built from the production data. We did not run probabilistic DCA or RTA to determine CR or PR because we do not have production data to input in the models. Based on the Reserves GQ results, we will determine if this approach is appropriate to estimate the ratios of Reserves and ROTR categories.

When compared to the probabilistic DCA results for Well 6 presented in **Eq. 63**, we found that the 3-point GQ underestimates the 1P ratio by 73 per cent, overestimates the 2P ratio by 0 per cent, and overestimates the 3P by 9 per cent.

$$\Omega_{\text{3-pt GQ\_Well6}} = \left(0.06 \times 1P\right) + \left(0.20 \times 2P\right) + \left(0.74 \times 3P\right) \quad \textbf{(63)}$$

We can say that these results of the 3-point GQ are acceptable. We must also keep in mind that we are not comparing the same values. We are truly comparing the P83 to P90, then P67 to P50, and the P17 to P10. However we can conclude that for this well, the GQ approximation is appropriate to determine the ratios of Reserves.

We perform the same analysis on the mean results of the 38 wells for the 3-point GQ and probabilistic DCA. The results of the average of the 38 wells of the 3-point GQ are presented in **Eq. 64**.

$$\Omega_{\text{3-pt GQ\_Mean}} = \left(0.07 \times 1P\right) + \left(0.20 \times 2P\right) + \left(0.67 \times 3P\right) \quad \textbf{(64)}$$

When compared with the probabilistic DCA results, presented in Eq. 51, we see that the 3-point GQ underestimates the 1P Reserves by 50 per cent, overestimates the 2P Reserves by 1 per cent, and overestimates the 3P Reserves by 6 per cent.

For the average the 38 wells in the University Lands, Midland Basin dataset, we can say that the results for the 2P and 3P ratios are acceptable. However, we see significant difference in the 1P results. It is important to note that here we only analyze 38 wells, and we see approximately a 50% difference on the 1P ratio result. We could incorporate an uncertainty factor in the calculation, however we do not have enough wells to build this with. We can conclude that these results are accurate for decision making, but a larger dataset would be more statistically significant. Furthermore, we do assume that these relationships are basin-specific, not unconventional reservoir-specific, and that they would change depending on the play analyzed.

To summarize, for Well 6:

- 50% difference between 3-point GQ and probabilistic DCA for 1P (6% vs. 12%)
- 0% difference between 3-point GQ and probabilistic DCA for 2P (20% vs. 20%)
- 9% difference between 3-point GQ and probabilistic DCA for 3P (74% vs. 67%)

To summarize, for the mean of the 38 wells in the Midland Basin dataset:

- 36% difference between 3-point GQ and probabilistic DCA for 1P (7% vs. 11%)
- 1% difference between 3-point GQ and probabilistic DCA for 2P (21% vs. 20%)
- 6% difference between 3-point GQ and probabilistic DCA for 3P (72% vs. 67%)

For both Well 6 and for the mean cases, we see that the GQ accurately estimates the 2P and 3P, but we see significant error in the 1P estimates. This error may be because we are not comparing P90 to P90, but P90 to P83.

We then compare the probabilistic DCA to SM results, and the 3-point GQ to the SM results determine if the GQ provides a more accurate representation of the ratio of Reserves in each category.

To summarize, for Well 6:

- 84% higher Reserves weights between DCA and SM for 1P (12% vs. 30%)

- 65% higher Reserves weights between DCA and SM for 2P (20% vs. 40%)
- 77% lower Reserves weights between DCA and SM for 3P (67% vs. 30%)

To summarize, for the mean of the 38 wells in the Midland Basin dataset:

- 90% lower Reserves weights between DCA and SM for 1P (11% vs. 30%)
- 62% lower Reserves weights between DCA and SM for 2P (21% vs. 40%)
- 77% higher Reserves weights between DCA and SM for 3P (68% vs. 30%)

To summarize, for Well 6:

- 136% lower Reserves weights between the 3-point GQ and SM for 1P (6% vs. 30%)
- 64% lower Reserves weights between 3-point GQ and SM for 2P (20% vs. 40%)
- 84% higher Reserves weights between 3-point GQ and SM for 3P (74% vs. 30%)

To summarize, for the mean of the 38 wells in the Midland Basin dataset:

- 126% lower Reserves weights between 3-point GQ and SM for 1P (7% vs. 30%)
- 61% lower Reserves weights between 3-point GQ and SM for 2P (20% vs. 40%)
- 82% higher Reserves weights between 3-point GQ and SM for 3P (67% vs. 30%)

The DCA results do demonstrate that the GQ more accurately represents the weights of Reserves distributed lognormally as compared to the SM method. Comparing the averages of the probabilistic DCA and GQ results with those from SM, we observe that the probabilistic DCA and 3-point GQ underestimate the 1P and 2P Reserves, and underestimate 3P Reserves.

Stated simply, the ratios based on the SM method are less accurate than those from the GQ method as the results of the SM method clearly show greater variation from our "truth case" (*i.e.*, the probabilistic DCA results). Furthermore, we see that the 1C, 2C, 3C, and 1U, 2U, and 3U Contingent and Prospective Resources from the 3-point GQ results are distributed in a similar way (because both are skewed, lognormal distributions like Reserves), but with greater variance that we implemented.

4.5 Summary of Key Points

The following is a summary of the key points of the results of this work:

- These distributions of Reserves and ROTR are important for planning and for resource inventorying for internal company use.
- The GQ method will aid entities in reporting Reserves in different categories to regulatory agencies, and allow for internal tracking of Reserves and ROTR.
- The GQ estimates of CR were very similar to those of Reserves when we increase the standard deviation by 20 per cent, meaning in cases with lower uncertainty, we can estimate the CR ratios based on the Reserves ratios
- The GQ estimates of CR when we increase the standard deviation by 50 per cent show significant increase in the 3C percentiles, and thus the ratios. We see that the 1C estimates are approximately half of those estimated from the CR case with only 20 per cent increase on the standard deviation.
- The GQ estimates of PR show an even more significant shift of the percentiles to the 3U category. The percentiles from this analysis are higher than CR and Reserves, but the majority of those lay in the 3U category.
- We conclude the "less accurate" status of the SM method
- This method can easily be recreated for any reservoir, conventional or unconventional.

5. DEVELOP AND DEFINE THE FUNCTIONAL RELATIONSHIPS ACROSS THE VERTICAL ELEMENTS OF THE PRMS MATRIX*

5.1 Introduction

In this chapter, we aim to provide a methodology that will allow evaluators to progress resources from classifications with lower chances of commerciality (COC) to classes with higher chances of commerciality. We and also to progress resources from categories with large uncertainty to categories with less uncertainty of eventual recovery. This is important to entities of all sizes for planning purposes because companies should track their resources regardless of project stage or size. Our methodology provides continuous tracking of volumes when moving from Prospective Resources (PR) to Contingent Resources (CR) to Reserves throughout the life of the project, and allows for more accurate Reserves reporting.

We begin this work with the relationship between the Reserves, CR, and PR categories in the PRMS matrix, modeled using the Gaussian Quadrature (GQ) presented in **Chapter 4**. We implement the COC presented by Etherington *et al.* (2010) to develop relationships between the vertical elements of the PRMS matrix using the 3-point GQ ratios. These values are user-defined; Etherington's values are used purely as an example to produce results for this work.

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We then develop functional relationships across the vertical elements of the PRMS matrix by including the event-variant movement across categories. These movements are presented extensively in **Chapter 3** of this dissertation, and discuss how volumes move between classes and categories. We show certain scenarios and provide examples, but these movements are project-dependent. It is at the engineer's discretion to evaluate what events will cause a change in class and category.

The ratios of CR and PR categories increases as we move down the PRMS matrix, which we accounted for in Chapter 3 by increasing the standard deviation of each class. We note that the COC is user-defined for every project, so the proposed relationships will differ for every project The time-rate of movement between categories also differs for every project; there is no "one-size-fits-all" solution. The COC changes for each project because the risks differ in each project and it is at the engineer's discretion to use the appropriate COC. Once the GQ has been implemented, we incorporate the COC to understand the relationship when these volumes are classified as Contingent and Prospective Resources.

5.2 Incorporating the Chance of Commerciality to the Gaussian Quadrature Results

In Chapter 3 we found that the average GQ results are implemented using a 3-point, 5-point, and 10-point GQ approximation to obtain the weights, percentiles, and ratios for the 1P, 2P, and 3P Reserves, 1C, 2C, and 3C CR, and 1U, 2U, 3U PR of each well.

As a reminder, we first determined the mean (μ) and standard deviation (σ) of the production data of each well. They then transformed the GQ from the normal distribution [-1,1] coordinates to the lognormal [a,b] coordinates. The *a*- and *b*-coordinates are user defined, and can range from [0,+∞], as these are the boundaries of the lognormal distribution. We did this for every well and took the arithmetic average to obtain the mean of the results of the 38 wells. **Eq. 65** through **Eq. 74** present the results of Well 6 and of the mean of the 38 wells for Reserves, CR, and PR.

The 3-point GQ results of the Reserves of Well 6 are:

$$\Omega_{\text{3-pt GQ\_Well6}} = \left(0.06 \times 1P\right) + \left(0.2 \times 2P\right) + \left(0.74 \times 3P\right) \quad \textbf{(65)}$$

The mean of the 38 wells using the 3-point GQ method results are:

$$\Omega_{\text{3-pt GQ\_Mean}} = \left(0.07 \times 1P\right) + \left(0.20 \times 2P\right) + \left(0.67 \times 3P\right) \quad \textbf{(66)}$$

The 3-point GQ results of the CR with 20 per cent increase on the standard deviation of Well 6 are:

$$\Omega_{\text{3-pt GQ\_Well6\_CR 20\%}} = \left(0.06 \times 1C\right) + \left(0.21 \times 2C\right) + \left(0.73 \times 3C\right) \quad \textbf{(67)}$$

The mean of the 38 wells of the 3-point GQ for CR with 20 per cent increase on the standard deviation are.

$$\Omega_{\text{3-pt GQ\_Mean\_CR 20\%}} = \left(0.08 \times 1C\right) + \left(0.22 \times 2C\right) + \left(0.7 \times 3C\right) \quad \textbf{(68)}$$

The 3-point GQ results of the CR with 50 per cent increase on the standard deviation of Well 6 are:

$$\Omega_{\text{3-pt GQ\_Well6\_CR 50\%}} = \left(0.03 \times 1C\right) + \left(0.15 \times 2C\right) + \left(0.82 \times 3C\right) \quad \textbf{(69)}$$

The mean of the 38 wells of the 3-point GQ for CR with 50 per cent increase on the standard deviation are.

$$\Omega_{\text{3-pt GQ\_Mean\_CR 50\%}} = \left(0.05\times 1C\right)+\left(0.17\times 2C\right)+\left(0.78\times 3C\right)\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\textbf{(70)}$$

The 3-point GQ results of the PR with 90 per cent increase on the standard deviation of Well 6 are:

$$\Omega_{\text{3-pt GQ\_Well6\_PR 90\%}} = \left(0.01\times 1U\right)+\left(0.1\times 2U\right)+\left(0.89\times 3U\right)\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\textbf{(71)}$$

The mean of the 38 wells of the 3-point GQ for PR with 90 per cent increase on the standard deviation are.

$$\Omega_{\text{3-pt GQ\_Mean\_PR 90\%}} = \left(0.03\times 1U\right)+\left(0.12\times 2U\right)+\left(0.85\times 3U\right)\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\textbf{(72)}$$

The 3-point GQ results of the PR with 100 per cent increase on the standard deviation of Well 6 are:

$$\Omega_{\text{3-pt GQ\_Well6\_PR 100\%}} = \left(0.01\times 1U\right)+\left(0.09\times 2U\right)+\left(0.91\times 3U\right)\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\textbf{(73)}$$

The mean of the 38 wells of the 3-point GQ for PR with 100 per cent increase on the standard deviation are.

$$\Omega_{\text{3-pt GQ\_Mean\_PR 100\%}} = \left(0.02\times 1U\right)+\left(0.11\times 2U\right)+\left(0.87\times 3U\right)\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\textbf{(74)}$$

In **Fig. 35** we present the elements of the PRMS matrix and show a visual representation of the vertical relationships we are trying to understand.

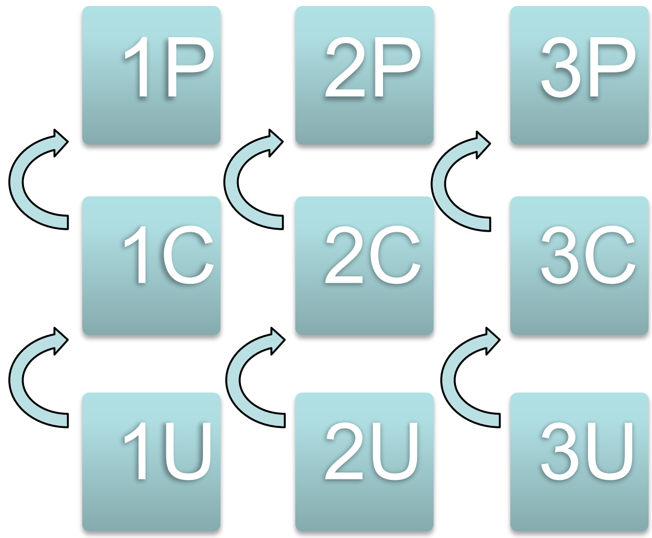

Figure 35 — Visual representation relating the elements of the PRMS matrix. The Contingent and Prospective Resources are assumed to have the same weight distributions as Reserves, but with decreased chance of commerciality. This figure serves to visually represent the relationships we are trying to understand (reprinted with permission from Moridis *et al.*, 2019, SPE 198296).

Beginning with Well 6, we incorporate the COC for PR, CR, and Reserves. We then do the same for the mean of the 38 wells. Neither PRMS nor SEC provide guidelines on how to determine the COC of a project, which makes it difficult to decide what the correct COC of a project is. Etherington *et al.* (2010) presented possible COC values, presented in **Fig. 36**, and state that these values are often based on qualitative interpretations.

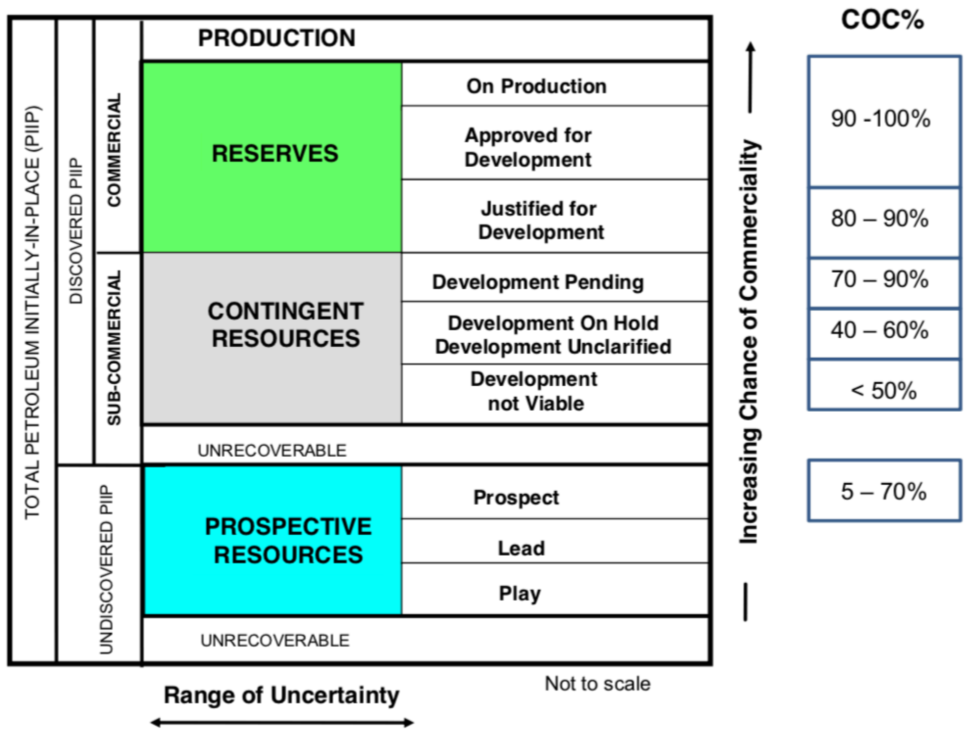

Figure 36 — PRMS classification matrix and quantification applied to PRMS subclasses (reprinted from Etherington *et al.*, 2010).

For the continuation of this work, we will implement the COC values from Fig. 38. The authors provide a range of possible COC for the different classifications, but to take this a step further, we will present three cases for each: high/medium/low COC for Reserves, Contingent Resources, and Prospective Resources. These three cases we propose for each volumes class are presented in **Table 38**.

Class		COC(%)
Reserves	High	100
	Medium	90
	Low	80
Contingent Resources	High	90
	Medium	65
	Low	40
Prospective Resources (only Prospect)	High	70
	Medium	30
	Low	5

Table 38— High, medium, and low COC values for each volumes class

We begin with our results for Reserves, CR, and PR that we defined in Eq. 65 through 74, and incorporate the COC. We now assign a new variable, Ξ, to define the equations for Reserves, CR, and PR with the COC. The general equation is presented in **Eq. 75.**

$$\Xi_{Method\_Well} = \Omega_{Method\_Well} COC \quad \textbf{(75)}$$

The equations for Reserves, CR, and PR of Well 6 and the mean of the 38 wells are presented in **Eq. 76** through **Eq. 85.**

$$\Xi_{\text{3-pt GQ\_Well6}} = \left[\left(0.06\times 1P\right)+\left(0.2\times 2P\right)+\left(0.74\times 3P\right)\right]COC_{\text{Reserves}} \quad \textbf{(76)}$$

$$\Xi_{\text{3-pt GQ\_Well6\_CR 20\%}} = \left[\left(0.06\times 1C\right)+\left(0.21\times 2C\right)+\left(0.73\times 3C\right)\right]COC_{CR} \quad \textbf{(77)}$$

$$\Xi_{\text{3-pt GQ\_Well6\_CR 50\%}} = \left[\left(0.03\times 1C\right)+\left(0.15\times 2C\right)+\left(0.82\times 3C\right)\right]COC_{CR} \quad \textbf{(78)}$$

$$\Xi_{\text{3-pt GQ\_Well6\_PR 90\%}} = \left[\left(0.01\times 1U\right)+\left(0.1\times 2U\right)+\left(0.89\times 3U\right)\right]COC_{PR} \quad \textbf{(79)}$$

$$\Xi_{\text{3-pt GQ\_Well6\_PR 100\%}} = \left[\left(0.01\times 1U\right)+\left(0.09\times 2U\right)+\left(0.91\times 3U\right)\right]COC_{PR} \quad \textbf{(80)}$$

Similarly, we have the following relationships for the mean of the 38 wells:

$$\Xi_{\text{3-pt GQ\_Mean}} = \left[\left(0.07\times 1P\right)+\left(0.20\times 2P\right)+\left(0.67\times 3P\right)\right]COC_{\text{Reserves}} \quad \textbf{(81)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_CR 20\%}} = \left[\left(0.08 \times 1C\right) + \left(0.22 \times 2C\right) + \left(0.7 \times 3C\right)\right] COC_{CR} \quad \textbf{(82)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_CR 50\%}} = \left[\left(0.05 \times 1C\right) + \left(0.17 \times 2C\right) + \left(0.78 \times 3C\right)\right] COC_{CR} \quad \textbf{(83)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_PR 90\%}} = \left[\left(0.03 \times 1U\right) + \left(0.12 \times 2U\right) + \left(0.85 \times 3U\right)\right] COC_{PR} \quad \textbf{(84)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_PR 100\%}} = \left[\left(0.02 \times 1U\right) + \left(0.11 \times 2U\right) + \left(0.87 \times 3U\right)\right] COC_{PR} \quad \textbf{(85)}$$

Now that we have the general equations for the relationship of each class, we will solve for each case and implement the COC for the three cases. The resulting relationships are presented in **Section 5.2.1** through **Section 5.2.3**.

5.2.1 Reserves Relationships

As stated in Table 38, we present a high, medium, and low cases of Reserves which include the COC. We see that when the COC is 100 per cent, the Reserves are on production. When the COC is 90 per cent, the Reserves are approved for development, so they are not fully commercial. Finally, we see that when the COC is 80 per cent, the Reserves are Justified for Development. These three cases are proposed by Etherington *et al.* (2010), and are presented as an example. These COC values are dependent on the project, and it is at the engineer's discretion to set these values. The results for Well 6 are presented in **Eq. 86** through **Eq. 88**, and the results of the mean of the 38 wells are presented in **Eq. 89** through **Eq. 91**.

$$\Xi_{\text{3-pt GQ\_Well6\_High}} = \left(0.06 \times 1P\right) + \left(0.2 \times 2P\right) + \left(0.74 \times 3P\right) \quad \textbf{(86)}$$

$$\begin{aligned} \Xi_{\text{3-pt GQ\_Well6\_Medium}} &= 0.9(0.06 \times 1P + 0.2 \times 2P + 0.74 \times 3P) \\ \Xi_{\text{3-pt GQ\_Well6\_Medium}} &= \left(0.054 \times 1P\right) + \left(0.18 \times 2P\right) + \left(0.666 \times 3P\right) \end{aligned} \quad \textbf{(87)}$$

$$\Xi_{\text{3-pt GQ\_Well6\_Low}} = 0.8(0.06\times 1P + 0.2\times 2P + 0.74\times 3P)$$
$$\Xi_{\text{3-pt GQ\_Well6\_Low}} = \left(0.048\times 1P\right) + \left(0.16\times 2P\right) + \left(0.592\times 3P\right) \quad \textbf{(88)}$$

We see that the ratios of the 1P, 2P, and 3P categories decrease for Well 6, and they change in direct relationship to the COC. This relationship is expected, and we see how much of an impact the COC has on the Reserves booked.

$$\Xi_{\text{3-pt GQ\_Mean\_High}} = \left(0.07\times 1P\right) + \left(0.20\times 2P\right) + \left(0.67\times 3P\right) \quad \textbf{(89)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_Medium}} = 0.9(0.07\times 1P + 0.20\times 2P + 0.67\times 3P)$$
$$\Xi_{\text{3-pt GQ\_Mean\_Medium}} = \left(0.063\times 1P\right) + \left(0.18\times 2P\right) + \left(0.603\times 3P\right) \quad \textbf{(90)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_Low}} = 0.8(0.07\times 1P + 0.20\times 2P + 0.67\times 3P)$$
$$\Xi_{\text{3-pt GQ\_Mean\_Low}} = \left(0.056\times 1P\right) + \left(0.16\times 2P\right) + \left(0.536\times 3P\right) \quad \textbf{(91)}$$

We see that the ratios of the 1P, 2P, and 3P categories decrease with the mean results, just like they do for the results of Well 6. What is important to note from these results is that even in Reserves, we see how much the COC will impact the

5.2.2 Contingent Resources Relationships

As stated in Table 38, we present a high, medium, and low cases of Contingent Resources which include the COC. We see that when the COC is 90 per cent, the CR are sub-classified as development pending. When the COC is 65 per cent, the CR are considered development on hold, or development unclarified. Finally, we see that when the COC is 40 per cent, the CR are considered development no viable. These three cases are proposed by Etherington *et al.* (2010), and are presented as an example. These COC values are dependent on the project, and it is at the engineer's discretion to set these values.

5.2.2.1 20 Per Cent Increase On The Standard Deviation Of The CR Relationships

The results for Well 6 are presented in **Eq. 92** through **Eq. 94**, and the results of the mean of the 38 wells are presented in **Eq. 95** through **Eq. 97**.

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_CR 20\%\_High}} &= 0.9(0.06\times 1C + 0.21\times 2C + 0.73\times 3C)\\ \Xi_{\text{3-pt GQ\_Well6\_CR 20\%\_High}} &= \left(0.054\times 1C\right)+\left(0.189\times 2C\right)+\left(0.657\times 3C\right)\end{aligned} \qquad \textbf{(92)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_CR 20\%\_Medium}} &= 0.65(0.06\times 1C + 0.21\times 2C + 0.73\times 3C)\\ \Xi_{\text{3-pt GQ\_Well6\_CR 20\%\_Medium}} &= \left(0.027\times 1C\right)+\left(0.95\times 2C\right)+\left(0.328\times 3C\right)\end{aligned} \qquad \textbf{(93)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_CR 20\%\_Low}} &= 0.4(0.06\times 1C + 0.21\times 2C + 0.73\times 3C)\\ \Xi_{\text{3-pt GQ\_Well6\_CR 20\%\_Low}} &= \left(0.024\times 1C\right)+\left(0.084\times 2C\right)+\left(0.292\times 3C\right)\end{aligned} \qquad \textbf{(94)}$$

We see that the ratios of the 1C, 2C, and 3C categories decrease for Well 6, and they change in direct relationship to the COC. This relationship is expected, and we see how much of an impact the COC has on the CR.

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_CR 20\%\_High}} &= 0.9(0.08\times 1C + 0.22\times 2C + 0.7\times 3C)\\ \Xi_{\text{3-pt GQ\_Mean\_CR 20\%\_High}} &= \left(0.072\times 1C\right)+\left(0.198\times 2C\right)+\left(0.63\times 3C\right)\end{aligned} \qquad \textbf{(95)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_CR 20\%\_Medium}} &= 0.65(0.08\times 1C + 0.22\times 2C + 0.7\times 3C)\\ \Xi_{\text{3-pt GQ\_Mean\_CR 20\%\_Medium}} &= \left(0.052\times 1C\right)+\left(0.14\times 2C\right)+\left(0.46\times 3C\right)\end{aligned} \qquad \textbf{(96)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_CR 20\%\_Low}} &= 0.4(0.08\times 1C + 0.22\times 2C + 0.7\times 3C)\\ \Xi_{\text{3-pt GQ\_Mean\_CR 20\%\_Low}} &= \left(0.032\times 1C\right)+\left(0.09\times 2C\right)+\left(0.28\times 3C\right)\end{aligned} \qquad \textbf{(97)}$$

We see that the ratios of the 1C, 2C, and 3C categories decrease with the mean results, just like they do for the results of Well 6. What is important to note from these results is how much the COC will impact the ratios and thus decreasing the amount of hydrocarbon estimated in Contingent Resources.

5.2.2.2 50 Per Cent Increase On The Standard Deviation Of The PR Relationships

The results for Well 6 are presented in **Eq. 98** through **Eq. 100**, and the results of the mean of the 38 wells are presented in **Eq. 101** through **Eq. 103**.

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_CR 50\%\_High}} &= 0.9(0.03\times 1C + 0.15\times 2C + 0.82\times 3C)\\ \Xi_{\text{3-pt GQ\_Well6\_CR 50\%\_High}} &= 0.027\times 1C + 0.135\times 2C + 0.7\times 3C\end{aligned} \quad \text{.......................}\textbf{(98)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_CR 50\%\_Medium}} &= 0.65(0.03\times 1C + 0.15\times 2C + 0.82\times 3C)\\ \Xi_{\text{3-pt GQ\_Well6\_CR 50\%\_Medium}} &= 0.014\times 1C + 0.068\times 2C + 0.35\times 3C\end{aligned} \quad \text{....................}\textbf{(99)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_CR 50\%\_Low}} &= 0.4(0.03\times 1C + 0.15\times 2C + 0.82\times 3C)\\ \Xi_{\text{3-pt GQ\_Well6\_CR 50\%\_Low}} &= 0.012\times 1C + 0.06\times 2C + 0.31\times 3C\end{aligned} \quad \text{.......................}\textbf{(100)}$$

As in the previous section, we see that the ratios of the 1C, 2C, and 3C categories decrease for Well 6, and they change in direct relationship to the COC. This relationship is expected, and we see how much of an impact the COC has on the CR.

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_CR 50\%\_High}} &= 0.9(0.05\times 1C + 0.17\times 2C + 0.78\times 3C)\\ \Xi_{\text{3-pt GQ\_Mean\_CR 50\%\_High}} &= \left(0.045\times 1C\right) + \left(0.15\times 2C\right) + \left(0.70\times 3C\right)\end{aligned} \quad \text{.....................}\textbf{(101)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_CR 50\%\_Medium}} &= 0.65(0.05\times 1C + 0.17\times 2C + 0.78\times 3C)\\ \Xi_{\text{3-pt GQ\_Mean\_CR 50\%\_Medium}} &= \left(0.033\times 1C\right) + \left(0.11\times 2C\right) + \left(0.51\times 3C\right)\end{aligned} \quad \text{..................}\textbf{(102)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_CR 50\%\_Low}} &= 0.4(0.05\times 1C + 0.17\times 2C + 0.78\times 3C)\\ \Xi_{\text{3-pt GQ\_Mean\_CR 50\%\_Low}} &= \left(0.02\times 1C\right) + \left(0.07\times 2C\right) + \left(0.31\times 3C\right)\end{aligned} \quad \text{.....................}\textbf{(103)}$$

We see that the ratios of the 1C, 2C, and 3C categories decrease with the mean results, just like they do for the results of Well 6. What is important to note from these results is how much the COC will impact the ratios and thus decreasing the amount of hydrocarbon estimated in Contingent Resources.

5.2.3 Prospective Resources Relationships

As stated in Table 38, we present a high, medium, and low cases of Prospective Resources which include the COC. In this case, all the volumes are considered prospects, and we present three cases within prospects. We present the 70 per cent, 30 per cent, and 5 per cent cases. These three cases are proposed by Etherington *et al.* (2010), and are presented as an example. These COC values are dependent on the project, and it is at the engineer's discretion to set these values.

5.2.3.1 90 Per Cent Increase On The Standard Deviation Of The PR Relationships

The results for Well 6 are presented in **Eq. 104** through **Eq. 106**, and the results of the mean of the 38 wells are presented in **Eq. 107** through **Eq. 109**.

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_PR 90\%\_High}} &= 0.7(0.01\times 1U + 0.1\times 2U + 0.89\times 3U) \\ \Xi_{\text{3-pt GQ\_Well6\_PR 90\%\_High}} &= \left(0.007\times 1U\right)+\left(0.07\times 2U\right)+\left(0.62\times 3U\right)\end{aligned} \quad \text{...................}\mathbf{(104)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_PR 90\%\_Medium}} &= 0.3(0.01\times 1U + 0.1\times 2U + 0.89\times 3U) \\ \Xi_{\text{3-pt GQ\_Well6\_PR 90\%\_Medium}} &= \left(0.003\times 1U\right)+\left(0.03\times 2U\right)+\left(0.27\times 3U\right)\end{aligned} \quad \text{..................}\mathbf{(105)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_PR 90\%\_Low}} &= 0.05(0.01\times 1U + 0.1\times 2U + 0.89\times 3U) \\ \Xi_{\text{3-pt GQ\_Well6\_PR 90\%\_Low}} &= \left(0.0005\times 1U\right)+\left(0.005\times 2U\right)+\left(0.045\times 3U\right)\end{aligned} \quad \text{..................}\mathbf{(106)}$$

We see that the ratios of the 1U, 2U, and 3U categories decrease for Well 6, and they change in direct relationship to the COC. This relationship is expected, and we see how much of an impact the COC has on the PR.

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_PR 90\%\_High}} &= 0.7(0.03\times 1U + 0.12\times 2U + 0.85\times 3U)\\ \Xi_{\text{3-pt GQ\_Mean\_PR 90\%\_High}} &= \left(0.021\times 1U\right)+\left(0.084\times 2U\right)+\left(0.595\times 3U\right)\end{aligned} \quad \text{………………...}\textbf{(107)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_PR 90\%\_Medium}} &= 0.3(0.03\times 1U + 0.12\times 2U + 0.85\times 3U)\\ \Xi_{\text{3-pt GQ\_Mean\_PR 90\%\_Medium}} &= \left(0.009\times 1U\right)+\left(0.036\times 2U\right)+\left(0.255\times 3U\right)\end{aligned} \quad \text{……..……...}\textbf{(108)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Mean\_PR 90\%\_Low}} &= 0.05(0.03\times 1U + 0.12\times 2U + 0.85\times 3U)\\ \Xi_{\text{3-pt GQ\_Mean\_PR 90\%\_Low}} &= \left(0.0015\times 1U\right)+\left(0.006\times 2U\right)+\left(0.043\times 3U\right)\end{aligned} \quad \text{……..……...}\textbf{(109)}$$

We see that the ratios of the 1U, 2U, and 3U categories decrease with the mean results, just like they do for the results of Well 6. What is important to note from these results is how much the COC will impact the ratios and thus decreasing the amount of hydrocarbon estimated in Prospective Resources.

5.2.3.2 100 Per Cent Increase On The Standard Deviation Of The PR Relationships

The results for Well 6 are presented in **Eq. 110** through **Eq. 112**, and the results of the mean of the 38 wells are presented in **Eq. 113** through **Eq. 115**.

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_PR 100\%\_High}} &= 0.7(0.01\times 1U + 0.09\times 2U + 0.91\times 3U)\\ \Xi_{\text{3-pt GQ\_Well6\_PR 100\%\_High}} &= \left(0.007\times 1U\right)+\left(0.063\times 2U\right)+\left(0.62\times 3U\right)\end{aligned} \quad \text{………………...}\textbf{(110)}$$

$$\begin{aligned}\Xi_{\text{3-pt GQ\_Well6\_PR 100\%\_Medium}} &= 0.3(0.01\times 1U + 0.09\times 2U + 0.91\times 3U)\\ \Xi_{\text{3-pt GQ\_Well6\_PR 100\%\_Medium}} &= \left(0.003\times 1U\right)+\left(0.027\times 2U\right)+\left(0.27\times 3U\right)\end{aligned} \quad \text{……...…… }\textbf{(111)}$$

$$\Xi_{\text{3-pt GQ\_Well6\_PR 100\%\_Low}} = 0.05(0.01\times 1U + 0.09\times 2U + 0.91\times 3U)$$
$$\Xi_{\text{3-pt GQ\_Well6\_PR 100\%\_Low}} = \left(0.0005\times 1U\right)+\left(0.0045\times 2U\right)+\left(0.045\times 3U\right) \quad \text{.....………} \ \mathbf{(112)}$$

We see that the ratios of the 1U, 2U, and 3U categories decrease for Well 6, and they change in direct relationship to the COC. This relationship is expected, and we see how much of an impact the COC has on the PR.

$$\Xi_{\text{3-pt GQ\_Mean\_PR 100\%\_High}} = 0.7(0.02\times 1U + 0.11\times 2U + 0.87\times 3U)$$
$$\Xi_{\text{3-pt GQ\_Mean\_PR 100\%\_High}} = \left(0.014\times 1U\right)+\left(0.077\times 2U\right)+\left(0.61\times 3U\right) \quad \text{.........………........} \mathbf{(113)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_PR 100\%\_Medium}} = 0.3(0.02\times 1U + 0.11\times 2U + 0.87\times 3U)$$
$$\Xi_{\text{3-pt GQ\_Mean\_PR 100\%\_Medium}} = \left(0.006\times 1U\right)+\left(0.033\times 2U\right)+\left(0.26\times 3U\right) \quad \text{…………….....} \mathbf{(114)}$$

$$\Xi_{\text{3-pt GQ\_Mean\_PR 100\%\_Low}} = 0.05(0.02\times 1U + 0.11\times 2U + 0.87\times 3U)$$
$$\Xi_{\text{3-pt GQ\_Mean\_PR 100\%\_Low}} = \left(0.001\times 1U\right)+\left(0.006\times 2U\right)+\left(0.045\times 3U\right) \quad \text{……………......} \mathbf{(115)}$$

As with the previous PR results, we see that the ratios of the 1U, 2U, and 3U categories decrease with the mean results, just like they do for the results of Well 6. What is important to note from these results is how much the COC will impact the ratios and thus decreasing the amount of hydrocarbon estimated in Prospective Resources.

5.2.4 Summarizing the Results in PRMS Matrices

To summarize these results, we present them to mimic the PRMS matrix. We first present the Well 6 results, with two matrices to include the two cases of CR and PR, and then the mean of the 38 wells, with two matrices to include the two cases of CR and PR.

5.2.4.1 Well 6 Results Presented in the PRMS Matrix

5.2.4.1.1 High Cases of Well 6 Presented in the PRMS Matrix

Table 39 presents the high case of Reserves, CR with 20 per cent increase in standard deviation, and PR with 90 per cent increase in standard deviation. In **Table 40** we present the second high case with the CR with 50 per cent increase in standard deviation, and the PR with 100 per cent higher standard deviation.

Reserves	6% x 1P	20% x 2P	74% x 3P
Contingent Resources (20%)	5.4% x 1C	19% x 2C	66% x 3C
Prospective Resources (90%)	0.7% x 1U	7% x 2U	62% x 3U

Table 39—High case of COC of Reserves, CR, and PR. We take the CR with 20 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 90 per cent increase on the standard deviation to account for the uncertainty of those volumes.

Reserves	6% x 1P	20% x 2P	74% x 3P
Contingent Resources (50%)	2.7% x 1C	14% x 2C	70% x 3C
Prospective Resources (100%)	0.7% x 1U	6% x 2U	64% x 3U

Table 40—High case of COC of Reserves, CR, and PR. We take the CR with 50 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 100 per cent increase on the standard deviation to account for the uncertainty of those volumes.

From Table 39, we see that the COC of the CR are similar to those of Reserves. The 1U COC is significantly lower than the 1P COC, as is the 2U COC. However we see very similar COC values between 3P, 3C, and 3U. These relationships validate that (1) that the COC of Prospective Resources are lower than both CR Reserves, and (2) the uncertainty is least on the left side, and highest on the right side of the PRMS matrix. We can validate this because the 1P, 1C, and 1U percentiles are lower than the 3P, 3C, and 3U.

In Table 40, we see that the COC of the 1C category is significantly lower than the one presented in Table 40. This is due to the added uncertainty that we incorporated tot this case, by increasing the standard deviation by 50 per cent. We notice that this increase impacts the COC of the 1C category the most, and this is due to the increase in standard deviation. As we presented in Chapter 4, the standard deviation impacts the shape of the lognormal PDF and CDF. What is most interesting to note from these results is that the uncertainty of the Contingent Resources and Prospective Resources mostly impacts the ratios of all the categories of the three classes, and the COC has a significantly lower impact on these volumes.

5.2.4.1.2 Medium Cases of Well 6 Presented in the PRMS Matrix

We now present the two medium cases. In **Table 41** we present the medium case of Reserves, CR with 20 per cent increase in standard deviation, and PR with 90 per cent increase in standard deviation. In **Table 42** we present the second high case with the CR with 50 per cent increase in standard deviation, and the PR with 100 per cent higher standard deviation. We present these tables with the respective percentages of each category.

Reserves	5.4% x 1P	18% x 2P	67% x 3P
Contingent Resources (20%)	2.7% x 1C	9% x 2C	33% x 3C
Prospective Resources (90%)	0.3% x 1U	3% x 2U	27% x 3U

Table 41—Medium case of COC of Reserves, CR, and PR. We take the CR with 20 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 90 per cent increase on the standard deviation to account for the uncertainty of those volumes.

Reserves	5.4% x 1P	18% x 2P	67% x 3P
Contingent Resources (50%)	1% x 1C	7% x 2C	35% x 3C
Prospective Resources (100%)	0.3% x 1U	3% x 2U	27% x 3U

Table 42—Medium case of COC of Reserves, CR, and PR. We take the CR with 50 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 100 per cent increase on the standard deviation to account for the uncertainty of those volumes.

From Table 41, we see that the COC of the 1C category is similar to those of Table 40 of the high case. However, we see that the 2C and 3C COC results are significantly lower than before. We see how the COC impacts the ratio of each category, and we see that all three categories are impacted in this case. This is not the trend we saw in the high case in the previous section.

In Table 42, we see a higher COC with both uncertainty cases greatly impacts the ratio of each category. The Reserves remain relatively consistent because they are, by definition, commercial. We see the greatest impact in the ratios of the PR categories, where the 1U ratio is less than 1.

5.2.4.1.3 Low Cases of Well 6 Presented in the PRMS Matrix

We now present the two low cases. In **Table 43** we present the medium case of Reserves, CR with 20 per cent increase in standard deviation, and PR with 90 per cent increase in standard deviation. In **Table 44** we present the second high case with the CR with 50 per cent increase in standard deviation, and the PR with 100 per cent higher standard deviation. We present these tables with the respective percentages of each category.

Reserves	4.8% x 1P	16% x 2P	59% x 3P
Contingent Resources (20%)	2% x 1C	8% x 2C	29% x 3C
Prospective Resources (90%)	0.1% x 1U	1% x 2U	4% x 3U

Table 43—Low case of COC of Reserves, CR, and PR. We take the CR with 20 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 90 per cent increase on the standard deviation to account for the uncertainty of those volumes.

Reserves	4.8% x 1P	16% x 2P	59% x 3P
Contingent Resources (50%)	1% x 1C	6% x 2C	31% x 3C
Prospective Resources (100%)	0.1% x 1U	0.5% x 2U	5% x 3U

Table 44—Low case of COC of Reserves, CR, and PR. We take the CR with 50 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 100 per cent increase on the standard deviation to account for the uncertainty of those volumes.

From Table 43, we see that the COC of the 1C category is similar to that of Table 41 of the medium case. The 2C and 3C ratios are also similar to those of Table 41. We also note that the results of the PR are not significantly lower than the previous case.

In Table 44, we see a higher COC with both uncertainty cases greatly impacts the ratio of each category. The Reserves remain relatively consistent because they are, by definition, commercial. We see the greatest impact in the ratios of the PR categories, where the 1U and 2U ratios are less than 1.

5.2.4.2 Mean of 38 Wells Presented in the PRMS Matrix

5.2.4.2.1 High Cases of the Mean of the 38 Wells Presented in the PRMS Matrix

Table 45 presents the high case of Reserves, CR with 20 per cent increase in standard deviation, and PR with 90 per cent increase in standard deviation. In **Table 46** we present the second high case with the CR with 50 per cent increase in standard deviation, and the PR with 100 per cent higher standard deviation. We present these tables with the respective percentages of each category.

Mean Reserves	7% x 1P	20% x 2P	67% x 3P
Mean Contingent Resources (20%)	7% x 1C	20% x 2C	63% x 3C
Mean Prospective Resources (90%)	2% x 1U	8% x 2U	60% x 3U

Table 45—High case of COC of Reserves, CR, and PR. We take the CR with 20 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 90 per cent increase on the standard deviation to account for the uncertainty of those volumes.

Mean Reserves	7% x 1P	20% x 2P	67% x 3P
Mean Contingent Resources (50%)	5% x 1C	15% x 2C	70% x 3C
Mean Prospective Resources (100%)	1% x 1U	8% x 2U	61% x 3U

Table 46—High case of COC of Reserves, CR, and PR. We take the CR with 50 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 100 per cent increase on the standard deviation to account for the uncertainty of those volumes.

From Table 45, we see that the COC of the CR are similar to those of Reserves. The only difference we see is between the ratios of the 3P and 3C results. We see a decrease in the ratios of the 1U and 2U categories, but we see that the 3U is very similar to 3P and 3C. We see again that the uncertainty plays the biggest role in the results of the ratios, and the COC does not impact the results as much when we consider a high case.

In Table 46, we see that the categories of Reserves and Contingent Resources are approximately the same, and most importantly we notice that the 3C COC is higher than the 3P. The remaining of the results are as expected and follow the same trend as the previous tables.

5.2.4.2.2 Medium Cases of the Mean of the 38 Wells Presented in the PRMS Matrix

We now present the two medium cases. In **Table 47** we present the medium case of Reserves, CR with 20 per cent increase in standard deviation, and PR with 90 per cent increase in standard deviation. In **Table 48** we present the second high case with the CR with 50 per cent increase in standard deviation, and the PR with 100 per cent higher standard deviation. We present these tables with the respective percentages of each category.

Mean Reserves	6% x 1P	18% x 2P	60% x 3P
Mean Contingent Resources (20%)	5% x 1C	14% x 2C	46% x 3C
Mean Prospective Resources (90%)	1% x 1U	4% x 2U	26% x 3U

Table 47—Medium case of COC of Reserves, CR, and PR. We take the CR with 20 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 90 per cent increase on the standard deviation to account for the uncertainty of those volumes.

Mean Reserves	6% x 1P	18% x 2P	60% x 3P
Mean Contingent Resources (50%)	3% x 1C	11% x 2C	51% x 3C
Mean Prospective Resources (100%)	1% x 1U	3% x 2U	26% x 3U

Table 48—Medium case of COC of Reserves, CR, and PR. We take the CR with 50 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 100 per cent increase on the standard deviation to account for the uncertainty of those volumes.

From Table 47, we see that the Contingent Resources are lower than the Reserves for all three categories, as are the Prospective Resources. These results are as expected and we see the impact of the COC and the uncertainty. They follow the trends noticed from the last sections. Similarly, we see the results of Table 48 that follow the same trends.

5.2.4.2.3 Low Cases of the Mean of the 38 Wells Presented in the PRMS Matrix

We now present the two low cases. In **Table 49** we present the medium case of Reserves, CR with 20 per cent increase in standard deviation, and PR with 90 per cent increase in standard deviation. In **Table 50** we present the second high case with the CR with 50 per cent increase in standard deviation, and the PR with 100 per cent higher standard deviation. We present these tables with the respective percentages of each category.

Mean Reserves	6% x 1P	16% x 2P	54% x 3P
Mean Contingent Resources (20%)	2% x 1C	8% x 2C	29% x 3C
Mean Prospective Resources (90%)	3% x 1U	9% x 2U	28% x 3U

Table 49—Low case of COC of Reserves, CR, and PR. We take the CR with 20 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 90 per cent increase on the standard deviation to account for the uncertainty of those volumes.

Mean Reserves	6% x 1P	16% x 2P	54% x 3P
Mean Contingent Resources (50%)	2% x 1C	7% x 2C	31% x 3C
Mean Prospective Resources (100%)	0.1% x 1U	1% x 2U	4% x 3U

Table 50—Low case of COC of Reserves, CR, and PR. We take the CR with 50 per cent increase on the standard deviation to account for the uncertainty of those volumes, and the PR with 100 per cent increase on the standard deviation to account for the uncertainty of those volumes.

In Tables 49 and 50, we see the most extreme cases. As with the low cases for Well 6, we see how low the PR COC results are, and when the PR has 100 per cent increase on the standard deviation, the 1U COC approaches 0.

These results are as expected – Prospective Resources are the most uncertain and least commercial, followed by Contingent Resources, and finally Reserves. These results only show three cases for each class of volumes, and it should be noted that there are several results between the presented results that are also accurate. Furthermore, these results are only examples based on Etherington's (2010) assumed COC, but these values should be input by the user. However, this methodology allows you to track Reserves and ROTR and see how these volumes move during the life of a project.

The full set of results of the remaining 37 wells are presented in **Appendix H.**

5.2.5 Movement of Volume, Mass, or Energy Across Categories

We have performed this work thus far in oilfield units, however in other countries hydrocarbon is reported differently. For example, in Russia they report units of energy, not barrels of oil.

Energy content varies from one oil to another, and is measured in combustion experiments in the laboratory. We present **Table 51** with different energy sources and their respective energy content in million British thermal units (MBTU).

Energy Source	Unit	Energy Content (MBTU)
Crude Oil	1 ton	28
Fuel Oil no.1	1 Bbl	5.8
Fuel Oil no.2	1 Bbl	6.0
Fuel Oil no.3	1 Bbl	6.0
Fuel Oil no.4	1 Bbl	6.1
Fuel Oil no.5	1 Bbl	6.2
Fuel Oil no.6	1 Bbl	6.4
Diesel Fuel	1 Bbl	5.8
Gasoline	1 Bbl	5.2
Natural Gas	1 Cubic Foot (cu.ft.)	950 - 1150 BTU

Table 51—Table of energy sources converted to energy content in MBTU (adapted from Engineering ToolBox, 2005).

The fuel oil no. 1 through no. 6 are defined as follows (Wikipedia, Fuel oil, 2020):

- Number 1 fuel oil is a volatile distillate oil intended for vaporizing pot-type burners. It is the kerosene refinery cut that boils off immediately after the heavy naphtha cut used for gasoline. This is also called coal oil, stove oil, and range oil.
- Number 2 fuel oil "is a distillate home heating oil. Trucks and some cars use similar diesel fuel with a cetane number limit describing the ignition quality of the fuel. Both are typically obtained from the light gas oil cut"
- Number 3 fuel oil "was a distillate for burners requiring low-viscosity fuel"
- Number 4 fuel oil "is a commercial heating oil for burner installations not equipped with preheaters. It may be obtained from heavy gas oil cut"
- Number 5 fuel oil "is a residual-type industrial heating oil requiring preheating to 77-104°C for proper atomization at the burners. It may be obtained from the heavy gas oil cut, or it may be a blend of residual oil with enough number 2 oil to adjust viscosity until it can be pumped without preheating"
- Number 6 fuel oil "is a high-viscosity residual oil requiring preheating to 104-127°C.

residual means the material remaining after the more valuable cuts of crude oil have boiled off. The residue may contain various undesirable impurities, including 2% water and 0.5% mineral soil. This fuel may be known as residual fuel oil (RFO)"

In Russia, "mazut is a residual fuel oil often derived from Russian petroleum sources and is either blended with lighter petroleum fractions or burned directly in specialized boilers and furnaces. It is also used as a petrochemical feedstock. In the Russian practice, though, "mazut" is an umbrella term roughly synonymous with the fuel oil in general, that covers most of the types mentioned above, except US grades 1 and 2/3, for which separate terms exist. This is further separated in two grades, "naval mazut" being analogous to US grades 4 and 5, and "furnace mazut", a heaviest residual fraction of the crude, almost exactly corresponding to US Number 6 fuel oil and further graded by viscosity and sulfur content" (Wikipedia, Fuel Oil, 2020). Understanding these relationships is important for reporting agencies in Russia.

We present the conversion to MBTU in Table 51, but if we want to convert the energy to kilowatt-hours (kWh), we use the conversion in **Eq. 116**.

$$1\ kWh = 3.412\ MBTU \qquad \textbf{(116)}$$

These conversions are linear, so the GQ results would be identical to those of in barrels, presented in Chapter 4.

Similarly to converting volume to energy, if we want to convert the volume of hydrocarbon to mass, we have to determine the density of hydrocarbon. The volume is inversely proportional to the density, so to calculate the mass of the hydrocarbon, we can use the conversion in **Eq. 117**.

$$mass = Volume * density \quad \text{(117)}$$

Again we see that the conversion is linear, so the Reserves and ROTR relationships will be the same as they are for volume and for energy. These results are important because whatever unit you are reporting in, the ratios of the relationships between the Reserves and ROTR categories will remain constant.

5.3 Modulate the Rate of Conversion Between Classes and Categories

In this section, we present an example of the time movements of ROTR. This example is only to show proof of concept, but the time of any project depends on the project, on the contingencies that each project must overcome, and the country in which they must be overcome. Certain countries have additional uncertain, such as political influences, that may delay the movement from ROTR to Reserves. This also depends on the play type, because each basin has different challenges. For example, unconventional reservoirs have a large uncertainty of properly estimating the Reserves because of the intricacies of the reservoir, and because the conventional equations do not apply. Deep water, offshore Gulf of Mexico (GoM) face different challenges, such as correctly identifying the net pay and accounting for geologic uncertainty associated with these projects.

There are five unique stages in oil and gas activity, which are exploration, appraisal, development, production, and decommissioning (Reporting Oil and Gas, 2016). In unconventional resources, there is very little time in the exploration phase, but in offshore projects, this phase takes years and is very costly. The exploration stage can last up to five years (Darko, 2014). If this exploration stage is successful, we move into the appraisal phase because we have decided that there is enough hydrocarbon in the field to be developed. The exploration phase also includes drilling the first well with successful hydrocarbon recovery, so we move from PR to CR in this phase.

In the appraisal phase, we want to “reduce the uncertainty or possibility of losses about the size of the oil or gas field and its properties” (Reporting Oil and Gas, 2016). In this stage, more wells are drilled and more geologic surveys are run to obtain more information about the field and the reservoir being produced. We can assume that we remain in Contingent Resources because the field has not yet been developed. The wells that have been drilled are producing and are not commercial because there is no profit at this stage of the project, so the volumes remain in Contingent Resources. However, those wells’ production profiles may act as analogs for the future planned wells. The appraisal phase can take between four and ten years to complete, depending on the project (Darko, 2014).

We move into the development stage and create a plan to develop the field by (1) formulating a plan to develop the hydrocarbon, (2) determining how many wells should be drilled for production, (3) understanding what production facilities are needed to transport the hydrocarbon and what the best export routes are. This phase of development can last up to ten years and can cost hundreds of billions of dollars for offshore projects, and significantly less for unconventional projects (Darko, 2014).

We move into the production stage where we extract the hydrocarbon from the field and the company begins making revenue from the production. In this stage we have moved into Reserves because not only is there production, but it is commercial. During this phase of the project, the company spends millions of dollars on operations, maintenance, and safe practices to avoid accidents that would harm the workforce and the environment. The production phase can last between 20 and 50 years for a conventional project (Darko, 2014), however deepwater offshore projects only last between five to ten years because of the high extraction costs (Planète-Énergies, 2015).

Finally, the project moves into the decommissioning phase, where facilities are removed and the sites are restored to their original conditions, or as close to as possible. This phase usually refers to offshore facilities, where platforms are moved and deconstructed. No hydrocarbon is produced in this phase, and no area is being evaluated, so we have completed the project (Reporting Oil and Gas, 2016). This phase can last between two to ten years, again depending on the project (Darko, 2014).

5.3.1 Moving Through Prospective Resources to Contingent Resources

From the five stages of oil and gas activity discussed, we can say that the exploration phase is where the volumes are in Prospective Resources. Recall Fig. 5 from Chapter 3, presented again in **Fig. 37**. This figure presents the steps necessary for volumes to become discovered, moving them from Prospective Resources to Contingent Resources. What this figure does not answer is: *How are these movements related through time?*

The PR sub-classes are presented on the left side of the figure to show how the undiscovered Resources are characterized as chance of discovery increases. Each step in the discovery process is labeled (1-3), eventually reaching a point where we determine whether the resources are undiscovered or discovered. We include also the CR sub-classes on the right side of the figure to reference where the discovered volumes land within the CR class, and how they progress to other classifications.

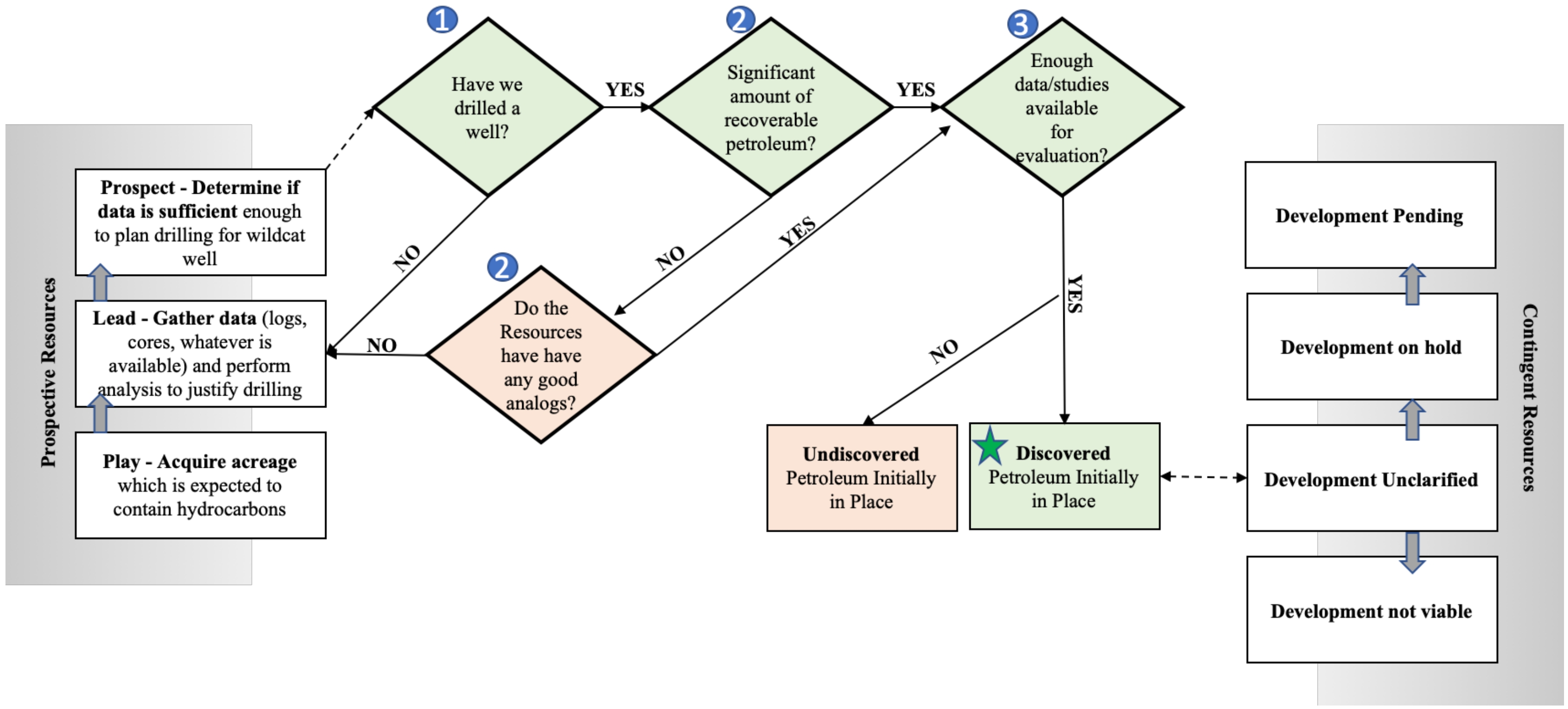

Figure 37 — A visual representation of a process that can be used to move from "undiscovered Resources" to "discovered." (reprinted with permission from Moridis *et al.* 2019, SPE 195298).

Looking at Fig. 37, moving through the three sub-classes of Prospective Resources represents the exploration phase of the project. Recall from Table 38 and Fig. 36 that the Play and Lead subclasses of PR are not commercial (COC=0). The Play subclass is where we acquire acreage, which we expect to contain hydrocarbon. If we are operating in an unconventional play, such as the Midland Basin, TX, we expect that the shale reservoir will contain hydrocarbon but will require specific technology to be produced (*i.e.:* hydraulic fracturing). As we move to the Lead subclass, where we gather data and perform the analysis to justify drilling, this step also takes little time in an unconventional. And finally, as we move into the Prospect subclass, where we decide if we have sufficient data to move forward to drill a wildcat well. These definitions are more specific to conventional reservoirs, and from our background we know that these three subclasses define the exploration phase. The exploration phase includes drilling the first well with successful hydrocarbon recovery, so we expect that the hydrocarbon becomes discovered. An oil and gas project can take between one to five years to move through the exploration phase, according to Darko (2014). This timeline is specific to a conventional project and is presented in **Fig. 38**.

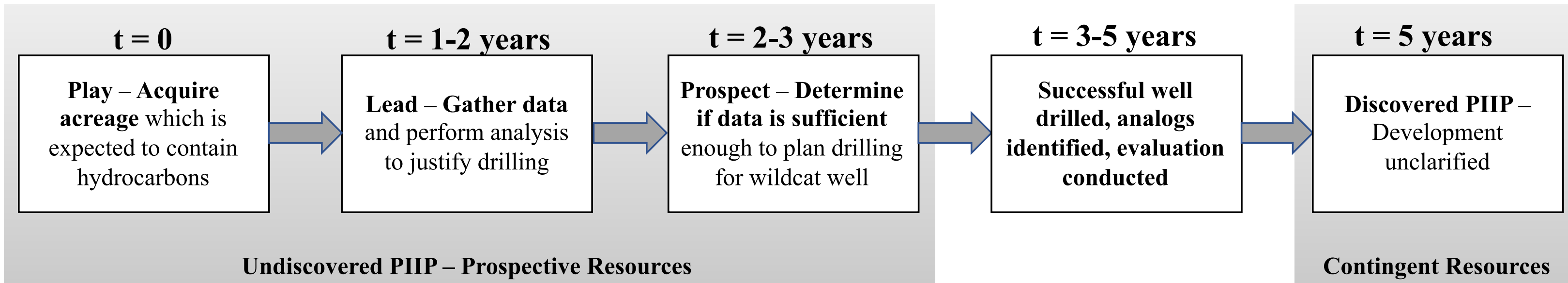

Figure 38 — Time to move through the Prospective Resources subclasses that are defined as the exploration phase of an oil and gas project.

The volumes move to the development unclarified subclass of Contingent Resources, so it takes up to five years to move through PR to make it to CR. We begin at the play subclass where we have acquired an acreage, but may not have a clear understanding of the size of the reservoir. As we gather more data to determine if we should drill a well, we obtain more information about the reservoir. We can begin to estimate the volume of hydrocarbon and make 1U, 2U, and 3U estimates. We notice that Fig. 40 does not specify the categories of PR, it moves through the subclasses to arrive to CR. However, we know that according to the PRMS matrix, the uncertainty decreases as we move to the right of the matrix, meaning that 3U volumes are the most uncertain and the 1U are the least uncertain of Prospective Resources. The 3U estimate includes volumes in the three subclasses, as do the 2U and 1U estimates, the difference being the amount of hydrocarbon in each category.

If this exploration stage is successful, we move into the appraisal phase because we have decided that there is enough hydrocarbon in the field to be developed.

5.3.2 Moving Through the Subclasses of Contingent Resources

From Fig. 37 and Fig. 38, we see that we have moved into the CR class of the PRMS matrix. We also discussed that we had completed the exploration phase of an oil and gas project, so we move into the appraisal phase. In this phase, more wells are drilled and more geologic surveys are run to obtain more information about the field and the reservoir being produced. We remain in CR because the field has not yet been developed. The wells that have been drilled are producing and are not commercial because there is no profit at this stage of the project, so the volumes remain in Contingent Resources. However, those wells' production profiles may act as analogs for the future planned wells. This phase can last between four and ten years, depending on the project (Darko, 2014). Once the appraisal phase is completed, we move into the development stage and create a plan to develop the field by formulating a plan to develop the hydrocarbon, determining how many wells should be drilled for production, and understanding what production facilities are needed to transport the hydrocarbon and what the best export routes are. During the development stage, we remain in CR. We combine the appraisal and development stages and aim to understand how they relate to the movement through the CR subclasses.

Recall Fig. 6 from Chapter 3, presented in **Fig. 39.** This figure presents the steps necessary to move through the subclasses of CR. What this figure does not answer is: *How are these movements related through time?*

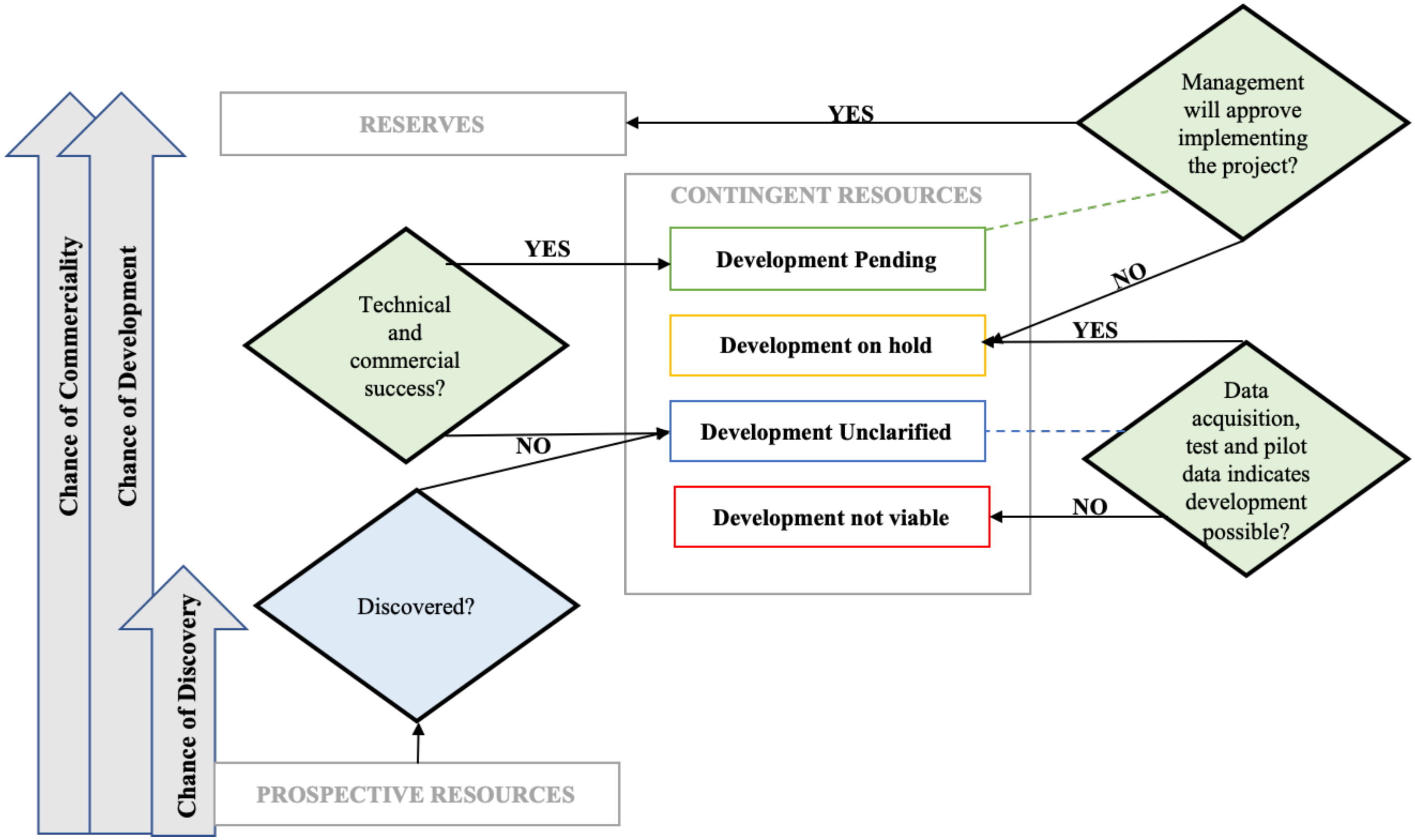

Figure 39 — A visual representation of progression of the chance of development/commerciality within the project maturity sub-classes of the Contingent Resources classification. (reprinted with permission from Moridis *et al.* 2019, SPE 195298).

This graphic shows the decisions that are made and the work done with each subclass, and how the outcome of those decisions affect the chance of development for given Resources.

We begin where Fig. 38 left off, we are at year 5 of the project, and we are now moving into the appraisal phase, as shown in **Fig. 40**. We begin with the discovered PIIP, which are defined as the development unclarified CR subclass.

As we move up the PRMS matrix, the chance of commerciality is dependent on both the chance of discovery times the chance of development (Eq. 2). Translating this to Fig. 40, the chance of development and of commerciality increase from the left to the right of the figure.

At 5 years, the volumes are discovered, but the chance of development and commerciality still remain low. At this stage of the project, the engineer has created the 1U, 2U, and 3U estimates of PR and we begin working to understand if these volumes can be moved in the CR class, and which remain in PR.

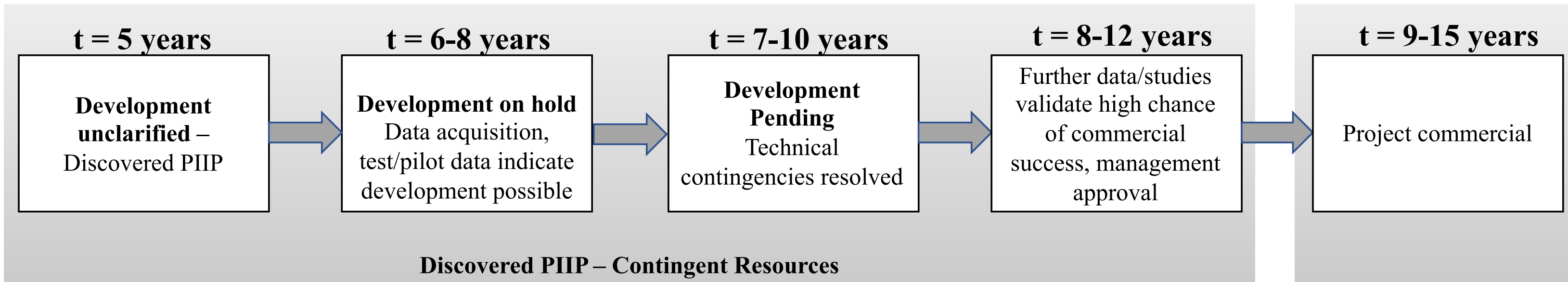

Figure 40 — Time to move through the Contingent Resources subclasses that are defined as the appraisal and development phases of an oil and gas project.

Once the volumes are discovered, we continue to gather more data to determine if development is possible. This stage includes creating a plan to develop the field, determining how many wells should be drilled, and what facilities are needed to transport the hydrocarbon. It may also include access to pipelines, either onshore or offshore, depending on the type of project. We estimate that this stage takes up to three years, and the volumes remain in the development on hold subclass of CR. If we can determine that development is possible, we also begin to pinpoint the areas that we want to develop. These volumes will be classified as CR, and the areas that we cannot currently develop will remain in PR.

Now that we have decided that development is possible, we must resolve the technical contingencies. We move into the developing pending subclass when we can resolve the technical contingencies of the project. This includes ensuring that the technology being implemented is established technology, as presented in Chapter 3, Fig. 7 and Fig. 8. This step includes the technology used to develop the field and used to evaluate the field (to drill and produce the field), but also ensuring that the technology is commercial. This step can take several months or several years, depending on the type of project. We present time ranges for conventional projects, but in unconventional projects, we expect that this step would be relatively quick. To drill in an unconventional reservoir, we require a horizontal well to connect to the maximum of the reservoir. To produce it, we rely on hydraulic fracturing to create a fracture with high permeability to connect the reservoir to the wellbore. It takes approximately 12 to 15 days to drill a well in the Permian Basin, (McEwen, 2018), and between three to five days to hydraulically fracture it (cred.org, 2016). In contrast, it can take up to a year to drill a single well in an offshore field (Diamond Offshore, 2019).

The last step before we can move this project into Reserves is determining if we need further data or if we need to run more studies to validate the analysis. This step includes finalizing the analysis to ensure the project is commercial and presenting it to management for their approval. Fig. 42 indicates that this step can take years, and again this depends on the project. An offshore, deepwater GoM would require significant review before moving forward. In contrast, an onshore unconventional project would not require much additional work.

Now that we have moved through the appraisal and development stages of a project, and we have understood the time it takes to make these movements, we will discuss the movements through Reserves subclasses and categories.

5.3.3 Moving Through the Reserves Categories

We move into the production stage of the project where we extract the hydrocarbon from the field and the company begins making revenue from the production. In this stage we have moved into Reserves because not only is there production, but it is commercial.

We have now moved the project from ROTR into Reserves, but we need to determine the timeline to move through the subclasses of Reserves. **Fig. 41** presents the three subclasses, and how they are separated.

Reserves are separated into three subclasses: on production, approved for development, and justified for development. However only the "on production" Reserves are developed volumes. There is little information on the time it takes to move through the Reserves subclasses. In Chapter 6 we discuss how to identify PUDs in relation to a horizontal well and its related 1P, 2P, and 3P Reserves. In this stage, we estimate the Reserves of the field. There does not seem to be a linear progression between the subclasses of the Reserves because certain steps do not need to be taken to move through these subclasses. For example, you drill a well and have your 1P, 2P, and 3P estimates, and have the PUD locations associated with this well. Those locations are justified for development, and then approved for development, and those locations can be produced once another well is drilled, or a secondary or tertiary recovery method is implemented that would produce the undeveloped areas.

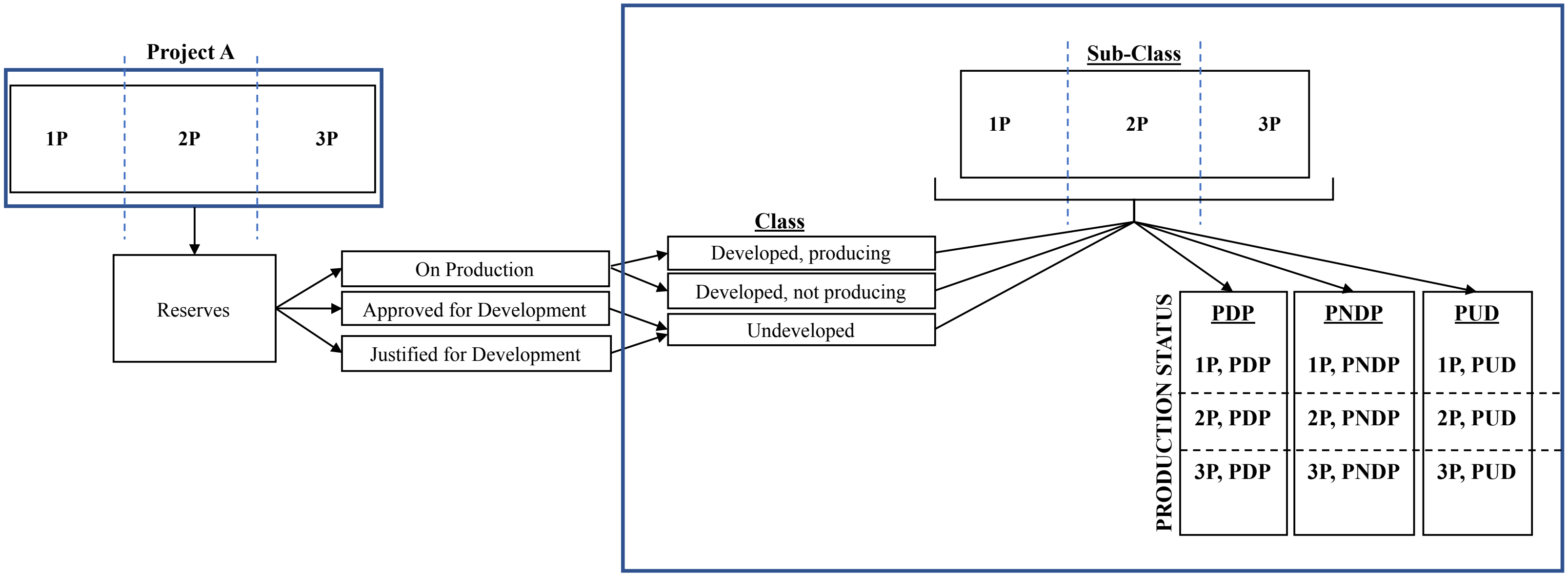

Figure 41 — Time to move through the Contingent Resources subclasses that are defined as the appraisal phase of an oil and gas project.

5.4 Summary of Key Points

The following are the key points are derived from the observations and results of this work:

- The COC impacts the ratio of Reserves and Contingent Resources, however we see the maximum impact in Prospective Resources
- The results of the high COC cases show that the uncertainty we place on the Contingent Resources and Prospective Resources is what mostly impacts the ratios of the categories of the three classes
- The low COC has a significantly higher impact on the volumes with higher uncertainty, where we see that ratios approach zero, especially for the PR cases
- Mass and energy are linearly related to volume, and we expect that the GQ ratios of mass and energy are identical to those of the volumes
- We propose the time to move through the subclasses of ROTR and Reserves, and discuss these movements in terms of the different phases of a project

6. UNDERSTANDING THE CONTINUITY OF RESERVES AND ROTR THROUGH TIME*

6.1 Introduction

This chapter has two objectives. The first is to understand how the well spacing impacts the EUR and the Reserves of horizontal wells in the subsurface. To determine the spatial well relationships that may trigger movements in certain regulatory frameworks, we first follow the Monograph 3 (SPEE, 2013) methodology. We then create diagrams that show the 1P, 2P, and 3P Reserves and the PUD locations in relation to a horizontal well. These visual representations help in understanding where the volumes are located both in gun-barrel view and aerial view. We performed a literature review to understand how the well spacing impacted the estimated ultimate recovery (EUR) and Reserves of horizontal wells in the Wolfcamp A, and used the results to build three theoretical well spacing cases with wells from our dataset.

Once we understand how the well spacing impacts recoverable volumes, we create a model which includes the production history and the forecasted EURs. We perform a two-segmented decline curve analysis (DCA) to determine the EUR and Reserves for the 38 wells in our dataset. To do this, we identify the different flow regimes using diagnostic plots.

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*Parts of this chapter are reprinted with permission from *Estimating Reserves and Tracking the Classification of Reserves and Resources Other than Reserves (ROTR) in Unconventional Reservoirs* by Nefeli Moridis, Valerie Jochen, W. John Lee, Wayne Sim, and Thomas Blasingame, 2019. Society of Petroleum Engineers, American Association of Petroleum Geologists, and Society of Exploration Geologists, Conference Paper URTeC 336, Copyright 2019 by the Society of Petroleum Engineers, American Association of Petroleum Geologists, and Society of Exploration Geologists.

We match the first segment that is in linear flow with a *b*-factor of 2 (or slightly less than 2 if not "perfectly" linear), and the second segment that is boundary dominated flow (BDF) with a *b*-factor of 0.3 (Fetkovich, 1987) using the full dataset. We then perform the same analysis with a truncated dataset and we use the two sets of EUR and Reserves results to determine the Reserves actually booked. The continuity of the model through time will track the volumes, and it needs to be able to do so consistently.

For the purpose of this work, to determine how PUDs can be moved to 1P Reserves, we focus on the direct offsets of producing wells.

6.2 Well Spacing Sensitivity Analysis

This part of research focuses on well spacing sensitivity analysis. We began by determining the well placement at the surface, and performed a literature review of sensitivity analyses done in the Wolfcamp A field of the Midland Basin, which is where our wells are located. We set up three example cases to determine how the volumes are currently classified. We then discussed the movements that would cause volumes to be re-classified or re-categorized as Reserves or ROTR.

6.2.1 Sensitivity Analysis On Well Placement To Determine The Spatial And Proximity Relationships

We determined the surface locations of the wells in the provided dataset. We were only provided production data so we supplemented the dataset using Enverus DrillingInfo to obtain latitude, longitude, and lateral length data. From this we determined the surface distance between the wells by converting the latitude and longitude to feet. Unfortunately, surface locations do not translate to subsurface spacing or well pattern, so we based the sensitivity analysis on previous spacing studies done in the region. **Fig. 44** shows the spatial surface relationship between the different blocks of wells on a latitude vs. longitude graph.

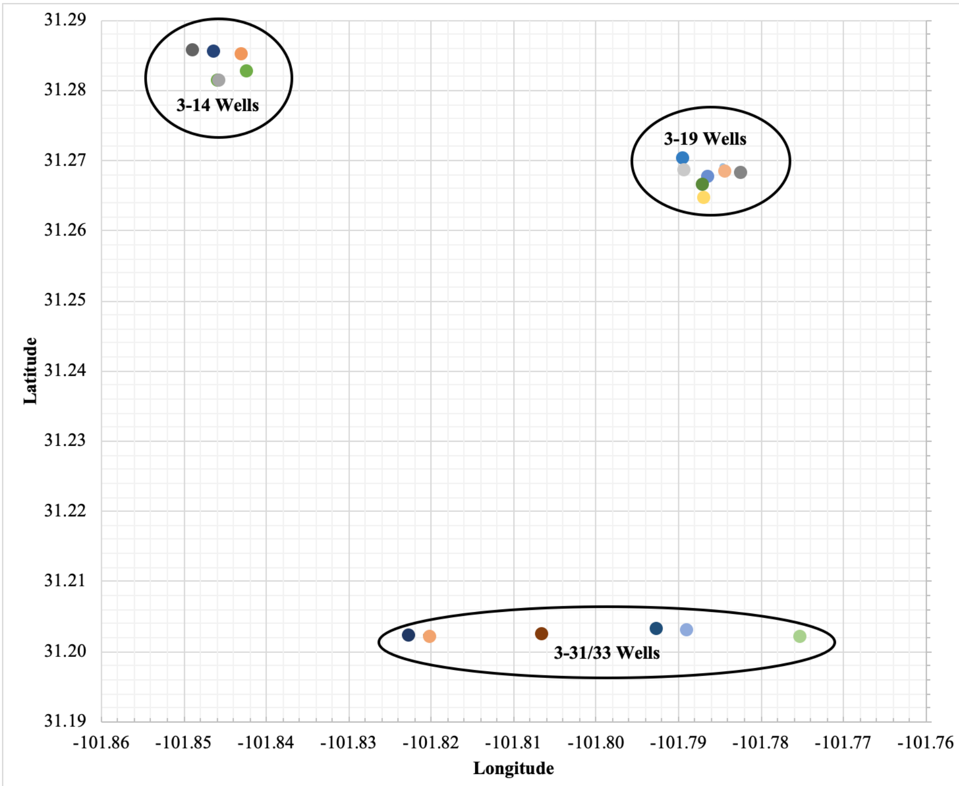

Figure 42 — Well locations of the 38 wells in the Midland Basin, TX presented in on a latitude vs. longitude plot. The 3-14 and 3-19 blocks each have 14 wells, and the 3-31/33 blocks have 10 wells

With the data provided, we can assume that the 3-14 and 3-19 blocks have fourteen wells per lease, the 3-31 and 3-32 blocks have two wells per lease, and the 3-33 well cluster has six wells per lease. **Appendix A** provides more detailed maps that show specific well locations of each block.

We calculated the distance between wells by converting the longitude and latitude to feet with **Eq. 118** (BlueMM, 2007) to validate that the wells were part of the same lease. We see that if they are located near each other they were drilled on the same pad and thus can be grouped together.

$$\begin{aligned}&\text{Distance}_{miles} = ACOS(COS(RADIANS(90-Lat1))*COS(RADIANS(90-Lat2))+\\&SIN(RADIANS(90-Lat1))*SIN(RADIANS(90-Lat2))*\\&COS(RADIANS(Long1-Long2)))*3958.756\end{aligned} \quad \text{.....}\mathbf{(118)}$$

To then convert the distance to feet, we use the conversion in **Eq. 119**.

$$\text{Distance}_{feet} = \text{Distance}_{miles} * 5{,}280\frac{ft}{miles} \quad \ldots\ldots\ldots\mathbf{(119)}$$

where,

Lat1	=	Latitude of well 1
Lat2	=	Latitude of well 2
Long1	=	Longitude of well 1
Long2	=	Longitude of well 2
3958.756	=	Earth’s radius, miles

The results of the distances between the wells are presented in **Table 52**.

Block	Distance Between	Distance (ft)
Univ 03-14	Wells 1-2	30
	Wells 2-3	30
	Wells 5-6	60
	Welsl 7-8	30
	Welsl 8-9	30
	Well 10-11	30
	Wells 12-13	30
	Wells 13-14	30
Univ 03-19	Wells 15-16	30
	Wells 16-17	30
	Wells 18-19	45
	Well 20-21	45
	Wells 22-23	30
	Wells 23-24	30
	Wells 25-26	190
Univ 03-31	Wells 29-30	4,296
Univ 03-32	Wells 31-32	4,341
Univ 03-33	Wells 33-34	30
	Wells 34-35	30
	Wells 36-37	30
	Wells 37-38	30

Table 52—The calculated surface distances between the wells in each block of the dataset.

Now that we have determined the surface relationships of our given wells, we focus on understanding how well spacing impacts the estimated ultimate recovery (EUR). Zhu *et al.* (2017) present results of well spacing based on a 70% and a 50% completion efficiency. These results are representative of industry publications that "measure cluster efficiency using fiber optic sensing or production logs." Assuming that the fracture half-length is 220 ft for the 70% completion efficiency case and 280 ft for the 50% completion efficiency case, they found that the EUR per lease section increases as well spacing decreases, but there is a point of "diminishing returns". This is presented in **Fig. 43**, which was recreated from Zhu's paper.

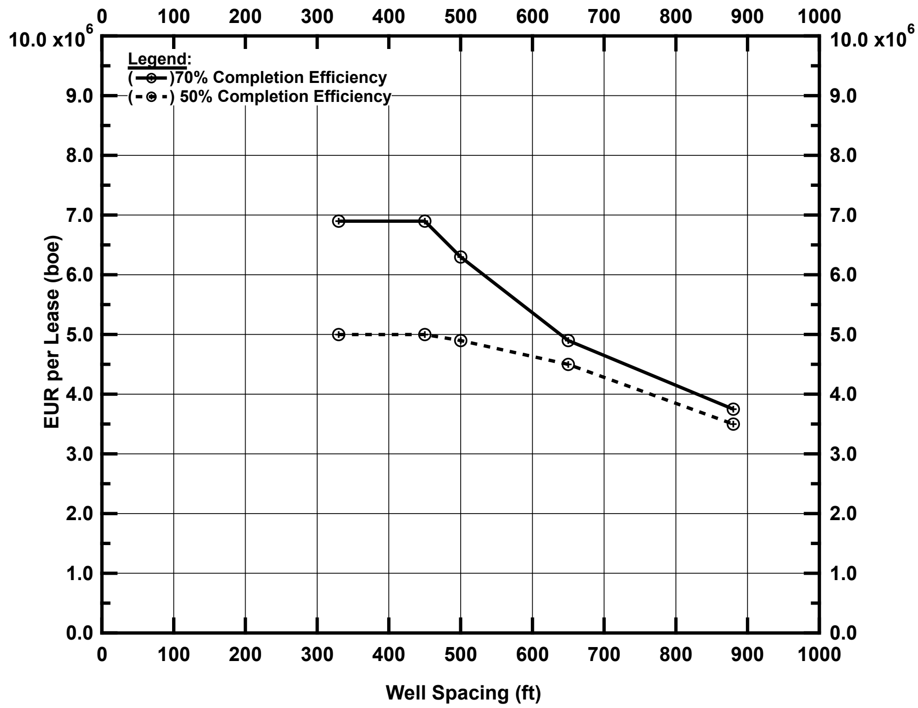

Figure 43 — The EUR per lease increases as well spacing decreases, but we see that at approximately 450 ft, the EUR begins to plateau. These results indicate that the optimal well spacing for recovery in the Wolfcamp A is approximately 450 ft, which is double the fracture half length (adapted from Zhu *et al.*, 2017, Fig. 17).

Lower well spacing means there are more wells drilled in a section, which is very expensive. Ideally, we want to optimize the spacing to produce the maximum amount of hydrocarbon but by keeping costs low. Fig. 43 shows that the optimal well spacing in the Wolfcamp A is 450 ft. The EUR remains the same for the 330 ft and 450 ft well spacing, meaning less money is spent on drilling wells but the estimated recoverable hydrocarbon is the same. We also see that with increasing well spacing, the EUR decreases significantly, meaning that a significant amount of hydrocarbon is left in the reservoir. We use these results in **Section 6.3.1.3** to demonstrate how the spacing impacts 1P, 2P, and 3P Reserves, and how PUDs can be moved to 1P Reserves. We present three theoretical cases and use the 450 ft well spacing as the best case.

6.2.2 Monograph 3 (SPEE 2013) Guidelines

The SPEE Monograph 3 recommends a maximum number of PUD offsets per producing well for both vertical and horizontal wells based on the phase of development, presented in **Table 53**.

	PHASE OF RESOURCE PLAY DEVELOPMENT			
	Early	**Intermediate**	**Statistical**	**Mature**
Recommended maximum number of PUD offsets per producing well (vertical wells)	4	8	Statistical	Statistical
Recommended maximum number of PUD offsets per producing well (horizontal wells)	2-4	4-8	Statistical	Statistical

Table 53—Recommended maximum number of PUD offsets at various stages of resource play development (reprinted from SPEE 2013, Fig. 3.4)

We focus on the horizontal well recommendations provided by SPEE because all our wells are horizontal. From Table 55, the early phase PUD values " reflect the *traditional* evaluation practice of assigning PUDs to a one-offset location." In the intermediate phase, well count and control has increased, and the number PUDs doubles. Statistical analysis is meaningful only once enough wells are drilled, so these methods can be used when the play enters the statistical phase. “Eventually the Resource Play enters the mature phase. At this point, many undrilled locations are one-offset locations.” (SPEE 2013, p. 43).

The Midland Basin had reached peak oil in the early 1970s but with advancements in hydraulic fracturing and horizontal drilling, it exceeded this peak in 2018. It accounts for 35% of the oil production and 9% of the gas production in the United States (EIA 2019). In October 2018, the Midland Basin had 16,889 producing wells (Coyne, 2019). Because the Midland Basin has been produced for this long, we categorize it in mature development, and so the undrilled locations are one-offset locations, meaning they can be considered PUDs. Furthermore, SPEE states that “it seems reasonable to assign PUDs at a distance of 2 or perhaps 3 development spacings away from proven developed producing (PDP) wells as long as these PUD locations are bounded by other PDP wells” (SPEE, p. 43). **Fig. 44** and **Fig. 45** provide a visual representation of the PUD locations in relation to the producing well in gun barrel view, and in cross-section, respectively.

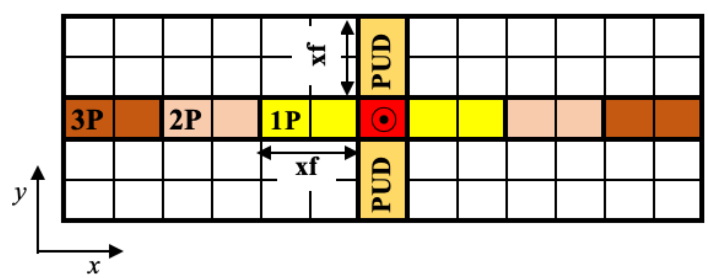

Figure 44 — Gun-barrel view of the well where the red box in the center of the figure represents the well. The 1P, 2P, and 3P Reserves are to the right and left of the wellbore in the x-direction, and the PUD volumes are above and below the well in the y-direction.

Based on Monograph 3 (SPEE, 2013), we found that the horizontal wells have four PUD locations. Two are shown above and below the wellbore, as presented in Fig. 45. The other two locations are located to the on either side of the lateral, as presented in Fig. 46.

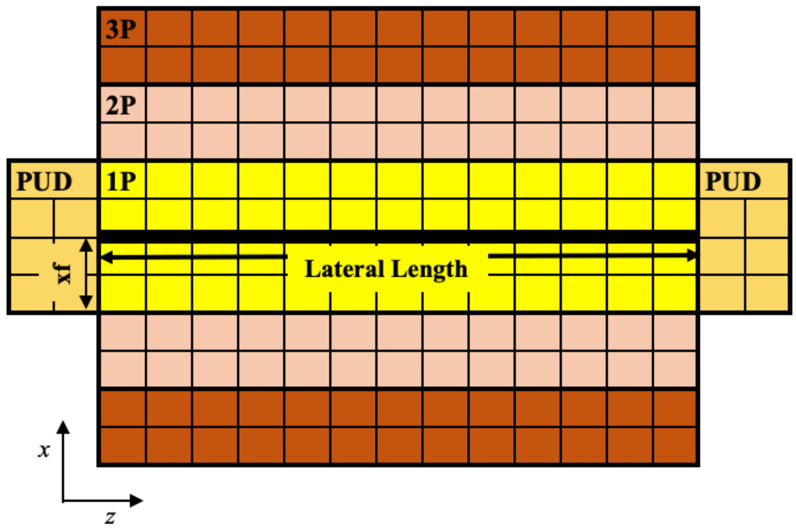

Figure 45 — Cross-section of the well location, represented by the bold line. The proved reserves (1P) in yellow, the probable reserves in orange, and the possible reserves in brown are in the *x*-direction. The PUD locations are in dark yellow on either side of the wellbore in the *z*-direction. This cross-section is for one well to illustrate how the volumes are distributed.

From Fig. 45 and Fig. 46, we see that the 1P locations are two blocks from the well, and we set this to be the fracture half-length (x_f). The size of the development blocks depends on the fracture half-length so it will change for every well, and this must be determined by the engineer.

Similarly, the 2P locations are an additional 2 blocks from the 1P, and the 3P locations are two additional blocks from the 2P. The orange area represents the incremental P2 volume (probable Reserves), and the 2P Reserves=1P+P2. The brown area represents the incremental P3 volume (possible Reserves), and the 3P Reserves=2P+P3. The size of each block changes for every well

6.2.3 Movements In Regulatory Frameworks

From Zhu *et al.*'s results, we build three theoretical cases of what the wells look like in the subsurface. We use the 70% completion efficiency results, the 220 ft fracture half length, and Wells 5 and 6 in the Midland Basin. These two wells are drilled 60 ft from each other at the surface (presented in Table 54 and graphically in Appendix A). Please note that these diagrams are not to scale, and are only intended to illustrate the design of each case.

6.2.3.1 Case 1 – 450 ft Well Spacing

The first case we discuss is with a well spacing of 450' in the subsurface. **Fig. 46** provides a visual representation of this, where the distance between the wells is 450 ft, and the fracture half-length is assumed to be 220 ft (as per Zhu *et al.,* 2017).

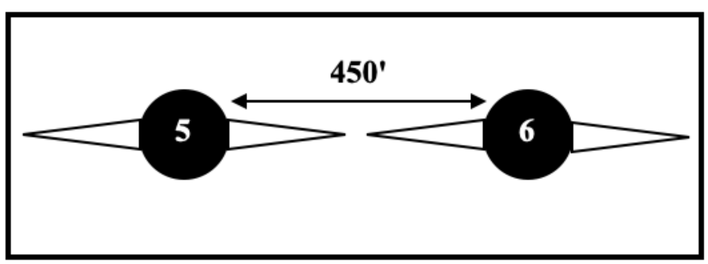

Figure 46 — Wells 5 and 6 with 450 ft well spacing. The triangles are representative of the fracture half-length, assumed to be 220 ft.

We consider this spacing to be optimal based on the results from Zhu *et al.* (2017), presented in Fig. 43. Our evaluation, using a two-segment decline curve analysis (DCA) approach, is presented in depth in the following section. We obtained the following results, presented in **Table 54**, for the 1P, 2P, and 3P EUR and Reserves as of August 1, 2019. The cumulative production of each well through August 1, 2019 is also presented in Table 54.

		Well 5	Well 6
Cumulative Production as of Aug-1-2019 (Mbbl)		106	136
EUR (Mbbl)	**1P**	153	206
	2P	234	299
	3P	355	370
Reserves (Mbbl) as of Aug-1-19	**1P**	46	69
	2P	128	163
	3P	249	234

Table 54—1P, 2P, and 3P EUR and Reserves (as of 8/1/2019) results for wells 5 and 6 in the 3-14 block of the Midland Basin, TX.

Fig. 47 presents these results in graphical form to better relate the EUR and Reserves results.

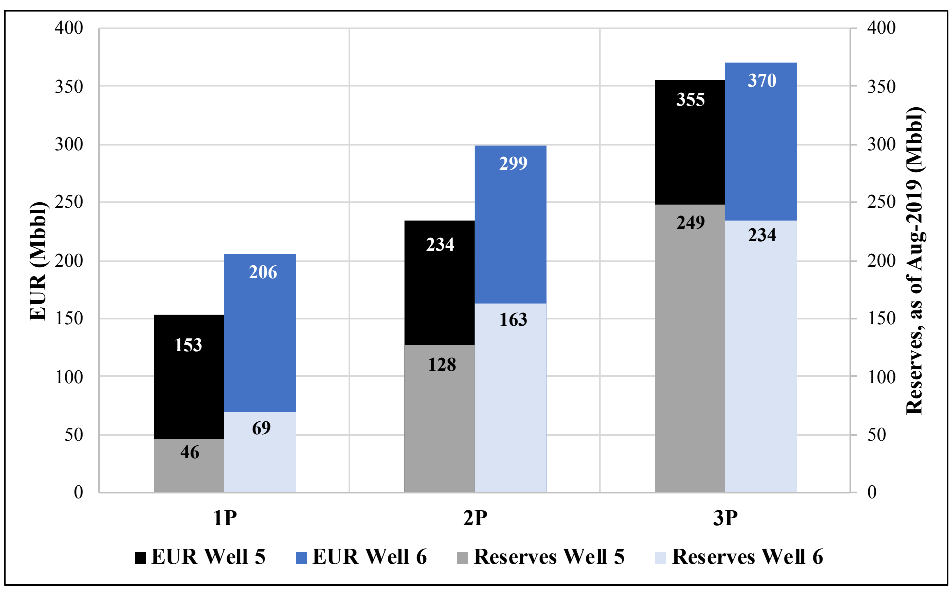

Figure 47 — 1P, 2P, and 3P Reserves vs. EUR for wells 5 and 6 from block 03-14 of the Midland Basin, TX.

From these results, we see that there are considerable Reserves remaining as of August 2019. Without running an economic analysis to know the specific monetary value, we can assume that these two wells are profitable because of the amount of the 1P results. The 1P result is the most important number because it is the volume reported to the SEC and is used to determine a company's value, so we will focus on the 1P results throughout this work.

Fig. 48 and **Fig. 49** show the areal extent of these volumes based of the example provided in Fig. 44 and Fig. 45.

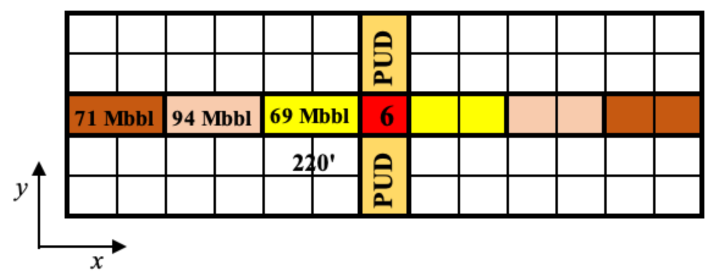

Figure 48 — Well 6, denoted by the red box at the center, with the 1P Reserves in yellow, the probable reserves in orange (2P-1P), and the possible reserves in brown (3P-2P). The entire block sums the Reserves of this well. The first two PUDs are located above and below the well.

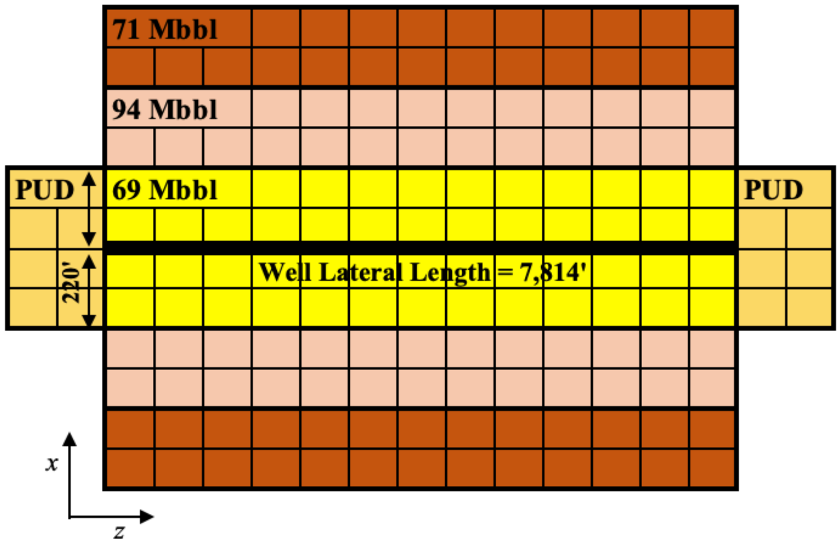

Figure 49 — Well 6 has a lateral length of 7,814 ft and a fracture half-length of 220 ft. Similarly to Fig. 47, the yellow area denotes the 1P Reserves, the orange volume area the 2P Reserves, and the brown area the 3P Reserves. The PUD locations are on either side of the wellbore, two blocks from the 1P Reserves.

Now that we understand the relationship between the 1P, 2P, 3P and PUD volumes for the optimal well spacing, we explore these relationships with the two cases at larger well spacing.

6.2.3.2 Case 2 – 650 ft Well Spacing

The second case we discuss is with a well spacing of 650 ft in the subsurface. **Fig. 50** provides a visual representation of this, where the distance between the wells is 650 ft, and the fracture half-length is assumed to be 220 ft (as per Zhu *et al.,* 2017).

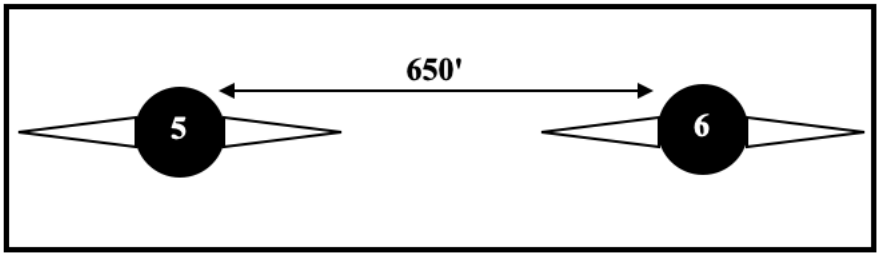

Figure 50 — Wells 5 and 6 with 650 ft well spacing. The triangles are representative of the fracture half-length, assumed to be 220 ft.

Based on the results from Fig. 43, Zhu *et al.* (2017) found that the EUR per lease only captured 71% of the EUR determined at the 450 ft optimal well spacing. Therefore, in this case, we determine that the EUR and Reserves are 71% of those presented for Case 1. So based on this analysis, the EUR and Reserves are presented in **Table 55** and **Fig. 51** below.

		Well 5	Well 6
Cumulative Production as of Aug-1-2019 (Mbbl)		106	136
EUR (Mbbl)	**1P**	108	146
	2P	166	213
	3P	252	263
Reserves (Mbbl) as of Aug-1-19	**1P**	2	10
	2P	60	76
	3P	146	127

Table 55—1P, 2P, and 3P EUR and Reserves (as of 8/1/2019) results for wells 5 and 6 with 650 ft well spacing in the 3-14 block of the Midland Basin, TX.

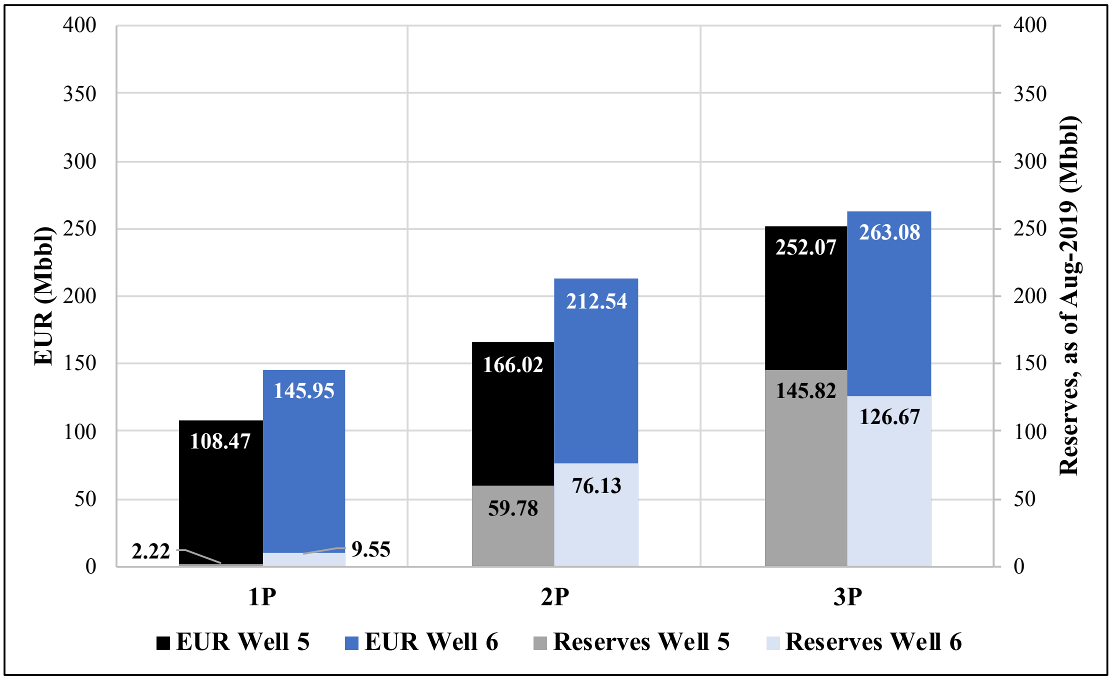

Figure 51 — 1P, 2P, and 3P Reserves vs. EUR for wells 5 and 6 with 650 ft well spacing from block 03-14 of the Midland Basin, TX

Compared to the results of Case 1, the Reserves are significantly lower with this well spacing. The cumulative production through August 2019 remains constant because it is an actual value, but since the EUR with 650 ft well spacing only captured 71% of the EUR of the optimal case, we see that there are few remaining volumes, particularly in Well 5.

6.2.3.3 Case 3 – 880 ft Well Spacing

The third case, illustrated in **Fig. 52,** provides a visual representation of well spacing of 880 ft, and assuming the fracture half-length to be 220 ft (as per Zhu *et al.,* 2017).

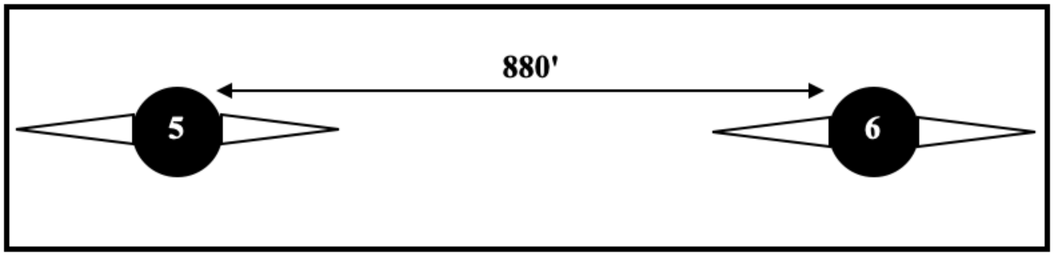

Figure 52 — Wells 5 and 6 with 880 ft well spacing. The triangles are representative of the fracture half-length, assumed to be 220 ft.

Similar to the analysis done for the 650 ft well spacing, Fig. 45, Zhu *et al.* (2017) found that the EUR per lease only captured 54% of the EUR of the 450 ft optimal well spacing. Therefore, in this case, we determine the Reserves, as presented in **Table 56** and **Fig. 53**.

		Well 5	Well 6
Cumulative Production as of Aug-1-2019 (Mbbl)		106	136
EUR (Mbbl)	**1P**	83	112
	2P	127	163
	3P	193	201
Reserves (Mbbl) as of Aug-1-19	**1P**	-23	-25
	2P	21	26
	3P	87	65

Table 56—1P, 2P, and 3P EUR and Reserves (as of 8/1/2019) results for wells 5 and 6 with 880’ well spacing in the 3-14 block of the Midland Basin, TX.

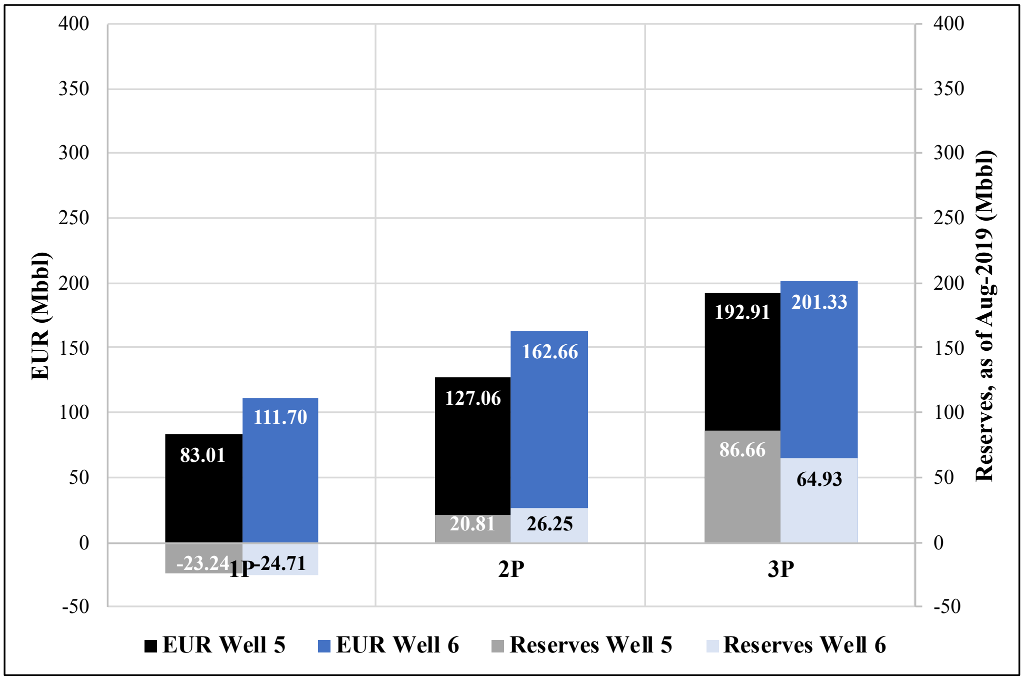

Figure 53 — 1P, 2P, and 3P Reserves vs. EUR for wells 5 and 6 with 880' well spacing from block 03-14 of the Midland Basin, TX

Compared to the results of Case 1, the Reserves are significantly lower with this well spacing. The cumulative production through August 2019 remains constant because it is an actual value, but since the EUR with 880 ft well spacing only captured 54% of the EUR of the optimal case, we see that there are few remaining volumes, and none in the 1P category.

It is impossible to have negative Reserves, so when the well spacing is 880 ft, it is possible that we have drained the 1P Reserves. These volumes can be reclassified and grouped into the 2P Reserves, or they may drop off into Contingent Resources, assuming that there is currently no reliable technology to produce them. We see the EUR for Wells 5 and 6 is 83 Mbbl, and 112 Mbbl, respectively so this volume must be placed elsewhere because as of

August 2019, the reservoir has produced a certain amount of oil that exceeds to amount we estimate to be remaining.

When we compare all three cases graphically, presented in **Fig. 54,** we see the significant impact of the spacing on the Reserves.

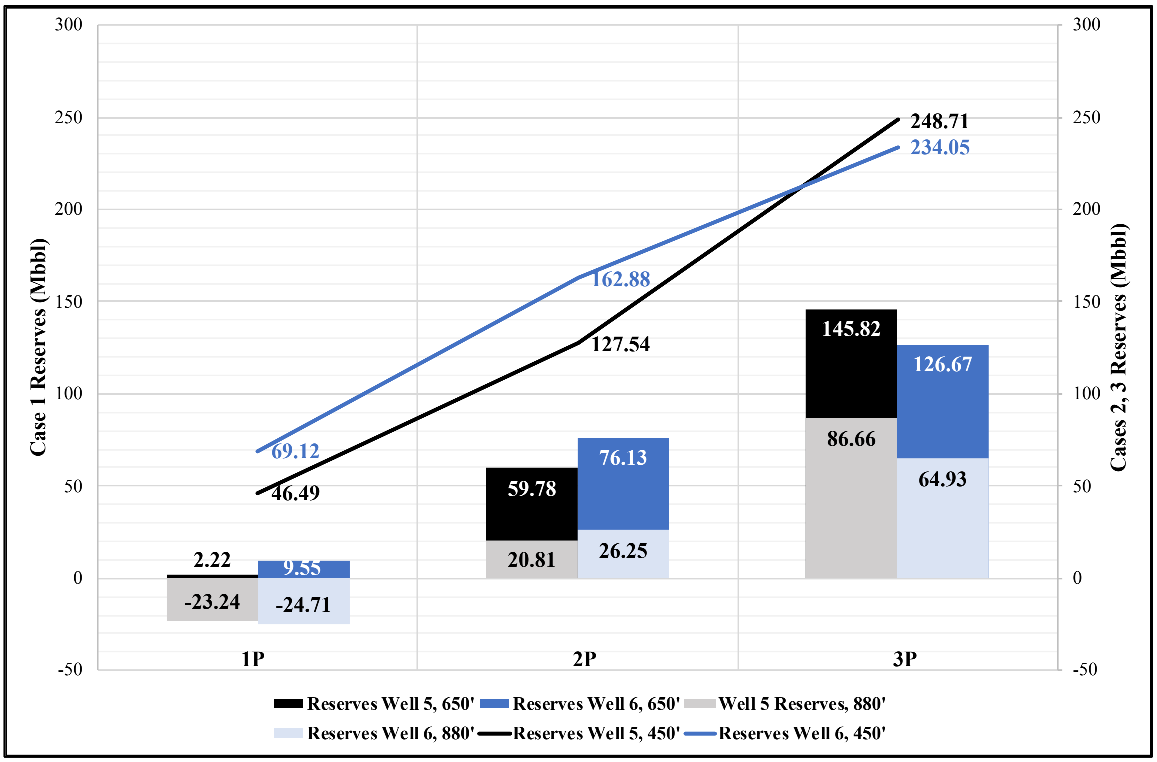

Figure 54 — The Reserves of wells 5, 6 of case 1 compared with the Reserves of cases 2 and 3 (represented by the columns). The results of well 5 are represented in black and grey, and the results of well 6 are represented in light and dark blue. We see that the well spacing greatly impacts the amount of remaining commercially recoverable hydrocarbon.

Based on these results, we see that by increasing the well spacing to 880 ft in the Wolfcamp A field, the Reserves not only decrease, but must be re-categorized and re-classified. These wells have begun to drain the Reserves from offsetting locations, reducing the reserves there.

The 1P Reserves for the 650 ft well spacing are relatively low for both wells, and it may no longer be economic to produce this well so these volumes may also need to be re-categorized and re-classified. It is at the discretion of the operator to determine which wells are commercial to remain classified as Reserves. We recommend running an economic evaluation to determine the volumes that remain commercial and which are no longer commercial.

6.3 Building a Model to Understand the Continuity of Reserves Through Time

Before we begin building the model, we explore the effective Reserves estimation methods in unconventional reservoirs**.** We implement a two-segment DCA model for this analysis because we observe that this approach is most effective in unconventional reservoirs when specifically relevant models are used for transient flow and boundary-dominated flow. We previously discussed implementing RTA (Chapter 4), and suggest that RTA, using analytical models, expands possibilities of forecasting for changes in well conditions and for well spacing studies. Though time and computationally time consuming, compositional simulation is required for confident analysis of near-critical reservoir fluids.

6.3.1 Decline Curve Analysis

Decline curve analysis (DCA) is one of the most frequently used deterministic approaches to forecast future production of a well and can be used once there is enough history to show a well performance trend. DCA is best applied to individual wells rather than to groups of wells or reservoirs. The most common decline model was proposed by Arps (1945), and has three forms: exponential, hyperbolic, and harmonic. The Arps decline models assume a stabilized, unchanging drainage area for a well, which is not the case for many months or years in unconventional low-permeability reservoirs. Wells in these reservoirs have long-duration transient (unstabilized) flow, with drainage area increasing with time. For improved production forecasts in unconventional reservoirs, common practice is to use two-segment Arps models: the first segment for the transient flow period and the second for the stabilized flow period. The long-duration transient flow periods are caused by the ultra-low permeabilities in unconventional reservoirs. The DCA plots are usually semi-log plots of production rate vs. production (not calendar) time. Because the Arps decline model, even with two or more segments, is more empirical than physics-based, there is considerable uncertainty in forecasted results using this model. This uncertainty provides an opportunity to use probabilistic methods to quantify the uncertainty in forecasts with Arps decline models.

Arps decline models include exponential, hyperbolic, and harmonic decline. The models differ in the value of the exponent b in **Eq. 120**.

$$q = \frac{q_i}{\left(1 + bDt\right)^{1/b}} \qquad \textbf{(120)}$$

where,

q	=	Instantaneous rate at time before or after q_i, vol/unit time
q_i	=	Initial instantaneous flow rate (time 0), vol/unit time
b	=	Hyperbolic exponent factor
D	=	Initial nominal decline, 1/unit time
t	=	time

Multi-segment DCA can be applied successfully for unconventional wells as long as good judgement and evaluation practice are used. Furthermore, this analysis requires only time and production rate data, whereas rate transient analysis and reservoir simulation require significantly more data. DCA does not require any specialized or commercial software. It can be performed using a simple spreadsheet, which is currently the best method for analysis of unconventional reservoirs. RTA requires more data and takes more time to build the model. There are several commercial software packages available to run RTA. Finally, reservoir simulation requires the most data and the most time. As previously mentioned, we focus our efforts on implementing the two-segment DCA method to determine the EUR and Reserves of the 38 wells in the Midland Basin dataset.

6.3.2 Identifying Flow Regimes To Build Multi-Segment DCA Models

When implementing DCA in unconventional reservoirs, it is important to first identify the flow regimes. We do this by identifying negative unit and half slopes on a diagnostic plot. The steps to do this are presented in **Fig. 55.**

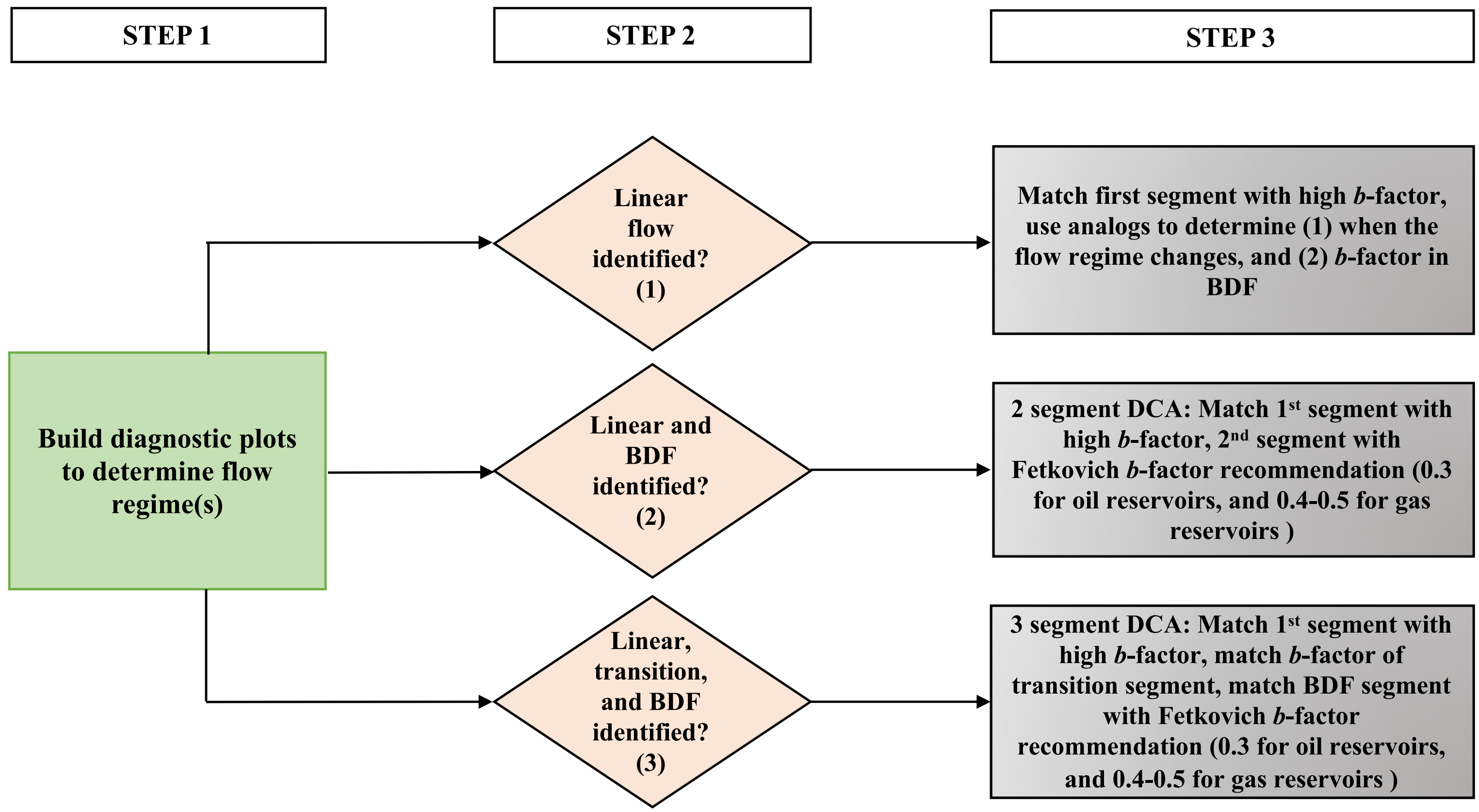

Figure 55 — The steps to run DCA analysis in unconventional reservoirs. We begin with building diagnostic plots to determine the flow regimes in each production history, and then implement the 2- or 3-segment DCA (reprinted with permission from Moridis *et al*., 2019, URTeC 336).

As Fig. 55 indicates, to implement DCA in unconventional reservoirs, we must first determine the flow regimes. There are three possible outcomes when building the diagnostic plots. The first is that only linear (or near-linear) flow is identified, meaning that the well has not been on production long enough to reach boundary dominated flow (BDF). Because we do not know when the well will reach BDF, we recommend using analog wells in this case. We might switch to BDF at a minimum decline rate, D_{min}, determined from analog wells. The second is that we identify two flow regimes; linear (or near-linear flow by a slope near -½, and BDF by a negative unit slope. The third is that we identify three flow regimes; (near-) linear flow and BDF at early and late times, respectively, and a transitional region between the two other flow regimes.

In **Fig. 56** we present the diagnostic plot for Well 6 in the Midland Basin (TX), which is a log-log plot of the production data against the material balance time (MBT) (**Eq. 121**).

$$MBT = \frac{Q}{q} \qquad \textbf{(121)}$$

where,

MBT = Material Balance Time
Q = cumulative production
q = flow rate

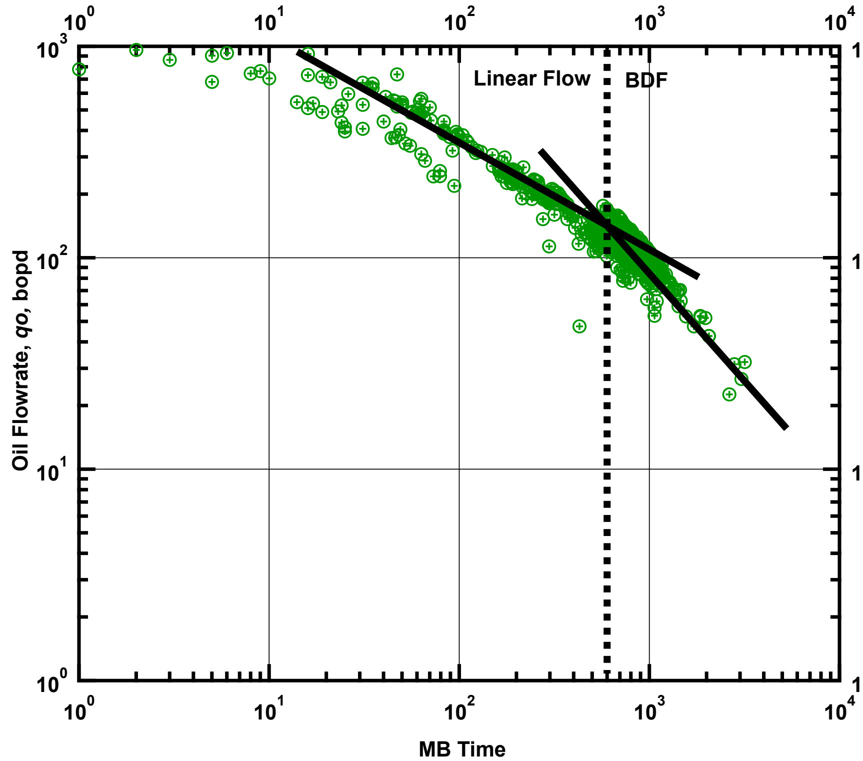

Figure 56 — Diagnostic plot of Well 6 in the Midland Basin (TX) shows two flow regimes and the time when the drainage boundary is felt (probably interference between adjacent hydraulic fractures), indicated by the dashed line. As expected, linear flow is identified by the negative half slope on the left side of the graph and BDF is identified by the negative unit slope on the right side of the graph (reprinted with permission from Moridis *et al.*, 2019, URTeC 336).

In Fig. 56, we first identify the flow regimes by identifying the –½ slope representative of transient linear flow, and the negative unit slope representative of BDF. If the slope is not exactly -½, we can still call the flow regime "linear," although is not "ideal" linear flow. The dashed line indicates the transition between the two flow regimes. It is possible that liquid loading will cause data to fall on the unit slope line so we cannot immediately assume that the well has reached BDF. Earliest data typically fall on a trend below the half-slope line; the cause is fracture-fluid clean-up and choked flow in most cases.

Once we have identified the flow regimes, we can clean up the data and remove the early-time outliers.

6.3.3 Two-Segment Decline Curve Analysis (DCA)

The two-segment DCA is an estimation method for unconventional reservoirs that incorporates the physics of fluid flow through porous media, and uses a strict mathematical solution. The two-segment DCA approach matches the first segment when the well is in linear flow with a *b*-factor of two (or near two if almost linear), and the second segment when the well is in BDF with a *b*-factor of 0.3 for oil well, or 0.4-0.5 for gas wells as per Fetkovich's recommendations (1987). As opposed to a modified hyperbolic approach where the well is modeled until it hits the minimum decline and then goes into an exponential decline once the minimum decline is reached, the two-segment DCA is based on the well's flow regimes, and that is a significant difference. The minimum decline rate is an arbitrary value and it is not based on a change in flow regime. We found that this methodology is robust and can be used for wells in unconventional reservoirs.

To implement the two-segment DCA, we first match the linear flow where we expect the *b*-factor to be greater than 1. We then match the BDF to be 0.3 for oil wells and between 0.4 and 0.5 for gas wells (Fetkovich, 1987). For Well 6, the *b*-factor in near-linear flow is 1.9 and it would be exactly 2.0 in ideal transient linear flow. We match the *b*-factor to 0.3 in BDF, as presented in **Fig. 57**. Well 6 came on production on October 21, 2014 and we see that the switch to MBT occurs at 621 days (1.7 years) of production. We will continue presenting the results for Well 6 and the information for the other wells is presented in **Appendix J.**

We set the economic limit (EL) to a flowrate of 5 bopd, which gives an EUR of 400 Mbbls. This analysis is deterministic and these results are best described as the best estimate, or 2P Reserves.

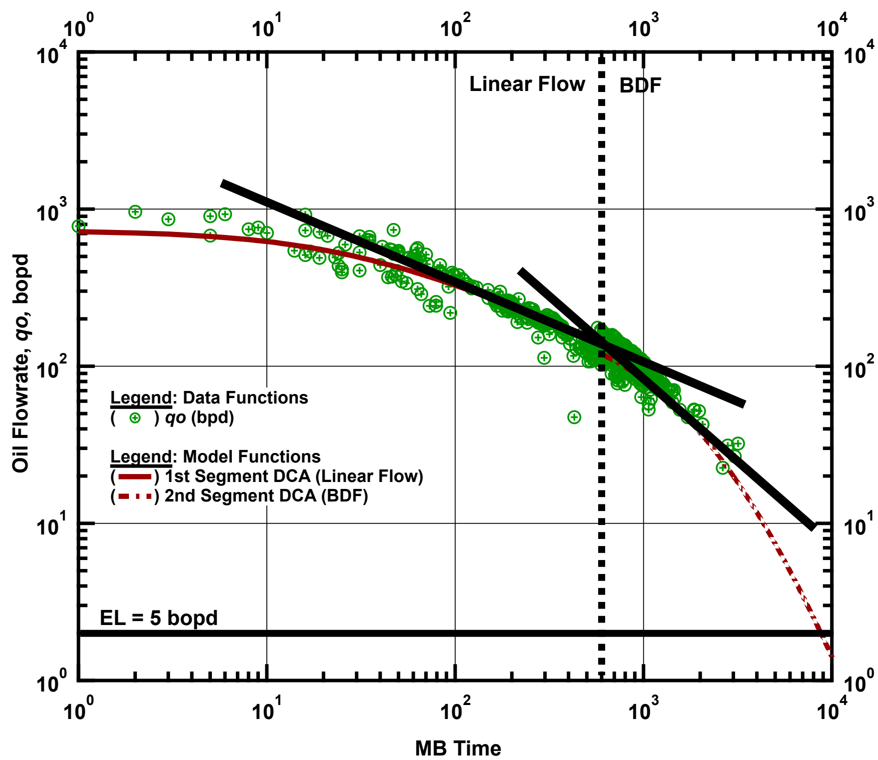

Figure 57 — Two-segment DCA of Well 6 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3 (reprinted with permission from Moridis *et al.*, 2019, URTeC 336).

To create the model, we implemented the two-segment DCA on the 38 wells. Once we identified the linear flow and BDF, we determined the low, best, and high EUR values using the entirety of the data set by manipulating the *b*-factor and decline rate of the two segments to match the lower production data, the best match to the production data, and the higher portion of the production data. From these volumes, we determined the 1P, 2P, and 3P Reserves.

We then truncated the dataset by removing one year of data and re-ran the two-segment DCA to determine the 1P, 2P, and 3P EUR. We compared the two sets of EUR, and also compared the 1P, 2P, and 3P Reserves as of July 2016 and August 2019. From this we were able to determine the volumes that were reported as 1P, 2P, and 3P Reserves and if those volumes remained constant with the two data sets.

6.3.4 Comparing The EUR of the Full Dataset Vs. the Truncated Data To Determine Continuity

We began this portion of first implementing the two-segment DCA presented in the previous section and running three cases: one "low" estimate EUR, one "best" estimate EUR, and one "high" estimate EUR, also referred to as 1P, 2P, and 3P, respectively. We did this by keeping the *b*-factor the same for the two segments but by manipulating the decline rate of the two segments to match a "low", a "best," and a "high" case. We did this once with the full dataset, with daily production data from first day of production through July 2016. We then truncated this dataset by one year, to July 2015, and re-ran the analysis. Finally we calculated the 1P, 2P, and 3P Reserves as of August 1, 2019, based on both sets of EUR results. We calculated the Reserves to August 2019 because Enverus DrillingInfo had cumulative production of each well through this date, and by definition, Reserves are remaining as of a given date. We compared the two sets of estimates to see (1) how the estimates change with an increasing amount of data, and (2) how the Reserves that were estimated with the truncated data differ to the Reserves estimated with the entire data set. We compared these estimates because it tells us the amount of hydrocarbon that was actually moved to Reserves. This is how we maintain the consistency that we discussed previously.

Fig. 58 shows the 1P, 2P, and 3P EUR results using the entire dataset, and **Fig. 59** shows the same results but with the truncated dataset.

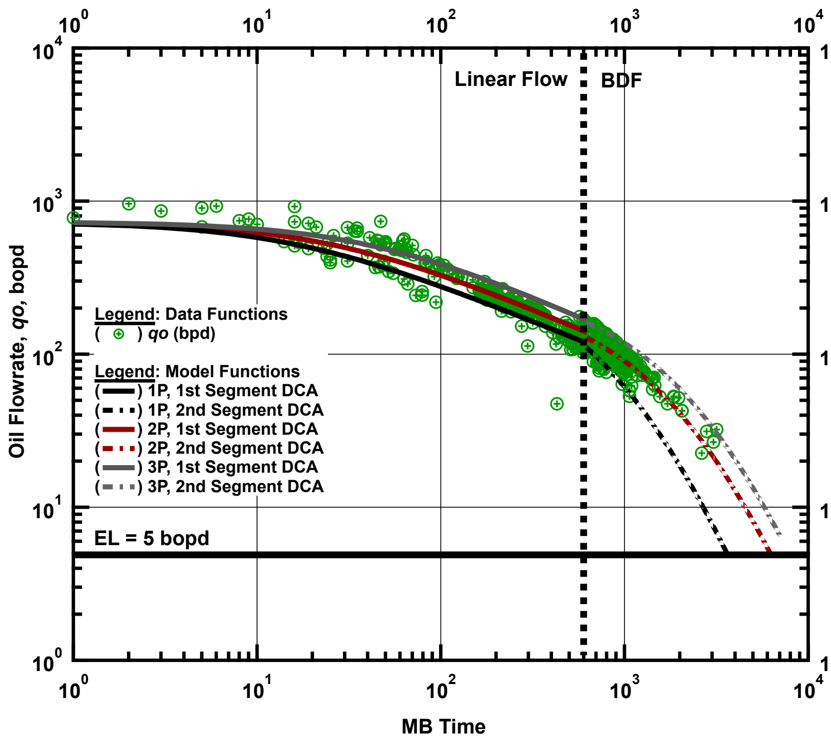

Figure 58 — Two-segment DCA of Well 6 in the Midland Basin (TX) shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves (bold and dashed lines) are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

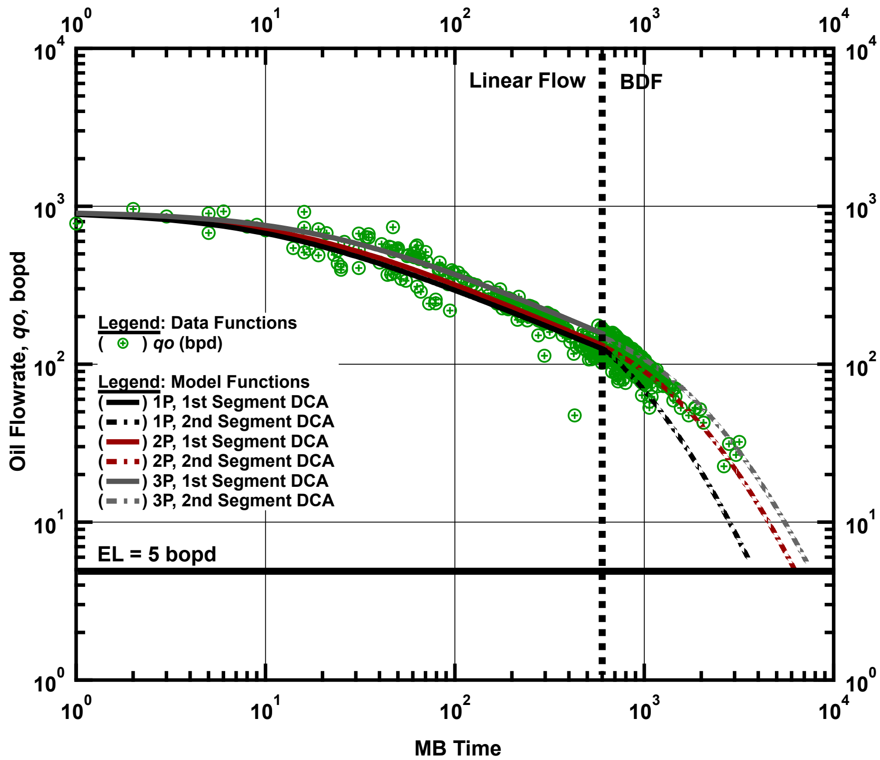

Figure 59 — Two-segment DCA of Well 6 in the Midland Basin (TX) with the truncated data set. As in Fig. 18, the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves (bold and dashed lines) are the 2P results, the black are the 1P, and the grey are the 3P.

We manipulated the decline rate of the two segments of each case to match three cases: one low, one best, and one high. This practice is deterministic, so we chose the values that best fit the data at the low, best, and high portions. If we refer back to the definition of 1P and 3P Reserves, they state that they are the 1P Reserves are the "low estimate of Reserves" (PRMS, p. 37) and the 3P Reserves are the "the high estimate of Reserves" (PRMS, p. 37). These definitions do not provide much guidance in estimating the "low" and "high" estimates. If we were to run a probabilistic analysis, the 1P is equivalent to P90, meaning there is 90 per cent certainty of producing that amount of hydrocarbon or more, and the 3P is equivalent to P10, meaning there is at least a 10 per cent certainty of producing that amount of hydrocarbon or more. Because we propose a deterministic approach, we have changed the decline rate by ± 20 per cent to build the "high" and "low" cases. The full set of parameters is presented in **Table 212** and **Table 213** in **Appendix I.**

In **Table 57** we present the EUR, the Reserves as of July 2016 and as of August 2019 of the full dataset. In **Table 58** we present the EUR of the truncated data dataset, along with the Reserves as of July 2016 and August 2019. We present the actual EUR and Reserves results, and then we present the EUR normalized linearly to 10,000 ft. This creates continuity in our analysis because each well has a different lateral length and by normalizing them, we can compare the results of the 38 wells to a given lateral length. In **Table 59** we present the ratio of the full versus the truncated results of the four results for 1P, 2P, and 3P values. Table 60 shows the percent difference between the full and truncated dataset with respect to the full dataset. This allows for a clearer understanding of the relationships of the different estimations.

WELL 6	**FULL DATA SET RESULTS (Mbbl)**		
Lat. Length = 7,814’	**1P**	**2P**	**3P**
EUR	206	299	370
Reserves (07/2016)	97	191	262
Reserves (08/2019)	69	163	234
Normalized EUR	263	383	474

Table 57—1P, 2P, and 3P EUR and Reserves, and normalized EUR results for Well 6.

WELL 6	TRUNCATED DATA SET RESULTS (Mbbl)		
Lat. Length = 7,814’	1P	2P	3P
EUR	227	311	391
Reserves (07/2016)	118	203	283
Reserves (08/2019)	91	175	255
Normalized EUR	290	398	501

Table 58—1P, 2P, and 3P EUR and Reserves, and normalized EUR results for Well 6.

WELL 6	FULL/TRUNCATED (%)		
Lat. Length = 7,814’	1P	2P	3P
EUR	91%	96%	95%
Reserves (07/2016)	82%	94%	93%
Reserves (08/2019)	76%	93%	92%
Normalized EUR	91%	96%	95%

Table 59—1P, 2P, and 3P EUR and Reserves, and normalized EUR results for Well 6.

WELL 6	FULL/TRUNCATED DIFFERENCE (%)		
	1P	2P	3P
EUR	-10%	-4%	-3%
Reserves (07/2016)	-22%	-4%	-8%
Reserves (08/2019)	-32%	-7%	-9%
Normalized EUR	-10%	-4%	-3%

Table 60—The percent difference of the truncated results with respect to the full dataset results for Well 6.

We see from Table 60 that the greatest uncertainty comes in the Reserves as of August 2019. However, we see that the EUR results are very similar for well 6, and that the truncated dataset slightly overestimates the EUR in comparison to the EUR calculated with the full dataset.

The cumulative production through July 2016 is 108.6 Mbbl, and the cumulative production through August 2019 is 136.4 Mbbl. As we expect, the Reserves as of July 2016 are higher than those of August 2019. We also see that the estimates with the truncated dataset are higher than those with the full dataset, so in our case, less data leads to overestimating the EUR and the Reserves.

Referring back to the proposed scenario, we see that with the truncated dataset we estimated 118.36 Mbbl of 1P Reserves as of July 2016, but the full set estimates 96.92 Mbbl of 1P Reserves. This means that we have only booked 82% of the originally calculated 1P Reserves. Similarly, we book 94% of the 2P Reserves and 93% of the 3P Reserves.

We performed the same analysis for the Reserves as August 2019. We saw that we book 76% of the 1P Reserves, 93% of the 2P Reserves, and 92% of the 3P Reserves. Finally we performed the same analysis with the two sets of EUR results. We found the full to truncated percentage to be 91% for 1P EUR, 95% for 2P EUR, and 96% for 3P EUR.

These results are interesting because we see how more data impacts our results, but it also helps us estimate the volumes through time. Because we have three sets of results, we average the three and determine that 83% of 1P Reserves are actually booked, 94% of 2P Reserves are reported, and 93% of 3P Reserves when compared to the initial estimate. For simplicity, we will refer to 1P as x, 2P as y, and 3P as z.

We initially estimated that we will book *x*, but book 0.83*x*. Similarly, we estimated that we will book *y*, but book 0.94y, and finally we estimated that we will book *z*, but book 0.93*z*. This means that 0.17*x*, 0.06*y*, and 0.07*z* are re-classified as 1C, 2C, and 3C Contingent Resources, respectively, because that fraction of hydrocarbon is no longer commercial. Based on this well, an increase in production data leads to the EUR becoming more accurate because the model can better match the data.

One well cannot be used to build a generalization or a model. We ran this analysis on all 38 wells, and those results are presented in the appendices. We took the mean of the 38 wells and present the results of the full dataset EUR in **Table 61**, the truncated dataset EUR in **Table 62**, and the full/truncated results of the mean of the 38 wells in **Table 63**. We present the percent difference between the full and truncated dataset results with respect to the full dataset results in **Table 64**.

Mean	**FULL DATA SET RESULTS (Mbbl)**		
	1P	**2P**	**3P**
EUR	268	318	405
Reserves (07/2016)	170	223	307
Reserves (08/2019)	90	140	227
Normalized EUR	290	346	440

Table 61—1P, 2P, and 3P EUR and Reserves, and normalized EUR results for the mean of the 38 wells.

Mean	TRUNCATED DATA SET RESULTS (Mbbl)		
	1P	2P	3P
EUR	253	312	381
Reserves (07/2016)	155	214	283
Reserves (08/2019)	75	135	203
Normalized EUR	274	339	414

Table 62—1P, 2P, and 3P EUR and Reserves, and normalized EUR results for the mean of the 38 wells.

WELL 6	FULL/TRUNCATED (%)		
	1P	2P	3P
EUR	106%	102%	106%
Reserves (07/2016)	110%	104%	108%
Reserves (08/2019)	120%	103%	113%
Normalized EUR	106%	102%	106%

Table 63—1P, 2P, and 3P EUR and Reserves, and normalized EUR results for the mean of the 38 wells.

WELL 6	FULL/TRUNCATED DIFFERENCE (%)		
	1P	2P	3P
EUR	6%	2%	6%
Reserves (07/2016)	9%	4%	8%
Reserves (08/2019)	17%	4%	11%
Normalized EUR	6%	2%	6%

Table 64—The percent difference of the truncated results with respect to the full dataset results for the mean of the 38 wells.

From the results in Tables 61 through 63, we see that the mean of the EUR results are very similar for the truncated set and the full dataset. Table 64 shows that there is a slight underprediction of the truncated dataset but that the wells' EUR is accurate relative to the full dataset. This is particularly interesting because wells 7 through 14, wells 19 through 21, and wells 27 and 28 had very little production (see Table 211 and Table 213 in Appendix IX) and when truncated, needed to use analog data to model the second segment of the 2-segment DCA. This means that even though we did not have data we were able to appropriately match the wells' behavior. We notice the identical behavior for the normalized

EUR of the truncated and full dataset. It would be interesting to compare these results against estimates in the future and see if our proposed relationships become more accurate.

Referring back to the proposed scenario, we see that with the mean of truncated dataset we estimated 155 Mbbl of 1P Reserves as of July 2016, and with the mean of the full set, we estimate 170 Mbbl of 1P Reserves. This mean of the ratios shows that we have booked 98% of the originally calculated 1P Reserves. Similarly, we book 65% of the 2P Reserves and 146% of the 3P Reserves.

We found the mean percentages for the 38 wells. We book 83% of the 1P Reserves, 113% of the 2P Reserves, and 113% of the 3P Reserves. Finally we performed the same analysis with the two sets of EUR results. We found the full to truncated percentage to be 106% for 1P EUR, 102% for 2P EUR, and 106% for 3P EUR.

These results are interesting because we see how more data impacts our results, but it also helps us estimate the volumes through time. As previously done for Well 6, we average the three averaged results and determine that 91% of 1P Reserves are actually booked, 89% of 2P Reserves are reported, and 130% of 3P Reserves when compared to the initial estimate. For simplicity, we will refer to 1P as x, 2P as y, and 3P as z.

With the mean results, we found that we initially estimated that we will book x, but book 0.91. Similarly, we estimated that we will book y, but book $0.89y$, and finally we estimated that we will book z, but book $1.3z$. This means that $0.11x$ and $0.09y$ are re-classified as 1C and 2C Contingent Resources, respectively, because that fraction of hydrocarbon is no longer commercial. This also means that there is an additional 0.3*z* in 3P Reserves that needs to be moved because we have overestimated this category. Based on the mean of the 38 wells, an increase in production data leads to the EUR becoming more accurate because the model can better match the data. However, we also see that unlike the results from Well 6, there is an overestimation in the 2P and 3P categories.

The full set of results of the EUR using the full dataset are presented in **Appendix K**, the full set of results of the EUR using the truncated dataset are presented in **Appendix L**, and finally the Reserves are presented in **Appendix M**.

This analysis can be done for any reservoir, and it depends on the EUR and Reserves based on the wells' production data. In our case, we see that the results with the full dataset have lower estimates than the results with the truncated dataset. We do not have production data through 2019 so we assume that the full dataset provided is accurate. Ideally, we would perform the same analysis with the full dataset through the end of 2019 and build a model to determine the fraction of Reserves that is booked.

6.4 Summary of Key Points

The summary of key points of the work in Chapter 6 are as follows:

- Visual representation in gun-barrel view and cross-section of 1P, 2P, and 3P Reserves and PUDs for horizontal wells in unconventional reservoirs. This is a novel approach for presenting these volumes visually.

- This methodology helps to determine Reserves, PUDs, and Contingent Resources in offset wells
- This methodology can be implemented in both conventional and unconventional fields, but currently relevant to unconventional reservoirs. The PUD placement must be adjusted for conventional reservoirs if they have vertical wells.
- If there is economic producibility in one direction, we can call those volumes Contingent Resources.
- The multi-segment DCA approach is most effective in unconventional reservoirs when specifically relevant models are used for transient flow and boundary-dominated flow.
- The continuity of volumes through time depend on each project, and we present the results based on the wells in the Midland Basin, TX.

7. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS FOR FUTURE WORK

7.1 Summary of the Research Presented

The work presented in Chapter 3 provides a visual representation of the movement from Prospective Resources to Contingent Resources that shows the necessary steps for volumes to become discovered. We then present a workflow of the progression in chance of development and commerciality within project maturity sub-classes of Contingent Resources, presented in Fig. 17. Once we have moved through the maturity sub-classes of Contingent Resources, we present the steps for a technology to become "established" through laboratory and field testing in Fig. 18 and 19. Finally, in Fig. 20 we present a workflow of the contingencies that must be resolved to move from Contingent Resources to Reserves. These four steps, coupled with the definitions presented in Chapter 2, and the definitions of the necessary criteria that must be met before volumes can be reclassified and/or recategorized between the Resources classes.

The work presented in Chapter 4 provides probabilistic DCA results that indicate that the Swanson's Mean (SM) method is an inaccurate method for estimating the relative weights of each Reserves category. Our results show that the Gaussian Quadrature (GQ) method was able to capture an accurate representation of the Reserves weights. We believe that 1C, 2C, 3C, and 1U, 2U, and 3U Contingent Resources and Prospective Resources, respectively, also follow a lognormal distribution but have greater variance.

Based on our results, we conclude that the GQ method is accurate and can be used to approximate the relationship between the relative weights of resources in PRMS categories. This proposed relationship will aid entities in reporting Reserves of different categories to regulatory agencies because it can be recreated for any field, play, or region. These distributions of Reserves and ROTR are important for planning and for resource inventorying. The GQ method provides a measure of confidence in our prediction of the Reserves weights because of the relatively smaller percentage differences between the probabilistic DCA, RTA, and GQ weights than those implied by the SM method.

The work presented in Chapter 5 shows that based on our results, the uncertainty of the relative weights of Contingent Resources and Prospective Resources categories increases as we move down the PRMS matrix, so as we incorporate this uncertainty, the ratios differ slightly from those estimated for Reserves. We also note that the COC is user-defined for every project, so the proposed relationships will differ for every project The time-rate of movement between categories also differs for every project; there is no "one-size-fits-all" solution. The COC changes for each project because the risks differ in each project and it is at the engineer's discretion to use the appropriate COC.

Engineers often build a reservoir simulation model early in the evaluation process to estimate recoverable hydrocarbon in the field they are evaluating. This means that the field may not necessarily have all the wells drilled, even if they are planned. This means that the estimated volumes may be classified as Contingent Resources. The longer the field produces, the more wells we drill and the more we refine the model, moving the estimated volumes to Reserves.

The work presented in Chapter 6 provides an analysis of best practices for each Reserves estimation method. This includes an example of how to identify the flow regimes from a diagnostic plot and how to implement a two-segment DCA. When evaluating Reserves in unconventional reservoirs, it is important to understand how to estimate the volumes with adequate accuracy. We only present a deterministic approach to the two-segment DCA, meaning that we present the "best fit," 2P Reserves for Well 6. The "low estimate," 1P Reserves, and "high estimate,"3P Reserves can also be determined with higher and lower values for the *b*-factor and decline rate. We also discuss the amount of Reserves in the three categories that are actually booked. We did this by comparing the Reserves from a full and from a truncated dataset.

7.2 Conclusions of Each Task

<u>The conclusions of Task 1 (Chapter 3) are as follows:</u>

- Understanding the relationships of volumes is vital to companies or entities to track the volumes of hydrocarbon through the life of a project.
- The flowcharts presented help engineers visualize how the volumes move and are easier to understand compare to reading the PRMS document.
- Understanding the contingencies and how to overcome them can quicken the movement to Reserves, which are used to determine the value of a company.
- Reserves are volumes and are the basis when running economics. When we include the price of oil or gas, and remove the capital expenditures (CAPEX), operating expenses (OPEX), and taxes, we obtain a monetary value. This value defines the a project's worth, and can define the amount that banks or investors are willing to lend.

The conclusions of Task 2 (Chapter 4) are as follows:

- The GQ method is accurate and can be used to approximate the relationship between the relative weights of resources in PRMS categories.
- The GQ method will aid entities in reporting Reserves in different categories to regulatory agencies, and allow for internal tracking of Reserves and ROTR.
- The GQ method is more accurate than the SM method as a means to approximate the relative ratios of volumes in different categories of Reserves, CR, and PR.
- We conclude the "less accurate" status of the SM method based on the smaller percent differences between weights calculated with the GQ and probabilistic DCA methods.
- If the uncertainty of the CR volumes is low, we can estimate the CR volumes and ratios based on the Reserves GQ results. This is not consistent for CR volumes with higher uncertainty.
- The GQ estimates of PR show a significant shift of the percentile volumes to the 3U category.
- This method can easily be recreated for any reservoir, conventional or unconventional.

The conclusions of Task 3 (Chapter 5) are as follows:

- The COC impacts the ratio of Reserves and Contingent Resources, however we see the maximum impact in Prospective Resources
- The results of the high COC cases show that the uncertainty we place on the Contingent Resources and Prospective Resources is what mostly impacts the ratios of the categories of the three classes
- The low COC has a significantly higher impact on the volumes with higher uncertainty,

where we see that ratios approach zero, especially for the PR cases

<u>The conclusions of Task 4 (Chapter 6) are as follows:</u>

- The multi-segment DCA approach is most effective in unconventional reservoirs when specifically relevant models are used for transient flow and boundary-dominated flow.
- The proposed methodology helps to visualize Reserves, PUDs, and Contingent Resources in offset wells
- If there is economic producibility in one direction, we can call those volumes Contingent Resources.
- The continuity of volumes through time depend on each project, and we present the results based on the wells in the Midland Basin, TX.
- This methodology can be implemented in both conventional and unconventional fields, but currently relevant to unconventional reservoirs. The PUD placement must be adjusted for conventional reservoirs if they have vertical wells.

7.3 Recommendations For Future Work

We propose the following as recommendations of future work based on the results of this research.

<u>The recommended future work of Task 2 (Chapter 4) is</u>:

- Refine the modelling procedure to decrease the percentage difference between the probabilistic DCA and the GQ results (significant improvement may not be possible, but this should be considered).

- Implement the same analysis in different types of reservoirs to confirm the relationship between the horizontal elements (*i.e.*, different classifications of resources) in the PRMS matrix.
- Such future work will further test our hypothesis that the GQ method is more appropriate than the SM method for determining the relative weights of the Reserves in the low, best, and high categories.

<u>The recommended future work of Task 3 (Chapter 5) is</u>:

- With data from an operator, see if our proposed mathematical models of Reserves and ROTR with the incorporated COC are accurate
- Obtain data from an operator to build actual time relationships of the movement through the sub-classes and categories of Reserves and ROTR. We know there are distinctive differences between a conventional and unconventional projects, but public data is limited. This would allow to build a model specific to reservoir type to help companies with planning from the beginning of their project.
- Present CR uncertainty cases for increments of 10 per cent (20 per cent through 50 per cent). Similarly, present PR uncertainty cases for increments of 10 per cent (60 per cent through 100 per cent).
- Implement the GQ in other unconventional plays and see how the relationships change based on the reservoir. Then implement this methodology in a conventional field and compare those results with the results of the wells we have in the Midland Basin.

The recommended future work of Task 4 (Chapter 6) is:

- Given the proper data, run well spacing sensitivity analysis.
- Incorporate cluster spacing, amount of proppant pumped, for additional analysis in understanding how operational parameters influence EUR, Reserves, and ROTR.
- Obtain updated dataset with production to today and create a third case with updated EUR and Reserves to the current date.
- Perform continuity study in other plays to ensure we obtain the same trends, build an that can define the relationships more accurately.

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APPENDIX A

WELL LOCATIONS OF EACH BLOCK OF WELLS IN THE MIDLAND BASIN

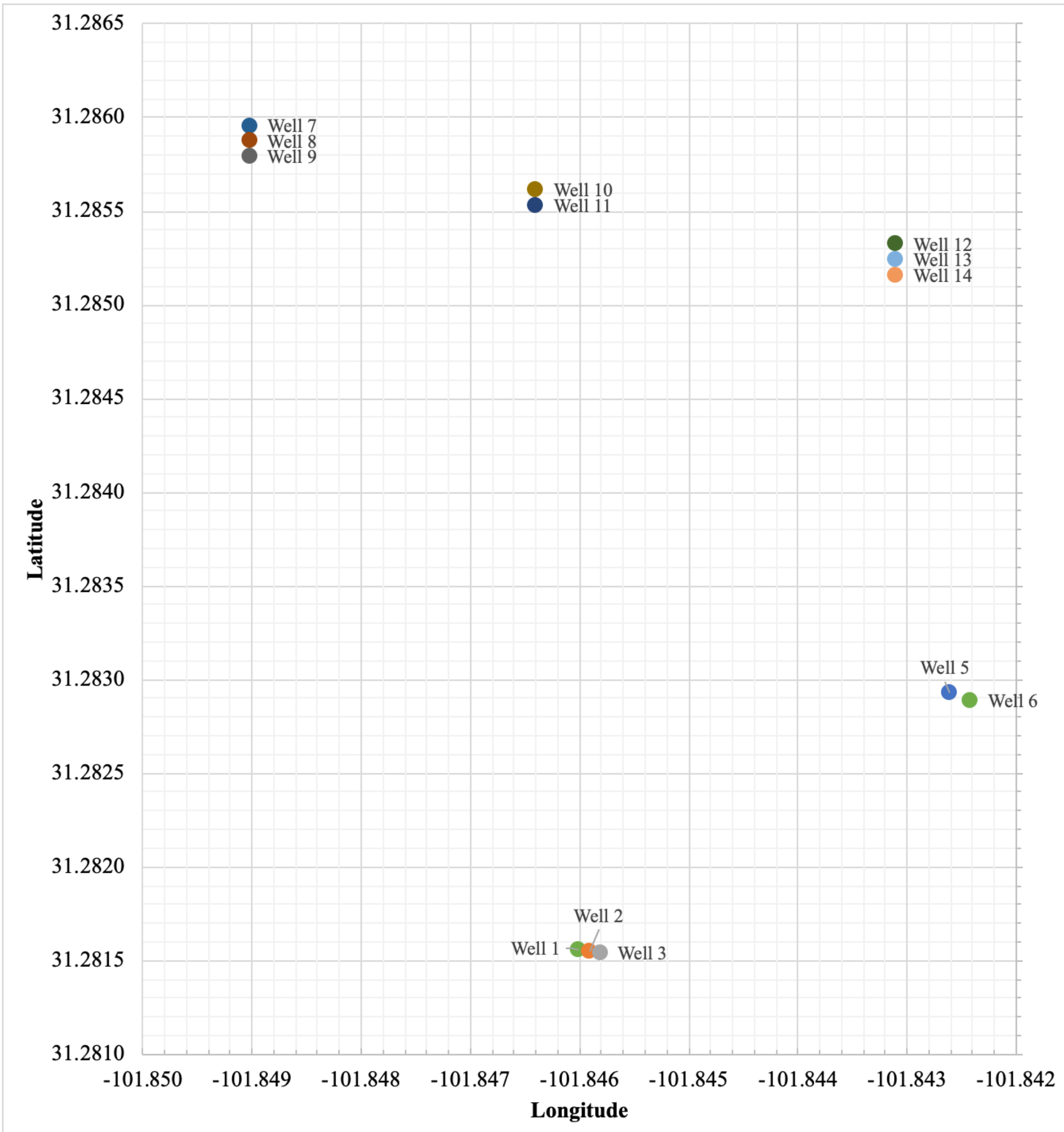

Figure 60 — Well locations of the14 wells in the 3-14 well cluster presented on a latitude vs. longitude plot. Each grouping of wells is 30’ apart on the surface, so we can assume that they are part of the same pad. Wells 5 and 6 are 60’ apart but we can assume the same.

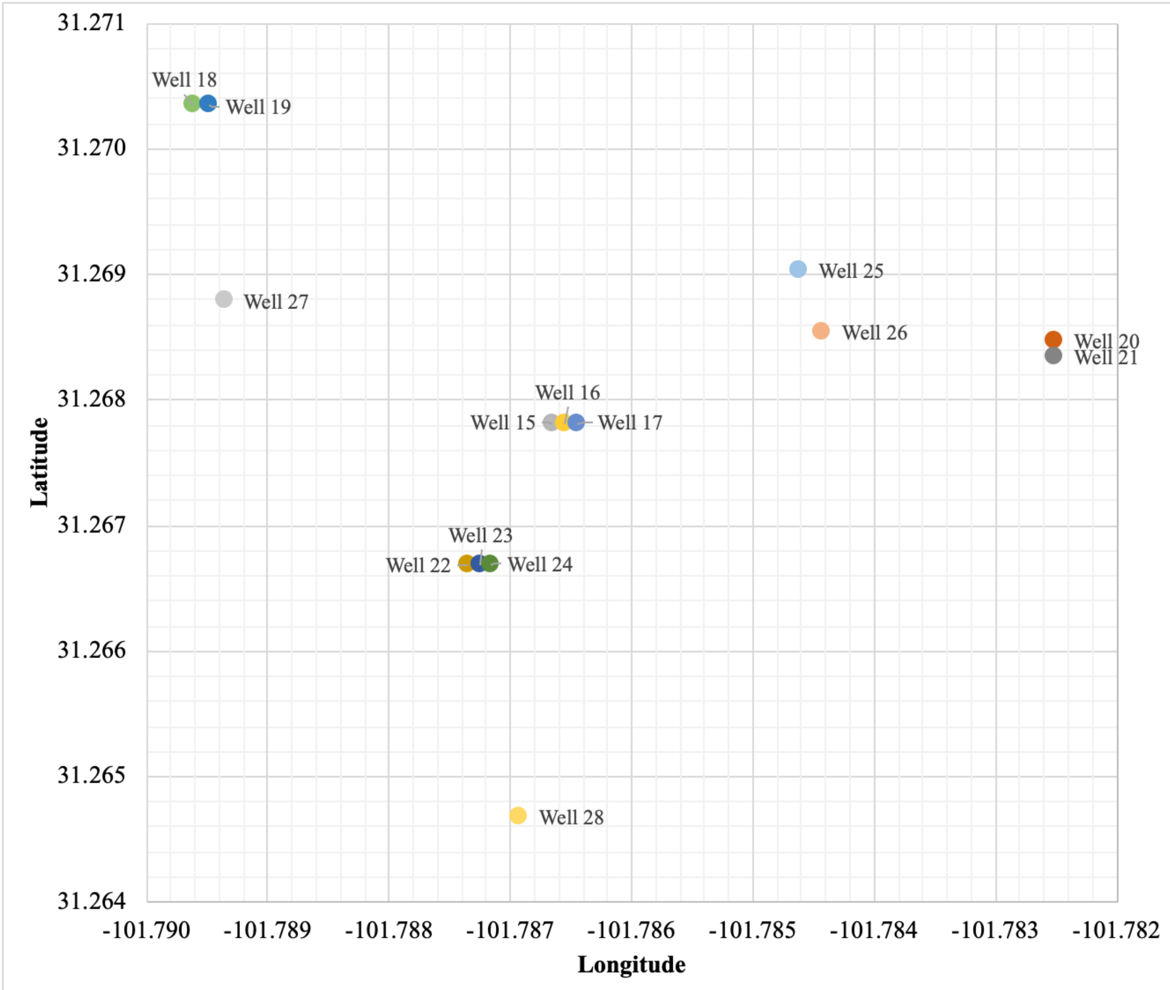

Figure 61 — Well locations of the14 wells in the 3-19 well cluster presented on a latitude vs. longitude plot. The surface distance between wells 15-16, 16-17, 22-23, 23-24 is 30’, wells 18-19 and 20-21 is 45’, and wells 25-26 is 190’.

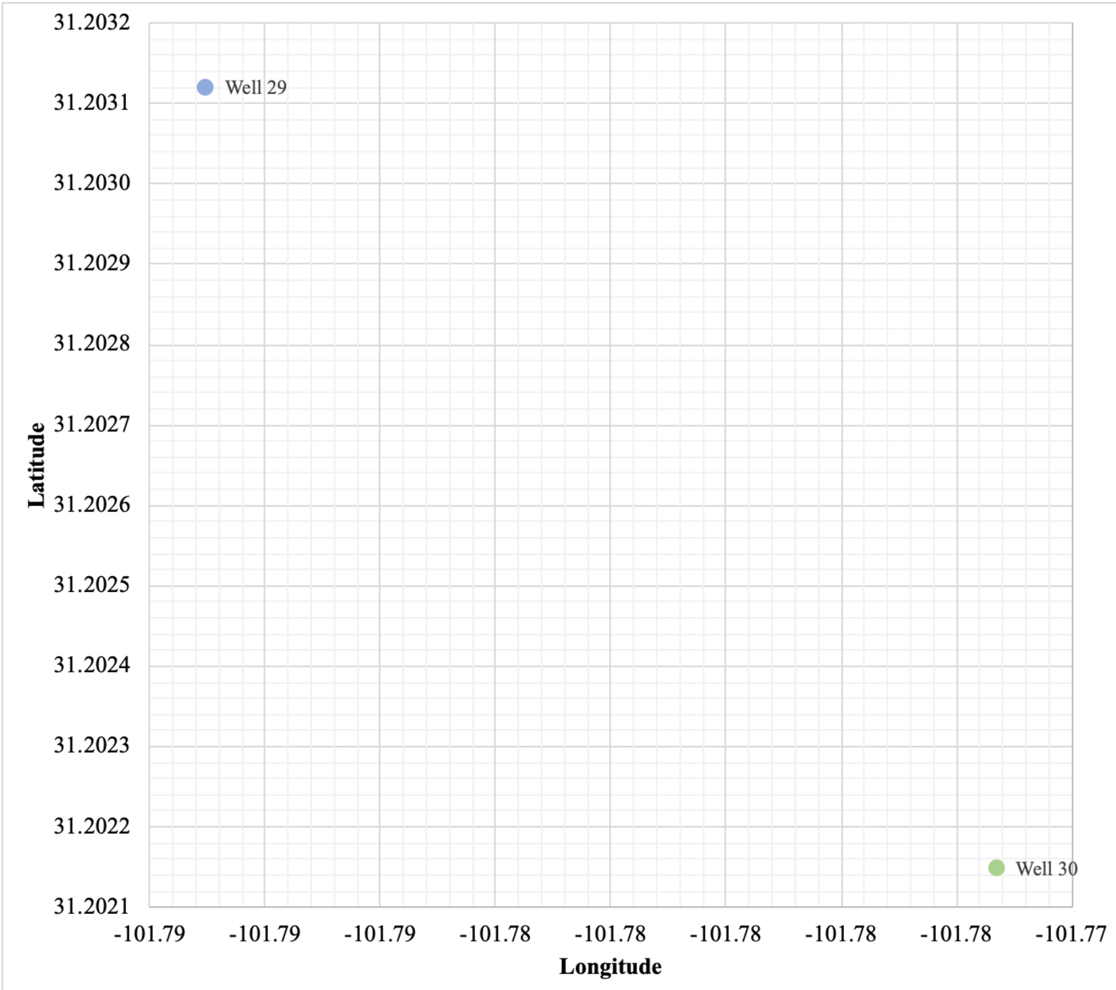

Figure 62 — Well locations of the two wells in the 3-31 block presented on a latitude vs. longitude plot. The surface distance between these two wells is 4,296'.

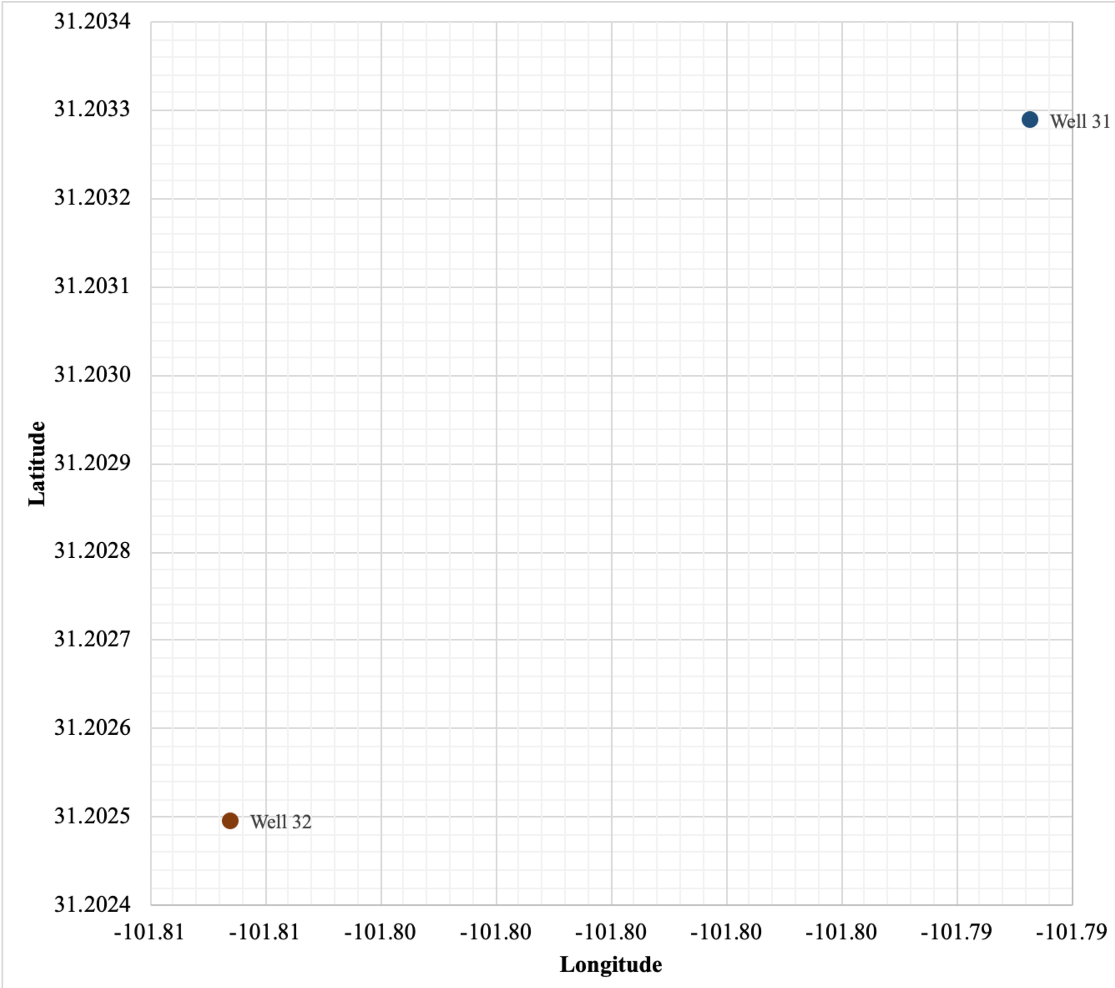

Figure 63 — Well locations of the two wells in the 3-32 block presented on a latitude vs. longitude plot. The surface distance between these two wells is 4,341'.

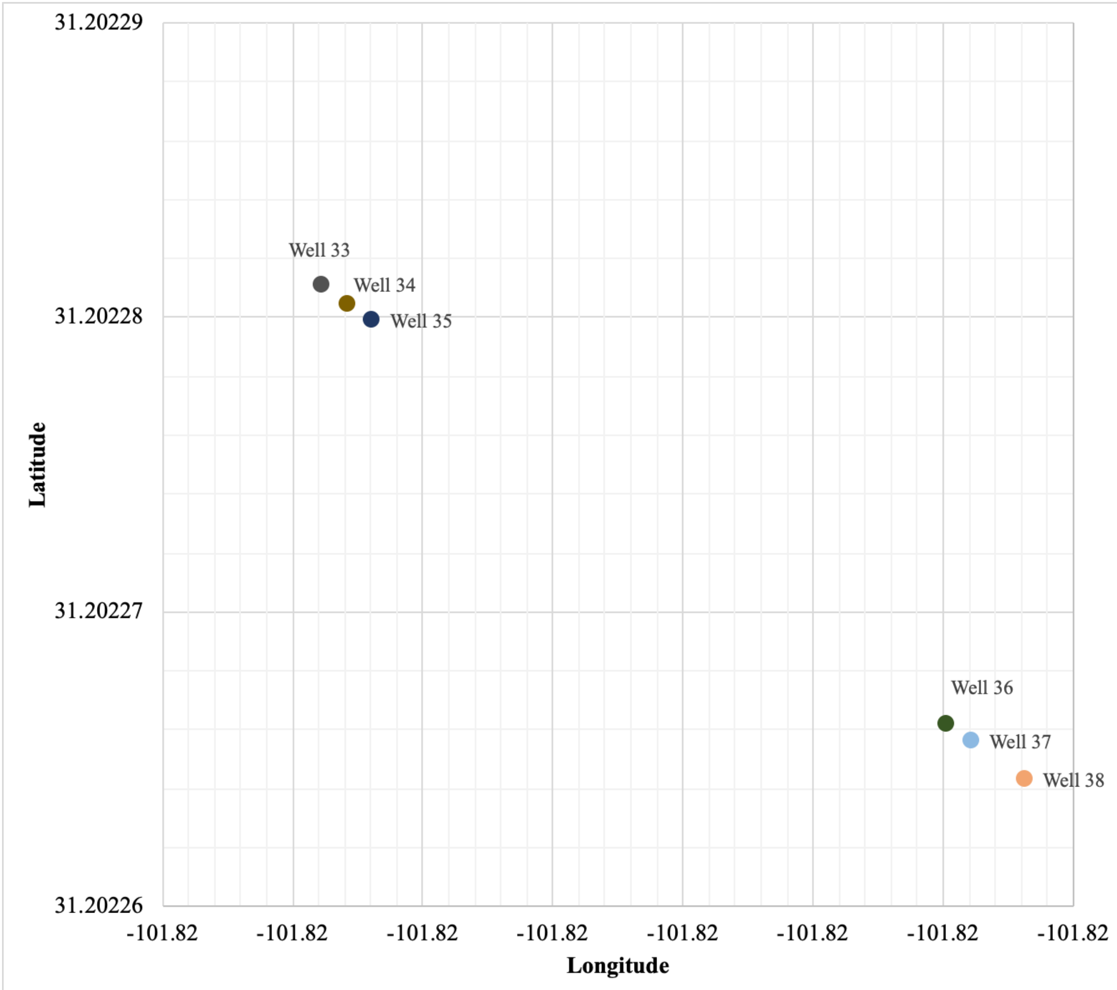

Figure 64 — Well locations of the six wells in the 3-33 block presented on a latitude vs. longitude plot. The surface distance between wells 33-34, 34-35, 36-37, and 37-38 are 30’.

APPENDIX B

CDF OF THE PROBABILISTIC DCA RESULTS FOR THE REMAINING 37 WELLS OF THE MIDLAND BASIN

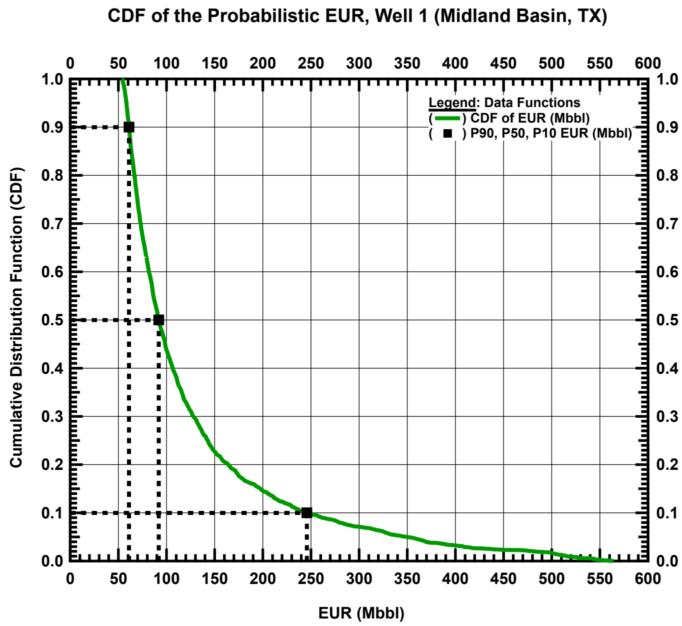

Figure 65 — CDF of the EUR of Well 1 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 61.01 Mbbls, the 2P (P50) is 91.89 Mbbls, and the 3P (P10) is 245.65 Mbbls.

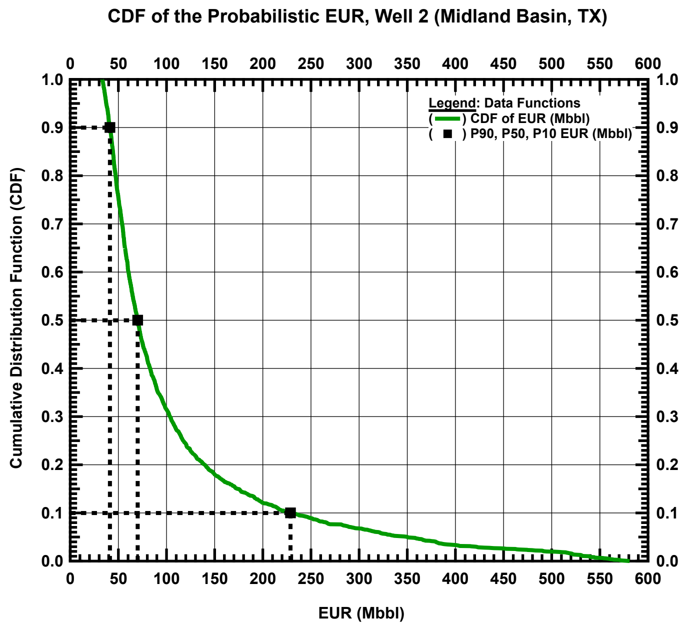

Figure 66 — CDF of the EUR of Well 2 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 41.09 Mbbls, the 2P (P50) is 69.88 Mbbls, and the 3P (P10) is 228.59 Mbbls.

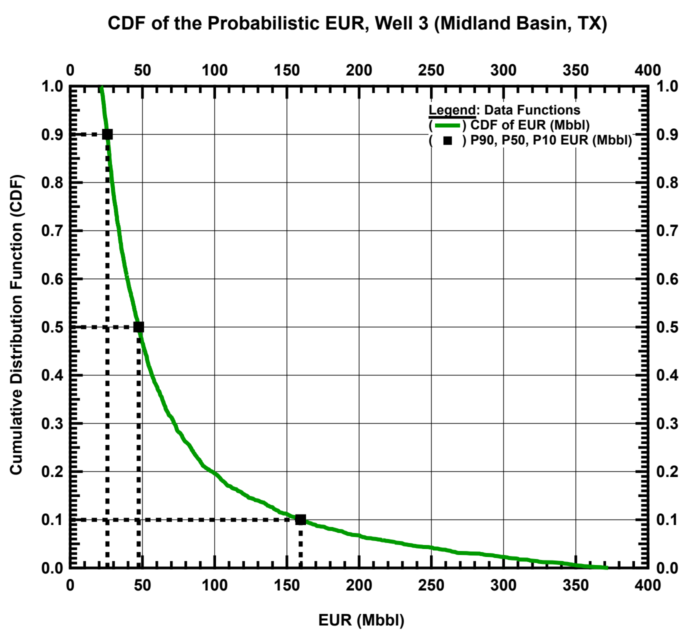

Figure 67 — CDF of the EUR of Well 3 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 25.66 Mbbls, the 2P (P50) is 47.39 Mbbls, and the 3P (P10) is 159.5 Mbbls.

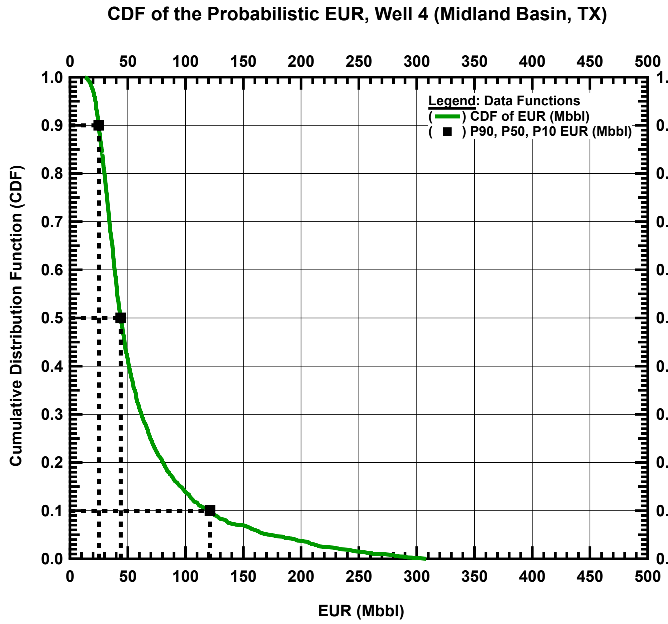

Figure 68 — CDF of the EUR of Well 4 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 24.81 Mbbls, the 2P (P50) is 43.87 Mbbls, and the 3P (P10) is 121.14 Mbbls.

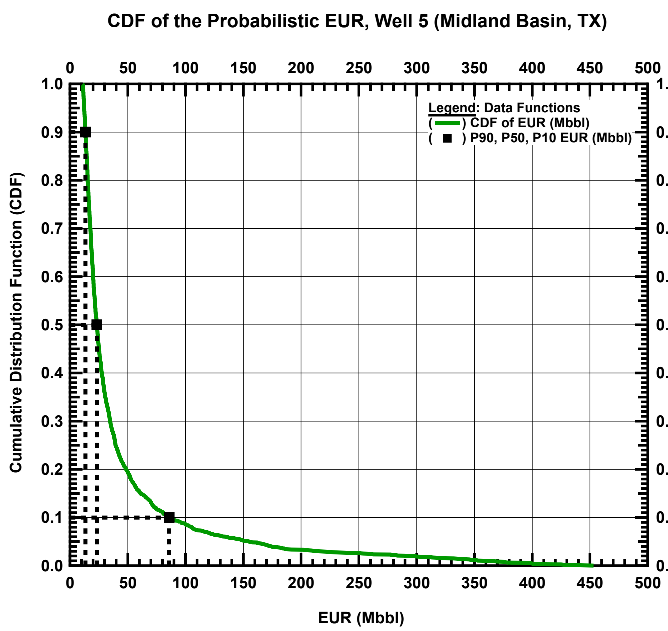

Figure 69 — CDF of the EUR of Well 5 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 13.35 Mbbls, the 2P (P50) is 23.13 Mbbls, and the 3P (P10) is 85.75 Mbbls.

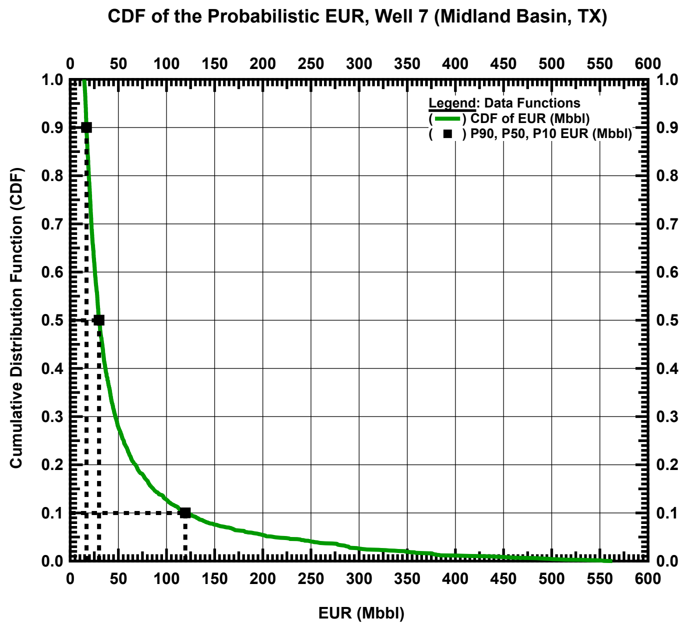

Figure 70 — CDF of the EUR of Well 7 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 16.76 Mbbls, the 2P (P50) is 29.9 Mbbls, and the 3P (P10) is 2119.46 Mbbls.

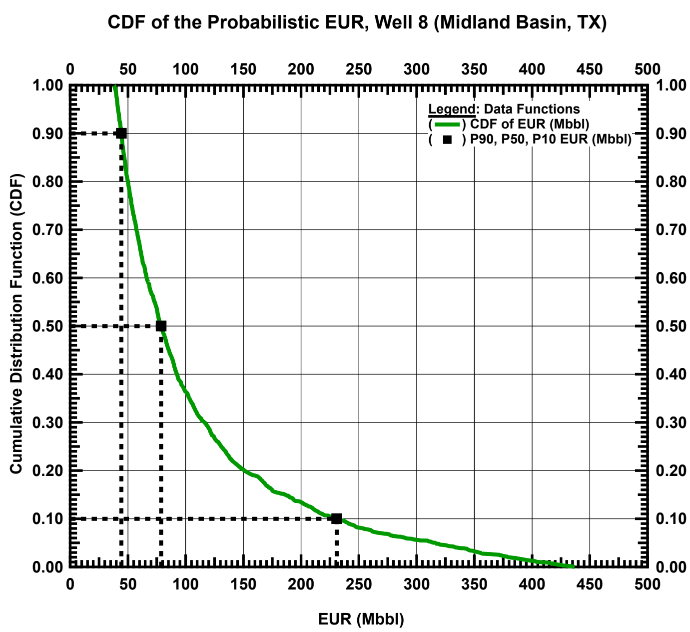

Figure 71 — CDF of the EUR of Well 8 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 44.28 Mbbls, the 2P (P50) is 78.68 Mbbls, and the 3P (P10) is 230.82 Mbbls.

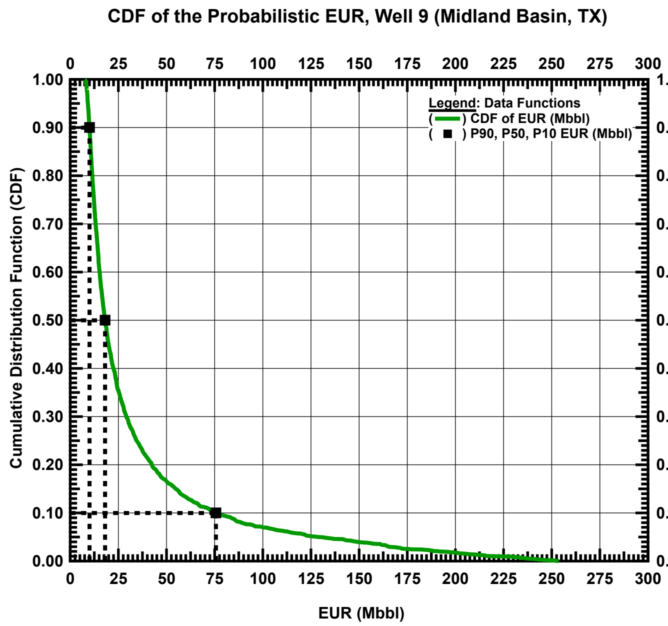

Figure 72 — CDF of the EUR of Well 9 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 9.98 Mbbls, the 2P (P50) is 18.1 Mbbls, and the 3P (P10) is 75.6 Mbbls.

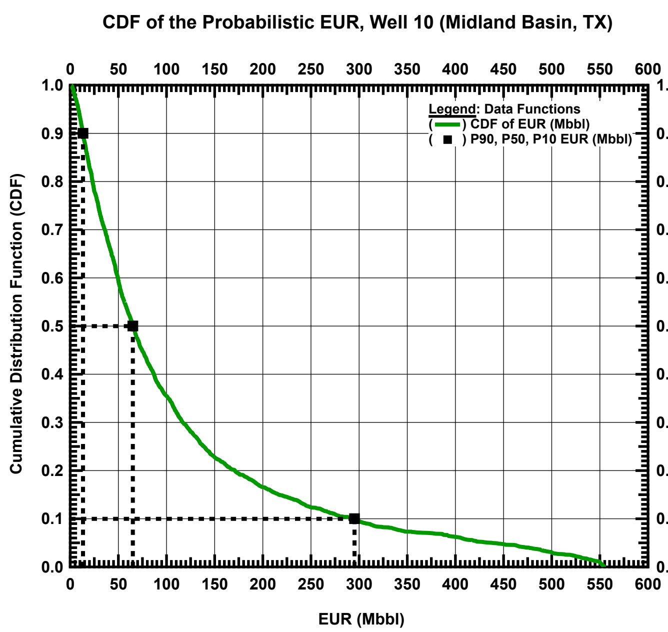

Figure 73 — CDF of the EUR of Well 10 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 13.13 Mbbls, the 2P (P50) is 64.96 Mbbls, and the 3P (P10) is 295.18 Mbbls.

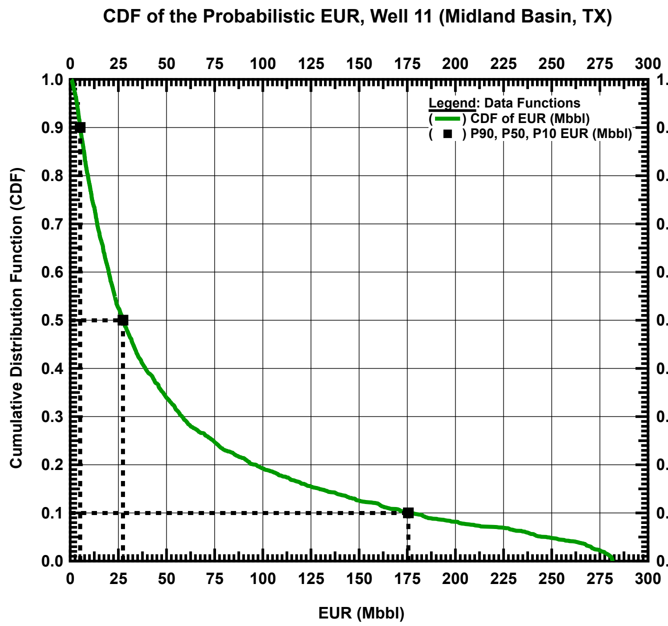

Figure 74 — CDF of the EUR of Well 11 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 5.11 Mbbls, the 2P (P50) is 27.35 Mbbls, and the 3P (P10) is 175.55 Mbbls.

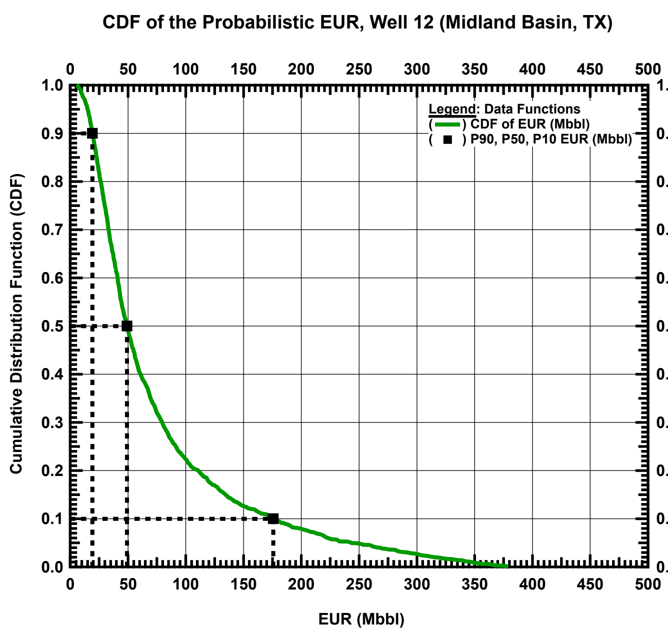

Figure 75 — CDF of the EUR of Well 12 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 19.03 Mbbls, the 2P (P50) is 49 Mbbls, and the 3P (P10) is 175.66 Mbbls.

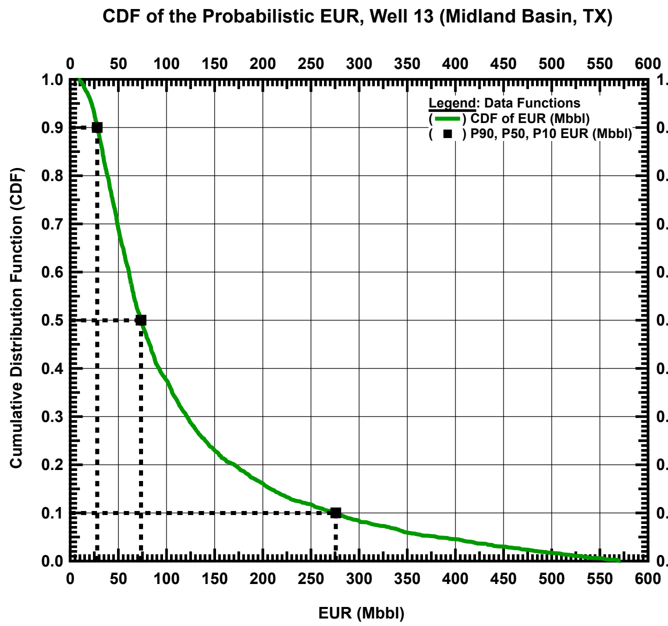

Figure 76 — CDF of the EUR of Well 13 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 29 Mb8ls, the 2P (P50) is 73.46 Mbbls, and the 3P (P10) is 275.77 Mbbls.

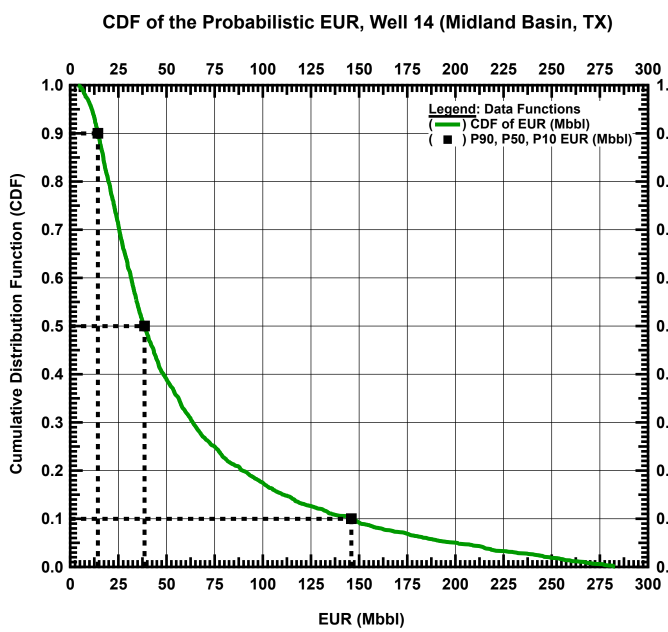

Figure 77 — CDF of the EUR of Well 14 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 14.34 Mbbls, the 2P (P50) is 38.54 Mbbls, and the 3P (P10) is 145.92 Mbbls.

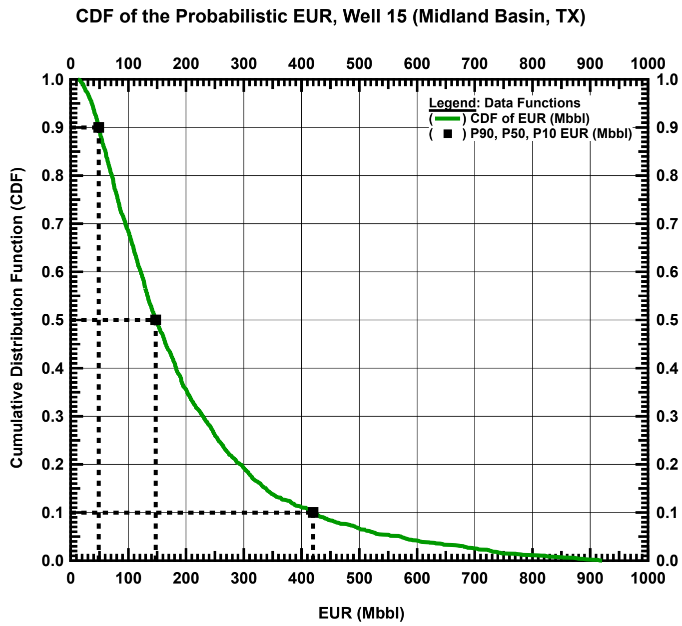

Figure 78 — CDF of the EUR of Well 15 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 48.55 Mbbls, the 2P (P50) is 147.27 Mbbls, and the 3P (P10) is 419.8 Mbbls.

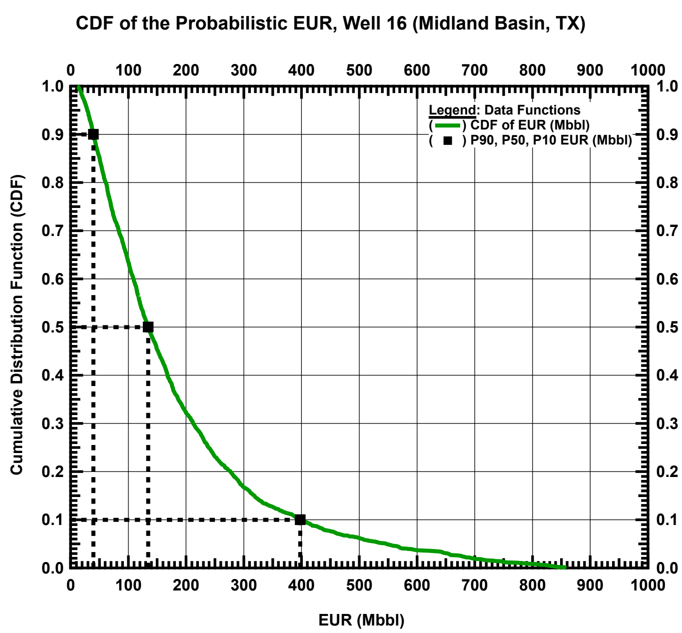

Figure 79 — CDF of the EUR of Well 16 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 39.34 Mbbls, the 2P (P50) is 134.4 Mbbls, and the 3P (P10) is 397.54 Mbbls.

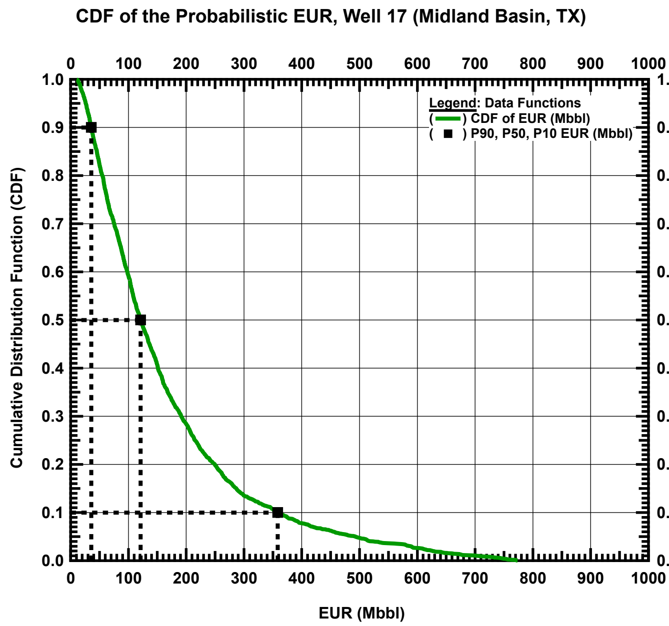

Figure 80 — CDF of the EUR of Well 17 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 35.45 Mbbls, the 2P (P50) is 121.1 Mbbls, and the 3P (P10) is 358.16 Mbbls.

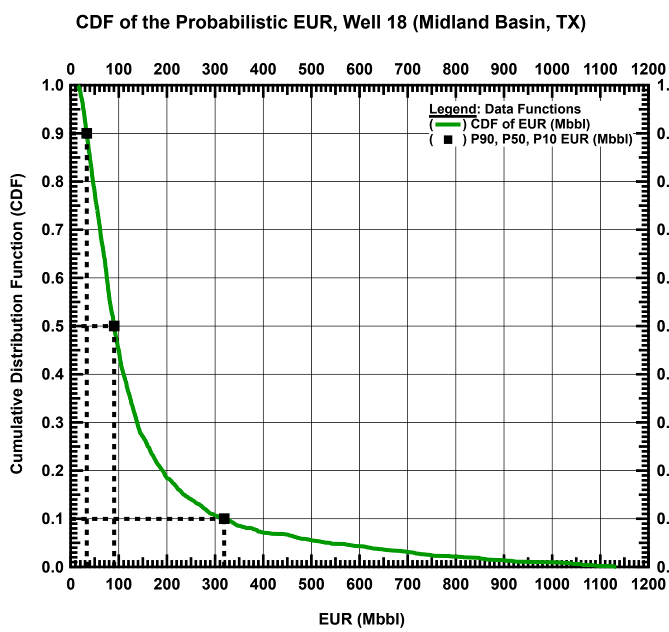

Figure 81 — CDF of the EUR of Well 18 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 33.28 Mbbls, the 2P (P50) is 90.36 Mbbls, and the 3P (P10) is 318.71 Mbbls.

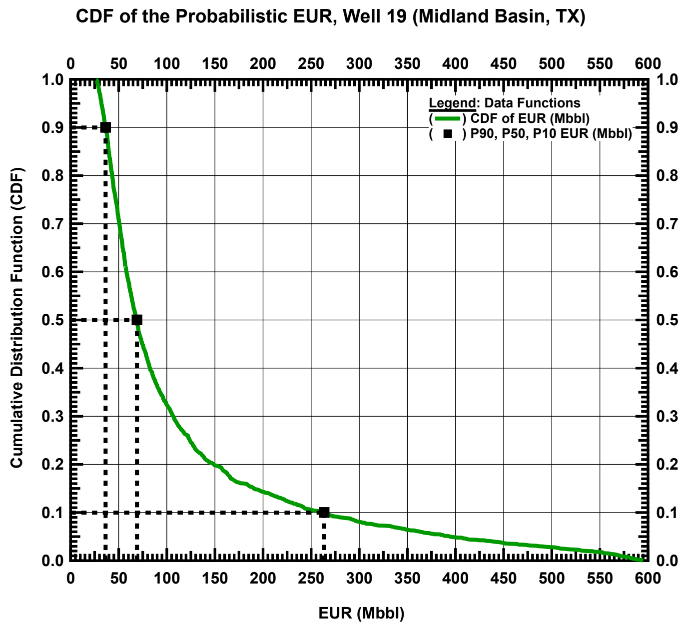

Figure 82 — CDF of the EUR of Well 19 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 36.31 Mbbls, the 2P (P50) is 68.84 Mbbls, and the 3P (P10) is 263.31 Mbbls.

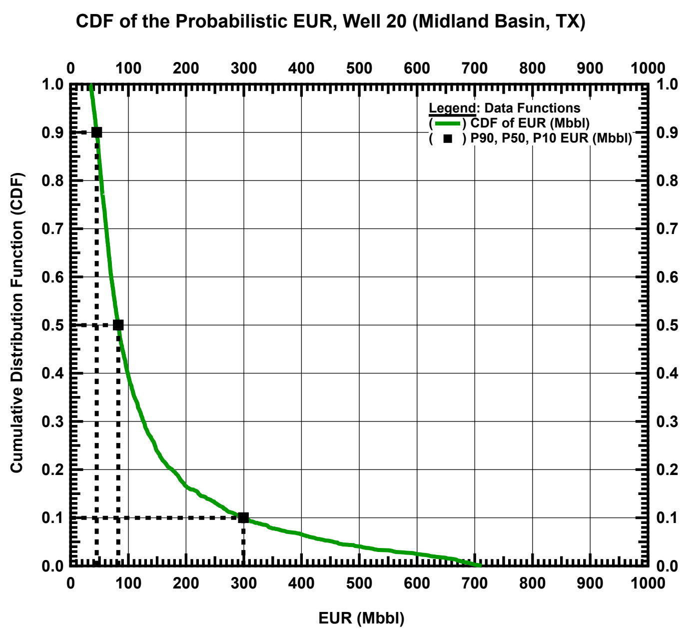

Figure 83 — CDF of the EUR of Well 20 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 45.05 Mbbls, the 2P (P50) is 82.6 Mbbls, and the 3P (P10) is 299.15 Mbbls.

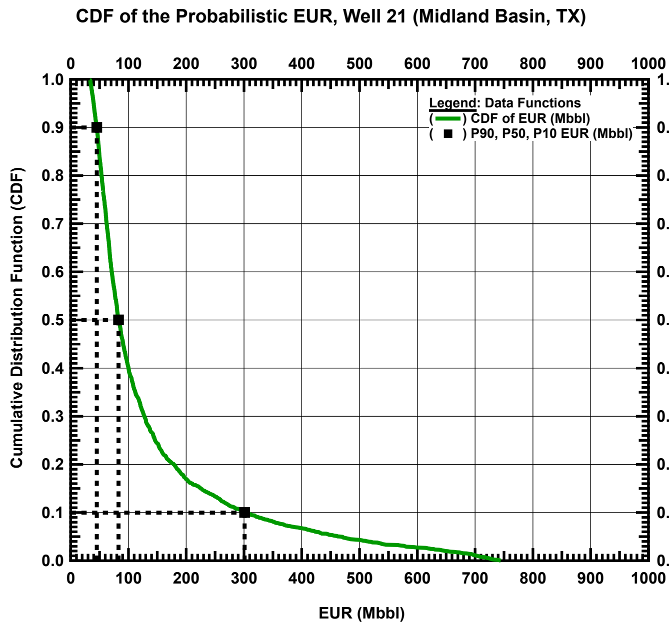

Figure 84 — CDF of the EUR of Well 21 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 45 Mbbls, the 2P (P50) is 82.85 Mbbls, and the 3P (P10) is 300.88 Mbbls.

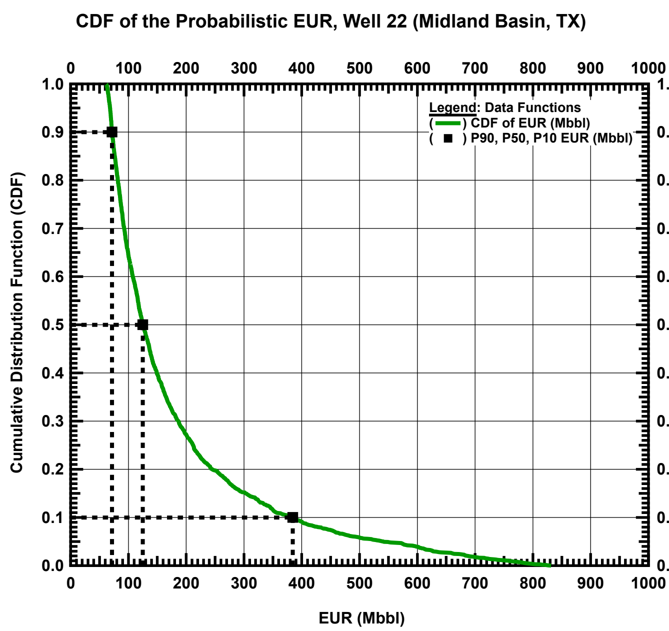

Figure 85 — CDF of the EUR of Well 22 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 71.42 Mbbls, the 2P (P50) is 124.64 Mbbls, and the 3P (P10) is 384.15 Mbbls.

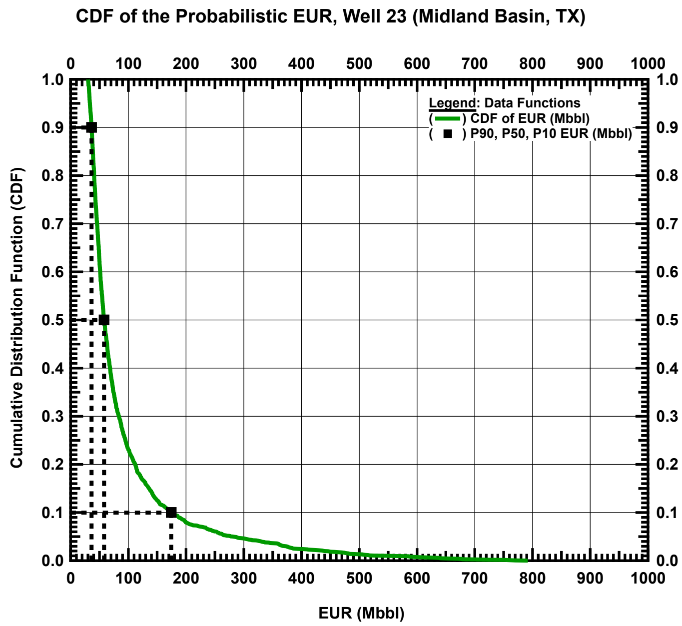

Figure 86 — CDF of the EUR of Well 23 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 36.14 Mbbls, the 2P (P50) is 57.86 Mbbls, and the 3P (P10) is 174.3 Mbbls.

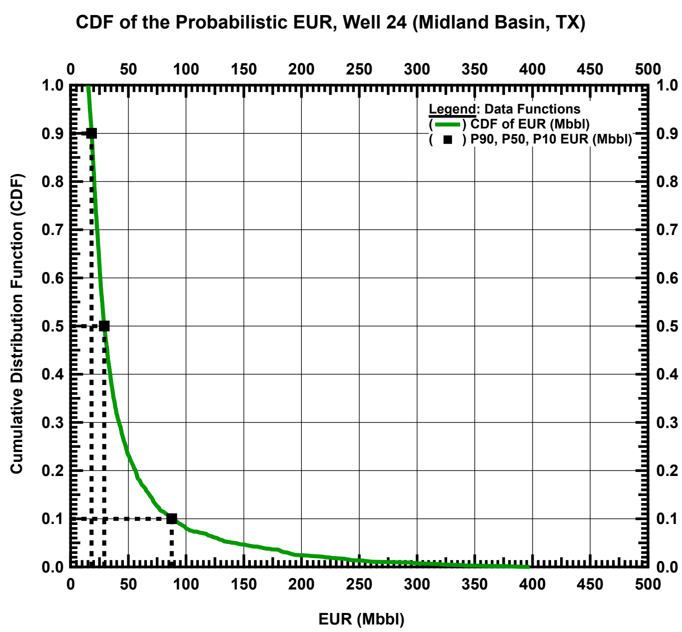

Figure 87 — CDF of the EUR of Well 24 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 18.15 Mbbls, the 2P (P50) is 29.06 Mbbls, and the 3P (P10) is 87.54 Mbbls.

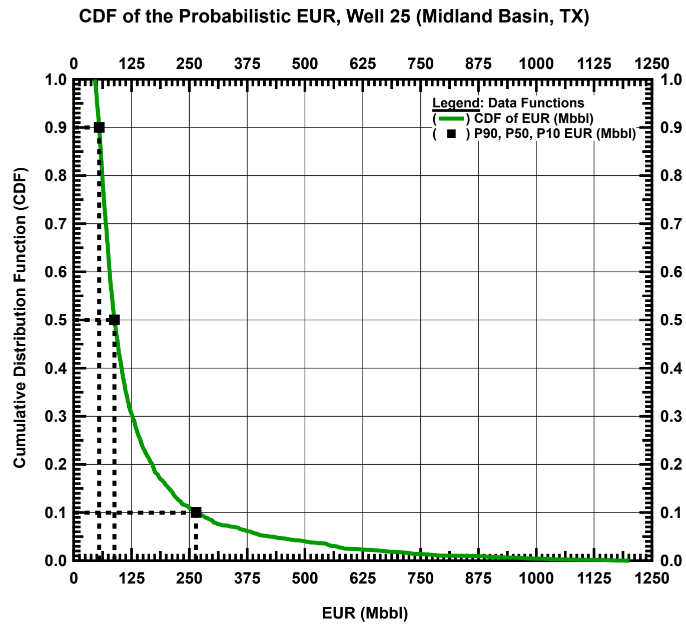

Figure 88 — CDF of the EUR of Well 25 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 54.86 Mbbls, the 2P (P50) is 87.83 Mbbls, and the 3P (P10) is 264.57 Mbbls.

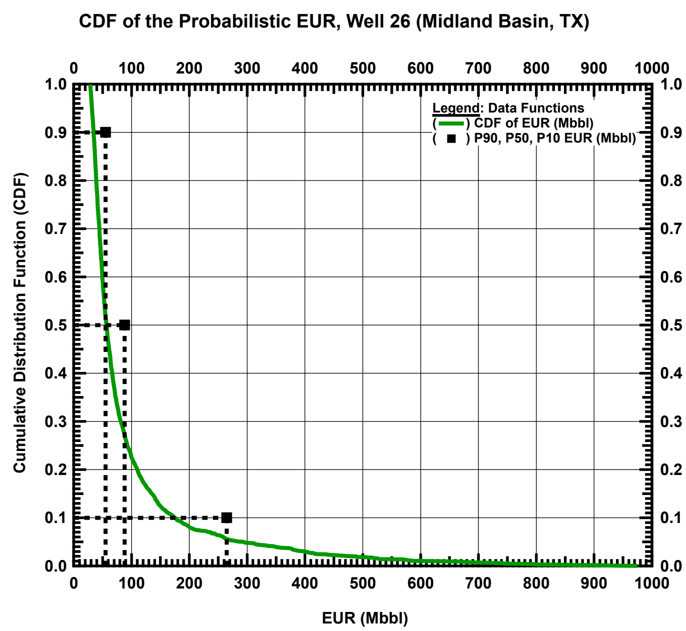

Figure 89 — CDF of the EUR of Well 21 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 54.86 Mbbls, the 2P (P50) is 87.83 Mbbls, and the 3P (P10) is 264.57 Mbbls.

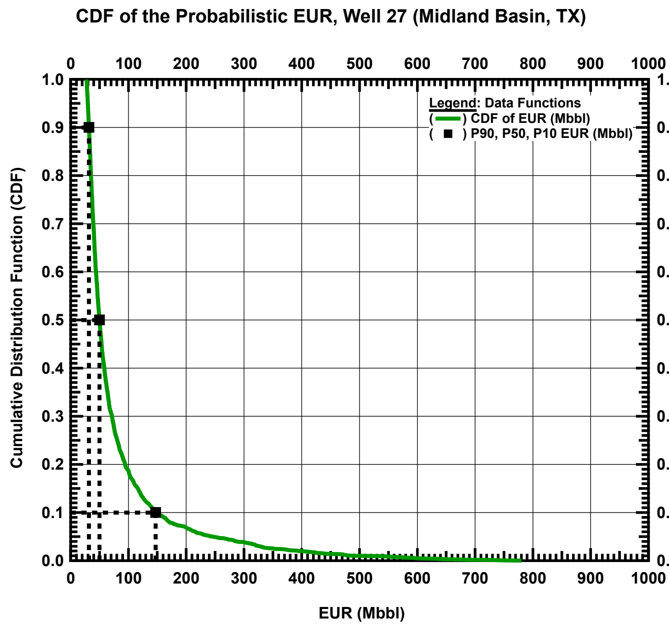

Figure 90 — CDF of the EUR of Well 27 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 31.59 Mbbls, the 2P (P50) is 49.73 Mbbls, and the 3P (P10) is 147.1 Mbbls.

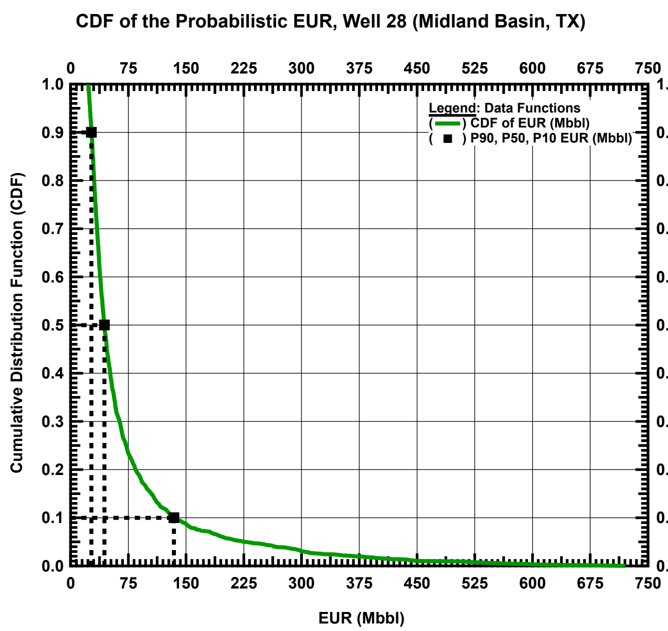

Figure 91 — CDF of the EUR of Well 28 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 27.01 Mbbls, the 2P (P50) is 43.79 Mbbls, and the 3P (P10) is 134.02 Mbbls.

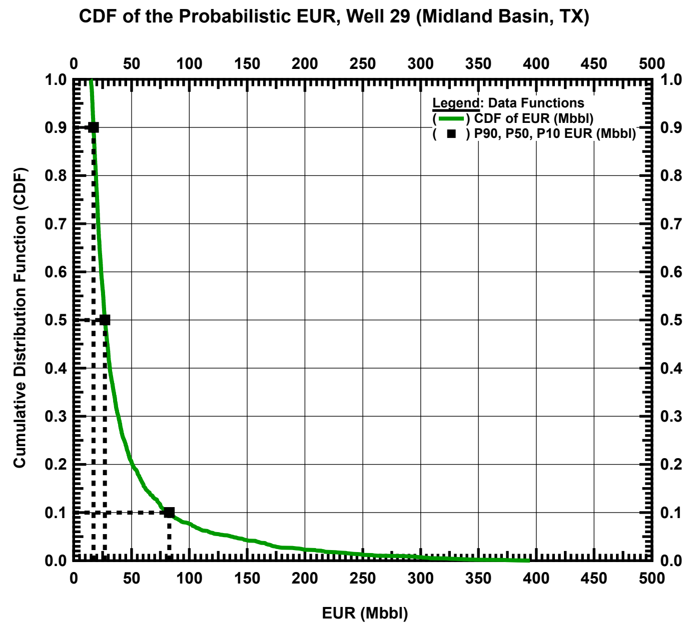

Figure 92 — CDF of the EUR of Well 29 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 17.08 Mbbls, the 2P (P50) is 26.89 Mbbls, and the 3P (P10) is 82.58 Mbbls.

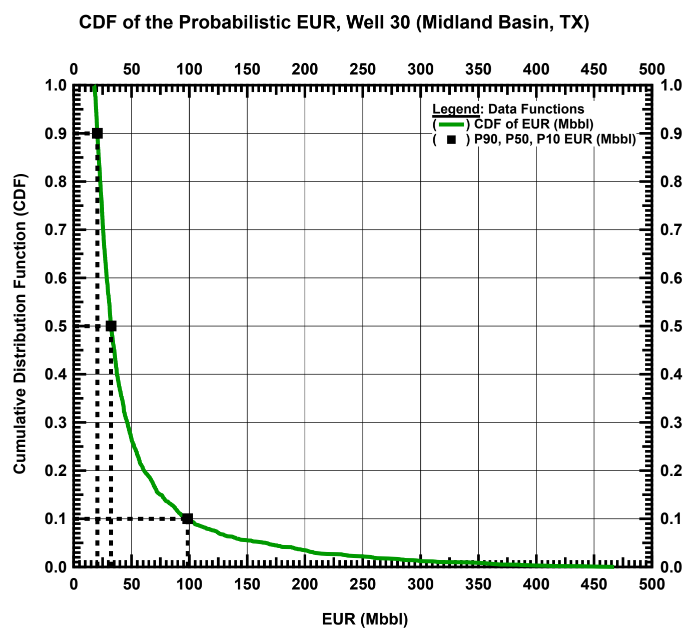

Figure 93 — CDF of the EUR of Well 30 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 20.36 Mbbls, the 2P (P50) is 32.28 Mbbls, and the 3P (P10) is 98.56 Mbbls.

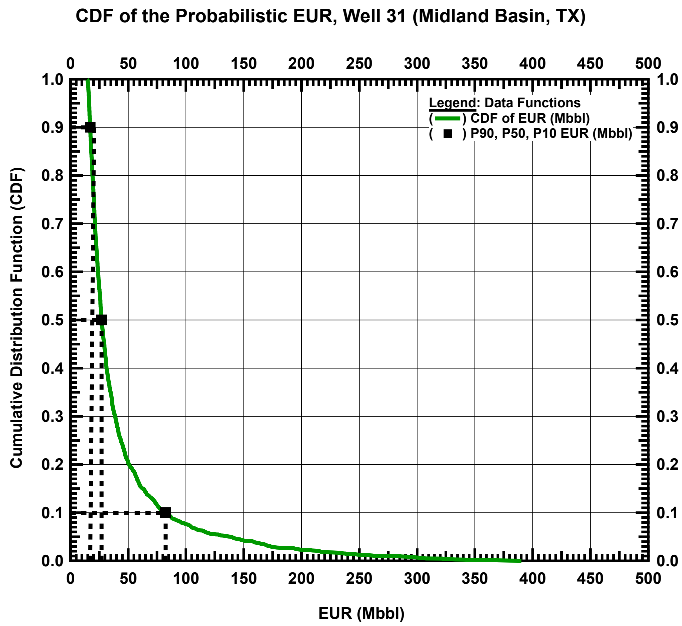

Figure 94 — CDF of the EUR of Well 31 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 17 Mbbls, the 2P (P50) is 26.96 Mbbls, and the 3P (P10) is 82.3 Mbbls.

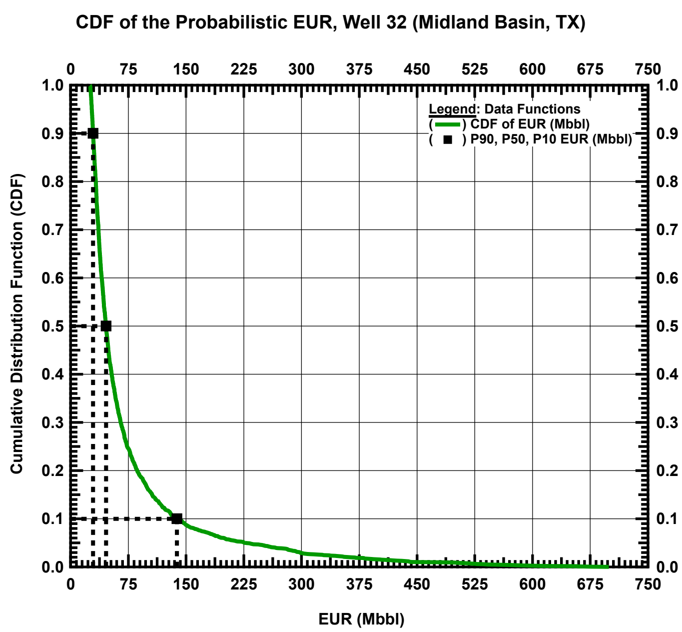

Figure 95 — CDF of the EUR of Well 32 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 29.08 Mbbls, the 2P (P50) is 45.95 Mbbls, and the 3P (P10) is 138.04 Mbbls.

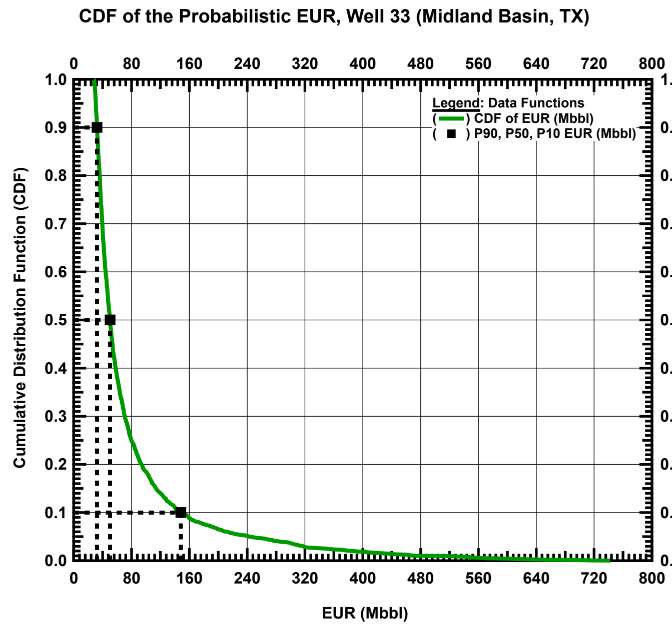

Figure 96 — CDF of the EUR of Well 33 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 32.15 Mbbls, the 2P (P50) is 50.2 Mbbls, and the 3P (P10) is 148.24 Mbbls.

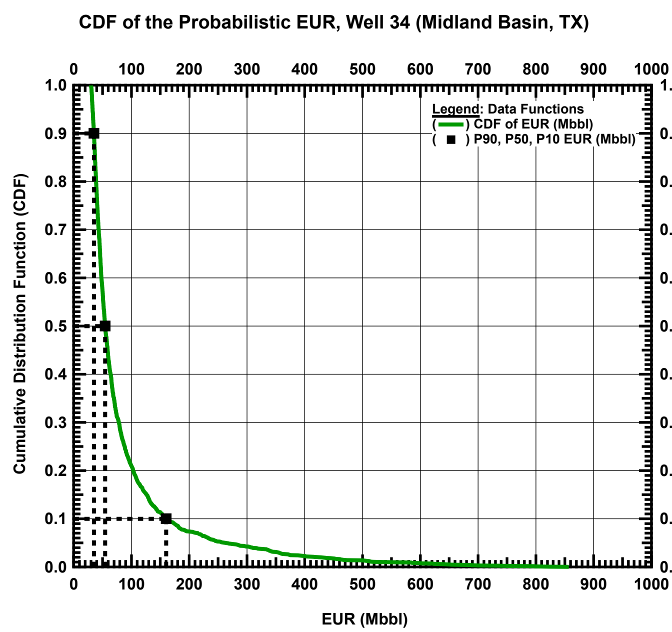

Figure 97 — CDF of the EUR of Well 34 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 35 Mbbls, the 2P (P50) is 54.54 Mbbls, and the 3P (P10) is 160 Mbbls.

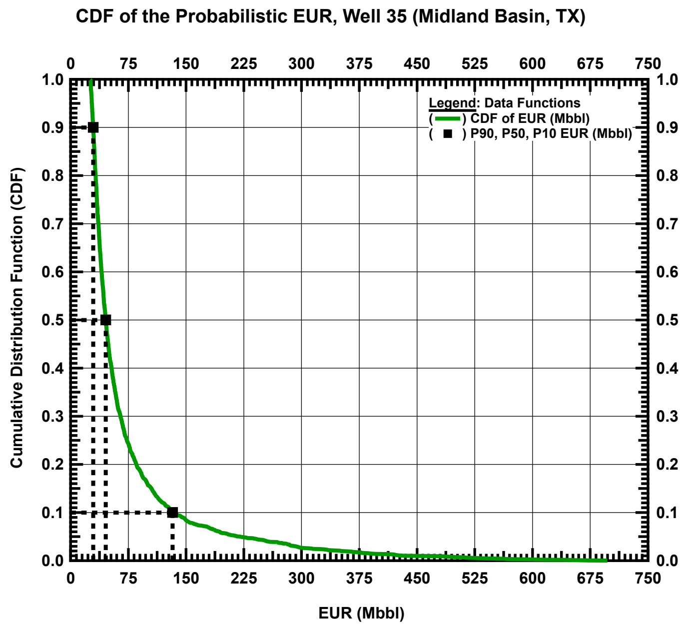

Figure 98 — CDF of the EUR of Well 35 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 29.29 Mbbls, the 2P (P50) is 45.54 Mbbls, and the 3P (P10) is 132.4 Mbbls.

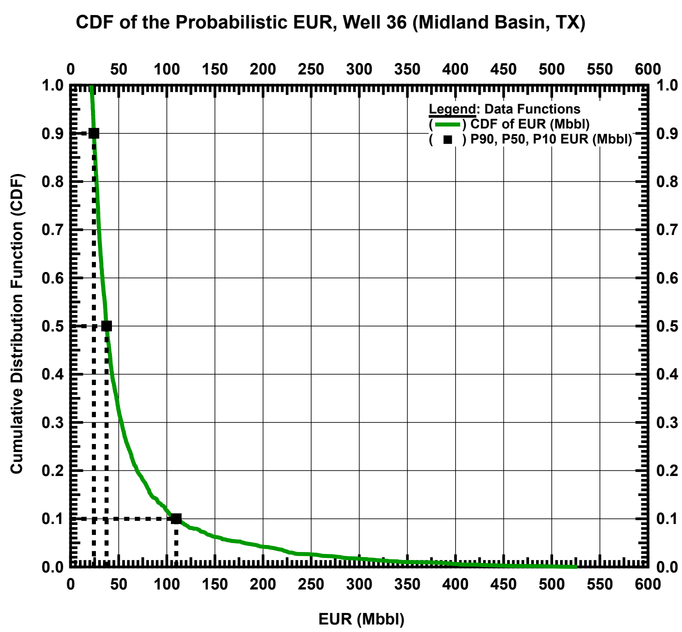

Figure 99 — CDF of the EUR of Well 36 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 24.2 Mbbls, the 2P (P50) is 37.27 Mbbls, and the 3P (P10) is 109.64 Mbbls.

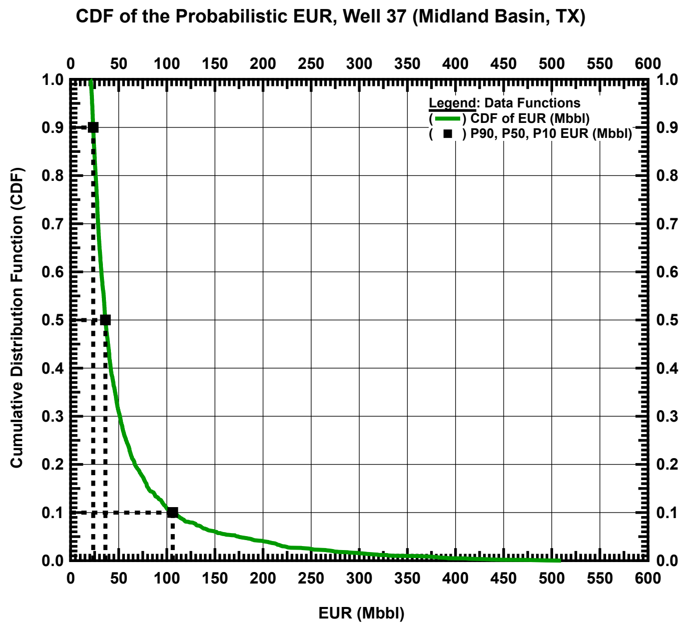

Figure 100 — CDF of the EUR of Well 37 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 23.43 Mbbls, the 2P (P50) is 36.08 Mbbls, and the 3P (P10) is 106.14 Mbbls.

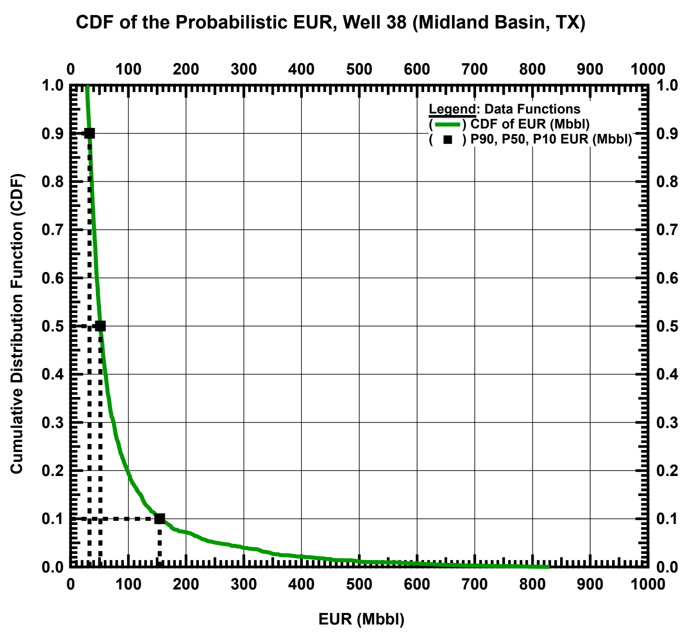

Figure 101 — CDF of the EUR of Well 38 in the Midland Basin, TX. From this graph, we read that the 1P (P90) is 32.65 Mbbls, the 2P (P50) is 51.57 Mbbls, and the 3P (P10) is 154.17 Mbbls.

APPENDIX C

TABLES OF PROBABILISTIC DCA AND PROBABILISTIC RTA RESULTS

We present the summary of 1P, 2P, and 3P Reserves from the probabilistic DCA in **Table 65**, and then present the cumulative distribution function graphs of the EUR to determine the 1P, 2P, and 3P volumes for each well in the Midland Basin dataset.

We present the summary of 1P, 2P, and 3P Reserves from the probabilistic RTA in **Table 66**, and then present the cumulative distribution function graphs of the EUR to determine the 1P, 2P, and 3P volumes for each well in the Midland Basin dataset.

We present the percent difference between the 1P, 2P, and 3P Reserves ratios in **Table 67**.

Well #	1P (Mbbl)	2P (Mbbl)	3P (Mbbl)	Summed Reserves	1P Ratio	2P Ratio	3P Ratio
1	60	95	254	409	0.15	0.23	0.62
2	40	70	225	335	0.12	0.21	0.67
3	25	50	175	250	0.10	0.20	0.70
4	25	42	120	187	0.13	0.22	0.64
5	15	25	90	130	0.12	0.19	0.69
6	30	50	165	245	0.12	0.20	0.67
7	25	40	125	190	0.13	0.21	0.66
8	42	80	230	352	0.12	0.23	0.65
9	10	20	80	110	0.09	0.18	0.73
10	15	60	310	385	0.04	0.16	0.81
11	5	30	170	205	0.02	0.15	0.83
12	20	50	180	250	0.08	0.20	0.72
13	30	80	270	380	0.08	0.21	0.71
14	15	40	150	205	0.07	0.20	0.73
15	50	150	425	625	0.08	0.24	0.68
16	40	140	400	580	0.07	0.24	0.69
17	40	130	350	520	0.08	0.25	0.67
18	35	100	330	465	0.08	0.22	0.71
19	40	60	250	350	0.11	0.17	0.71
20	50	90	300	440	0.11	0.20	0.68
21	45	90	300	435	0.10	0.21	0.69
22	70	120	390	580	0.12	0.21	0.67
23	40	55	180	275	0.15	0.20	0.65
24	20	30	90	140	0.14	0.21	0.64
25	60	95	280	435	0.14	0.22	0.64
26	40	60	180	280	0.14	0.21	0.64
27	30	50	155	235	0.13	0.21	0.66
28	30	40	160	230	0.13	0.17	0.70
29	20	30	80	130	0.15	0.23	0.62
30	20	40	110	170	0.12	0.24	0.65
31	20	30	82	132	0.15	0.23	0.62
32	25	40	140	205	0.12	0.20	0.68
33	30	50	150	230	0.13	0.22	0.65
34	35	55	170	260	0.13	0.21	0.65
35	30	50	135	215	0.14	0.23	0.63
36	25	40	110	175	0.14	0.23	0.63
37	25	40	110	175	0.14	0.23	0.63
38	30	50	150	230	0.13	0.22	0.65

Table 65—Summary of 1P, 2P, and 3P results from the probabilistic decline curve analysis, and the 1P, 2P, and 3P ratios based on the probabilistic DCA results.

Well #	1P (bbl)	2P (bbl)	3P (bbl)	Summed Reserves	1P Ratio	2P Ratio	3P Ratio
1	136	216	238	590	0.23	0.37	0.40
2	185	347	896	1428	0.13	0.24	0.63
3	172	198	228	598	0.29	0.33	0.38
4	134	153	175	462	0.29	0.33	0.38
5	128	148	168	444	0.29	0.33	0.38
6	197	223	259	679	0.29	0.33	0.38
7	215	396	829	1440	0.15	0.28	0.58
8	208	243	284	735	0.28	0.33	0.39
9	92	107	125	324	0.28	0.33	0.39
10	197	233	278	708	0.28	0.33	0.39
11	121	142	172	435	0.28	0.33	0.40
12	119	139	166	424	0.28	0.33	0.39
13	192	242	288	722	0.27	0.34	0.40
14	102	126	155	383	0.27	0.33	0.40
15	195	227	258	680	0.29	0.33	0.38
16	237	272	301	810	0.29	0.34	0.37
17	267	306	340	913	0.29	0.34	0.37
18	311	372	447	1130	0.28	0.33	0.40
19	247	302	366	915	0.27	0.33	0.40
20	288	390	409	1087	0.26	0.36	0.38
21	217	275	326	818	0.27	0.34	0.40
22	214	260	293	767	0.28	0.34	0.38
23	189	213	232	634	0.30	0.34	0.37
24	125	144	165	434	0.29	0.33	0.38
25	283	332	375	990	0.29	0.34	0.38
26	162	188	214	564	0.29	0.33	0.38
27	167	206	237	610	0.27	0.34	0.39
28	130	161	186	477	0.27	0.34	0.39
29	183	203	218	604	0.30	0.34	0.36
30	210	229	253	692	0.30	0.33	0.37
31	127	142	152	421	0.30	0.34	0.36
32	241	267	287	795	0.30	0.34	0.36
33	182	211	238	631	0.29	0.33	0.38
34	192	220	247	659	0.29	0.33	0.37
35	181	206	233	620	0.29	0.33	0.38
36	172	201	225	598	0.29	0.34	0.38
37	149	176	195	520	0.29	0.34	0.38
38	216	252	286	754	0.29	0.33	0.38

Table 66—Summary of 1P, 2P, and 3P results from the probabilistic RTA, and the 1P, 2P, and 3P ratios based on the probabilistic RTA results.

Well #	1P	2P	3P
1	44%	45%	42%
2	8%	15%	7%
3	97%	49%	59%
4	74%	38%	52%
5	86%	54%	59%
6	81%	47%	55%
7	13%	27%	13%
8	81%	37%	51%
9	103%	58%	61%
10	151%	71%	69%
11	168%	76%	71%
12	111%	48%	59%
13	108%	46%	56%
14	114%	51%	58%
15	113%	33%	57%
16	124%	33%	60%
17	117%	29%	58%
18	114%	42%	57%
19	81%	63%	56%
20	80%	55%	58%
21	88%	48%	54%
22	79%	48%	55%
23	69%	51%	57%
24	67%	43%	51%
25	70%	42%	52%
26	67%	43%	52%
27	73%	45%	52%
28	71%	64%	56%
29	65%	37%	52%
30	88%	34%	56%
31	66%	39%	53%
32	85%	53%	62%
33	75%	42%	53%
34	74%	45%	54%
35	71%	35%	50%
36	67%	38%	50%
37	67%	39%	51%
38	75%	42%	53%

Table 67—Percent difference between the probabilistic DCA and probabilistic RTA results.

APPENDIX D

PDF AND CDF OF SYNTHETIC LOGNORMAL DATASET BUILT FROM THE PROPERTIES OF THE PRODUCTION DATA OF THE REMAINING 37 WELLS TO BUILD GAUSSIAN QUADRATURE

In **Table 68** we present mean, standard deviation, variance, skewness, and kurtosis of the production data of the 38 wells in the Midland Basin. In **Table 69** we present the scaled values of the mean, standard deviation, and variance that were used to build the synthetic datasets that follow a lognormal distribution. In **Table 70**, we present the first four moments of the synthetic lognormal distribution, which are the mean, variance, skewness, and kurtosis. Finally in **Table 71**, we compare the actual and synthetic results and present the percent difference.

We then present the PDF and CDF results of the synthetic dataset that was built from the scaled mean and standard deviation of their respective wells production data.

Well	Characteristics of Production Data				
	Mean	Standard Deviation	Variance	Skewness	Kurtosis
1	157	99	9,854	3	14
2	151	121	15,250	2	12
3	158	123	15,250	3	12
4	124	114	12,897	2	12
5	123	131	17,132	3	8
6	173	148	22,004	3	7
7	173	121	14,629	2	2
8	253	118	13,991	1	1
9	116	69	4,708	1	0
10	241	143	20,446	1	0
11	155	74	5,538	1	0
12	152	91	8,199	2	2
13	238	128	16,493	1	0
14	123	51	2,557	0	0
15	160	216	46,524	2	5
16	197	229	52,665	2	7
17	217	289	83,593	3	11
18	407	233	54,454	1	1
19	302	111	12,242	0	0
20	313	255	65,050	0	-1
21	285	187	35,040	1	1
22	178	168	28,204	2	4
23	152	158	25,014	2	2
24	108	114	13,026	3	11
25	232	208	43,382	2	4
26	137	151	22,859	3	9
27	202	143	20,506	2	3
28	146	153	23,477	2	6
29	87	71	4,993	2	6
30	114	99	9,715	2	7
31	61	60	3,642	3	10
32	124	107	11,401	3	10
33	148	118	13,949	2	6
34	155	150	22,409	2	6
35	136	123	15,231	2	7
36	141	113	12,765	2	7
37	120	91	8,222	3	9
38	172	163	26,505	3	9

Table 68—The mean, standard deviation, variance, skewness, and kurtosis of the production data of the 38 wells.

	Scaled Results		
Well	Mean	Standard Deviation	Variance
1	4.89	0.58	0.34
2	4.77	0.70	0.49
3	4.82	0.69	0.48
4	4.51	0.78	0.61
5	4.43	0.87	0.76
6	4.87	0.74	0.55
7	4.95	0.63	0.40
8	5.43	0.44	0.20
9	4.60	0.55	0.30
10	5.33	0.55	0.30
11	4.94	0.46	0.21
12	4.87	0.55	0.31
13	5.34	0.51	0.26
14	4.73	0.40	0.16
15	4.55	1.02	1.04
16	4.86	0.93	0.86
17	4.87	1.01	1.02
18	5.87	0.53	0.28
19	5.65	0.35	0.13
20	5.49	0.71	0.51
21	5.47	0.60	0.36
22	4.86	0.80	0.64
23	4.65	0.86	0.74
24	4.31	0.86	0.75
25	5.15	0.77	0.59
26	4.52	0.89	0.80
27	5.10	0.64	0.41
28	4.62	0.86	0.74
29	4.22	0.71	0.51
30	4.46	0.75	0.56
31	3.77	0.83	0.68
32	4.54	0.74	0.55
33	4.75	0.70	0.49
34	4.72	0.81	0.66
35	4.61	0.78	0.60
36	4.70	0.70	0.50
37	4.57	0.67	0.45
38	4.83	0.80	0.64

Table 69—The scaled results of the mean, standard deviation, and variance, used to build the synthetic lognormal distribution

	4 Moments of Synthetic Lognormal Distribution from Production			
Well	**E[X]=Mean**	**E[X2]=Variance**	**E[X3]=Skewness**	**E[X4]=Kurtosis**
1	159	9815	1.81	5.06
2	150	13288	2.67	13.68
3	156	14247	2.44	11.36
4	123	12012	2.80	12.86
5	124	15684	3.10	15.46
6	169	17380	1.99	6.35
7	174	13419	1.83	4.94
8	251	13120	1.27	2.17
9	117	4807	2.17	10.03
10	239	21594	2.08	7.91
11	155	5550	1.60	4.32
12	152	8013	1.82	5.19
13	243	17327	1.65	4.15
14	122	2550	1.27	3.09
15	158	39860	4.48	34.50
16	200	55330	3.92	24.31
17	226	100333	4.68	34.24
18	405	51132	1.74	5.31
19	305	12954	1.27	3.53
20	309	69939	2.99	14.40
21	297	40358	2.40	11.66
22	181	28565	3.79	30.77
23	157	27259	3.53	19.21
24	111	16015	5.32	51.08
25	235	45959	3.91	30.59
26	144	27146	5.37	57.46
27	207	19249	1.85	5.32
28	148	31430	7.62	114.74
29	90	6304	3.52	24.32
30	114	8636	2.75	14.78
31	61	3312	3.22	17.31
32	124	11305	2.73	11.17
33	151	15068	2.85	13.79
34	160	23922	3.70	26.64
35	135	13565	2.73	12.04
36	141	10930	2.28	9.78
37	121	9042	2.91	15.32
38	177	29716	3.67	24.56

Table 70—First four moments of the synthetic lognormal distribution built using the scaled mean and standard deviation of the 38 wells in the Midland Basin dataset.

	% Difference (Prod Data vs. Synthetic Lognormal Distr.)			
Well	**E[X]=Mean**	**E[X2]=Variance**	**E[X3]=Skewness**	**E[X4]=Kurtosis**
1	1.01%	0.40%	50%	95%
2	0.61%	9.16%	20%	77%
3	1.39%	6.80%	13%	4%
4	0.33%	7.11%	23%	95%
5	1.06%	8.82%	16%	63%
6	2.21%	23.48%	26%	14%
7	1.09%	8.63%	8%	74%
8	0.66%	6.42%	23%	116%
9	0.86%	2.08%	73%	211%
10	0.47%	5.46%	94%	212%
11	0.00%	0.21%	77%	221%
12	0.19%	2.29%	17%	97%
13	2.15%	4.93%	69%	210%
14	1.01%	0.24%	96%	153%
15	0.80%	15.43%	65%	150%
16	1.52%	4.94%	46%	108%
17	4.17%	18.20%	57%	105%
18	0.43%	6.29%	28%	141%
19	0.98%	5.65%	127%	211%
20	1.18%	7.24%	165%	241%
21	4.03%	14.11%	69%	174%
22	1.54%	1.27%	61%	152%
23	3.63%	8.59%	75%	155%
24	2.22%	20.59%	62%	131%
25	1.21%	5.77%	78%	154%
26	5.18%	17.15%	65%	145%
27	2.77%	6.32%	4%	43%
28	0.90%	28.97%	113%	180%
29	3.53%	23.21%	47%	126%
30	0.14%	11.77%	16%	69%
31	0.01%	9.47%	5%	53%
32	0.37%	0.84%	1%	9%
33	2.30%	7.71%	24%	79%
34	3.15%	6.53%	42%	124%
35	0.47%	11.57%	15%	58%
36	0.16%	15.49%	12%	37%
37	0.61%	9.50%	3%	56%
38	3.08%	11.42%	36%	96%

Table 71—Percent difference between the actual data and synthetic dataset mean, variance, skewness, and kurtosis, the first four moments of the distribution.

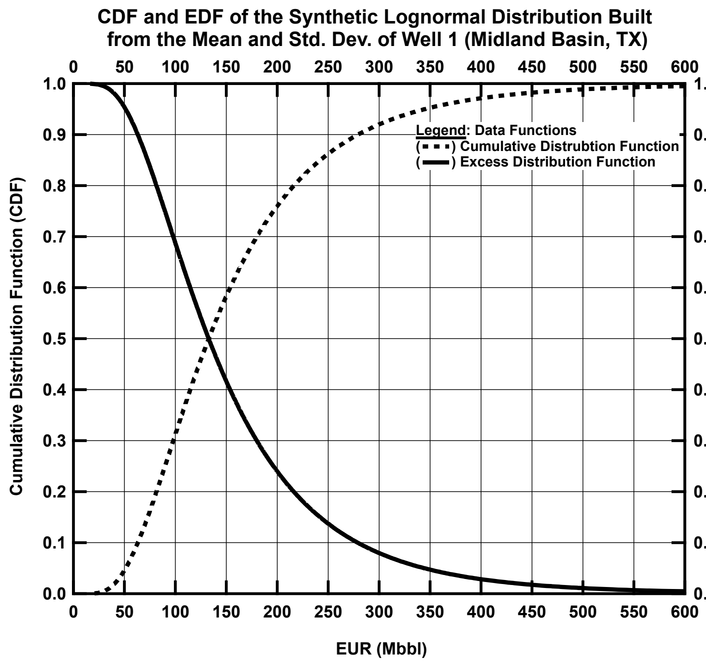

Figure 102 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 1.

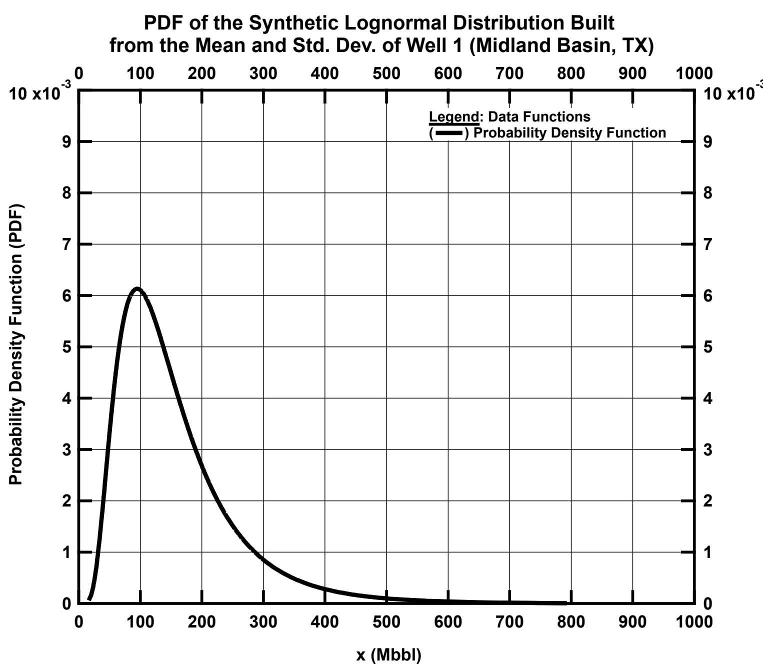

Figure 103 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 1.

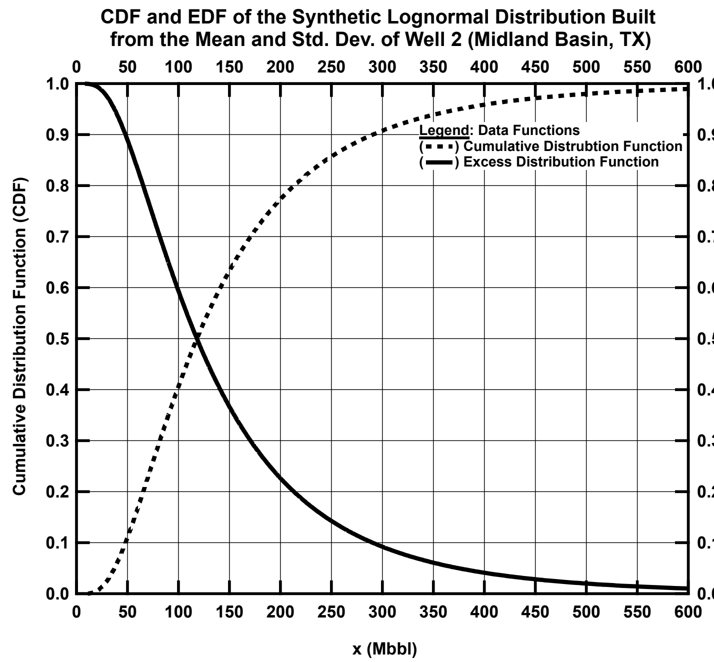

Figure 104 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 2.

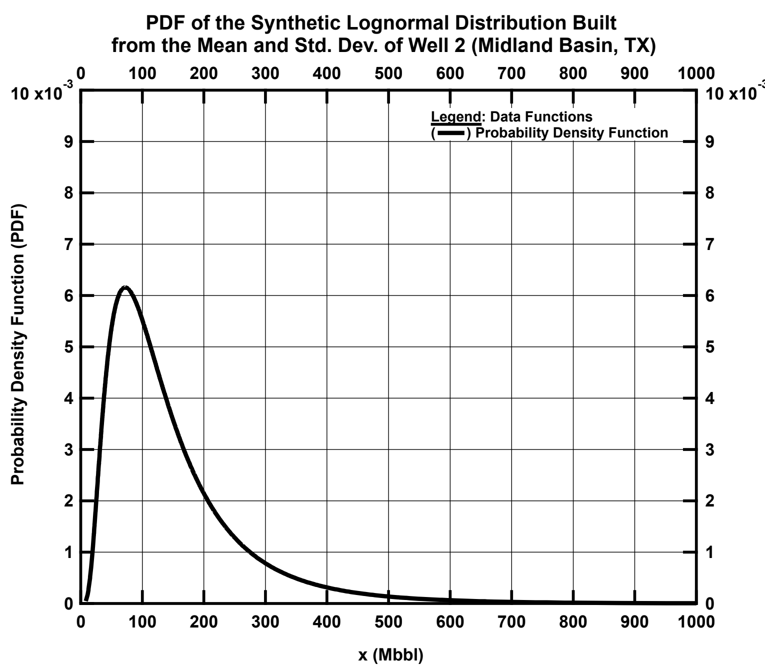

Figure 105 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 2.

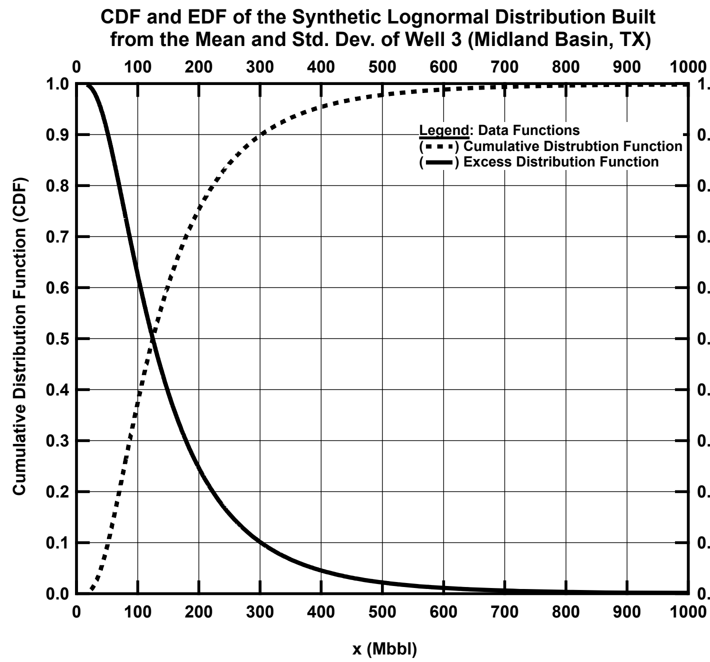

Figure 106 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 3.

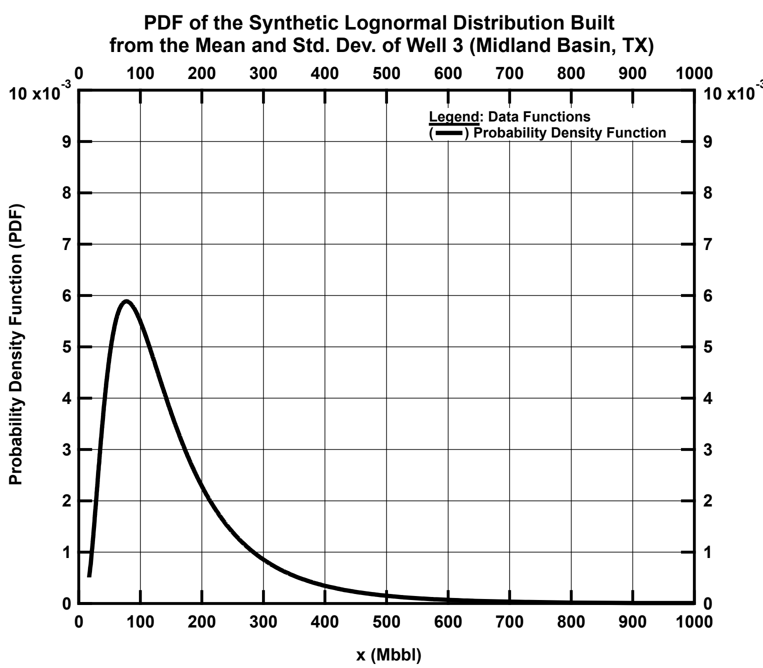

Figure 107 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 3.

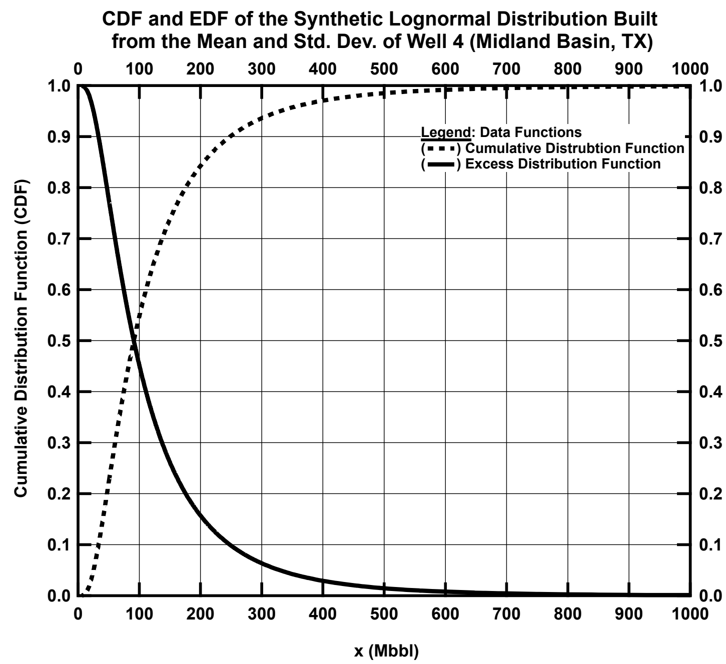

Figure 108 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 4.

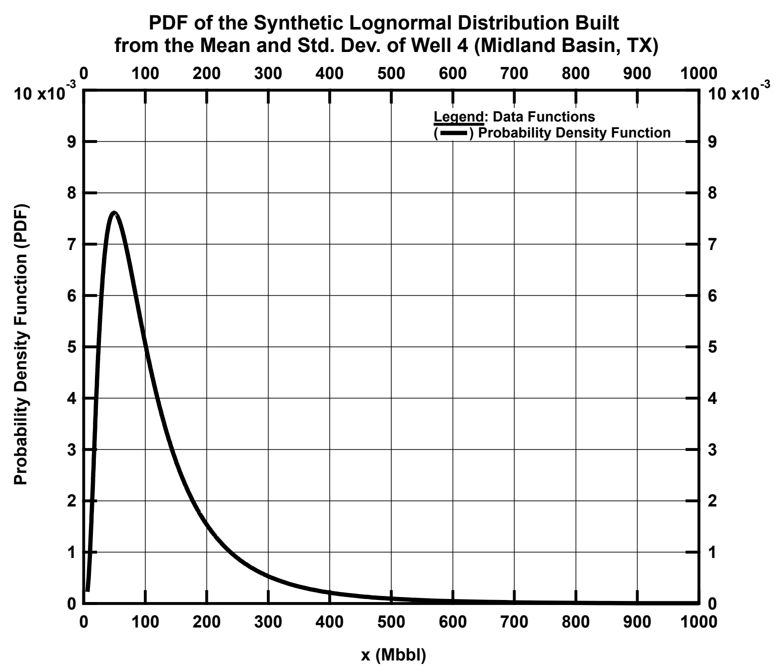

Figure 109 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 4.

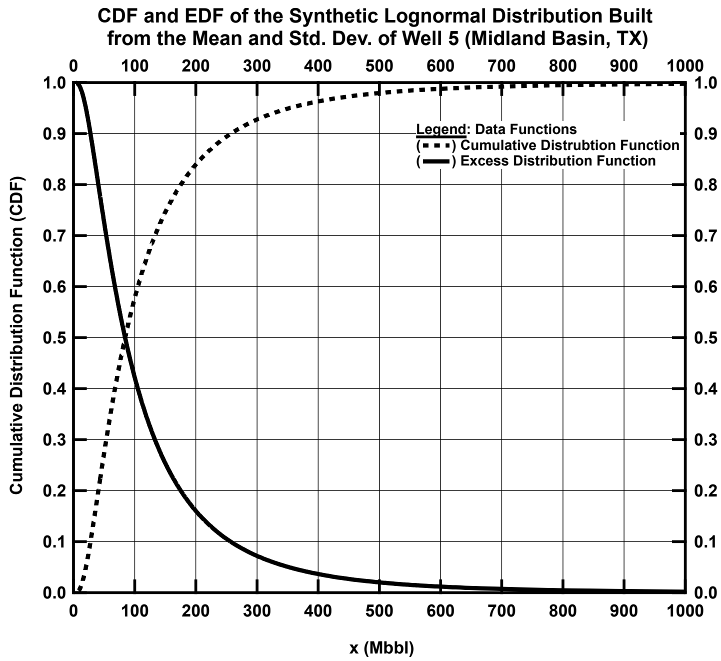

Figure 110 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 5.

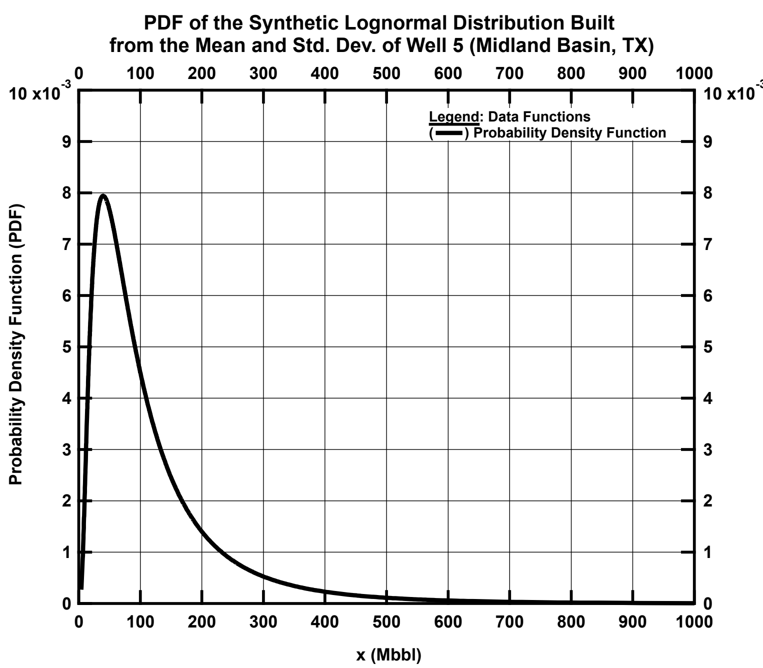

Figure 111 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 5.

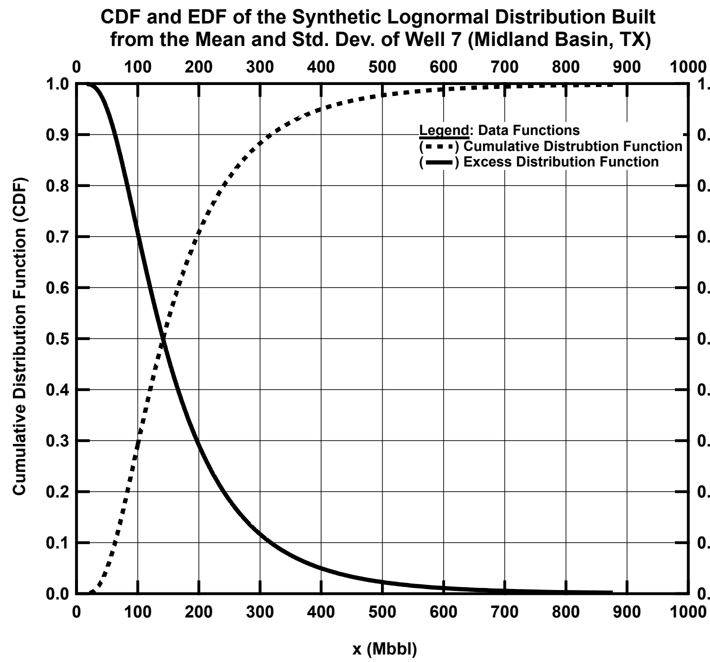

Figure 112 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 7.

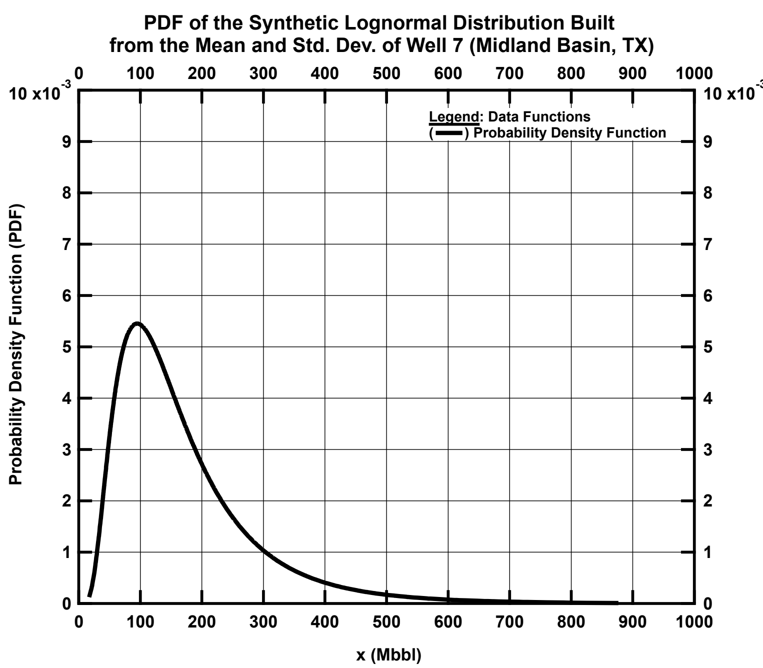

Figure 113 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 7.

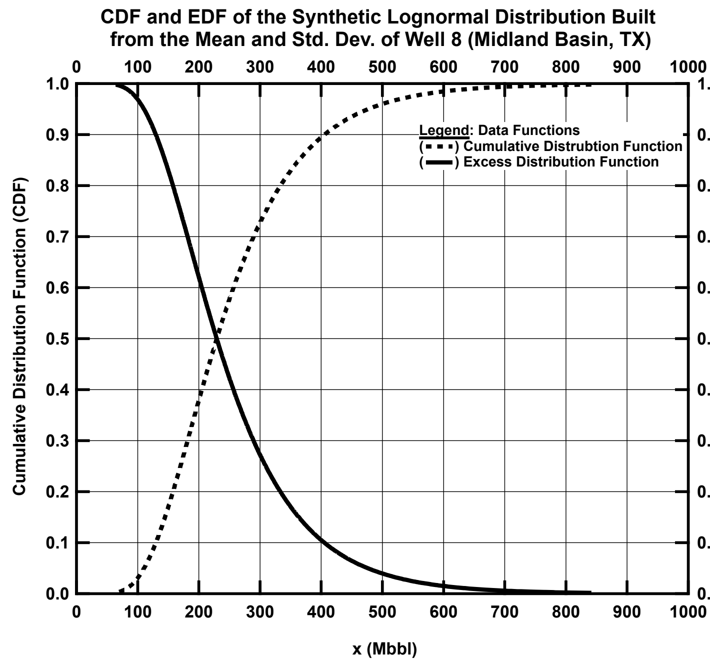

Figure 114 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 8.

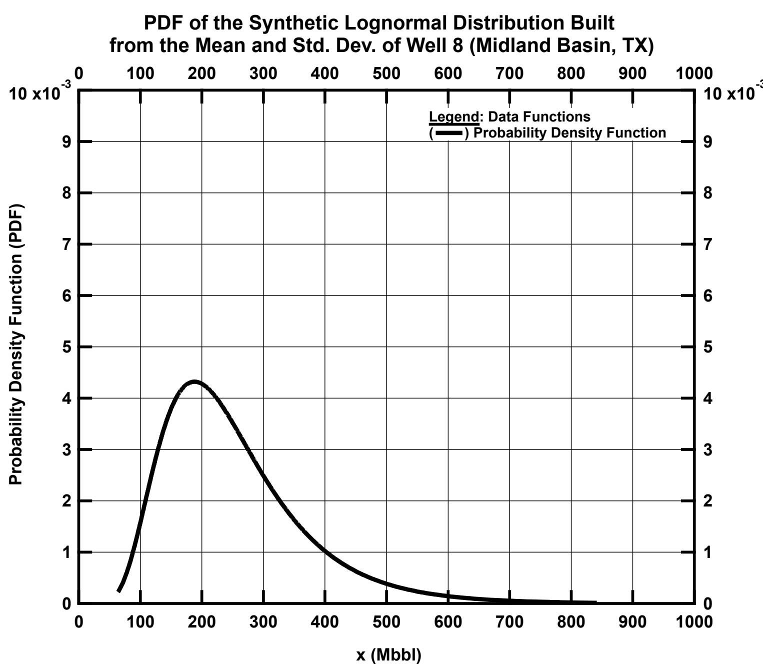

Figure 115 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 8.

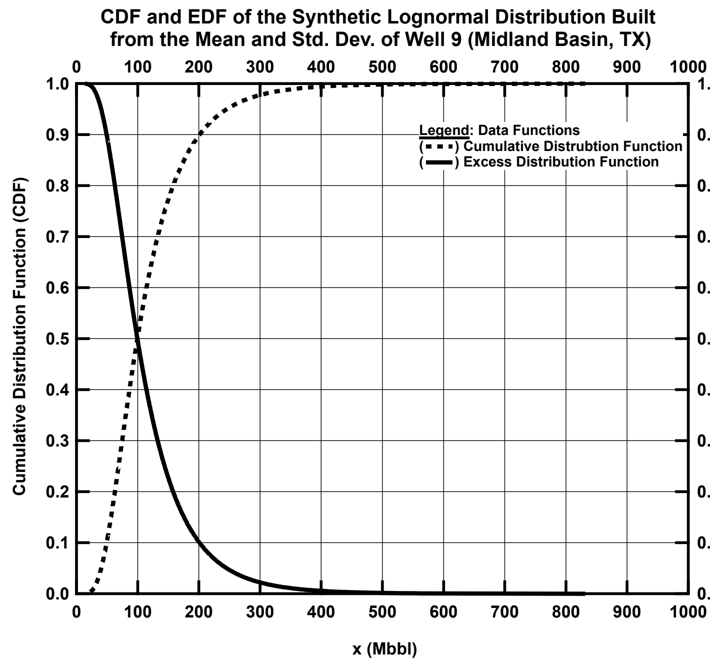

Figure 116 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 9.

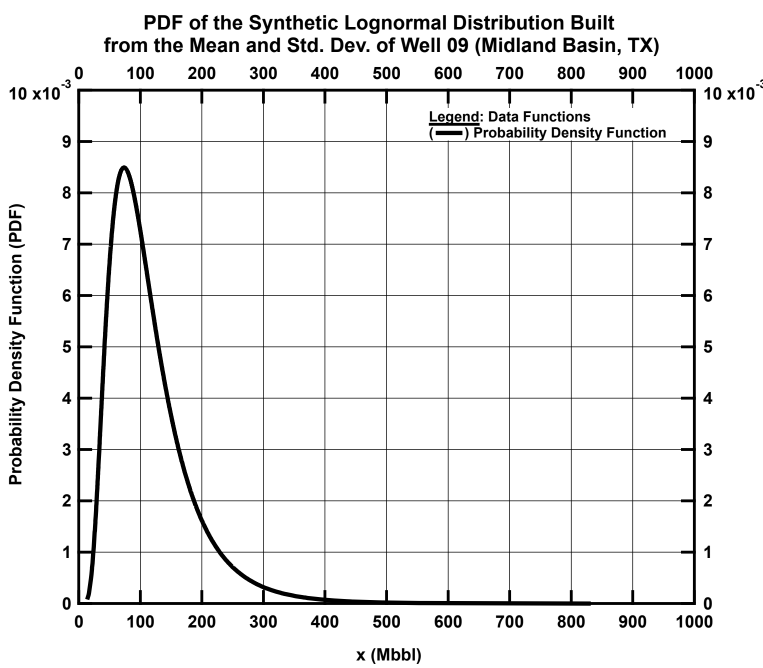

Figure 117 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 9.

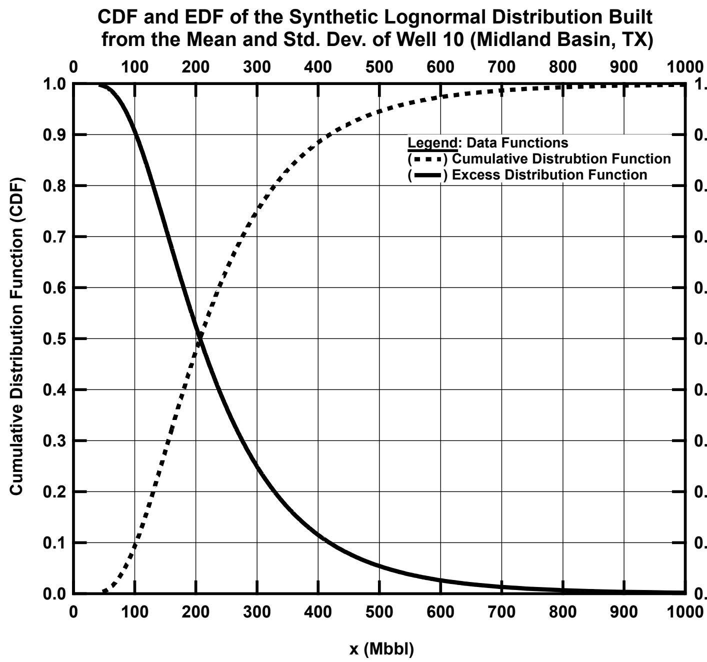

Figure 118 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 10.

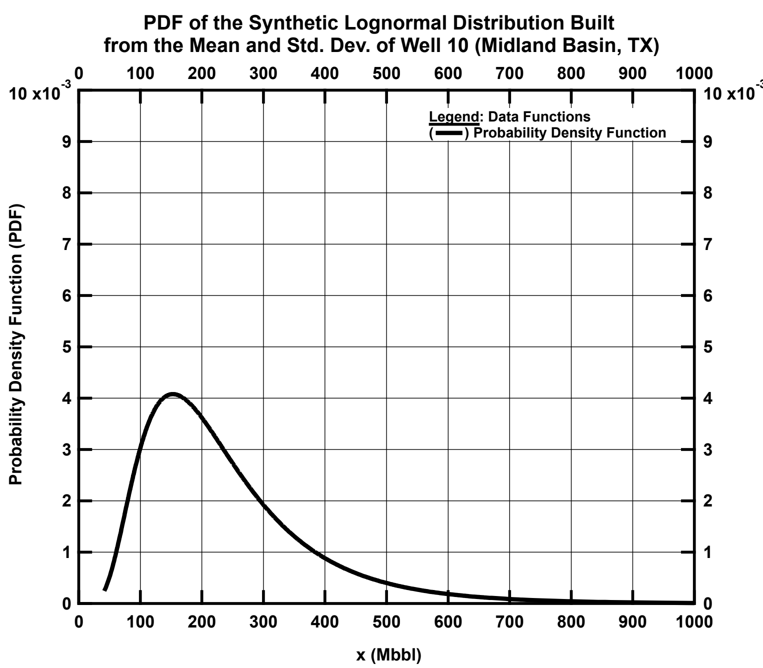

Figure 119 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 10.

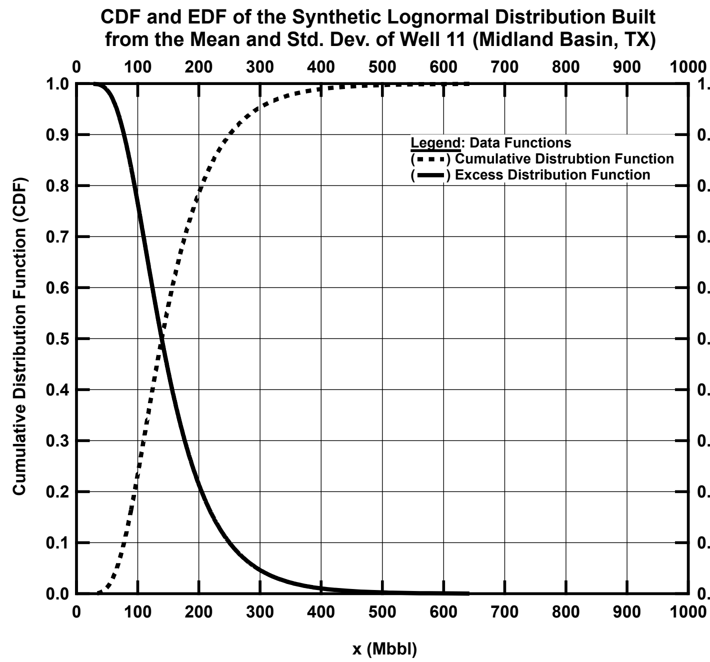

Figure 120 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 11.

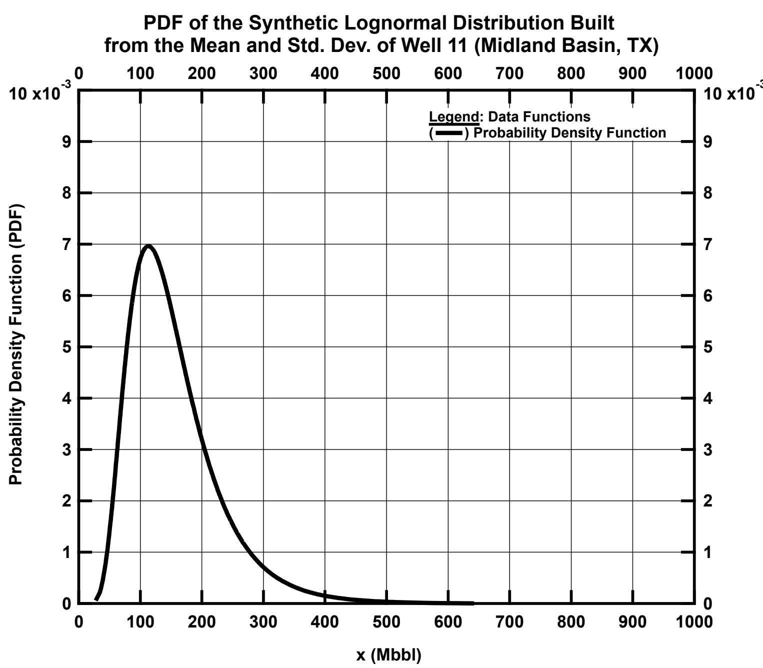

Figure 121 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 11.

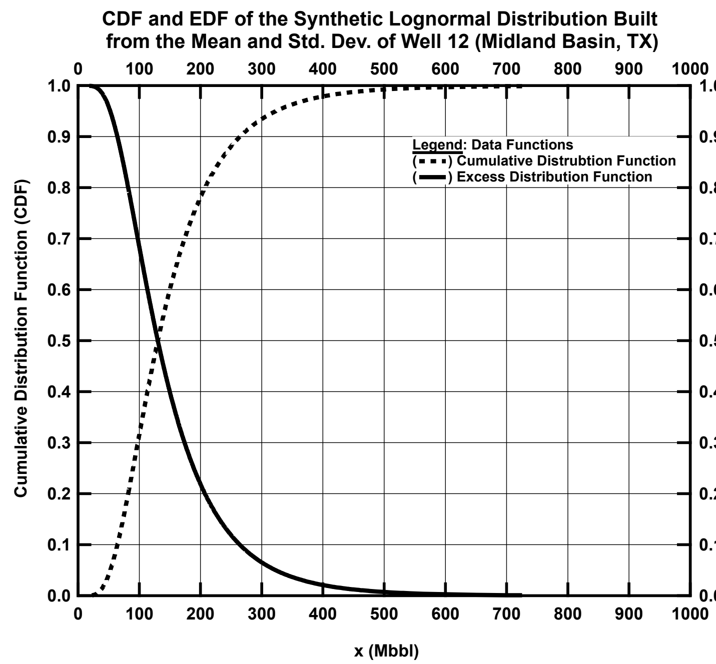

Figure 122 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 12.

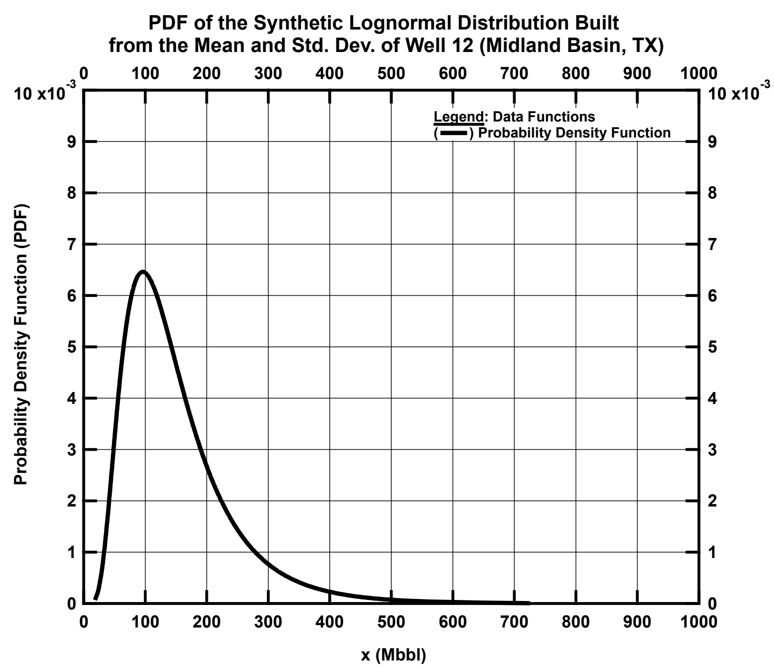

Figure 123 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 12.

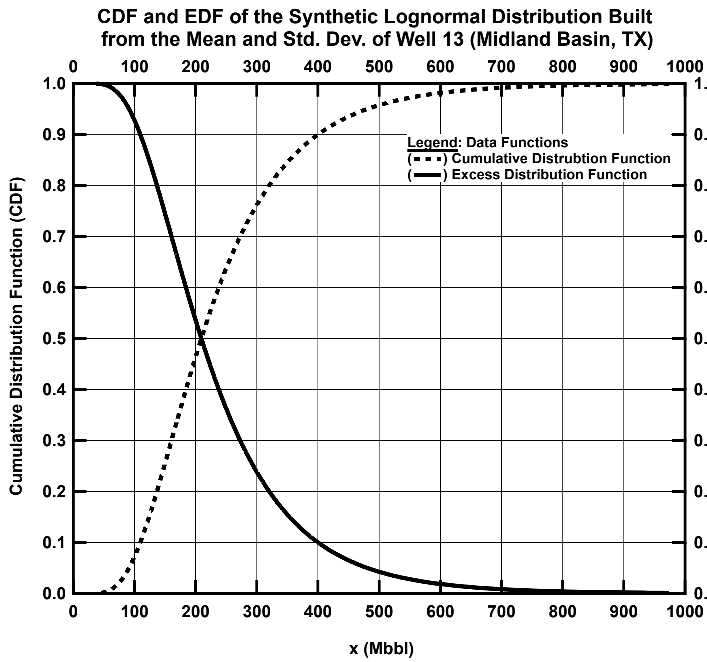

Figure 124 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 13.

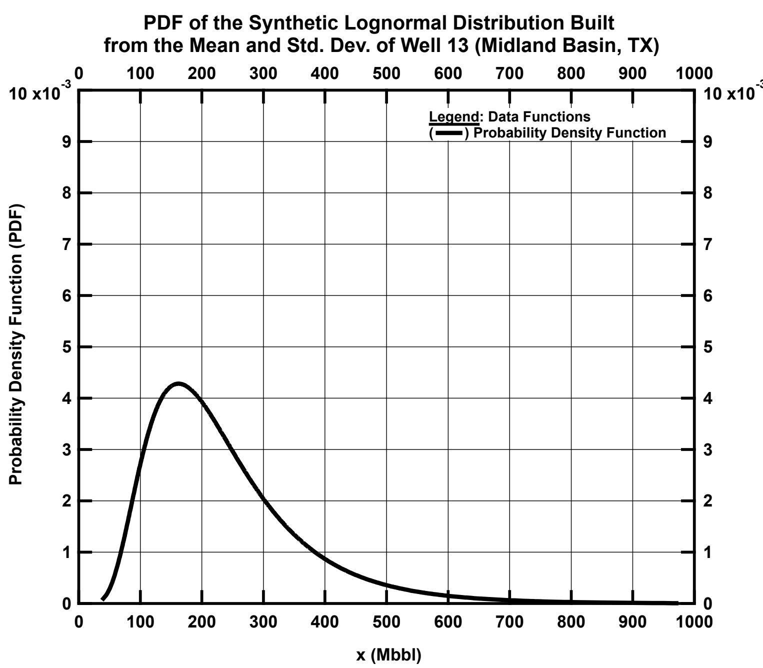

Figure 125 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 13.

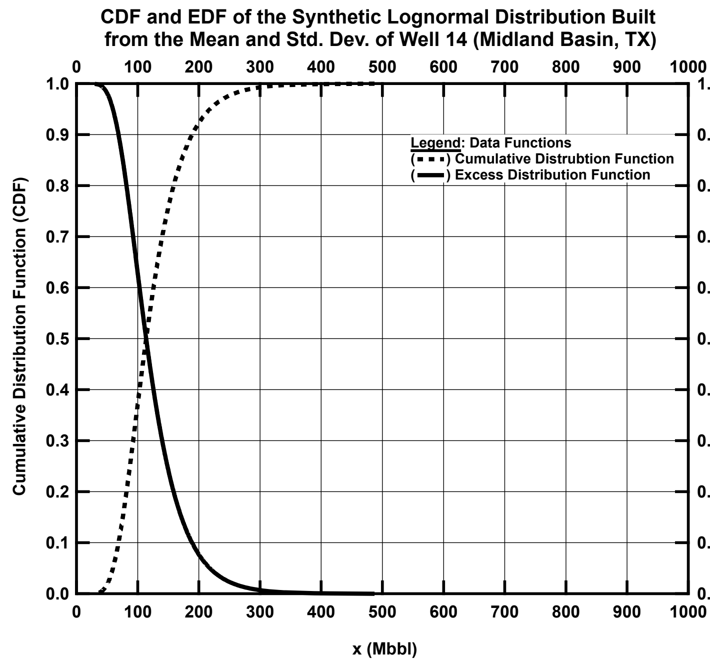

Figure 126 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 14.

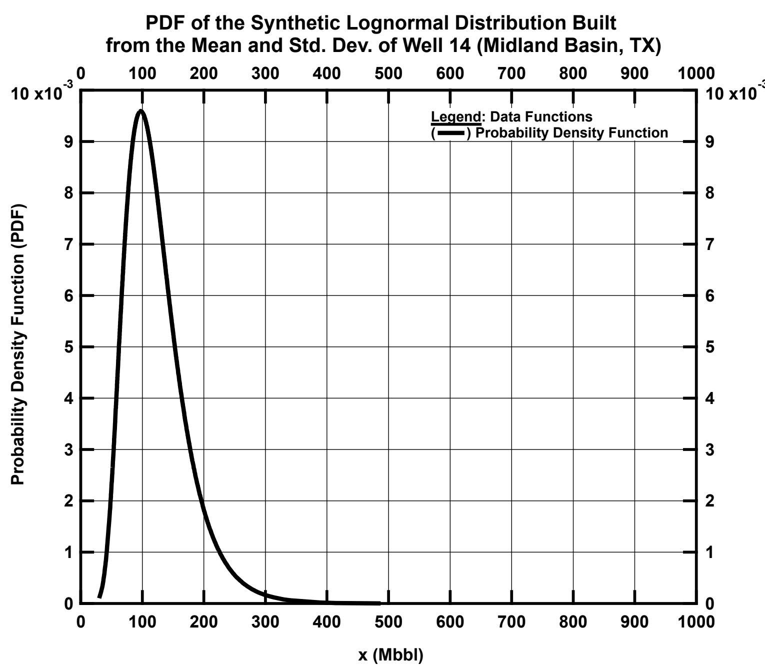

Figure 127 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 14.

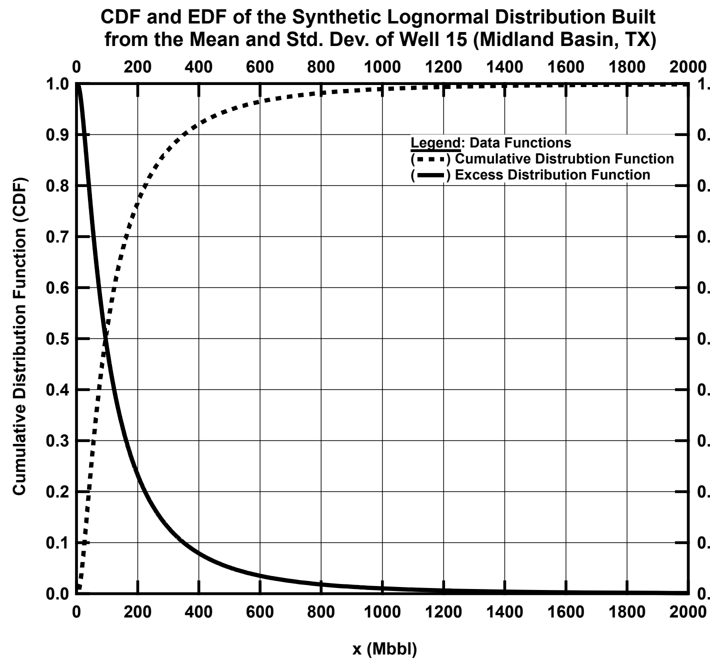

Figure 128 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 15.

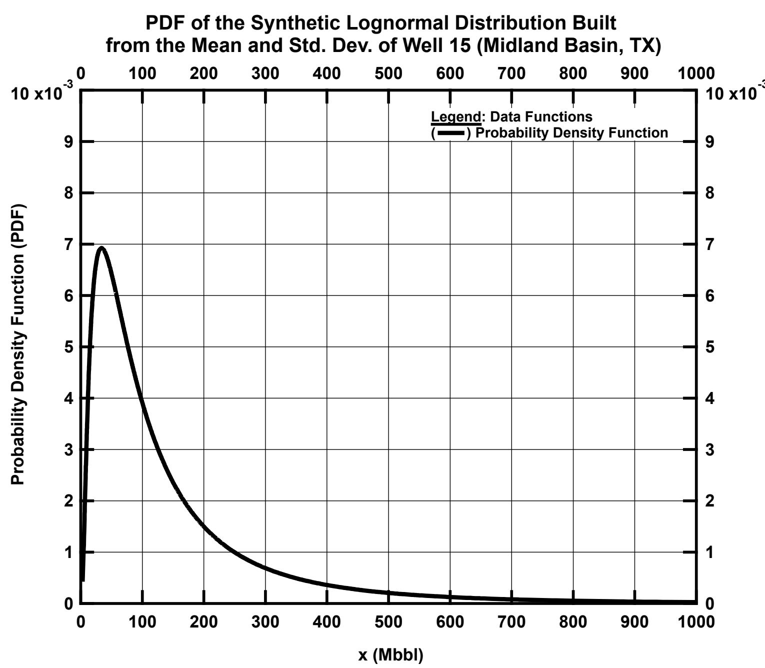

Figure 129 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 15.

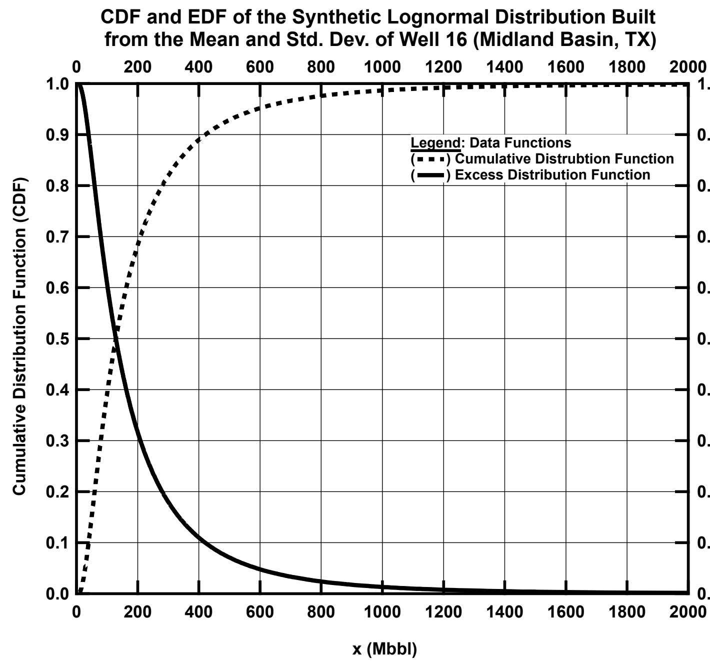

Figure 130 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 16.

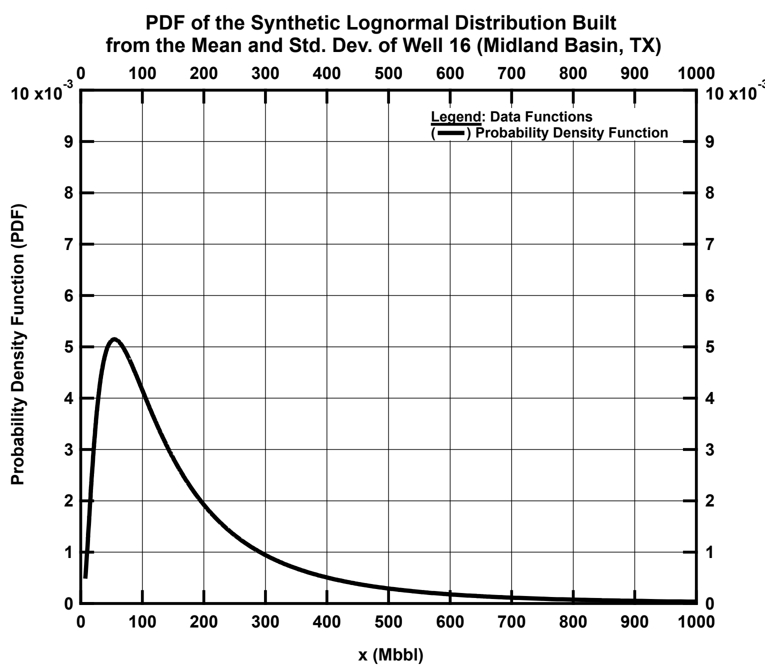

Figure 131 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 16.

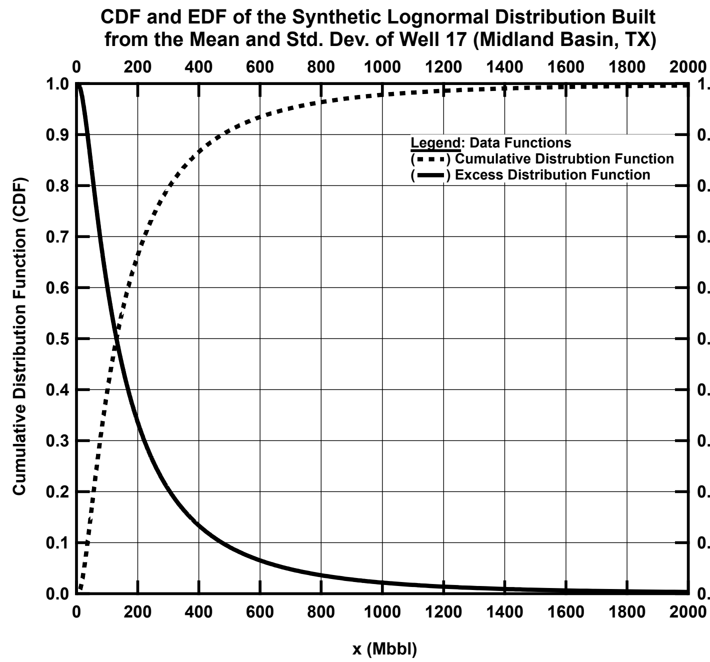

Figure 132 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 17.

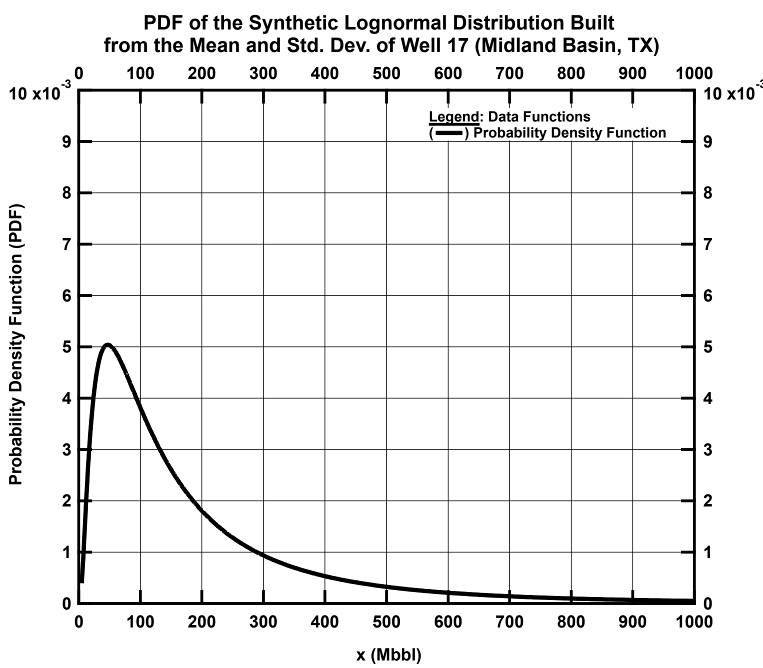

Figure 133 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 17.

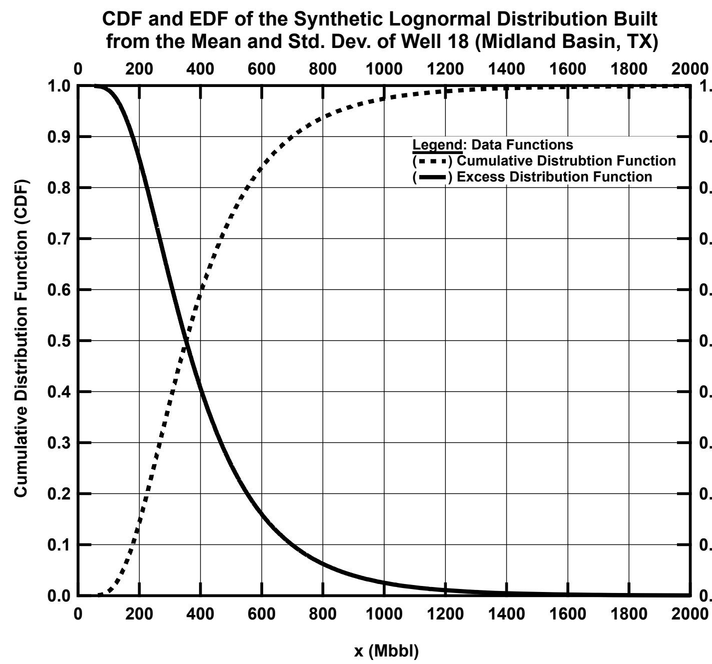

Figure 134 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 18.

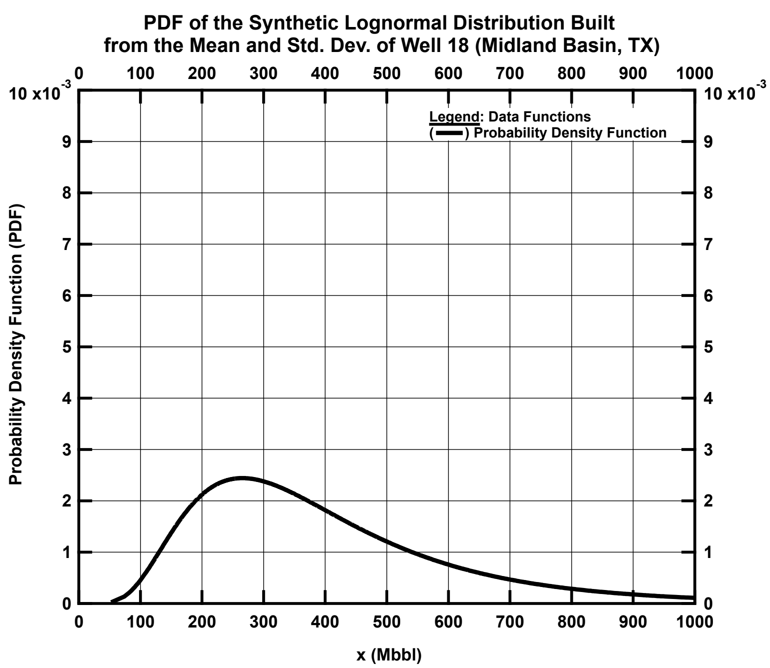

Figure 135 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 18.

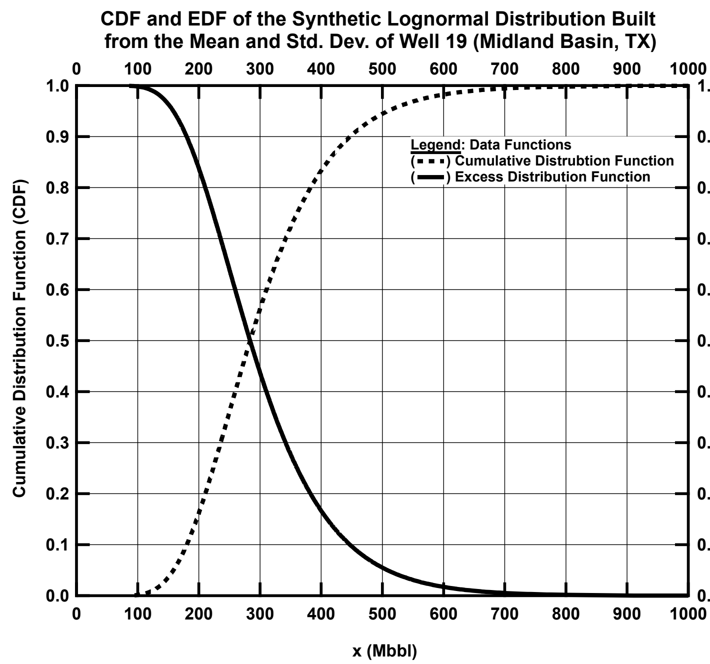

Figure 136 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 19.

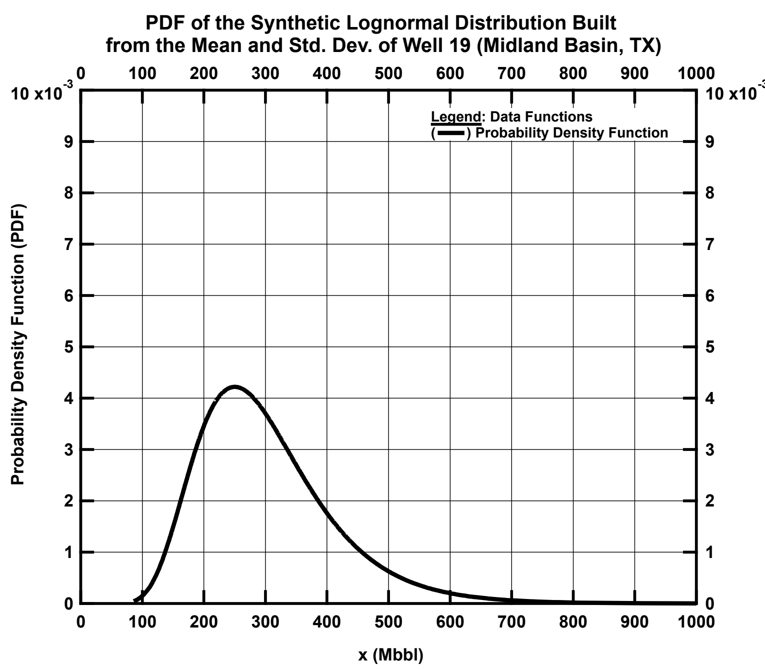

Figure 137 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 19.

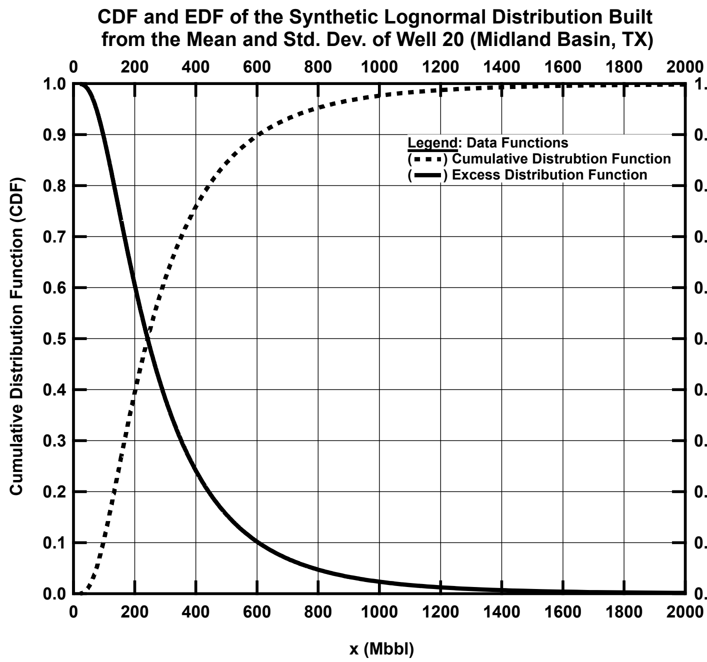

Figure 138 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 20.

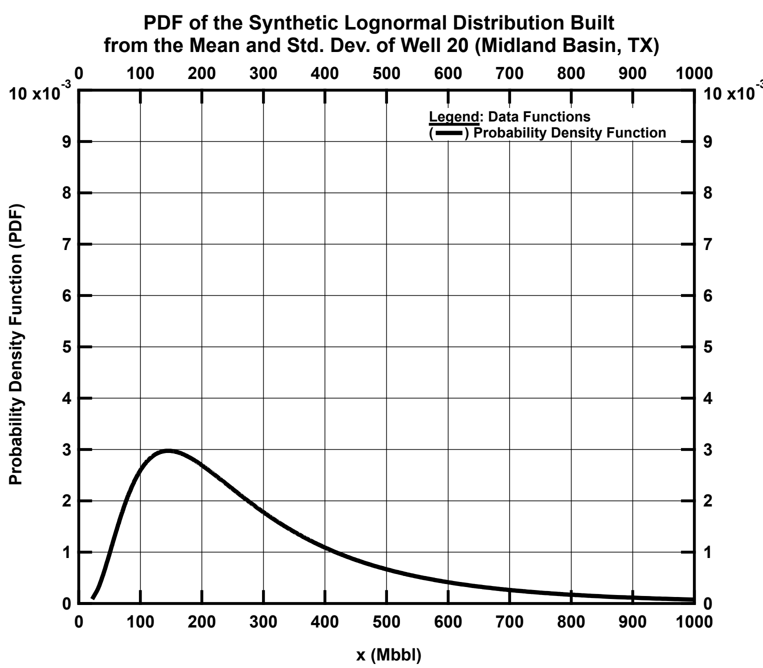

Figure 139 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 20.

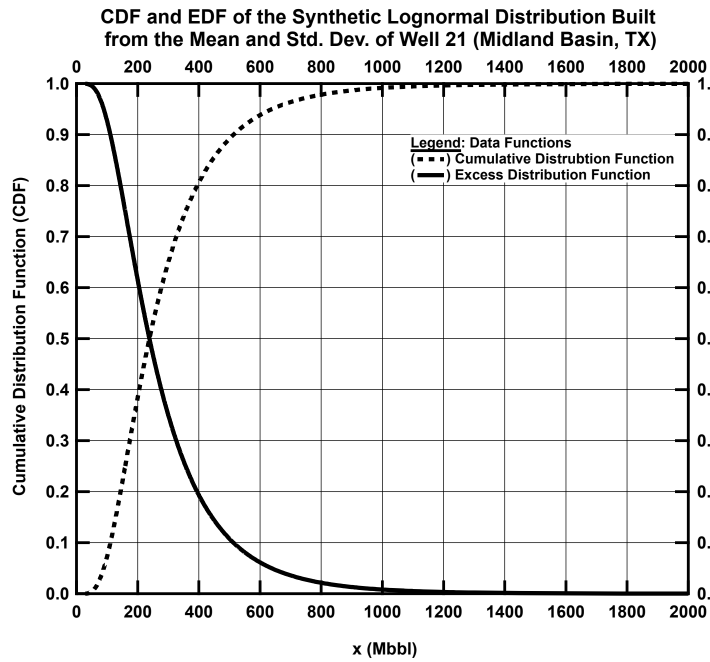

Figure 140 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 21.

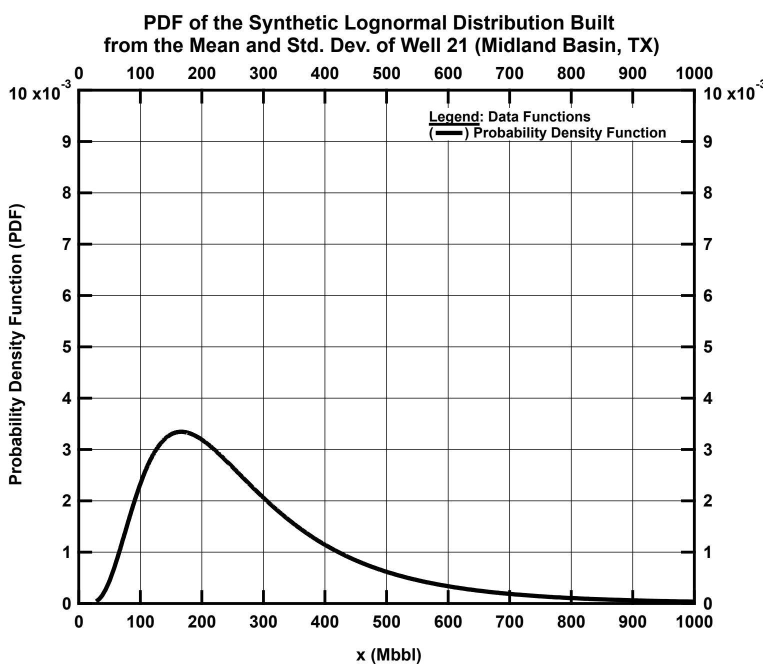

Figure 141 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 21.

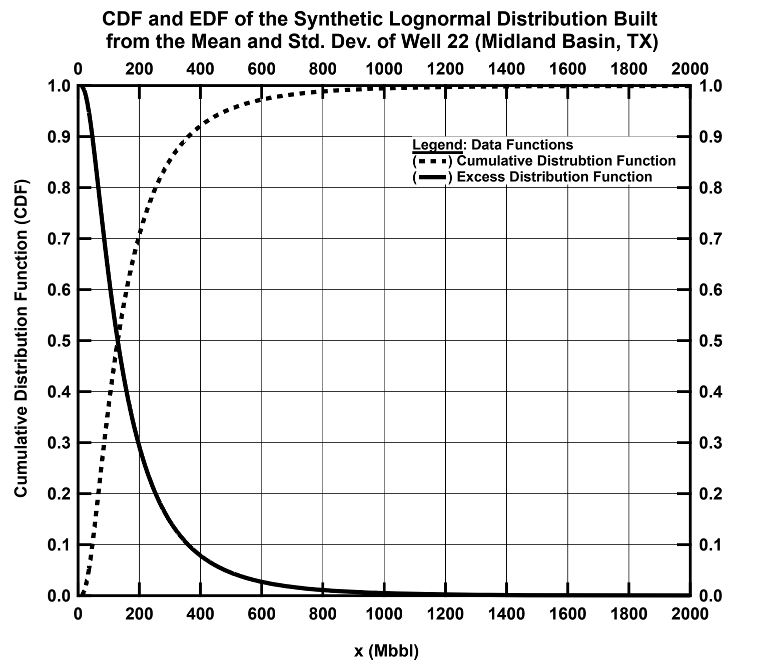

Figure 142 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 22.

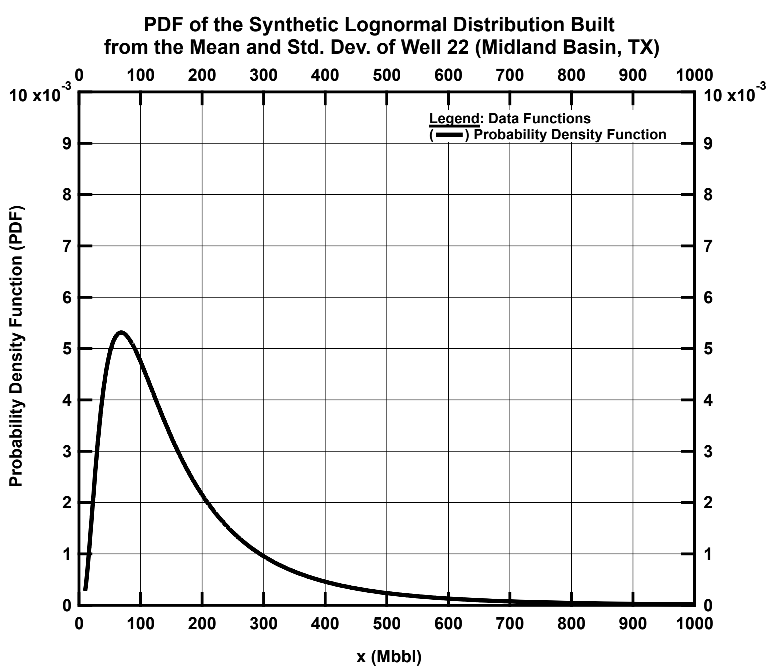

Figure 143 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 22.

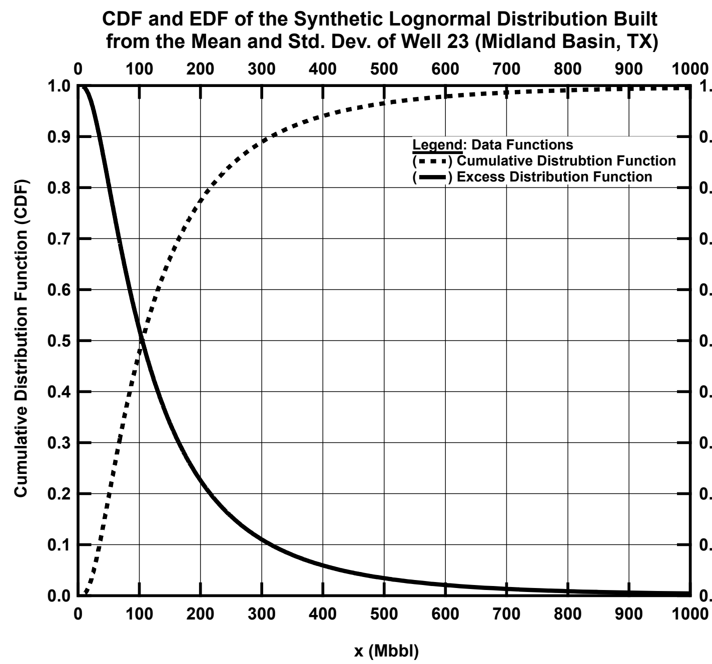

Figure 144 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 23.

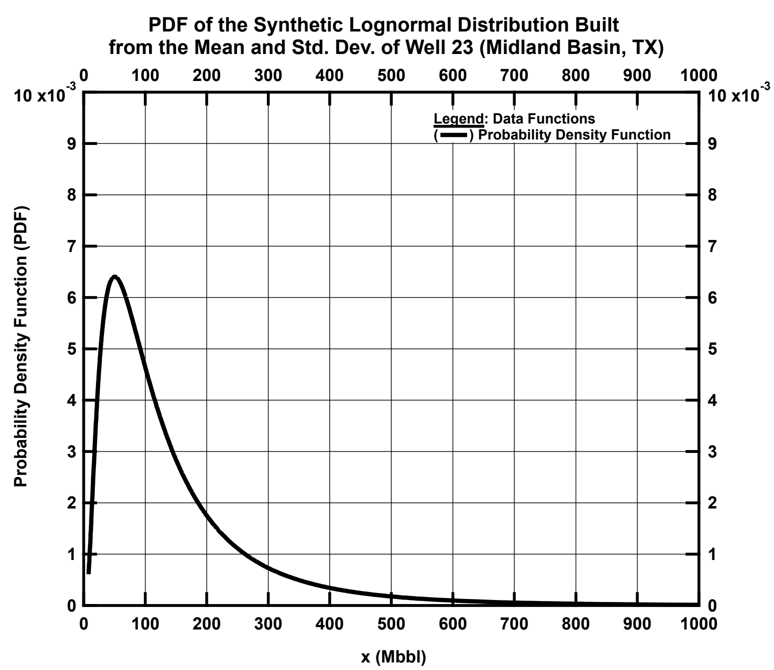

Figure 145 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 23.

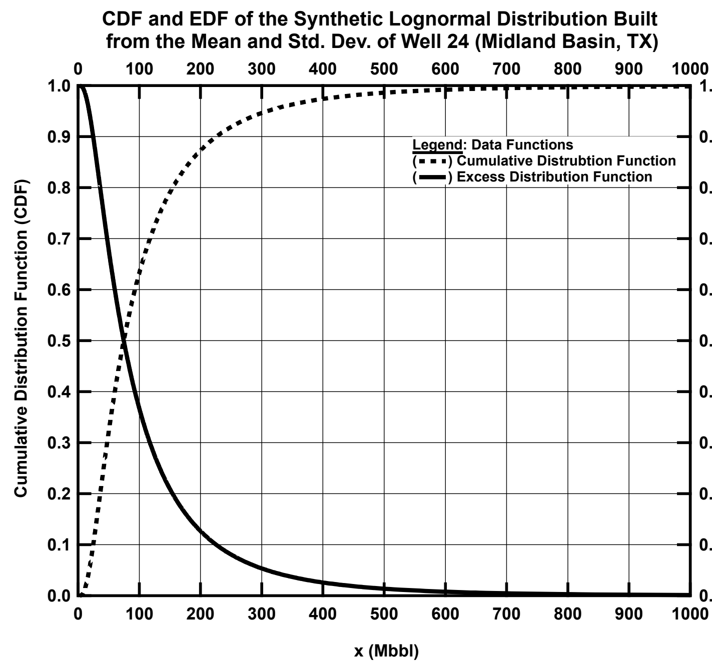

Figure 146 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 24.

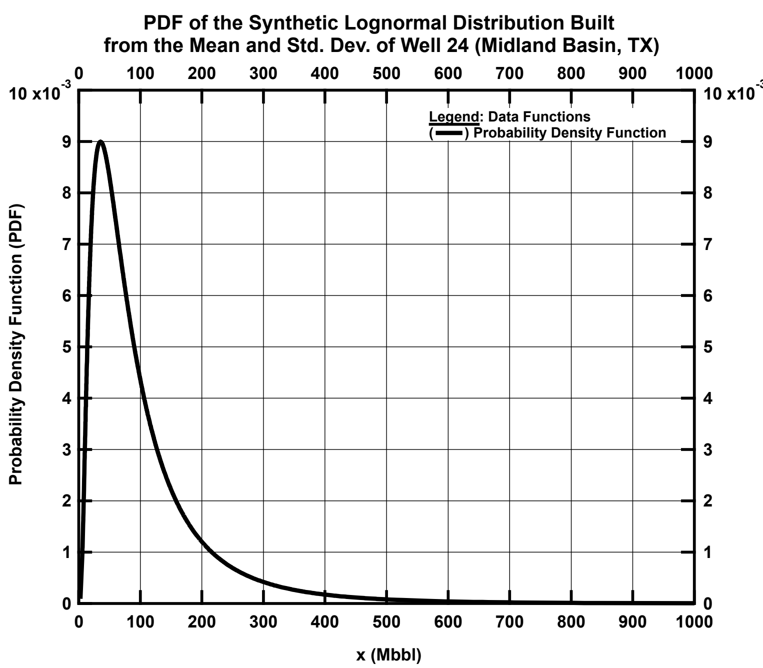

Figure 147 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 24.

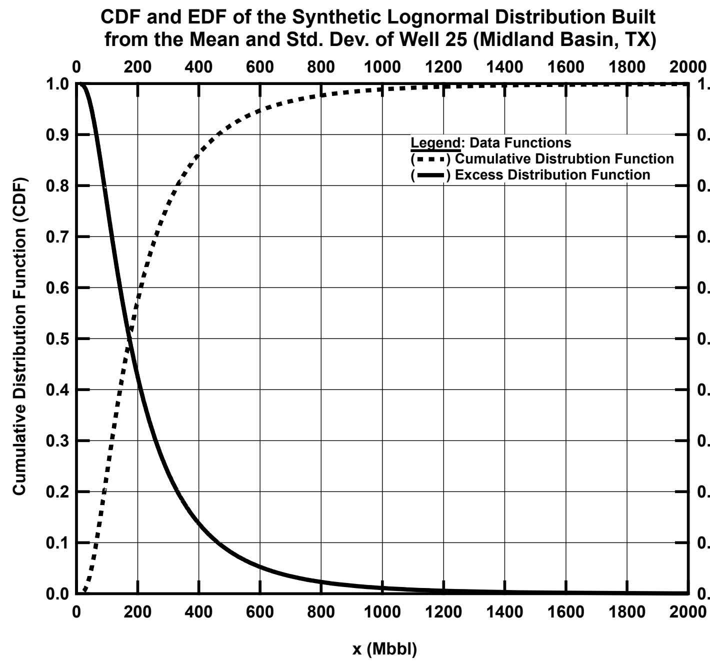

Figure 148 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 25.

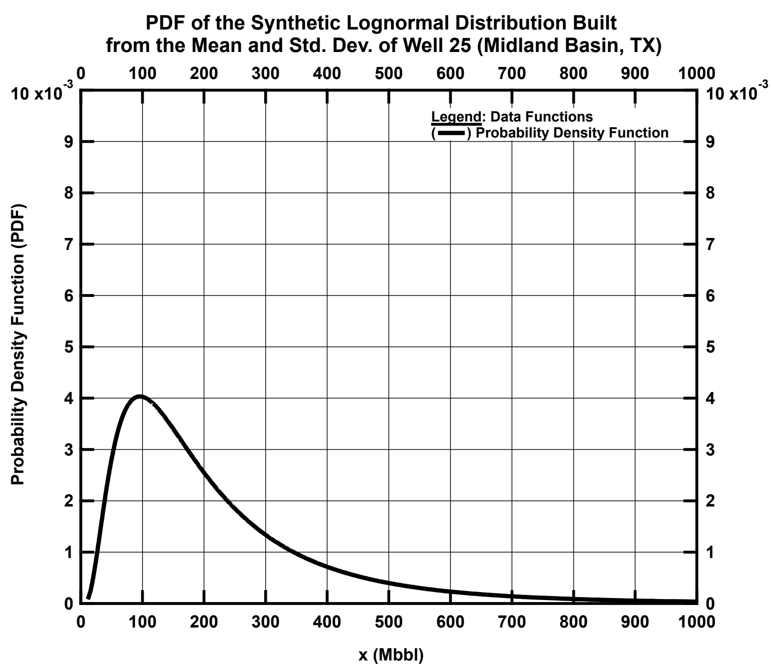

Figure 149 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 25.

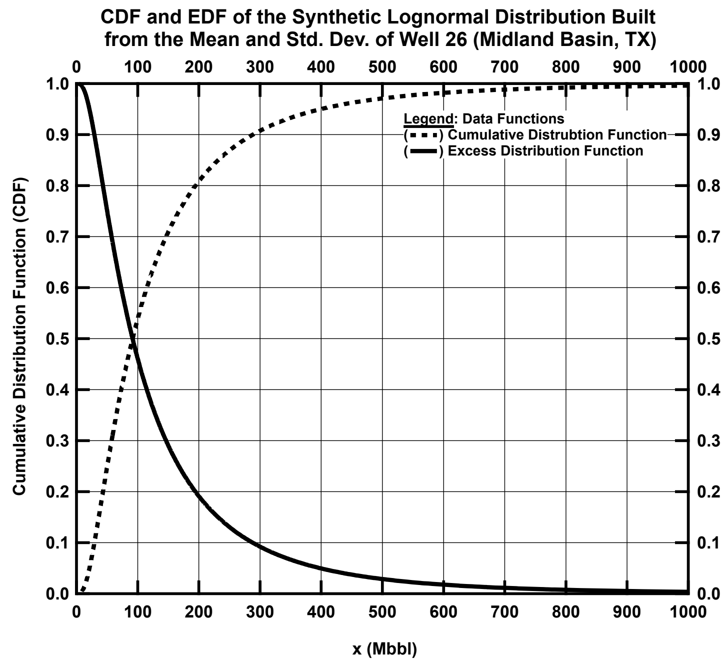

Figure 150 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 26.

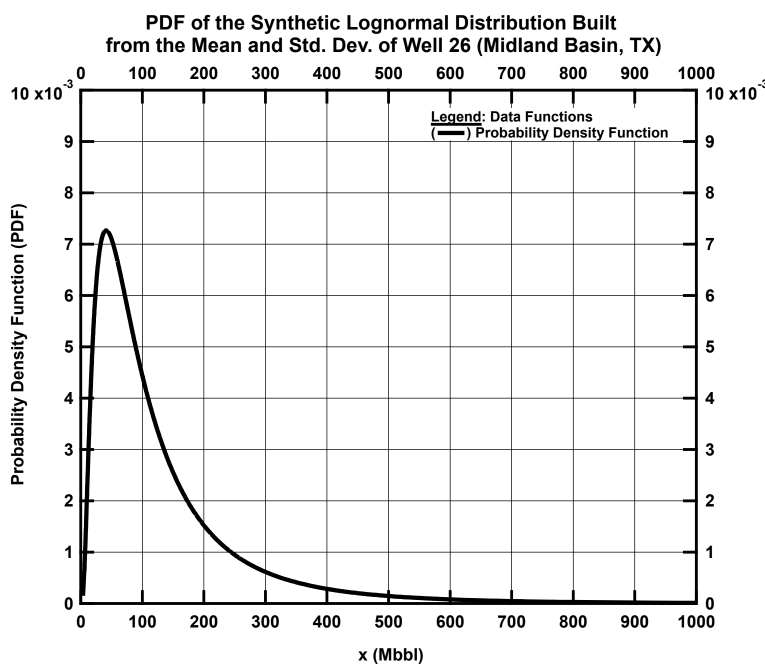

Figure 151 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 26.

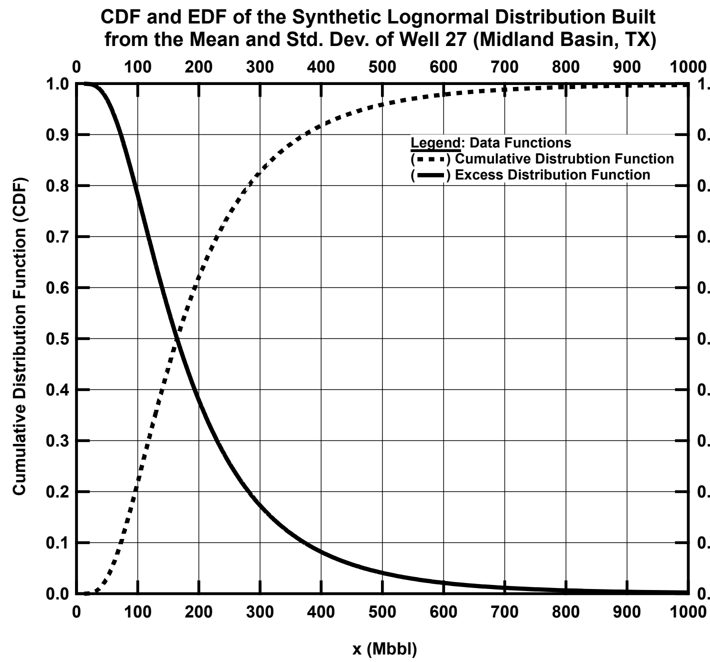

Figure 152 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 27.

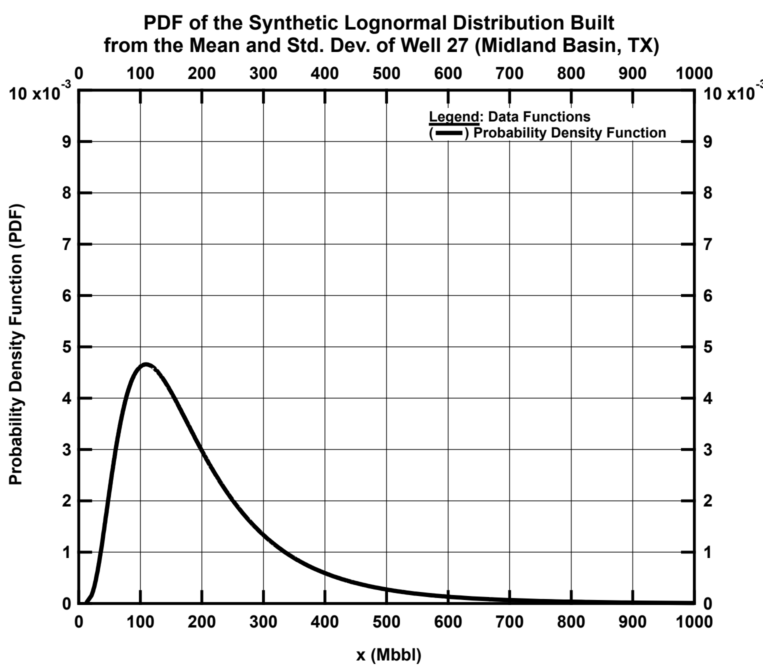

Figure 153 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 27.

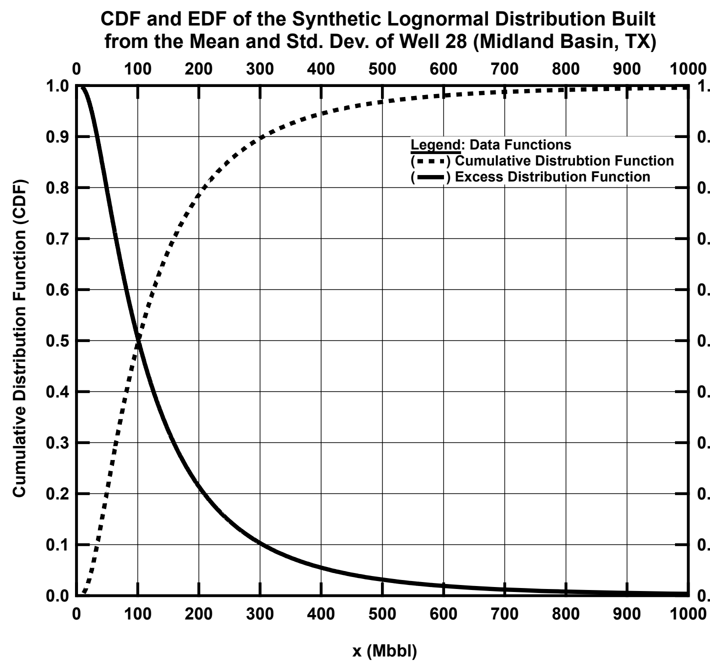

Figure 154 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 28.

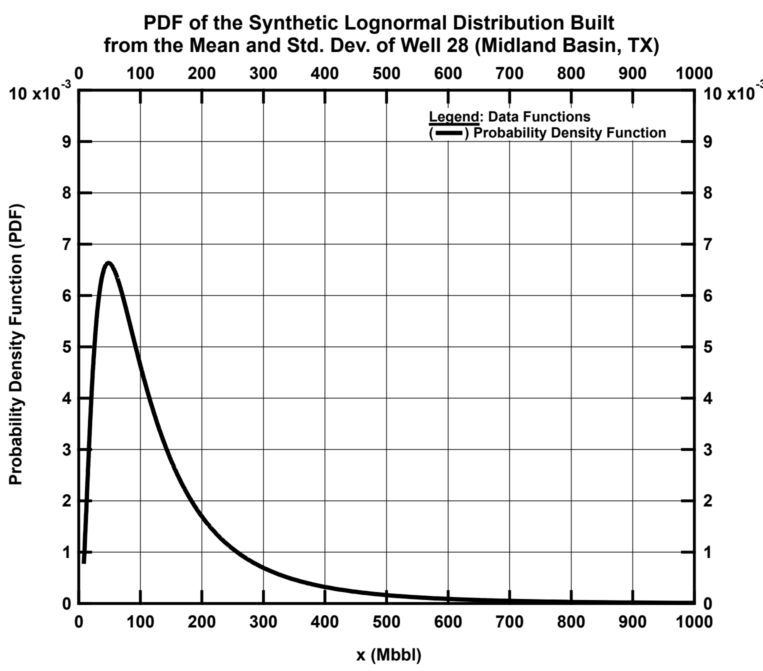

Figure 155 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 28.

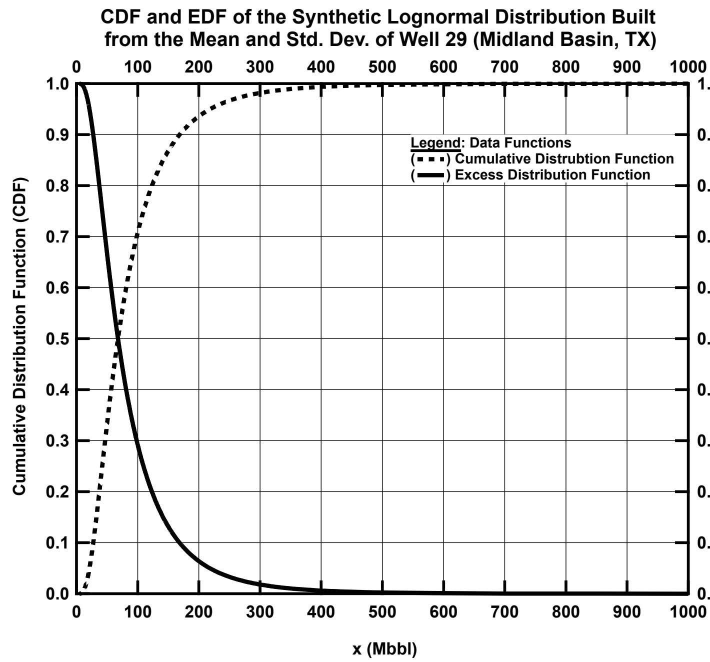

Figure 156 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 29.

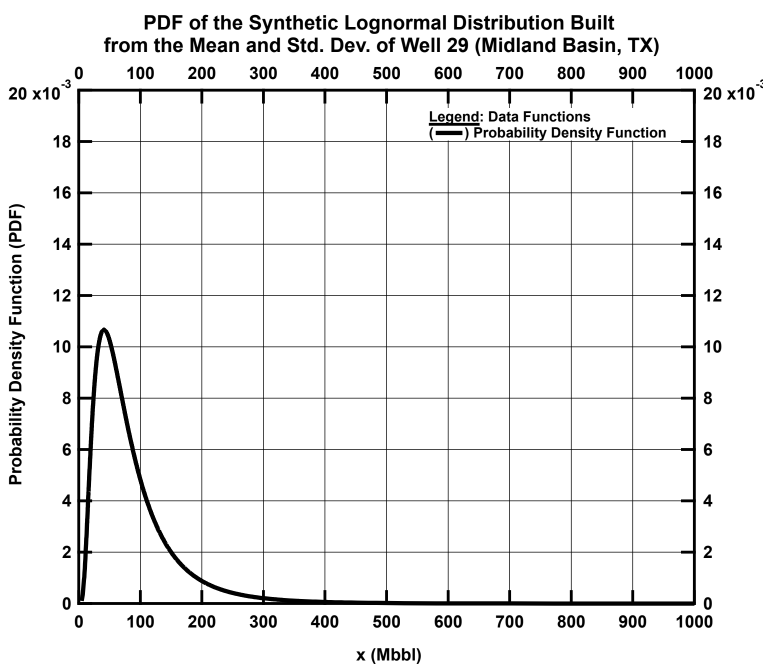

Figure 157 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 29.

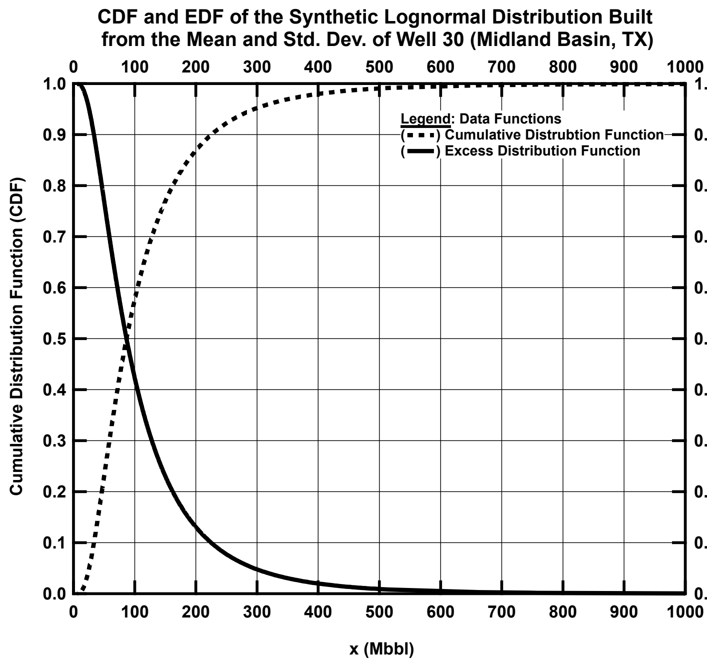

Figure 158 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 30.

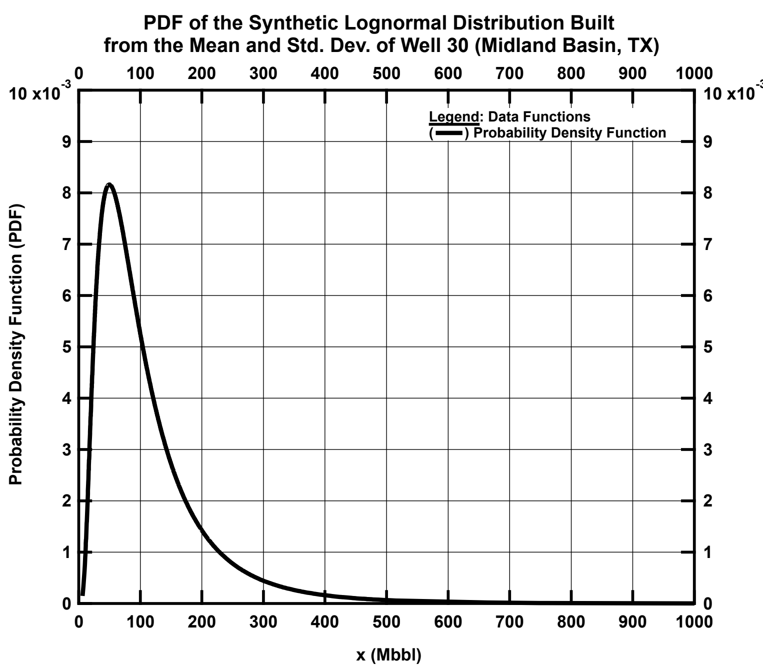

Figure 159 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 30.

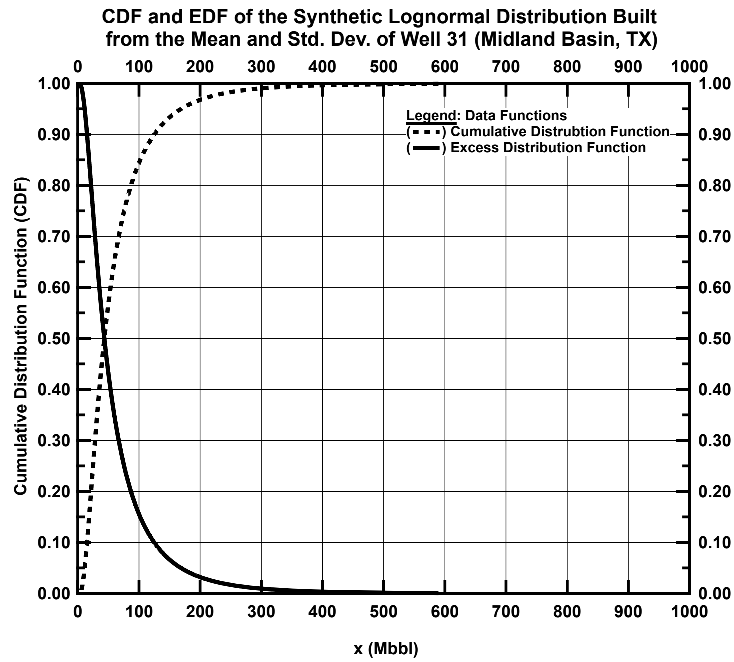

Figure 160 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 31.

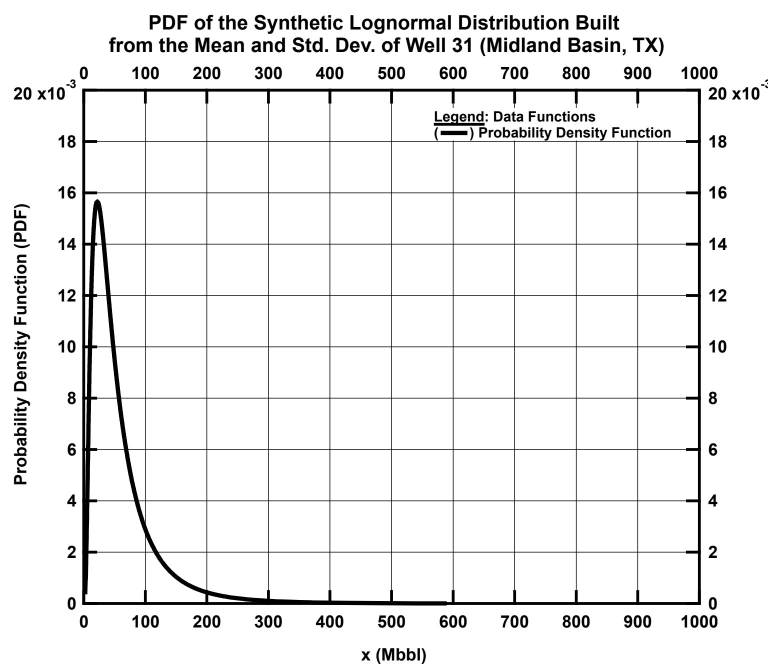

Figure 161 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 31.

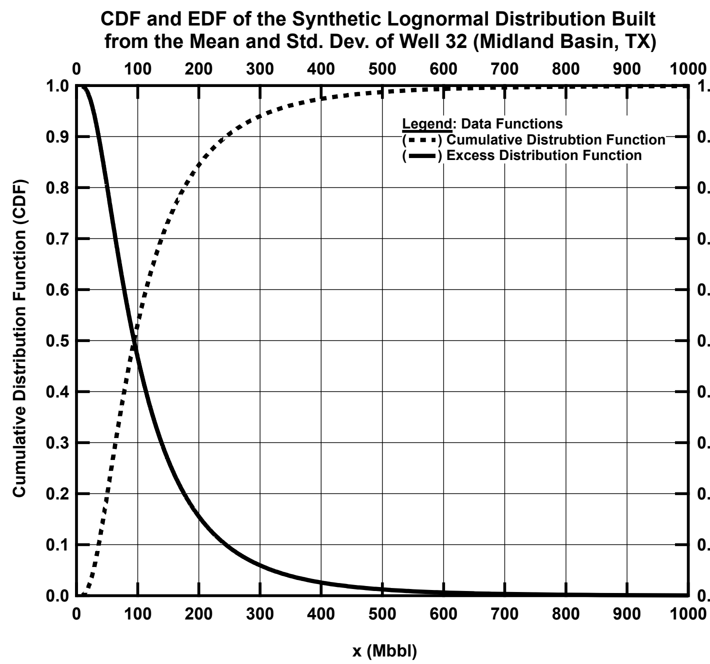

Figure 162 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 32.

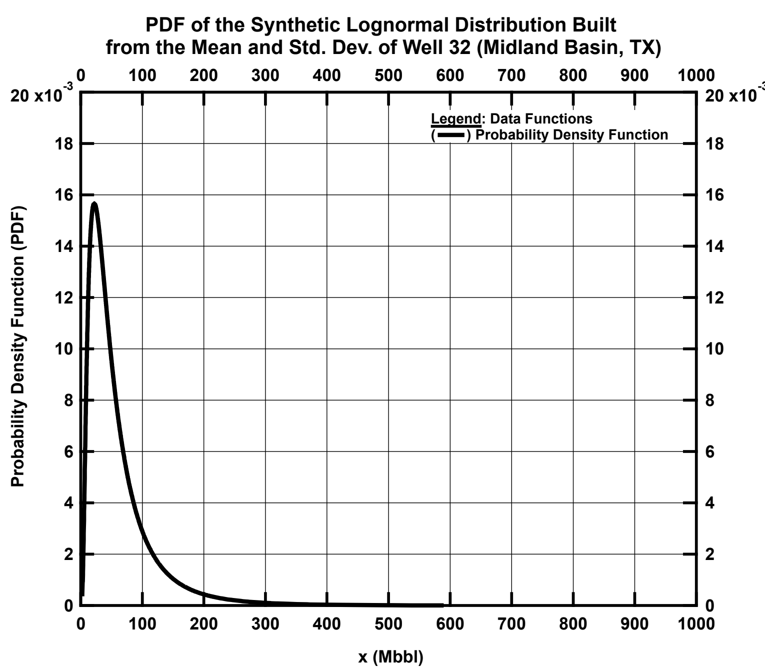

Figure 163 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 32.

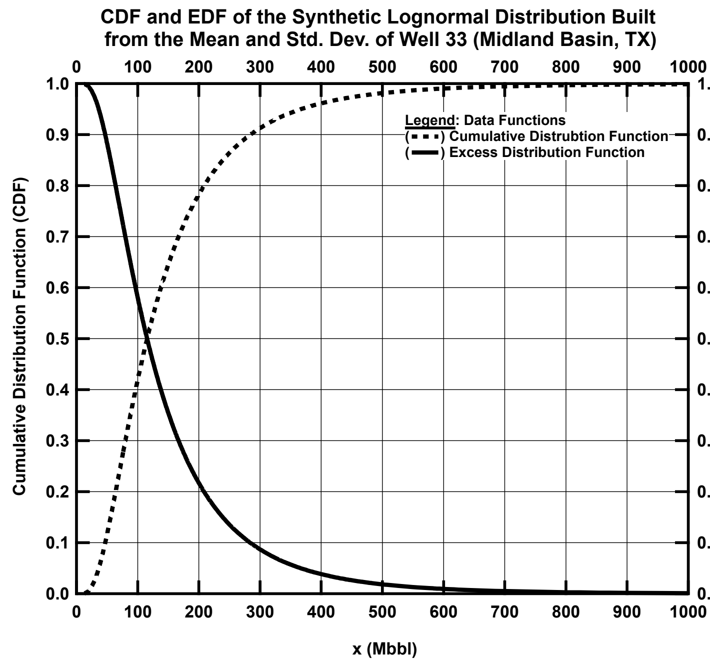

Figure 164 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 33.

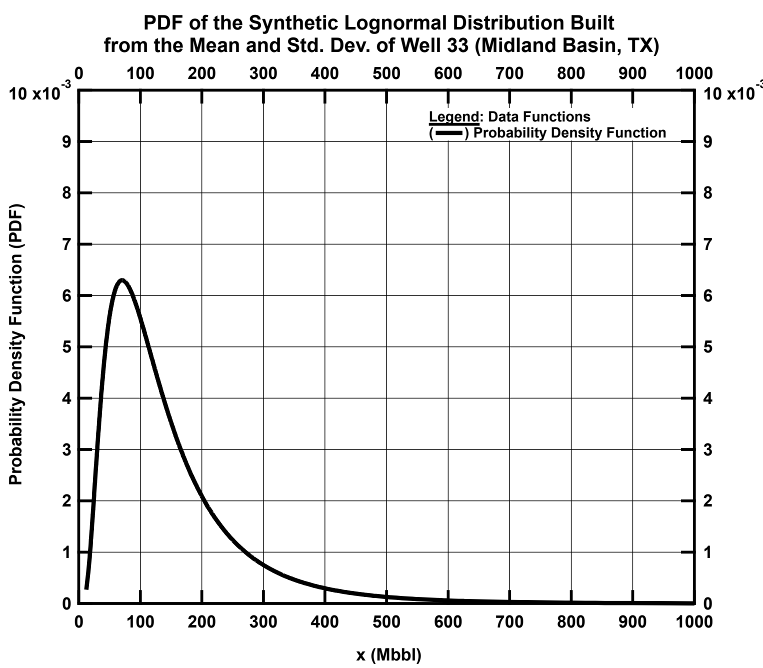

Figure 165 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 33.

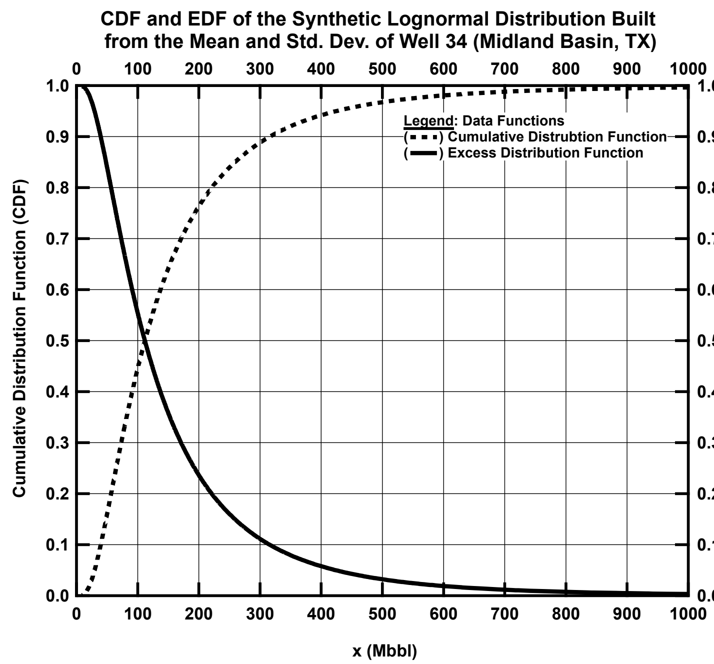

Figure 166 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 34.

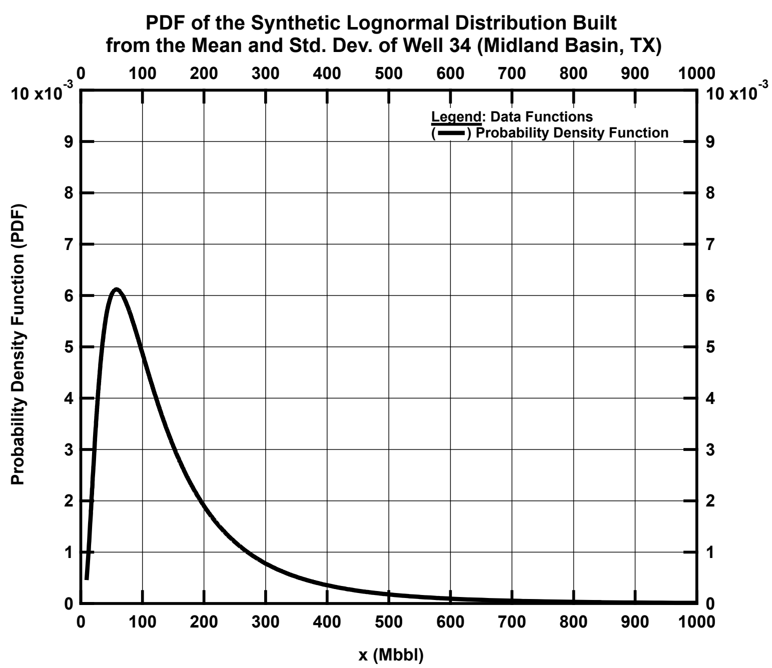

Figure 167 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 34.

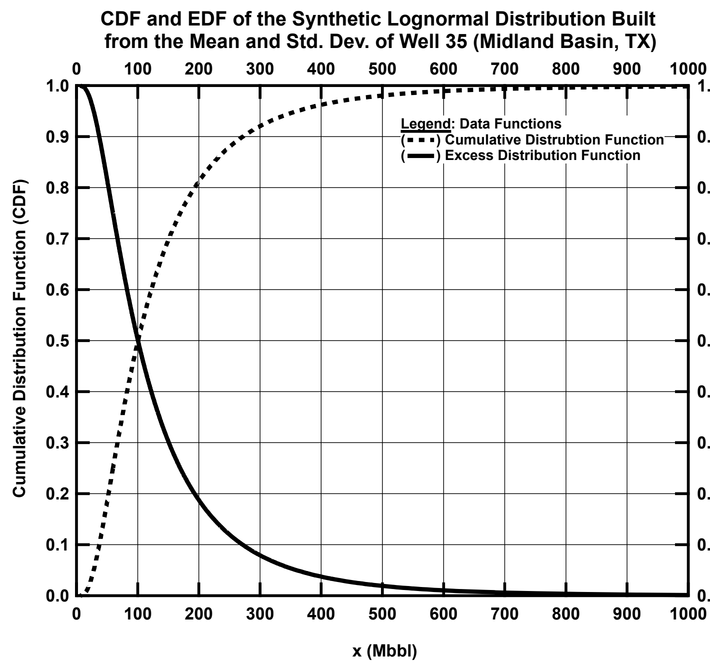

Figure 168 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 35.

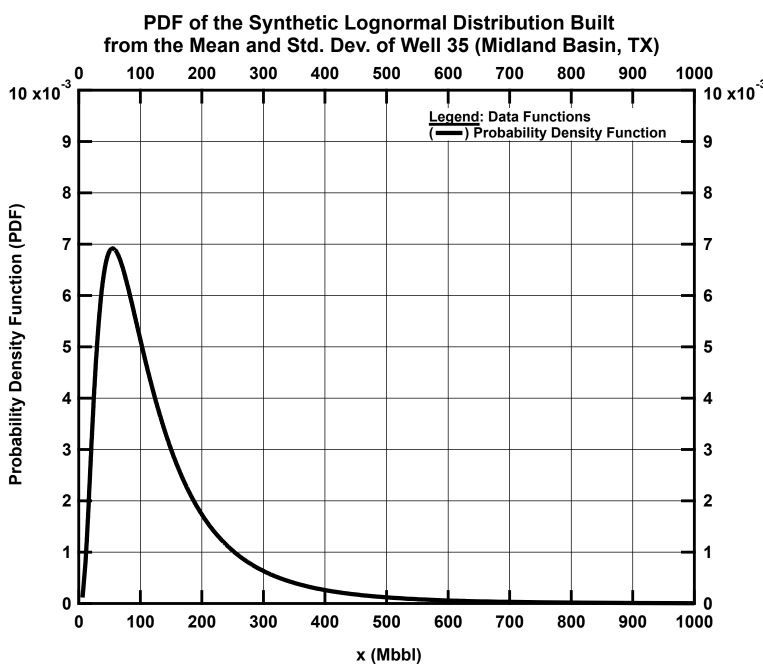

Figure 169 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 35.

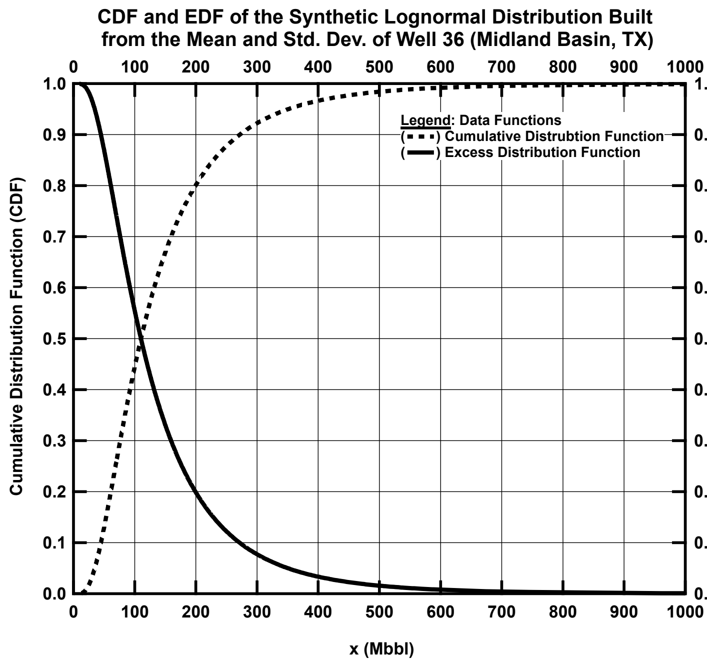

Figure 170 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 36.

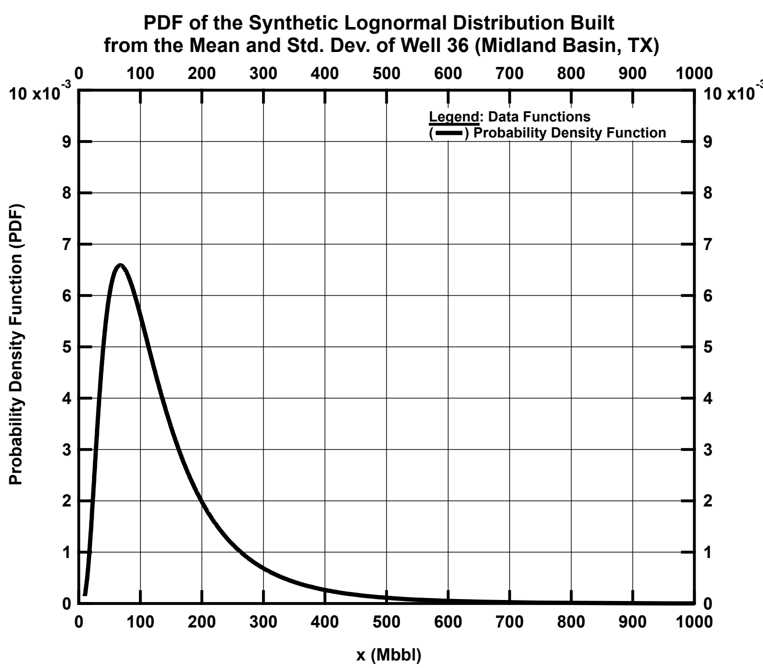

Figure 171 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 36.

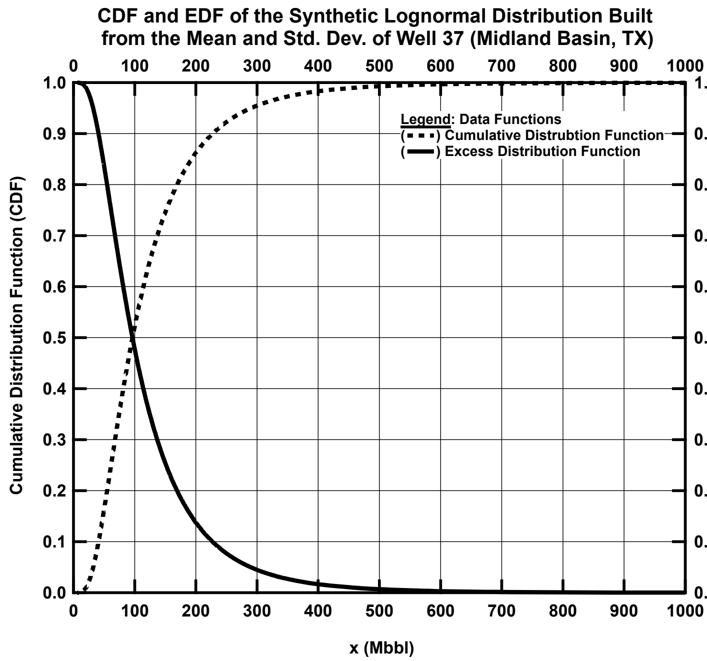

Figure 172 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 37.

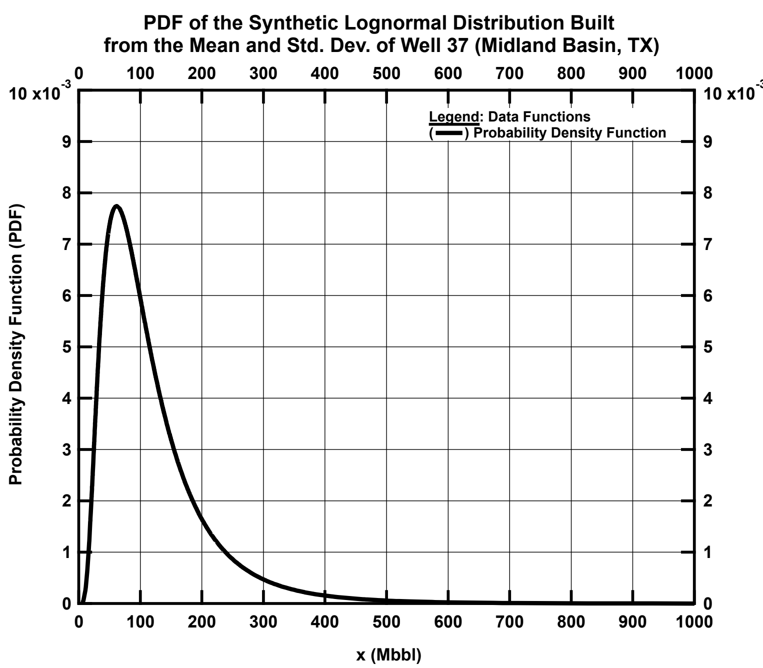

Figure 173 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 37.

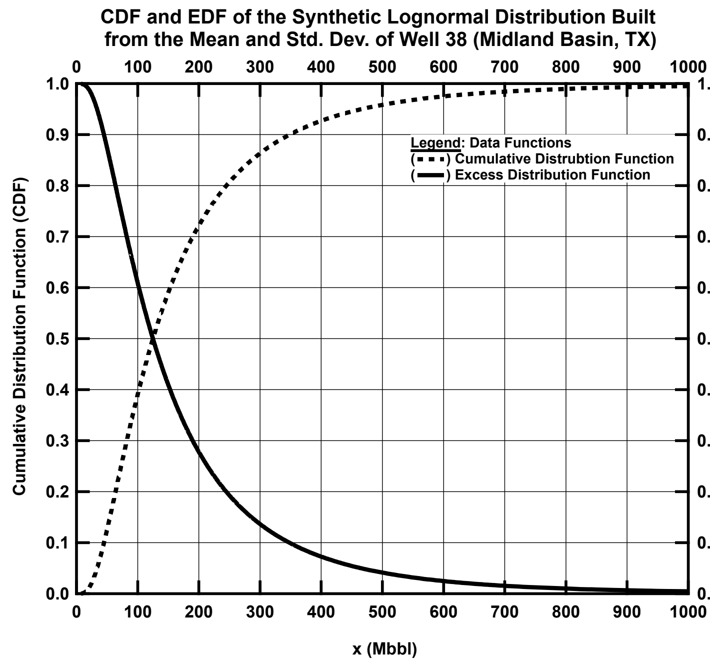

Figure 174 — CDF and EDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 38.

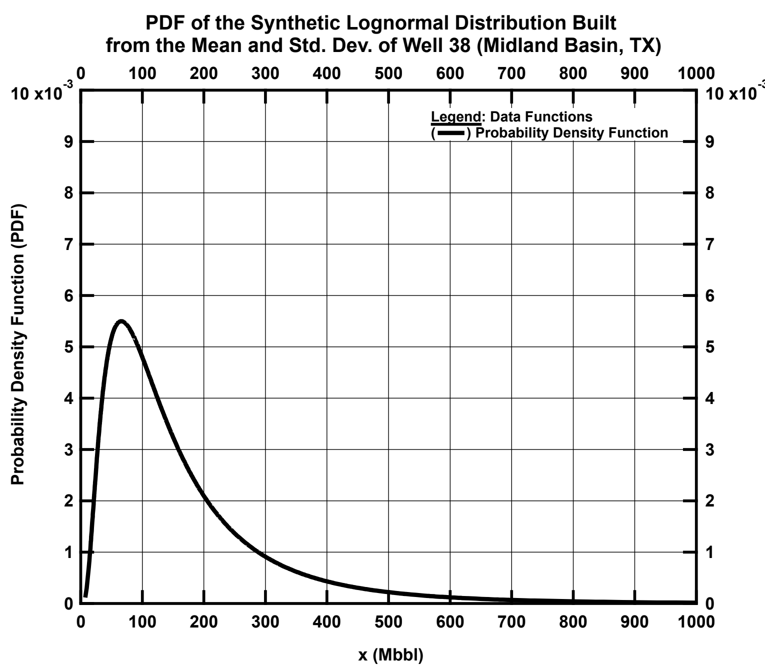

Figure 175 — PDF of the synthetic lognormal distribution built by using the mean and standard deviation from Well 38.

APPENDIX E

3-POINT, 5-POINT, AND 10-POINT GAUSSIAN QUADRUATURE RESERVES RESULTS

In Appendix E, we present **Table 72** through **Table 76** that present the 3-point, 5-point, and 10-point GQ results of Reserves.

3-point	P83	P67	P17	P83 Ratio	P67 Ratio	P17 Ratio
Well 1	49	132	361	9%	24%	67%
Well 2	35	118	400	6%	21%	72%
Well 3	38	125	411	7%	22%	72%
Well 4	23	90	349	5%	20%	75%
Well 5	19	84	379	4%	17%	79%
Well 6	36	131	470	6%	20%	74%
Well 7	47	141	423	8%	23%	69%
Well 8	107	230	495	13%	28%	60%
Well 9	37	97	258	9%	25%	66%
Well 10	80	207	536	10%	25%	65%
Well 11	60	136	309	12%	27%	61%
Well 12	50	130	339	10%	25%	65%
Well 13	88	210	503	11%	26%	63%
Well 14	58	114	225	15%	29%	57%
Well 15	16	95	556	2%	14%	83%
Well 16	26	128	638	3%	16%	81%
Well 17	23	131	751	3%	14%	83%
Well 18	139	352	889	10%	26%	64%
Well 19	155	285	524	16%	30%	54%
Well 20	70	243	836	6%	21%	73%
Well 21	84	238	673	8%	24%	68%
Well 22	32	129	516	5%	19%	76%
Well 23	24	105	464	4%	18%	78%
Well 24	17	74	328	4%	18%	78%
Well 25	46	173	655	5%	20%	75%
Well 26	19	91	430	4%	17%	80%
Well 27	54	164	498	8%	23%	69%
Well 28	22	100	447	4%	18%	79%
Well 29	20	68	232	6%	21%	73%
Well 30	23	84	312	5%	20%	74%
Well 31	10	43	181	4%	18%	77%
Well 32	26	94	341	6%	20%	74%
Well 33	34	115	388	6%	21%	72%
Well 34	27	112	455	5%	19%	77%
Well 35	26	101	386	5%	20%	75%
Well 36	32	110	374	6%	21%	72%
Well 37	23	83	299	6%	20%	74%
Well 38	31	124	499	5%	19%	76%

Table 72—3-point gaussian quadrature results of the percentiles, and ratios for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 3-point GQ are 0.17, 0.67, 0.17 for all the wells.

5-point	P99	P78	P53	P22	P1
Well 1	25	60	132	290	691
Well 2	16	46	118	307	880
Well 3	17	49	125	317	893
Well 4	10	31	90	260	839
Well 5	7	26	84	273	1,011
Well 6	16	48	131	356	1,081
Well 7	23	60	141	333	862
Well 8	65	126	230	419	814
Well 9	19	45	97	209	486
Well 10	43	99	207	436	994
Well 11	35	72	136	259	526
Well 12	27	61	130	275	631
Well 13	50	106	210	416	886
Well 14	37	67	114	194	350
Well 15	5	24	95	379	1,748
Well 16	9	37	128	450	1,810
Well 17	7	33	131	513	2,337
Well 18	76	170	352	727	1,623
Well 19	104	176	285	459	779
Well 20	32	92	243	639	1,866
Well 21	43	106	238	537	1,322
Well 22	13	44	129	382	1,267
Well 23	9	33	105	336	1,219
Well 24	6	23	74	238	859
Well 25	19	61	173	490	1,555
Well 26	7	27	91	307	1,178
Well 27	26	69	164	391	1,022
Well 28	8	31	100	323	1,183
Well 29	9	26	68	177	517
Well 30	10	30	84	235	728
Well 31	4	14	43	133	460
Well 32	11	34	94	258	790
Well 33	16	44	115	298	853
Well 34	11	37	112	336	1,135
Well 35	11	35	101	288	923
Well 36	14	42	110	286	829
Well 37	10	30	83	227	688
Well 38	13	42	124	369	1,229

Table 73—5-point gaussian quadrature results of the percentiles for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

5-point	P99 Ratio	P78 Ratio	P53 Ratio	P22 Ratio	P22 Ratio
Well 1	2%	5%	11%	24%	58%
Well 2	1%	3%	9%	22%	64%
Well 3	1%	3%	9%	23%	64%
Well 4	1%	3%	7%	21%	68%
Well 5	0%	2%	6%	20%	72%
Well 6	1%	3%	8%	22%	66%
Well 7	2%	4%	10%	23%	61%
Well 8	4%	8%	14%	25%	49%
Well 9	2%	5%	11%	24%	57%
Well 10	2%	6%	12%	25%	56%
Well 11	3%	7%	13%	25%	51%
Well 12	2%	5%	12%	24%	56%
Well 13	3%	6%	13%	25%	53%
Well 14	5%	9%	15%	25%	46%
Well 15	0%	1%	4%	17%	78%
Well 16	0%	1%	5%	18%	74%
Well 17	0%	1%	4%	17%	77%
Well 18	3%	6%	12%	25%	55%
Well 19	6%	10%	16%	25%	43%
Well 20	1%	3%	8%	22%	65%
Well 21	2%	5%	11%	24%	59%
Well 22	1%	2%	7%	21%	69%
Well 23	1%	2%	6%	20%	72%
Well 24	1%	2%	6%	20%	72%
Well 25	1%	3%	8%	21%	68%
Well 26	0%	2%	6%	19%	73%
Well 27	2%	4%	10%	23%	61%
Well 28	1%	2%	6%	20%	72%
Well 29	1%	3%	8%	22%	65%
Well 30	1%	3%	8%	22%	67%
Well 31	1%	2%	7%	20%	70%
Well 32	1%	3%	8%	22%	67%
Well 33	1%	3%	9%	22%	64%
Well 34	1%	2%	7%	21%	70%
Well 35	1%	3%	7%	21%	68%
Well 36	1%	3%	9%	22%	65%
Well 37	1%	3%	8%	22%	66%
Well 38	1%	2%	7%	21%	69%

Table 74—5-point gaussian quadrature results of the ratios for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

10-point	P100	P99	P98	P86	P66	P34	P14	P2	P1	P0
Well 1	8	17	31	57	100	175	309	557	1,051	2,202
Well 2	4	10	21	42	84	167	332	678	1,464	3,588
Well 3	4	11	22	45	89	174	342	690	1,471	3,549
Well 4	2	6	13	29	62	132	283	628	1,478	4,005
Well 5	1	4	10	23	55	128	301	731	1,900	5,784
Well 6	4	9	21	44	91	187	386	821	1,849	4,758
Well 7	6	15	29	56	104	192	357	681	1,365	3,068
Well 8	27	47	77	120	186	285	440	690	1,122	1,974
Well 9	6	13	24	43	74	128	222	394	731	1,501
Well 10	14	29	53	93	159	271	464	810	1,479	2,981
Well 11	14	25	42	68	108	171	272	441	741	1,357
Well 12	9	18	33	58	100	170	293	514	943	1,911
Well 13	18	34	60	100	164	268	440	734	1,277	2,432
Well 14	17	28	43	64	94	138	203	303	466	770
Well 15	1	2	8	21	58	156	424	1,196	3,658	13,448
Well 16	1	5	13	33	82	201	499	1,282	3,544	11,578
Well 17	1	4	11	30	80	213	574	1,604	4,858	17,644
Well 18	26	52	93	161	272	456	771	1,329	2,391	4,736
Well 19	51	80	119	170	240	338	477	683	1,006	1,578
Well 20	8	19	41	85	172	343	691	1,430	3,132	7,798
Well 21	13	28	54	99	178	318	574	1,057	2,042	4,397
Well 22	3	7	18	40	88	191	417	941	2,261	6,271
Well 23	2	5	12	30	69	159	369	885	2,272	6,803
Well 24	1	3	9	21	49	113	261	624	1,598	4,773
Well 25	4	11	26	56	119	251	533	1,168	2,716	7,258
Well 26	1	4	10	25	59	141	339	844	2,254	7,079
Well 27	7	17	34	64	121	224	420	806	1,626	3,681
Well 28	1	5	12	28	66	152	355	857	2,216	6,692
Well 29	2	5	12	24	48	95	192	397	866	2,152
Well 30	2	6	13	28	59	122	255	549	1,257	3,292
Well 31	1	2	6	13	29	65	146	338	836	2,404
Well 32	3	7	15	31	65	135	280	598	1,355	3,513
Well 33	4	9	20	41	82	162	322	657	1,418	3,474
Well 34	2	6	15	34	75	165	367	839	2,044	5,766
Well 35	2	6	15	32	69	146	314	691	1,620	4,364
Well 36	4	9	19	39	78	155	310	637	1,385	3,422
Well 37	2	6	13	28	58	119	246	522	1,176	3,027
Well 38	3	7	17	38	84	183	403	912	2,199	6,126

Table 75—10-point gaussian quadrature results of the percentiles for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

10-point	P100 Ratio	P99 Ratio	P98 Ratio	P86 Ratio	P66 Ratio	P34 Ratio	P14 Ratio	P2 Ratio	P1 Ratio	P0 Ratio
Well 1	0%	0%	1%	1%	2%	4%	7%	12%	23%	49%
Well 2	0%	0%	0%	1%	1%	3%	5%	11%	23%	56%
Well 3	0%	0%	0%	1%	1%	3%	5%	11%	23%	55%
Well 4	0%	0%	0%	0%	1%	2%	4%	9%	22%	60%
Well 5	0%	0%	0%	0%	1%	1%	3%	8%	21%	65%
Well 6	0%	0%	0%	1%	1%	2%	5%	10%	23%	58%
Well 7	0%	0%	0%	1%	2%	3%	6%	12%	23%	52%
Well 8	1%	1%	2%	2%	4%	6%	9%	14%	23%	40%
Well 9	0%	0%	1%	1%	2%	4%	7%	13%	23%	48%
Well 10	0%	0%	1%	1%	3%	4%	7%	13%	23%	47%
Well 11	0%	1%	1%	2%	3%	5%	8%	14%	23%	42%
Well 12	0%	0%	1%	1%	2%	4%	7%	13%	23%	47%
Well 13	0%	1%	1%	2%	3%	5%	8%	13%	23%	44%
Well 14	1%	1%	2%	3%	4%	6%	10%	14%	22%	36%
Well 15	0%	0%	0%	0%	0%	1%	2%	6%	19%	71%
Well 16	0%	0%	0%	0%	0%	1%	3%	7%	21%	67%
Well 17	0%	0%	0%	0%	0%	1%	2%	6%	19%	71%
Well 18	0%	1%	1%	2%	3%	4%	7%	13%	23%	46%
Well 19	1%	2%	3%	4%	5%	7%	10%	14%	21%	33%
Well 20	0%	0%	0%	1%	1%	3%	5%	10%	23%	57%
Well 21	0%	0%	1%	1%	2%	4%	7%	12%	23%	50%
Well 22	0%	0%	0%	0%	1%	2%	4%	9%	22%	61%
Well 23	0%	0%	0%	0%	1%	2%	3%	8%	21%	64%
Well 24	0%	0%	0%	0%	1%	2%	4%	8%	21%	64%
Well 25	0%	0%	0%	0%	1%	2%	4%	10%	22%	60%
Well 26	0%	0%	0%	0%	1%	1%	3%	8%	21%	66%
Well 27	0%	0%	0%	1%	2%	3%	6%	12%	23%	53%
Well 28	0%	0%	0%	0%	1%	1%	3%	8%	21%	64%
Well 29	0%	0%	0%	1%	1%	3%	5%	10%	23%	57%
Well 30	0%	0%	0%	1%	1%	2%	5%	10%	23%	59%
Well 31	0%	0%	0%	0%	1%	2%	4%	9%	22%	63%
Well 32	0%	0%	0%	1%	1%	2%	5%	10%	23%	59%
Well 33	0%	0%	0%	1%	1%	3%	5%	11%	23%	56%
Well 34	0%	0%	0%	0%	1%	2%	4%	9%	22%	62%
Well 35	0%	0%	0%	0%	1%	2%	4%	10%	22%	60%
Well 36	0%	0%	0%	1%	1%	3%	5%	11%	23%	57%
Well 37	0%	0%	0%	1%	1%	2%	5%	10%	23%	58%
Well 38	0%	0%	0%	0%	1%	2%	4%	9%	22%	61%

Table 76—10-point gaussian quadrature results of the ratios for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

APPENDIX F

3-POINT, 5-POINT, AND 10-POINT GAUSSIAN QUADRUATURE CONTINGENT RESOURCES RESULTS

In Appendix F.1, we present **Table 77** through **Table 81** that present the 3-point, 5-point, and 10-point GQ results of Contingent Resources with 20 per cent increase on the standard deviation.

In Appendix F.2, we present **Table 82** through **Table 86** that present the 3-point, 5-point, and 10-point GQ results of Contingent Resources with 50 per cent increase on the standard deviation.

F.1 20% increase in standard deviation

3-point	P83	P67	P17	P83 Ratio	P67 Ratio	P17 Ratio	P17/P83
Well 1	57	125	273	13%	27%	60%	5
Well 2	35	109	338	7%	23%	70%	10
Well 3	39	115	343	8%	23%	69%	9
Well 4	21	82	325	5%	19%	76%	16
Well 5	14	76	405	3%	15%	82%	29
Well 6	35	120	416	6%	21%	73%	12
Well 7	52	132	334	10%	25%	65%	6
Well 8	138	221	354	19%	31%	50%	3
Well 9	44	92	194	13%	28%	59%	4
Well 10	97	197	399	14%	28%	58%	4
Well 11	76	130	223	18%	30%	52%	3
Well 12	60	123	253	14%	28%	58%	4
Well 13	110	200	366	16%	30%	54%	3
Well 14	76	111	161	22%	32%	46%	2
Well 15	9	84	782	1%	10%	89%	87
Well 16	18	115	750	2%	13%	85%	43
Well 17	13	115	1036	1%	10%	89%	81
Well 18	170	334	657	15%	29%	57%	4
Well 19	205	277	375	24%	32%	44%	2
Well 20	70	224	716	7%	22%	71%	10
Well 21	97	224	518	12%	27%	62%	5
Well 22	28	118	493	4%	18%	77%	18
Well 23	18	95	485	3%	16%	81%	26
Well 24	13	67	341	3%	16%	81%	26
Well 25	42	158	600	5%	20%	75%	14
Well 26	14	82	478	2%	14%	83%	34
Well 27	60	153	396	10%	25%	65%	7
Well 28	17	90	472	3%	16%	82%	28
Well 29	20	62	198	7%	22%	71%	10
Well 30	21	77	280	6%	20%	74%	13
Well 31	9	39	180	4%	17%	79%	21
Well 32	24	86	304	6%	21%	73%	12
Well 33	35	106	328	7%	23%	70%	9
Well 34	23	101	443	4%	18%	78%	19
Well 35	24	92	357	5%	19%	76%	15
Well 36	32	101	318	7%	22%	70%	10
Well 37	22	76	265	6%	21%	73%	12
Well 38	27	113	478	4%	18%	77%	18

Table 77—3-point gaussian quadrature results of the Contingent Resources with 20 per cent increase in the standard deviation. We present the percentiles, ratios, and P17/P83 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 3-point GQ are 0.17, 0.67, 0.17 for all the wells.

5-point	P99	P78	P53	P22	P1
Well 1	34	68	125	231	455
Well 2	17	45	109	264	702
Well 3	19	49	115	271	696
Well 4	9	28	82	241	792
Well 5	5	20	76	281	1,204
Well 6	15	45	120	317	932
Well 7	28	64	132	273	612
Well 8	102	153	221	320	480
Well 9	27	51	92	165	314
Well 10	61	113	197	342	632
Well 11	54	86	130	198	315
Well 12	38	70	123	216	404
Well 13	74	125	200	321	542
Well 14	60	83	111	148	205
Well 15	2	15	84	481	3,330
Well 16	5	26	115	498	2,539
Well 17	3	21	115	643	4,307
Well 18	110	197	334	567	1,018
Well 19	169	219	277	351	457
Well 20	33	90	224	556	1,525
Well 21	56	116	224	432	894
Well 22	11	38	118	361	1,248
Well 23	6	26	95	340	1,402
Well 24	5	19	67	240	982
Well 25	17	55	158	449	1,430
Well 26	4	21	82	326	1,505
Well 27	32	73	153	322	732
Well 28	6	25	90	329	1,386
Well 29	9	25	62	154	421
Well 30	9	28	77	212	646
Well 31	3	12	39	129	485
Well 32	11	32	86	231	688
Well 33	17	44	106	256	680
Well 34	9	32	101	322	1,155
Well 35	10	32	92	266	861
Well 36	15	41	101	248	670
Well 37	10	29	76	202	593
Well 38	10	37	113	350	1,221

Table 78—5-point gaussian quadrature results of the Contingent Resources with 20 per cent increase in standard deviation. We present the percentiles for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

5-point	P99 Ratio	P78 Ratio	P53 Ratio	P22 Ratio	P1 Ratio	P22/P78
Well 1	4%	7%	14%	25%	50%	3
Well 2	1%	4%	10%	23%	62%	6
Well 3	2%	4%	10%	24%	61%	6
Well 4	1%	2%	7%	21%	69%	9
Well 5	0%	1%	5%	18%	76%	14
Well 6	1%	3%	8%	22%	65%	7
Well 7	3%	6%	12%	25%	55%	4
Well 8	8%	12%	17%	25%	38%	2
Well 9	4%	8%	14%	25%	48%	3
Well 10	5%	8%	15%	25%	47%	3
Well 11	7%	11%	17%	25%	40%	2
Well 12	4%	8%	14%	25%	47%	3
Well 13	6%	10%	16%	25%	43%	3
Well 14	10%	14%	18%	24%	34%	2
Well 15	0%	0%	2%	12%	85%	33
Well 16	0%	1%	4%	16%	80%	19
Well 17	0%	0%	2%	13%	85%	31
Well 18	5%	9%	15%	25%	46%	3
Well 19	11%	15%	19%	24%	31%	2
Well 20	1%	4%	9%	23%	63%	6
Well 21	3%	7%	13%	25%	52%	4
Well 22	1%	2%	7%	20%	70%	9
Well 23	0%	1%	5%	18%	75%	13
Well 24	0%	1%	5%	18%	75%	13
Well 25	1%	3%	7%	21%	68%	8
Well 26	0%	1%	4%	17%	78%	16
Well 27	2%	6%	12%	25%	56%	4
Well 28	0%	1%	5%	18%	75%	13
Well 29	1%	4%	9%	23%	63%	6
Well 30	1%	3%	8%	22%	66%	7
Well 31	0%	2%	6%	19%	73%	11
Well 32	1%	3%	8%	22%	66%	7
Well 33	2%	4%	10%	23%	62%	6
Well 34	1%	2%	6%	20%	71%	10
Well 35	1%	3%	7%	21%	68%	8
Well 36	1%	4%	9%	23%	62%	6
Well 37	1%	3%	8%	22%	65%	7
Well 38	1%	2%	7%	20%	71%	10

Table 79—5-point gaussian quadrature results of the Contingent Resources with 20 per cent increase on the standard deviation. We present the ratios and P22/P78 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

10-point	P100	P99	P98	P86	P66	P34	P14	P2	P1	P0
Well 1	14	25	41	64	100	155	242	384	631	1,126
Well 2	5	11	22	42	80	150	284	551	1,126	2,584
Well 3	5	12	24	46	85	157	290	550	1,098	2,452
Well 4	2	5	12	26	56	121	263	589	1,405	3,864
Well 5	1	2	7	18	47	121	313	839	2,430	8,383
Well 6	4	9	20	42	85	170	343	713	1,568	3,921
Well 7	10	19	35	60	102	171	290	501	904	1,796
Well 8	59	84	113	149	194	253	329	434	585	827
Well 9	11	20	32	49	75	113	173	268	429	744
Well 10	27	45	71	108	161	240	358	543	851	1,434
Well 11	29	43	61	83	112	152	205	281	394	585
Well 12	16	28	44	67	101	151	226	346	545	927
Well 13	37	58	84	120	169	237	334	476	697	1,088
Well 14	39	51	65	81	100	123	152	189	239	315
Well 15	0	1	3	13	45	157	555	2,061	8,474	43,949
Well 16	1	2	8	23	68	194	562	1,695	5,574	22,284
Well 17	0	1	5	18	62	213	739	2,686	10,789	54,438
Well 18	50	83	127	189	277	404	592	881	1,351	2,223
Well 19	119	149	180	215	255	302	358	428	518	647
Well 20	9	20	42	84	162	310	599	1,188	2,482	5,856
Well 21	21	39	67	110	177	283	455	746	1,271	2,361
Well 22	2	6	15	35	79	176	395	917	2,272	6,529
Well 23	1	3	9	24	60	150	377	986	2,778	9,275
Well 24	1	2	7	17	43	106	266	692	1,940	6,443
Well 25	4	10	23	51	109	229	489	1,073	2,500	6,698
Well 26	1	2	6	18	50	134	364	1,029	3,151	11,592
Well 27	11	22	39	69	118	200	342	597	1,089	2,190
Well 28	1	3	8	22	57	143	366	970	2,774	9,424
Well 29	2	6	12	23	45	86	166	328	684	1,606
Well 30	2	5	12	26	54	111	230	490	1,107	2,859
Well 31	1	2	4	11	26	60	143	349	918	2,823
Well 32	3	6	14	30	61	123	250	525	1,166	2,954
Well 33	5	10	21	41	78	146	276	534	1,089	2,498
Well 34	2	5	12	29	67	153	353	841	2,140	6,351
Well 35	2	6	13	29	63	134	290	643	1,520	4,137
Well 36	4	9	20	38	73	139	267	523	1,082	2,518
Well 37	2	6	13	27	54	108	219	454	997	2,494
Well 38	2	6	14	33	76	169	383	895	2,233	6,472

Table 80—10-point gaussian quadrature of the Contingent Resources with 20 per cent increase in the standard deviation, and the results of the percentiles for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

10-point	P100 Ratio	P99 Ratio	P98 Ratio	P86 Ratio	P66 Ratio	P34 Ratio	P14 Ratio	P2 Ratio	P1 Ratio	P0 Ratio	P14/P86
Well 1	0.5%	0.9%	1.5%	2.3%	4%	6%	9%	14%	23%	40%	4
Well 2	0.1%	0.2%	0.4%	0.9%	2%	3%	6%	11%	23%	53%	7
Well 3	0.1%	0.3%	0.5%	1.0%	2%	3%	6%	12%	23%	52%	6
Well 4	0.0%	0.1%	0.2%	0.4%	1%	2%	4%	9%	22%	61%	10
Well 5	0.0%	0.0%	0.1%	0.2%	0%	1%	3%	7%	20%	69%	17
Well 6	0.1%	0.1%	0.3%	0.6%	1%	2%	5%	10%	23%	57%	8
Well 7	0.2%	0.5%	0.9%	1.5%	3%	4%	7%	13%	23%	46%	5
Well 8	2.0%	2.8%	3.7%	4.9%	6%	8%	11%	14%	19%	27%	2
Well 9	0.6%	1.0%	1.6%	2.6%	4%	6%	9%	14%	22%	39%	4
Well 10	0.7%	1.2%	1.9%	2.8%	4%	6%	9%	14%	22%	37%	3
Well 11	1.5%	2.2%	3.1%	4.3%	6%	8%	11%	14%	20%	30%	2
Well 12	0.7%	1.1%	1.8%	2.7%	4%	6%	9%	14%	22%	38%	3
Well 13	1.1%	1.7%	2.6%	3.6%	5%	7%	10%	14%	21%	33%	3
Well 14	2.9%	3.8%	4.8%	6.0%	7%	9%	11%	14%	18%	23%	2
Well 15	0.0%	0.0%	0.0%	0.0%	0%	0%	1%	4%	15%	80%	44
Well 16	0.0%	0.0%	0.0%	0.1%	0%	1%	2%	6%	18%	73%	24
Well 17	0.0%	0.0%	0.0%	0.0%	0%	0%	1%	4%	16%	79%	41
Well 18	0.8%	1.3%	2.1%	3.1%	4%	7%	10%	14%	22%	36%	3
Well 19	3.7%	4.7%	5.7%	6.8%	8%	10%	11%	13%	16%	20%	2
Well 20	0.1%	0.2%	0.4%	0.8%	2%	3%	6%	11%	23%	54%	7
Well 21	0.4%	0.7%	1.2%	2.0%	3%	5%	8%	13%	23%	43%	4
Well 22	0.0%	0.1%	0.1%	0.3%	1%	2%	4%	9%	22%	63%	11
Well 23	0.0%	0.0%	0.1%	0.2%	0%	1%	3%	7%	20%	68%	16
Well 24	0.0%	0.0%	0.1%	0.2%	0%	1%	3%	7%	20%	68%	16
Well 25	0.0%	0.1%	0.2%	0.5%	1%	2%	4%	10%	22%	60%	10
Well 26	0.0%	0.0%	0.0%	0.1%	0%	1%	2%	6%	19%	71%	20
Well 27	0.2%	0.5%	0.8%	1.5%	3%	4%	7%	13%	23%	47%	5
Well 28	0.0%	0.0%	0.1%	0.2%	0%	1%	3%	7%	20%	68%	17
Well 29	0.1%	0.2%	0.4%	0.8%	2%	3%	6%	11%	23%	54%	7
Well 30	0.0%	0.1%	0.2%	0.5%	1%	2%	5%	10%	23%	58%	9
Well 31	0.0%	0.0%	0.1%	0.2%	1%	1%	3%	8%	21%	65%	13
Well 32	0.0%	0.1%	0.3%	0.6%	1%	2%	5%	10%	23%	58%	8
Well 33	0.1%	0.2%	0.5%	0.9%	2%	3%	6%	11%	23%	53%	7
Well 34	0.0%	0.0%	0.1%	0.3%	1%	2%	4%	8%	22%	64%	12
Well 35	0.0%	0.1%	0.2%	0.4%	1%	2%	4%	9%	22%	61%	10
Well 36	0.1%	0.2%	0.4%	0.8%	2%	3%	6%	11%	23%	54%	7
Well 37	0.1%	0.1%	0.3%	0.6%	1%	2%	5%	10%	23%	57%	8
Well 38	0.0%	0.1%	0.1%	0.3%	1%	2%	4%	9%	22%	63%	11

Table 81—10-point gaussian quadrature results of the Contingent Resources with 20 per cent increase in the standard deviation. The ratios and P14/P86 values for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

F.2 50% increase in standard deviation

3-point	P83	P67	P17	P83 Ratio	P67 Ratio	P17 Ratio	P17/P83
Well 1	38	114	344	8%	23%	69%	29
Well 2	21	97	453	4%	17%	79%	22
Well 3	23	103	457	4%	18%	78%	20
Well 4	11	72	452	2%	13%	84%	39
Well 5	7	65	585	1%	10%	89%	81
Well 6	20	106	568	3%	15%	82%	29
Well 7	32	119	433	6%	20%	74%	13
Well 8	105	208	413	14%	29%	57%	4
Well 9	29	84	241	8%	24%	68%	8
Well 10	66	180	494	9%	24%	67%	8
Well 11	56	122	264	13%	28%	60%	5
Well 12	41	113	314	9%	24%	67%	8
Well 13	78	185	442	11%	26%	63%	6
Well 14	61	105	183	17%	30%	52%	3
Well 15	4	71	1,191	0%	6%	94%	283
Well 16	9	98	1,107	1%	8%	91%	128
Well 17	6	97	1,573	0%	6%	94%	261
Well 18	117	307	807	10%	25%	66%	7
Well 19	169	266	417	20%	31%	49%	2
Well 20	41	198	967	3%	16%	80%	24
Well 21	62	203	659	7%	22%	71%	11
Well 22	15	103	691	2%	13%	85%	45
Well 23	10	82	698	1%	10%	88%	73
Well 24	7	58	491	1%	10%	88%	72
Well 25	23	138	831	2%	14%	84%	36
Well 26	7	70	698	1%	9%	90%	99
Well 27	37	138	514	5%	20%	75%	14
Well 28	9	78	682	1%	10%	89%	77
Well 29	11	55	268	3%	17%	80%	23
Well 30	12	68	385	3%	15%	83%	32
Well 31	5	34	256	2%	12%	87%	56
Well 32	14	76	416	3%	15%	82%	30
Well 33	20	94	439	4%	17%	79%	22
Well 34	12	88	625	2%	12%	86%	50
Well 35	13	80	496	2%	14%	84%	38
Well 36	19	90	428	4%	17%	80%	23
Well 37	13	67	361	3%	15%	82%	29
Well 38	14	98	672	2%	13%	86%	47

Table 82—3-point gaussian quadrature results of the Contingent Resources with 50 per cent increase in the standard deviation. We present the percentiles, ratios, and P17/P83 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 3-point GQ are 0.17, 0.67, 0.17 for all the wells.

5-point	P99	P78	P53	P22	P1
Well 1	18	48	114	270	706
Well 2	8	29	97	324	1,232
Well 3	9	32	103	330	1,206
Well 4	3	17	72	303	1,490
Well 5	2	12	65	363	2,438
Well 6	7	28	106	394	1,692
Well 7	14	43	119	327	1,005
Well 8	67	121	208	356	646
Well 9	15	37	84	192	480
Well 10	34	82	180	397	951
Well 11	34	66	122	223	437
Well 12	21	51	113	251	609
Well 13	44	94	185	366	777
Well 14	42	68	105	162	261
Well 15	1	8	71	645	7,453
Well 16	2	15	98	653	5,355
Well 17	1	11	97	860	9,584
Well 18	63	145	307	654	1,509
Well 19	126	187	266	378	560
Well 20	15	57	198	685	2,705
Well 21	29	81	203	510	1,418
Well 22	4	23	103	457	2,385
Well 23	2	15	82	438	2,812
Well 24	2	11	58	309	1,967
Well 25	7	34	138	563	2,665
Well 26	2	12	70	424	3,104
Well 27	16	49	138	386	1,209
Well 28	2	14	78	425	2,795
Well 29	4	16	55	190	745
Well 30	4	18	68	264	1,188
Well 31	1	7	34	165	948
Well 32	5	20	76	287	1,256
Well 33	7	28	94	314	1,192
Well 34	3	19	88	408	2,231
Well 35	4	19	80	334	1,615
Well 36	7	26	90	305	1,181
Well 37	4	18	67	251	1,077
Well 38	4	22	98	443	2,341

Table 83—5-point gaussian quadrature results of the Contingent Resources with 50 per cent increase in standard deviation. We present the percentiles for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

5-point	P99 Ratio	P78 Ratio	P53 Ratio	P22 Ratio	P1 Ratio	P22/P78
Well 1	1.6%	4%	10%	23%	61%	6
Well 2	0.5%	2%	6%	19%	73%	11
Well 3	0.5%	2%	6%	20%	72%	10
Well 4	0.2%	1%	4%	16%	79%	18
Well 5	0.1%	0%	2%	13%	85%	31
Well 6	0.3%	1%	5%	18%	76%	14
Well 7	0.9%	3%	8%	22%	67%	8
Well 8	4.8%	9%	15%	25%	46%	3
Well 9	1.8%	5%	10%	24%	59%	5
Well 10	2.1%	5%	11%	24%	58%	5
Well 11	3.8%	8%	14%	25%	50%	3
Well 12	2.0%	5%	11%	24%	58%	5
Well 13	3.0%	6%	13%	25%	53%	4
Well 14	6.6%	11%	16%	25%	41%	2
Well 15	0.0%	0%	1%	8%	91%	83
Well 16	0.0%	0%	2%	11%	87%	45
Well 17	0.0%	0%	1%	8%	91%	78
Well 18	2.3%	5%	11%	24%	56%	5
Well 19	8.3%	12%	18%	25%	37%	2
Well 20	0.4%	2%	5%	19%	74%	12
Well 21	1.3%	4%	9%	23%	63%	6
Well 22	0.1%	1%	3%	15%	80%	20
Well 23	0.1%	0%	2%	13%	84%	29
Well 24	0.1%	0%	2%	13%	84%	28
Well 25	0.2%	1%	4%	17%	78%	17
Well 26	0.0%	0%	2%	12%	86%	36
Well 27	0.9%	3%	8%	21%	67%	8
Well 28	0.1%	0%	2%	13%	84%	30
Well 29	0.4%	2%	5%	19%	74%	12
Well 30	0.3%	1%	4%	17%	77%	15
Well 31	0.1%	1%	3%	14%	82%	23
Well 32	0.3%	1%	5%	17%	76%	14
Well 33	0.5%	2%	6%	19%	73%	11
Well 34	0.1%	1%	3%	15%	81%	21
Well 35	0.2%	1%	4%	16%	79%	17
Well 36	0.4%	2%	6%	19%	73%	12
Well 37	0.3%	1%	5%	18%	76%	14
Well 38	0.1%	1%	3%	15%	80%	20

Table 84—5-point gaussian quadrature results of the Contingent Resources with 50 per cent increase on the standard deviation. We present the ratios and P22/P78 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

10-point	P100	P99	P98	P86	P66	P34	P14	P2	P1	P0
Well 1	5	12	23	45	83	155	290	556	1,121	2,536
Well 2	1	4	11	26	63	150	358	884	2,345	7,301
Well 3	2	5	12	29	68	156	363	874	2,252	6,777
Well 4	0	2	5	15	43	121	341	1,003	3,212	12,444
Well 5	0	1	3	10	35	120	418	1,520	6,115	30,922
Well 6	1	3	9	25	66	169	439	1,178	3,420	11,820
Well 7	3	8	19	40	83	170	355	760	1,727	4,490
Well 8	30	50	78	116	172	252	372	557	860	1,428
Well 9	4	9	18	34	62	113	205	382	746	1,627
Well 10	11	22	42	77	136	239	423	765	1,450	3,049
Well 11	14	24	40	63	98	151	235	370	605	1,072
Well 12	6	14	26	48	85	150	268	489	935	1,987
Well 13	16	31	53	89	145	237	387	645	1,118	2,121
Well 14	22	34	48	66	90	123	168	232	329	494
Well 15	0	0	1	6	32	156	772	4,060	24,293	194,973
Well 16	0	1	3	13	50	193	763	3,177	14,785	88,565
Well 17	0	0	2	9	45	212	1,026	5,268	30,702	238,992
Well 18	21	42	77	136	235	403	696	1,226	2,260	4,603
Well 19	75	105	139	181	234	302	389	508	676	943
Well 20	2	7	20	52	127	309	758	1,924	5,250	16,897
Well 21	7	18	37	75	146	282	550	1,100	2,323	5,543
Well 22	0	2	7	20	60	175	516	1,583	5,299	21,639
Well 23	0	1	4	13	45	149	502	1,772	6,903	33,607
Well 24	0	1	3	9	32	105	354	1,242	4,811	23,274
Well 25	1	3	11	30	84	229	631	1,812	5,644	21,190
Well 26	0	1	3	10	37	133	490	1,893	8,121	44,230
Well 27	3	9	21	45	95	199	420	911	2,097	5,535
Well 28	0	1	3	12	42	143	488	1,751	6,940	34,474
Well 29	1	2	6	15	36	86	210	531	1,443	4,619
Well 30	1	2	6	16	42	111	295	818	2,455	8,820
Well 31	0	1	2	6	19	60	188	615	2,205	9,758
Well 32	1	2	7	18	47	122	320	871	2,561	8,988
Well 33	1	4	10	26	61	145	347	856	2,268	7,051
Well 34	0	2	5	17	51	153	463	1,464	5,064	21,475
Well 35	0	2	6	17	48	134	375	1,092	3,457	13,227
Well 36	1	4	10	24	58	139	337	844	2,271	7,192
Well 37	1	2	6	16	42	108	279	750	2,175	7,518
Well 38	0	2	6	19	58	169	501	1,548	5,229	21,563

Table 85—10-point gaussian quadrature of the Contingent Resources with 50 per cent increase in the standard deviation, and the results of the percentiles for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

10-point	P100 Ratio	P99 Ratio	P98 Ratio	P86 Ratio	P66 Ratio	P34 Ratio	P14 Ratio	P2 Ratio	P1 Ratio	P0 Ratio
Well 1	0%	0%	0%	1%	2%	3%	6%	12%	23%	53%
Well 2	0%	0%	0%	0%	1%	1%	3%	8%	21%	66%
Well 3	0%	0%	0%	0%	1%	1%	3%	8%	21%	64%
Well 4	0%	0%	0%	0%	0%	1%	2%	6%	19%	72%
Well 5	0%	0%	0%	0%	0%	0%	1%	4%	16%	79%
Well 6	0%	0%	0%	0%	0%	1%	3%	7%	20%	69%
Well 7	0%	0%	0%	1%	1%	2%	5%	10%	23%	59%
Well 8	1%	1%	2%	3%	4%	6%	9%	14%	22%	36%
Well 9	0%	0%	1%	1%	2%	4%	6%	12%	23%	51%
Well 10	0%	0%	1%	1%	2%	4%	7%	12%	23%	49%
Well 11	1%	1%	1%	2%	4%	6%	9%	14%	23%	40%
Well 12	0%	0%	1%	1%	2%	4%	7%	12%	23%	50%
Well 13	0%	1%	1%	2%	3%	5%	8%	13%	23%	44%
Well 14	1%	2%	3%	4%	6%	8%	10%	14%	20%	31%
Well 15	0%	0%	0%	0%	0%	0%	0%	2%	11%	87%
Well 16	0%	0%	0%	0%	0%	0%	1%	3%	14%	82%
Well 17	0%	0%	0%	0%	0%	0%	0%	2%	11%	87%
Well 18	0%	0%	1%	1%	2%	4%	7%	13%	23%	47%
Well 19	2%	3%	4%	5%	7%	8%	11%	14%	19%	27%
Well 20	0%	0%	0%	0%	1%	1%	3%	8%	21%	67%
Well 21	0%	0%	0%	1%	1%	3%	5%	11%	23%	55%
Well 22	0%	0%	0%	0%	0%	1%	2%	5%	18%	74%
Well 23	0%	0%	0%	0%	0%	0%	1%	4%	16%	78%
Well 24	0%	0%	0%	0%	0%	0%	1%	4%	16%	78%
Well 25	0%	0%	0%	0%	0%	1%	2%	6%	19%	72%
Well 26	0%	0%	0%	0%	0%	0%	1%	3%	15%	81%
Well 27	0%	0%	0%	0%	1%	2%	5%	10%	22%	59%
Well 28	0%	0%	0%	0%	0%	0%	1%	4%	16%	79%
Well 29	0%	0%	0%	0%	1%	1%	3%	8%	21%	66%
Well 30	0%	0%	0%	0%	0%	1%	2%	7%	20%	70%
Well 31	0%	0%	0%	0%	0%	0%	1%	5%	17%	76%
Well 32	0%	0%	0%	0%	0%	1%	2%	7%	20%	69%
Well 33	0%	0%	0%	0%	1%	1%	3%	8%	21%	65%
Well 34	0%	0%	0%	0%	0%	1%	2%	5%	18%	75%
Well 35	0%	0%	0%	0%	0%	1%	2%	6%	19%	72%
Well 36	0%	0%	0%	0%	1%	1%	3%	8%	21%	66%
Well 37	0%	0%	0%	0%	0%	1%	3%	7%	20%	69%
Well 38	0%	0%	0%	0%	0%	1%	2%	5%	18%	74%

Table 86—10-point gaussian quadrature results of the Contingent Resources with 50 per cent increase in the standard deviation. The ratios and P14/P86 values for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

APPENDIX G

3-POINT, 5-POINT, AND 10-POINT GAUSSIAN QUADRUATURE PROSPECTIVE RESOURCES RESULTS

In Appendix G.1, we present **Table 87** through **Table 91** that present the 3-point, 5-point, and 10-point GQ results of Prospective Resources with 90 per cent increase on the standard deviation.

In Appendix G.2, we present **Table 92** through **Table 96** that present the 3-point, 5-point, and 10-point GQ results of Prospective Resources with 100 per cent increase on the standard deviation.

G.1 90% increase on standard deviation

3-point	P83	P67	P17	P83 Ratio	P67 Ratio	P17 Ratio	P17/P83
Well 1	21	100	469	4%	17%	79%	22
Well 2	11	83	659	1%	11%	88%	62
Well 3	12	88	661	2%	12%	87%	56
Well 4	5	61	681	1%	8%	91%	125
Well 5	3	54	913	0%	6%	94%	283
Well 6	10	90	841	1%	10%	89%	87
Well 7	18	103	609	2%	14%	83%	35
Well 8	70	190	516	9%	24%	67%	7
Well 9	17	74	326	4%	18%	78%	19
Well 10	39	160	661	5%	19%	77%	17
Well 11	36	110	337	7%	23%	70%	9
Well 12	24	100	421	4%	18%	77%	18
Well 13	48	167	575	6%	21%	73%	12
Well 14	43	97	220	12%	27%	61%	5
Well 15	2	58	1940	0%	3%	97%	1118
Well 16	4	81	1758	0%	4%	95%	471
Well 17	3	80	2557	0%	3%	97%	1022
Well 18	70	274	1070	5%	19%	76%	15
Well 19	127	249	490	15%	29%	57%	4
Well 20	20	170	1415	1%	11%	88%	69
Well 21	35	178	910	3%	16%	81%	26
Well 22	7	87	1049	1%	8%	92%	147
Well 23	4	68	1084	0%	6%	94%	252
Well 24	3	48	762	0%	6%	94%	247
Well 25	11	117	1247	1%	9%	91%	113
Well 26	3	58	1098	0%	5%	95%	354
Well 27	20	120	725	2%	14%	84%	37
Well 28	4	65	1061	0%	6%	94%	268
Well 29	6	47	391	1%	11%	88%	68
Well 30	6	58	574	1%	9%	90%	98
Well 31	2	29	393	0%	7%	93%	188
Well 32	7	65	618	1%	9%	90%	91
Well 33	10	81	639	1%	11%	87%	62
Well 34	6	74	954	1%	7%	92%	165
Well 35	6	68	745	1%	8%	91%	120
Well 36	9	77	625	1%	11%	88%	354
Well 37	6	57	535	1%	10%	89%	37
Well 38	7	83	1022	1%	7%	92%	151

Table 87—3-point gaussian quadrature results of the Prospective Resources with 90 per cent increase in the standard deviation. We present the percentiles, ratios, and P17/P83 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 3-point GQ are 0.17, 0.67, 0.17 for all the wells.

5-point	P99	P78	P53	P22	P1
Well 1	8	30	100	335	1,275
Well 2	3	17	83	421	2,524
Well 3	3	18	88	427	2,442
Well 4	1	9	61	403	3,265
Well 5	1	6	54	494	5,706
Well 6	2	16	90	518	3,587
Well 7	6	26	103	414	1,927
Well 8	37	87	190	415	988
Well 9	6	23	74	236	852
Well 10	15	53	160	486	1,660
Well 11	17	46	110	264	697
Well 12	9	33	100	308	1,070
Well 13	22	63	167	439	1,286
Well 14	25	51	97	185	374
Well 15	0	4	58	905	18,958
Well 16	1	7	81	901	12,972
Well 17	0	5	80	1,204	24,268
Well 18	29	94	274	796	2,593
Well 19	82	147	249	423	760
Well 20	5	32	170	892	5,606
Well 21	12	50	178	638	2,624
Well 22	1	12	87	610	5,303
Well 23	1	8	68	594	6,527
Well 24	1	6	48	419	4,558
Well 25	2	18	117	746	5,789
Well 26	0	6	58	580	7,380
Well 27	6	29	120	491	2,333
Well 28	1	7	65	578	6,516
Well 29	1	9	47	247	1,542
Well 30	1	10	58	349	2,548
Well 31	0	4	29	222	2,152
Well 32	2	11	65	378	2,676
Well 33	3	16	81	408	2,442
Well 34	1	10	74	548	5,008
Well 35	1	10	68	443	3,527
Well 36	2	15	77	396	2,435
Well 37	1	10	57	329	2,282
Well 38	1	12	83	592	5,217

Table 88—5-point gaussian quadrature results of the Prospective Resources with 90 per cent increase in standard deviation. We present the percentiles for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

5-point	P99	P78	P53	P22	P1	P22/P78
Well 1	0.5%	1.7%	6%	19%	73%	11
Well 2	0.1%	0.5%	3%	14%	83%	25
Well 3	0.1%	0.6%	3%	14%	82%	23
Well 4	0.0%	0.2%	2%	11%	87%	44
Well 5	0.0%	0.1%	1%	8%	91%	83
Well 6	0.1%	0.4%	2%	12%	85%	33
Well 7	0.2%	1.0%	4%	17%	78%	16
Well 8	2.1%	5.1%	11%	24%	58%	5
Well 9	0.5%	2.0%	6%	20%	71%	10
Well 10	0.7%	2.2%	7%	20%	70%	9
Well 11	1.5%	4.1%	10%	23%	61%	6
Well 12	0.6%	2.1%	7%	20%	70%	9
Well 13	1.1%	3.2%	8%	22%	65%	7
Well 14	3.5%	7.0%	13%	25%	51%	4
Well 15	0.0%	0.0%	0%	5%	95%	243
Well 16	0.0%	0.1%	1%	6%	93%	124
Well 17	0.0%	0.0%	0%	5%	95%	227
Well 18	0.8%	2.5%	7%	21%	68%	8
Well 19	4.9%	8.8%	15%	25%	46%	3
Well 20	0.1%	0.5%	3%	13%	84%	28
Well 21	0.3%	1.4%	5%	18%	75%	13
Well 22	0.0%	0.2%	1%	10%	88%	50
Well 23	0.0%	0.1%	1%	8%	91%	76
Well 24	0.0%	0.1%	1%	8%	91%	75
Well 25	0.0%	0.3%	2%	11%	87%	40
Well 26	0.0%	0.1%	1%	7%	92%	99
Well 27	0.2%	1.0%	4%	16%	78%	17
Well 28	0.0%	0.1%	1%	8%	91%	79
Well 29	0.1%	0.5%	3%	13%	83%	27
Well 30	0.0%	0.3%	2%	12%	86%	36
Well 31	0.0%	0.2%	1%	9%	89%	60
Well 32	0.0%	0.4%	2%	12%	85%	34
Well 33	0.1%	0.5%	3%	14%	83%	25
Well 34	0.0%	0.2%	1%	10%	89%	54
Well 35	0.0%	0.3%	2%	11%	87%	42
Well 36	0.1%	0.5%	3%	14%	83%	27
Well 37	0.1%	0.4%	2%	12%	85%	33
Well 38	0.0%	0.2%	1%	10%	88%	51

Table 89—5-point gaussian quadrature results of the Prospective Resources with 90 per cent increase on the standard deviation. We present the ratios and P22/P78 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

10-point	P100	P99	P98	P86	P66	P34	P14	P2	P1	P0
Well 1	1	4	11	27	65	154	370	915	2,430	7,577
Well 2	0	1	4	15	47	149	480	1,618	5,995	27,535
Well 3	0	1	5	16	50	155	485	1,584	5,669	25,010
Well 4	0	0	2	8	31	120	470	1,943	8,961	53,124
Well 5	0	0	1	5	25	120	592	3,109	18,589	149,052
Well 6	0	1	4	14	48	168	597	2,218	9,135	47,447
Well 7	1	3	8	23	63	170	464	1,315	4,047	14,975
Well 8	12	24	45	82	144	251	443	797	1,501	3,137
Well 9	1	3	9	21	49	112	260	620	1,582	4,707
Well 10	3	9	21	48	108	238	532	1,223	3,004	8,547
Well 11	5	11	22	43	81	151	284	548	1,112	2,536
Well 12	2	5	13	30	67	150	338	785	1,950	5,624
Well 13	5	13	28	58	118	236	476	985	2,160	5,387
Well 14	10	18	30	49	77	122	194	314	527	962
Well 15	0	0	0	3	22	155	1,132	8,910	82,345	1,096,272
Well 16	0	0	1	6	34	192	1,096	6,691	47,016	454,971
Well 17	0	0	1	4	30	211	1,502	11,516	103,452	1,332,507
Well 18	6	16	39	87	187	401	868	1,934	4,585	12,524
Well 19	37	62	94	141	206	301	441	657	1,008	1,661
Well 20	0	2	8	28	94	307	1,022	3,553	13,615	65,040
Well 21	2	6	17	45	113	281	708	1,848	5,195	17,307
Well 22	0	0	2	10	43	174	715	3,101	15,062	94,835
Well 23	0	0	1	7	31	148	709	3,601	20,755	159,484
Well 24	0	0	1	5	22	105	499	2,520	14,438	110,156
Well 25	0	1	4	16	61	227	867	3,481	15,566	88,990
Well 26	0	0	1	5	26	133	699	3,926	25,199	219,489
Well 27	1	3	9	26	73	199	550	1,584	4,953	18,670
Well 28	0	0	1	6	30	142	690	3,571	20,989	164,969
Well 29	0	1	2	8	26	86	283	979	3,733	17,726
Well 30	0	1	2	8	30	110	404	1,555	6,658	36,180
Well 31	0	0	1	3	14	60	263	1,225	6,438	44,421
Well 32	0	1	3	10	34	122	437	1,646	6,883	36,387
Well 33	0	1	4	14	45	144	465	1,566	5,794	26,566
Well 34	0	0	2	9	36	152	645	2,892	14,578	95,849
Well 35	0	0	2	9	35	133	516	2,108	9,601	56,101
Well 36	0	1	4	13	43	138	453	1,551	5,848	27,411
Well 37	0	1	2	9	31	107	380	1,411	5,810	30,173
Well 38	0	0	2	10	41	168	695	3,040	14,912	94,960

Table 90—10-point gaussian quadrature of the Prospective Resources with 90 per cent increase in the standard deviation, and the results of the percentiles for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

10-point	P100 Ratio	P99 Ratio	P98 Ratio	P86 Ratio	P66 Ratio	P34 Ratio	P14 Ratio	P2 Ratio	P1 Ratio	P0 Ratio	P14/P86
Well 1	0%	0%	0%	0.2%	0.6%	1.3%	3.2%	8%	21%	66%	14
Well 2	0%	0%	0%	0.0%	0.1%	0.4%	1.3%	5%	17%	77%	33
Well 3	0%	0%	0%	0.0%	0.2%	0.5%	1.5%	5%	17%	76%	30
Well 4	0%	0%	0%	0.0%	0.0%	0.2%	0.7%	3%	14%	82%	59
Well 5	0%	0%	0%	0.0%	0.0%	0.1%	0.3%	2%	11%	87%	119
Well 6	0%	0%	0%	0.0%	0.1%	0.3%	1.0%	4%	15%	80%	44
Well 7	0%	0%	0%	0.1%	0.3%	0.8%	2.2%	6%	19%	71%	20
Well 8	0%	0%	0.7%	1.3%	2.2%	3.9%	6.9%	12%	23%	49%	5
Well 9	0%	0%	0.1%	0.3%	0.7%	1.5%	3.5%	8%	21%	64%	12
Well 10	0%	0%	0.2%	0.4%	0.8%	1.7%	3.9%	9%	22%	62%	11
Well 11	0%	0%	0.5%	0.9%	1.7%	3.1%	5.9%	11%	23%	53%	7
Well 12	0%	0%	0.1%	0.3%	0.7%	1.7%	3.8%	9%	22%	63%	11
Well 13	0%	0%	0.3%	0.6%	1.2%	2.5%	5.0%	10%	23%	57%	8
Well 14	0%	1%	1.3%	2.1%	3.4%	5.3%	8.4%	14%	23%	42%	4
Well 15	0%	0%	0.0%	0.0%	0.0%	0.0%	0.1%	1%	7%	92%	380
Well 16	0%	0%	0.0%	0.0%	0.0%	0.0%	0.2%	1%	9%	89%	183
Well 17	0%	0%	0.0%	0.0%	0.0%	0.0%	0.1%	1%	7%	92%	352
Well 18	0%	0%	0.2%	0.4%	0.9%	1.9%	4.2%	9%	22%	61%	10
Well 19	1%	1%	2.0%	3.0%	4.5%	6.5%	9.6%	14%	22%	36%	3
Well 20	0%	0%	0.0%	0.0%	0.1%	0.4%	1.2%	4%	16%	78%	36
Well 21	0%	0%	0.1%	0.2%	0.4%	1.1%	2.8%	7%	20%	68%	16
Well 22	0%	0%	0%	0.0%	0.0%	0.2%	0.6%	3%	13%	83%	68
Well 23	0%	0%	0%	0.0%	0.0%	0.1%	0.4%	2%	11%	86%	108
Well 24	0%	0%	0%	0.0%	0.0%	0.1%	0.4%	2%	11%	86%	106
Well 25	0%	0%	0%	0.0%	0.1%	0.2%	0.8%	3%	14%	81%	55
Well 26	0%	0%	0%	0.0%	0.0%	0.1%	0.3%	2%	10%	88%	144
Well 27	0%	0%	0%	0.1%	0.3%	0.8%	2.1%	6%	19%	72%	21
Well 28	0%	0%	0%	0.0%	0.0%	0.1%	0.4%	2%	11%	87%	113
Well 29	0%	0%	0%	0.0%	0.1%	0.4%	1.2%	4%	16%	78%	36
Well 30	0%	0%	0%	0.0%	0.1%	0.2%	0.9%	3%	15%	80%	49
Well 31	0%	0%	0%	0.0%	0.0%	0.1%	0.5%	2%	12%	85%	84
Well 32	0%	0%	0%	0.0%	0.1%	0.3%	1.0%	4%	15%	80%	46
Well 33	0%	0%	0%	0.0%	0.1%	0.4%	1.3%	5%	17%	77%	33
Well 34	0%	0%	0%	0.0%	0.0%	0.1%	0.6%	3%	13%	84%	75
Well 35	0%	0%	0%	0.0%	0.1%	0.2%	0.8%	3%	14%	82%	57
Well 36	0%	0%	0%	0.0%	0.1%	0.4%	1.3%	4%	16%	77%	35
Well 37	0%	0%	0%	0.0%	0.1%	0.3%	1.0%	4%	15%	80%	44
Well 38	0%	0%	0%	0.0%	0.0%	0.1%	0.6%	3%	13%	83%	70

Table 91—10-point gaussian quadrature results of the Prospective Resources with 90 per cent increase in the standard deviation. The ratios and P14/P86 values for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

G.2 100% increase in standard deviation

3-point	P83	P67	P17	P83 Ratio	P67 Ratio	P17 Ratio	P17/P83
Well 1	19	97	506	3%	16%	81%	27
Well 2	9	80	721	1%	10%	89%	80
Well 3	10	85	722	1%	10%	88%	72
Well 4	5	59	750	1%	7%	92%	163
Well 5	3	52	1,011	0%	5%	95%	377
Well 6	8	87	923	1%	9%	91%	113
Well 7	15	100	661	2%	13%	85%	44
Well 8	63	186	546	8%	23%	69%	9
Well 9	15	72	351	3%	16%	80%	24
Well 10	34	156	710	4%	17%	79%	21
Well 11	32	108	359	6%	22%	72%	11
Well 12	21	97	453	4%	17%	79%	22
Well 13	43	162	615	5%	20%	75%	14
Well 14	39	95	231	11%	26%	63%	6
Well 15	1	55	2,167	0%	2%	97%	1525
Well 16	3	78	1,955	0%	4%	96%	634
Well 17	2	77	2,855	0%	3%	97%	1392
Well 18	62	266	1,148	4%	18%	78%	19
Well 19	117	245	511	13%	28%	59%	4
Well 20	17	164	1,549	1%	9%	90%	90
Well 21	30	172	984	3%	15%	83%	33
Well 22	6	83	1,157	0%	7%	93%	193
Well 23	4	66	1,200	0%	5%	95%	335
Well 24	3	47	843	0%	5%	95%	329
Well 25	9	113	1,372	1%	8%	92%	148
Well 26	3	56	1,218	0%	4%	95%	474
Well 27	17	116	788	2%	13%	86%	46
Well 28	3	62	1,175	0%	5%	95%	357
Well 29	5	46	428	1%	10%	89%	88
Well 30	5	56	631	1%	8%	91%	128
Well 31	2	28	434	0%	6%	94%	249
Well 32	6	62	678	1%	8%	91%	119
Well 33	9	78	699	1%	10%	89%	80
Well 34	5	71	1,053	0%	6%	93%	218
Well 35	5	65	820	1%	7%	92%	157
Well 36	8	74	684	1%	10%	89%	85
Well 37	5	55	587	1%	9%	91%	37
Well 38	6	80	1,127	0%	7%	93%	199

Table 92—3-point gaussian quadrature results of the Prospective Resources with 100 per cent increase in the standard deviation. We present the percentiles, ratios, and P17/P83 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 3-point GQ are 0.17, 0.67, 0.17 for all the wells.

5-point	P99	P78	P53	P22	P1
Well 1	6	27	97	353	1,475
Well 2	2	14	80	448	2,995
Well 3	3	16	85	454	2,891
Well 4	1	8	59	431	3,924
Well 5	0	5	52	531	6,944
Well 6	2	14	87	552	4,284
Well 7	4	23	100	439	2,256
Well 8	31	80	186	432	1,102
Well 9	5	21	72	249	982
Well 10	13	47	156	511	1,906
Well 11	15	42	108	276	784
Well 12	8	29	97	324	1,229
Well 13	18	57	162	460	1,460
Well 14	22	48	95	191	411
Well 15	0	3	55	977	23,418
Well 16	0	6	78	970	15,885
Well 17	0	5	77	1,300	29,954
Well 18	24	85	266	836	2,967
Well 19	73	138	245	435	824
Well 20	4	28	164	950	6,667
Well 21	10	44	172	674	3,051
Well 22	1	11	83	653	6,392
Well 23	1	7	66	638	7,930
Well 24	0	5	47	449	5,537
Well 25	2	16	113	797	6,947
Well 26	0	5	56	624	9,007
Well 27	3	26	116	520	2,735
Well 28	0	6	62	620	7,924
Well 29	1	8	46	263	1,833
Well 30	1	8	56	372	3,051
Well 31	0	3	28	238	2,604
Well 32	1	10	62	403	3,199
Well 33	2	14	78	434	2,897
Well 34	1	9	71	587	6,048
Well 35	1	9	65	474	4,237
Well 36	2	13	74	422	2,892
Well 37	1	9	55	351	2,726
Well 38	1	10	80	634	6,291

Table 93—5-point gaussian quadrature results of the Prospective Resources with 100 per cent increase in standard deviation. We present the percentiles for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

5-point	P99 Ratio	P78 Ratio	P53 Ratio	P22 Ratio	P1 Ratio	P22/P78
Well 1	0%	1%	5%	18%	75%	13
Well 2	0%	0%	2%	13%	85%	31
Well 3	0%	0%	2%	13%	84%	28
Well 4	0%	0%	1%	10%	89%	54
Well 5	0%	0%	1%	7%	92%	104
Well 6	0%	0%	2%	11%	87%	40
Well 7	0%	1%	4%	16%	80%	19
Well 8	2%	4%	10%	24%	60%	5
Well 9	0%	2%	5%	19%	74%	12
Well 10	0%	2%	6%	19%	72%	11
Well 11	1%	3%	9%	23%	64%	7
Well 12	0%	2%	6%	19%	73%	11
Well 13	1%	3%	8%	21%	68%	8
Well 14	3%	6%	12%	25%	54%	4
Well 15	0%	0%	0%	4%	96%	310
Well 16	0%	0%	0%	6%	94%	156
Well 17	0%	0%	0%	4%	96%	289
Well 18	1%	2%	6%	20%	71%	10
Well 19	4%	8%	14%	25%	48%	3
Well 20	0%	0%	2%	12%	85%	34
Well 21	0%	1%	4%	17%	77%	15
Well 22	0%	0%	1%	9%	90%	62
Well 23	0%	0%	1%	7%	92%	95
Well 24	0%	0%	1%	7%	92%	93
Well 25	0%	0%	1%	10%	88%	50
Well 26	0%	0%	1%	6%	93%	124
Well 27	0%	1%	3%	15%	80%	20
Well 28	0%	0%	1%	7%	92%	100
Well 29	0%	0%	2%	12%	85%	33
Well 30	0%	0%	2%	11%	87%	45
Well 31	0%	0%	1%	8%	91%	75
Well 32	0%	0%	2%	11%	87%	42
Well 33	0%	0%	2%	13%	85%	31
Well 34	0%	0%	1%	9%	90%	68
Well 35	0%	0%	1%	10%	89%	52
Well 36	0%	0%	2%	12%	85%	32
Well 37	0%	0%	2%	11%	87%	40
Well 38	0%	0%	1%	9%	90%	63

Table 94—5-point gaussian quadrature results of the Prospective Resources with 100 per cent increase on the standard deviation. We present the ratios and P22/P78 values for the 38 wells in the Midland Basin dataset. As previously discussed in Chapter 3, the weights of the 5-point GQ are 0.0.01, 0.22, 0.53, 0.22, 0.01 for all the wells.

10-point	P100	P99	P98	P86	P66	P34	P14	P2	P1	P0
Well 1	1	3	9	24	61	154	392	1,034	2,940	9,916
Well 2	0	1	3	13	44	149	515	1,869	7,497	37,783
Well 3	0	1	4	14	47	155	520	1,826	7,069	34,172
Well 4	0	0	2	7	29	120	507	2,268	11,399	74,665
Well 5	0	0	1	4	23	119	641	3,668	24,029	214,299
Well 6	0	1	3	12	45	168	642	2,576	11,523	65,903
Well 7	0	2	7	20	59	170	495	1,502	4,975	20,050
Well 8	9	20	39	74	137	251	463	873	1,731	3,838
Well 9	1	3	7	19	46	112	275	698	1,904	6,120
Well 10	2	7	18	43	102	238	563	1,374	3,599	11,036
Well 11	4	9	19	39	77	151	298	605	1,297	3,154
Well 12	1	4	11	26	63	150	357	883	2,340	7,276
Well 13	4	10	24	53	112	236	501	1,096	2,549	6,808
Well 14	8	15	27	45	75	122	202	340	596	1,144
Well 15	0	0	0	2	20	155	1,234	10,645	108,549	1,620,506
Well 16	0	0	1	5	31	192	1,191	7,935	61,275	661,775
Well 17	0	0	0	4	28	211	1,637	13,749	136,230	1,966,779
Well 18	4	13	33	77	177	401	918	2,166	5,468	16,068
Well 19	31	53	85	131	199	301	456	703	1,121	1,929
Well 20	0	2	7	24	87	307	1,097	4,111	17,076	89,606
Well 21	1	5	14	39	106	281	753	2,097	6,324	22,860
Well 22	0	0	2	9	40	174	772	3,629	19,227	133,952
Well 23	0	0	1	6	29	148	768	4,242	26,774	228,639
Well 24	0	0	1	4	21	105	540	2,968	18,618	157,845
Well 25	0	1	3	14	56	227	935	4,059	19,757	124,683
Well 26	0	0	1	4	24	133	759	4,642	32,696	317,256
Well 27	1	2	7	23	68	198	587	1,811	6,098	25,055
Well 28	0	0	1	5	27	142	748	4,211	27,105	236,867
Well 29	0	0	2	7	24	85	304	1,133	4,680	24,407
Well 30	0	0	2	7	28	110	434	1,810	8,423	50,463
Well 31	0	0	1	3	13	60	284	1,438	8,260	63,192
Well 32	0	0	2	8	32	121	470	1,913	8,692	50,624
Well 33	0	1	3	12	42	144	499	1,809	7,245	36,446
Well 34	0	0	2	7	34	152	696	3,389	18,655	135,850
Well 35	0	0	2	8	32	133	556	2,459	12,203	78,752
Well 36	0	1	3	11	40	138	486	1,793	7,325	37,691
Well 37	0	0	2	7	28	107	408	1,639	7,330	41,909
Well 38	0	0	2	8	38	168	751	3,559	19,048	134,251

Table 95—10-point gaussian quadrature of the Prospective Resources with 100 per cent increase in the standard deviation, and the results of the percentiles for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

10-point	P100 Ratio	P99 Ratio	P98 Ratio	P86 Ratio	P66 Ratio	P34 Ratio	P14 Ratio	P2 Ratio	P1 Ratio	P0 Ratio	P14/P86
Well 1	0%	0%	0%	0%	0%	1%	3%	7%	20%	68%	16
Well 2	0%	0%	0%	0%	0%	0%	1%	4%	16%	79%	41
Well 3	0%	0%	0%	0%	0%	0%	1%	4%	16%	78%	37
Well 4	0%	0%	0%	0%	0%	0%	1%	3%	13%	84%	75
Well 5	0%	0%	0%	0%	0%	0%	0%	2%	10%	88%	152
Well 6	0%	0%	0%	0%	0%	0%	1%	3%	14%	81%	55
Well 7	0%	0%	0%	0%	0%	1%	2%	6%	18%	73%	25
Well 8	0%	0%	1%	1%	2%	3%	6%	12%	23%	52%	6
Well 9	0%	0%	0%	0%	1%	1%	3%	8%	21%	67%	15
Well 10	0%	0%	0%	0%	1%	1%	3%	8%	21%	65%	13
Well 11	0%	0%	0%	1%	1%	3%	5%	11%	23%	56%	8
Well 12	0%	0%	0%	0%	1%	1%	3%	8%	21%	65%	14
Well 13	0%	0%	0%	0%	1%	2%	4%	10%	22%	60%	10
Well 14	0%	1%	1%	2%	3%	5%	8%	13%	23%	44%	4
Well 15	0%	0%	0%	0%	0%	0%	0%	1%	6%	93%	495
Well 16	0%	0%	0%	0%	0%	0%	0%	1%	8%	90%	235
Well 17	0%	0%	0%	0%	0%	0%	0%	1%	6%	93%	458
Well 18	0%	0%	0%	0%	1%	2%	4%	9%	22%	63%	12
Well 19	1%	1%	2%	3%	4%	6%	9%	14%	22%	38%	3
Well 20	0%	0%	0%	0%	0%	0%	1%	4%	15%	80%	45
Well 21	0%	0%	0%	0%	0%	1%	2%	6%	19%	70%	19
Well 22	0%	0%	0%	0%	0%	0%	0%	2%	12%	85%	86
Well 23	0%	0%	0%	0%	0%	0%	0%	2%	10%	88%	137
Well 24	0%	0%	0%	0%	0%	0%	0%	2%	10%	88%	135
Well 25	0%	0%	0%	0%	0%	0%	1%	3%	13%	83%	69
Well 26	0%	0%	0%	0%	0%	0%	0%	1%	9%	89%	184
Well 27	0%	0%	0%	0%	0%	1%	2%	5%	18%	74%	26
Well 28	0%	0%	0%	0%	0%	0%	0%	2%	10%	88%	145
Well 29	0%	0%	0%	0%	0%	0%	1%	4%	15%	80%	44
Well 30	0%	0%	0%	0%	0%	0%	1%	3%	14%	82%	61
Well 31	0%	0%	0%	0%	0%	0%	0%	2%	11%	86%	107
Well 32	0%	0%	0%	0%	0%	0%	1%	3%	14%	82%	57
Well 33	0%	0%	0%	0%	0%	0%	1%	4%	16%	79%	41
Well 34	0%	0%	0%	0%	0%	0%	0%	2%	12%	86%	95
Well 35	0%	0%	0%	0%	0%	0%	1%	3%	13%	84%	72
Well 36	0%	0%	0%	0%	0%	0%	1%	4%	15%	79%	43
Well 37	0%	0%	0%	0%	0%	0%	1%	3%	14%	81%	55
Well 38	0%	0%	0%	0%	0%	0%	0%	2%	12%	85%	88

Table 96—10-point gaussian quadrature results of the Prospective Resources with 100 per cent increase in the standard deviation. The ratios and P14/P86 values for the 38 wells in the Midland Basin dataset are presented. As previously discussed in Chapter 3, the weights of the 10-point GQ are 0, 0.01, 0.02, 0.14, 0.35, 0.35, 0.14, 0.02, 0.01, 0 for all the wells.

APPENDIX H

CHANCE OF COMMERCIALITY RESULTS FOR RESERVES, CONTINGENT RESOURCES AND PROSPECTIVE RESOURCES

The results of wells 1 through 38 are presented in this appendix. Similarly to the results presented in Chapter 4, they are separated in high, medium, and low COC cases. The high cases of COC are 100 per cent for Reserves, 90 per cent for Contingent Resources, and 70 per cent for Prospective Resources. The medium cases of COC are 90 per cent for Reserves, 45 per cent for Contingent Resources, and 30 per cent for Prospective Resources. Finally, the low cases of COC are 80 per cent for Reserves, 30 per cent for Contingent Resources, and 5 per cent for Prospective Resources.

H.1 High Case Results

Reserves	9% x 1P	24% x 2P	67% x 3P
Contingent Resources (20%)	11% x 1C	25% x 2C	54% x 3C
Contingent Resources (50%)	7% x 1C	21% x 2C	62% x 3C
Prospective Resources (90%)	3% x 1U	12% x 2U	56% x 3U
Prospective Resources (100%)	2% x 1U	11% x 2U	57% x 3U

Table 97—High case of COC for Well 1 of Reserves, CR, and PR, with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	21% x 2P	72% x 3P
Contingent Resources (20%)	7% x 1C	20% x 2C	63% x 3C
Contingent Resources (50%)	3% x 1C	15% x 2C	71% x 3C
Prospective Resources (90%)	1% x 1U	8% x 2U	61% x 3U
Prospective Resources (100%)	1% x 1U	7% x 2U	62% x 3U

Table 98—High case of COC for Well 2 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	7% x 1P	22% x 2P	72% x 3P
Contingent Resources (20%)	7% x 1C	21% x 2C	62% x 3C
Contingent Resources (50%)	4% x 1C	16% x 2C	71% x 3C
Prospective Resources (90%)	1% x 1U	8% x 2U	61% x 3U
Prospective Resources (100%)	1% x 1U	7% x 2U	62% x 3U

Table 99—High case of COC for Well 3 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	20% x 2P	75% x 3P
Contingent Resources (20%)	4% x 1C	17% x 2C	68% x 3C
Contingent Resources (50%)	2% x 1C	12% x 2C	76% x 3C
Prospective Resources (90%)	1% x 1U	6% x 2U	64% x 3U
Prospective Resources (100%)	0% x 1U	5% x 2U	65% x 3U

Table 100—High case of COC for Well 4 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	17% x 2P	79% x 3P
Contingent Resources (20%)	3% x 1C	14% x 2C	74% x 3C
Contingent Resources (50%)	1% x 1C	9% x 2C	80% x 3C
Prospective Resources (90%)	0% x 1U	4% x 2U	66% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	66% x 3U

Table 101—High case of COC for Well 5 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	20% x 2P	74% x 3P
Contingent Resources (20%)	5% x 1C	19% x 2C	66% x 3C
Contingent Resources (50%)	3% x 1C	14% x 2C	74% x 3C
Prospective Resources (90%)	1% x 1U	7% x 2U	63% x 3U
Prospective Resources (100%)	1% x 1U	6% x 2U	63% x 3U

Table 102—High case of COC for Well 6 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	23% x 2P	69% x 3P
Contingent Resources (20%)	9% x 1C	23% x 2C	58% x 3C
Contingent Resources (50%)	5% x 1C	18% x 2C	67% x 3C
Prospective Resources (90%)	2% x 1U	10% x 2U	58% x 3U
Prospective Resources (100%)	1% x 1U	9% x 2U	60% x 3U

Table 103—High case of COC for Well 7 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	13% x 1P	28% x 2P	60% x 3P
Contingent Resources (20%)	17% x 1C	28% x 2C	45% x 3C
Contingent Resources (50%)	13% x 1C	26% x 2C	51% x 3C
Prospective Resources (90%)	6% x 1U	17% x 2U	47% x 3U
Prospective Resources (100%)	6% x 1U	16% x 2U	48% x 3U

Table 104—High case of COC for Well 8 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	9% x 1P	25% x 2P	66% x 3P
Contingent Resources (20%)	12% x 1C	25% x 2C	53% x 3C
Contingent Resources (50%)	7% x 1C	21% x 2C	61% x 3C
Prospective Resources (90%)	3% x 1U	12% x 2U	55% x 3U
Prospective Resources (100%)	2% x 1U	12% x 2U	56% x 3U

Table 105—High case of COC for Well 9 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	10% x 1P	25% x 2P	65% x 3P
Contingent Resources (20%)	13% x 1C	26% x 2C	52% x 3C
Contingent Resources (50%)	8% x 1C	22% x 2C	60% x 3C
Prospective Resources (90%)	3% x 1U	13% x 2U	54% x 3U
Prospective Resources (100%)	3% x 1U	12% x 2U	55% x 3U

Table 106—High case of COC for Well 10 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	12% x 1P	27% x 2P	61% x 3P
Contingent Resources (20%)	16% x 1C	27% x 2C	47% x 3C
Contingent Resources (50%)	11% x 1C	25% x 2C	54% x 3C
Prospective Resources (90%)	3% x 1U	16% x 2U	49% x 3U
Prospective Resources (100%)	5% x 1U	15% x 2U	50% x 3U

Table 107—High case of COC for Well 11 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	10% x 1P	25% x 2P	65% x 3P
Contingent Resources (20%)	12% x 1C	25% x 2C	52% x 3C
Contingent Resources (50%)	8% x 1C	22% x 2C	60% x 3C
Prospective Resources (90%)	3% x 1U	13% x 2U	54% x 3U
Prospective Resources (100%)	3% x 1U	12% x 2U	56% x 3U

Table 108—High case of COC for Well 12 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	11% x 1P	26% x 2P	63% x 3P
Contingent Resources (20%)	15% x 1C	27% x 2C	49% x 3C
Contingent Resources (50%)	10% x 1C	24% x 2C	56% x 3C
Prospective Resources (90%)	4% x 1U	15% x 2U	51% x 3U
Prospective Resources (100%)	4% x 1U	14% x 2U	52% x 3U

Table 109—High case of COC for Well 13 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	14% x 1P	29% x 2P	57% x 3P
Contingent Resources (20%)	20% x 1C	29% x 2C	42% x 3C
Contingent Resources (50%)	16% x 1C	27% x 2C	47% x 3C
Prospective Resources (90%)	8% x 1U	19% x 2U	43% x 3U
Prospective Resources (100%)	8% x 1U	18% x 2U	44% x 3U

Table 110—High case of COC for Well 14 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	2% x 1P	14% x 2P	83% x 3P
Contingent Resources (20%)	1% x 1C	9% x 2C	80% x 3C
Contingent Resources (50%)	0% x 1C	5% x 2C	85% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	68% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	68% x 3U

Table 111—High case of COC for Well 15 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	16% x 2P	81% x 3P
Contingent Resources (20%)	2% x 1C	12% x 2C	77% x 3C
Contingent Resources (50%)	1% x 1C	7% x 2C	82% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	67% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	67% x 3U

Table 112—High case of COC for Well 16 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	14% x 2P	83% x 3P
Contingent Resources (20%)	1% x 1C	9% x 2C	80% x 3C
Contingent Resources (50%)	0% x 1C	5% x 2C	84% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	68% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	68% x 3U

Table 113—High case of COC for Well 17 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	10% x 1P	26% x 2P	64% x 3P
Contingent Resources (20%)	13% x 1C	26% x 2C	51% x 3C
Contingent Resources (50%)	9% x 1C	22% x 2C	59% x 3C
Prospective Resources (90%)	3% x 1U	14% x 2U	53% x 3U
Prospective Resources (100%)	3% x 1U	13% x 2U	54% x 3U

Table 114—High case of COC for Well 18 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	16% x 1P	30% x 2P	54% x 3P
Contingent Resources (20%)	22% x 1C	29% x 2C	39% x 3C
Contingent Resources (50%)	18% x 1C	28% x 2C	44% x 3C
Prospective Resources (90%)	10% x 1U	20% x 2U	40% x 3U
Prospective Resources (100%)	9% x 1U	20% x 2U	41% x 3U

Table 115—High case of COC for Well 19 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	21% x 2P	73% x 3P
Contingent Resources (20%)	6% x 1C	20% x 2C	64% x 3C
Contingent Resources (50%)	3% x 1C	15% x 2C	72% x 3C
Prospective Resources (90%)	1% x 1U	7% x 2U	62% x 3U
Prospective Resources (100%)	1% x 1U	7% x 2U	63% x 3U

Table 116—High case of COC for Well 20 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	24% x 2P	68% x 3P
Contingent Resources (20%)	10% x 1C	24% x 2C	56% x 3C
Contingent Resources (50%)	6% x 1C	20% x 2C	64% x 3C
Prospective Resources (90%)	2% x 1U	11% x 2U	57% x 3U
Prospective Resources (100%)	2% x 1U	10% x 2U	58% x 3U

Table 117—High case of COC for Well 21 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	19% x 2P	76% x 3P
Contingent Resources (20%)	4% x 1C	17% x 2C	69% x 3C
Contingent Resources (50%)	2% x 1C	11% x 2C	77% x 3C
Prospective Resources (90%)	0% x 1U	5% x 2U	64% x 3U
Prospective Resources (100%)	0% x 1U	5% x 2U	65% x 3U

Table 118—High case of COC for Well 22 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	18% x 2P	78% x 3P
Contingent Resources (20%)	3% x 1C	14% x 2C	73% x 3C
Contingent Resources (50%)	1% x 1C	9% x 2C	80% x 3C
Prospective Resources (90%)	0% x 1U	4% x 2U	66% x 3U
Prospective Resources (100%)	0% x 1U	4% x 2U	66% x 3U

Table 119—High case of COC for Well 23 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	18% x 2P	78% x 3P
Contingent Resources (20%)	3% x 1C	14% x 2C	73% x 3C
Contingent Resources (50%)	1% x 1C	9% x 2C	80% x 3C
Prospective Resources (90%)	0% x 1U	4% x 2U	66% x 3U
Prospective Resources (100%)	0% x 1U	4% x 2U	66% x 3U

Table 120—High case of COC for Well 24 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	20% x 2P	75% x 3P
Contingent Resources (20%)	5% x 1C	18% x 2C	68% x 3C
Contingent Resources (50%)	2% x 1C	13% x 2C	75% x 3C
Prospective Resources (90%)	1% x 1U	6% x 2U	63% x 3U
Prospective Resources (100%)	0% x 1U	5% x 2U	64% x 3U

Table 121—High case of COC for Well 25 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	17% x 2P	80% x 3P
Contingent Resources (20%)	2% x 1C	13% x 2C	75% x 3C
Contingent Resources (50%)	1% x 1C	8% x 2C	81% x 3C
Prospective Resources (90%)	0% x 1U	4% x 2U	66% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	67% x 3U

Table 122—High case of COC for Well 26 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	23% x 2P	69% x 3P
Contingent Resources (20%)	9% x 1C	23% x 2C	59% x 3C
Contingent Resources (50%)	5% x 1C	18% x 2C	67% x 3C
Prospective Resources (90%)	2% x 1U	10% x 2U	59% x 3U
Prospective Resources (100%)	1% x 1U	9% x 2U	60% x 3U

Table 123—High case of COC for Well 27 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	18% x 2P	79% x 3P
Contingent Resources (20%)	3% x 1C	14% x 2C	73% x 3C
Contingent Resources (50%)	1% x 1C	9% x 2C	80% x 3C
Prospective Resources (90%)	0% x 1U	4% x 2U	66% x 3U
Prospective Resources (100%)	0% x 1U	4% x 2U	66% x 3U

Table 124—High case of COC for Well 28 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	21% x 2P	73% x 3P
Contingent Resources (20%)	6% x 1C	20% x 2C	64% x 3C
Contingent Resources (50%)	3% x 1C	15% x 2C	72% x 3C
Prospective Resources (90%)	1% x 1U	7% x 2U	62% x 3U
Prospective Resources (100%)	1% x 1U	7% x 2U	63% x 3U

Table 125—High case of COC for Well 29 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	20% x 2P	74% x 3P
Contingent Resources (20%)	5% x 1C	18% x 2C	67% x 3C
Contingent Resources (50%)	2% x 1C	13% x 2C	75% x 3C
Prospective Resources (90%)	1% x 1U	6% x 2U	63% x 3U
Prospective Resources (100%)	0% x 1U	6% x 2U	64% x 3U

Table 126—High case of COC for Well 30 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	18% x 2P	77% x 3P
Contingent Resources (20%)	3% x 1C	16% x 2C	71% x 3C
Contingent Resources (50%)	1% x 1C	10% x 2C	78% x 3C
Prospective Resources (90%)	0% x 1U	5% x 2U	65% x 3U
Prospective Resources (100%)	0% x 1U	4% x 2U	66% x 3U

Table 127—High case of COC for Well 31 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	20% x 2P	74% x 3P
Contingent Resources (20%)	5% x 1C	19% x 2C	66% x 3C
Contingent Resources (50%)	2% x 1C	13% x 2C	74% x 3C
Prospective Resources (90%)	1% x 1U	7% x 2U	63% x 3U
Prospective Resources (100%)	1% x 1U	6% x 2U	64% x 3U

Table 128—High case of COC for Well 32 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	21% x 2P	72% x 3P
Contingent Resources (20%)	7% x 1C	20% x 2C	63% x 3C
Contingent Resources (50%)	3% x 1C	15% x 2C	71% x 3C
Prospective Resources (90%)	1% x 1U	8% x 2U	61% x 3U
Prospective Resources (100%)	1% x 1U	7% x 2U	62% x 3U

Table 129—High case of COC for Well 33 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	19% x 2P	77% x 3P
Contingent Resources (20%)	4% x 1C	16% x 2C	70% x 3C
Contingent Resources (50%)	2% x 1C	11% x 2C	78% x 3C
Prospective Resources (90%)	0% x 1U	5% x 2U	65% x 3U
Prospective Resources (100%)	0% x 1U	4% x 2U	65% x 3U

Table 130—High case of COC for Well 34 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	20% x 2P	75% x 3P
Contingent Resources (20%)	5% x 1C	18% x 2C	68% x 3C
Contingent Resources (50%)	2% x 1C	12% x 2C	76% x 3C
Prospective Resources (90%)	1% x 1U	6% x 2U	64% x 3U
Prospective Resources (100%)	0% x 1U	5% x 2U	64% x 3U

Table 131—High case of COC for Well 35 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	21% x 2P	72% x 3P
Contingent Resources (20%)	6% x 1C	20% x 2C	63% x 3C
Contingent Resources (50%)	3% x 1C	15% x 2C	72% x 3C
Prospective Resources (90%)	1% x 1U	8% x 2U	61% x 3U
Prospective Resources (100%)	1% x 1U	7% x 2U	62% x 3U

Table 132—High case of COC for Well 36 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	20% x 2P	74% x 3P
Contingent Resources (20%)	5% x 1C	19% x 2C	66% x 3C
Contingent Resources (50%)	3% x 1C	14% x 2C	74% x 3C
Prospective Resources (90%)	1% x 1U	7% x 2U	63% x 3U
Prospective Resources (100%)	1% x 1U	6% x 2U	63% x 3U

Table 133—High case of COC for Well 37 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	2019 x 2P	76% x 3P
Contingent Resources (20%)	4% x 1C	16% x 2C	70% x 3C
Contingent Resources (50%)	2% x 1C	11% x 2C	77% x 3C
Prospective Resources (90%)	0% x 1U	5% x 2U	64% x 3U
Prospective Resources (100%)	0% x 1U	5% x 2U	65% x 3U

Table 134—High case of COC for Well 38 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

H.2 Medium Case Results

Reserves	8% x 1P	22% x 2P	60% x 3P
Contingent Resources (20%)	6% x 1C	12% x 2C	27% x 3C
Contingent Resources (50%)	3% x 1C	10% x 2C	31% x 3C
Prospective Resources (90%)	1% x 1U	5% x 2U	22% x 3U
Prospective Resources (100%)	1% x 1U	5% x 2U	26% x 3U

Table 135—Medium case of COC for Well 1 of Reserves, CR, and PR, with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	19% x 2P	65% x 3P
Contingent Resources (20%)	3% x 1C	10% x 2C	31% x 3C
Contingent Resources (50%)	2% x 1C	8% x 2C	36% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	28% x 3U

Table 136— Medium case of COC for Well 2 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	20% x 2P	65% x 3P
Contingent Resources (20%)	4% x 1C	10% x 2C	31% x 3C
Contingent Resources (50%)	2% x 1C	8% x 2C	36% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	24% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	28% x 3U

Table 137— Medium case of COC for Well 3 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	18% x 2P	66% x 3P
Contingent Resources (20%)	2% x 1C	9% x 2C	34% x 3C
Contingent Resources (50%)	1% x 1C	6% x 2C	38% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	29% x 3U

Table 138— Medium case of COC for Well 4 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	16% x 2P	71% x 3P
Contingent Resources (20%)	1% x 1C	7% x 2C	37% x 3C
Contingent Resources (50%)	0% x 1C	4% x 2C	40% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	30% x 3U

Table 139— Medium case of COC for Well 5 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	18% x 2P	66% x 3P
Contingent Resources (20%)	3% x 1C	9% x 2C	33% x 3C
Contingent Resources (50%)	1% x 1C	7% x 2C	37% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	29% x 3U

Table 140— Medium case of COC for Well 6 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	7% x 1P	21% x 2P	62% x 3P
Contingent Resources (20%)	5% x 1C	11% x 2C	29% x 3C
Contingent Resources (50%)	2% x 1C	9% x 2C	33% x 3C
Prospective Resources (90%)	1% x 1U	4% x 2U	23% x 3U
Prospective Resources (100%)	1% x 1U	4% x 2U	27% x 3U

Table 141— Medium case of COC for Well 7 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	12% x 1P	25% x 2P	54% x 3P
Contingent Resources (20%)	9% x 1C	14% x 2C	22% x 3C
Contingent Resources (50%)	6% x 1C	13% x 2C	26% x 3C
Prospective Resources (90%)	3% x 1U	7% x 2U	19% x 3U
Prospective Resources (100%)	2% x 1U	7% x 2U	22% x 3U

Table 142— Medium case of COC for Well 8 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	22% x 2P	59% x 3P
Contingent Resources (20%)	6% x 1C	13% x 2C	26% x 3C
Contingent Resources (50%)	4% x 1C	11% x 2C	31% x 3C
Prospective Resources (90%)	1% x 1U	5% x 2U	22% x 3U
Prospective Resources (100%)	1% x 1U	5% x 2U	25% x 3U

Table 143— Medium case of COC for Well 9 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	9% x 1P	23% x 2P	59% x 3P
Contingent Resources (20%)	6% x 1C	13% x 2C	26% x 3C
Contingent Resources (50%)	4% x 1C	11% x 2C	30% x 3C
Prospective Resources (90%)	1% x 1U	5% x 2U	22% x 3U
Prospective Resources (100%)	1% x 1U	5% x 2U	25% x 3U

Table 144— Medium case of COC for Well 10 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	11% x 1P	24% x 2P	55% x 3P
Contingent Resources (20%)	8% x 1C	14% x 2C	23% x 3C
Contingent Resources (50%)	6% x 1C	12% x 2C	27% x 3C
Prospective Resources (90%)	2% x 1U	6% x 2U	20% x 3U
Prospective Resources (100%)	2% x 1U	7% x 2U	23% x 3U

Table 145— Medium case of COC for Well 11 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	9% x 1P	23% x 2P	59% x 3P
Contingent Resources (20%)	6% x 1C	13% x 2C	26% x 3C
Contingent Resources (50%)	4% x 1C	11% x 2C	30% x 3C
Prospective Resources (90%)	1% x 1U	5% x 2U	22% x 3U
Prospective Resources (100%)	1% x 1U	5% x 2U	25% x 3U

Table 146— Medium case of COC for Well 12 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	10% x 1P	24% x 2P	57% x 3P
Contingent Resources (20%)	7% x 1C	13% x 2C	24% x 3C
Contingent Resources (50%)	5% x 1C	12% x 2C	28% x 3C
Prospective Resources (90%)	2% x 1U	6% x 2U	20% x 3U
Prospective Resources (100%)	2% x 1U	6% x 2U	24% x 3U

Table 147— Medium case of COC for Well 13 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	13% x 1P	26% x 2P	51% x 3P
Contingent Resources (20%)	10% x 1C	14% x 2C	21% x 3C
Contingent Resources (50%)	8% x 1C	14% x 2C	24% x 3C
Prospective Resources (90%)	3% x 1U	8% x 2U	17% x 3U
Prospective Resources (100%)	3% x 1U	8% x 2U	20% x 3U

Table 148— Medium case of COC for Well 14 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	2% x 1P	13% x 2P	75% x 3P
Contingent Resources (20%)	0% x 1C	4% x 2C	40% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	42% x 3C
Prospective Resources (90%)	0% x 1U	1% x 2U	27% x 3U
Prospective Resources (100%)	0% x 1U	1% x 2U	31% x 3U

Table 149— Medium case of COC for Well 15 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	15% x 2P	73% x 3P
Contingent Resources (20%)	1% x 1C	6% x 2C	38% x 3C
Contingent Resources (50%)	0% x 1C	4% x 2C	41% x 3C
Prospective Resources (90%)	0% x 1U	1% x 2U	27% x 3U
Prospective Resources (100%)	0% x 1U	1% x 2U	30% x 3U

Table 150— Medium case of COC for Well 16 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	2% x 1P	13% x 2P	75% x 3P
Contingent Resources (20%)	0% x 1C	4% x 2C	40% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	42% x 3C
Prospective Resources (90%)	0% x 1U	1% x 2U	27% x 3U
Prospective Resources (100%)	0% x 1U	1% x 2U	31% x 3U

Table 151— Medium case of COC for Well 17 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	9% x 1P	23% x 2P	58% x 3P
Contingent Resources (20%)	7% x 1C	13% x 2C	25% x 3C
Contingent Resources (50%)	4% x 1C	11% x 2C	29% x 3C
Prospective Resources (90%)	1% x 1U	5% x 2U	21% x 3U
Prospective Resources (100%)	1% x 1U	6% x 2U	24% x 3U

Table 152— Medium case of COC for Well 18 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	14% x 1P	27% x 2P	39% x 3P
Contingent Resources (20%)	11% x 1C	15% x 2C	20% x 3C
Contingent Resources (50%)	9% x 1C	14% x 2C	22% x 3C
Prospective Resources (90%)	4% x 1U	8% x 2U	16% x 3U
Prospective Resources (100%)	4% x 1U	9% x 2U	18% x 3U

Table 153— Medium case of COC for Well 19 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	19% x 2P	65% x 3P
Contingent Resources (20%)	3% x 1C	10% x 2C	32% x 3C
Contingent Resources (50%)	2% x 1C	7% x 2C	36% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	28% x 3U

Table 154— Medium case of COC for Well 20 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	22% x 2P	61% x 3P
Contingent Resources (20%)	5% x 1C	12% x 2C	28% x 3C
Contingent Resources (50%)	3% x 1C	10% x 2C	32% x 3C
Prospective Resources (90%)	1% x 1U	4% x 2U	23% x 3U
Prospective Resources (100%)	1% x 1U	105 x 2U	26% x 3U

Table 155— Medium case of COC for Well 21 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	17% x 2P	69% x 3P
Contingent Resources (20%)	2% x 1C	8% x 2C	35% x 3C
Contingent Resources (50%)	1% x 1C	6% x 2C	38% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	29% x 3U

Table 156— Medium case of COC for Well 22 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	70% x 3P
Contingent Resources (20%)	1% x 1C	7% x 2C	36% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	40% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	30% x 3U

Table 157— Medium case of COC for Well 23 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	70% x 3P
Contingent Resources (20%)	1% x 1C	7% x 2C	36% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	40% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	30% x 3U

Table 158— Medium case of COC for Well 24 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	18% x 2P	67% x 3P
Contingent Resources (20%)	2% x 1C	9% x 2C	34% x 3C
Contingent Resources (50%)	1% x 1C	6% x 2C	38% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	29% x 3U

Table 159— Medium case of COC for Well 25 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	15% x 2P	72% x 3P
Contingent Resources (20%)	1% x 1C	6% x 2C	37% x 3C
Contingent Resources (50%)	0% x 1C	4% x 2C	41% x 3C
Prospective Resources (90%)	0% x 1U	1% x 2U	27% x 3U
Prospective Resources (100%)	0% x 1U	1% x 2U	30% x 3U

Table 160— Medium case of COC for Well 26 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	7% x 1P	21% x 2P	63% x 3P
Contingent Resources (20%)	4% x 1C	11% x 2C	29% x 3C
Contingent Resources (50%)	2% x 1C	9% x 2C	34% x 3C
Prospective Resources (90%)	1% x 1U	4% x 2U	23% x 3U
Prospective Resources (100%)	1% x 1U	4% x 2U	27% x 3U

Table 161— Medium case of COC for Well 27 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	71% x 3P
Contingent Resources (20%)	1% x 1C	7% x 2C	37% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	40% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	30% x 3U

Table 162— Medium case of COC for Well 28 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	19% x 2P	65% x 3P
Contingent Resources (20%)	3% x 1C	10% x 2C	32% x 3C
Contingent Resources (50%)	2% x 1C	7% x 2C	36% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	28% x 3U

Table 163— Medium case of COC for Well 29 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	18% x 2P	67% x 3P
Contingent Resources (20%)	3% x 1C	9% x 2C	33% x 3C
Contingent Resources (50%)	1% x 1C	7% x 2C	37% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	29% x 3U

Table 164— Medium case of COC for Well 30 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	17% x 2P	69% x 3P
Contingent Resources (20%)	2% x 1C	8% x 2C	36% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	39% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	30% x 3U

Table 165— Medium case of COC for Well 31 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	18% x 2P	67% x 3P
Contingent Resources (20%)	3% x 1C	9% x 2C	33% x 3C
Contingent Resources (50%)	1% x 1C	7% x 2C	37% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	29% x 3U

Table 166— Medium case of COC for Well 32 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	19% x 2P	65% x 3P
Contingent Resources (20%)	3% x 1C	10% x 2C	31% x 3C
Contingent Resources (50%)	2% x 1C	8% x 2C	36% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	24% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	28% x 3U

Table 167— Medium case of COC for Well 33 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	17% x 2P	69% x 3P
Contingent Resources (20%)	2% x 1C	8% x 2C	35% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	39% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	29% x 3U

Table 168— Medium case of COC for Well 34 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	18% x 2P	68% x 3P
Contingent Resources (20%)	2% x 1C	9% x 2C	34% x 3C
Contingent Resources (50%)	1% x 1C	6% x 2C	38% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	29% x 3U

Table 169— Medium case of COC for Well 35 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	19% x 2P	65% x 3P
Contingent Resources (20%)	3% x 1C	10% x 2C	32% x 3C
Contingent Resources (50%)	2% x 1C	8% x 2C	36% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	28% x 3U

Table 170— Medium case of COC for Well 36 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	18% x 2P	66% x 3P
Contingent Resources (20%)	3% x 1C	9% x 2C	33% x 3C
Contingent Resources (50%)	1% x 1C	7% x 2C	37% x 3C
Prospective Resources (90%)	0% x 1U	3% x 2U	25% x 3U
Prospective Resources (100%)	0% x 1U	3% x 2U	29% x 3U

Table 171— Medium case of COC for Well 37 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	17% x 2P	69% x 3P
Contingent Resources (20%)	2% x 1C	8% x 2C	35% x 3C
Contingent Resources (50%)	1% x 1C	6% x 2C	39% x 3C
Prospective Resources (90%)	0% x 1U	2% x 2U	26% x 3U
Prospective Resources (100%)	0% x 1U	2% x 2U	29% x 3U

Table 172— Medium case of COC for Well 38 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

H.3 Low Case Results

Reserves	7% x 1P	20% x 2P	53% x 3P
Contingent Resources (20%)	4% x 1C	8% x 2C	18% x 3C
Contingent Resources (50%)	2% x 1C	7% x 2C	21% x 3C
Prospective Resources (90%)	0.1% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.3% x 3U

Table 173— Low case of COC for Well 1 of Reserves, CR, and PR, with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	17% x 2P	58% x 3P
Contingent Resources (20%)	2% x 1C	7% x 2C	21% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	24% x 3C
Prospective Resources (90%)	0% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.4% x 3U

Table 174— Low case of COC for Well 2 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	17% x 2P	57% x 3P
Contingent Resources (20%)	2% x 1C	7% x 2C	21% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	24% x 3C
Prospective Resources (90%)	0% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.4% x 3U

Table 175— Low case of COC for Well 3 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	60% x 3P
Contingent Resources (20%)	1% x 1C	6% x 2C	6823 x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	25% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 176— Low case of COC for Well 4 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	14% x 2P	63% x 3P
Contingent Resources (20%)	1% x 1C	5% x 2C	25% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	27% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 177— Low case of COC for Well 5 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	16% x 2P	59% x 3P
Contingent Resources (20%)	2% x 1C	6% x 2C	22% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	25% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.4% x 3U

Table 178— Low case of COC for Well 6 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	18% x 2P	55% x 3P
Contingent Resources (20%)	3% x 1C	8% x 2C	19% x 3C
Contingent Resources (50%)	2% x 1C	6% x 2C	22% x 3C
Prospective Resources (90%)	0% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.3% x 3U

Table 179— Low case of COC for Well 7 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	10% x 1P	22% x 2P	48% x 3P
Contingent Resources (20%)	6% x 1C	9% x 2C	15% x 3C
Contingent Resources (50%)	4% x 1C	9% x 2C	17% x 3C
Prospective Resources (90%)	0.1% x 1U	0.3% x 2U	1% x 3U
Prospective Resources (100%)	0.1% x 1U	0.4% x 2U	1.1% x 3U

Table 180— Low case of COC for Well 8 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	7% x 1P	20% x 2P	53% x 3P
Contingent Resources (20%)	4% x 1C	8% x 2C	18% x 3C
Contingent Resources (50%)	2% x 1C	7% x 2C	20% x 3C
Prospective Resources (90%)	0.1% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0.1% x 1U	0.3% x 2U	1.3% x 3U

Table 181— Low case of COC for Well 9 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	20% x 2P	52% x 3P
Contingent Resources (20%)	4% x 1C	9% x 2C	17% x 3C
Contingent Resources (50%)	3% x 1C	7% x 2C	20% x 3C
Prospective Resources (90%)	0.1% x 1U	0.3% x 2U	1% x 3U
Prospective Resources (100%)	0.1% x 1U	0.3% x 2U	1.2% x 3U

Table 182— Low case of COC for Well 10 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	9% x 1P	22% x 2P	49% x 3P
Contingent Resources (20%)	5% x 1C	9% x 2C	16% x 3C
Contingent Resources (50%)	4% x 1C	8% x 2C	18% x 3C
Prospective Resources (90%)	0.1% x 1U	0.3% x 2U	1% x 3U
Prospective Resources (100%)	0.1% x 1U	0.3% x 2U	1.1% x 3U

Table 183— Low case of COC for Well 11 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	20% x 2P	52% x 3P
Contingent Resources (20%)	4% x 1C	8% x 2C	17% x 3C
Contingent Resources (50%)	3% x 1C	7% x 2C	20% x 3C
Prospective Resources (90%)	0.1% x 1U	0.3% x 2U	1% x 3U
Prospective Resources (100%)	0.1% x 1U	0.3% x 2U	1.2% x 3U

Table 184— Low case of COC for Well 12 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	9% x 1P	21% x 2P	50% x 3P
Contingent Resources (20%)	5% x 1C	9% x 2C	16% x 3C
Contingent Resources (50%)	3% x 1C	8% x 2C	19% x 3C
Prospective Resources (90%)	0.1% x 1U	0.3% x 2U	1% x 3U
Prospective Resources (100%)	01% x 1U	0.3% x 2U	1.2% x 3U

Table 185— Low case of COC for Well 13 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	12% x 1P	23% x 2P	45% x 3P
Contingent Resources (20%)	7% x 1C	10% x 2C	14% x 3C
Contingent Resources (50%)	5% x 1C	9% x 2C	16% x 3C
Prospective Resources (90%)	0.2% x 1U	0.4% x 2U	1% x 3U
Prospective Resources (100%)	0.2% x 1U	0.4% x 2U	1% x 3U

Table 186— Low case of COC for Well 14 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	2% x 1P	11% x 2P	67% x 3P
Contingent Resources (20%)	0% x 1C	3% x 2C	27% x 3C
Contingent Resources (50%)	0% x 1C	2% x 2C	28% x 3C
Prospective Resources (90%)	0% x 1U	0% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0% x 2U	1.5% x 3U

Table 187— Low case of COC for Well 15 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	13% x 2P	64% x 3P
Contingent Resources (20%)	1% x 1C	4% x 2C	26% x 3C
Contingent Resources (50%)	0% x 1C	2% x 2C	27% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 188— Low case of COC for Well 16 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	2% x 1P	12% x 2P	66% x 3P
Contingent Resources (20%)	0% x 1C	3% x 2C	27% x 3C
Contingent Resources (50%)	0% x 1C	2% x 2C	28% x 3C
Prospective Resources (90%)	0% x 1U	0% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0% x 2U	1.5% x 3U

Table 189— Low case of COC for Well 17 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	8% x 1P	20% x 2P	52% x 3P
Contingent Resources (20%)	4% x 1C	9% x 2C	17% x 3C
Contingent Resources (50%)	3% x 1C	7% x 2C	20% x 3C
Prospective Resources (90%)	0.1% x 1U	0.3% x 2U	1% x 3U
Prospective Resources (100%)	0.1% x 1U	0.3% x 2U	1.2% x 3U

Table 190— Low case of COC for Well 18 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	13% x 1P	24% x 2P	44% x 3P
Contingent Resources (20%)	7% x 1C	10% x 2C	13% x 3C
Contingent Resources (50%)	6% x 1C	9% x 2C	15% x 3C
Prospective Resources (90%)	0.2% x 1U	0.4% x 2U	1% x 3U
Prospective Resources (100%)	0.2% x 1U	0.4% x 2U	0.9% x 3U

Table 191— Low case of COC for Well 19 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	17% x 2P	58% x 3P
Contingent Resources (20%)	2% x 1C	7% x 2C	21% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	24% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.4% x 3U

Table 192— Low case of COC for Well 20 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	7% x 1P	19% x 2P	54% x 3P
Contingent Resources (20%)	3% x 1C	8% x 2C	19% x 3C
Contingent Resources (50%)	2% x 1C	7% x 2C	21% x 3C
Prospective Resources (90%)	0% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.3% x 3U

Table 193— Low case of COC for Well 21 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	15% x 2P	61% x 3P
Contingent Resources (20%)	1% x 1C	6% x 2C	23% x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	26% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 194— Low case of COC for Well 22 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	14% x 2P	63% x 3P
Contingent Resources (20%)	1% x 1C	5% x 2C	24% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	27% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 195— Low case of COC for Well 23 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	14% x 2P	63% x 3P
Contingent Resources (20%)	1% x 1C	5% x 2C	24% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	27% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.4% x 3U

Table 196— Low case of COC for Well 24 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	60% x 3P
Contingent Resources (20%)	2% x 1C	6% x 2C	23% x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	25% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.4% x 3U

Table 197— Low case of COC for Well 25 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	13% x 2P	64% x 3P
Contingent Resources (20%)	1% x 1C	4% x 2C	25% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	27% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 198— Low case of COC for Well 26 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	6% x 1P	18% x 2P	56% x 3P
Contingent Resources (20%)	3% x 1C	8% x 2C	20% x 3C
Contingent Resources (50%)	2% x 1C	6% x 2C	22% x 3C
Prospective Resources (90%)	0% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.3% x 3U

Table 199— Low case of COC for Well 27 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	3% x 1P	14% x 2P	63% x 3P
Contingent Resources (20%)	1% x 1C	5% x 2C	24% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	27% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 200— Low case of COC for Well 28 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	17% x 2P	58% x 3P
Contingent Resources (20%)	2% x 1C	7% x 2C	21% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	24% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.4% x 3U

Table 201— Low case of COC for Well 29 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	60% x 3P
Contingent Resources (20%)	2% x 1C	6% x 2C	22% x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	25% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.4% x 3U

Table 202— Low case of COC for Well 30 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	15% x 2P	62% x 3P
Contingent Resources (20%)	1% x 1C	5% x 2C	24% x 3C
Contingent Resources (50%)	0% x 1C	3% x 2C	26% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 203— Low case of COC for Well 31 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	59% x 3P
Contingent Resources (20%)	2% x 1C	6% x 2C	22% x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	25% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.4% x 3U

Table 204— Low case of COC for Well 32 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	17% x 2P	58% x 3P
Contingent Resources (20%)	2% x 1C	7% x 2C	21% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	24% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.4% x 3U

Table 205— Low case of COC for Well 33 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	15% x 2P	61% x 3P
Contingent Resources (20%)	1% x 1C	5% x 2C	23% x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	26% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 206— Low case of COC for Well 34 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	16% x 2P	60% x 3P
Contingent Resources (20%)	2% x 1C	6% x 2C	23% x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	25% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 207— Low case of COC for Well 35 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	17% x 2P	58% x 3P
Contingent Resources (20%)	2% x 1C	7% x 2C	21% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	24% x 3C
Prospective Resources (90%)	0% x 1U	0.2% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.2% x 2U	1.4% x 3U

Table 208— Low case of COC for Well 36 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	5% x 1P	16% x 2P	59% x 3P
Contingent Resources (20%)	2% x 1C	6% x 2C	22% x 3C
Contingent Resources (50%)	1% x 1C	5% x 2C	25% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.4% x 3U

Table 209— Low case of COC for Well 37 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

Reserves	4% x 1P	15% x 2P	61% x 3P
Contingent Resources (20%)	1% x 1C	5% x 2C	23% x 3C
Contingent Resources (50%)	1% x 1C	4% x 2C	26% x 3C
Prospective Resources (90%)	0% x 1U	0.1% x 2U	1% x 3U
Prospective Resources (100%)	0% x 1U	0.1% x 2U	1.5% x 3U

Table 210— Low case of COC for Well 38 of Reserves, CR, and PR with both cases of uncertainty for the CR and the PR.

APPENDIX I

TABLES OF WELL DATA FOR CHAPTER 6

Table 211 presents the lateral length, first production and time to material balance time of the 38 wells in our dataset. We also present which wells use analog parameters in the second segment when analyzing the truncated dataset because there was not enough production data to match the curve. **Table 212** presents the parameters used for the full dataset for the first and second segments, and **Table 213** presents the parameters used for the truncated dataset. The highlighted wells are those where we used analog data for the second segment because of lack of production data.

In **Appendix J** we present the graphical results of the 1P, 2P, and 3P EUR. **Table 214** presents the 1P, 2P, and 3P EUR results and the normalized results to 10,000’ for the full dataset.

In **Appendix K** we present the graphical results of the 1P, 2P, and 3P EUR. **Table 215** presents the 1P, 2P, and 3P EUR results and the normalized results to 10,000 ft for the truncated dataset.

Well #	Lateral Length (ft)	1st production	MBT switch (days)	MBT switch (months)	MBT switch (years)	Analog for 2-segm w/ truncated data set
1	8,234	10/28/14	432	14.4	1.18	
2	8,289	10/31/14	621	20.7	1.70	
3	8,233	11/1/14	621	20.7	1.70	
4	7,829	10/24/14	629	21.0	1.72	
5	7,806	11/5/14	619	20.6	1.70	
6	7,814	10/23/14	621	20.7	1.70	
7	9,068	5/20/15	620	20.7	1.70	yes
8	8,954	5/29/15	621	20.7	1.70	yes
9	8,942	5/28/15	629	21.0	1.72	yes
10	8,982	6/2/15	365	12.2	1.00	yes
11	8,957	6/2/15	629	21.0	1.72	yes
12	8,976	5/15/15	629	21.0	1.72	yes
13	8,943	5/15/15	629	21.0	1.72	yes
14	8,901	5/17/15	629	21.0	1.72	yes
15	10,554	7/4/14	629	21.0	1.72	
16	10,495	7/3/14	629	21.0	1.72	
17	10,492	6/25/14	629	21.0	1.72	
18	9,566	6/16/15	629	21.0	1.72	yes
19	9,559	6/16/15	629	21.0	1.72	yes
20	10,239	6/7/15	629	21.0	1.72	yes
21	10,265	6/8/15	629	21.0	1.72	yes
22	9,026	8/18/14	629	21.0	1.72	
23	10,257	8/29/14	629	21.0	1.72	
24	10,288	8/25/14	629	21.0	1.72	
25	9,749	8/27/14	629	21.0	1.72	
26	9,106	8/28/14	629	21.0	1.72	
27	9,516	5/1/15	629	21.0	1.72	yes
28	7,839	3/11/15	629	21.0	1.72	yes
29	6,597	6/1/12	629	21.0	1.72	
30	7,705	11/12/12	629	21.0	1.72	
31	6,524	5/31/12	629	21.0	1.72	
32	7,661	10/12/12	629	21.0	1.72	
33	10,518	5/22/14	629	21.0	1.72	
34	10,511	5/2/14	629	21.0	1.72	
35	10,529	4/23/14	629	21.0	1.72	
36	10,376	4/24/14	629	21.0	1.72	
37	10,434	5/2/14	629	21.0	1.72	
38	10,419	4/19/14	629	21.0	1.72	

Table 211—Specific data for the full dataset, including the lateral length, first production, and the time to MBT.

	FULL											
Well	1P				2P				3P			
#	b1	D1	b2	D2	b1	D1	b2	D2	b1	D1	b2	D2
1	2	0.028	0.3	0.0025	1.9	0.019	0.3	0.0019	1.8	0.013	0.3	0.0013
2	2	0.028	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.013	0.3	0.0013
3	2	0.03	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.013	0.3	0.0013
4	1.9	0.019	0.3	0.0012	1.9	0.014	0.3	0.001	1.8	0.012	0.3	0.001
5	2	0.03	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
6	2	0.03	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
7	2	0.02	0.3	0.0018	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
8	2	0.02	0.3	0.0018	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
9	2	0.02	0.3	0.0018	2	0.01	0.3	0.0012	1.8	0.009	0.3	0.001
10	2	0.018	0.3	0.0018	1.9	0.012	0.3	0.0012	1.8	0.009	0.3	0.001
11	2	0.022	0.3	0.0018	2	0.019	0.3	0.0012	1.8	0.009	0.3	0.001
12	2	0.02	0.3	0.0015	2	0.017	0.3	0.0012	1.8	0.009	0.3	0.001
13	2	0.018	0.3	0.0014	2	0.015	0.3	0.0012	1.8	0.01	0.3	0.001
14	2	0.016	0.3	0.00115	2	0.015	0.3	0.0011	2	0.014	0.3	0.00105
15	2	0.021	0.3	0.0011	1.9	0.019	0.3	0.001	2	0.017	0.3	0.0009
16	2	0.03	0.3	0.0013	2	0.025	0.3	0.0012	2	0.017	0.3	0.0009
17	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.017	0.3	0.001
18	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.017	0.3	0.001
19	2	0.022	0.3	0.0015	1.9	0.015	0.3	0.0012	2	0.012	0.3	0.001
20	2	0.022	0.3	0.0015	1.9	0.015	0.3	0.0012	2	0.012	0.3	0.001
21	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
22	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.001	2	0.012	0.3	0.001
23	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.001	2	0.012	0.3	0.001
24	2	0.032	0.3	0.0015	2	0.033	0.3	0.0012	2	0.022	0.3	0.001
25	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.015	0.3	0.001
26	2	0.048	0.3	0.0015	2	0.042	0.3	0.0012	2	0.036	0.3	0.001
27	2	0.028	0.3	0.0015	1.9	0.024	0.3	0.0012	2	0.018	0.3	0.001
28	2	0.021	0.3	0.0013	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
29	2	0.022	0.3	0.0014	1.9	0.015	0.3	0.0012	2	0.012	0.3	0.001
30	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
31	2	0.022	0.3	0.0014	2	0.019	0.3	0.0012	2	0.012	0.3	0.001
32	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
33	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
34	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
35	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
36	2	0.015	0.3	0.0014	2	0.01	0.3	0.0012	2	0.009	0.3	0.001
37	2	0.023	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.015	0.3	0.001
38	2	0.021	0.3	0.0013	2	0.019	0.3	0.0012	2	0.015	0.3	0.001

Table 212—Parameters for the two segments of the full dataset for the 1P, 2P, and 3P EUR calculations.

Well	TRUNCATED											
	1P				2P				3P			
#	b1	D1	b2	D2	b1	D1	b2	D2	b1	D1	b2	D2
1	2	0.028	0.3	0.0025	1.9	0.019	0.3	0.0019	1.8	0.013	0.3	0.0013
2	2	0.028	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.013	0.3	0.0013
3	2	0.03	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.013	0.3	0.0013
4	1.9	0.019	0.3	0.0012	1.9	0.014	0.3	0.001	1.8	0.012	0.3	0.001
5	2	0.03	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
6	2	0.03	0.3	0.0025	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
7	2	0.02	0.3	0.0018	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
8	2	0.02	0.3	0.0018	1.9	0.019	0.3	0.0012	1.8	0.012	0.3	0.001
9	2	0.02	0.3	0.0018	2	0.01	0.3	0.0012	1.8	0.009	0.3	0.001
10	2	0.018	0.3	0.0018	1.9	0.012	0.3	0.0012	1.8	0.009	0.3	0.001
11	2	0.022	0.3	0.0018	2	0.019	0.3	0.0012	1.8	0.009	0.3	0.001
12	2	0.02	0.3	0.0015	2	0.017	0.3	0.0012	1.8	0.009	0.3	0.001
13	2	0.018	0.3	0.0014	2	0.015	0.3	0.0012	1.8	0.01	0.3	0.001
14	2	0.016	0.3	0.00115	2	0.015	0.3	0.0011	2	0.014	0.3	0.00105
15	2	0.021	0.3	0.0011	1.9	0.019	0.3	0.001	2	0.017	0.3	0.0009
16	2	0.03	0.3	0.0013	2	0.025	0.3	0.0012	2	0.017	0.3	0.0009
17	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.017	0.3	0.001
18	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.017	0.3	0.001
19	2	0.022	0.3	0.0015	1.9	0.015	0.3	0.0012	2	0.012	0.3	0.001
20	2	0.022	0.3	0.0015	1.9	0.015	0.3	0.0012	2	0.012	0.3	0.001
21	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
22	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.001	2	0.012	0.3	0.001
23	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.001	2	0.012	0.3	0.001
24	2	0.032	0.3	0.0015	2	0.033	0.3	0.0012	2	0.022	0.3	0.001
25	2	0.022	0.3	0.0015	1.9	0.019	0.3	0.0012	2	0.015	0.3	0.001
26	2	0.048	0.3	0.0015	2	0.042	0.3	0.0012	2	0.036	0.3	0.001
27	2	0.028	0.3	0.0015	1.9	0.024	0.3	0.0012	2	0.018	0.3	0.001
28	2	0.021	0.3	0.0013	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
29	2	0.022	0.3	0.0014	1.9	0.015	0.3	0.0012	2	0.012	0.3	0.001
30	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
31	2	0.022	0.3	0.0014	2	0.019	0.3	0.0012	2	0.012	0.3	0.001
32	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
33	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
34	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
35	2	0.022	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.012	0.3	0.001
36	2	0.015	0.3	0.0014	2	0.01	0.3	0.0012	2	0.009	0.3	0.001
37	2	0.023	0.3	0.0014	1.9	0.019	0.3	0.0012	2	0.015	0.3	0.001
38	2	0.021	0.3	0.0013	2	0.019	0.3	0.0012	2	0.015	0.3	0.001

Table 213—Parameters of the truncated dataset for the 1P, 2P, and 3P EUR calculations.

APPENDIX J

DIAGNOSTIC PLOTS TO IDENTIFY THE TWO FLOW REGIMES BEFORE PERFORMING TWO-SEGMENT DCA

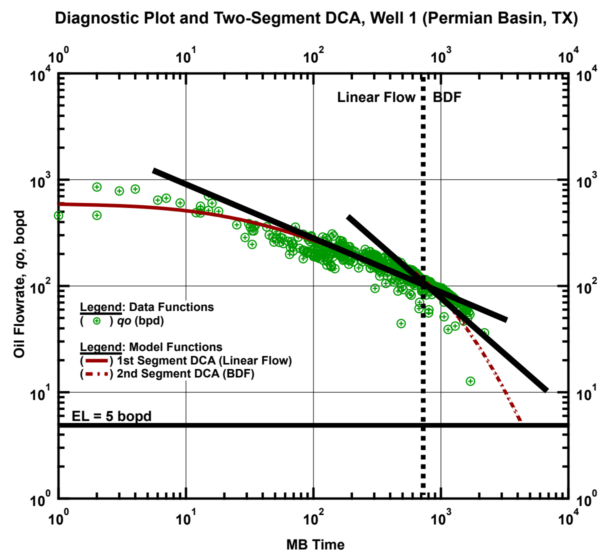

Figure 176 — Two-segment DCA of Well 1 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

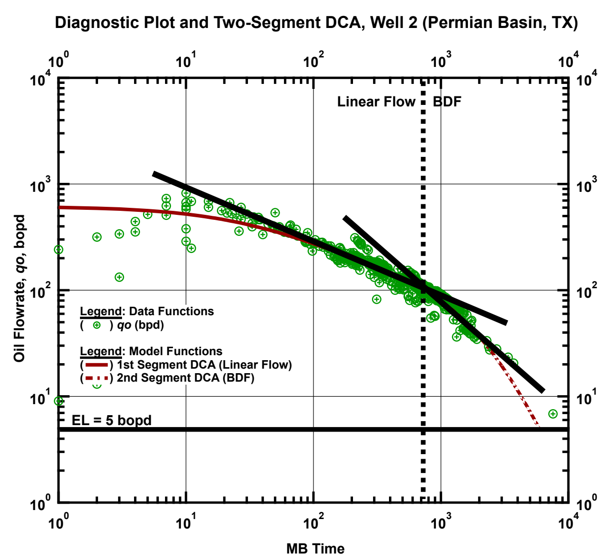

Figure 177 — Two-segment DCA of Well 2 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

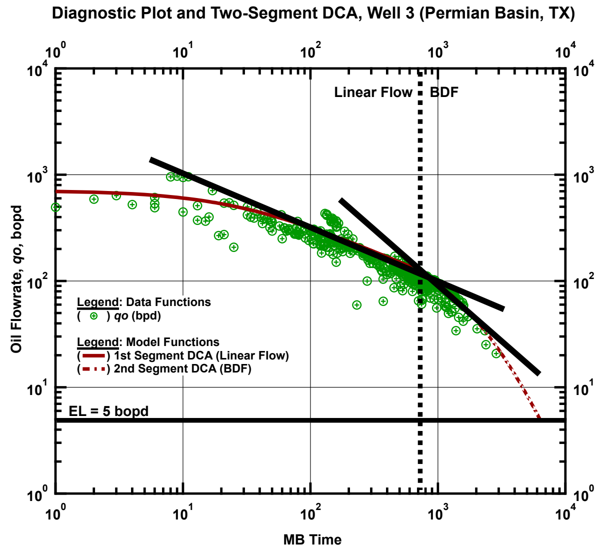

Figure 178 — Two-segment DCA of Well 3 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

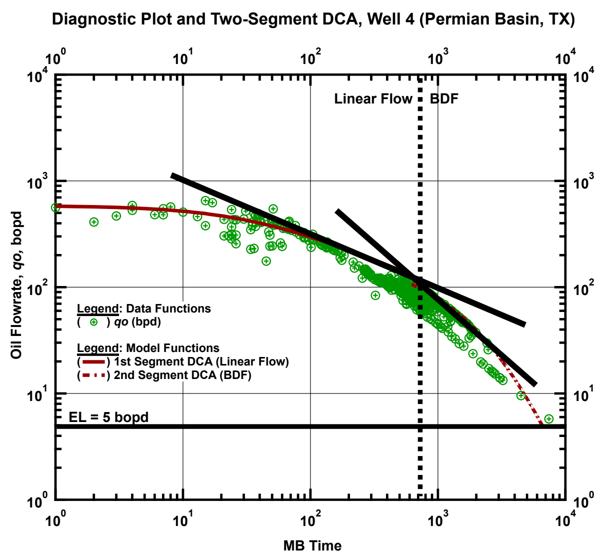

Figure 179 — Two-segment DCA of Well 4 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

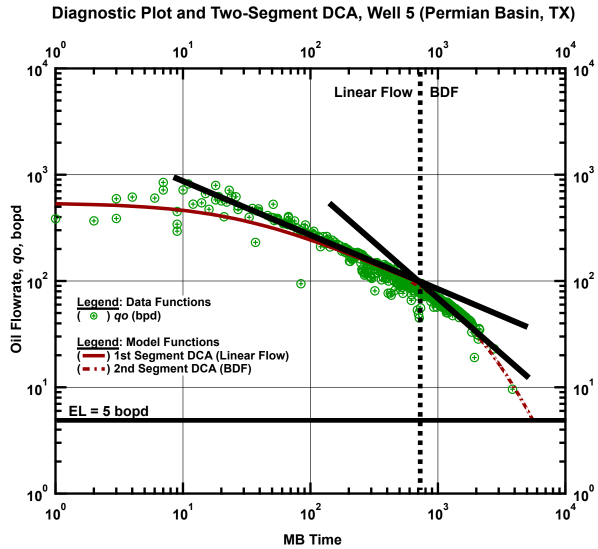

Figure 180 — Two-segment DCA of Well 5 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

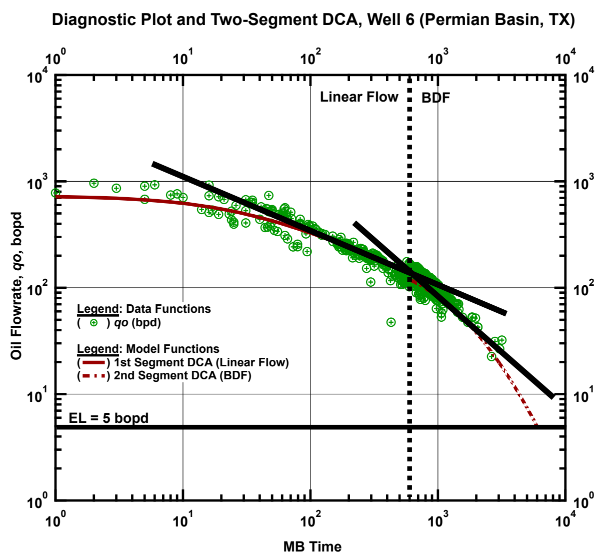

Figure 181 — Two-segment DCA of Well 6 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

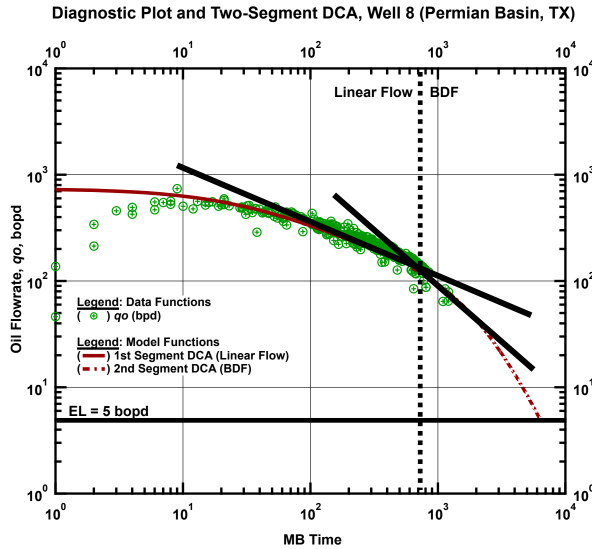

Figure 182 — Two-segment DCA of Well 8 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

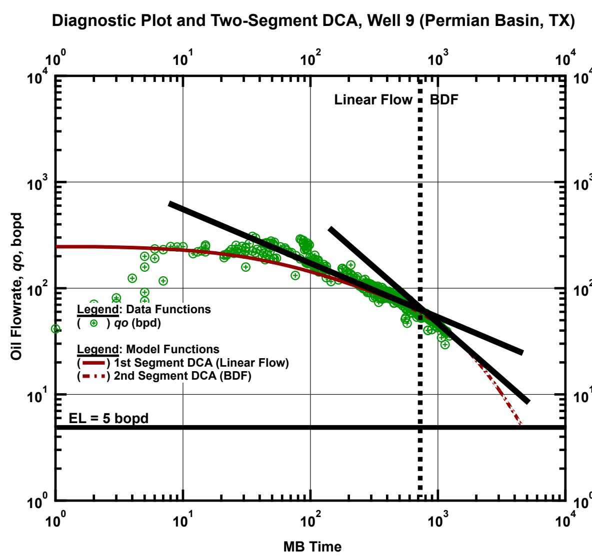

Figure 183 — Two-segment DCA of Well 9 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line (as in Fig. 6). We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

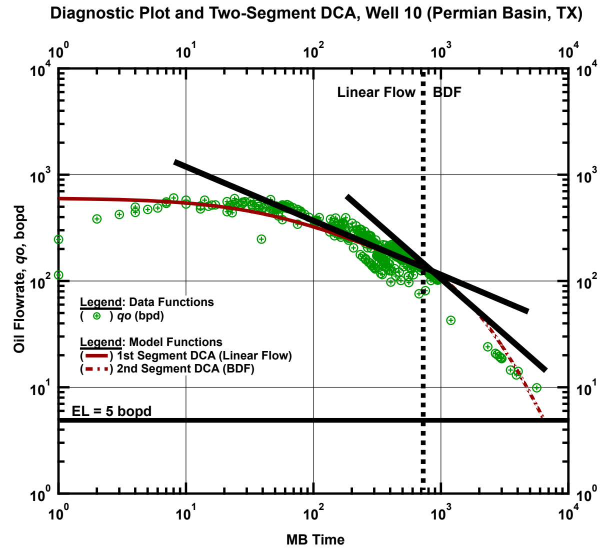

Figure 184 — Two-segment DCA of Well 10 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

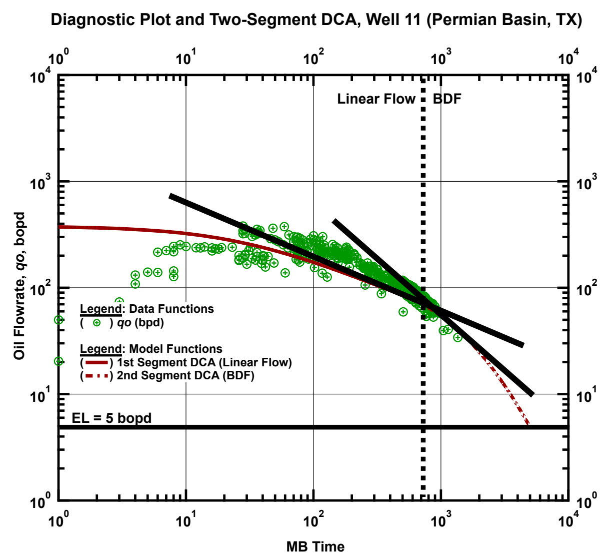

Figure 185 — Two-segment DCA of Well 11 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

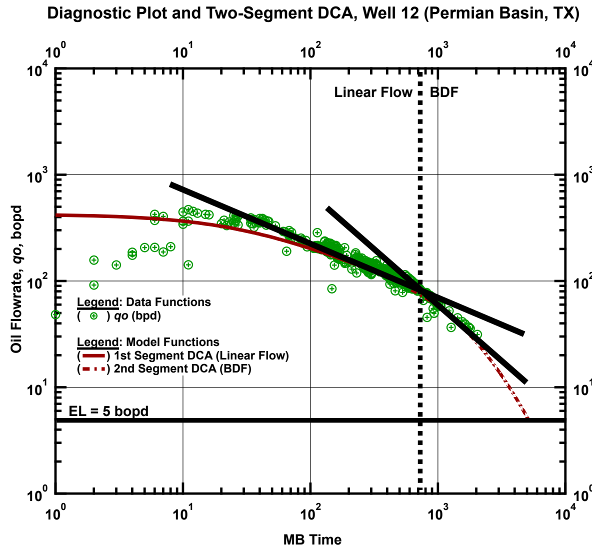

Figure 186 — Two-segment DCA of Well 12 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

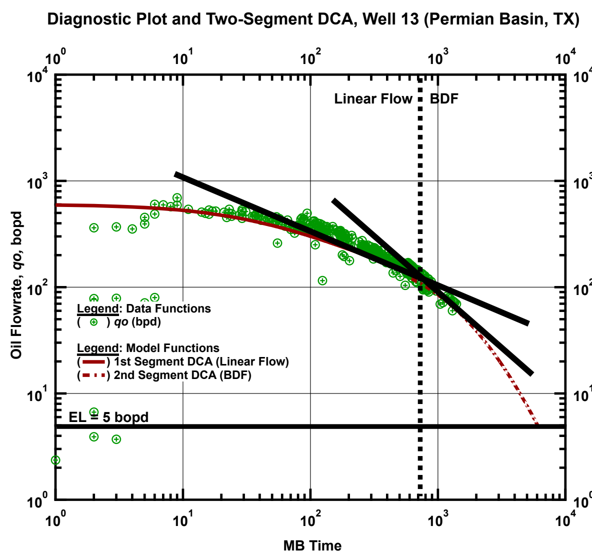

Figure 187 — Two-segment DCA of Well 13 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

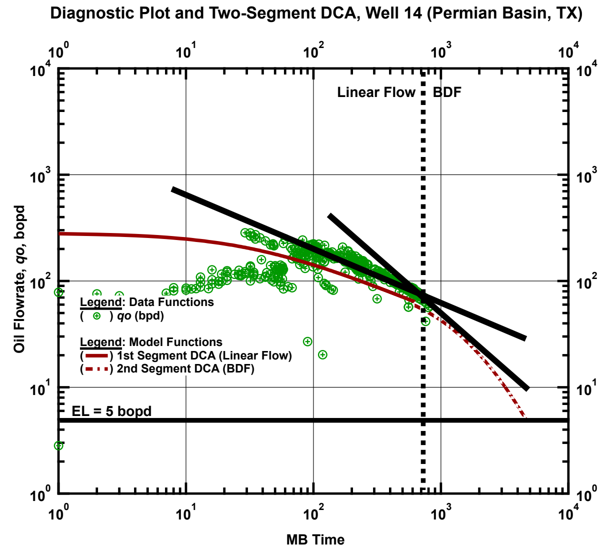

Figure 188 — Two-segment DCA of Well 14 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

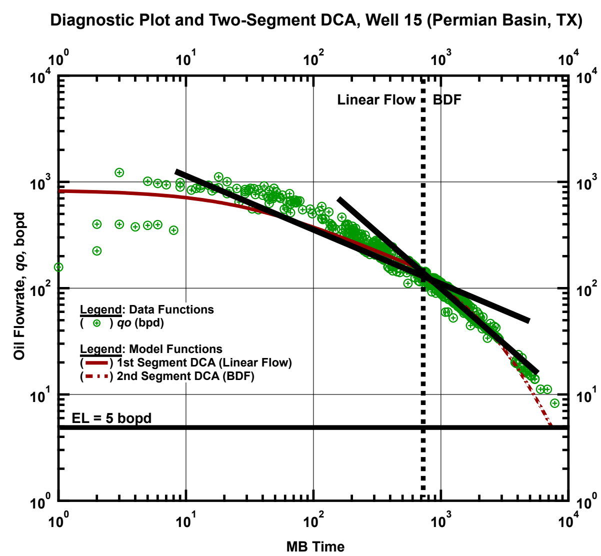

Figure 189 — Two-segment DCA of Well 15 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

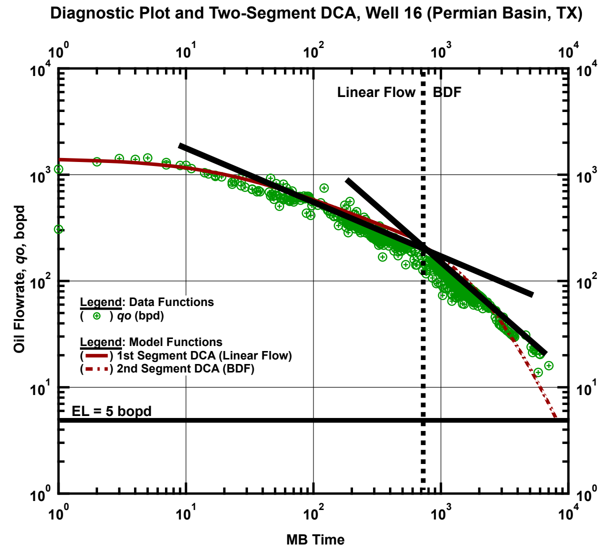

Figure 190 — Two-segment DCA of Well 16 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

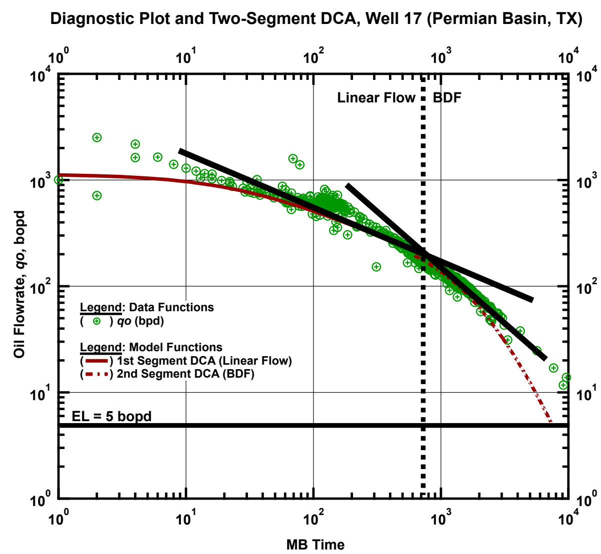

Figure 191 — Two-segment DCA of Well 17 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

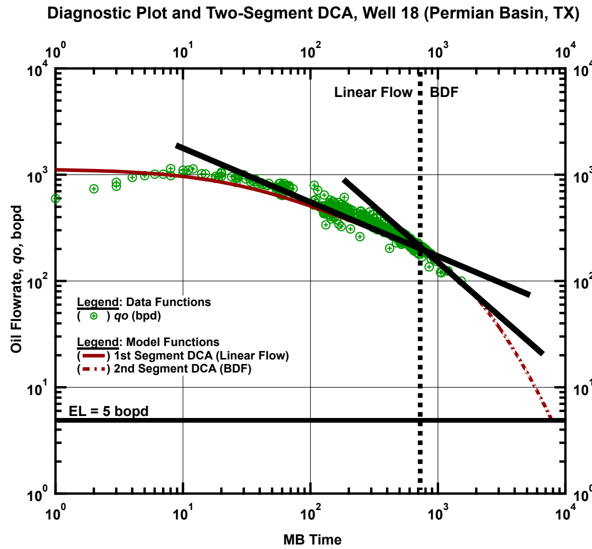

Figure 192 — Two-segment DCA of Well 18 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

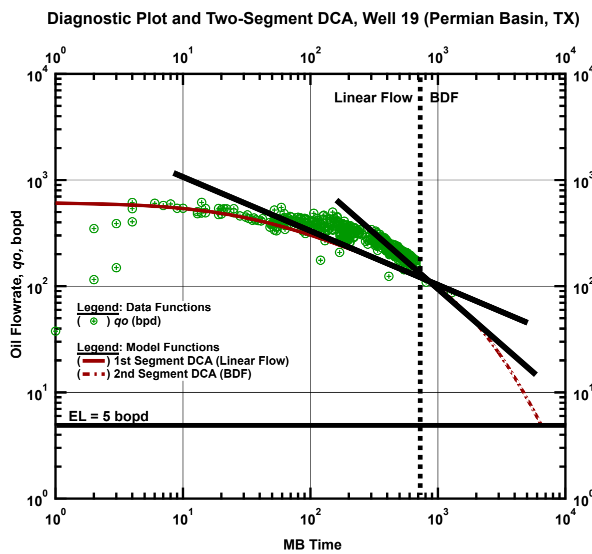

Figure 193 — Two-segment DCA of Well 19 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

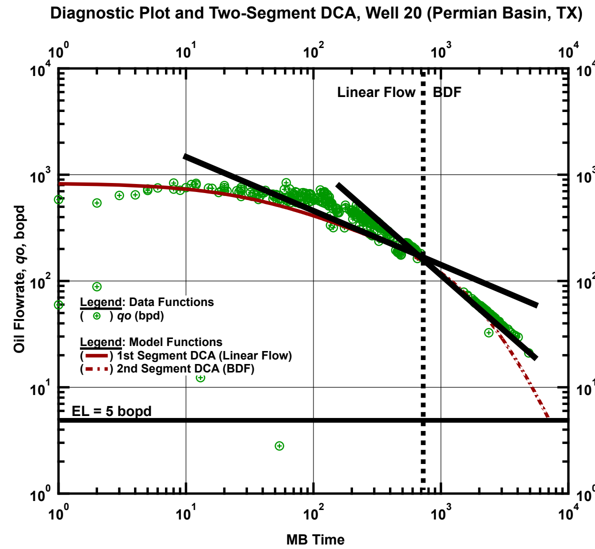

Figure 194 — Two-segment DCA of Well 20 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

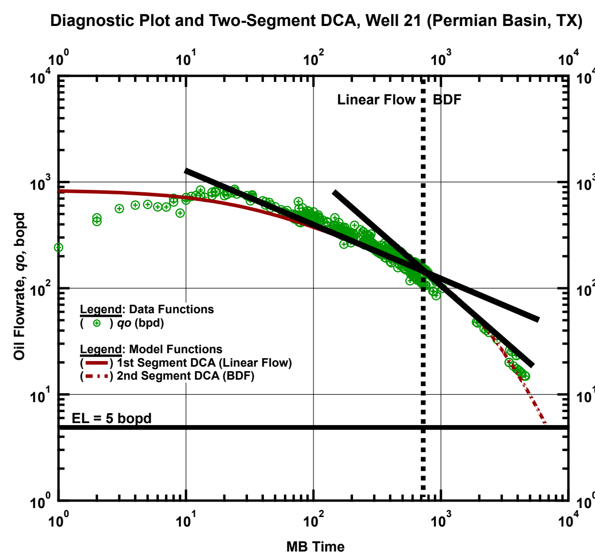

Figure 195 — Two-segment DCA of Well 21 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

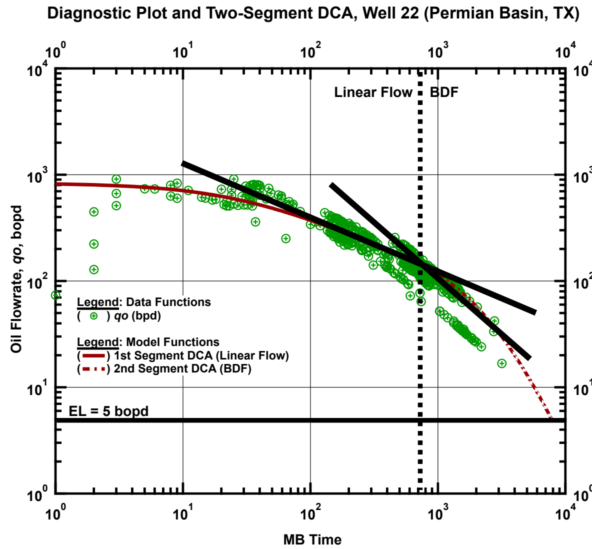

Figure 196 — Two-segment DCA of Well 22 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

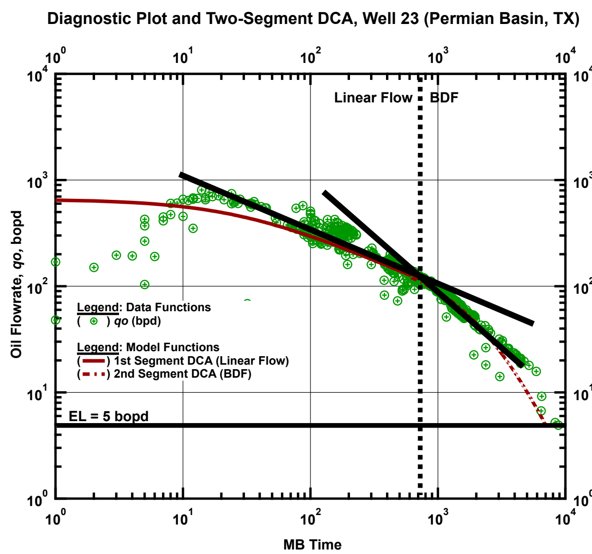

Figure 197 — Two-segment DCA of Well 23 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

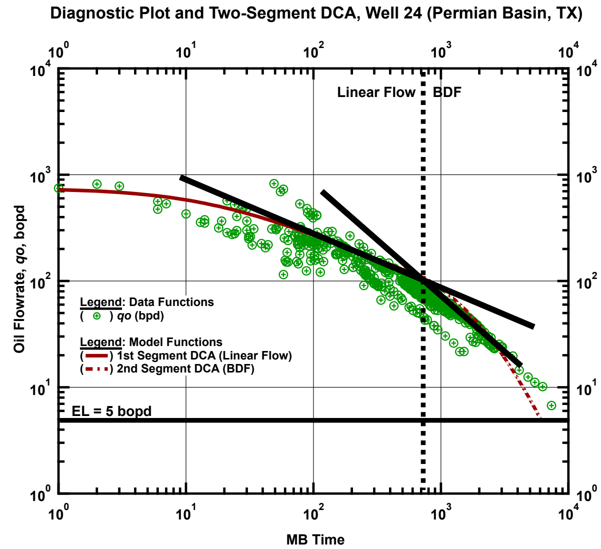

Figure 198 — Two-segment DCA of Well 24 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

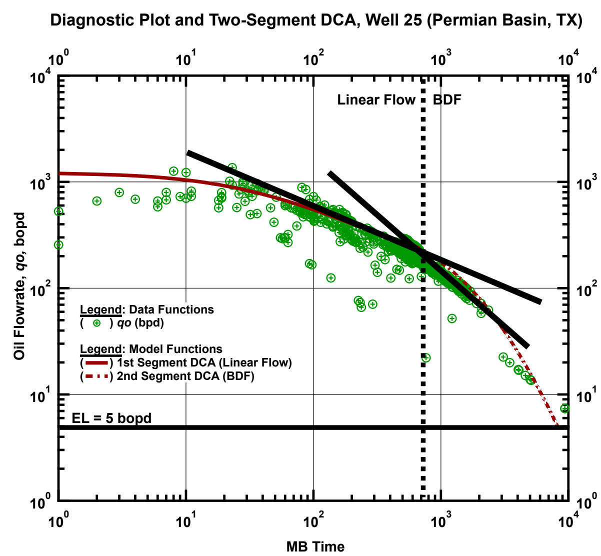

Figure 199 — Two-segment DCA of Well 25 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

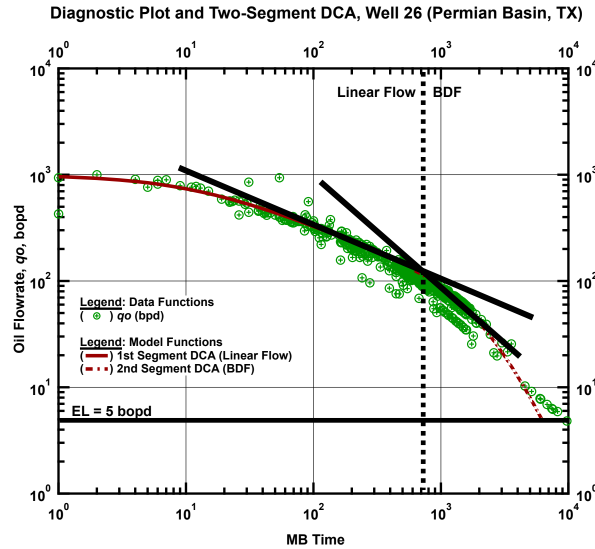

Figure 200 — Two-segment DCA of Well 26 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

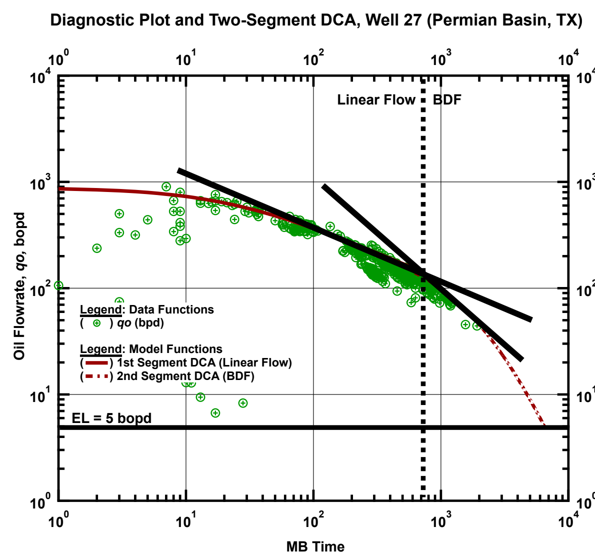

Figure 201 — Two-segment DCA of Well 27 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

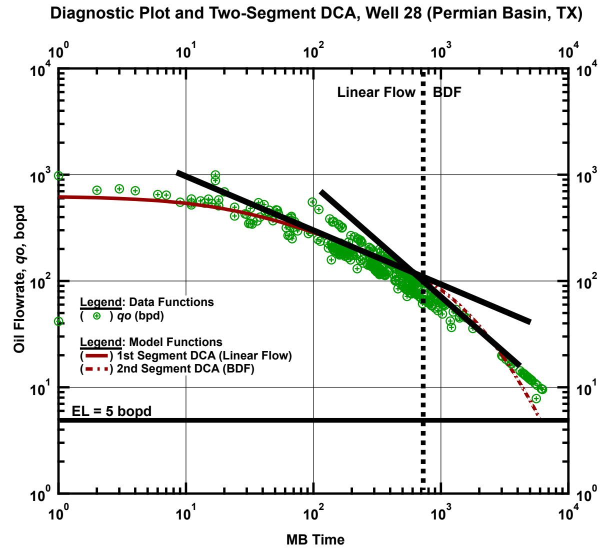

Figure 202 — Two-segment DCA of Well 28 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

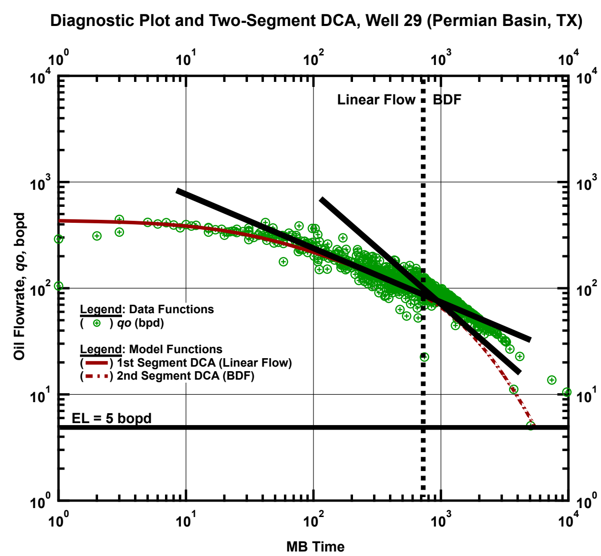

Figure 203 — Two-segment DCA of Well 29 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

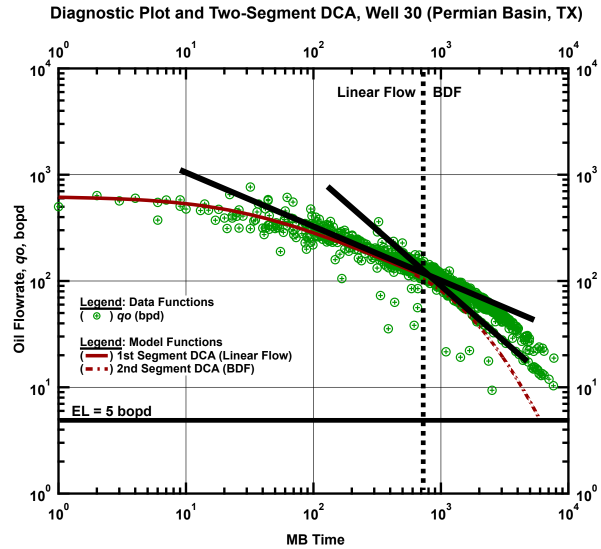

Figure 204 — Two-segment DCA of Well 30 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

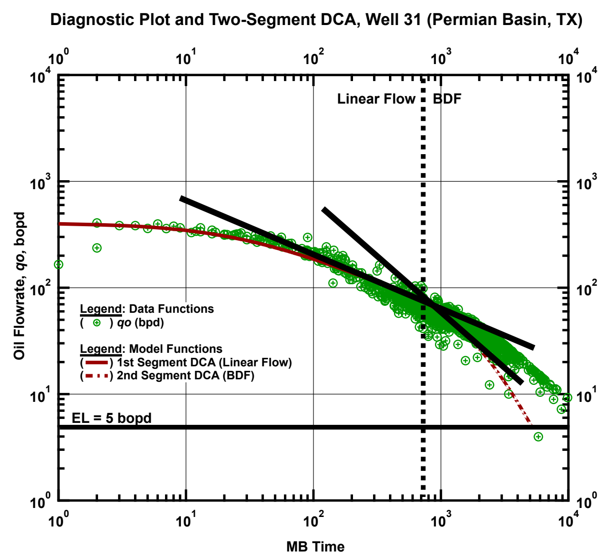

Figure 205 — Two-segment DCA of Well 31 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

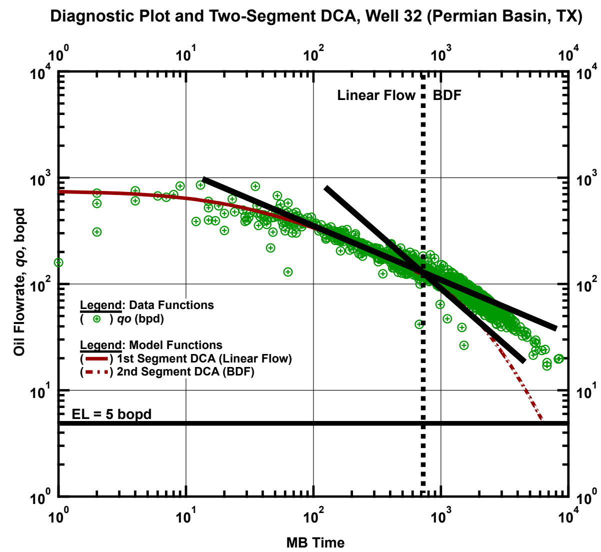

Figure 206 — Two-segment DCA of Well 32 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

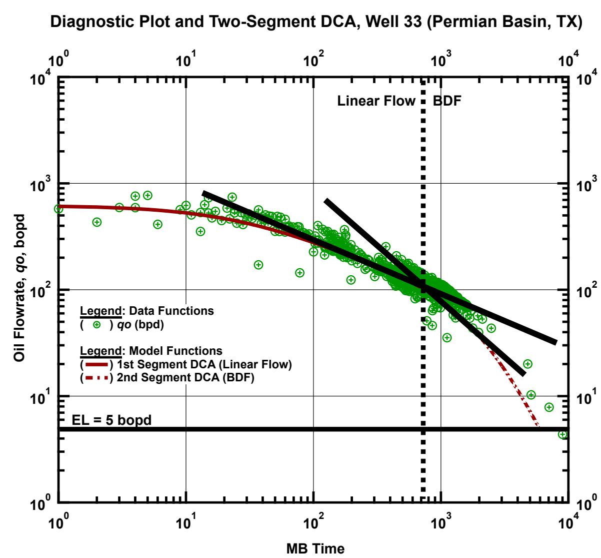

Figure 207 — Two-segment DCA of Well 33 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

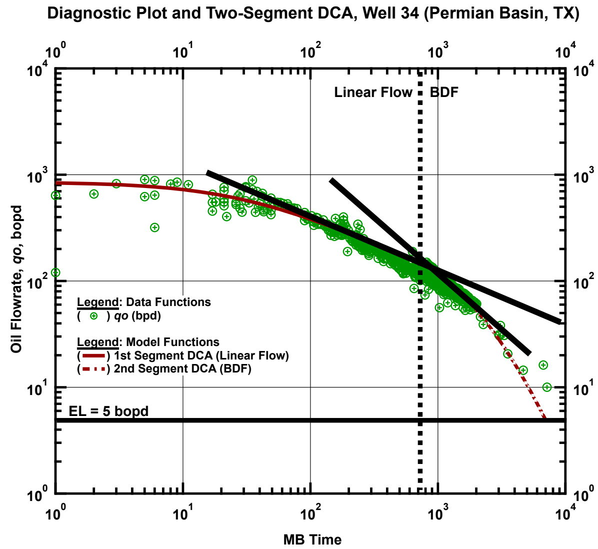

Figure 208 — Two-segment DCA of Well 34 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

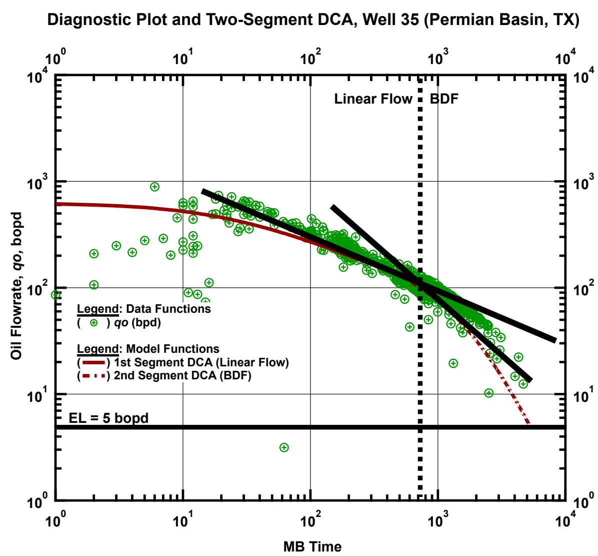

Figure 209 — Two-segment DCA of Well 35 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

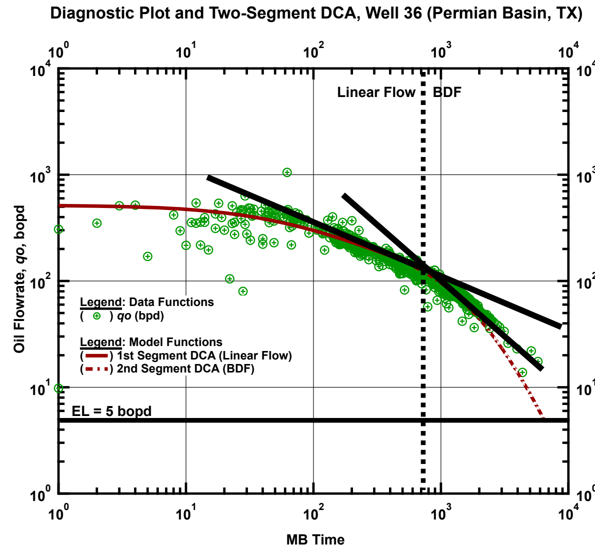

Figure 210 — Two-segment DCA of Well 36 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

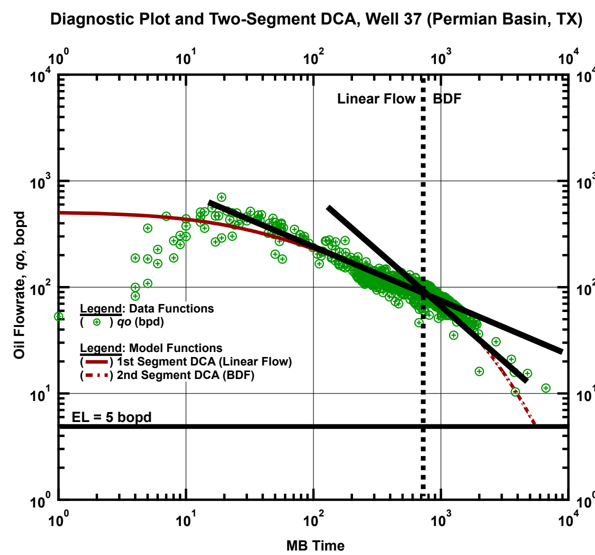

Figure 211 — Two-segment DCA of Well 37 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 1.9 and in BDF it is 0.3.

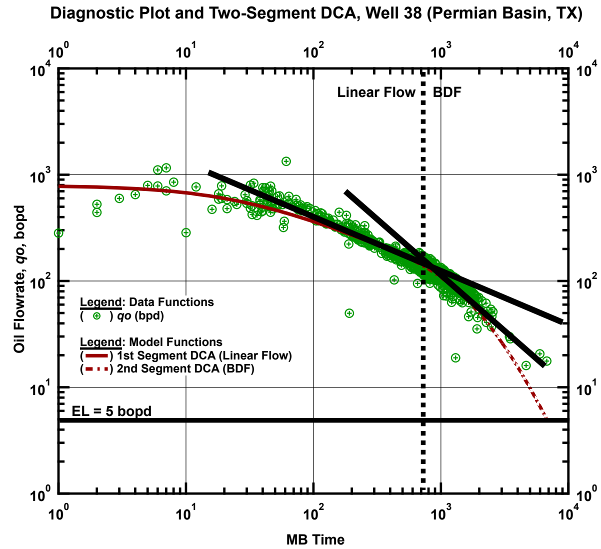

Figure 212 — Two-segment DCA of Well 38 in the Midland Basin (TX) shows the two segments of the DCA with the transition indicated by the dashed line. We see that in linear flow, the *b*-factor is 2 and in BDF it is 0.3.

APPENDIX K

EUR FIGURES USING THE FULL DATASET

	FULL					
Well	EUR (Mbbl)			NORMALIZED EUR (MBBL), 10,000'		
#	1P	2P	3P	1P	2P	3P
1	167.89	211.66	272.54	203.90	257.05	330.99
2	181.95	270.20	300.34	219.50	325.97	362.34
3	205.57	316.43	353.40	249.69	384.34	429.24
4	257.88	328.27	339.81	329.39	419.30	434.04
5	152.74	233.79	354.96	195.67	299.50	454.72
6	207.96	314.96	421.49	266.14	403.07	539.41
7	199.13	226.02	306.01	219.59	249.25	337.47
8	290.75	323.59	428.77	324.71	361.39	478.86
9	90.25	145.53	154.22	100.93	162.75	172.46
10	231.51	332.50	417.68	257.74	370.19	465.02
11	132.24	175.49	244.12	147.63	195.92	272.55
12	171.20	196.37	268.15	190.73	218.78	298.75
13	269.85	316.38	385.59	301.75	353.77	431.17
14	134.80	141.33	148.51	151.44	158.78	166.84
15	395.88	410.58	484.73	375.10	389.03	459.28
16	538.81	594.95	832.25	513.40	566.89	793.00
17	462.21	509.04	634.44	440.54	485.17	604.69
18	462.45	510.52	629.02	483.43	533.69	657.56
19	243.45	318.87	377.23	254.68	333.58	394.63
20	324.65	414.13	524.41	317.07	404.47	512.17
21	327.86	374.97	541.47	319.39	365.29	527.49
22	337.00	410.94	528.92	373.37	455.29	585.99
23	265.90	316.82	413.04	259.24	308.88	402.69
24	252.66	281.33	351.52	245.59	273.45	341.68
25	486.07	590.31	724.81	498.59	605.51	743.47
26	281.47	314.64	374.42	309.11	345.53	411.18
27	309.69	350.72	463.84	325.44	368.55	487.43
28	273.86	283.03	403.92	349.35	361.05	515.26
29	182.31	218.74	267.36	276.35	331.57	405.28
30	255.84	278.73	373.33	332.05	361.75	484.53
31	162.47	189.33	237.81	249.04	290.21	364.51
32	306.50	328.31	447.36	400.08	428.55	583.94
33	250.30	272.46	368.52	237.97	259.05	350.37
34	343.55	393.94	557.46	326.85	374.79	530.36
35	252.00	280.55	367.72	239.34	266.45	349.25
36	243.17	318.04	348.19	234.36	306.51	335.57
37	196.86	227.40	278.72	188.67	217.94	267.13
38	341.68	371.29	448.99	327.94	356.36	430.93

Table 214—Results of the EUR and the normalized EUR to 10,000' using the full dataset for the 38 wells

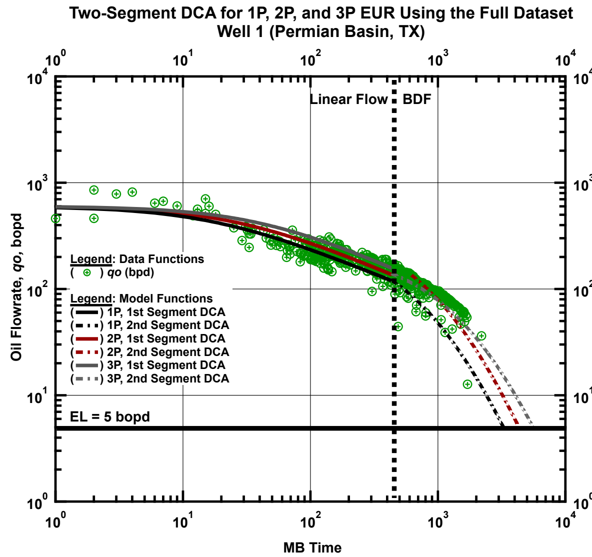

Figure 213 — Two-segment DCA of Well 1 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

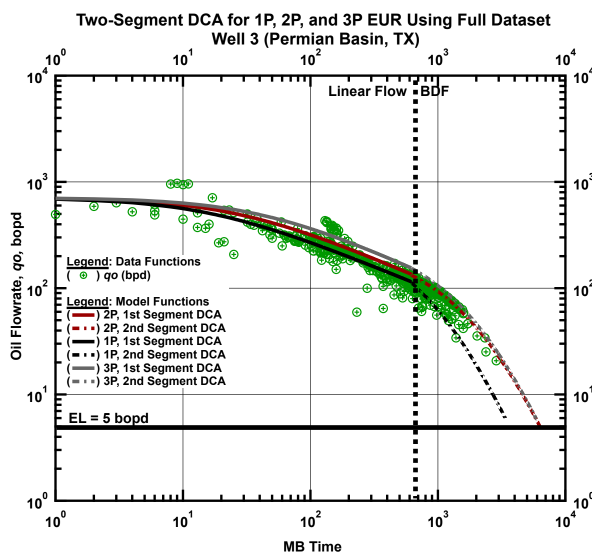

Figure 214 — Two-segment DCA of Well 2 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

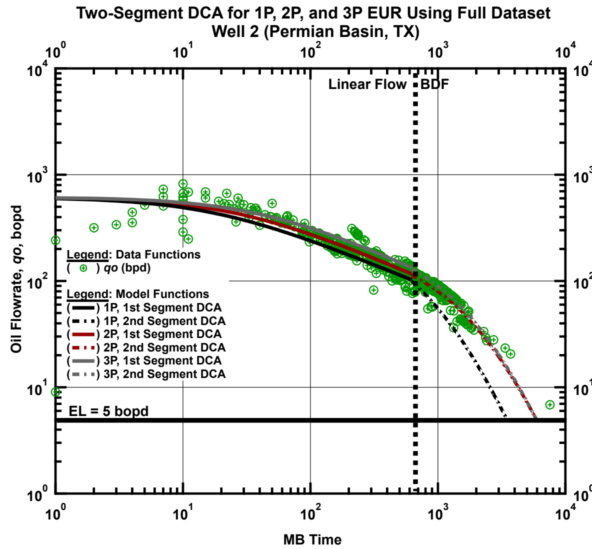

Figure 215 — Two-segment DCA of Well 3 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

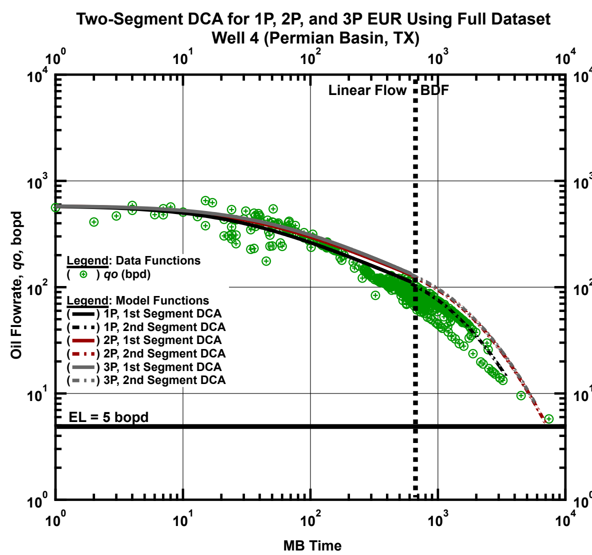

Figure 216 — Two-segment DCA of Well 4 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

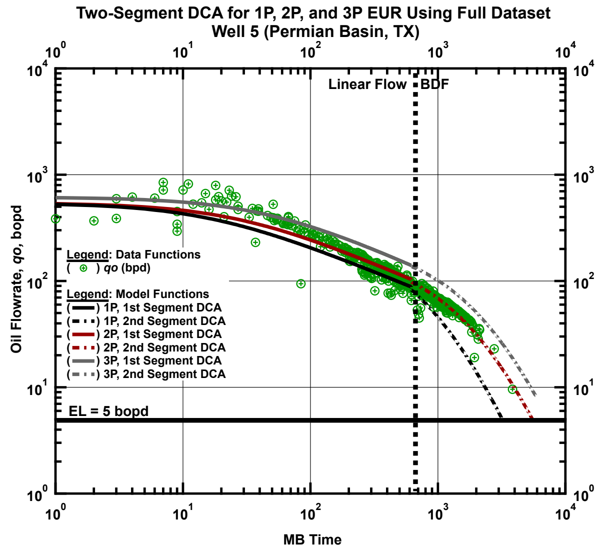

Figure 217 — Two-segment DCA of Well 5 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

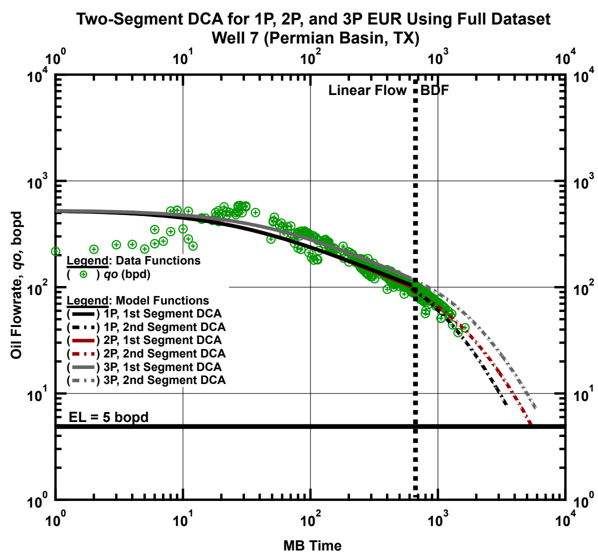

Figure 218 — Two-segment DCA of Well 7 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

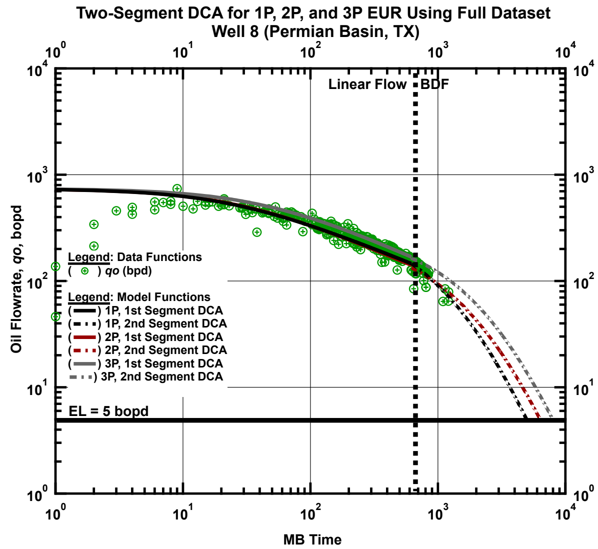

Figure 219 — Two-segment DCA of Well 8 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

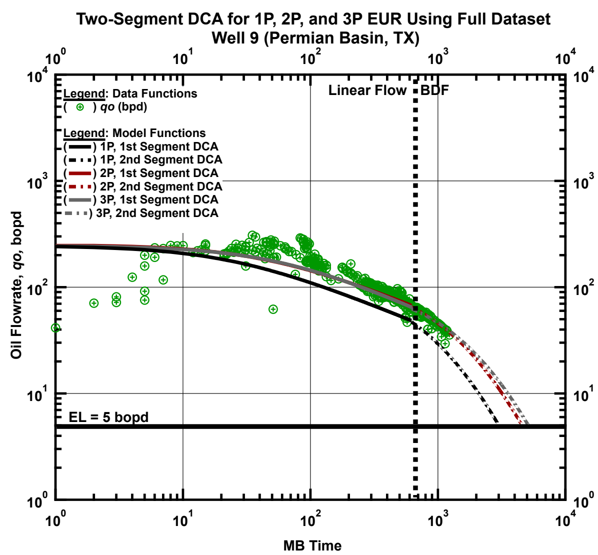

Figure 220 — Two-segment DCA of Well 9 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

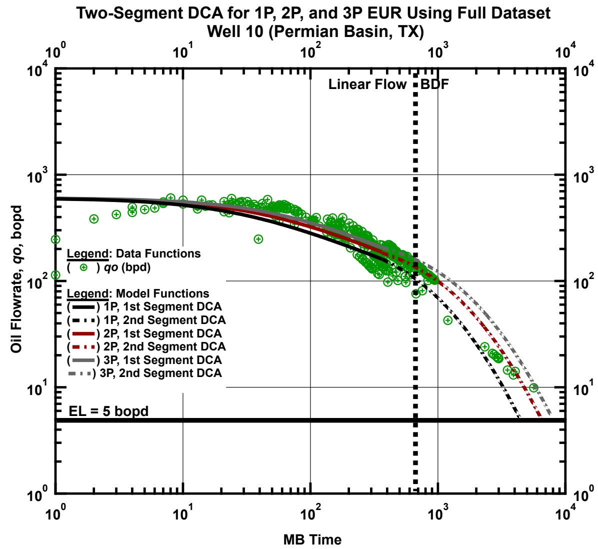

Figure 221 — Two-segment DCA of Well 10 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

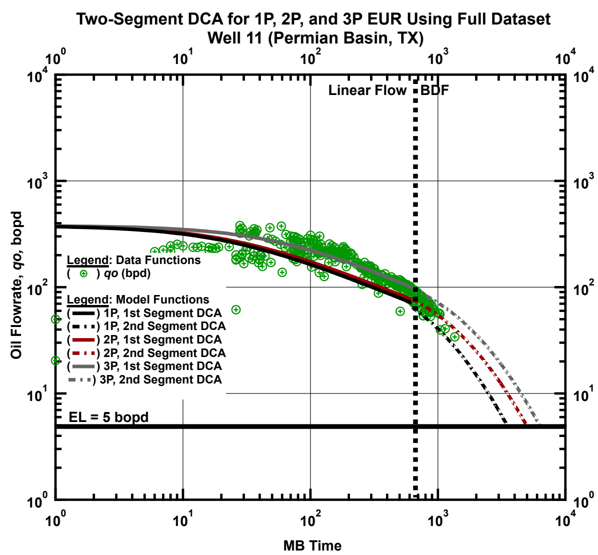

Figure 222 — Two-segment DCA of Well 11 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

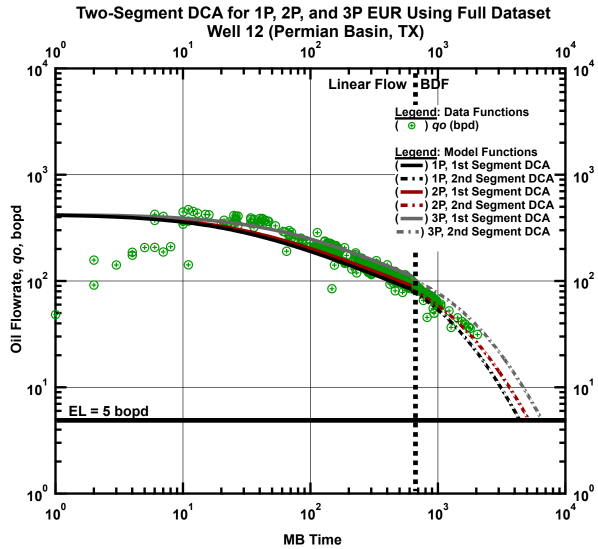

Figure 223 — Two-segment DCA of Well 12 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

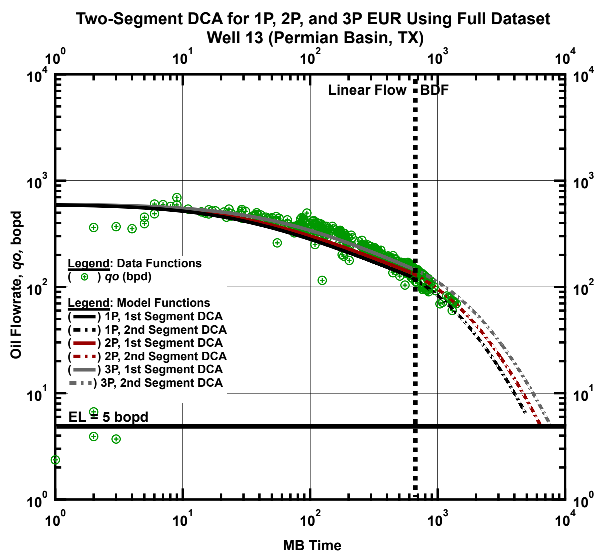

Figure 224 — Two-segment DCA of Well 13 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

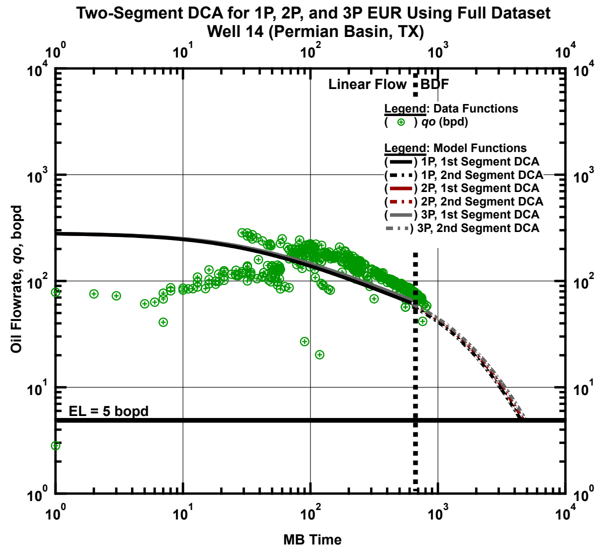

Figure 225 — Two-segment DCA of Well 14 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

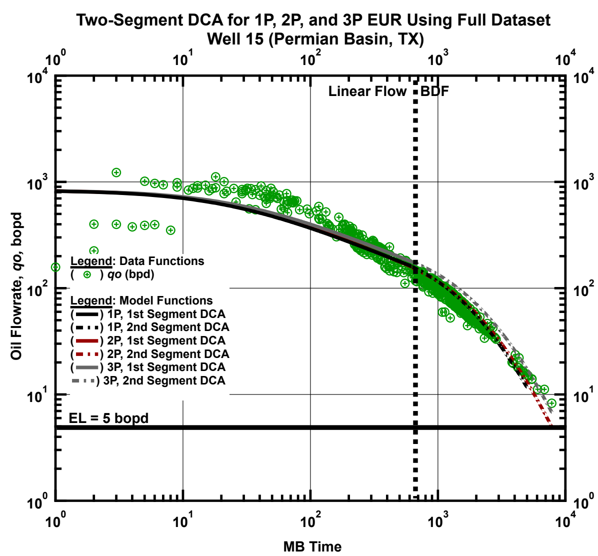

Figure 226 — Two-segment DCA of Well 15 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

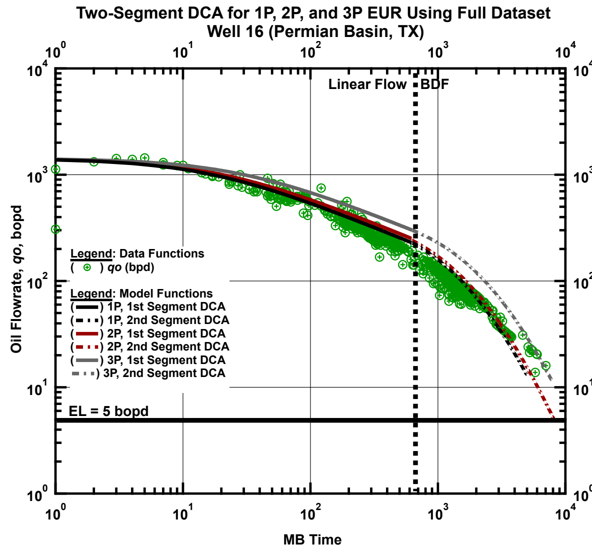

Figure 227 — Two-segment DCA of Well 16 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

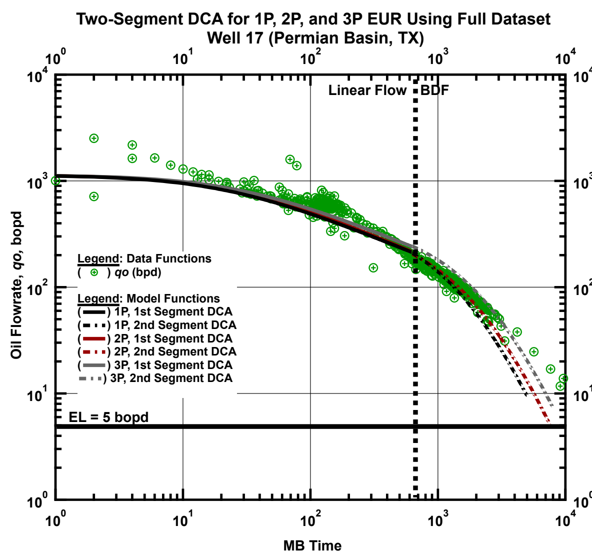

Figure 228 — Two-segment DCA of Well 17 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

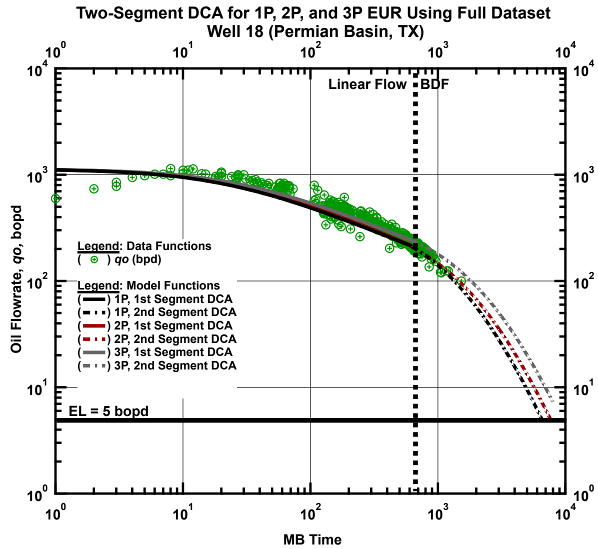

Figure 229 — Two-segment DCA of Well 18 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

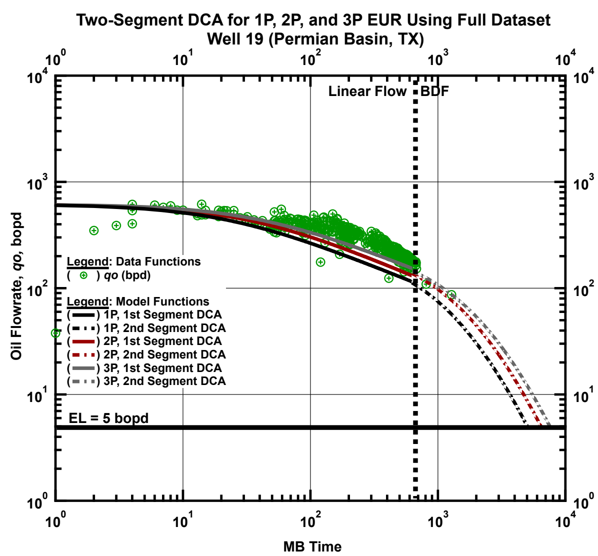

Figure 230 — Two-segment DCA of Well 19 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

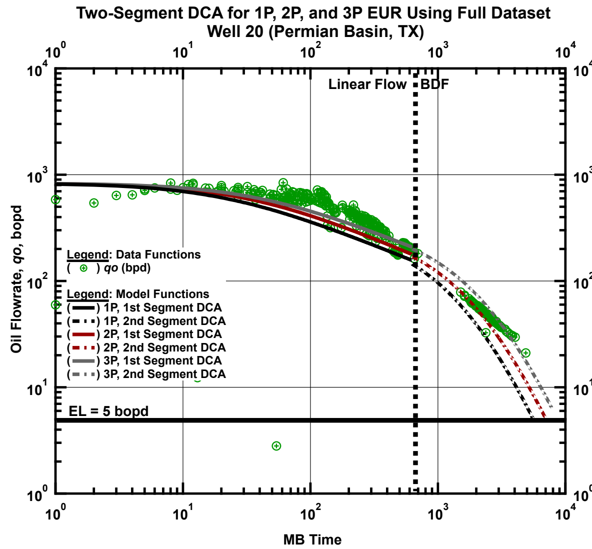

Figure 231 — Two-segment DCA of Well 20 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

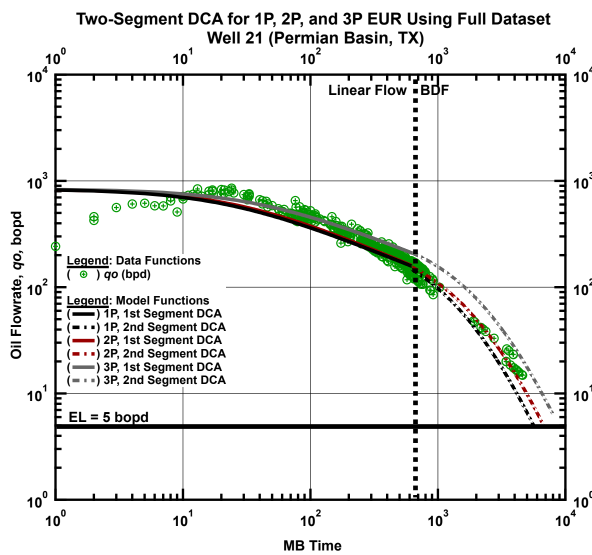

Figure 232 — Two-segment DCA of Well 21 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

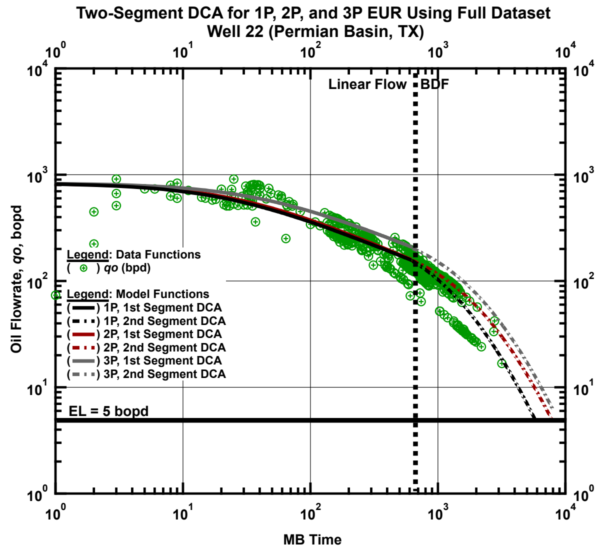

Figure 233 — Two-segment DCA of Well 22 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

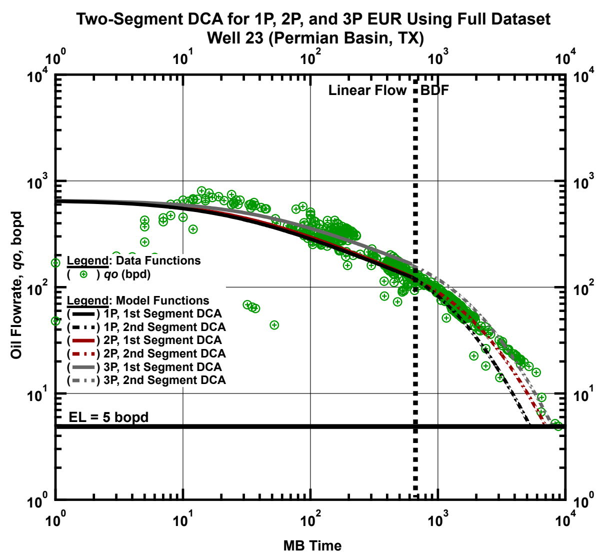

Figure 234 — Two-segment DCA of Well 23 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

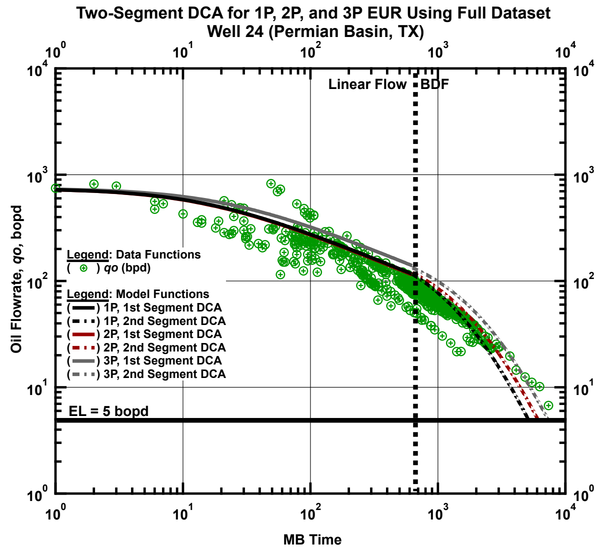

Figure 235 — Two-segment DCA of Well 24 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

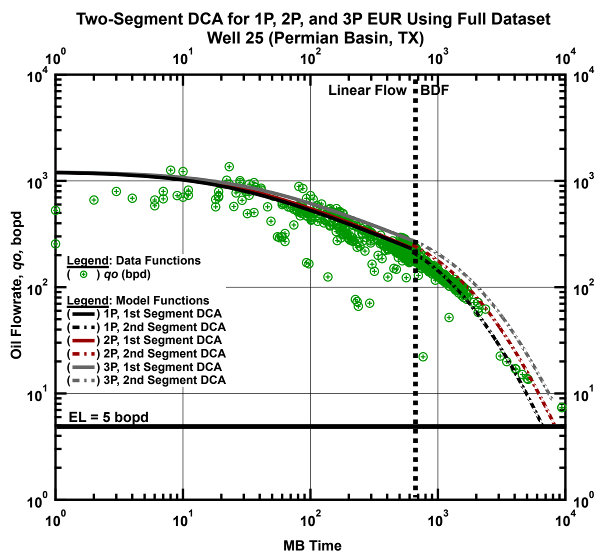

Figure 236 — Two-segment DCA of Well 25 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

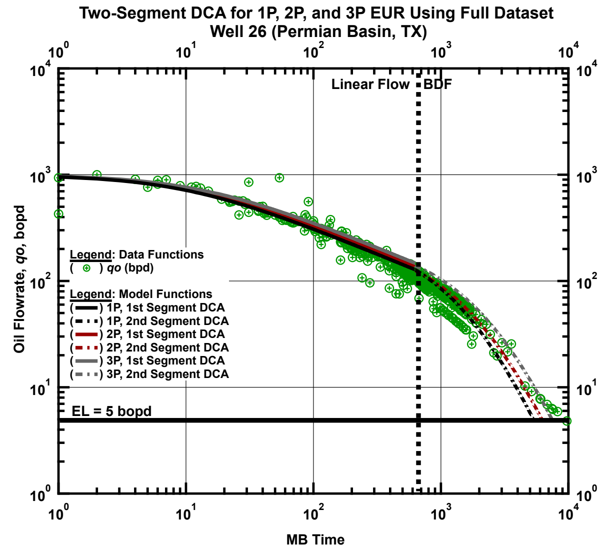

Figure 237 —Two-segment DCA of Well 26 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

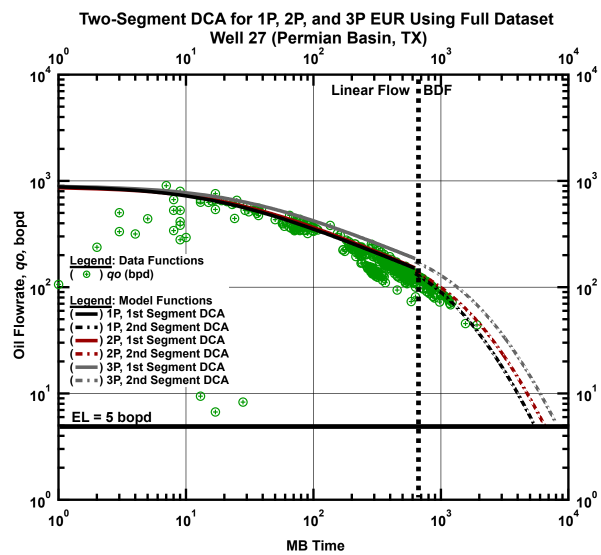

Figure 238 —Two-segment DCA of Well 27 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

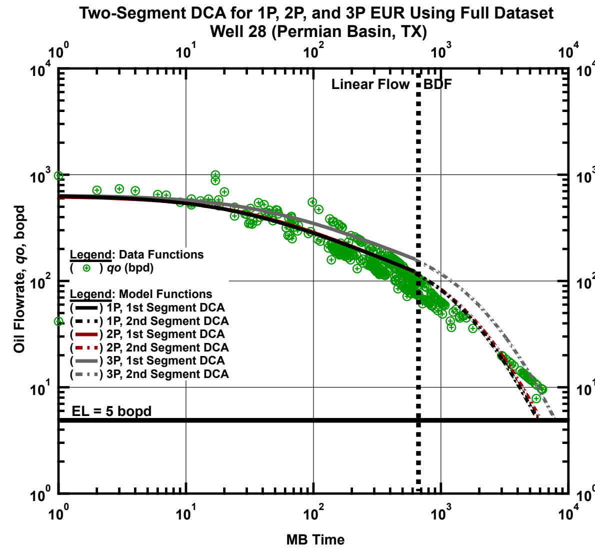

Figure 239 — Two-segment DCA of Well 28 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

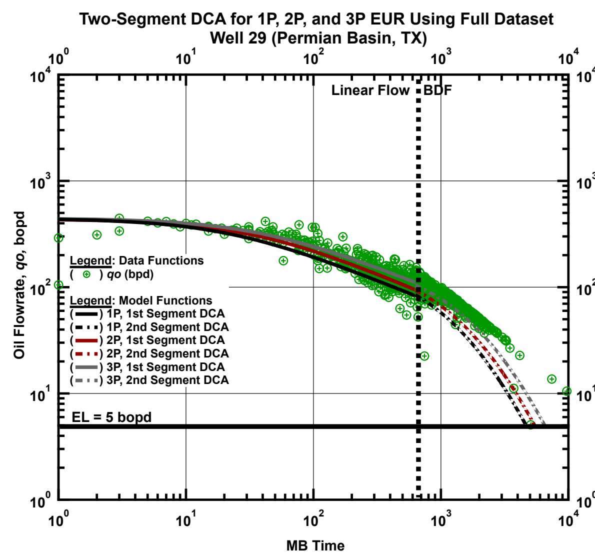

Figure 240 — Two-segment DCA of Well 29 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

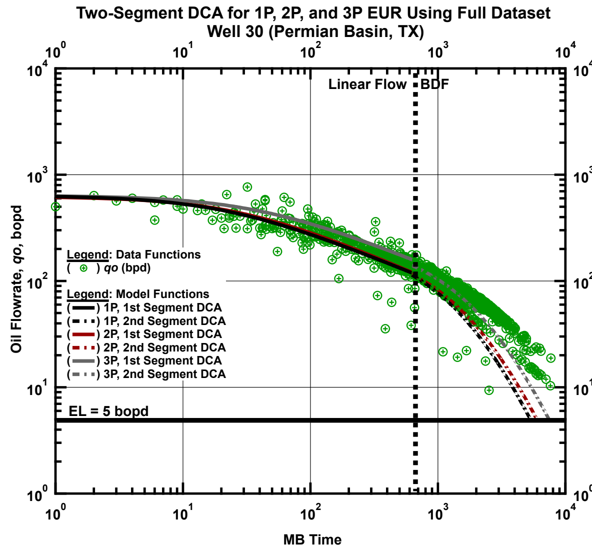

Figure 241 — Two-segment DCA of Well 30 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

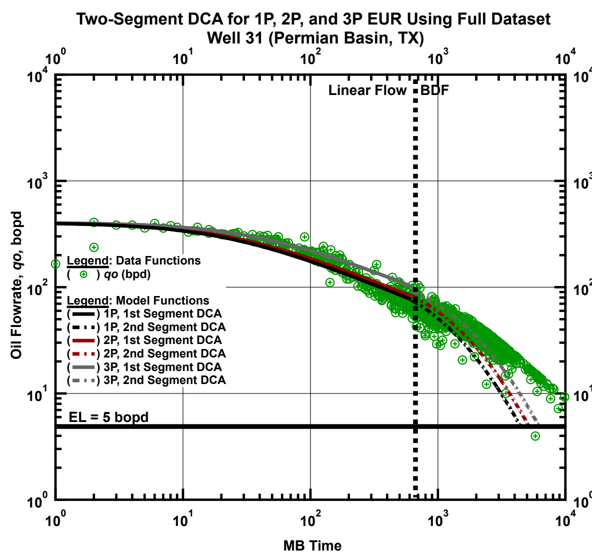

Figure 242 — Two-segment DCA of Well 31 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

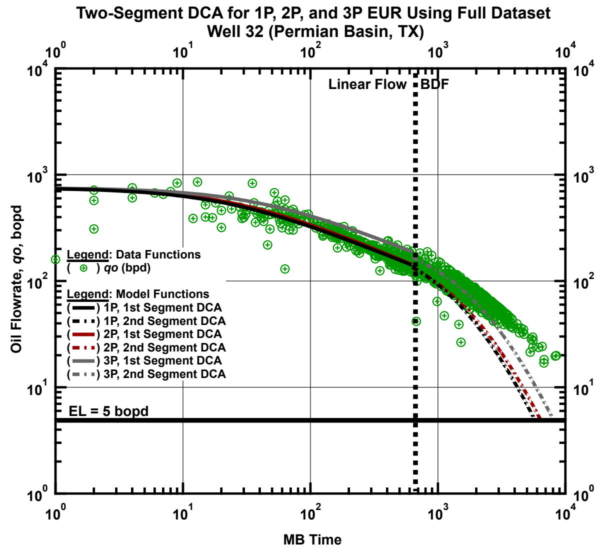

Figure 243 — Two-segment DCA of Well 32 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

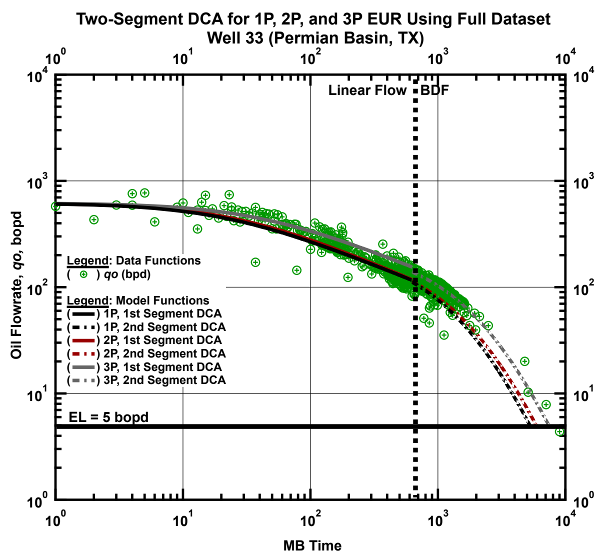

Figure 244 — Two-segment DCA of Well 33 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

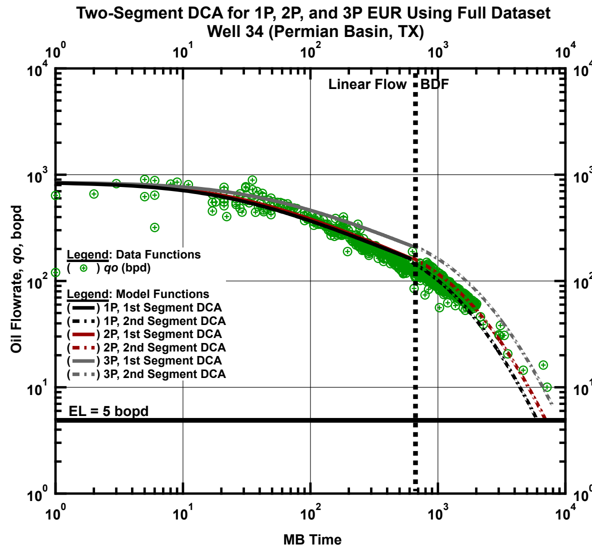

Figure 245 — Two-segment DCA of Well 34 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

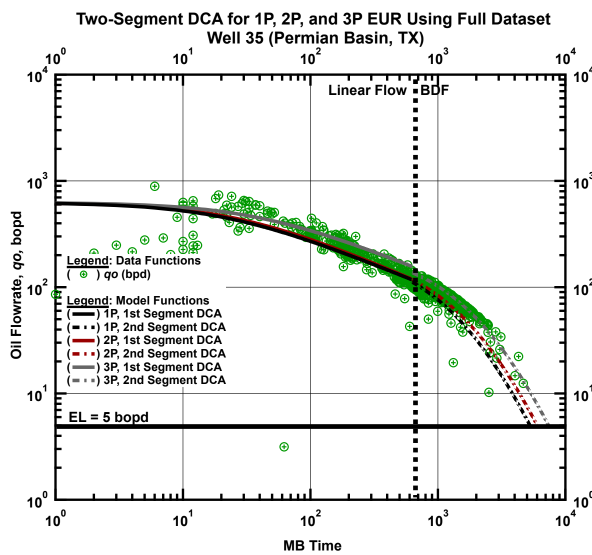

Figure 246 — Two-segment DCA of Well 35 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

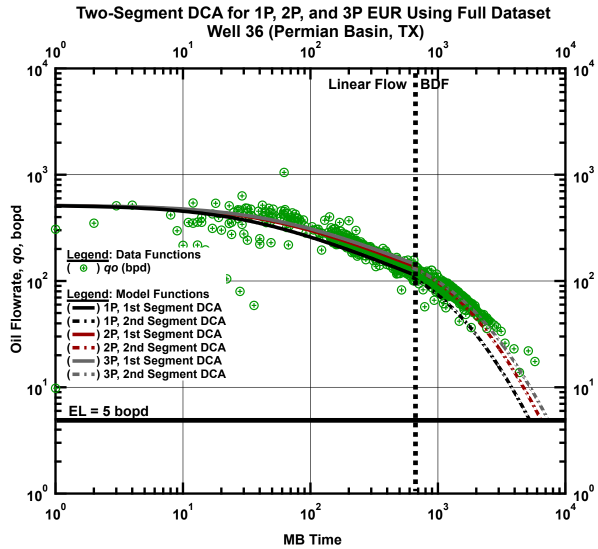

Figure 247 — Two-segment DCA of Well 36 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

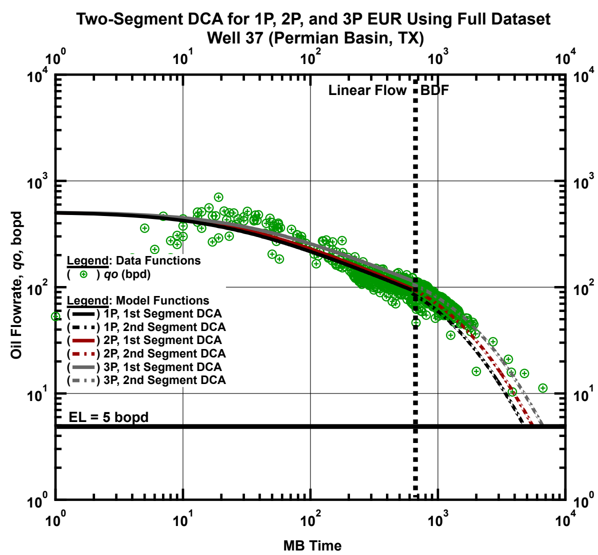

Figure 248 — Two-segment DCA of Well 37 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

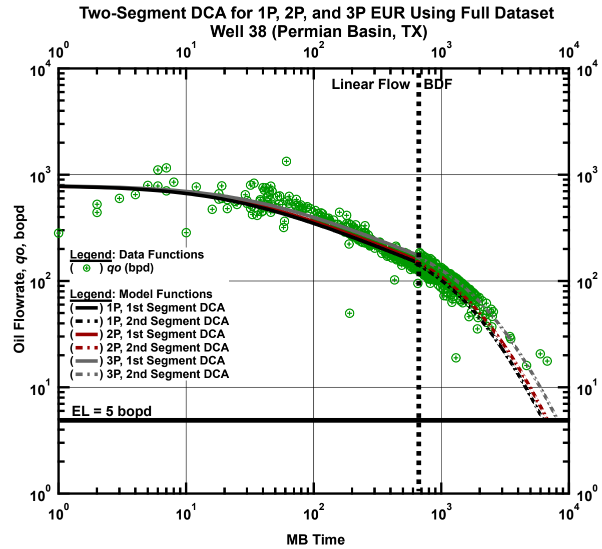

Figure 249 — Two-segment DCA of Well 38 shows the three sets of curves that represent the 1P, 2P, and 3P estimates. The maroon curves are the 2P results, the black curves are the 1P, and the grey curves are the 3P.

APPENDIX L

EUR FIGURES USING THE TRUNCATED DATASET

	TRUNCATED					
Well	EUR (Mbbl)			NORMALIZED EUR (MBBL), 10,000'		
#	1P	2P	3P	1P	2P	3P
1	182.65	226.26	290.81	221.82	274.78	353.18
2	184.53	257.35	278.96	222.62	310.47	336.55
3	207.56	295.43	326.32	252.11	358.84	396.36
4	210.63	249.37	275.01	269.04	318.52	351.27
5	177.61	254.72	305.46	227.54	326.32	391.31
6	226.96	311.35	391.29	290.45	398.45	500.75
7	180.41	229.77	325.50	198.96	253.38	358.96
8	210.50	279.89	372.15	235.09	312.58	415.62
9	87.48	130.70	133.71	97.83	146.17	149.53
10	199.17	375.65	552.11	221.74	418.23	614.68
11	77.59	104.43	150.56	86.62	116.59	168.10
12	191.76	242.48	309.36	213.63	270.14	344.66
13	271.50	321.45	384.86	303.59	359.44	430.34
14	39.00	46.13	58.64	43.82	51.83	65.88
15	416.07	460.75	524.44	394.23	436.56	496.92
16	412.80	482.02	626.25	393.33	459.29	596.72
17	484.05	563.99	705.55	461.35	537.54	672.46
18	463.54	518.45	627.09	484.57	541.97	655.54
19	244.49	370.21	388.38	255.77	387.28	406.29
20	426.80	507.10	606.43	416.84	495.26	592.27
21	355.34	409.03	496.05	346.17	398.47	483.24
22	266.71	343.22	404.99	295.49	380.26	448.70
23	261.36	336.05	366.74	254.81	327.63	357.55
24	194.76	230.50	277.44	189.31	224.05	269.68
25	374.20	473.44	567.99	383.84	485.63	582.62
26	245.35	310.19	376.37	269.43	340.65	413.32
27	237.33	288.78	351.06	249.40	303.47	368.92
28	269.81	275.59	341.50	344.19	351.56	435.64
29	182.31	218.74	267.36	276.35	331.57	405.28
30	258.63	281.58	410.51	335.66	365.45	532.79
31	162.47	189.33	227.15	249.04	290.21	348.17
32	274.68	326.19	403.27	358.55	425.79	526.39
33	255.01	303.61	382.63	242.45	288.65	363.78
34	312.14	343.02	440.06	296.97	326.35	418.67
35	262.13	297.79	367.50	248.96	282.83	349.04
36	259.37	315.09	366.51	249.97	303.67	353.23
37	203.31	237.56	286.62	194.86	227.68	274.70
38	331.19	453.97	505.45	317.87	435.72	485.12

Table 215—Results of the EUR and the normalized EUR to 10,000' using the truncated dataset for the 38 wells.

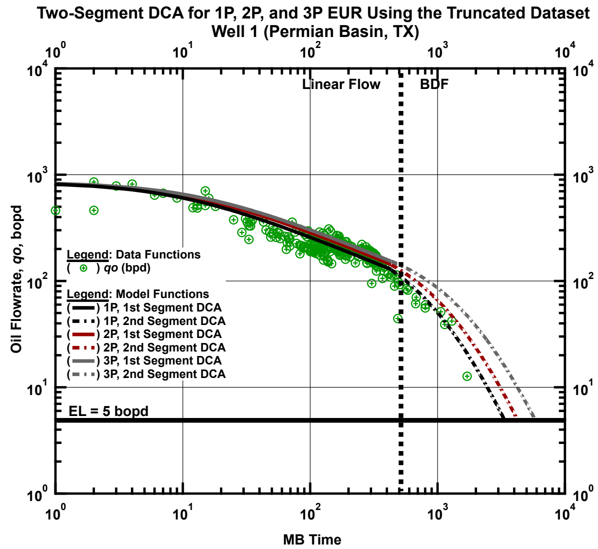

Figure 250 — Two-segment DCA of Well 1 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

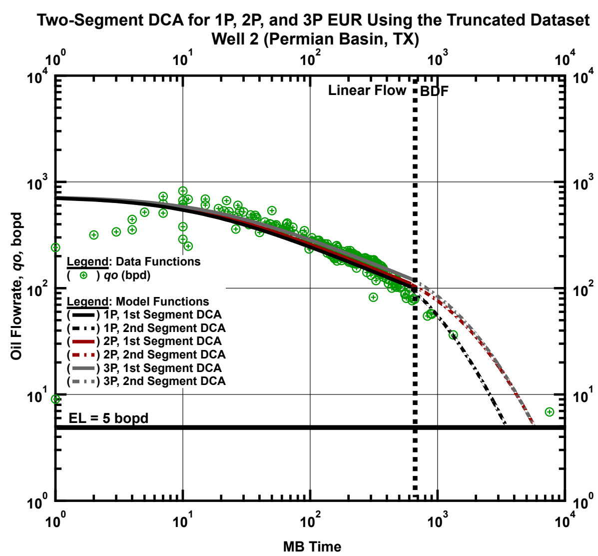

Figure 251 — Two-segment DCA of Well 2 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

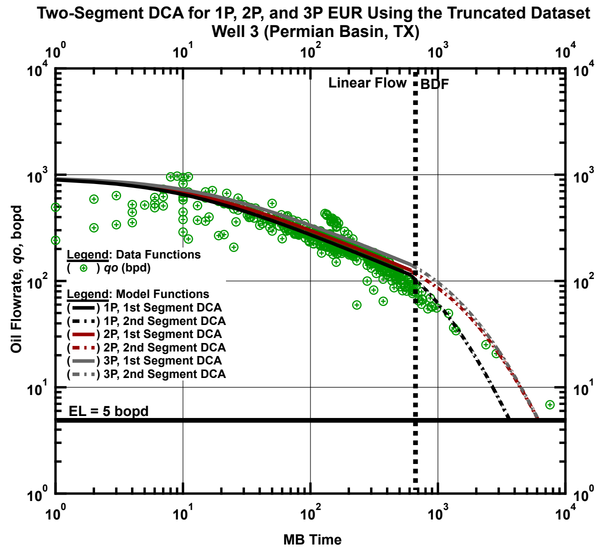

Figure 252 — Two-segment DCA of Well 3 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

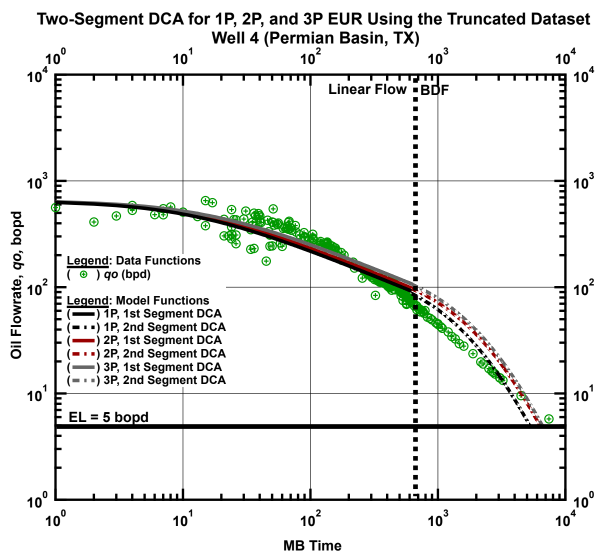

Figure 253 — Two-segment DCA of Well 4 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

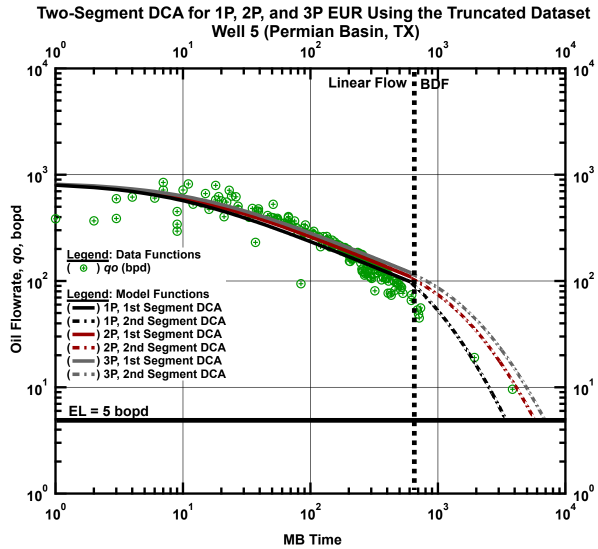

Figure 254 — Two-segment DCA of Well 5 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

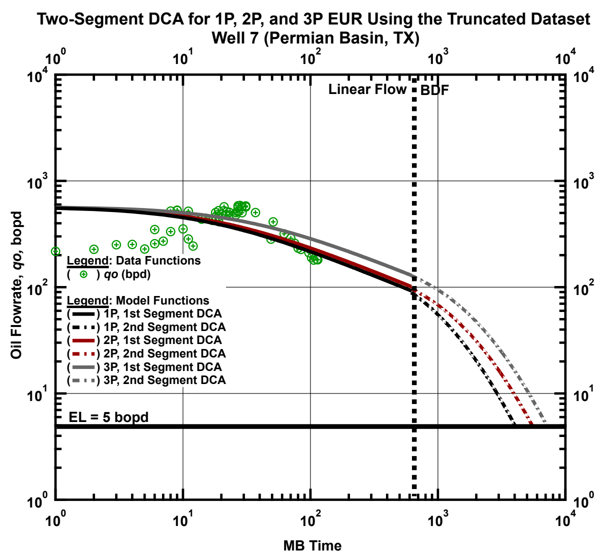

Figure 255 — Two-segment DCA of Well 7 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

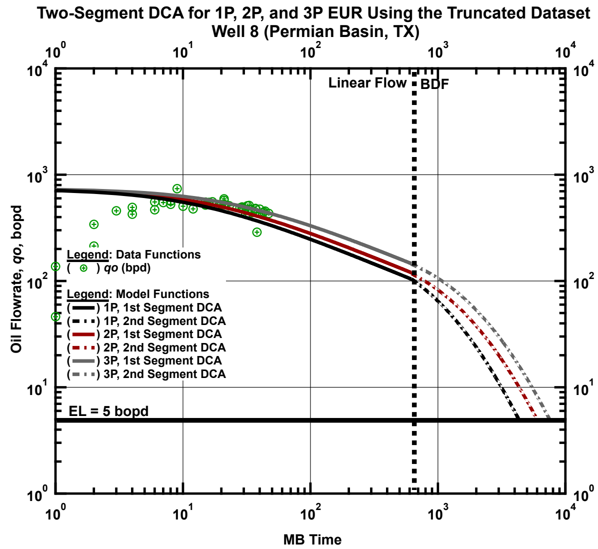

Figure 256 — Two-segment DCA of Well 8 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

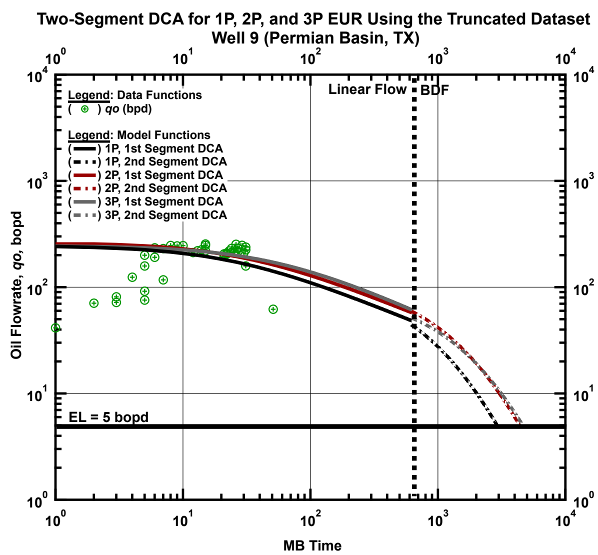

Figure 257 — Two-segment DCA of Well 9 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

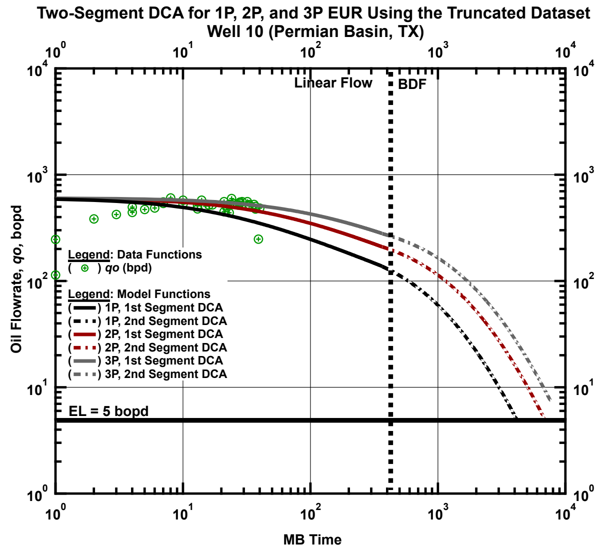

Figure 258 — Two-segment DCA of Well 10 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

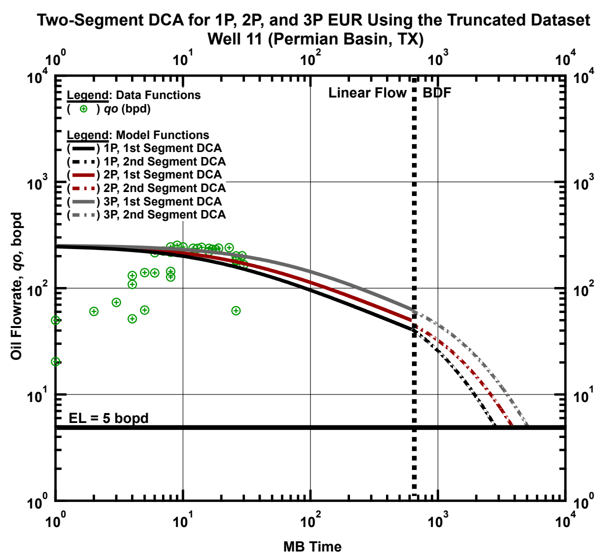

Figure 259 — Two-segment DCA of Well 11 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

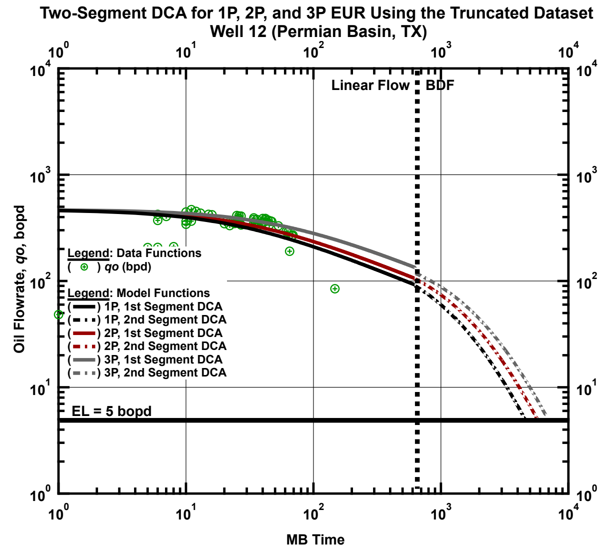

Figure 260 — Two-segment DCA of Well 12 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

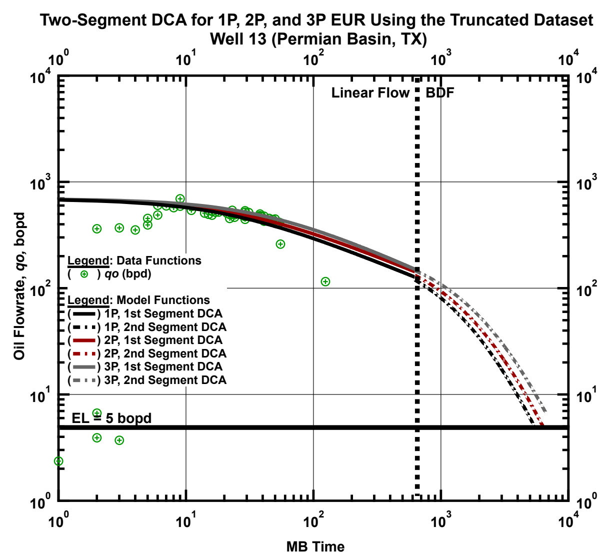

Figure 261 — Two-segment DCA of Well 13 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

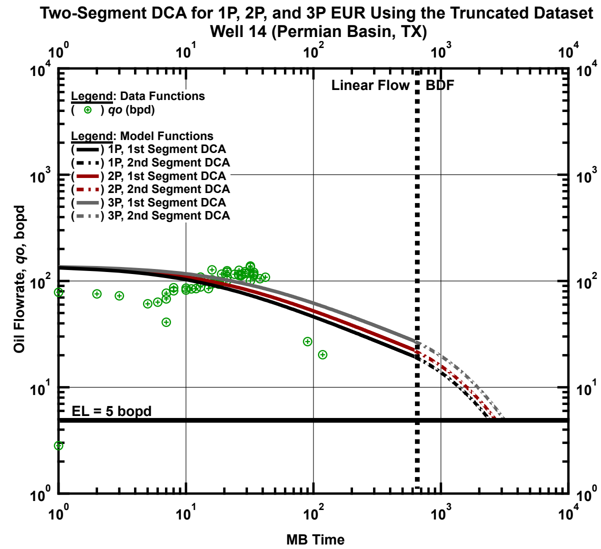

Figure 262 — Two-segment DCA of Well 14 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

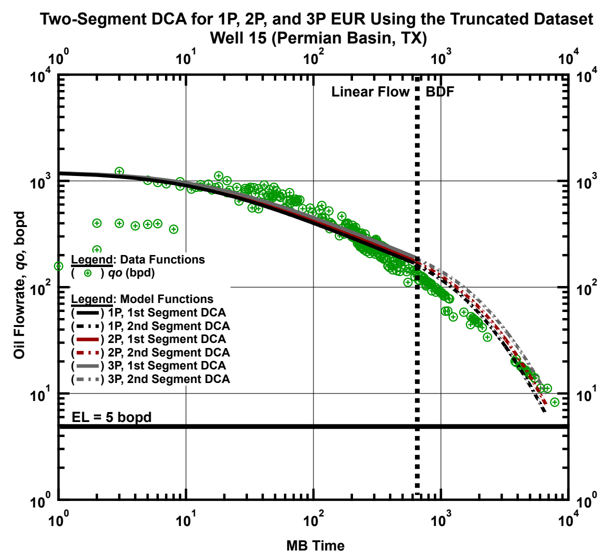

Figure 263 — Two-segment DCA of Well 15 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

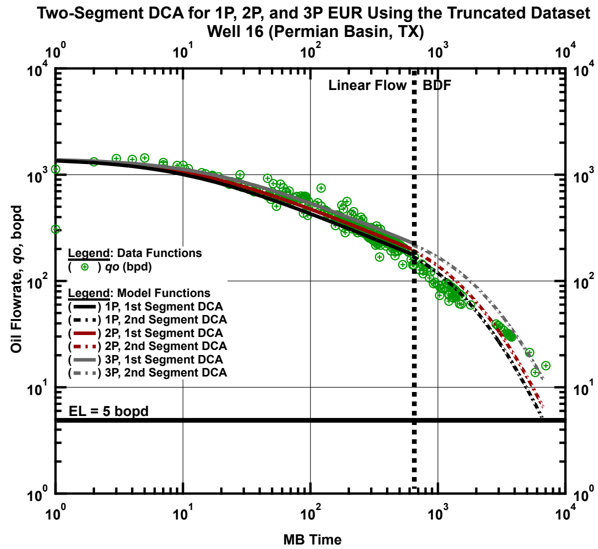

Figure 264 — Two-segment DCA of Well 16 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

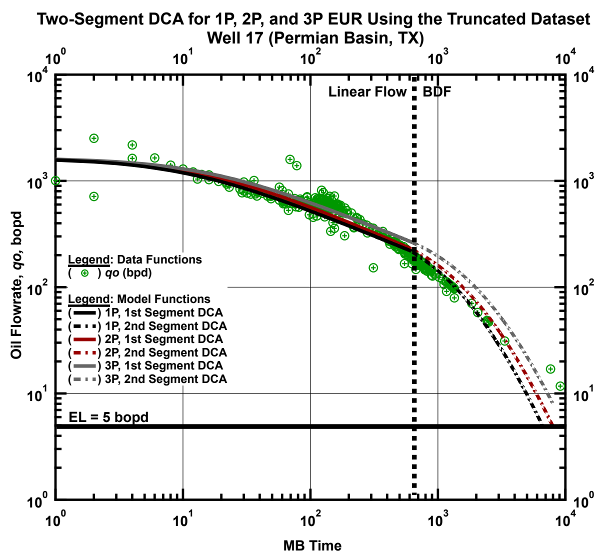

Figure 265 — Two-segment DCA of Well 17 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

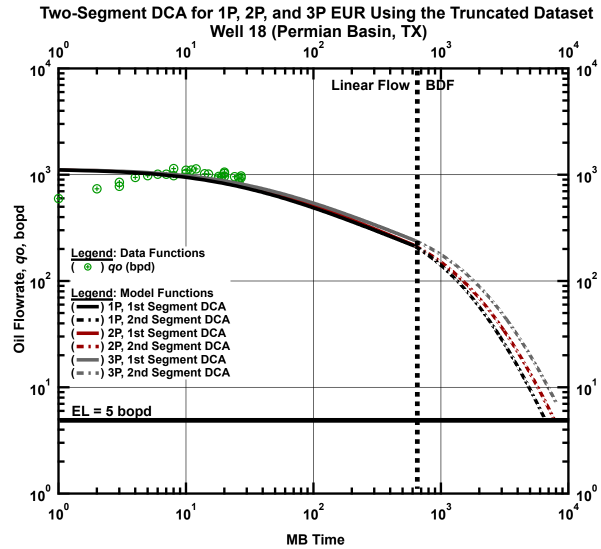

Figure 266 — Two-segment DCA of Well 18 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

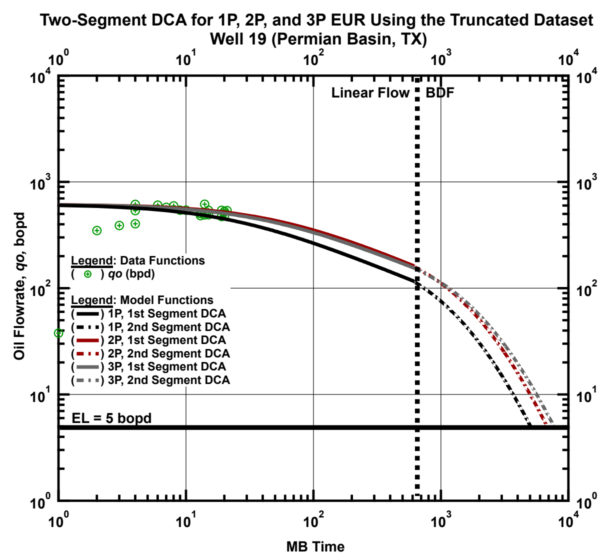

Figure 267 — Two-segment DCA of Well 19 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

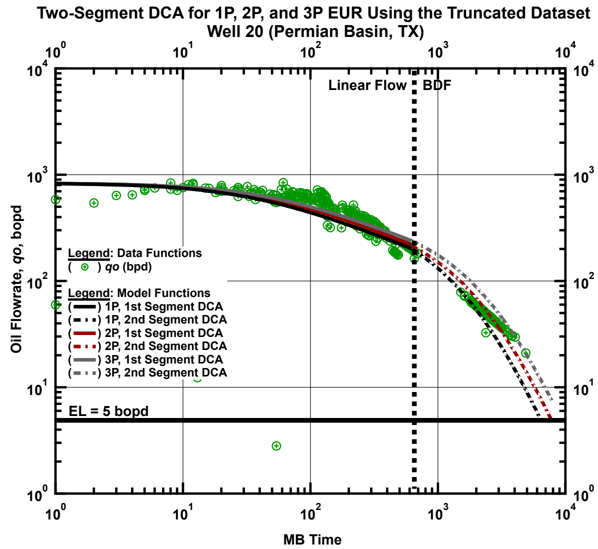

Figure 268 — Two-segment DCA of Well 20 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

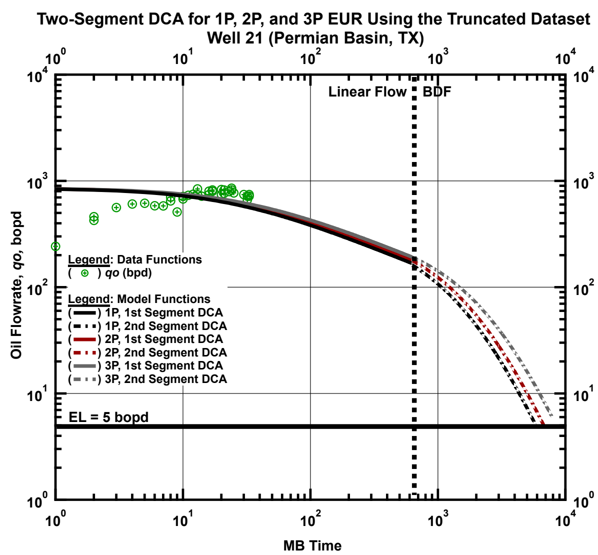

Figure 269 — Two-segment DCA of Well 21 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

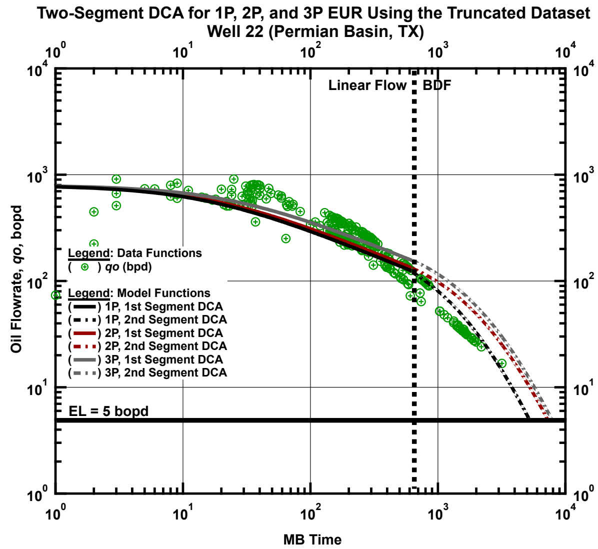

Figure 270 — Two-segment DCA of Well 22 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

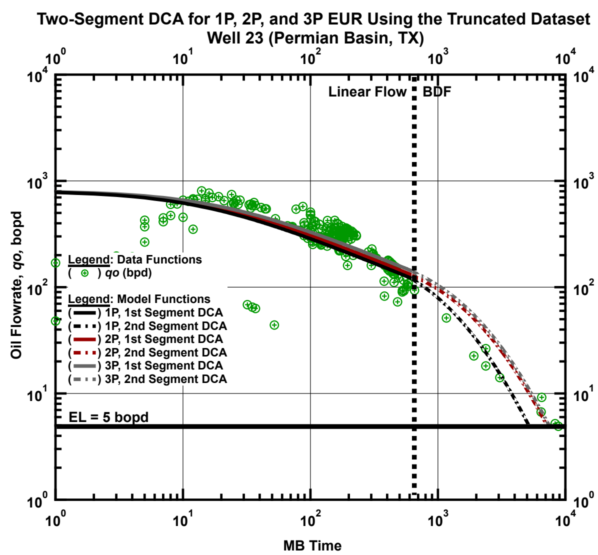

Figure 271 — Two-segment DCA of Well 23 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

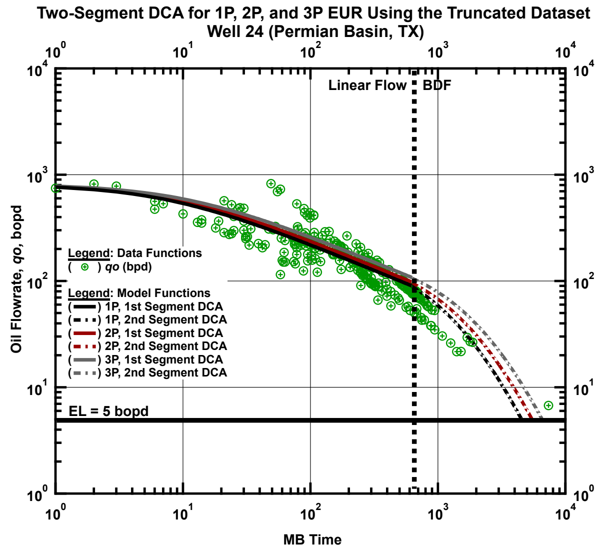

Figure 272 — Two-segment DCA of Well 24 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

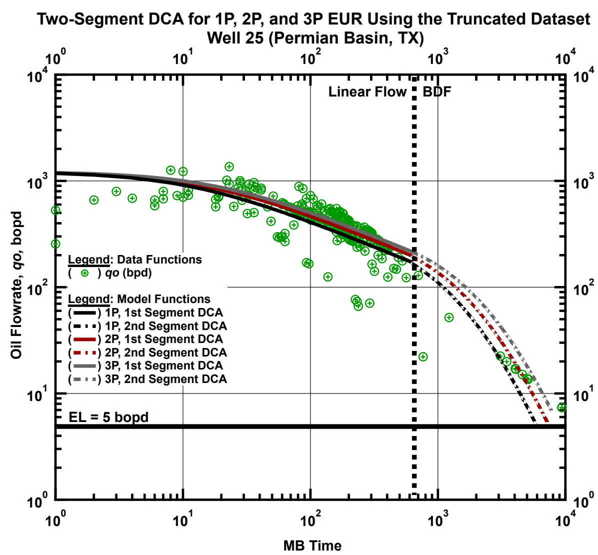

Figure 273 — Two-segment DCA of Well 25 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

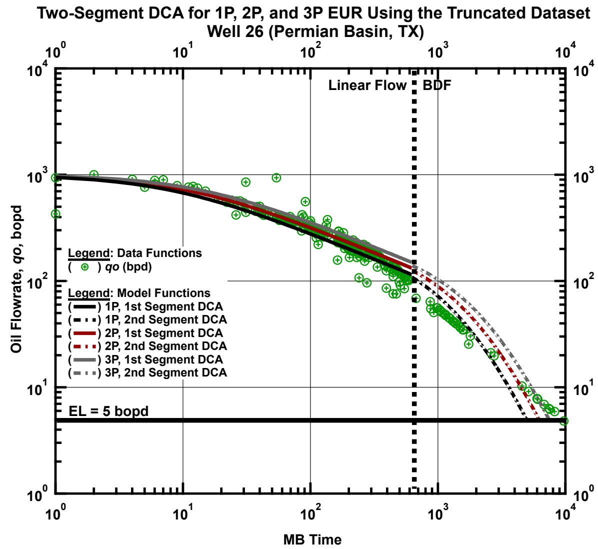

Figure 274 — Two-segment DCA of Well 26 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

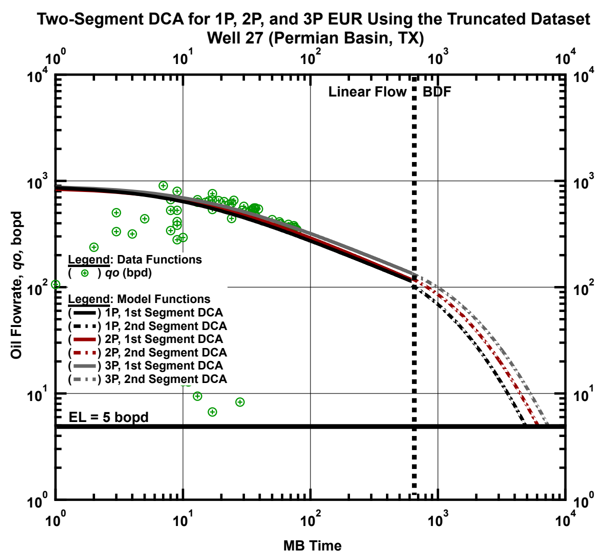

Figure 275 — Two-segment DCA of Well 27 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

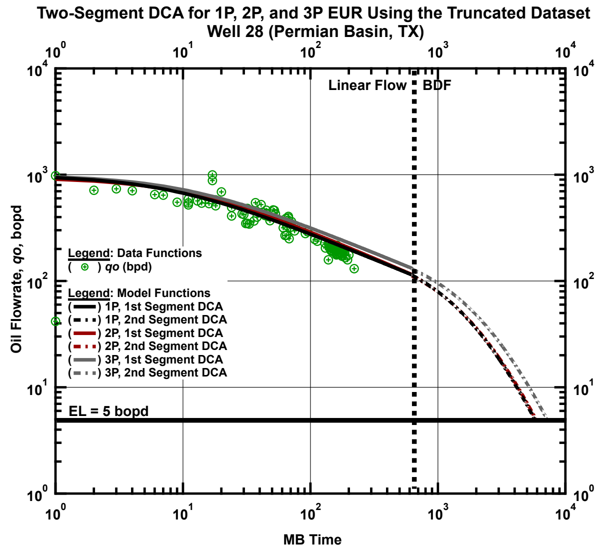

Figure 276 — Two-segment DCA of Well 28 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

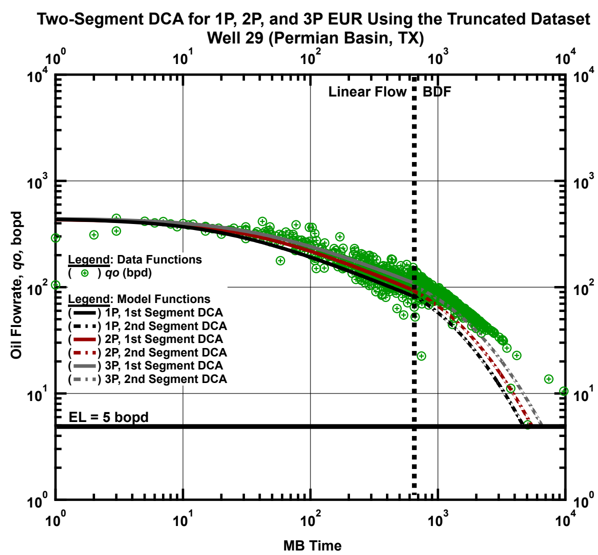

Figure 277 — Two-segment DCA of Well 29 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

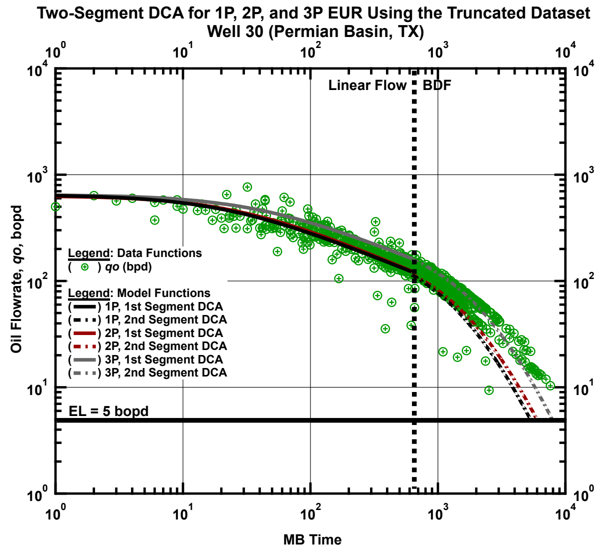

Figure 278 — Two-segment DCA of Well 30 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

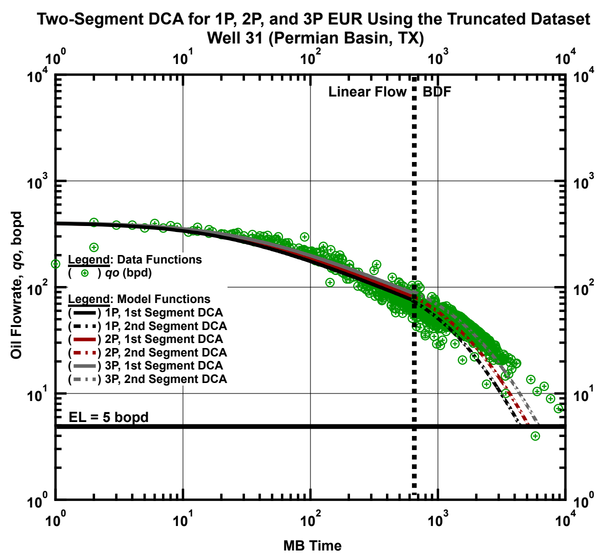

Figure 279 — Two-segment DCA of Well 31 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

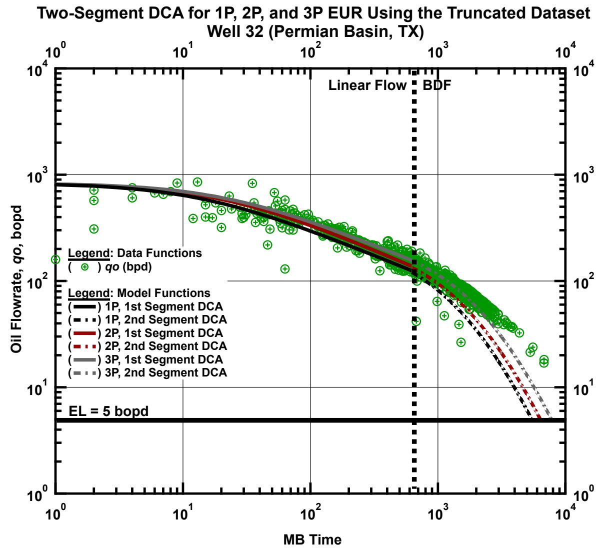

Figure 280 — Two-segment DCA of Well 32 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

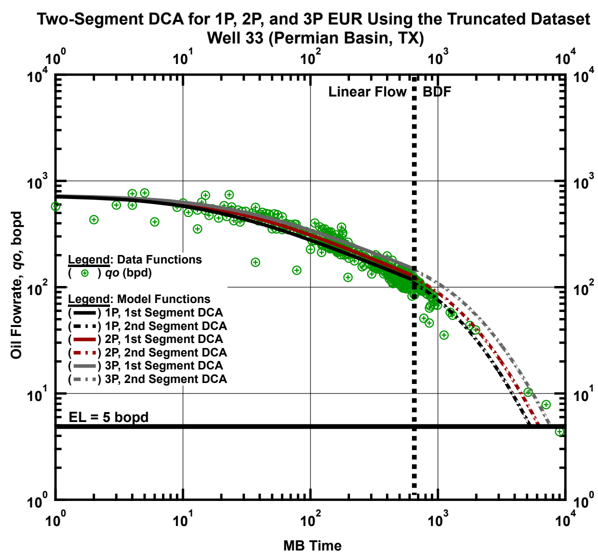

Figure 281 — Two-segment DCA of Well 33 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

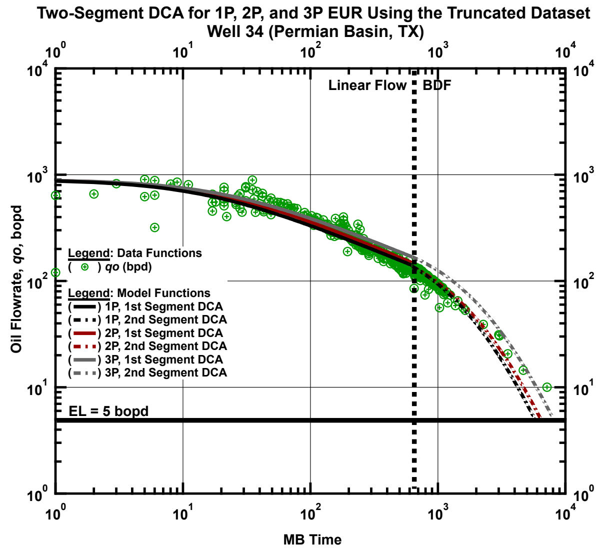

Figure 282 — Two-segment DCA of Well 34 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

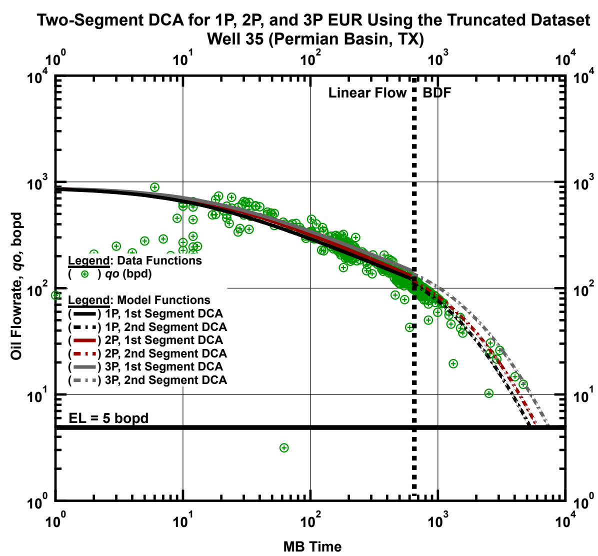

Figure 283 — Two-segment DCA of Well 35 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

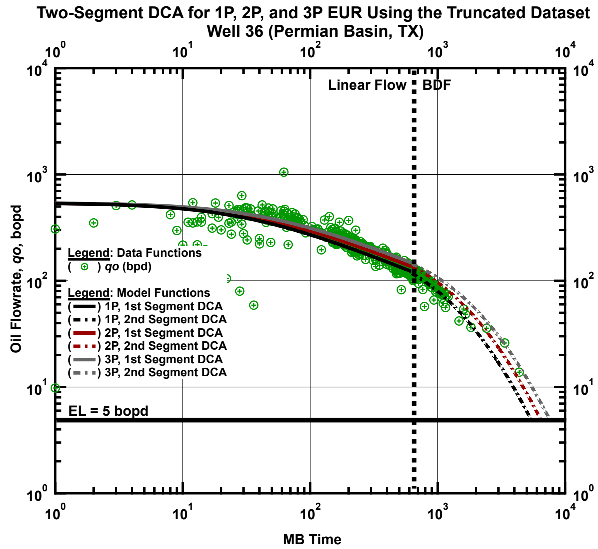

Figure 284 — Two-segment DCA of Well 36 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

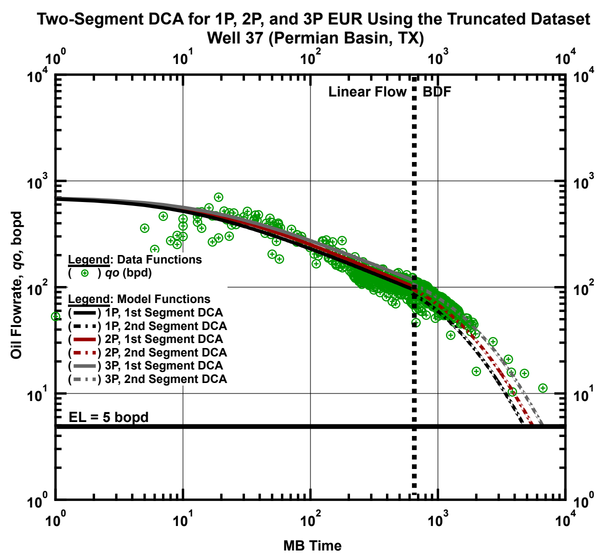

Figure 285 — Two-segment DCA of Well 37 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

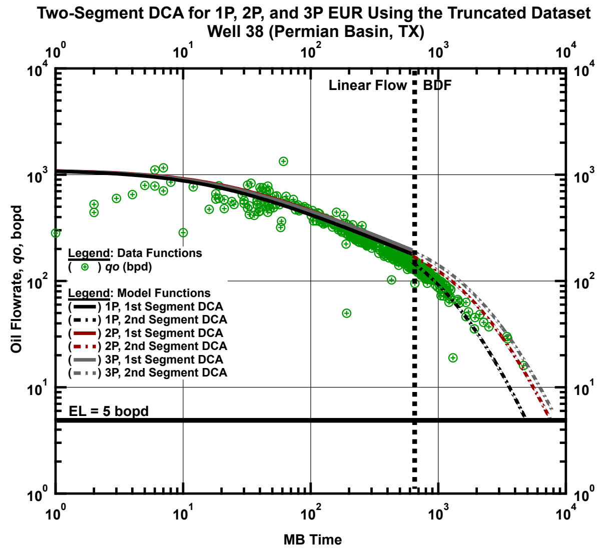

Figure 286 — Two-segment DCA of Well 38 with the truncated data set. The three sets of curves represent the 1P (in black), 2P (in maroon), and 3P (in grey).

APPENDIX M

FULL TO TRUNCATED EUR, RESERVES AS OF AUGUST 2019, AND RESERVES AS OF JULY 2016

We present the results of the full to truncated EUR percentages in **Table 216**, full to truncated Reserves as of August 2019 percentages in **Table 217**, and the full to truncated Reserves as of July 2016 percentages in **Table 218**. We average the 1P, 2P, and 3P EUR and Reserves for the three cases, and use these values to build the model, presented in **Table 219.**

Well	FULL/TRUNCATED EUR		
#	1P	2P	3P
1	92%	94%	94%
2	99%	105%	108%
3	99%	107%	108%
4	122%	132%	124%
5	86%	92%	116%
6	92%	101%	108%
8	138%	116%	115%
9	103%	111%	115%
12	89%	81%	87%
13	99%	98%	100%
15	95%	89%	92%
16	131%	123%	133%
17	95%	90%	90%
18	100%	98%	100%
19	100%	86%	97%
20	76%	82%	86%
21	92%	92%	109%
22	126%	120%	131%
23	102%	94%	113%
24	130%	122%	127%
25	130%	125%	128%
26	115%	101%	99%
28	101%	103%	118%
29	100%	100%	100%
30	99%	99%	91%
31	100%	100%	105%
32	112%	101%	111%
33	98%	90%	96%
34	110%	115%	127%
35	96%	94%	100%
36	94%	101%	95%
37	97%	96%	97%
38	103%	82%	89%

Table 216—Full vs. truncated percentages for the 1P, 2P, and 3P EUR results.

Well	FULL/TRUNCATED RESERVES AUG 2019		
#	1P	2P	3P
1	77%	87%	89%
2	96%	109%	113%
3	97%	114%	115%
4	172%	176%	150%
5	65%	86%	125%
6	79%	102%	112%
8	842%	154%	133%
9	35%	138%	149%
12	13%	38%	71%
13	82%	91%	101%
15	92%	83%	89%
16	152%	136%	145%
17	91%	83%	85%
18	99%	95%	101%
19	96%	67%	94%
20	33%	60%	75%
21	48%	68%	123%
22	146%	112%	143%
23	103%	92%	118%
24	190%	151%	150%
25	158%	140%	141%
26	136%	103%	99%
28	152%	155%	179%
29	100%	100%	100%
30	95%	96%	82%
31	100%	100%	110%
32	164%	102%	125%
33	95%	78%	94%
34	125%	132%	146%
35	92%	89%	100%
36	90%	101%	93%
37	93%	92%	96%
38	709%	34%	68%

Table 217—Full vs. truncated percentages for the 1P, 2P, and 3P Reserves as of August 2019 results.

Well	FULL/TRUNCATED RESERVES JULY 2016		
#	1P	2P	3P
1	83%	89%	91%
2	97%	108%	112%
3	98%	111%	112%
4	135%	146%	133%
5	76%	88%	122%
6	82%	101%	110%
8	175%	125%	121%
9	107%	118%	124%
12	84%	74%	83%
13	99%	98%	100%
15	93%	86%	90%
16	146%	133%	142%
17	93%	87%	87%
18	100%	98%	100%
19	99%	80%	96%
20	66%	76%	83%
21	89%	88%	112%
22	147%	181%	143%
23	103%	92%	117%
24	147%	132%	136%
25	149%	136%	137%
26	123%	102%	99%
28	102%	104%	123%
29	100%	100%	100%
30	98%	98%	88%
31	100%	100%	106%
32	120%	101%	115%
33	97%	85%	95%
34	116%	122%	136%
35	94%	91%	100%
36	90%	101%	93%
37	95%	94%	96%
38	105%	75%	85%

Table 218—Full vs. truncated percentages for the 1P, 2P, and 3P Reserves as of July 2016 results.

Well	FULL/TRUNCATED AVERAGES		
#	1P	2P	3P
1	84%	90%	91%
2	97%	107%	111%
3	98%	111%	112%
4	143%	151%	135%
5	76%	89%	121%
6	84%	101%	110%
8	385%	132%	123%
9	82%	122%	129%
12	62%	64%	80%
13	93%	96%	100%
15	94%	86%	91%
16	143%	131%	140%
17	93%	87%	87%
18	99%	97%	100%
19	98%	78%	96%
20	59%	73%	82%
21	76%	83%	115%
22	140%	137%	139%
23	102%	93%	116%
24	156%	135%	138%
25	146%	134%	135%
26	125%	102%	99%
28	118%	120%	140%
29	100%	100%	100%
30	97%	98%	87%
31	100%	100%	107%
32	132%	101%	117%
33	97%	84%	95%
34	117%	123%	136%
35	94%	92%	100%
36	91%	101%	94%
37	95%	94%	96%
38	306%	64%	81%

Table 219—Averages of the full vs. truncated percentages for the 1P, 2P, and 3P EUR, Reserves as of August 2019, and Reserves as of July 2016.