PROBABILISTIC RESERVES AND RESOURCES ESTIMATION OF THE WEST VIRGINIA MARCELLUS SHALE PLAY USING THE MCMC PDCA METHOD

A Thesis

by

REZA ALFAJRI

Submitted to the Office of Graduate and Professional Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

Chair of Committee,	Duane A. McVay
Committee Members,	George W. Voneiff
	Thomas E. Wehrly
Head of Department,	A. Daniel Hill

December 2015

Major Subject: Petroleum Engineering

ABSTRACT

The Marcellus shale is currently the most productive shale play in the United States. In 2015, the Marcellus shale play led in natural gas production per rig and had the highest shale gas production in the United States. Several reports and articles have been published on Marcellus shale play reserves/resources estimates. Some of these estimates were deterministic, while some were probabilistic. These published estimates are all now outdated. Updated probabilistic reserves and resources estimates for the Marcellus shale play are needed. The Marcellus shale play covers six states with the two most productive states being Pennsylvania (PA) and West Virginia (WV). Between these two states, only WV has monthly production data in its production reports; PA production is reported semi-annually.

The Markov Chain Monte Carlo (MCMC) method has been successfully used to quantify uncertainty in production forecasts and estimated ultimate recovery (EUR) for the Barnett shale and Eagle Ford shale. There are 20 shale plays that have been discovered in United States. Confirmation of the reliability of the MCMC method using other shale play data is still needed. The objectives of this work are to generate probabilistic reserves and resources estimates for the WV Marcellus shale play and to confirm the reliability of the MCMC method in quantifying uncertainty in production forecasts using production data from the WV Marcellus shale play.

Based on geology and initial gas-liquid-ratio (GLR) analysis, the WV Marcellus shale play was divided into liquid-rich and dry-gas regions. A hindcast study was

performed to confirm the reliability of the MCMC method in forecasting production and estimating reserves in the WV Marcellus shale play. Type probabilistic decline curves were then generated to forecast Technically Recoverable Resources (TRR) at 20 years (TRR20) for the wells in both the liquid-rich and dry-gas regions. Reserves and resources for the WV Marcellus shale play were estimated by performing Monte Carlo simulation. Based on the WV Marcellus shale play analysis, reserves and resources estimates for PA, Ohio (OH), and entire Marcellus shale play are then extrapolated.

Hindcast study results show that the MCMC Probabilistic Decline Curve Analysis (PDCA) method is able to reliably quantify uncertainty in production forecasts and reserves estimates in the WV Marcellus shale play. The total WV NGL reserves and resources range from a P10 of 0.12 billion barrels NGL (BBNGL) to a P90 of 0.58 BBNGL, with a P50 of 0.23 BBNGL. The total WV gas reserves and resources range from a P10 of 81.54 trillion cubic feet (TCF) to a P90 of 283.81 TCF, with a P50 of 145.091 TCF. These estimates are generally much higher than most of the previously published estimates.

DEDICATION

Alhamdulillah, praise only be to the one and only God, Allah swt.

This thesis is dedicated to my beloved wife who always stays by my side throughout this new journey that we embark together, to my mother who always loves me unconditionally and prays for me, my late father whom I hope I can make proud of, and all of my family for all the love, support, and patience that they give to me.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. McVay for his supervision, guidance, support, and patience during this research and my committee members, Dr. Voneiff for his helps, advices, guidance, and suggestions in this research, and Dr. Wehrly, for his guidance and support throughout the course of this research.

I would like to thank Harold Vance Department of Petroleum Engineering at Texas A&M University for giving me the opportunity to pursue a Master's degree. My gratitude towards PT. Pertamina, my company where I work for in Indonesia, for this huge sponsorship opportunity to make it possible for me to study and go after a graduate's degree in the United States.

My thanks also to my friends and colleagues in Dr. McVay's group and the department faculties and staffs for making my time at Texas A&M University a great experience.

Finally, thanks to my mother, my late father, and my family for their encouragement, prays and support for me. Special thanks and love to my wife for her patience, love, and care during our time together far away from home.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHAPTER I

INTRODUCTION

1.1. Shale Gas Play

The concept of the resource triangle states that all natural resources have a log-normal distribution in nature (Holditch 2006). The limited quantities of gas in conventional, high-permeability reservoirs are shown at the top of the triangle (**Fig. 1**). These resources are the best or the highest-grade deposits. They are small in size but once found, they are relatively easy to extract. Going deeper into the gas-resource triangle, reservoir quality will decrease, which means lower permeability. These low-permeability unconventional gas reservoirs are larger in size and easier to find than the conventional ones. However, the unconventional resources require improved technology and more economical gas prices than the conventional resources. Shale gas is one of the unconventional resources.

The advance of horizontal drilling as well as hydraulic fracturing has greatly increased the ability of producers to profitably recover natural oil and gas from low-permeability reservoirs, particularly shale plays. Shale gas dawned in the United States when Mitchell Energy and Development Corporation experimented with producing deep shale gas in the Barnett shale play located in North-Central Texas. As Mitchell Energy and Development Corporation gained success in its effort, other companies aggressively started working in the Barnett shale play. With the success of the shale gas production in the Barnett shale, companies started to pursue other shale plays including Haynesville, Marcellus, Eagle Ford, and others.

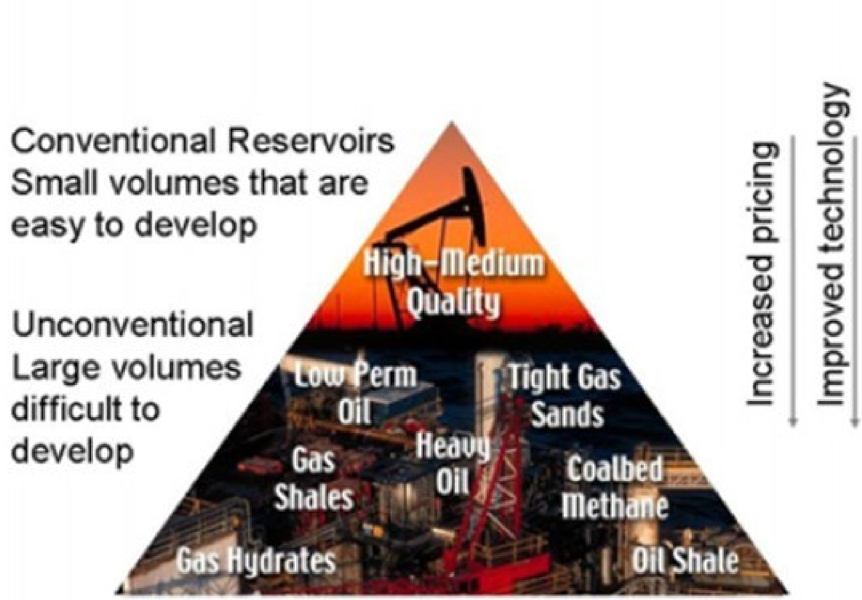

Fig. 1—Resource triangle for natural gas (Holditch and Ayers 2009).

The Energy Information Administration (EIA) (2011) recorded that the proliferation of activities in new shale plays has increased dry shale gas production in the United States from 1.0 TCF in 2006 to 4.8 TCF in 2010, or 23 percent of total U.S. dry natural gas production. Wet-gas reserves in shale plays increased to about 60.64 TCF by year-end 2009 when they comprised about 21 percent of overall U.S. natural gas reserves, now at the highest level since 1971. These data show that gas production from shale plays has grown rapidly in the past few years. **Fig. 2** shows that current and projected shale gas production in the United States is leading the growth in total gas production.

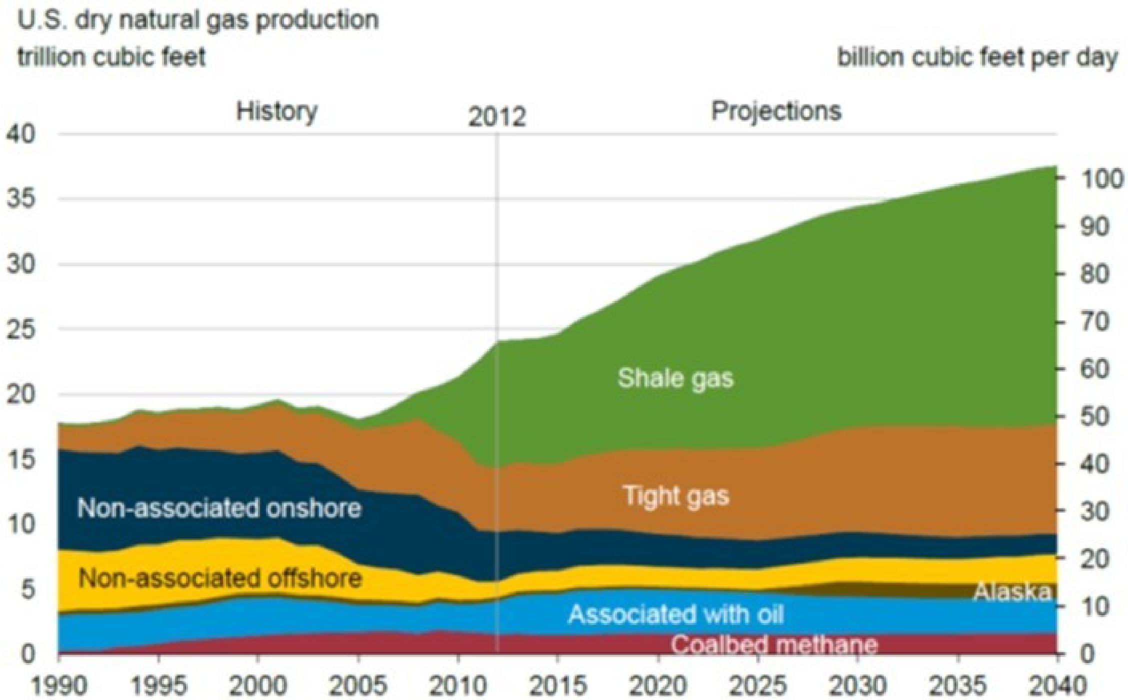

Fig. 2—Current and projected shale gas production lead growth in total gas production in the United States (EIA 2014a).

Gonzalez *et al*. (2012) explained in their paper that there is considerable uncertainty in production forecasting and reserves estimation for hydraulically fractured horizontal gas wells. Major sources of this uncertainty are complex flow geometry, large variability in reservoir and completion properties from well to well, and a lack of long-term production data. Complex flow geometry is caused by low matrix permeability, natural fractures, and desorption dynamics of adsorbed gas in the reservoir. Low matrix permeability requires the reservoir to be hydraulically fractured to become economical. Natural fractures affect hydraulic fracture geometry and reservoir depletion. Since shale gas production has proliferated in only the past few years, there are no long-term production data available. Production data of shale gas horizontal wells with multiple hydraulic fractures are only available for a few years.

1.2. Probabilistic Decline Curve Analysis (PDCA)

Because of their extremely low permeability, shale gas plays require a very long time to experience Boundary-Dominated Flow (BDF). Gonzalez *et al*. (2012) stated that only a small number of hydraulically fractured horizontal shale gas wells have experienced BDF. Decline Curve Analysis (DCA) is one of the most common techniques used for estimating reserves. Arps' DCA model, introduced in 1945, is the most common DCA model used in estimating EUR for oil and gas wells. Lee and Sidle (2010) pointed out that one of the assumptions in Arps' DCA is that the analyzed well has to have stabilized (boundary-dominated) flow. Horizontal shale gas wells usually do not meet this requirement. However, despite this lack of BDF, Lee and Sidle (2010) suggested using Arps' DCA combined with a minimum decline rate (D_{min}) to force exponential decline for the remaining life of the well. There are also several DCA methods that are developed to work specifically in shale gas reservoirs. Some of these methods are power-law exponential DCA (Ilk *et al*. 2008), Stretched Exponential Production Decline (SEPD) DCA (Valko and Lee 2010), and rate-decline analysis for fracture-dominated shale reservoirs (Duong 2011).

Besides having to deal with the common absence of BDF for horizontal shale gas wells, there is a large uncertainty associated with shale gas production forecasting and reserves estimation. A robust and reliable way to quantify this uncertainty is needed.

McVay and Dossary (2014) emphasized the value assessing uncertainty, and reliably quantifying uncertainty reduces or eliminates expected disappointment and expected decision error. Capen (1976) stated that uncertainty is often underestimated and pointed out that probabilistic analysis can make our estimates better. Combining probabilistic analysis with DCA, i.e. PDCA, provides a way to estimate reserves probabilistically, in which uncertainty is reliably quantified.

Several PDCA methods have been proposed for production forecasting and reserves estimation. Jochen and Spivey (1996) proposed the bootstrap method, which generates PDCA production forecasts and reserves estimates based on production data history. Cheng *et al*. (2010) pointed out a couple of weaknesses with the bootstrap method. This method assumes that production data are Independent and Identically Distributed (IID), while in reality production data are not independent but are a sequence of observations arising in succession with an overall decline trend. If production data points are IID, then there will be a possibility of meaningless inclined bootstrap realizations. Furthermore, the bootstrap method performs sampling with replacement for bootstrap realizations, causing some points to be duplicated and some omitted. This procedure does not abide with the rules of IID data.

Cheng *et al*. (2010) proposed the Modified Bootstrap Method (MBM) that uses a more rigorous model-based bootstrap algorithm to preserve data structure. The MBM uses a decline model (hyperbolic or exponential) to fit the production data and constructs residuals from the fitted model and the observed production data. New bootstrap realizations are then generated by incorporating random samples from the residuals into the fitted model. The weakness of this MBM is that it takes considerable time to generate probabilistic reserves forecasts (Gong *et al*. 2011).

Gong *et al*. (2011) then introduced the MCMC method, which is based on Arps' (1945) decline curve model, Bayes' theorem, and the MCMC sampling algorithm. The method was tested using 167 horizontal Barnett shale gas wells and the result was compared to the results when using the MBM. Gong *et al*. (2011) concluded that the MCMC method is better and faster than the MBM.

Gonzalez *et al*. (2012) then applied the MCMC method to six DCA models including Arps' (1945) DCA model. Three of these models are based on Arps' DCA model: Arps', Arps' with a minimum decline of 5%, and the modified Arps'. The three other methods are power-law model (Ilk *et al*. 2008), stretched exponential model (Valko and Lee 2010), and Duong's rate-decline analysis for fracture-dominated shale gas reservoirs (Duong 2011). The MCMC method was tested with 197 horizontal Barnett shale gas wells using hindcast. In a hindcast study, a user-defined portion of the known history data are used as input to the model (i.e., is matched) and the remainder of the known history data are considered to be "future" production and are compared to the model prediction to the same point in time (i.e., hindcast) (Gonzalez *et al*. 2012). The result showed that the combination of the MCMC method with the six DCA models still reliably quantified the uncertainty in production hindcast for shale gas wells in the Barnett shale.

Gong *et al*. (2013) then used the MCMC method to perform an assessment of the Eagle Ford shale oil and gas resources and compared the results with EIA (2011) Eagle

Ford shale estimates. Gong *et al*. (2013) divided the Eagle Ford shale play into eight production regions based on fluid type, performance indicators, and geology. The MCMC method was then used to generate type probabilistic decline curves for each production region. Probabilistic reserves and resources evaluation of the play was performed by considering well spacing, discovered and undiscovered areas, and well count. While Gong *et al*. (2013) reserves and resources estimates were probabilistic (incorporated uncertainty), EIA (2011) estimates were deterministic (no uncertainty quantification). Comparison between these two estimates showed that the P50 total reserves and resources of Gong *et al*. (2013) are much higher than the EIA (2011) resources estimate.

There are 20 shale plays that have been discovered in United States (EIA 2011). The MCMC method has only been tested for two shale plays in the United States: the Barnett shale and the Eagle Ford shale. Further tests should be performed to confirm that MCMC can reliably quantify uncertainty in reserves estimation for other shale plays.

1.3. Reserves and Resources Definitions

Reserves and resources framework was described in the Petroleum Resources Management System (PRMS), published by SPE *et al*. (2007) (**Fig. 3**).

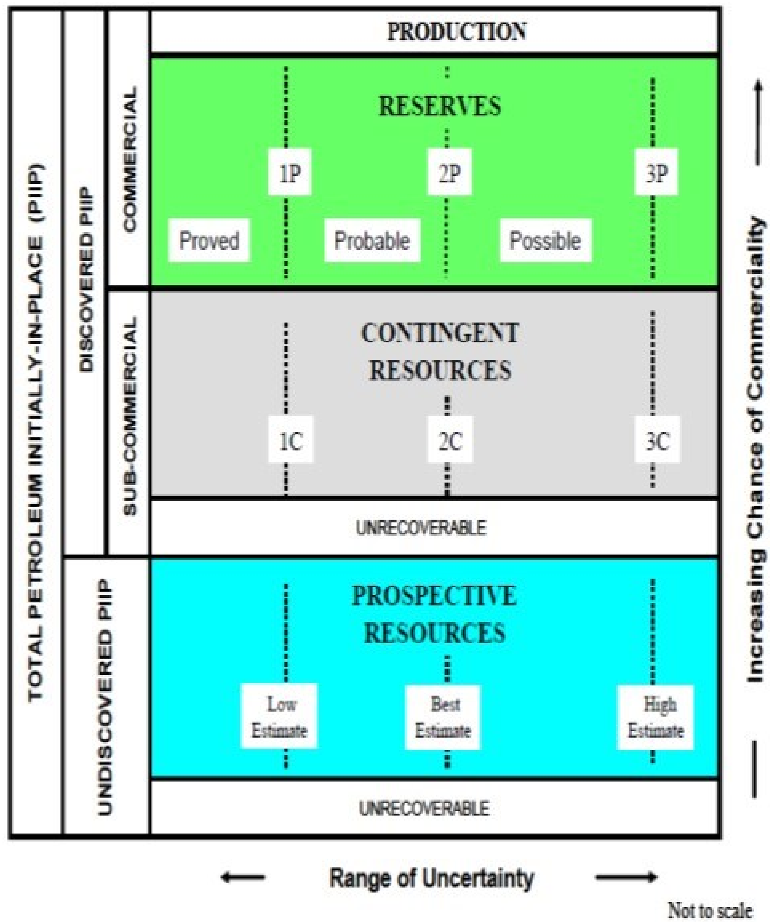

Fig. 3—PRMS resources classification framework (SPE *et al*. 2007).

SPE *et al*. (2007) also explained the definitions of reserves, contingent resources, and prospective resources:

- **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied.

- **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.
- **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development.

1.4. Marcellus Shale Play

1.4.1. Play Description

Marcellus shale play is located in the Appalachian Basin across the eastern part of the United States, and is Devonian in age. EIA (2011) reported the states that contain Marcellus shale are shown in **Table 1**.

Table 1—State distributions of the Marcellus shale play (EIA 2011).

State	Areal % of Marcellus
Maryland (MD)	1.09
New York (NY)	20.06
Ohio (OH)	18.19
Pennsylvania (PA)	35.35
Virginia (VA)	3.85
West Virginia (WV)	21.33

EIA (2011) reported that the Marcellus shale play has a total area of 95,000 square miles. It consists of 10,622 square miles of active area and 84,271 square miles of undiscovered area. The basis of this division is the area of the play under lease by companies and the area that has not been leased. The depth of the shale ranges between 4,000 and 8,500 feet, with thickness between 50 to 200 feet.

The majority of hydrocarbon production from the Marcellus shale is gas—liquid-rich and dry-gas. Wrightstone (2011) published a thermal maturity map that also shows the liquid-rich (wet) gas, dry-gas, and problematic (very high maturity) area of the play **(Fig. 4).**

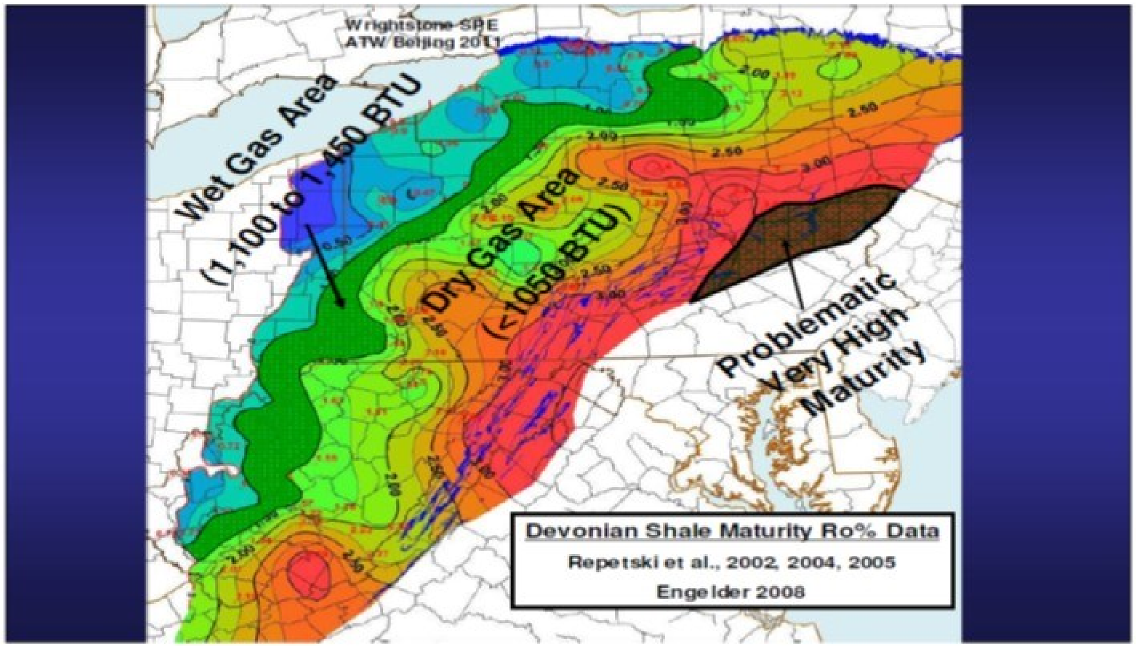

Fig. 4—The Marcellus shale play thermal maturity map that also shows the liquid-rich (wet) gas, dry-gas, and problematic (very high maturity area) of the play (Wrightstone 2011).

EIA (2014a) reported that the Marcellus shale play is leading US dry shale gas production (**Fig. 5**). EIA (2015), through its Drilling Productivity Report (DPR), reported that the Marcellus shale play led in natural gas production per rig in April 2014 and April 2015 (**Fig. 6**). The new-well gas production per rig shown in Fig. 6 is the total production from new wells in each region divided by the region's monthly rig count. EIA (2015) also reported that Marcellus shale play had the highest shale gas production in the U.S. on April 2014 and April 2015 (**Fig. 7**). EIA (2015) also showed that natural gas production of the Marcellus shale play has increased since 2007 and continues to increase (**Fig. 8**). These data show that the Marcellus shale play is currently the most productive shale in the Unites States.

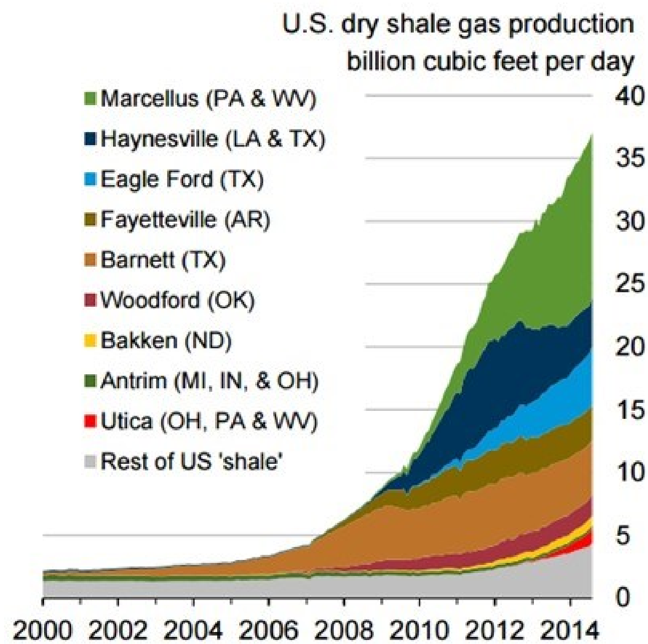

Fig. 5—U.S. natural gas and oil production from shale and other tight resources (EIA 2014a).

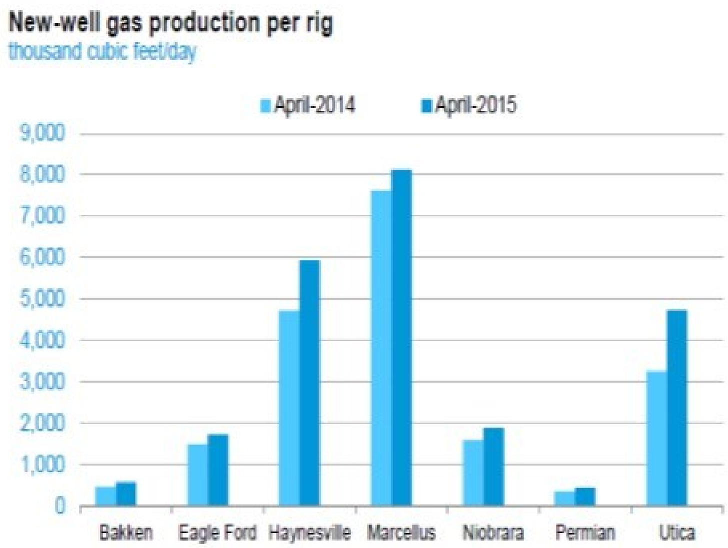

Fig. 6—New-well oil and natural gas production per rig in U.S. shale plays (EIA 2015).

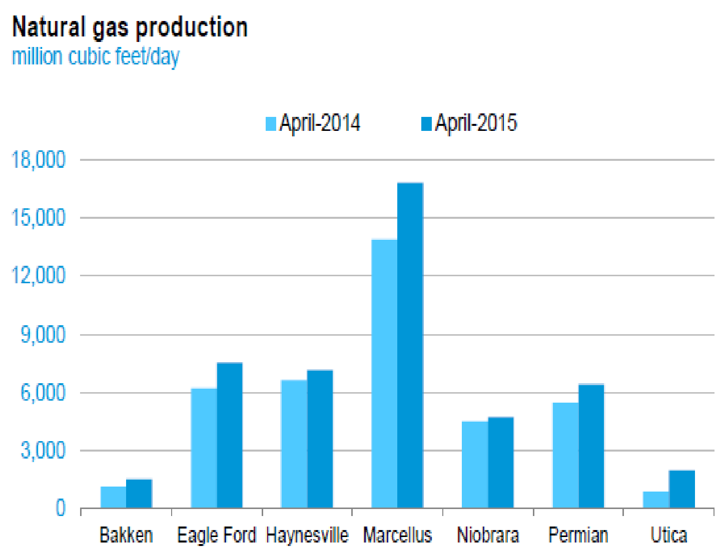

Fig. 7—The Marcellus shale play leads natural gas production in the United States (EIA 2015).

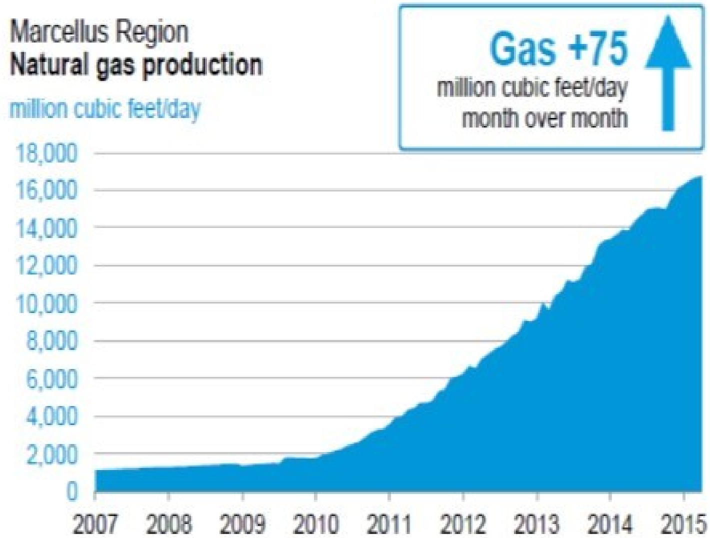

Fig. 8—Natural gas production in the Marcellus shale continues to increase (EIA 2015).

1.4.2. Reserves and Resources Estimates

The United States Geological Survey (USGS) performed an assessment of the undiscovered oil and gas potential of the Appalachian Basin Province in 2002, and published it in 2003. The assessment of the Appalachian Basin Province was based on the geologic elements of each total petroleum system (TPS) defined in the province, including hydrocarbon source rocks (source rock maturation, and hydrocarbon generation and migration), reservoir rocks (sequence stratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing) (USGS 2003). Using this geologic framework, the USGS defined 6 Total Petroleum Systems (TPS) and 26 AUs within these TPS, and estimated the undiscovered oil and gas resources probabilistically. The

Marcellus shale play was one of the 26 AUs under the Devonian Shale-Middle and Upper Paleozoic TPS. These USGS (2003) estimates are shown in **Table 2**.

Table 2—The Appalachian basin province assessment results for the Devonian Shale-Middle and Upper Paleozoic TPS (modified from USGS 2003).

Total Petroleum Systems (TPS) and Assessment Units (AU)	Field type	*Total undiscovered resources*											
		Oil (MMBO)				*Gas (BCFG)*				*NGL (MMBNGL)*			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Devonian Shale-Middle and Upper Paleozoic TPS													
Greater Big Sandy AU	*Gas*					3,877.33	6,089.06	9,562.42	6,322.67	34.06	59.66	104.50	63.23
Northwestern Ohio Shale AU	*Gas*					1,453.59	2,511.40	4,338.99	2,654.07	25.95	49.21	93.32	53.08
Devonian Siltstone and Shale AU	*Gas*					829.34	1,253.46	1,894.48	1,293.61	17.35	29.48	50.08	31.05
Marcellus Shale AU	*Gas*					821.83	1,736.12	3,667.59	1,925.18	4.50	10.21	23.14	11.55
Catskill Sandstones and Siltstones AU	*Gas*					6,843.68	11,222.04	18,401.55	11,740.93	121.19	219.91	399.03	234.82
Berea Sandstone AU	*Gas*					2,464.14	5,905.11	14,151.13	6,800.38	54.51	138.86	353.71	163.21

Table 2 shows that according to USGS (2003), the total undiscovered resources of the Marcellus shale play range from 0.8 to 3.7 TCF with a mean estimate of 1.9 TCF for gas and from 0.0045 to 0.02314 BBNGL with a mean estimate of 0.01155 BBNGL for NGL. These estimates are quite low. According to the EIA in Annual Energy Outlook (AEO) 2012, most of the wells' production data in USGS (2003) estimates came from vertical wells drilled in WV. Since 2003, technological improvements have led to more-productive and less-costly wells. Furthermore, the newer horizontal wells have higher EURs than the older vertical wells.

At the Petroleum Technology Transfer Council (PTTC) workshop in early January 2008, Gary Lash, Ph.D., and Terry Engelder Ph.D. pointed out that the Marcellus shale play would become one of the world's top super giant gas fields, according to volumetric calculations (Engelder 2009). The Marcellus shale play is prospective in 117 counties. These counties are graded into a six-tier system based on several geological parameters and gas production data from the play through May 15, 2009. Tier 1 is for the counties that have proven horizontal wells producing with P50 of initial production rate > 4 MMCFe/day or less than 10 miles from such wells. The other 5 tiers are not adequately tested by production and thus graded downward from tier 2 to 6 based on geological conditions. Engelder (2009) used well spacing of 80 acres/well and assumed that 70% of the sections in each county are accessible. Production decline was allowed to proceed for 50 years. Since there was not enough public production data to define a well's decline curve in the Marcellus shale play, Engelder (2009) relied on a pro forma decline curve from Chesapeake Energy (CHK) to generate a reasonable decline curve from the horizontal wells in the play. This curve predicted that a well with PIP (Practical Initial Production = 30-day production test) of 3.7 MMCFe/day would eventually yield 3.75 BCF EUR. The EUR from this decline curve was then used to estimate probabilistic EUR of the Marcellus shale play. **Table 3** shows Engelder (2009) EUR for the Marcellus shale play.

Table 3—Engelder (2009) estimates of the Marcellus shale play EUR for the next 50 years.

	Counties	Sections	Total Risked Potential	Total Risked Potential	Total Risked Potential
			P90	P50	P10
			Bcf	Bcf	Bcf
Maryland	1	656	3,123	6,980	11,756
New York	17	13,906	30,955	71,859	126,176
Pennsylvania	42	32,622	133,240	291,648	521,406
Ohio	18	9,298	18,361	41,166	71,010
West Virginia	39	16,851	35,022	77,588	136,814
Totals	**117**	**73,333**	**220,701**	**489,241**	**867,162**

EIA (2012a) pointed out that USGS (2003) estimate was apparently too low, since the cumulative production of the Marcellus shale play was on a path to exceed it within a year or two. For AEO 2011, the AIA hired an independent consultant to estimate the TRR of the Marcellus shale play. EIA (2011) reported that the total TRR for the Marcellus shale play is around 410 TCF. **Table 4** shows more detailed information about this report.

Table 4—EIA (2011) reserves and resources estimates for the Marcellus shale play.

	Active	Undeveloped
Area (sq. miles)	10,622	84,271
EUR (Bcfe/well)	3.5	1.15
Well Spacing (wells/sq. mile)	8	8
TRR (Tcf)	177.9	232.44

EIA (2012b) associated the term EUR, which was used in EIA (2011, 2012a), on a per-well basis. A well's EUR equals its cumulative production over a 30-year productive life, using current technology without consideration of economic or operating conditions. Technically Recoverable Resources (TRR) is the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs (EIA 2013). EIA (2012b) defined TRR as the product of land area, well spacing (wells per square mile), percentage of area untested, percentage of area with potential, and EUR per well.

Table 4 shows that EIA (2011) separated the TRR estimates of the Marcellus shale play into active and undeveloped areas. The criterion that separates these two areas is company leases. The active area is the acreage reportedly under lease by oil and gas companies, while the undeveloped area is the remainder area that has not been leased.

The term EUR in Engelder (2009) was used for both single well and the whole play. Engelder (2009) did not classify his estimates into reserves and/or resources. However, since there were counties in Tier 1 that have proven wells with initial production data, Engelder (2009) estimates can be categorized into the total of both reserves and resources.

In 2011, the USGS published an updated assessment of the undiscovered resources of the Marcellus shale play. USGS (2005a) defined undiscovered resources as resources postulated from geologic information and theory to exist outside of known oil and gas fields. USGS (2011b) divided the Marcellus shale play into three AUs based on the thickness of the shale, thermal maturity of the shale, and the degree of structure represented by the extent of the fold-and-thrust belt in the eastern part of the Appalachian Basin where the Marcellus Shale is present (**Fig. 9**). Using these three AUs, USGS (2011a) published a probabilistic assessment of the undiscovered resources of the Marcellus shale play (**Table 5**). USGS (2011b) determined that the quality of the production data from the wells in WV and PA that were available in the early 2011 were not sufficient for the construction of individual well EUR distributions. Therefore, USGS (2011b) chose analogs from other U.S. shale gas plays to determine the EUR distributions for its three Marcellus AUs. Since USGS estimates are only for undiscovered resources, it means that these estimates are comparable to the prospective resources in the PRMS classification from SPE *et al*. (2007).

Fig. 9—The Appalachian basin province and the three Marcellus AUs map (USGS 2011b).

Table 5—USGS (2011a) probabilistic undiscovered resources estimates of the Marcellus shale play.

Total Petroleum System (TPS) and Assessment Units (AU)	Field type	AU probability	Total undiscovered resources							
			Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean
Devonian Shale-Middle and Upper Paleozoic TPS										
Foldbelt Marcellus AU	*Gas*	1.0	345	698	1,410	765	0	0	0	0
Interior Marcellus AU	*Gas*	1.0	41,607	76,078	139,106	81,374	1,497	2,982	5,938	3,255
Western Margin Marcellus AU	*Gas*	1.0	1,002	1,907	3,629	2,059	57	113	224	124
Total undiscovered resources			**42,954**	**78,683**	**144,145**	**84,198**	**1,554**	**3,095**	**6,162**	**3,379**

One of the issues in focus in the AEO 2012 was the Marcellus shale play TRR estimates. Adopting the three USGS (2011b) AUs, the EIA updated its 2011 Marcellus shale play TRR estimates. **Tables 6** shows EIA (2012a) unproved TRR estimates for the Marcellus shale play.

Table 6—EIA (2012a) unproved TRR estimates for the Marcellus shale play.

Assessment Unit/State	Area (square miles)	Well spacing (wells per square mile)	Percent of area untested	Percent of area with potential	EUR (billion cubic feet per well) High	Mid	Low	Average	TRR (billion cubic feet)
Foldbelt	19,063	4	100	5	0.50	0.18	0.03	0.21	757
Maryland	435	4	100	5	0.50	0.18	0.03	0.21	17
Pennsylvania	7,951	4	100	5	0.50	0.18	0.03	0.21	316
Tennessee	353	4	100	5	0.50	0.18	0.03	0.21	14
Virginia	7,492	4	100	5	0.50	0.18	0.03	0.21	298
West Virginia	2,833	4	100	5	0.50	0.18	0.03	0.21	113
Interior	45,161	4	99	37	6.33	1.41	0.06	1.95	137,677
Maryland	763	4	100	37	2.02	0.30	0.02	0.52	629
New York	10,381	4	100	37	7.80	1.79	0.07	2.43	40,124
Ohio	361	4	99	37	2.02	0.30	0.02	0.52	296
Pennsylvania	23,346	4	98	37	7.80	1.79	0.07	2.43	88,182
Virginia	321	4	100	37	2.02	0.30	0.02	0.52	264
West Virginia	9,989	4	99	37	2.02	0.30	0.02	0.52	8,182
Western	39,844	5	100	7	0.35	0.11	0.03	0.13	2,107
Kentucky	207	5	100	7	0.35	0.11	0.03	0.13	11
New York	7,985	5	100	7	0.35	0.11	0.03	0.13	424
Ohio	13,515	5	100	7	0.35	0.11	0.03	0.13	718
Pennsylvania	6,582	5	100	7	0.35	0.11	0.03	0.13	350
Virginia	653	5	100	7	0.35	0.11	0.03	0.13	35
West Virginia	10,901	5	98	7	0.35	0.11	0.03	0.13	569
Total Marcellus	**104,067**	**5**	**99**	**18**	**5.05**	**1.13**	**0.05**	**1.56**	**140,541**

EIA (2014b) defined oil and natural-gas resources categories, including the term unproved TRR. **Fig. 10** shows the illustration of oil and natural-gas reserves and resources according to EIA (2014b).

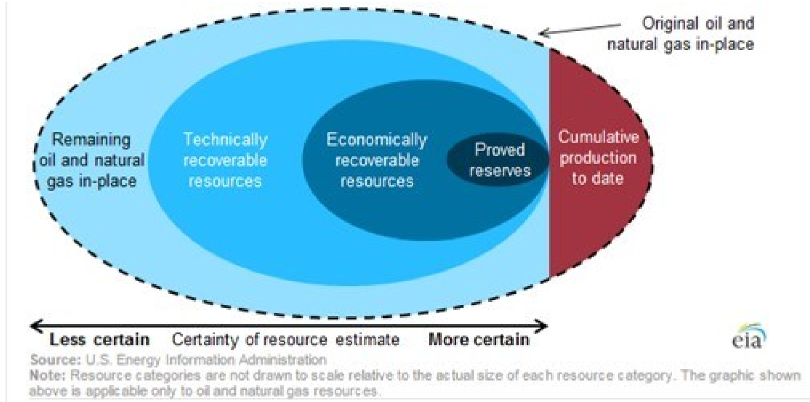

Fig. 10—Oil and natural gas resources category according to EIA (2014b).

The definitions of the resources in Fig. 10 according to EIA (2014b) are as follows:

- **Remaining oil and natural gas in-place** (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.
- **Technically recoverable resources.** The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

- **Economically recoverable resources.** The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.
- **Proved reserves.** The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

According to EIA (2014b), unproved technically recoverable oil and gas resources equals the total technically recoverable resources minus the proved oil and gas reserves.

Table 7 shows the comparison of EIA (2011), USGS (2011a), and EIA (2012a) estimates in AEO 2012.

Table 7—Comparison of EIA (2011), USGS (2011a), and EIA (2012a) reserves/resources estimates for the Marcellus shale play (after EIA 2012a).

Estimate	Area (square miles)	Well spacing		Percent of area untested	Percent of area with potential	Average EUR (billion cubic feet per well)	TRR (billion cubic feet)
		Acres	Wells per square mile				
AEO2011 (as of 1/1/2009)							
Marcellus	**94,893**	**80**	**8**	**99%**	**34%**	**1.62**	**410,374**
USGS (2011 assessment)							
Marcellus	**104,067**	**132**	**4.9**	**99%**	**18%**	**0.93**	**84,198**
Foldbelt	19,063	149	4.3	100%	5%	0.21	765
Interior	45,156	149	4.3	99%	37%	1.15	81,374
Western	39,844	117	5.5	99%	7%	0.13	2,059
AEO2012 (as of 1/1/2010)							
Marcellus	**104,067**	**132**	**4.9**	**99%**	**18%**	**1.56**	**140,541**
Foldbelt	19,063	149	4.3	100%	5%	0.21	757
Interior	45,161	149	4.3	99%	37%	1.95	137,677
Western	39,844	117	5.5	100%	7%	0.13	2,107

It can be seen from Table 7 that EIA (2011) estimates in AEO 2011 used production data as of 1/1/2009, and EIA (2012a) estimates in AEO 2012 used production data as of 1/1/2010. As explained before, USGS (2011a) determined the EUR distributions for its three AUs of the Marcellus shale play by using analogs from other U.S. shale gas plays along with performing analysis of the production data of the Marcellus shale play from PA and WV in the early 2011. **Table 8** shows the comparison of these five estimates in time order based on the production data used in the assessments.

Table 8—Comparison of the five previously published reserves/resources estimates of the Marcellus shale play.

SUMMARY		Production Data Used	Total Reserves		Total Resources		
			Existing Reserves	Undeveloped Reserves	Contingent Resources	Prospective Resources	
USGS (2003)		2002, combined with geologic elements including source rocks, reservoir rocks, and hydrocarbon traps.				NGI (MMBNGL)	Gas (BCF)
	P5		N/A			4.50	821.83
	P50		N/A			10.21	1,736.12
	P95		N/A			23.14	3,667.59
EIA (2011)		as of 1/1/2009	Gas (TCF)				
			177.90			232.44	
Engelder (2009)		Through May 15, 2009, combined with several geological parameters.	Gas (BCF)				
	P10		220,701				
	P50		489,241				
	P90		867,162				
EIA (2012)		as of 1/1/2010			Gas (BCF)		
			N/A		140,541.00		
USGS (2011)		Through early 2011. Combined with analogs from other U.S. Shale plays.				NGI (MMBNGL)	Gas (BCF)
	P5		N/A			1,554	42,954
	P50		N/A			3,095	78,683
	P95		N/A			6,162	144,145

Besides due to the production data used in the estimations, the difference in the five previously published estimates was also due to other parameters involved in calculating the estimates, i.e. discovered and undiscovered areas, well spacing, and end of forecast time. **Table 9** shows these parameters for each estimate.

Table 9—Comparison of the estimation parameters used in the five previously published estimates of the Marcellus shale play.

	USGS (2003)	EIA (2011)	Engelder (2009)	EIA (2012)	USGS (2011a)
Discovered (acres)	N/A	N/A	N/A	666,029	666,029
Undiscovered (acres)	N/A	N/A	N/A	65,936,851	65,936,851
Total Area (acres)	N/A	60,731,520	46,933,120	66,602,880	66,602,880
Well Spacing (acres/well)	N/A	80	80	132	132
End of forecast (years)	30	30	50	30	30

As stated before, most of the production data in USGS (2003) came from vertical wells drilled in WV. There were very limited public production data from wells in the Marcellus shale play when the USGS (2003) assessment was conducted because, until 2010, PA maintained a 5-year embargo on the release of well-level production data (EIA 2012a). This limitation, along with the state of technology at that time, made USGS (2003) the lowest estimate among the five previously published estimates of the Marcellus shale play.

As seen in Table 9, there was no information about the discovered, undiscovered, and total area, and well spacing for the Marcellus shale play estimates in USGS (2003). The end of forecast time information was taken from USGS (2002), which is 30 years. This 30-year end of forecast time is commonly used by the USGS for its resources estimates.

Based on the production data used in the assessments, the next estimates after USGS (2003) in the order of production data used are EIA (2011) estimates. Since USGS (2003) estimates were on a path to be exceeded by the actual cumulative production of the Marcellus shale play within a year or two, the EIA hired an independent consultant to estimate the TRR of the Marcellus shale play for the AEO 2011. These estimates were EIA (2011) estimates.

Engelder (2009) used production data through May 15, 2009. However, not all of the counties in the estimation have wells with adequately tested production data. Out of 117 counties, only eight counties, five in PA and three in WV, have proven horizontal wells producing with a P50 IP > 4 MMCFe/d or less than 10 miles from such wells. The other 109 counties were not adequately tested by production, so Engelder (2009) used geological parameters to grade these counties. Table 9 shows that the total area in Engelder (2009) estimates was smaller than the EIA (2011), EIA (2012a), and USGS (2011b) total areas. This was because Engelder assumed that only 70% of the counties are accessible.

The value of the total TRR in both the active and the undeveloped areas from EIA (2011) is close to the P50 value of Engelder (2009) estimates, 410 TCF compared to 489 TCF. However, EIA (2011) estimates were forecasted to 30 years while Engelder (2009) estimates were for 50 years.

EIA (2012a) estimates used production data as of 1/1/2010. However, the estimates were published in 2012 after USGS (2011a) estimates. EIA (2012a) adopted USGS (2011a) estimates of the Marcellus shale play areas, well spacing, and percent of area with potential. Well spacing is the main cause for why EIA (2012a) estimates were almost 70% lower than EIA (2011) estimates. As shown in Table 9, EIA (2012a) used 132 acres/well while EIA (2011) used 80 acres/well. There are also about 6 million acres difference in the total area used between the two estimates.

USGS (2011a) used EUR distributions from the other U.S. shale plays and combined them with the analysis of the Marcellus shale play production data that were available in the early 2011. Well spacing is also one of the main factors that makes USGS (2011a) estimates much lower than EIA (2011) estimates. The other main factors are the percent of area with potential and the average EUR per well, as shown in Table 7. For these two factors, USGS (2011a) used almost half of the values used in EIA (2011). There is also a difference in the total area used between these two estimates.

The difference between EIA (2012a) and USGS (2011a) estimates is caused by the average EUR per well parameter. The same as the EIA, the USGS also regards the term EUR as per-well basis. USGS (2005a) defined EUR as the total expected recoverable volume of oil, gas, and natural gas liquid production from a well, lease, or field under present economic and engineering conditions, synonymous with total recovery. It can be seen in Table 7 that EIA (2012a) used the average EUR per well value nearly 70% higher than the average EUR per well value in USGS (2011a) estimates.

All of these previous estimates have their own limitation and are outdated. USGS (2003) and Engelder (2009) had to deal with limited production data available during the assessments. USGS (2011a) combined analysis from the Marcellus shale play production data with EUR distributions from the other U.S. shale plays to determine the EUR distributions for its three Marcellus shale AUs. EIA (2011) and EIA (2012a) estimates are deterministic; there is no uncertainty quantification in these two estimates. Since there are more production data available nowadays in the Marcellus shale play, updated probabilistic estimates of reserves and resources in the Marcellus shale play are needed.

1.5. Research Objectives

The objectives of this work are to generate probabilistic reserves and resources estimates for the WV Marcellus shale play and to confirm the reliability of the MCMC method in quantifying uncertainty in production forecasts using production data from the WV Marcellus shale play.

1.6. Overview of Methodology

1. Obtained production data from the WV Marcellus shale play using Drilling Info (DI) Desktop application. Horizontal shale gas wells that had at least one year of production history and clear decline tend were selected. Wells in which the production data indicated irregular behavior were excluded. For wells which had obvious sudden production changes, only the latest production data with clear decline trend were considered.
2. Performed initial GLR analysis to all the wells selected in the WV Marcellus shale play and classified them into their fluid-type category based on McCain (1994) guidelines for determining fluid type from field data using initial producing GLR.
3. Divided the Marcellus shale play into production regions based on initial GLR analysis.
4. Tested the reliability of the MCMC method in quantifying uncertainty in production forecasts and reserves estimation by performing hindcast using production data from the WV Marcellus shale play.
5. Determined which decline curve model is well calibrated when coupled with the MCMC method in the hindcast study.
6. Generated type probabilistic decline curves for every production region.

7. Performed probabilistic reserves and resources evaluation for the Marcellus Shale play. Reserves and resources estimates considered well spacing, discovered and undiscovered areas, and well count. These reserves and resources estimates were calculated by performing Monte Carlo simulation.

CHAPTER II

LITERATURE REVIEW

This chapter describes all of the DCA models that are used in this work, the MCMC method, and calibration assessment tools. This work used six DCA models that are also used in Gonzalez *et al*. (2012). Three of them are the variants of Arps' DCA model (Arps', Arps' with minimum decline of 5%, and Modified Arps'). The other three DCA models are Power-law (Ilk *et al*. 2008), Stretched Exponential (Valko and Lee 2010), and Duong's rate-decline analysis for fracture-dominated shale gas reservoirs (Duong 2011). The MCMC method was used for production hindcast. In order to determine whether the hindcast study of a group of wells is well calibrated or not, calibration assessment tools are needed. The tools used in this work included Coverage Rate (CR), calibration plots, and calibration scores.

2.1. DCA Models

2.1.1. Arps' DCA Model

Arps' DCA model is the most commonly used model to forecast production and estimate reserves in the oil and gas industry. There are two types of decline in Arps' DCA model:

- Exponential decline

$$q(t) = q_i \exp(-D_i t) \text{ , for } b = 0 \tag{1}$$

- Hyperbolic decline

$$q(t) = \frac{q_i}{(1+D_i b t)^{1/b}} \text{ , for } 0 < b < 1 \tag{2}$$

$q(t)$ = production rate at time t, MCF/month

q_i = initial production rate, MCF/month

D_i = Arps' initial decline rate, 1/month

b = hyperbolic exponent, dimensionless

t = time, month

Lee and Sidle (2010) pointed out that one of the assumptions of Arps' DCA model is stabilized (BDF) flow. Due to shale gas reservoir's extremely low permeability, shale gas wells require a long time, often years, to experience BDF. It means that the production data available to be matched are often still in the transient flow. As shown in **Eqs. 1 and 2**, the *b* value for the exponential decline is zero, while the *b* value for the hyperbolic decline is between 0 and 1. However, since the production data to be matched are often still in the transient flow, matching production data can yield a *b* value greater than 1, which is not strictly valid (Lee and Sidle 2010). Lee and Sidle (2010) stated that the common approach to solve this issue is to use the Arps' parameters from the best fit (with $b > 1$) for forecasting, but impose D_{min} to force an exponential tail to the estimate.

2.1.2. Arps' DCA Model with Imposed Minimum Decline Rate

Hyperbolic decline equation (Eq. 2) is used to in this method. The problem with using Eq. 2 is that whenever $b > 1$, then cumulative production goes to infinity as time goes to infinity. As stated before, the common approach to solve this problem is to impose D_{min} to force an exponential tail to the estimate. However, the value of D_{min} is based on analogy or intuition, and even though the result appears reasonable, there is no physical basis for selecting this D_{min} (Lee and Sidle 2010).

2.1.3. Modified Arps' DCA Model

The modified Arps' DCA model is based on Arps' DCA model with an additional fourth parameter — the time when the production rate goes to exponential decline, T_0 (Gonzalez 2012). The modified Arps' equations are shown by **Eqs. 3 and 4**.

$$q(t) = \frac{q_i}{(1+D_i b t)^{1/b}} \text{, for } t \leq T_0 \tag{3}$$

$$q(t) = \frac{q_i}{(1+D_i b T_o)^{1/b}} exp\left(\frac{-D_i(t-T_0)}{1+bD_i T_0}\right) \text{, for } t > T_o \tag{4}$$

These equations can model both hyperbolic and exponential decline using the parameter T_0 as the cut-off between the two decline trends. If the data follow only the exponential decline, then T_0 can be set to zero. T_0 is set to an extremely high value if the data do not exhibit the exponential decline; only the hyperbolic decline will be fitted by the model. For forecasting production, if the latest trend is still in the hyperbolic decline, T_0 can be set to the end of the data to force an exponential tail to get a conservative estimate of the EUR.

2.1.4. Power-Law DCA Model

The Power-law DCA model was introduced by Ilk *et al*. (2008). This model is based on power-law loss ratio. The loss ratio can be approximated by a decaying power-law function with a constant behavior at large times (Ilk *et al*. 2008). This constant parameter at large times is symbolized with D_∞. This model is flexible enough to model transient, transition, and BDF (in many cases), but at long times, the relation reduces to the traditional exponential decline relation (i.e., the contribution of the power-law term is negligible).

The power-law rate-decline relation is defined by **Eq. 5**.

$$q = \hat{q}_i \exp(-D_\infty t - \hat{D}_i t^n) \tag{5}$$

q = production rate at time t, MCF/month

$\hat{q}_i$ = rate “intercept” (q at t = 0), MCF/month

D_∞ = decline constant at infinite time, 1/month

$\widehat{D}_i$ = power-law decline constant, 1/month

t = time, month

n = time exponent, dimensionless

2.1.5. Stretched Exponential Production Decline DCA Model

Valko and Lee (2010) introduced the Stretched Exponential Production Decline (SEPD) DCA Model. The rate expression of this model is shown in **Eq. 6**.

$$q = q_0 exp\left(-\left(\frac{t}{\tau}\right)^{\eta}\right) \tag{6}$$

q = production rate at time t, MCF/month

q_0 = initial production rate, MCF/month

τ = characteristic time parameter, month

t = time, month

η = decline exponent, dimensionless

Gong (2013) observed that if the D_∞ parameter from the power-law model is eliminated and Eq. 6 is rearranged, then the power-law and SEPD models are equivalent.

2.1.6. Rate Decline Analysis for Fracture Dominated Shale Reservoir

This DCA model was introduced by Duong (2011). This model is based on long-term linear flow in a large number of tight and shale gas reservoirs. Rate equation for this model is shown in **Eq. 7**.

$$q = q_1 t^{-m} exp\left[\frac{a}{1-m}(t^{1-m} - 1)\right] \tag{7}$$

q = production rate at time t, MCF/month

q_1 = initial production rate, MCF/month

t = time, month

a = intercept constant for Duong's model, 1/month

m = slope for Duong's model, dimensionless

Duong (2011) showed that the parameters *a* and *m* are correlated. **Fig. 11** shows this correlation from various gas plays.

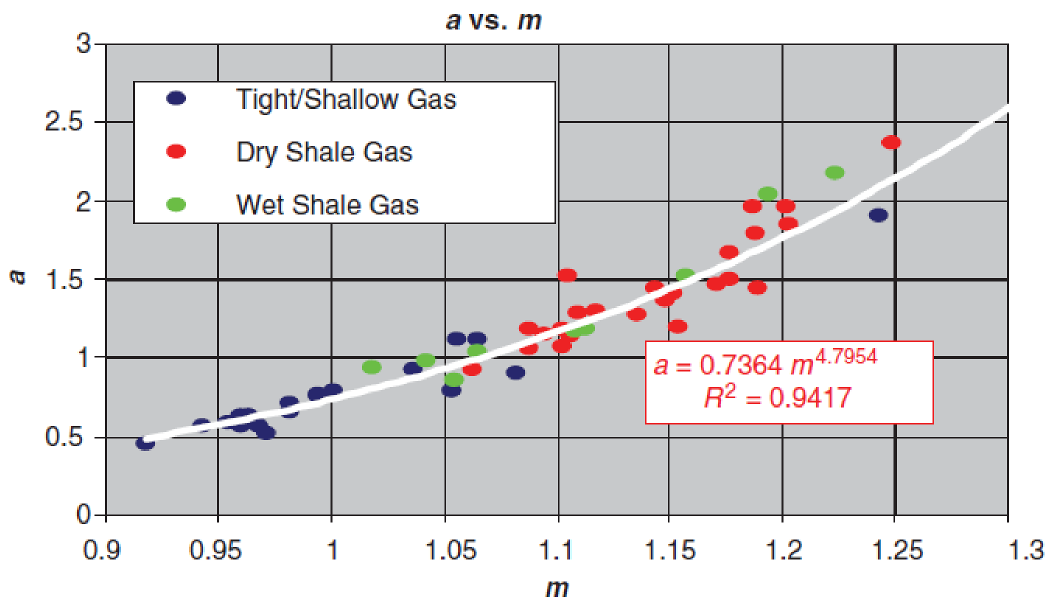

Fig. 11—Correlation between a and m for various gas plays (Duong 2011).

Fig. 11 shows that the value of a varies from 0 to 3 and m varies from 0.9 to 1.3. Fig. 11 also shows that m value is always greater than unity for shale gas reservoirs.

2.2. MCMC Method

Gong *et al*. (2011) developed the MCMC method based on Bayes' theorem. Bayes' theorem is shown in **Eq. 8.**

$$\pi(\theta_j|y) = \frac{f(y|\theta_j)\pi(\theta_j)}{\int f(y|\theta)\pi(\theta)d\theta} \tag{8}$$

$\pi(\theta|y)$ = posterior distribution

$f(y|\theta)$ = likelihood function

$\pi(\theta)$ = prior distribution of parameters

θ_j = candidate of decline curve parameters

y = historical production data

Prior distribution of parameters, likelihood function, and posterior distribution are the three important components in Bayes' theorem. The prior distribution is the distribution of DCA parameters before any production data are analyzed. The likelihood function is the probability density function of y assuming θ is the true parameter. The posterior distribution is the distribution of the unknown parameters after all the observed data are considered.

The posterior distribution is the objective of a Bayesian study. The problem with generating this distribution is that the integral of the denominator in Eq. 8 is often non-integrable (Gong *et al*. 2011). MCMC simulation is one method that can be used to solve this problem.

Procedures to apply this MCMC method, which is summarized from Gong (2013), are as follows. The procedures are explained using Arps' (1945) DCA model as an example.

1. Assume uniform distribution for prior distributions of Arps' DCA parameters, which are $\ln(q_i)$, $\ln(D_i)$, and *b*.

2. Set s = 1 and initial values of Arps' (1945) DCA parameters as the best fit parameters. These initial DCA parameters are calculated from the regression-fit of the production data using the Arps' DCA model equations. Variable s is the iteration number.
3. Calculate the sample standard deviation of the logarithmic residual (σ) between production data and production from the DCA model using **Eq. 9**. Variable y_i is production data at month i, $\hat{y}_i$ is DCA production data at month i, and t is the number of months of production data available. The sum of residuals squared is divided by *t-3* because the nonlinear regression model includes three decline curve variables (Gong 2013).

$$\sigma = \sqrt{\sum_{i=1}^{t} \frac{(y_i - \hat{y}_i)^2}{t-3}} \tag{9}$$

4. Use Metropolis algorithm to construct the Markov chain. In this algorithm the proposal distributions of $\ln(q_i)$, $\ln(D_i)$, and b are set as normal distributions with mean = $\ln(q_i)_{s-1}$, $\ln(D_i)_{s-1}$ and b_{s-1}, and standard deviations of 0.2, 0.4, and 0.2, respectively. Each DCA parameter is generated from this proposal distribution in each iteration.
5. Calculate the sample standard deviation of the logarithmic residual (σ) between production data and production from the DCA model using the DCA parameters from proposal distribution (**Eq. 10**).

$$\sigma_{proposal} = \sqrt{\sum_{i=1}^{t} \frac{\left(y_i - \hat{y}_{iproposal}\right)^2}{t}} \tag{10}$$

6. Calculate acceptance ratio (α) using **Eq. 11**.

$$\alpha = \min[1, \exp\left(\frac{\sigma_{s-1}^2 - \sigma_{proposal}^2}{\sigma^2}\right) x \prod_{\vartheta = ln(q_i), ln(D_i), b} \frac{\Phi\left(\frac{\vartheta_{upper} - \vartheta_{s-1}}{\sigma_\vartheta}\right) - \Phi\left(\frac{\vartheta_{lower} - \vartheta_{s-1}}{\sigma_\vartheta}\right)}{\Phi\left(\frac{\vartheta_{upper} - \vartheta_{proposal}}{\sigma_\vartheta}\right) - \Phi\left(\frac{\vartheta_{lower} - \vartheta_{proposal}}{\sigma_\vartheta}\right)} \tag{11}$$

ϑ is one of the three decline curve parameters and σ_ϑ, ϑ_{upper}, and ϑ_{lower} are the standard deviation, upper bound, and lower bound of the proposal distribution of ϑ, and Φ is the Cumulative Distribution Function (CDF) of the standard normal.

7. Generate a random number between 0 and 1.
8. If the random number < acceptance ratio, accept $\theta_{proposal}$, otherwise $\theta_s = \theta_{s-1}$.
9. Go to the next iteration until the maximum chain length is reached. When the maximum iteration is reached, the obtained Markov chain of the DCA parameters are used to calculate P90, P50, and P10 production forecasts and reserves.

2.3. Calibration Assessment Tools

One of the objectives of this work is to confirm the reliability of the MCMC method using the WV Marcellus shale play production data. This objective can be achieved by performing a hindcast study. In a hindcast study, a user-defined portion of the known history is used as input to the model (i.e., is matched) and the remainder of the known history is considered to be "future" production and is compared to the model prediction to the same point in time (i.e., hindcast) (Gonzalez *et al*. 2012).

In order to determine whether the probabilistic methodology is well calibrated or not, calibration assessment tools are needed. The tools used in this work were Coverage Rate (CR), calibration plots and calibration score.

Coverage Rate (CR) is the number of wells in which the true production falls within the $P_{90} – P_{10}$ range divided by the total number of wells (Gonzalez *et al*. 2012). Calibration plots (**Fig. 12**) can also be used to assess calibration of probabilistic forecasts. The x-axis represents the probability associated with each forecast, which in this work are P10, P50, and P90 values. The y-axis is the proportion correct, which is the fraction of wells that comply with the definition. For example, the well actual production at the end of the hindcast should be greater than the P10 estimate for approximately 90% of the wells being analyzed. The fraction of wells in which the actual production exceeded the P10 estimate was calculated and plotted on the y-axis. This process was repeated for the P50 and the P90 estimates. A methodology is well-calibrated if, for all estimates assigned the same probability, the proportion correct is equal to the probability assigned (Gonzalez *et al*. 2012).

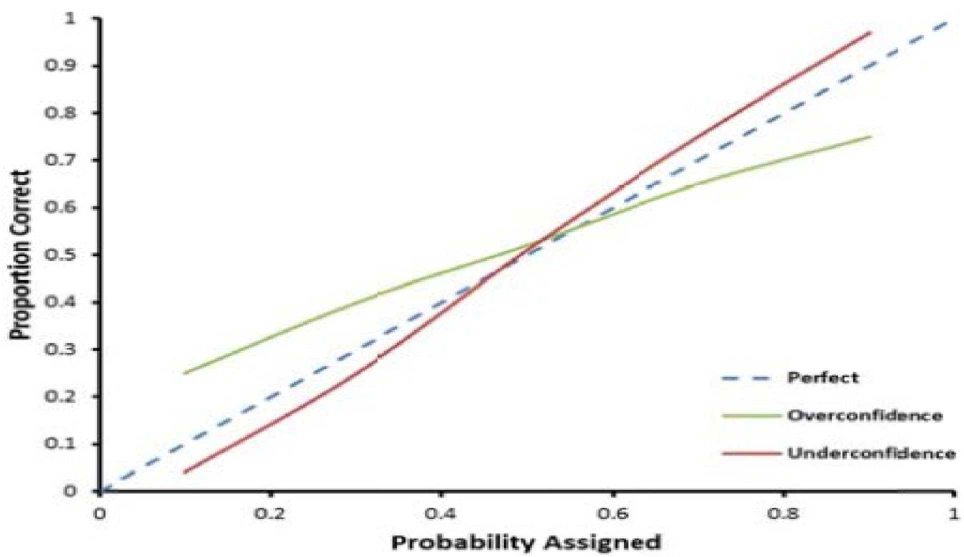

Fig. 12—Probability calibration plot. Well calibrated results should lie on the unit-slope (perfect) line (Gonzalez *et al*. 2012).

Another tool for calibration assessment is the calibration score. **Eq. 12** shows the calibration score equation (Fondren *et al*. 2013).

$$Calibration\ score = \frac{1}{N}\sum_{t=1}^{T} n_t (r_t - c_t)^2 \tag{12}$$

N = total number of assessments

T = total number of different response probabilities (e.g., 3 for 10%, 50%, 90%)

r_t = the response probability assigned to an assessment

n_t = the number of assessments for the response probability r_t

c_t = the percent correct

The calibration score is negatively oriented and ranges from 0 to 1, with the worst calibration score possible equal to 1.

CHAPTER III

METHODOLOGY AND RESULTS

This chapter presents the workflow, scope and limitation, methodology, and results of this work. First, the workflow and the scope and limitation are presented. After that, the method and its result are explained step by step.

3.1. Workflow

The first step of this work was to obtain the Marcellus shale play data. Production data were obtained by using the DI Desktop application. Several filters were inputted to the application so that only horizontal wells with at least 12 months of production data were included. The map of the three USGS (2011b) Marcellus shale play AUs was taken from the shape files in USGS (2014) and uploaded to the DI Desktop application. Initial GLR analysis was then performed for the first three producing months of the wells. Based on the initial GLR analysis results, the WV Marcellus shale play was then divided into two regions: liquid-rich region, since this region also produces Natural Gas Liquid (NGL), and dry-gas region.

The next step was to perform hindcast study on the WV Marcellus shale play wells. The purpose of this hindcast study was to confirm the reliability of the MCMC method in production forecasting and reserves estimation by using the WV Marcellus shale play production data. The hindcast study was also used to determine which DCA model was well calibrated when combined with the MCMC method.

The selected DCA model was then used to generate type probabilistic decline curves for both the liquid-rich and dry-gas regions. Both the NGL and gas production were considered for the liquid-rich region. However, only the gas production is considered for the dry-gas region, since all the wells in this region had either zero or negligible NGL production. The early time of the type curves was matched with the early time of the actual production data. D_{min} values were introduced to force exponential decline to the type probabilistic decline curves at the late time. Since there was no long-term production data in the Marcellus shale play on which to base D_{min} values, distributions of D_{min} for oil/NGL and gas production for the Eagle Ford play from Gong *et al*. (2013) were used. Imposing these D_{min} values contributed to the uncertainty in the TRR20 estimates from the type probabilistic decline curves.

With the type probabilistic decline curves for both fluid types for both regions, reserves and resources were estimated. Reserves consist of existing reserves from the existing wells and undeveloped reserves, which includes wells that can be drilled in the next five years. Resources consist of contingent resources, which are potentially available resources in the discovered area of the play but not drilled yet, and prospective resources, which are resources potentially available in the undiscovered area.

Well counts for each reserves and resources category were calculated based on existing well numbers, drilling rate, drilling success ratio, discovered and undiscovered area, fraction of undiscovered area with potential, and well spacing. Reserves and resources estimates of the WV Marcellus shale play were then calculated probabilistically by performing Monte Carlo simulation. Lastly, these reserves and resources estimates of the WV Marcellus shale play were extrapolated to estimate reserves and resources for the rest of the play.

This workflow is summarized as a flow diagram shown in **Fig. 13.**

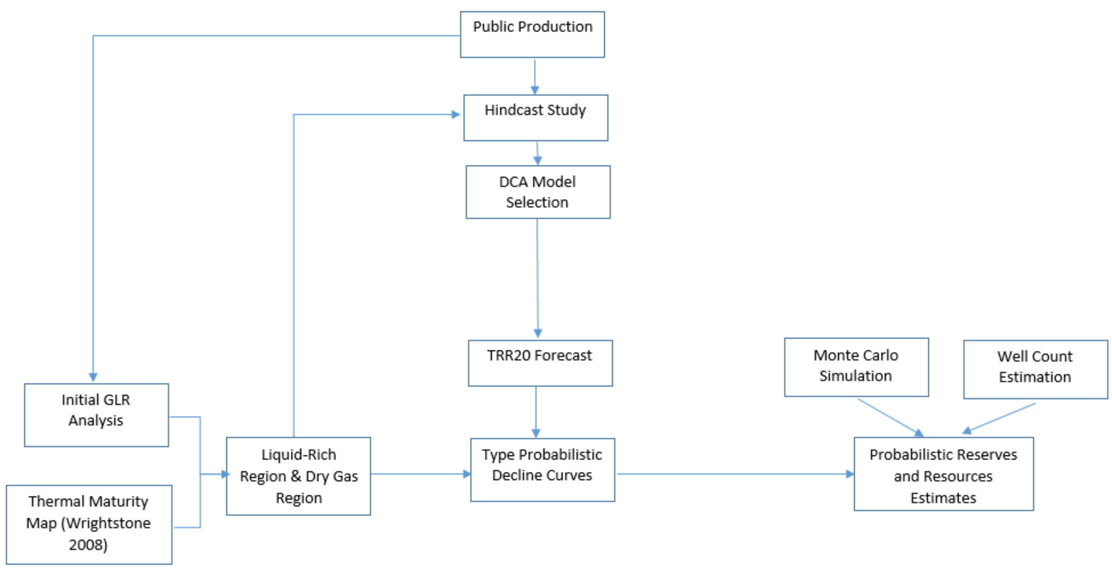

Fig. 13—Workflow diagram for the WV Marcellus shale play reserves and resources estimation.

3.2. Scope and Limitations

Every state in the Marcellus shale play has their own policy on how to report its oil and gas production data. PA requires operators to report their production data twice a year (semi-annually), Ohio (OH) requires it annually. WV requires their operators to report oil and gas production data once a year, but the report contains actual monthly production data.

Production data for this work were taken from the DI Desktop application. Since PA and OH only have semi-annual and annual production data, respectively, in order to be consistent with their data format, DI uses an algorithm to distribute this semi-annual / annual production data into monthly production data proportional to the number of days in each month. There is no problem with WV production data since they have actual monthly production data.

This work used PDCA software developed by Gong *et al*. (2011). The software was developed to deal with monthly production data. Because only the WV Marcellus shale play has actual monthly production data, and because it is difficult to forecast production using decline curves with semi-annual or annual data, the scope of this work was focused primarily on estimating reserves and resources of the WV Marcellus shale play.

3.3. Marcellus Shale Play Classification

3.3.1. Marcellus Shale Map

As explained before in Chapter I, USGS (2011b) divided the Marcellus shale play into three AUs based on the thickness of the shale, thermal maturity of the shale, and the degree of structure represented by the extent of the fold-and-thrust belt of the Marcellus shale. These three AUs are:

- Western margin Marcellus AU, which is the area with shale thickness less than 50 ft, depth less than 2,000 ft to more than 9,000 ft, and thermal maturity from pre-peak oil to past-peak gas.
- Interior Marcellus AU, which consists of area with shale thickness greater than 50 ft, depth from less than 2,000 ft to more than 11,000 ft, and thermal maturity from peak oil to past-peak gas.
- Marcellus foldbelt AU, which is the general extent of the fold-and-thrust belt in the eastern part of the Appalachian Basin where the Marcellus Shale is present, has shale thickness from a few feet to more than 350 ft, shale depth from outcrop to more than 11,000 ft, and thermal maturity from peak gas to past-peak gas.

These three AUs are shown in Fig. 9 in Chapter I.

The map of these three AUs of the Marcellus shale play, which is in the form of shapefiles, was uploaded into the DI Desktop map. These shapefiles were provided in USGS (2014). **Fig.14** shows these three Marcellus AU shapefiles on top of the U.S. counties and states maps.

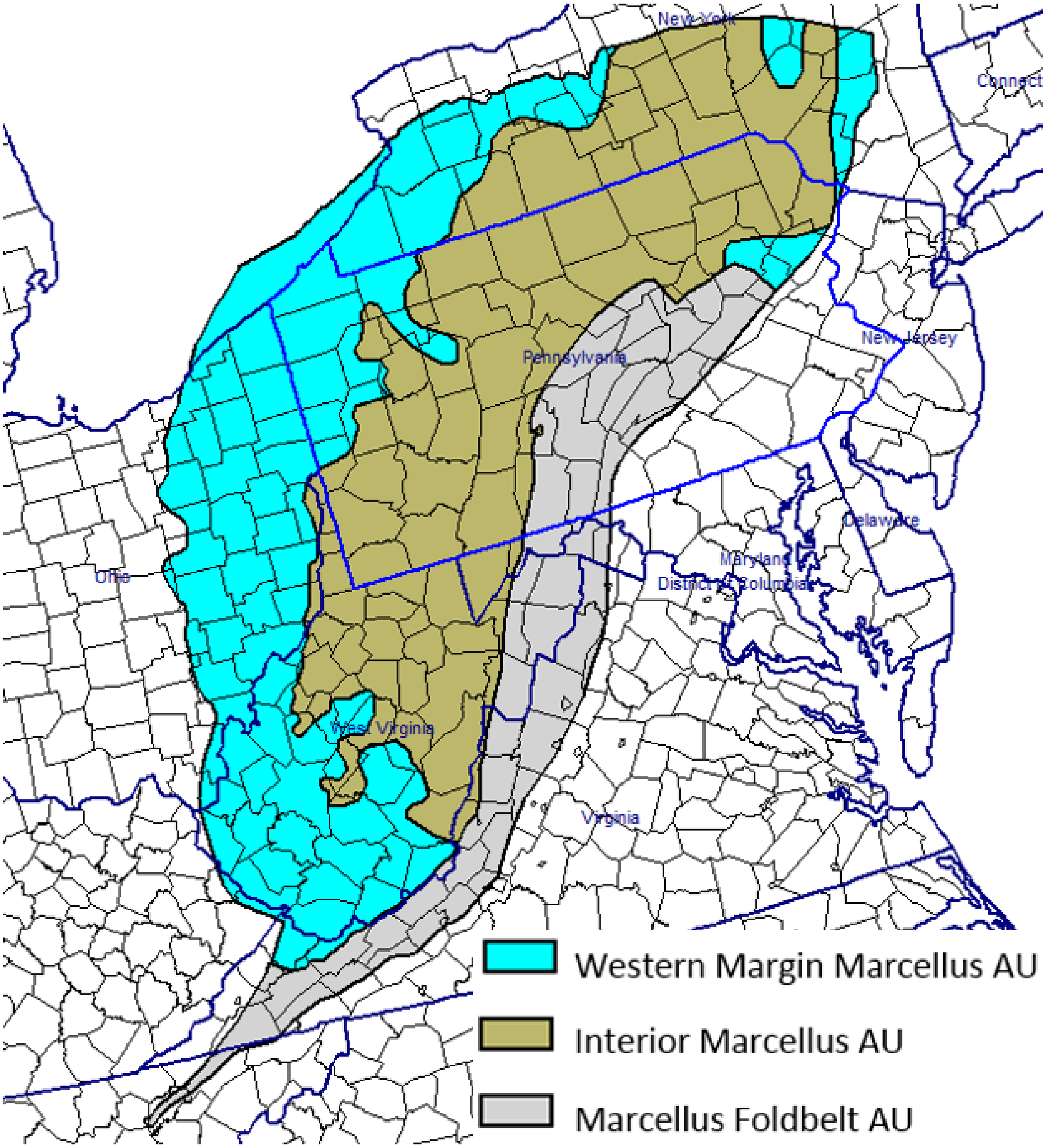

Fig. 14—Marcellus AUs map uploaded to the DI Desktop application.

3.3.2. Public Production Data of the WV Marcellus Shale Play

The production data of the WV Marcellus shale play were taken from the DI Desktop application. Several filters were applied so that only horizontal wells with at least 12 months of production data were included. **Fig. 15** shows the input filters used to obtain the desired production data. The locations of the selected wells in the WV Marcellus shale play are shown in **Fig. 16.**

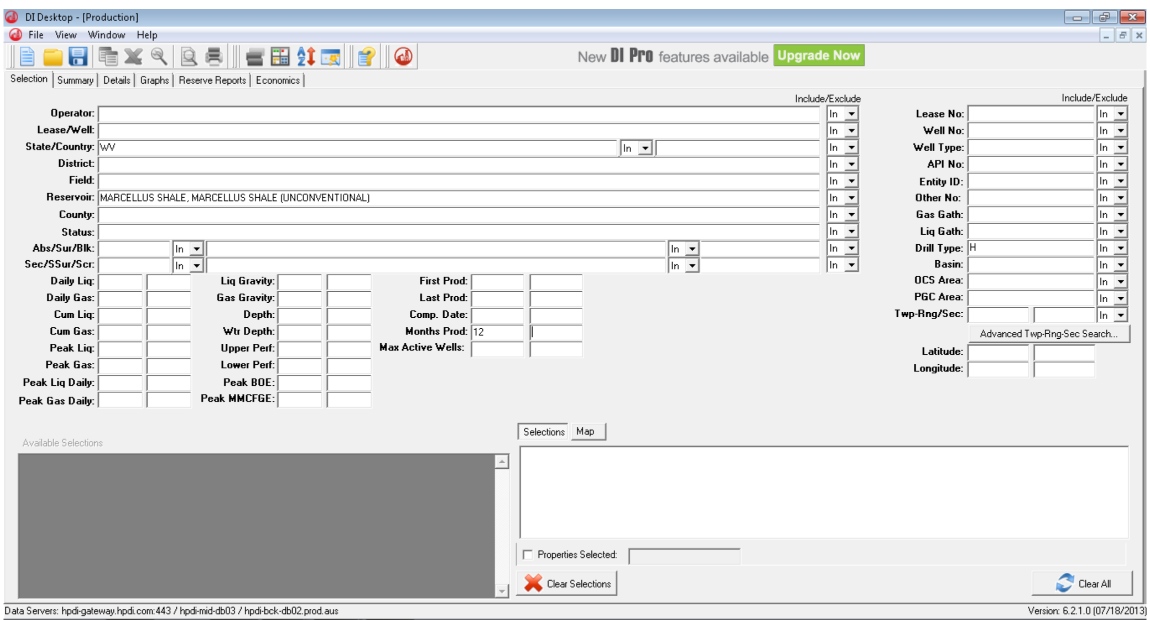

Fig. 15—DI Desktop production window shows input filters used to obtain the desired production data.

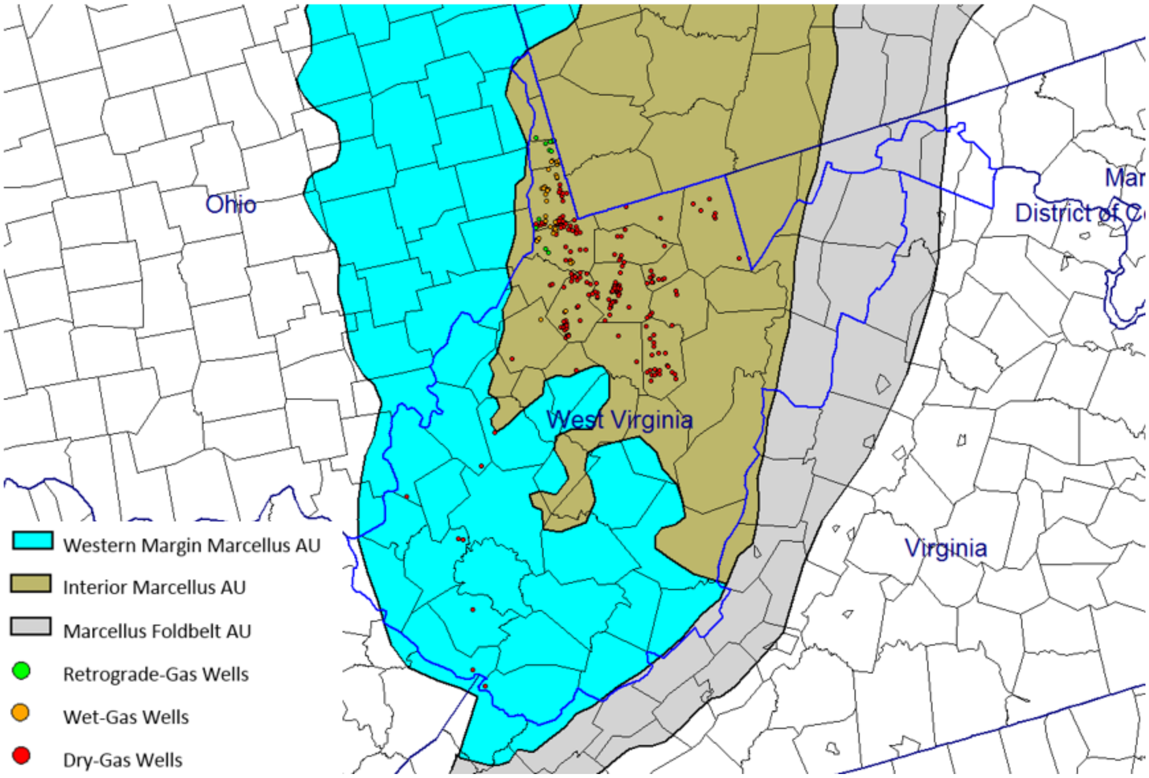

Fig. 16—Selected wells in the WV Marcellus shale play.

These data were as of December 1, 2013. A total of 584 horizontal shale gas wells in the WV Marcellus shale play with at least 12 months production data were included in this work.

3.3.3. Perform Initial GLR Analysis

In this step, GLR analysis was performed using the first three months of production data from each well. The reason for choosing the first three months in this analysis was that it was a reasonable amount of time to take precautions of a well's behavior at the start of the production. Sometimes a well's production at the beginning is usually distorted by some problems; e.g., drilling fluid comes back during production, or maybe a completion problem. Taking three months in the GLR analysis was an attempt to make sure that the GLR value really represents the ratio from the reservoir fluid of the observed well. To get the GLR for each well, the first three months of the gas production data were summed and divided by the sum of the first three months of the NGL production data. This GLR value was used to classify the fluid type of the well. The fluid type classification in this work was based on McCain's (1994) guidelines for determining fluid type from field data using initial producing GLR. These guidelines are shown in **Table 10.**

Table 10—Guidelines for determining fluid type from field data (McCain 1994).

	Black Oil	Volatile Oil	Retrograde Gas	Wet Gas	Dry Gas
Initial producing gas/liquid ratio, scf/STB	<1,750	1,750 to 3,200	>3,200	>15,000*	100,000*
Initial stock-tank liquid gravity, °API	<45	>40	>40	Up lo 70	No liquid
Color of stock-tank liquid	Dark	Colored	Lightly colored	Water white	No liquid

*For engineering purposes.

The results of this GLR analysis of 584 wells in the WV Marcellus shale play are shown in **Table 11**. Maps of well fluid type are shown in **Figs. 17-19**.

Table 11—Initial GLR analysis results for all wells in the WV Marcellus shale play.

Fluid Type	Number of Wells
Black Oil	0
Volatile Oil	0
Retrograde Gas	45
Wet Gas	51
Dry Gas	489
Total	585

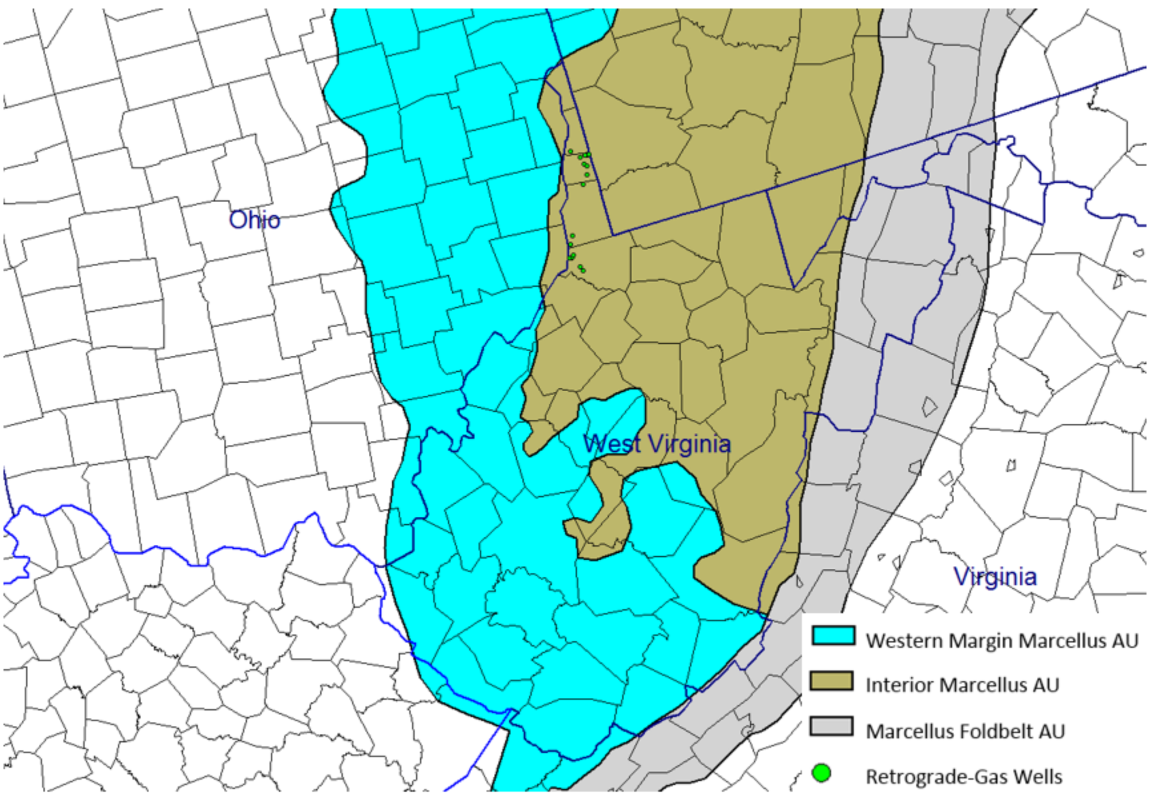

Fig. 17—Retrograde-gas wells in the WV Marcellus shale play.

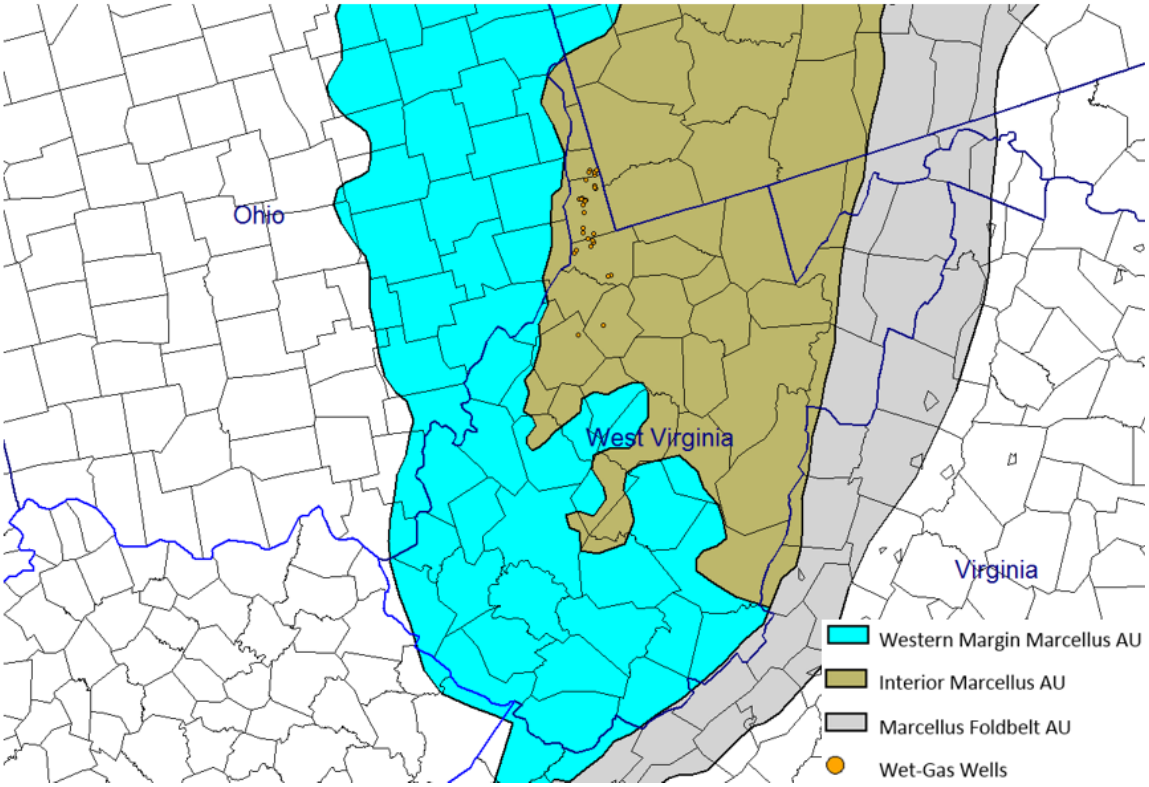

Fig. 18—Wet-gas wells in the WV Marcellus shale play.

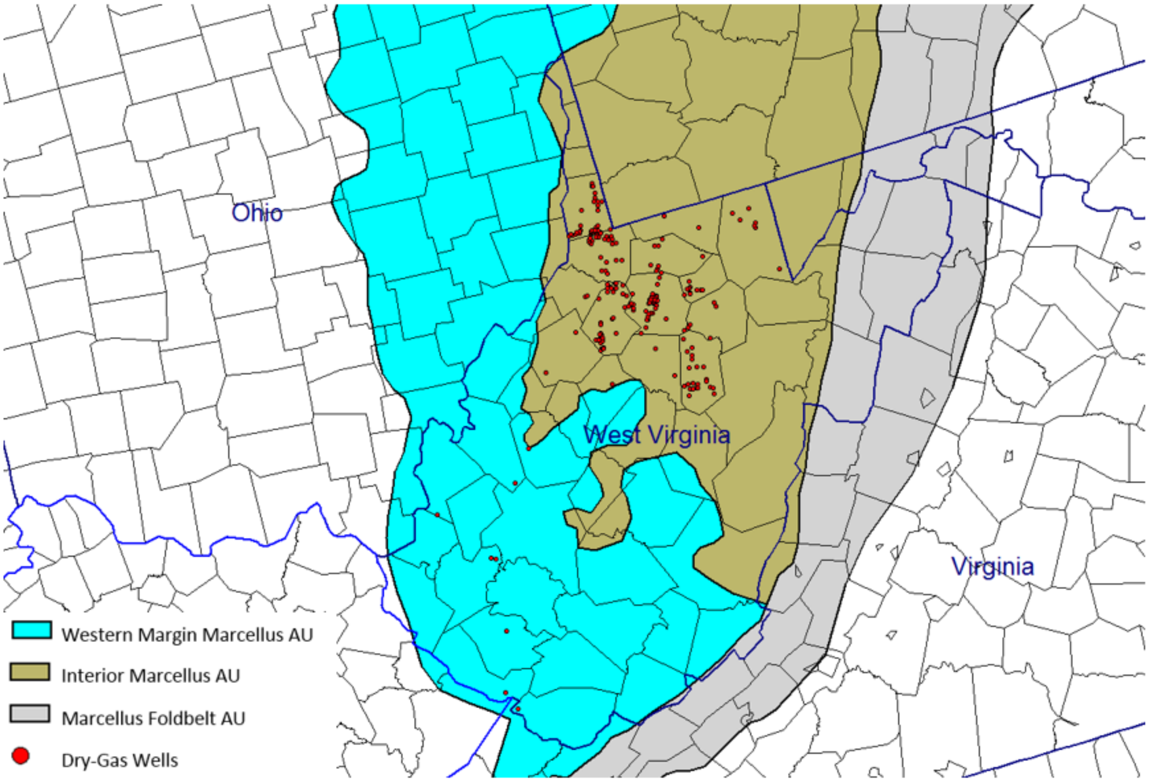

Fig. 19—Dry-gas wells in the WV Marcellus shale play.

Combining these initial GLR analysis results and well locations in Figs. 17-19, the boundary between the liquid-rich and dry-gas regions of the WV Marcellus shale play was drawn (**Fig. 20**). The liquid-rich region consists of retrograde and wet-gas wells, while the dry-gas region consists of only dry-gas wells.

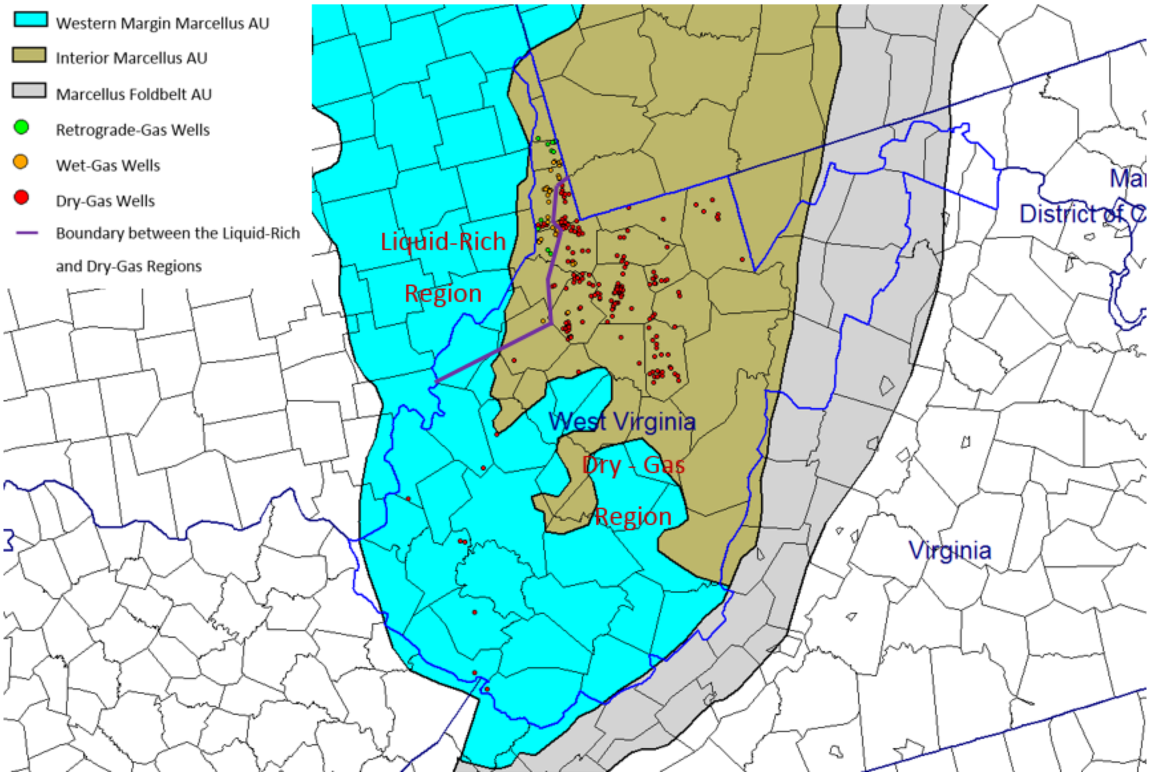

Fig. 20—The liquid-rich and dry-gas regions for the WV Marcellus shale play separated by a boundary. The part of the play located to the left of this boundary is the liquid-rich region; to the right of this boundary is the dry-gas region.

Ideally the boundary between the liquid-rich and dry-gas regions will result in a perfect separation of liquid-rich wells (wet-gas and retrograde-gas wells) and dry-gas wells. However, there are some dry-gas wells that are located at the area where the wells are liquid-rich dominant, and vice versa. Therefore, the purpose when drawing the boundary was to minimize the number of wrong-type wells in both regions. There are a total of 142 wells in the liquid-rich region and 438 wells in the dry-gas region. There are 51 wells that are considered dry-gas wells from the initial GLR analysis but are located in the liquid-rich region, and there are only five wells that are considered wet-gas wells from the initial GLR analysis but are located in the dry-gas region. These two regions and the three AUs from USGS (2011b) were used throughout this work.

3.4. The Reliability Confirmation of the MCMC Method and DCA Model Selection

In order to confirm the reliability of the MCMC method in production forecasting and reserves estimation, and to determine which DCA model was best calibrated when coupled with the MCMC method, a hindcast study was performed. In a hindcast study, the first part of the observed production data are considered history and the remaining production data are considered future production, which will be compared to the model's forecast results. In this work, hindcast studies were performed for NGL production data in the liquid-rich region and for gas production data in the dry-gas region. As for the history part of the production data, six-month and twelve-month histories were used. Only wells that had clear decline trends and at least two months of production data after the history part were selected. The start month of production analyzed was the first month on a clear decline trend. For example, if a clear decline trend is shown starting with month seven of the available production data of a well, the start month of production analyzed for this well was month seven.

When the first six months of the production data were used as the history part, there were 73 wells in the liquid-rich region and 392 wells in the dry-gas region that were suitable for the hindcast study. When the first twelve months of production data were used as the history part, there were 28 wells available in the liquid-rich region, and 355 wells in the dry-gas region that were suitable for the hindcast study. **Tables 12 through 15** show the number of months of production data after the history part and the corresponding numbers of wells in the hindcast study, for both regions and for six and twelve months of history.

Table 12—Number of months after the history part and the corresponding numbers of wells in the liquid-rich region when the first six months of the production data were used as the history part in the hindcast study.

Months after History	Number of wells
2	9
3	3
4	9
5	7
6	8
7	8
8	9
9	1
10	1
11	1
12	2
13	3
16	1
19	5
20	1
22	1
23	2
24	2
Total Wells	73

Table 13—Number of months after the history part and the corresponding number of wells in the liquid-rich region when the first twelve months of the production data were used as the history part in the hindcast study.

Months after History	Number of wells
2	8
3	1
4	1
5	1
6	2
7	3
10	1
13	5
14	1
16	1
17	2
18	2
Total Wells	28

Table 14—Number of months after the history part and the corresponding number of wells in the dry-gas region when the first six months of the production data were used as the history part in the hindcast study.

Months after History	Number of wells	Months after History	Number of wells
2	7	28	7
4	3	29	8
5	3	30	11
6	8	31	6
7	16	32	1
8	8	33	12
9	21	34	5
10	18	35	2
11	26	36	4
12	12	37	1
13	11	38	4
14	20	39	2
15	8	40	1
16	13	42	3
17	14	43	1
18	27	44	4
19	13	45	2
20	4	47	1
21	10	49	2
22	13	50	1
23	7	51	2
24	19	52	1
25	11	59	2
26	11	60	1
27	5		
Total Wells			
392			

Table 15—Number of months after the history part and the corresponding number of wells in the dry-gas region when the first twelve months of the production data were used as the history part in the hindcast study.

Months after History	Number of wells	Months after History	Number of wells
2	8	24	11
3	21	25	6
4	18	26	1
5	26	27	12
6	12	28	5
7	11	29	2
8	20	30	4
9	8	31	1
10	13	32	4
11	14	33	2
12	27	34	1
13	13	36	3
14	4	37	1
15	10	38	4
16	13	39	2
17	7	41	1
18	19	43	2
19	11	44	1
20	11	45	2
21	5	46	1
22	7	53	2
23	8	54	1
Total Wells			
355			

The prior distributions for the DCA parameters for all of the DCA models were independent and uninformative uniform distributions. The bounds for these prior distributions were selected so that the ranges of the parameters were wide and reasonable enough to accommodate all DCA parameters' combinations possible. This work used the

DCA parameters' bounds from Gonzalez *et al*. (2012), except for the m value in Duong's DCA model. This m value ranged from 1.00001 to 3, since Duong (2011) stated that the m value for shale gas reservoirs is always greater than unity. **Figs. 21a through 21d** show the DCA parameters' bounds used in the hindcast study for Arps', the power-law, the SEPD, and Duong's DCA models, respectively. Arps' with 5% D_{min} and the modified Arps' used the same DCA parameters as Arps'.

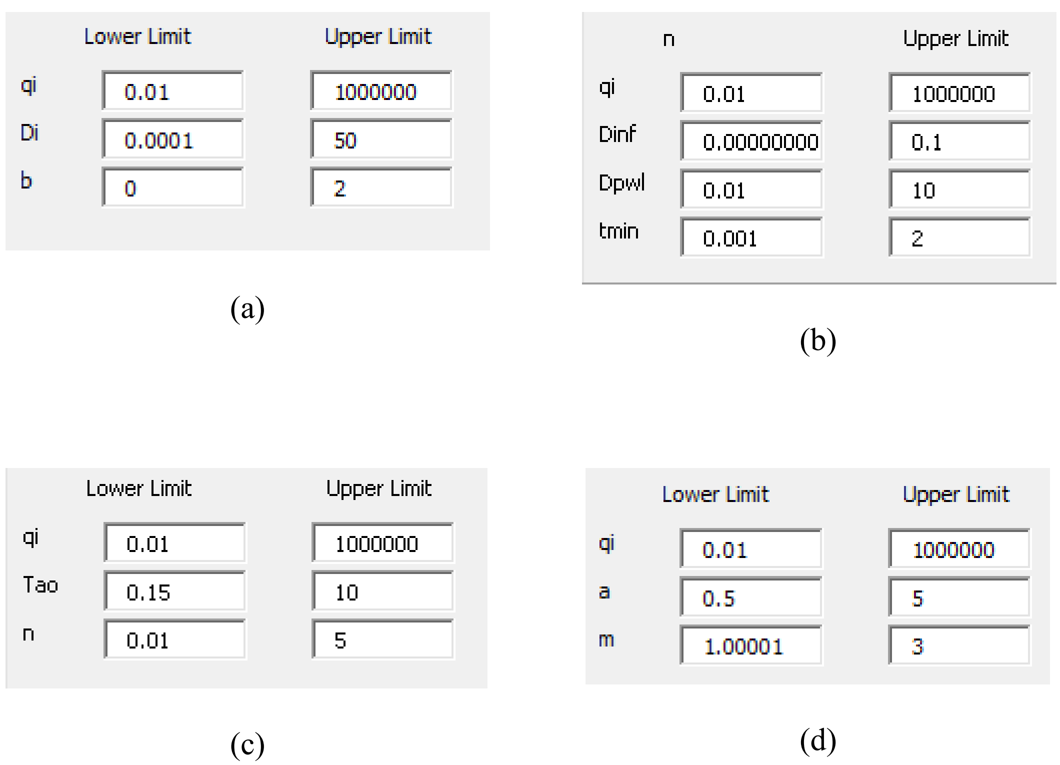

Fig. 21—DCA parameters for (a) Arps', Arps' with 5% minimum decline rate, the modified Arps', (b) the power-law, (c) the SEPD, and (d) Duong's DCA models for the hindcast study.

Calibration tools were used to evaluate the hindcast study results. These tools show which DCA models were well calibrated in the hindcast study. The tools that were used in this work are CR, calibration plots, and calibration scores. As explained in Chapter II, a high value for CR, low value for calibration score, and close fit to the perfect curve in the calibration plot are wanted. **Figs. 22 through 25** show the calibration plots for all DCA models in both production regions using the first six and twelve months of production data as the history part. **Tables 16 through 19** show the coverage rates and calibration scores.

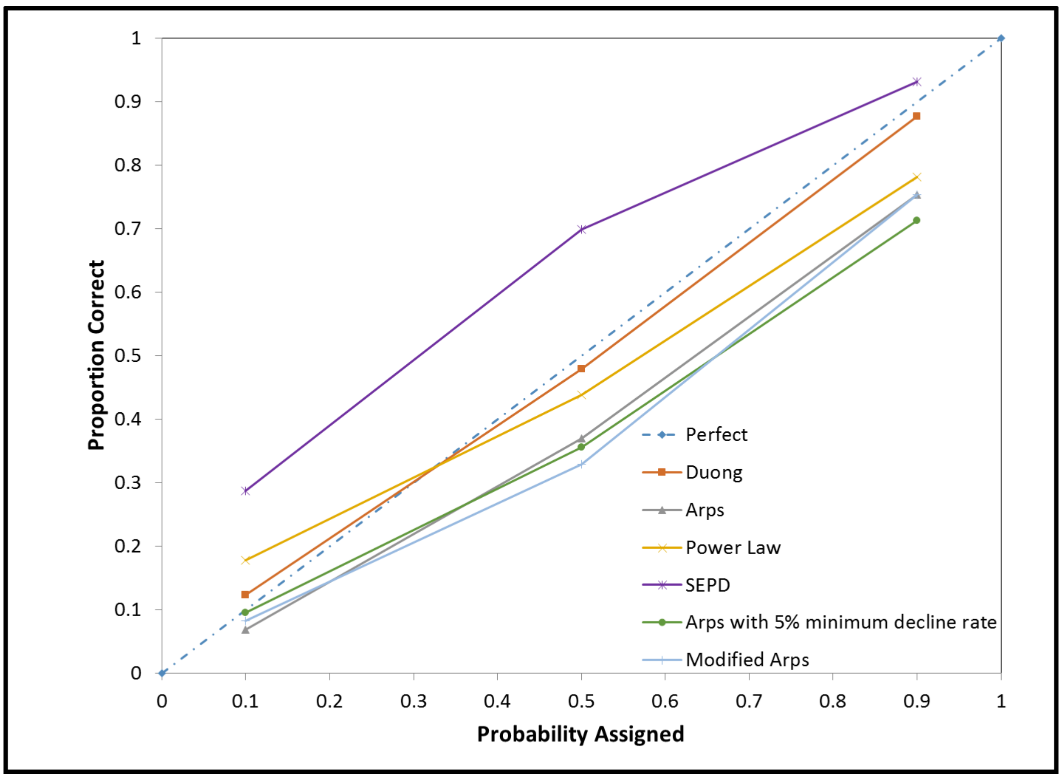

Fig. 22—The calibration plots for all DCA models in the liquid-rich region using the first six months of the production data as the history part in the hindcast study.

Table 16—The coverage rates and calibration scores for all DCA models in the liquid-rich region using the first six months of the production data as the history part in the hindcast study.

DCA Model	Coverage Rate	Calibration Score
Duong	75%	0.0005
Arps	68%	0.0131
Power Law	60%	0.0080
SEPD	64%	0.0252
Arps' with 5% minimum decline rate	62%	0.0186
Modified Arps	67%	0.0170

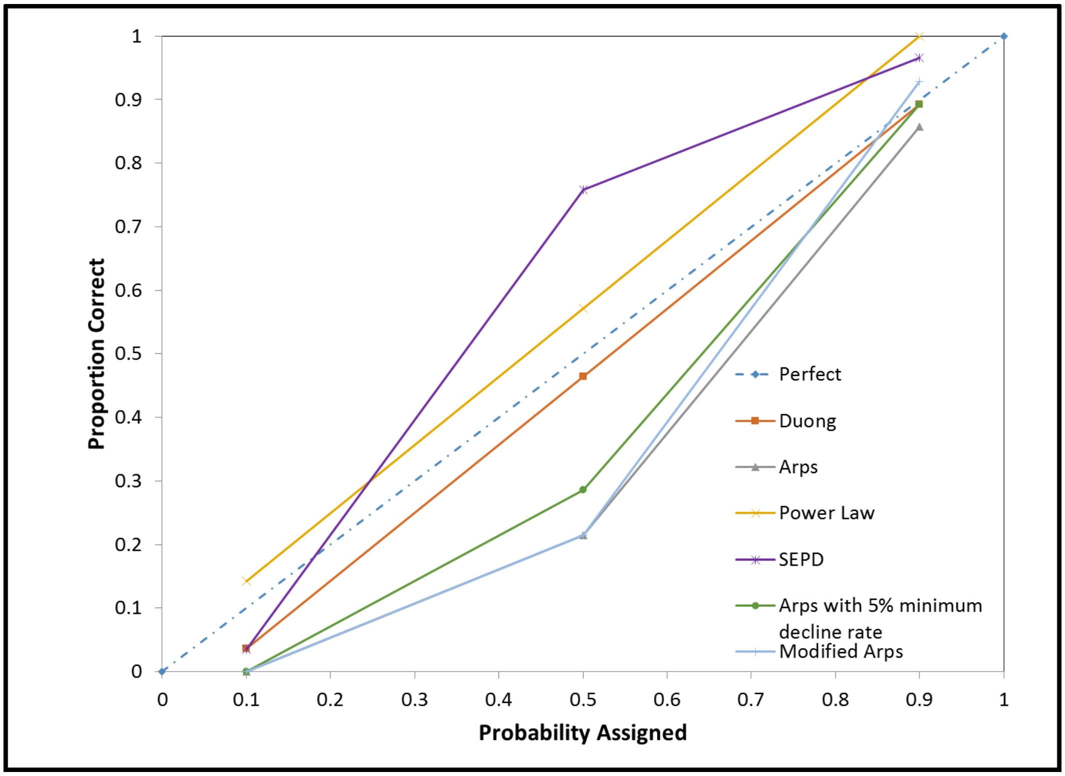

Fig. 23—The calibration plots for all DCA models in the liquid-rich region using the first twelve months of the production data as the history part in the hindcast study.

Table 17—The coverage rates and calibration scores for all DCA models in the liquid-rich region using the first twelve months of the production data as the history part in the hindcast study.

DCA Model	Coverage Rate	Calibration Score
Duong	86%	0.0018
Arps	86%	0.0312
Power Law	86%	0.0056
SEPD	93%	0.0252
Arps with 5% minimum decline rate	89%	0.0187
Modified Arps	93%	0.0308

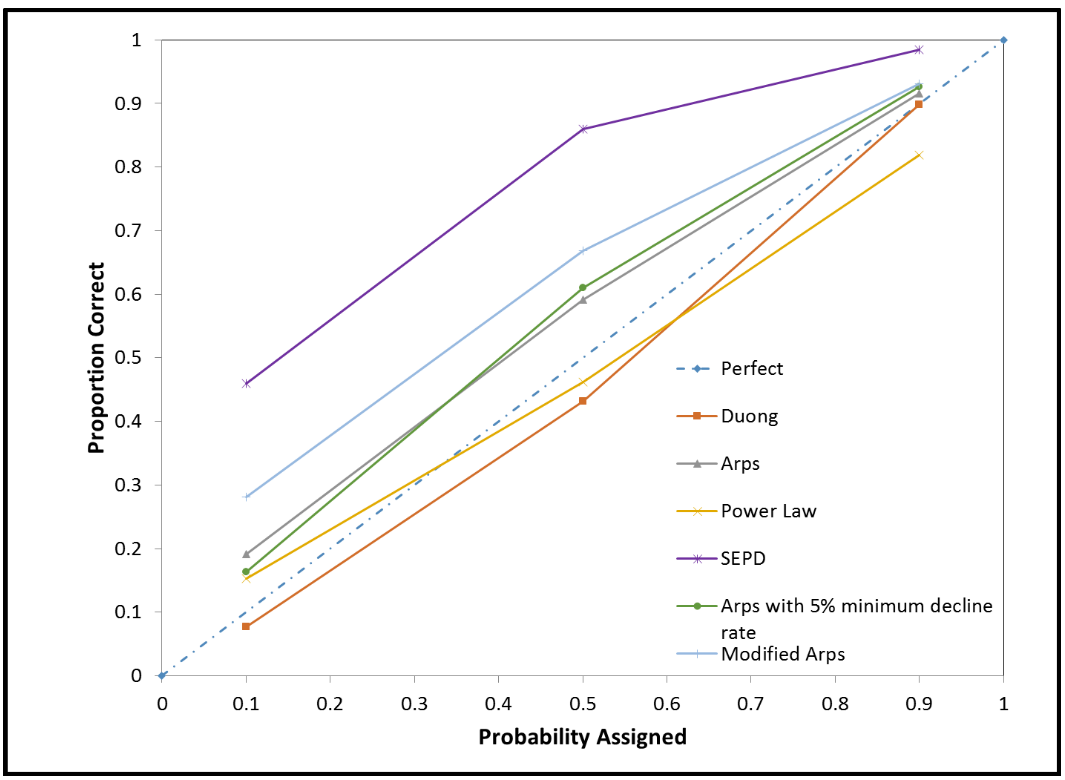

Fig. 24—The calibration plots for all DCA models in the dry-gas region using the first six months of the production data as the history part in the hindcast study.

Table 18—The coverage rates and calibration scores for all DCA models in the dry-gas region using the first six months of the production data as the history part in the hindcast study.

DCA Model	Coverage Rate	Calibration Score
Duong	82%	0.0018
Arps	72%	0.0057
Power Law	67%	0.0036
SEPD	53%	0.0885
Arps with 5% minimum decline rate	76%	0.0056
Modified Arps	65%	0.0206

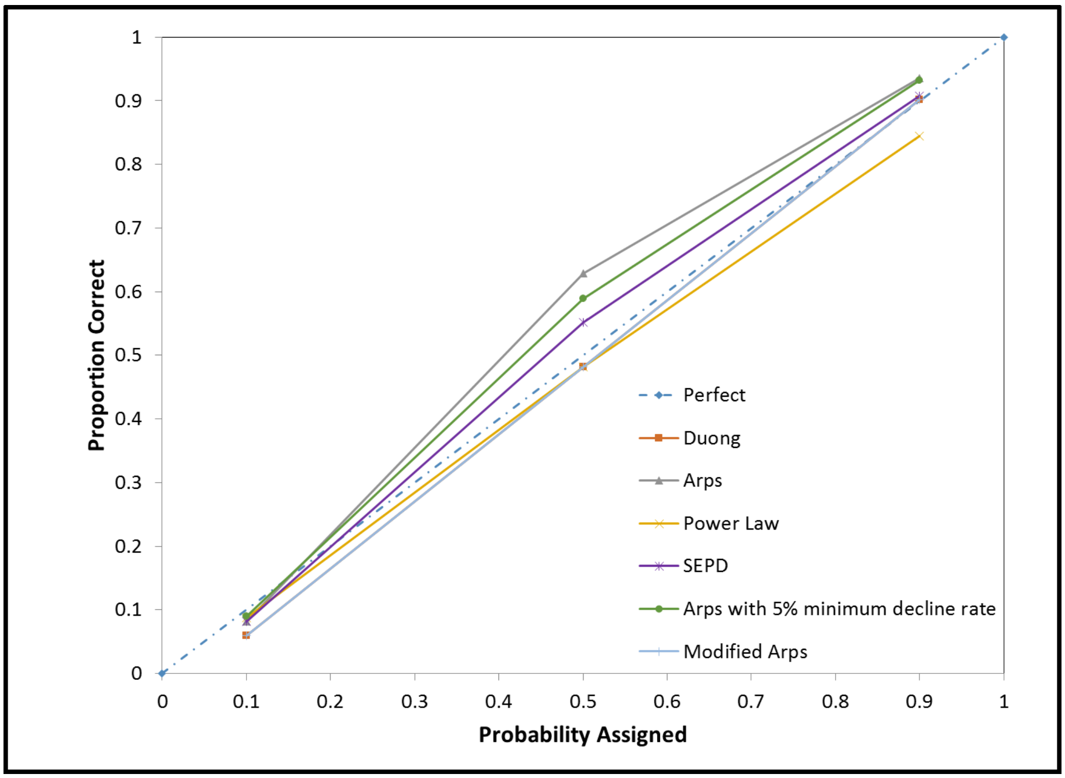

Fig. 25—The calibration plots for all DCA models in the dry-gas region using the first twelve months of the production data as the history part in the hindcast study.

Table 19—The coverage rates and calibration scores for all DCA models in the dry-gas region using the first twelve months of the production data as the history part in the hindcast study.

DCA Model	Coverage Rate	Calibration Score
Duong	84%	0.0007
Arps	85%	0.0060
Power Law	75%	0.0012
SEPD	83%	0.0010
Arps with 5% minimum decline rate	84%	0.0030
Modified Arps	84%	0.0007

From the calibration plots in Figs. 22 through 25 and the values of the coverage rates and calibration scores in Tables 16 through 19, it can be concluded that Duong's DCA model is well calibrated and gives the most consistent performance among the DCA models. Duong's DCA model always has the closest plot to the perfect unit-slope line on the calibration plots. It was only rivaled by the modified Arps' DCA model in Fig. 25. The calibration scores for Duong's DCA model are also consistently low and its CR values are consistently close to 80%.

It can be concluded from the hindcast study that the MCMC method combined with the Duong DCA model can reliably quantify uncertainty in production forecasting and reserves estimation in the WV Marcellus shale play. The hindcast results showed that Duong's DCA model was best calibrated and it was thus selected to be used in generating type probabilistic decline curves for this work.

Increasing the number of the MCMC iterations to 10,000 for the hindcast study was performed using Duong's DCA model to check whether it could improve the hindcast results. **Figs. 26 through 29** show the calibration plots for the hindcast study using 1000 and 10,000 MCMC iterations. **Tables 20 through 23** show the coverage rates and the calibration scores.

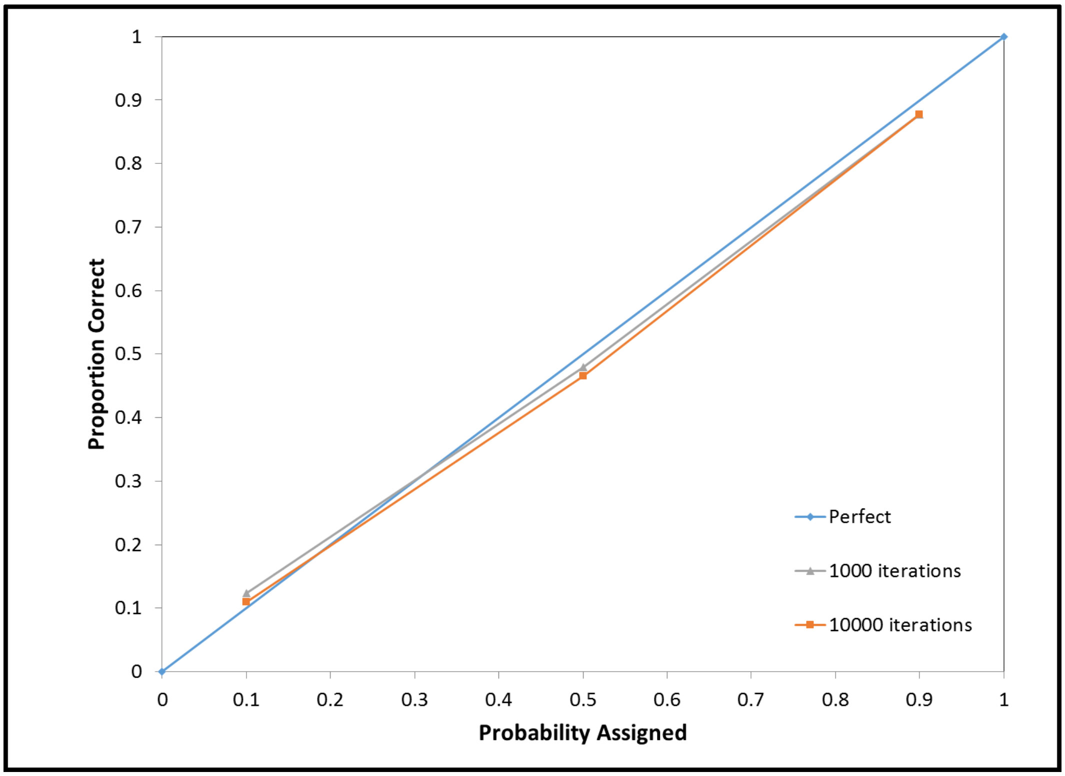

Fig. 26—The calibration plots for Duong's DCA model with 1000 and 10,000 MCMC iterations in the liquid-rich region using the first six months of production data as the history part in the hindcast study.

Table 20—The coverage rates and calibration scores for Duong's DCA model with 1000 and 10,000 MCMC iterations in the liquid-rich region using the first six months of production data as the history part in the hindcast study.

Iterations	Coverage Rate	Calibration Score
1000	75%	0.0005
10000	77%	0.0006

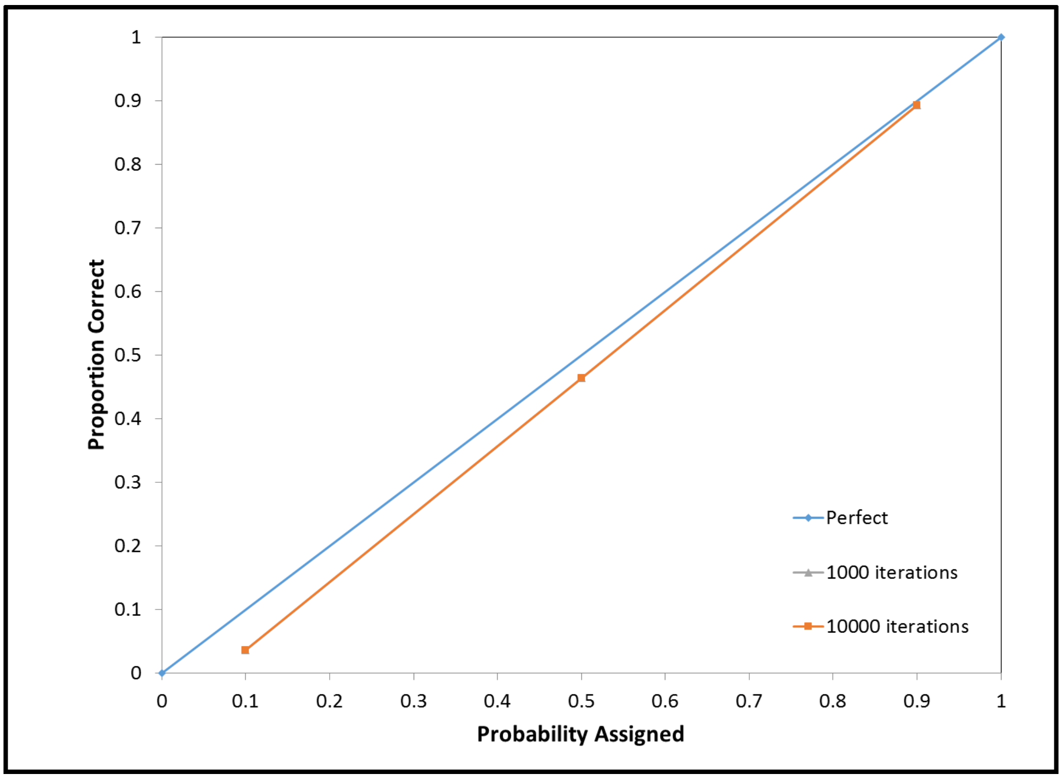

Fig. 27—The calibration plots for Duong's DCA model with 1000 and 10,000 MCMC iterations in the liquid-rich region using the first twelve months of production data as the history part in the hindcast study.

Table 21—The coverage rates and calibration scores for Duong's DCA model with 1000 and 10,000 MCMC iterations in the liquid-rich region using the first twelve months of production data as the history part in the hindcast study.

Iterations	Coverage Rate	Calibration Score
1000	86%	0.0018
10000	86%	0.0052

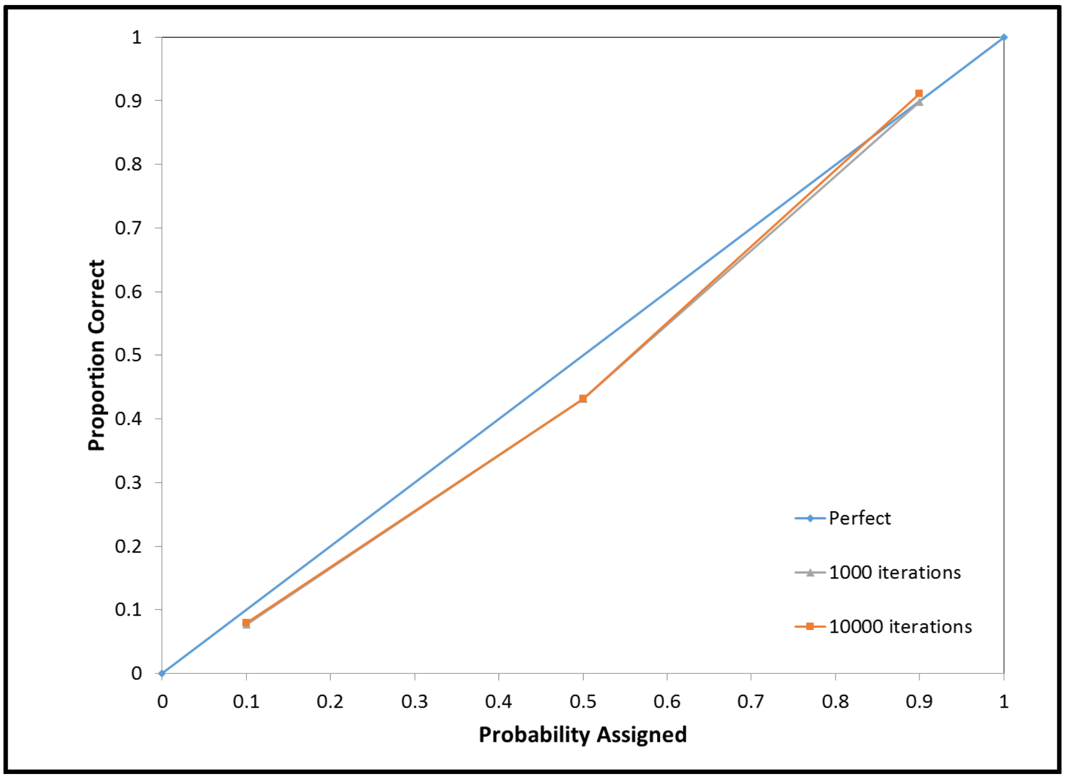

Fig. 28—The calibration plots for Duong's DCA model with 1000 and 10,000 MCMC iterations in the dry-gas region using the first six months of production data as the history part in the hindcast study.

Table 22—The coverage rates and calibration scores for Duong's DCA model with 1000 and 10,000 MCMC iterations in the dry-gas region using the first six months of production data as the history part in the hindcast study.

Iterations	Coverage Rate	Calibration Score
1000	82%	0.0018
10000	83%	0.0018

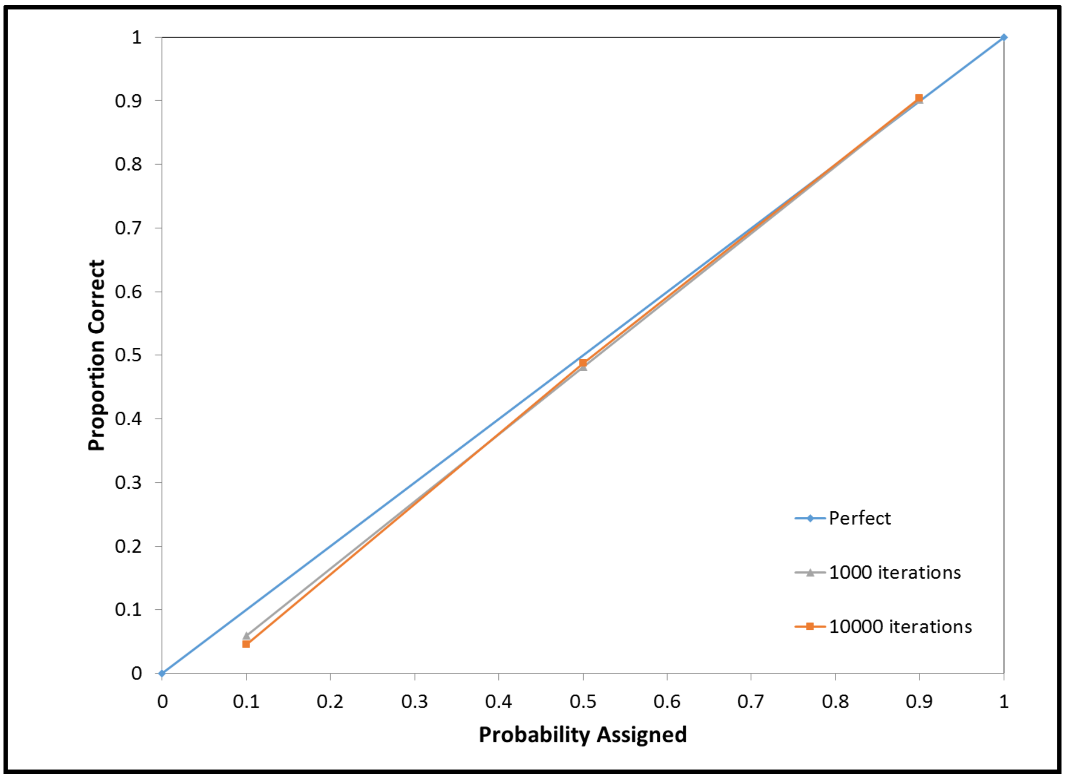

Fig. 29—The calibration plots for Duong's DCA model with 1000 and 10,000 MCMC iterations in the dry-gas region using the first twelve months of production data as the history part in the hindcast study.

Table 23—The coverage rates and calibration scores for Duong's DCA model with 1000 and 10,000 MCMC iterations in the dry-gas region using the first twelve months of production data as the history part in the hindcast study.

Iterations	Coverage Rate	Calibration Score
1000	84%	0.0007
10000	86%	0.0011

From the calibration plots in Figs. 26 through 29 and the coverage rates and calibration scores in Tables 20 through 23, it can be seen that increasing MCMC iterations from 1000 to 10,000 iterations does not result in significant improvement in the hindcast results; it only makes the simulation running time longer. Therefore, it was decided that using 1000 MCMC iterations for Duong's DCA model was sufficient.

3.5. Generating Type Probabilistic Decline Curves

Type probabilistic decline curves were generated to estimate reserves and resources of the play. These type probabilistic decline curves for both the liquid-rich and dry-gas regions represent the distributions of NGL and gas production of each well in the WV Marcellus shale play. The steps used to generate the type probabilistic decline curves are as follows.

- Rank all the wells in each region based on the cumulative production at the longest time when all or most of the wells have actual monthly production data. Sort all the wells from the smallest to the largest cumulative production value.

- Take the 10th, 50th, and 90th percentile of the wells and some wells above and below the percentile wells, and average the wells' production data for each percentile for each month. For example, if the number of wells in a region is 400, then the 40th well will be the 10th percentile well, the 200th well will be the 50th percentile well, and the 360th well will be the 90th percentile well. Some wells above and below the 40th, 200th, and 360th well are considered in the average monthly production data calculation. The numbers of wells above and below the percentile wells are different between the liquid-rich and dry-gas regions due to the different number of wells available in each region. In the dry-gas region, 10 wells above and below the percentile wells are selected. In the liquid-rich region, the maximum number of wells above and below the percentile wells that can be selected is 7.
- Fit Duong's DCA model to the average monthly production data for each percentile. The curve that fits the average monthly production data from the 90th percentile well group becomes the top (P90) curve of the type probabilistic decline curves. The curve that fits the average monthly production data from the 50th percentile well group becomes the middle (P50) curve of the type probabilistic decline curves. The curve that fits the average monthly production data from the 10th percentile well group becomes the bottom (P10) curve of the type probabilistic decline curves.
- Use the D_{min} distribution for gas production from Gong *et al.* (2013) to force exponential decline in the gas type probabilistic decline curves for both the dry-

gas and liquid-rich regions. Use the D_{min} distribution for oil/NGL production from Gong *et al*. (2013) for the NGL type probabilistic decline curves in the liquid-rich region. Duong (2011) based his DCA model on long-term linear flow, which means that relying solely on this method will overestimate TRR. Imposing D_{min} values to the type probabilistic decline curves will handle this problem. In order to create a wide enough decline tails and to incorporate uncertainty in long-term trends of the type probabilistic decline curves, different values of D_{min} for the bottom (P10), middle (P50), top (P90) curves were used; D_{min} value for the bottom (P10) curve > D_{min} value for the middle (P50) curve > D_{min} value for the top (P90) curve. The 10th percentile of the D_{min} distribution from Gong *et al.* (2013) is assigned as the D_{min} value for the top (P90) curve, the 50th percentile is assigned as the D_{min} value for the middle (P50) curve, and the 90th percentile is assigned as the D_{min} value for the bottom (P10) curve.

- Calibration plots are used to confirm whether the type probabilistic decline curves are well calibrated by comparing cumulative production (G_p) and production rate data between the type probabilistic decline curves and the actual production data.

Since there was no long-term production data available in the Marcellus shale play, there should be considerable uncertainty reflected in the decline tails of the probabilistic type curves. The P90-to-P10 ratio was used to judge the proper spread of the tails. A P90-to-P10 ratio in the 6-to-10 range was deemed to be a reasonable expression of the uncertainty in the long-term decline curves, given that there was no other information available for quantifying uncertainty.

3.5.1 Type Probabilistic Decline Curves for the Dry-Gas Region

Cumulative production data at the 12th month were selected to rank the wells. At the 12th month, most of the wells in the dry-gas region still had actual monthly production data. Out of 392 wells in this region, only 3% of the wells did not have actual production data. These 3% of the wells have some extrapolated monthly production data from the actual production data using Duong's DCA model (forecasted). For 392 wells, the 10th percentile of the wells is the 40th well, the 50th percentile of the wells is the 197th well, and the 90th percentile of the wells is the 353rd well. Ten wells above and below the percentile wells were included in the average monthly production calculation. DCA curves based on Duong's DCA model were fitted to the three average monthly production data streams to get Duong's DCA parameters that were used to generate the top (P90), middle (P50), and bottom (P10) curves of the type probabilistic decline curves for the dry-gas region.

The D_{min} distribution for gas production in the Eagle Ford play from Gong *et al*. (2013) was used for generating gas type probabilistic decline curves for the dry-gas region. **Fig. 30** and **Table 24** show the gas D_{min} distribution and the P10, P50, and P90 values of this D_{min} distribution, respectively. The P10, P50, and P90 values of this D_{min} distribution were then imposed to the top (P90), middle (P50), and bottom (P10) curves of the type probabilistic decline curves. **Figs. 31 and 32** show the type probabilistic decline curves for the dry-gas region and how the curves compare to the actual production data, respectively.

To check whether the type probabilistic decline curves for this region represent well the actual production data, the cumulative production at the 6th, 8th, and 12th month, along with the production rate at the 8th and 12th month from the actual data, were compared to similar values from the type probabilistic decline curves. In every comparison there should be 90% of the actual production data that exceed the P10 value, 50% of the actual production data that exceed the P50 value, and 10% of the actual production data that exceed the P90 value. The results are presented in calibration plots (**Fig. 33**) and calibration scores (**Table 25**).

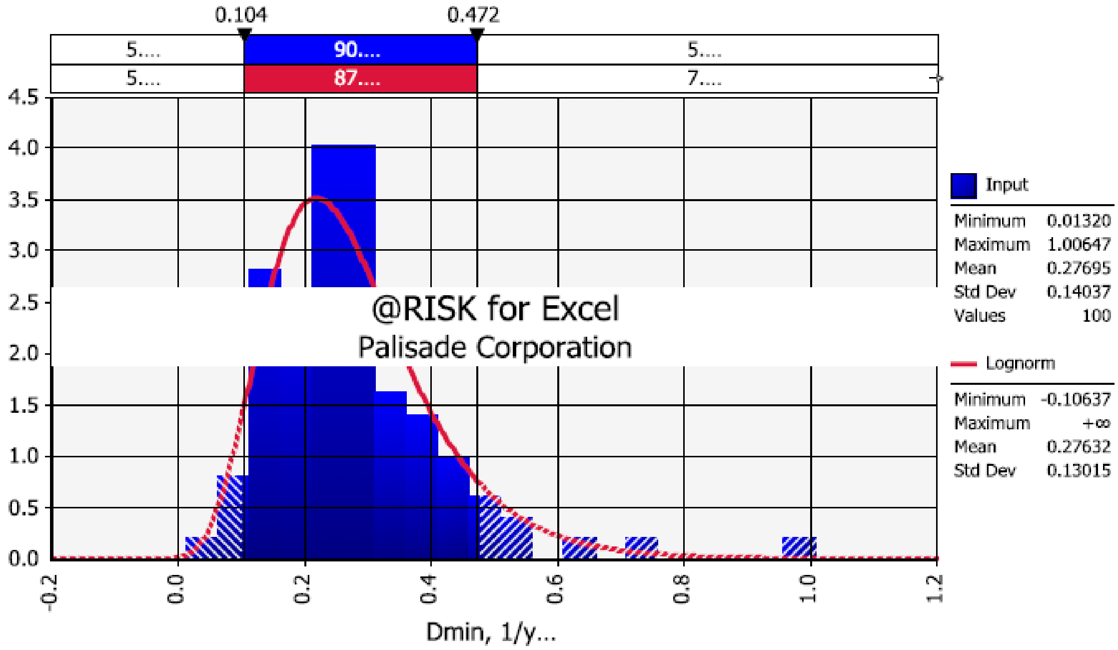

Fig. 30—D_{min} distribution for gas production in the Eagle Ford play (Gong *et al.* 2013).

Table 24—P10, P50, and P90 values of the Gong *et al.* (2013) D_{min} distribution for gas production in the Eagle Ford play.

Percentile	Dmin Value
P10	0.14082
P50	0.24985
P90	0.4427

Fig. 31—The type probabilistic decline curves for the dry-gas region.

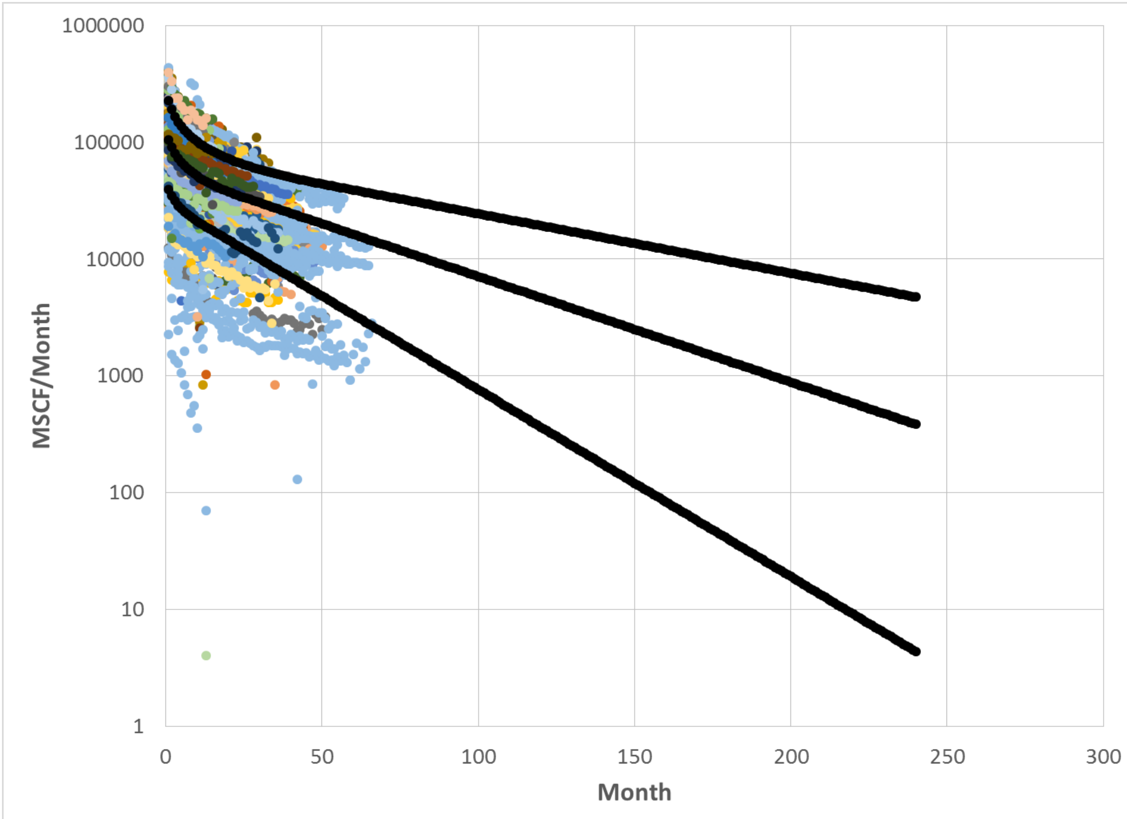

Fig. 32—The type probabilistic decline curves for the dry-gas region compared to the actual production data.

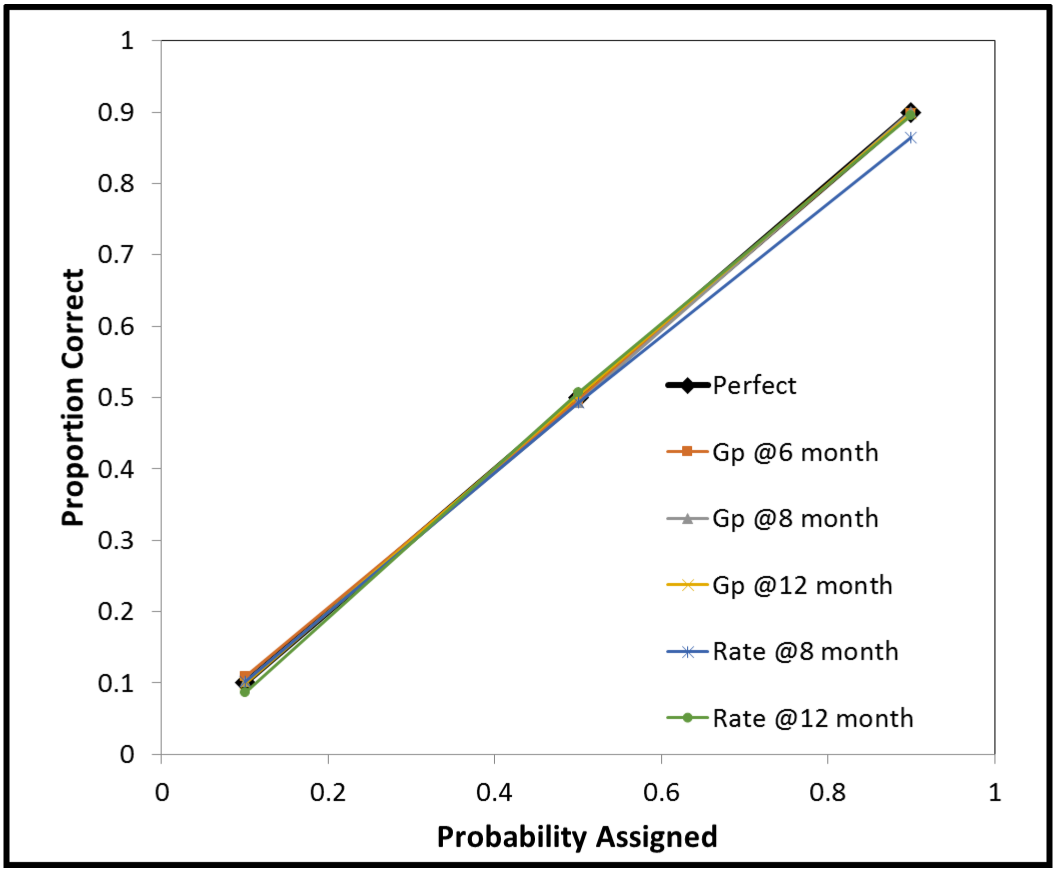

Fig. 33—The calibration plots for the comparison between the type probabilistic decline curves and actual production data in the dry-gas region.

Table 25—The calibration scores for the comparison between the type probabilistic decline curves and actual production data in the dry-gas region.

Comparison Base	Calibration Score
Gp @6 month	0.00003
Gp @8 month	0.00002
Gp @12 month	0.00000
Rate @8 month	0.00043
Rate @12 month	0.00009

Fig. 32 suggests that the type probabilistic decline curves might bracket the actual production data quite well. It is difficult to tell from the plot because the production data are so crowded. However, the calibration plots and calibration scores in Fig. 33 and Table 25 confirm that the type probabilistic decline curves for this region are well calibrated, which means that the type probabilistic decline curves represent the uncertainty in the actual data quite well. The P90-to-P10 ratio of the TRR20 values from these type probabilistic decline curves equals 8.61, indicating that considerable uncertainty is represented in the long-term trends of the type probabilistic decline curves.

3.5.2 Gas Type Probabilistic Decline Curves for the Liquid-Rich Region

Since the number of wells in the liquid-rich region was much smaller than in the dry-gas region, there was a selection limitation on the time when all or most of the wells have actual production data and on the number of wells above and below the percentile wells that can be included in the average monthly production calculation. Cumulative production data at the 8th month were selected to rank the wells. At the 8th month, all the wells in the liquid-rich region still had actual monthly production data. There were 68 wells with suitable gas production data available in the liquid-rich region. For 68 wells, the 10th percentile of the wells is the 8th well, the 50th percentile is the 35th well, and the 90th percentile is the 62nd well. Only a maximum of seven wells above and below the percentile wells can be included in the average monthly production calculation.

Using the same D_{min} distribution and the P10, P50, and P90 values of the D_{min} distribution as in the dry-gas region (Fig. 30 and Table 24), the gas type probabilistic decline curves for the liquid-rich region were generated. **Figs. 34 and 35** show the gas type probabilistic decline curves for the liquid-rich region and how the curves compare to actual production data, respectively. **Fig. 36** and **Table 26** show the calibration plots and calibration scores of the type probabilistic decline curves and actual data comparison, respectively.

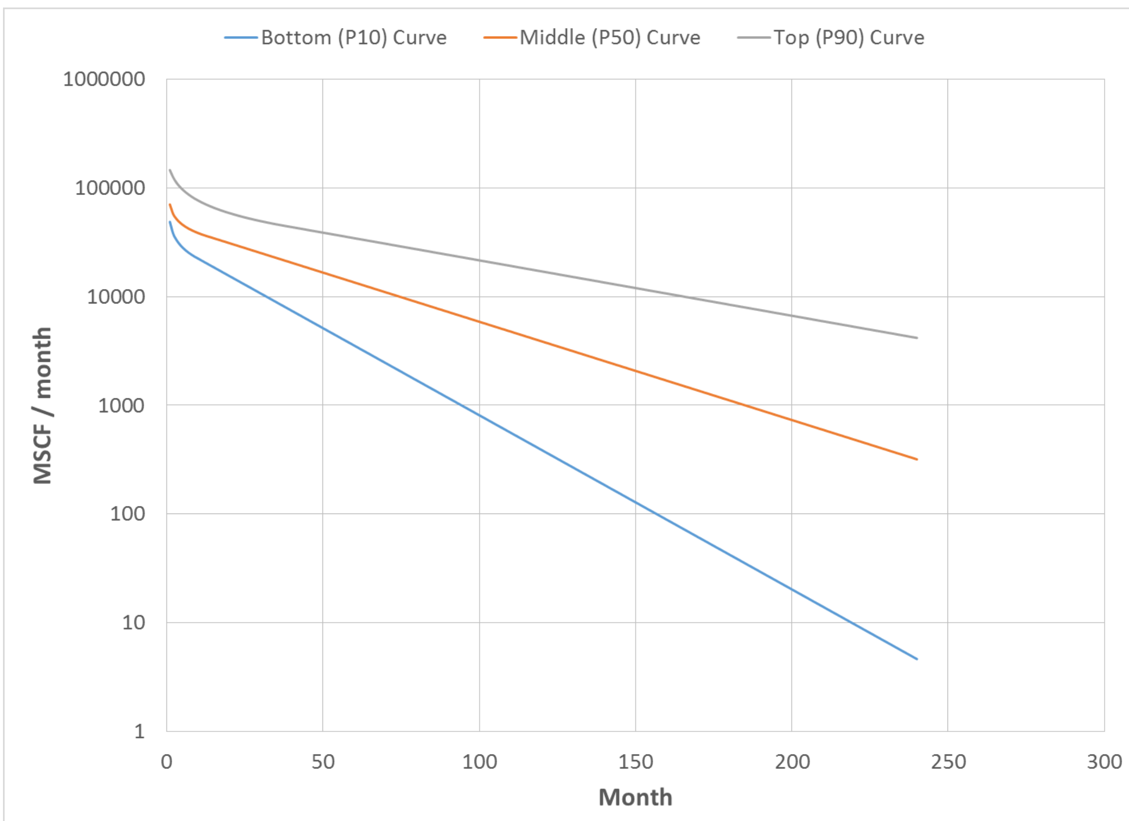

Fig. 34—The gas type probabilistic decline curves for the liquid-rich region.

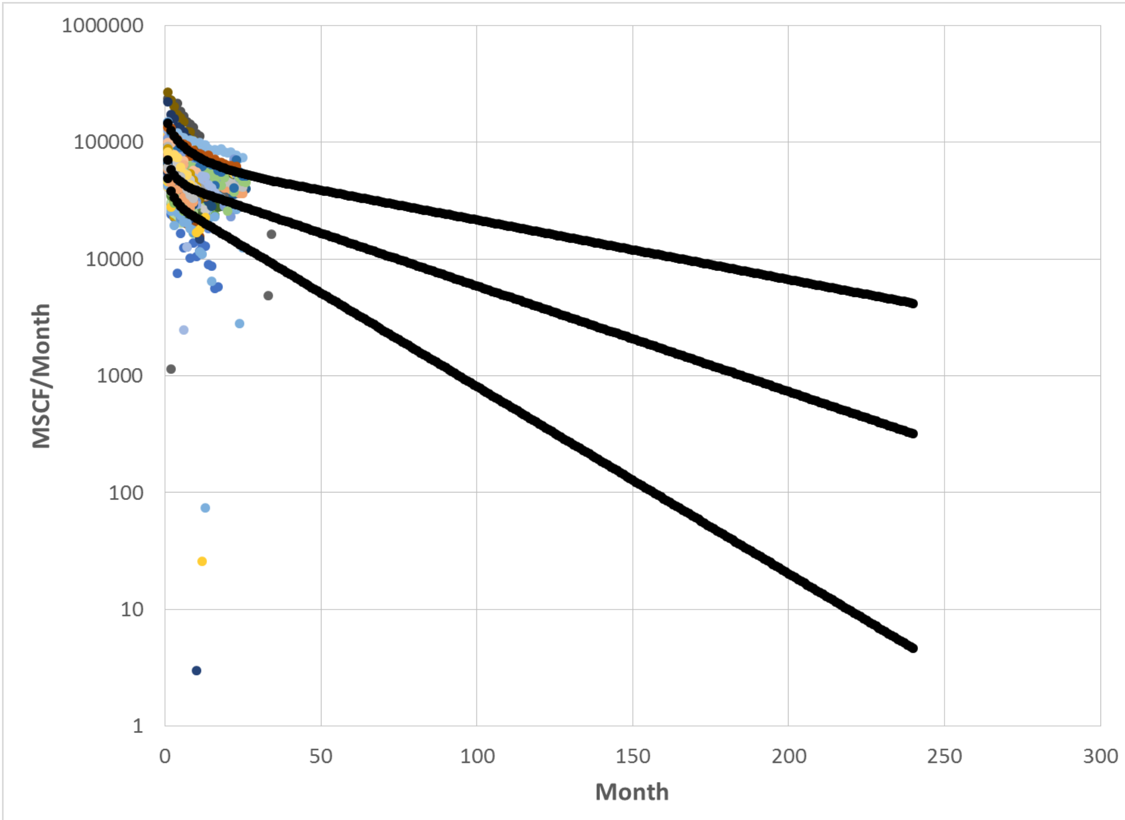

Fig. 35—The gas type probabilistic decline curves for the liquid-rich region on top of the actual production data.

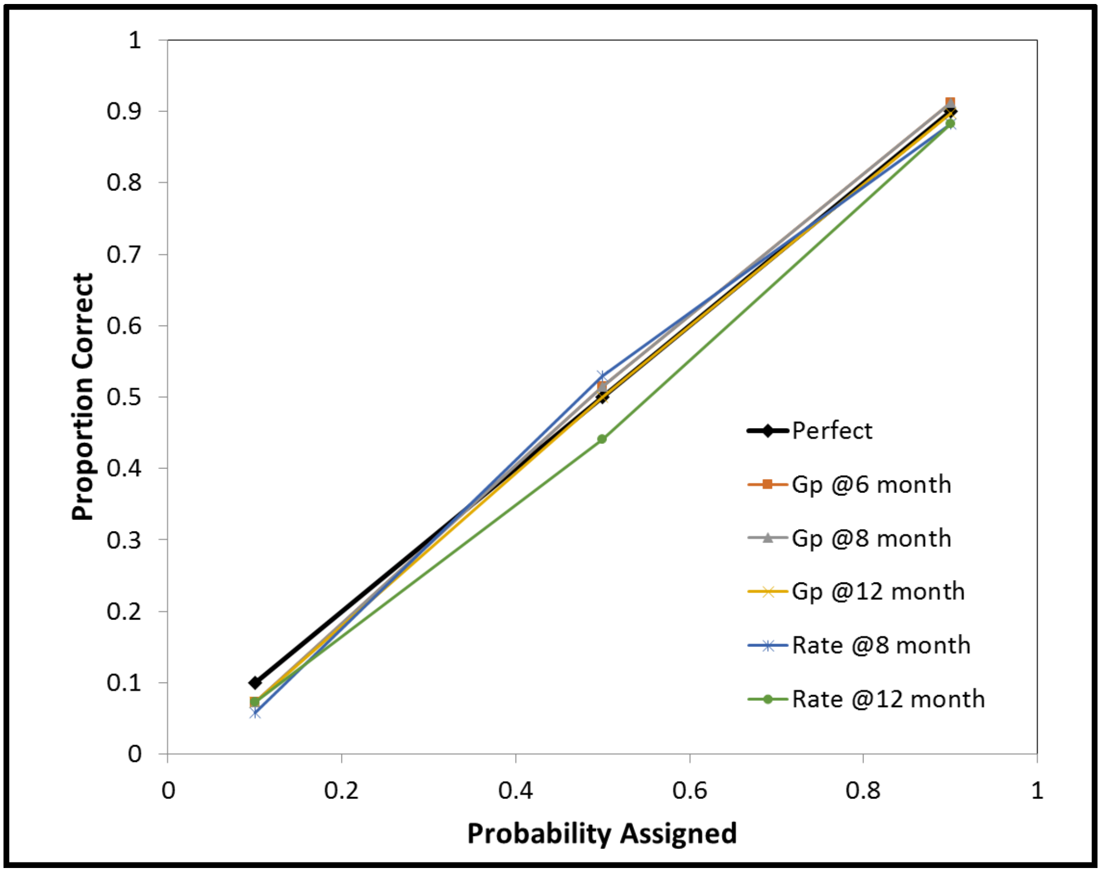

Fig. 36—Calibration plots for the comparison between the gas type probabilistic decline curves and actual gas production data in the liquid-rich region.

Table 26—The calibration scores for the comparison between the gas type probabilistic decline curves and actual gas production data in the liquid-rich region.

Comparison Base	Calibration Score
Gp @6 month	0.00035
Gp @8 month	0.00035
Gp @12 month	0.00024
Rate @8 month	0.00039
Rate @12 month	0.00149

Fig. 35 suggests that the type probabilistic decline curves bracket the actual production data quite well. It is confirmed by the calibration plots in Fig. 36, which are quite close to the unit-slope line, and by the calibration scores in Table 26, which are quite small. The P90-to-P10 ratio of the TRR20 values from these type probabilistic decline curves is 6.68, indicating that considerable uncertainty is represented in the long-term trends of the type probabilistic decline curves, as expected.

3.5.3 NGL Type Probabilistic Decline Curves for the Liquid-Rich Region

As with the gas type probabilistic decline curves in this region, cumulative production data at the 8th month was selected to rank the wells for NGL production. At the 8th month, all the wells in this region still had actual monthly production data. There were 73 wells with suitable NGL production data available in the liquid-rich region. The percentile wells for 73 wells are the same as for 68 wells, which are the 8th well for the 10th percentile well, the 35th well for the 50th percentile well, and the 62nd well for the 90th percentile well. Six wells above and below the percentile wells were included in the average monthly production calculation. A maximum of seven wells above and below the percentile wells was tried, but the result was not good. The middle curve fell slightly under the bottom curve at the end of forecast, which is not right. Thus, six wells above and below the percentile wells were used.

For generating the NGL type probabilistic decline curves for the liquid-rich region, the D_{min} distribution for oil/NGL production in the Eagle Ford play from

Gong *et al*. (2013) was used. **Fig. 37** and **Table 27** show the D_{min} distribution and the P10, P50, and P90 values for this distribution, respectively.

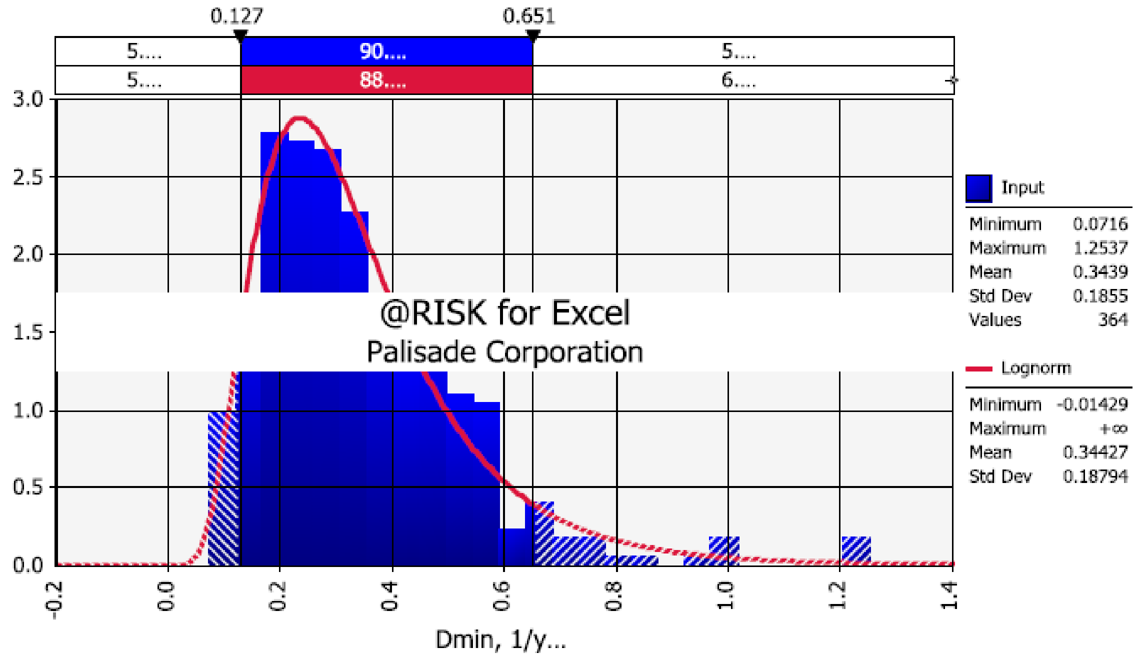

Fig. 37—D_{min} distribution for oil/NGL production in the Eagle Ford play (Gong *et al*. 2013).

Table 27—P10, P50, and P90 values of Gong *et al*. (2013) D_{min} distribution for oil/NGL production in the Eagle Ford play.

Percentile	Dmin Value
P10	0.1579
P50	0.322
P90	0.5775

Figs. 38 and 39 show the oil/NGL type probabilistic decline curves for the liquid-rich region and how the type curves compares to the actual production data, respectively. **Fig. 40** and **Table 28** show these calibration plots and calibration scores of the type probabilistic decline curves and actual data comparison, respectively.

Fig. 38—The NGL type probabilistic decline curves for the liquid-rich region.

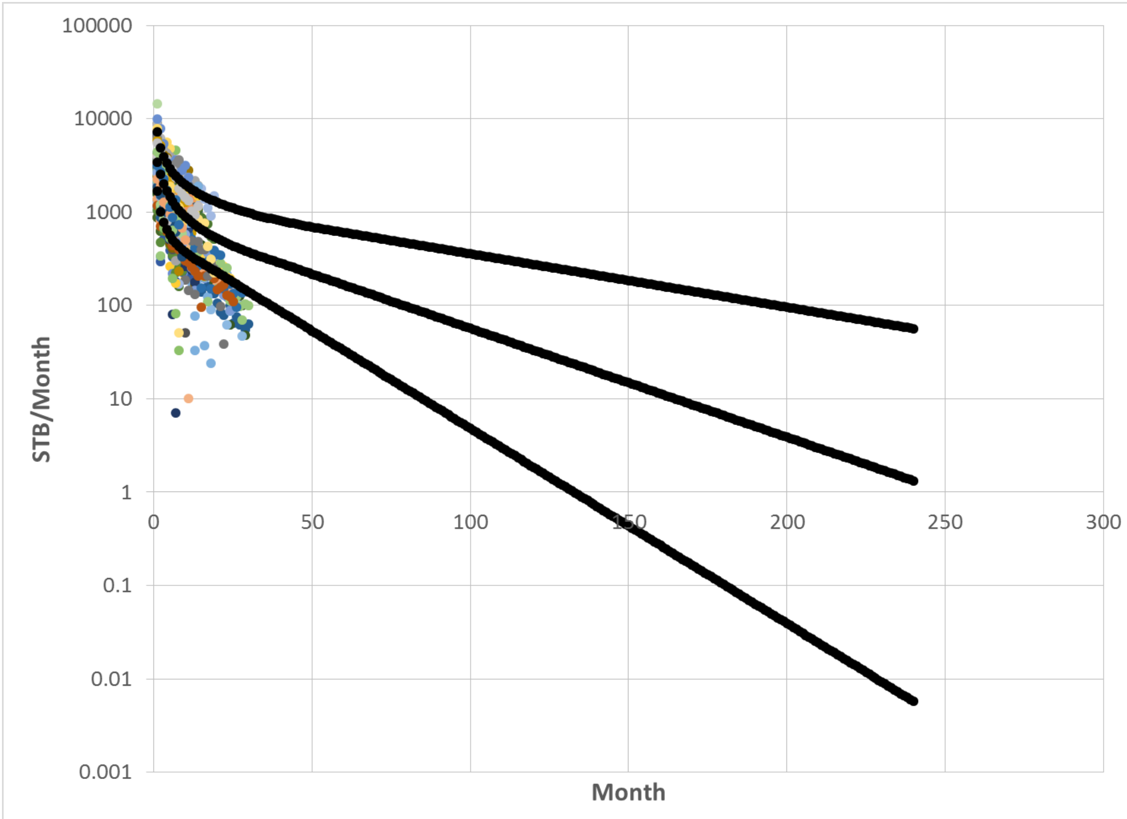

Fig. 39—The NGL type probabilistic decline curves for the liquid-rich region compared to the actual production data.

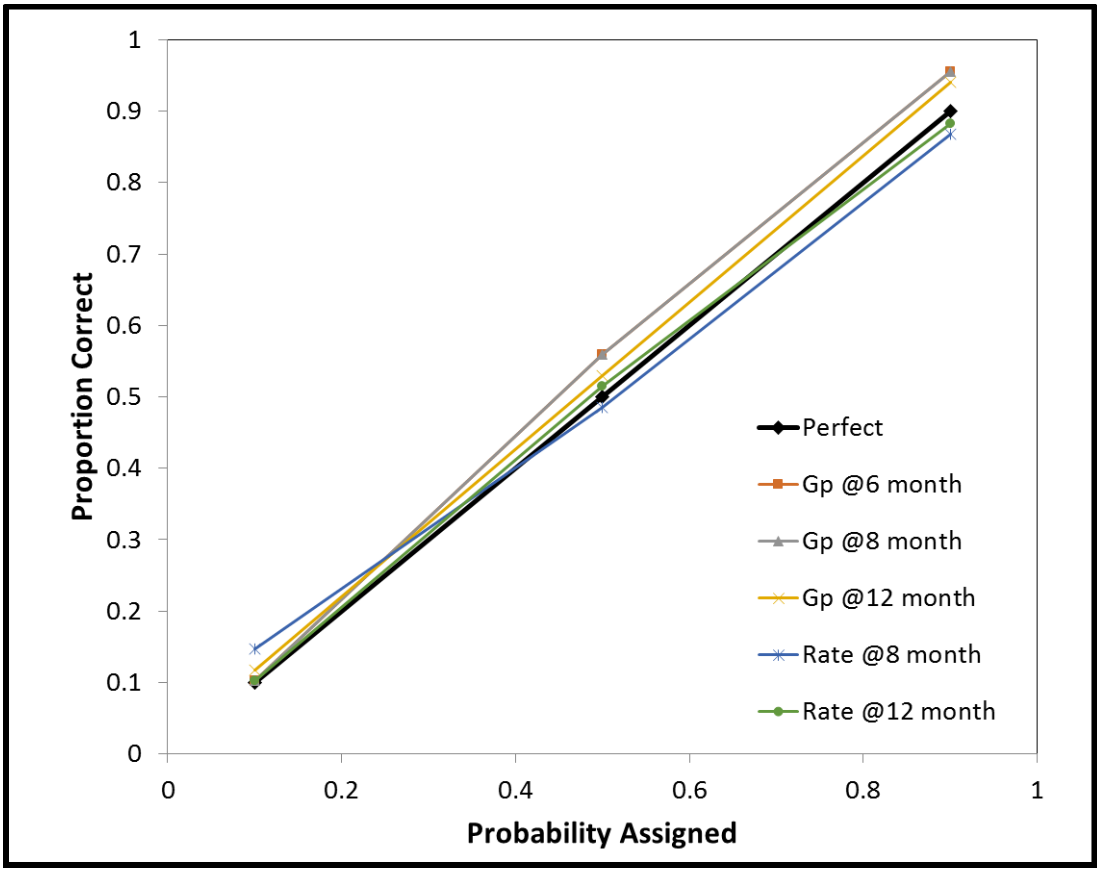

Fig. 40—Calibration plots for the comparison between the NGL type probabilistic decline curves and actual NGL production data in the liquid-rich region.

Table 28—Calibration scores for the comparison between NGL type probabilistic decline curves and actual NGL production data in the liquid-rich region.

Comparison Base	Calibration Score
Gp @6 month	0.00220
Gp @8 month	0.00220
Gp @12 month	0.00096
Rate @8 month	0.00042
Rate @12 month	0.00018

As with the other two type probabilistic decline curves, these curves also represent the actual production data quite well (Fig. 39). This is confirmed in the calibration plots in Fig. 40, which are quite close to the unit-slope line, and also in the calibration scores in Table 28, which are quite small. These type probabilistic decline curves also capture the large uncertainty in long-term production; the curves have an 8.69 P90-to-P10 ratio of the TRR20 values.

Table 29 shows the summary of the D_{min} values, TRR20, and P90-to-P10 ratio of the TRR20 values for both fluid types in the dry-gas region and liquid-rich region. It can be seen that all of the three type probabilistic decline curves (with P90-to-P10 ratios between 6 and 10) indicate considerable uncertainty in production over the next 20 years.

Table 29—Summary of the D_{min} values, TRR20, and P90-to-P10 ratio of the TRR20 values for both fluid types in both regions.

		Dry Gas Region	Liquid-Rich Region	
			For Gas Production	For NGL Production
Dmin	P10	0.14	0.14	0.16
	P50	0.25	0.25	0.32
	P90	0.44	0.44	0.58
TRR20 (Gas in MMSCF NGL in MBNGL)	P10	840.03	897.69	14.28
	P50	2894.86	2283.34	41.02
	P90	7233.82	5992.24	124.09
P90-to-P10 ratio of the TRR20		8.61	6.68	8.69

3.6. WV Marcellus Shale Play Reserves and Resources Estimates

The reserves and resources estimation for the WV Marcellus shale play was performed by using Monte Carlo simulation. The inputs for this simulation were well spacing, drilling rate, success ratio, percent area with potential, and the TRR20 distribution of each well in the play. The simulation outputs were well counts and reserves/resources estimates for the play. In order to calculate well counts, the discovered and undiscovered areas of the play were defined. The wells in the WV Marcellus shale play are assumed to be perfectly correlated in the simulation. The wells were assumed to be perfectly correlated (completely dependent) to each other. It means that if one well has high production, the other wells also have high production, and vice versa.

3.6.1. Reservoir Area

SPE *et al*. (2007) stated that the criterion that separates reserves and contingent resources is commerciality, and the criterion that distinguishes contingent resources from prospective resources is discovery. In order to observe commerciality of oil and gas wells, oil and gas price data are needed. These data (**Fig. 41**) were taken from Bloomberg (2015)**.** In order to simplify the calculations, it was assumed that the oil price was \$50/STB and the gas price was \$3/MSCF. **Table 30** shows the mean monetary value calculation for a well with the type probabilistic decline curves explained in Subchapter 3.5 in both regions.

Energy & Oil Prices

CRUDE OIL & NATURAL GAS

Commodity	Units	Price	Change	% Change	Contract	Time(ET)
Crude Oil (WTI)	USD/bbl.	48.26	+0.48	+1.00%	Mar 15	08:45:57
Crude Oil (Brent)	USD/bbl.	49.83	+0.80	+1.63%	Mar 15	08:45:36
TOCOM Crude Oil	JPY/kl	38,420.00	+280.00	+0.73%	Jun 15	08:46:55
NYMEX Natural Gas	USD/MMBtu	2.93	-0.05	-1.55%	Feb 15	08:46:34

REFINED PRODUCTS

Commodity	Units	Price	Change	% Change	Contract	Time(ET)
RBOB Gasoline	USd/gal.	133.77	+1.22	+0.92%	Feb 15	08:46:56
NYMEX Heating Oil	USd/gal.	167.15	+2.51	+1.52%	Feb 15	08:46:41
ICE Gasoil	USD/MT	485.25	+14.75	+3.13%	Mar 15	08:45:41
TOCOM Kerosene	JPY/kl	49,840.00	+310.00	+0.63%	Jul 15	08:46:56

EMISSIONS

Commodity	Units	Price	Change	% Change	Contract	Time(ET)
ICE ECX Emissions	EUR/MT	7.15	-0.26	-3.51%	Dec 15	09:06:16

Bloomberg Oil Buyers Guide subscriber? Log in

Fig. 41—Oil and gas price data (Bloomberg 2015).

Table 30—Mean monetary value calculation for both regions.

	Liquid-Rich Region		Dry Gas Region
	TRR20ngl (STB)	TRR20gas (BSCF)	TRR20gas (BSCF)
P10	14,279	0.90	0.84
P50	41,016	2.28	2.89
P90	124,091	5.99	7.23
Mean	59,896	3.04	3.62
Mean Monetary Value	$12,122,907.89		$10,855,631.22

Toon (2015) reported that the drilling and completion cost for a Marcellus well is \$6.5–7 million. Dugan (2014) from CONSOL Energy and McCown (2014) from GASTAR stated that the typical well cost for a well in the Marcellus shale play is \$6.7 million. The mean monetary values in Table 30 are greater than the maximum well cost from these sources, which is \$7 million.

In order to estimate discovered and undiscovered areas, the method of Gong *et al*. (2013) was used. They identified the area within a particular radius from the existing wells as the discovered area and the area outside the radius as the undiscovered area. To get the value of the radius, a variogram analysis of peak month gas production was calculated. The latitude and longitude values of the wells were converted to northing (y coordinate) and easting (x coordinate) to show the wells' locations. **Fig. 42** shows the areal distribution of peak month gas in the WV Marcellus shale play. The peak month gas value of each well is shown in color, and the color scale is shown in a color bar.

A variogram analysis was then performed to see the correlation between two wells with a lag interval of 0.5 miles. **Fig. 43** shows the variogram of the peak month gas data. In variogram analysis, the sill is the semivariance value at which the variogram levels off, which is the variance of the data. The range is the lag distance at which the semivariance reaches the sill value. There is no correlation between well pairs if the lag distance is beyond the range value. From Fig. 43, it can be inferred that the range of the variogram is 12 miles. Any wells that are located within this distance of a well have significant correlation in their peak month gas productions. This 12-mile distance was used as the radius to determine the discovered and undiscovered areas. Circles with 12-mile radii were then drawn around all of the existing wells (**Fig. 44**). The areas inside the circles were considered the discovered area, while the areas outside the circles were considered the undiscovered area.

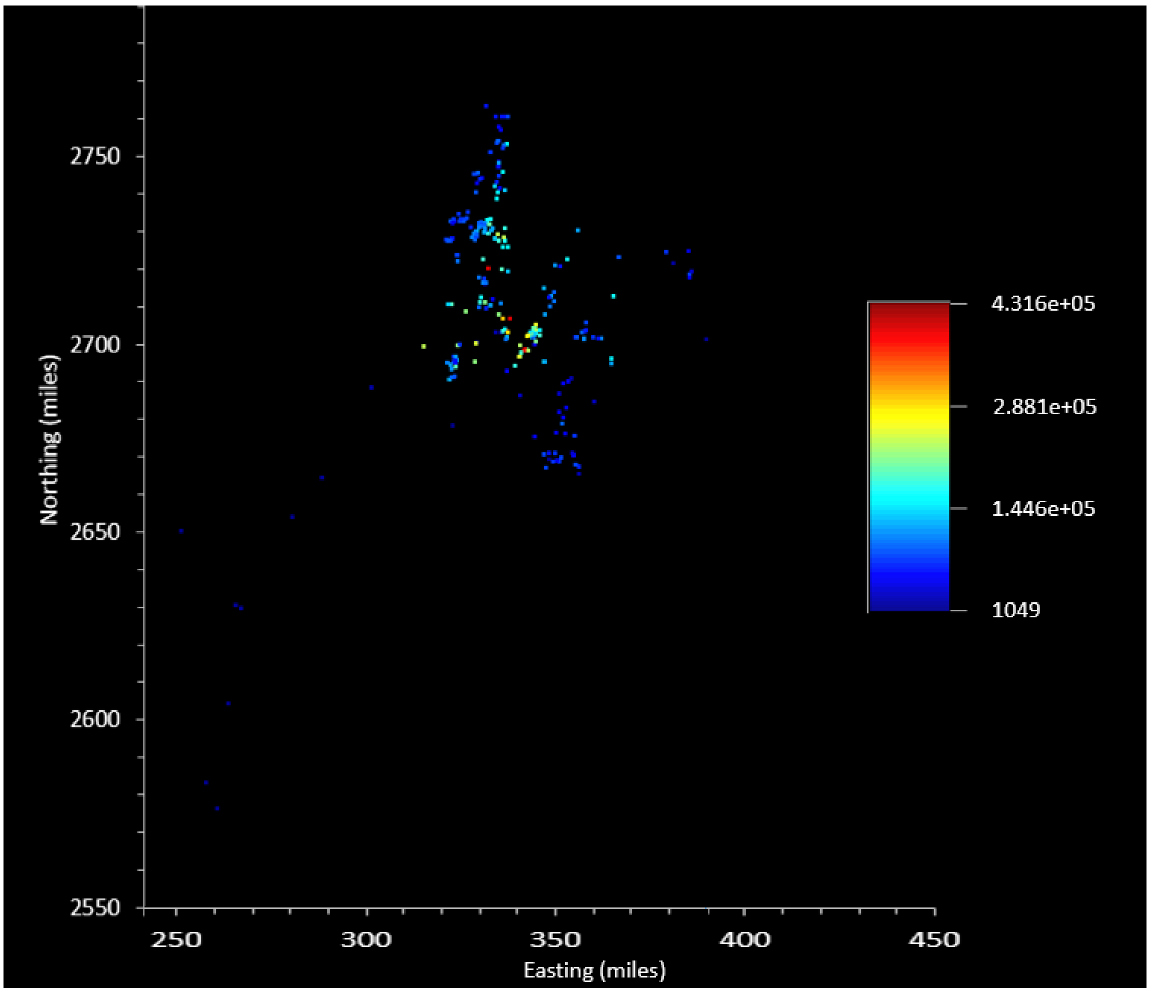

Fig. 42—Distribution of peak month gas of the wells in the WV Marcellus shale play.

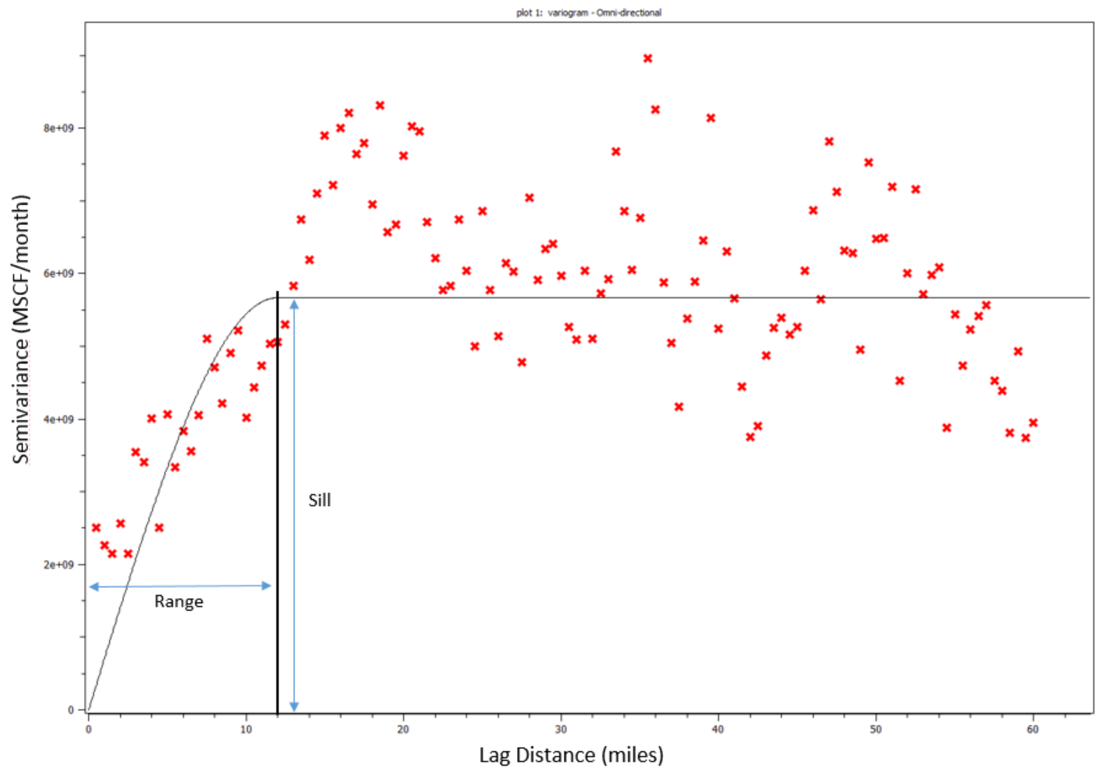

Fig. 43—Variogram of peak month gas of the wells in the WV Marcellus shale play.

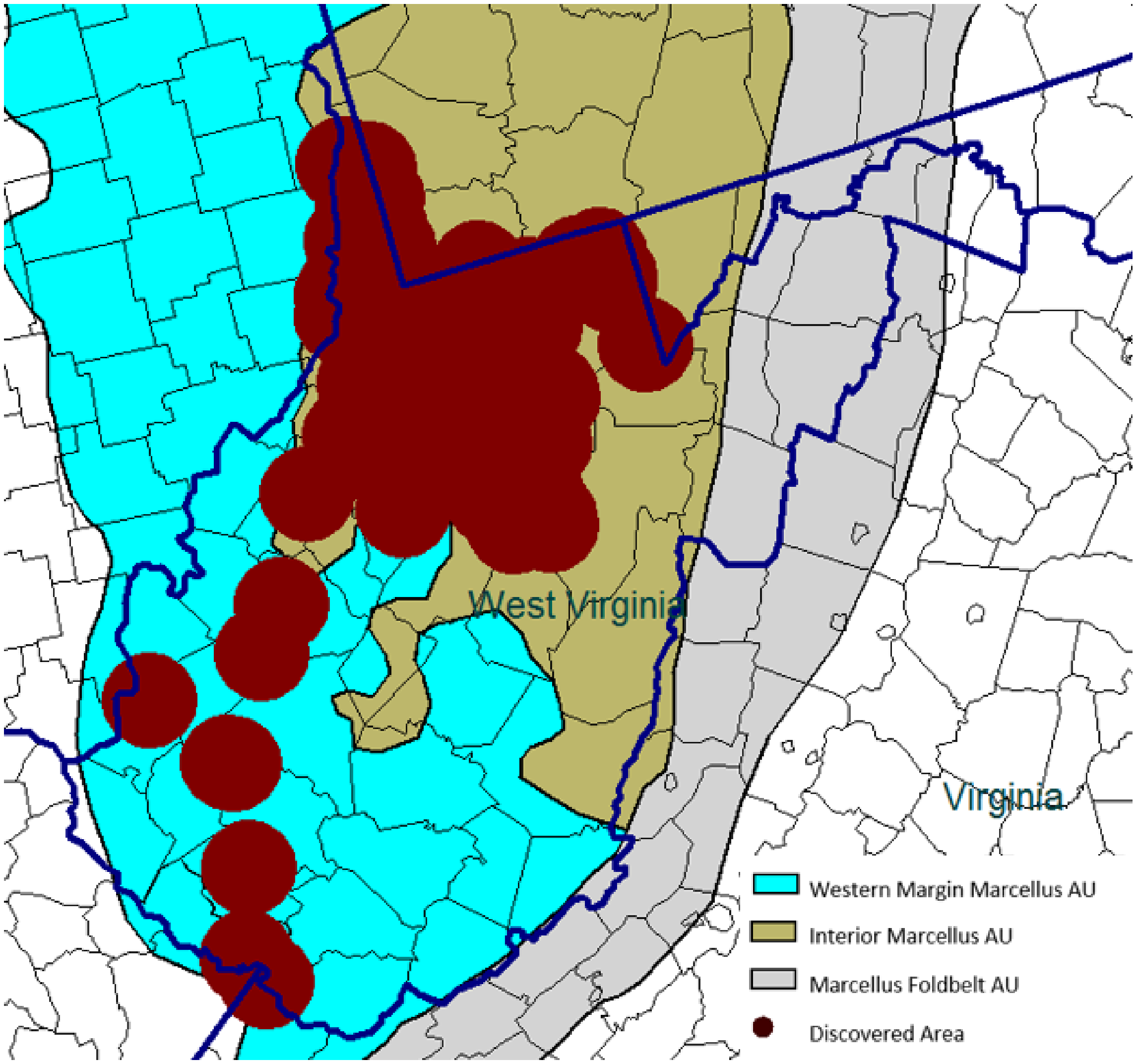

Fig. 44—The existing wells of the WV Marcellus shale play with 12-mile-radius circles around them.

The areas for the discovered and undiscovered regions were calculated for the three AUs. **Table 31** shows the liquid-rich and dry-gas regions areas along with the summary of the discovered and undiscovered area for all three AUs in the WV Marcellus shale play. It should be noted that the Marcellus foldbelt AU only exists in the dry-gas region.

Table 31—The discovered and undiscovered areas in the liquid-rich and dry-gas regions of the WV Marcellus shale play.

WV Marcellus Shale Play		Area (acres)
Liquid-Rich Region		1,008,851
Western AU	Discovered	32,438
	Undiscovered	244,874
	Total	277,311
Interior AU	Discovered	600,406
	Undiscovered	131,133
	Total	731,539
Dry-Gas Region		15,890,731
Western AU	Discovered	1,692,130
	Undiscovered	5,736,907
	Total	7,429,037
Interior AU	Discovered	3,118,746
	Undiscovered	3,361,041
	Total	6,479,787
Foldbelt AU	Discovered	-
	Undiscovered	1,981,907
	Total	1,981,907

3.6.2. Well Spacing, Percent of Area with Potential, and Future Success Ratio

USGS (2011b) described the three AUs along with some probabilistic distributions of estimation parameters, which were used in this work. These parameters were well spacing, percent of untested area with potential, and future success ratio. The USGS' untested area is termed undiscovered area in this work. **Table 32** shows the USGS (2011b) minimum, mode, and maximum values of the three estimation parameters' distributions for all AUs. The USGS used triangular distributions for these three parameters.

Table 32 —The minimum, mode, and maximum values of the three parameter distributions (USGS 2011a)

Assessment Unit	Well Spacing (acres/well)			Percent of area with potential (%)			Future Success Ratio (%)		
	Min	Mode	Max	Min	Mode	Max	Min	Mode	Max
Western	20	90	240	0.5	6.5	15	20	40	75
Interior	80	128	240	10	25	75	75	85	95
Foldbelt	80	128	240	0.5	3	10	20	40	60

USGS (2011a) performed its undiscovered resources assessment based on petroleum-charged cells. A cell is a volume within a continuous accumulation having areal dimensions related to the drainage area (which is not necessarily the current spacing) of wells and extending vertically through the strata to be assessed (USGS 2005b). There are three types of petroleum-charged cells: cells already tested by drilling, untested cells, and untested cells having potential to contribute to reserves in the time span of the forecast (**Fig. 45**). Only the area of untested cells with potential contributes to the resources assessment (USGS 2005b). USGS (2011a) used 30 years as the end of forecast time for its estimates and set a minimum total recovery per cell that has to be met in this 30-year forecast span. The cells that have total recovery less than the minimum total recovery value are not considered to be a significant resource in the 30-year forecast span and are excluded from the assessment (USGS 2002). The percent of area with potential is a subset of the untested AU area.

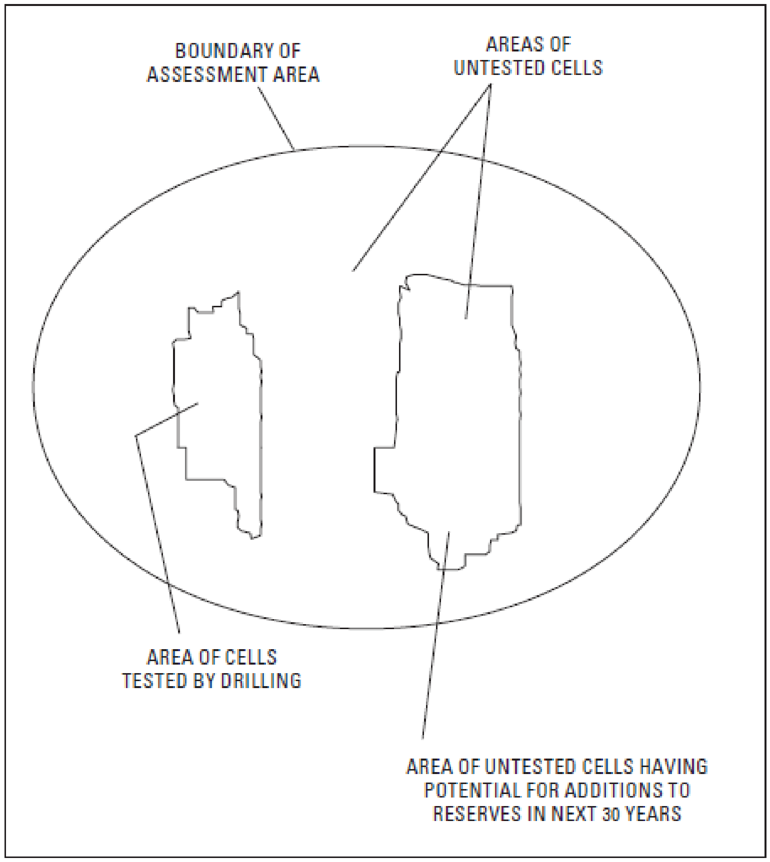

Fig. 45—Depiction of the three types of the petroleum-charged cells (USGS 2005b).

USGS (2005b) assessed sweet-spot and non-sweet-spot areas inside the untested area. Sweet-spot area is untested area having potential for additions to reserves/resources within 30 years (USGS 2005b). USGS assessed the fraction of an undiscovered sweet spot area inside the non-sweet-spot area. USGS used a future success ratio to model the probability of a successful well if drilled inside known sweet spots and another future success ratio to model the probability of a successful well if drilled inside undiscovered sweet-spot area inside the non-sweet-spot area. This work considered all undiscovered area to be non-sweet-spot area. It used the percent-of-area-with-potential distribution to model the fraction of sweet-spot area inside the undiscovered area. The future success ratio models the probability of successful wells if drilled inside the percent of area with potential.

3.6.3. Well Count

There were four different well counts used in this work: existing reserves', undeveloped reserves', contingent resources', and prospective resources'. The definitions are as follows.

- **Existing reserves' well count**

  The existing reserves' well count (ERWC) is constant because it consists of the existing wells that have been drilled and are producing as of December 1, 2013. As explained in Chapter III, there are some wells that are considered dry-gas wells from the initial GLR analysis but are located in the liquid-rich region, and there are a few wells that are considered wet-gas wells from the initial GLR analysis but are located in the dry-gas region. These wells were included in the existing reserves' well count because these wells have been drilled and are producing. Only gas production was considered for the dry-gas wells in the liquid-rich region. The NGL production from the wet-gas wells in the dry-gas region was ignored. The dry-gas wells in the liquid-rich region's and the wet-gas wells in the dry-gas region's TRR20 distributions are represented by the corresponding type probabilistic decline curves for the region where they are located.

- **Undeveloped reserves' well count**

The undeveloped reserves' well count (URWC) is based on the discovered area. SPE *et al*. (2007) stated that only the production of wells that will be drilled in the next five years can be considered as reserves. The drilling rates for this work are assumed to be about the same as the drilling rate in 2013, which were 303 wells/year for WV, 1304 wells/year for PA, and 1 well/year for OH according to the DI Desktop application. To model the uncertainty in the future drilling rate, this work used a triangular distribution with a minimum value of half the drilling rate in 2013, a maximum value of twice the drilling rate in 2013, and a most-likely value equal to the drilling rate in 2013.

Not all the undeveloped wells that are drilled within the discovered area are included in the URWC. Only wells that are considered to have significant contribution to the reserves estimates (successful wells) were included in the URWC. This was modeled by multiplying the total number of the undeveloped wells by the future success ratio. The total number of the undeveloped wells equals the minimum between the number of wells that can be drilled in the next five years and the number of wells to be drilled to reach the maximum well capacity in the discovered area. The maximum well capacity for each region in the discovered area equals the discovered area divided by the well spacing. The number of wells that can be drilled in the next five years equals the drilling rate times five. The number of wells to be drilled to reach the maximum well capacity equals the maximum well capacity minus the number of existing wells.

- **Contingent resources' well count**

  The contingent resources' well count (CRWC) is also based on the discovered area. The CRWC equals the maximum well capacity for each region in the discovered area minus the sum of ERWC and the total number of undeveloped wells, then multiplied by the future success ratio. This well count is negatively correlated to the URWC. The higher the URWC a region has, the lower the CRWC will be.

- **Prospective resources' well count**

  The prospective resources' well count (PRWC) is based on the undiscovered area. It equals the undiscovered area times the percent of area with potential, divided by the well spacing, and then multiplied by the future success ratio.

3.6.4. Monte Carlo Simulation

As previously stated, the inputs for this Monte Carlo Simulation were well spacing, drilling rate, future success ratio, percent area with potential, and the TRR20 distribution of each well in the play. The simulation outputs were well counts and reserves/resources estimates for the play. In the simulation, the wells were assumed to be perfectly correlated. Assuming that the wells are perfectly correlated (completely dependent) means that if one well has high production, the other wells will also have high production, and vice versa. Gong *et al.* (2013) stated that the true correlation between future wells is unknown; however, the correlation should neither be 100% independence nor 100% dependence.

Assuming the wells to be 100% independent will result in underestimating uncertainty, and assuming the wells to be 100% dependent will overestimate the uncertainty. Given the subjectivity in the minimum decline rates in the type probabilistic decline curves and the lack of long-term production data in the Marcellus shale play, overestimating the uncertainty is safer and preferable to underestimating it.

There were gas and NGL TRR20 distributions for the wells in the liquid-rich region. The wells in the dry-gas region have gas TRR20 distribution only. The existing dry-gas wells in the liquid-rich region, as explained before in the previous subchapter, only have gas TRR20 distribution. However, since they are located in the liquid-rich region they will follow the gas TRR20 distribution for this region. For the existing liquid-rich wells that are located in the dry-gas region, they will follow the gas TRR20 distribution for this region. As for all the wells in the dry-gas region, the NGL production from the existing wet-gas wells that are located in the dry-gas region will also be ignored. All of the future wells are assumed to be in accordance with their production region; they are liquid-rich wells (wet-gas and retrograde-gas wells) in the liquid-rich region, and dry-gas wells in the dry-gas region.

The TRR20 distributions were generated from the three type probabilistic decline curves shown in Fig. 31 for the dry-gas region, and Figs. 34 and 38 for the liquid-rich region. The TRR20 values from the top (P90), middle (P50), and bottom (P10) curves, as shown in Table 29, were used to form lognormal distributions of TRR20. **Figs. 46 and 47** show the NGL and gas TRR20 distributions for the wells in the liquid-rich region, respectively. **Fig. 48** shows the gas TRR20 distribution for wells in the dry-gas region.

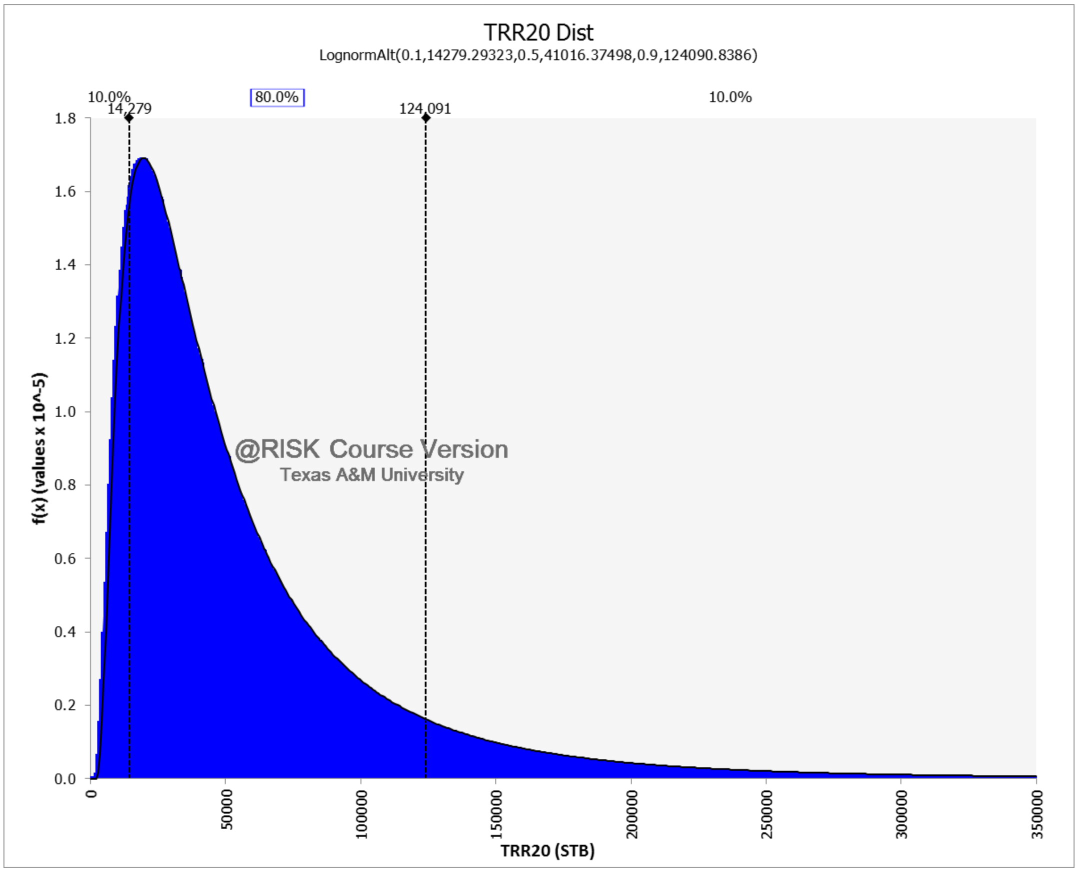

Fig. 46—The NGL TRR20 distribution for the wells in the liquid-rich region.

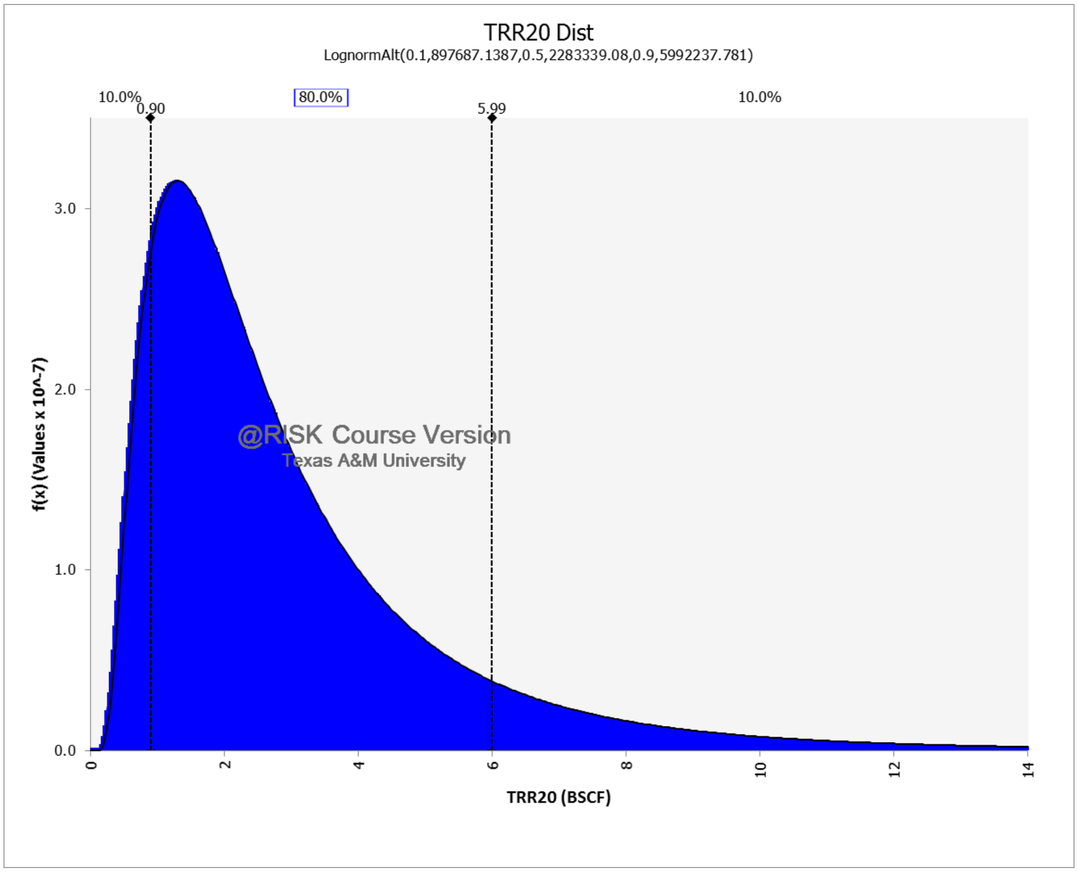

Fig. 47—The gas TRR20 distribution for the wells in the liquid-rich region.

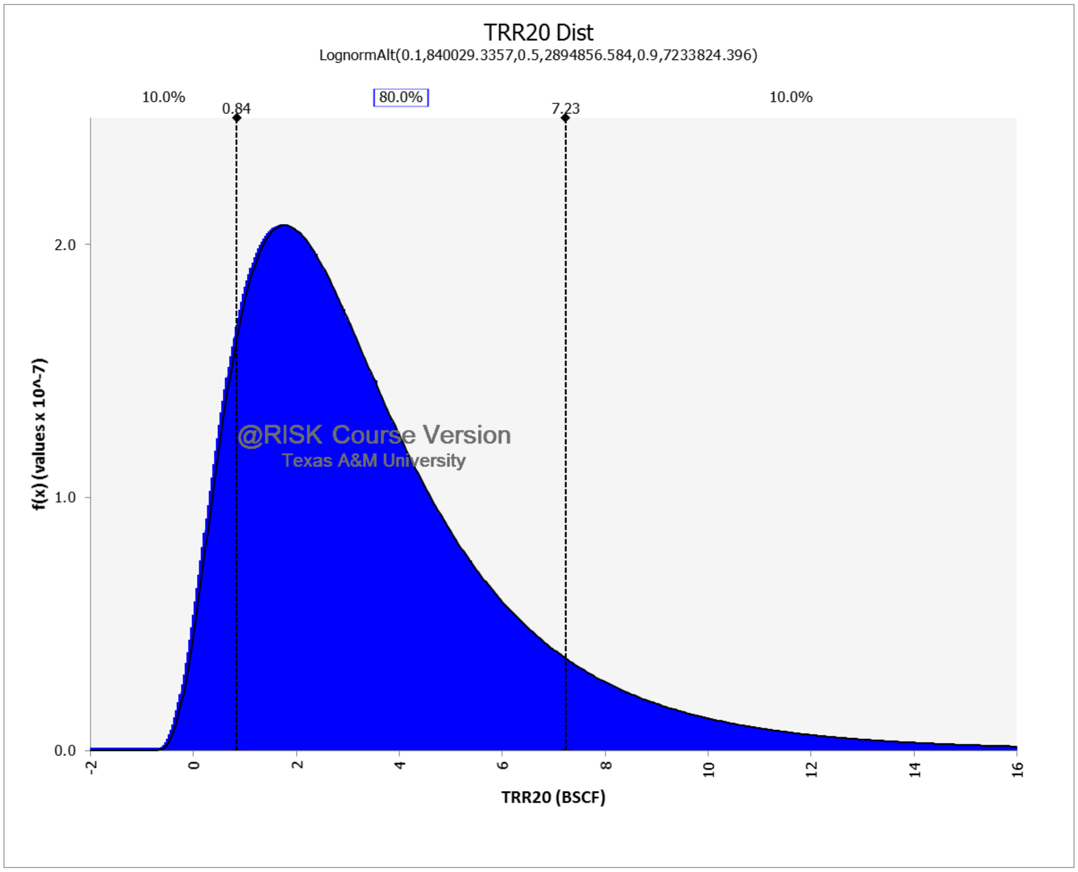

Fig. 48—The gas TRR20 distribution for the wells in the dry-gas region.

In order to check whether these three lognormal distributions fit the three TRR20 percentiles in Table 29 for each production region, the CDF of the lognormal distributions are plotted with the three percentiles from Table 29. **Fig. 49 through 51** show these comparisons.

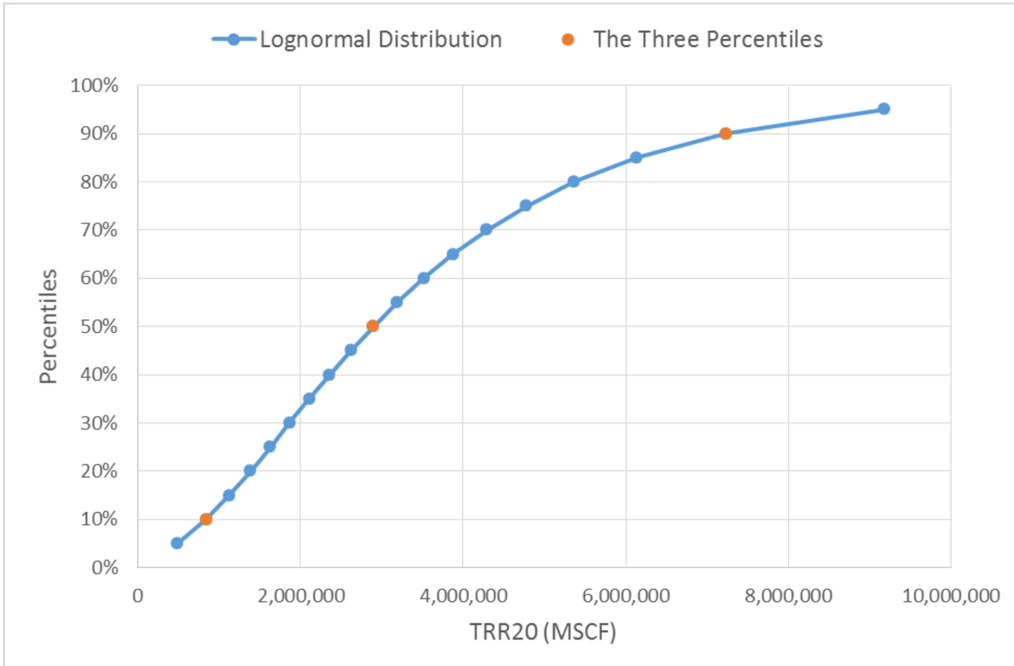

Fig. 49—The percentiles comparison for the TRR20 distribution in the dry-gas region.

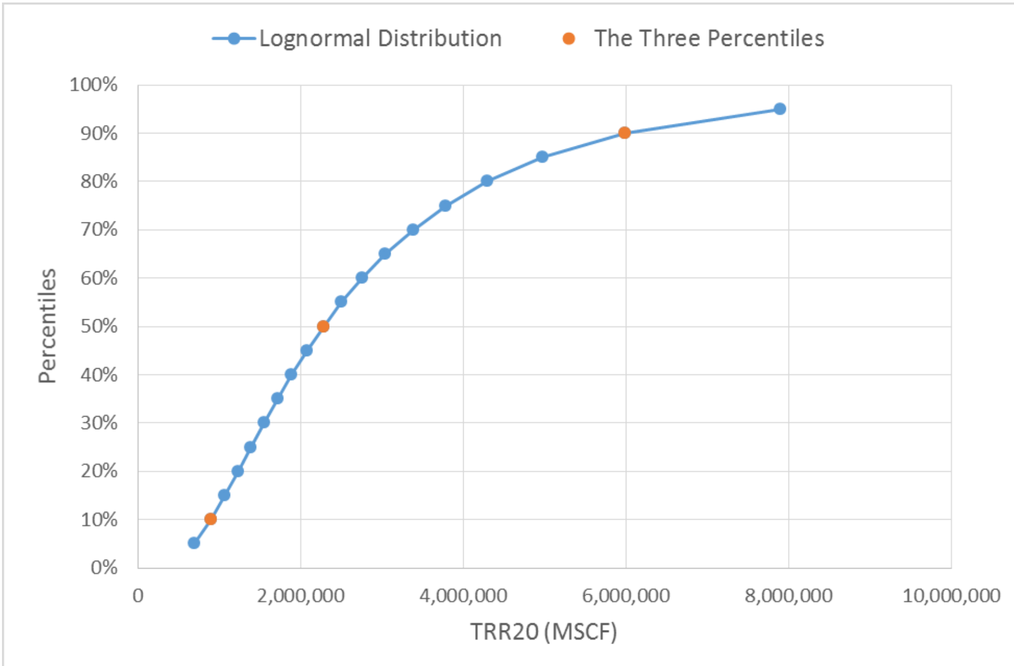

Fig. 50—The percentiles comparison for the gas TRR20 distribution in the liquid-rich region.

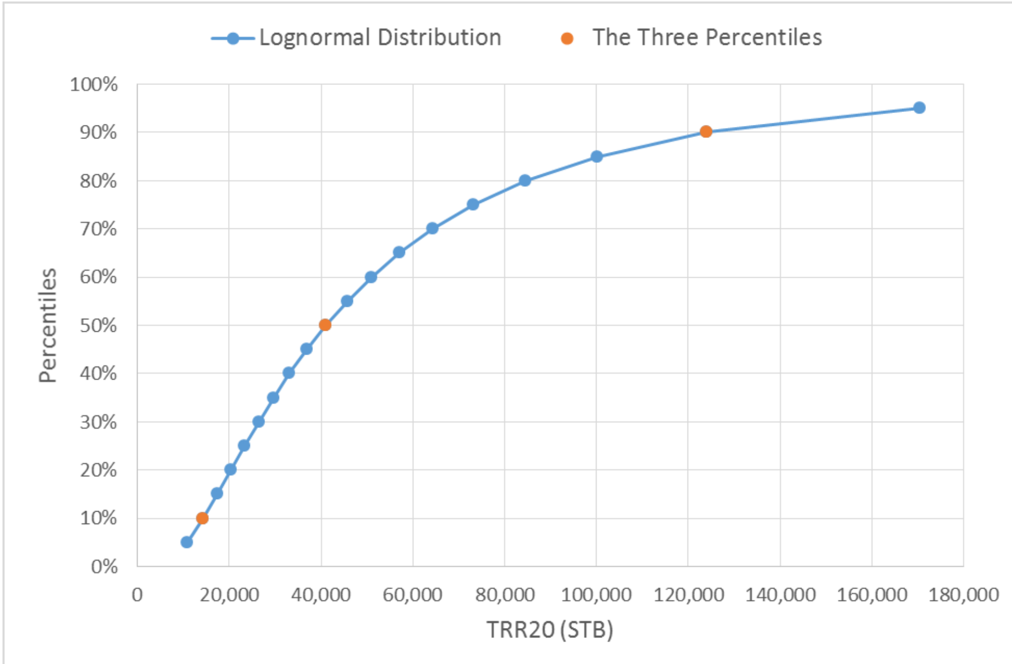

Fig. 51—The percentiles comparison for the NGL TRR20 distribution in the liquid-rich region.

From Fig. 49 through 51, it can be seen that all of the three lognormal distributions fit the three TRR20 percentiles from the type probabilistic decline curves well for every fluid type and production region. These three TRR20 distributions were used as inputs in the Monte Carlo simulation, and were truncated to make sure that there would be no negative values sampled from the distributions.

The lognormal distributions for TRR20 along with the triangular distributions for drilling rate, well spacing, future success ratio, and fraction/percent of area with potential were used to calculate well count and reserves/resources estimates for the WV Marcellus shale play in the Monte Carlo simulation. The simulation was performed on one run using

100000 iterations. The well count outputs were calculated using the definitions explained in Subchapter 3.6.3.

The reserves and resources estimates outputs consist of the existing reserves, undeveloped reserves, contingent resources, and prospective resources. The existing reserves were as of December 1, 2013. In order to calculate the existing reserves, the ERWC was multiplied by the TRR20, and then the result was subtracted by the cumulative production of the existing wells until December 1, 2013. Since the assumption in the simulation is that the wells are completely dependent, it will widen the range of the reserves and resources estimates output distributions. The wide range will cause the left tail to have the possibility of negative numbers. In order to handle this problem, instead of truncating the TRR20 distributions at 0, the TRR20 distributions are truncated at the cumulative production as of December 1, 2013. The undeveloped reserves, contingent resources, and prospective resources estimates were calculated by simply multiplying the well counts by the TRR20.

The reserves and resources estimates were performed for each production region in every AU, and also for the whole WV Marcellus shale play. The estimates for the whole WV Marcellus shale play were simply the summation of every reserves/resources category from all of the AUs. Total reserves were the summation of the existing and undeveloped reserves, and total resources were the summation of the contingent and prospective resources. **Fig. 52** shows the Excel® sheet used in the Monte Carlo simulation for calculating reserves and resources estimates in the interior Marcellus AU of the WV Marcellus shale play. The original Excel® sheet is for all three Marcellus AUs; however, for display purposes the sheet is edited for the interior Marcellus AU only. **Fig. 53** shows the simulation sheet to calculate the total reserves and resources for the WV Marcellus shale play.

Drilling Rate	353.5	wells/year			
Interior Marcellus AU					
Well Spacing	149.333333	acres/well			
Future Success Ratio	0.85				
Fraction of area with potential	0.36666667				
Liquid-Rich Region					
NGL TRR20 Distribution	77177.00	STB NGL			
Gas TRR20 Distribution	3353629.96	MSCF			
Dry-Gas Region					
Gas TRR20 Distribution	4554572.01	MSCF			
Liquid-Rich Region			**Dry-Gas Region**		
Area	731,539	acres	Area	6,479,787	acres
Discovered Area	600,406	acres	Discovered Area	3,118,746	acres
Undiscovered Area	131,133	acres	Undiscovered Area	3,361,041	acres
Undiscovered Area with Potential	48,082	acres	Undiscovered Area with Potential	1,232,382	acres
Discovered Area Max Well Capacity	4,020	wells	Discovered Area Max Well Capacity	20,884	wells
Number of wells that can be Drilled in the Next 5 years	1,767	wells	Number of wells that can be Drilled in the Next 5 years	1,767	wells
Number of wells to be drilled to reach the maximum well capacity	3,878	wells	Number of wells to be drilled to reach the maximum well capacity	20,449	wells
Cumulative NGL Production as of 12/1/2013 (Liquid-Rich Wells)	0.00231481	BBNGL			
Cumulative Gas Production as of 12/1/2013 (Liquid-Rich Wells)	0.07765155	TCF	Cumulative Gas Production as of 12/1/2013 (Liquid-Rich Wells)	0.005207692	TCF
Cumulative Gas Production as of 12/1/2013 (Dry-Gas Wells)	0.05859708	TCF	Cumulative Gas Production as of 12/1/2013 (Dry-Gas Wells)	0.721677586	TCF
Existing Reserves' Well Count (Liquid-Rich Wells)	91	wells	Existing Reserves' Well Count (Liquid-Rich Wells)	5	wells
Existing Reserves' Well Count (Dry-Gas Wells)	51	wells	Existing Reserves' Well Count (Dry-Gas Wells)	430	wells
Total number of undeveloped wells	1,767	wells	Total number of undeveloped wells	1,767	wells
Undeveloped Reserves' Well Count	1,501	wells	Undeveloped Reserves' Well Count	1,501	wells
Contingent Resources' Well Count	1,794	wells	Contingent Resources' Well Count	15,879	wells
Prospective Resources' Well Count	273	wells	Prospective Resources' Well Count	7,014	wells
Existing NGL Reserves	0.00471	BBNGL			
Existing Gas Reserves	0.33997	TCF	Existing Gas Reserves	1.25435	TCF
Undeveloped NGL Reserves	0.11584	BBNGL			
Undeveloped Gas Reserves	5.03380	TCF	Undeveloped Gas Reserves	6.83641	TCF
Contingent NGL Resources	0.13846	BBNGL			
Contingent Gas Resources	6.01641	TCF	Contingent Gas Resources	72.32205	TCF
Prospective NGL Resources	0.02107	BBNGL			
Prospective Gas Resources	0.91554	TCF	Prospective Gas Resources	31.94577	TCF

Fig. 52—The Excel® sheet to calculate well counts and reserves and resources estimates for each production region in interior Marcellus AU. The simulation was performed for all of the Marcellus AUs, but edited to show here only for the interior Marcellus AU.

Total WV Marcellus Reserves and Resources Estimates		
	NGL (BBNGL)	Gas (TCF)
Existing Reserves	0.0047	1.6231
Undeveloped Reserves	0.1233	15.1702
Total Reserves	0.1280	16.7933
Contingent Resources	0.1385	99.3711
Prospective Resources	0.0252	40.1121
Total Resources	0.1637	139.4832
Total Reserves + Resources	0.2917	156.2765

Fig. 53—The Excel® sheet to calculate the total reserves and resources estimates for the WV Marcellus shale play.

Tables 33 through 36 show the simulation results for the well count and reserves/resources estimates for every AU in the liquid-rich and dry-gas regions. **Tables 37 through 39** show the results of total reserves and resources estimates in the WV Marcellus shale play. **Figs. 54 and 55** show the distributions of the total reserves plus resources estimates for the WV Marcellus shale play. **Tables 40 through 42** show the P90-to-P10 ratios of the WV Marcellus shale play reserves and resources estimates.

Table 33 —Well count results for the liquid-rich region.

Liquid-Rich Region		Well Count			
		Existing Reserves'	Undeveloped Reserves'	Contingent Resources'	Prospective Resources'
Western AU	P10	N/A	70	-	26
	P50		127	-	67
	P90		257	-	158
Interior AU	P10	91 Liquid-Rich Wells, 51 Dry-Gas Wells	989	840	141
	P50		1,458	1,896	264
	P90		2,081	3,216	469

Table 34—Well count results for the dry-gas region.

Dry-Gas Region		Well Count			
		Existing Reserves'	Undeveloped Reserves'	Contingent Resources'	Prospective Resources'
Western AU	P10	8	448	3,007	630
	P50		751	5,863	1,577
	P90		1,204	12,547	3,706
Interior AU	P10	5 Liquid-Rich Wells, 430 Dry-Gas Wells	989	11,460	3,615
	P50		1,458	16,343	6,770
	P90		2,083	22,837	12,025
Foldbelt AU	P10	N/A	N/A	N/A	97
	P50				223
	P90				444

Table 35—Reserves estimates results for every AU in both regions.

SUMMARY		Existing Reserves			Undeveloped Reserves		
		Liquid-Rich Region		Dry Gas Region	Liquid-Rich Region		Dry Gas Region
		NGL (BBNGL)	Gas (TCF)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	Gas (TCF)
Western AU	P10	N/A	N/A	0.0067	0.0016	0.097	0.608
	P50			0.0229	0.0054	0.298	2.154
	P90			0.0576	0.0197	0.966	6.101
Interior AU	P10	0.0004	0.041	0.156	0.04	1.7	2.713
	P50	0.0028	0.226	0.894	0.08	3.7	5.445
	P90	0.0109	0.761	2.781	0.22	9.7	12.619
Foldbelt AU	P10	N/A	N/A	N/A	N/A	N/A	N/A
	P50						
	P90						

Table 36—Resources estimates results for every AU in both regions.

SUMMARY		Contingent Resources			Prospective Resources		
		Liquid-Rich Region		Dry Gas Region	Liquid-Rich Region		Dry Gas Region
		NGL (BBNGL)	Gas (TCF)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	Gas (TCF)
Western AU	P10	0	0	4.49	0.0007	0.04	1.01
	P50	0	0	17.06	0.0027	0.15	4.45
	P90	0	0	56.41	0.0111	0.56	16.18
Interior AU	P10	0.039	1.65	30.83	0.0062	0.266	10.75
	P50	0.105	4.68	61.08	0.0152	0.682	25.64
	P90	0.311	13.50	139.92	0.0446	1.936	65.24
Foldbelt AU	P10	N/A	N/A	N/A	N/A	N/A	0.304
	P50						0.838
	P90						2.305

Table 37—Reserves estimates results for the WV Marcellus shale play.

WV	Existing Reserves		Undeveloped Reserves		Total Reserves	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.00042	0.41	0.047	7.49	0.048	8.19
P50	0.00279	1.28	0.092	13.52	0.095	14.91
P90	0.01094	3.23	0.234	25.06	0.245	27.88

Table 38—Resources estimates results for the WV Marcellus shale play.

WV	Contingent Resources		Prospective Resources		Total Resources	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.039	50.49	0.00906	17.3	0.0517	70.65
P50	0.105	93.72	0.02013	35.4	0.1263	130.13
P90	0.311	186.21	0.05187	77.5	0.3579	259.51

Table 39—Combined reserves and resources estimates of the WV Marcellus shale play.

WV	Total Reserves and Resources	
	NGL (BBNGL)	Gas (TCF)
P10	0.1154	81.54
P50	0.2252	145.91
P90	0.5846	283.81

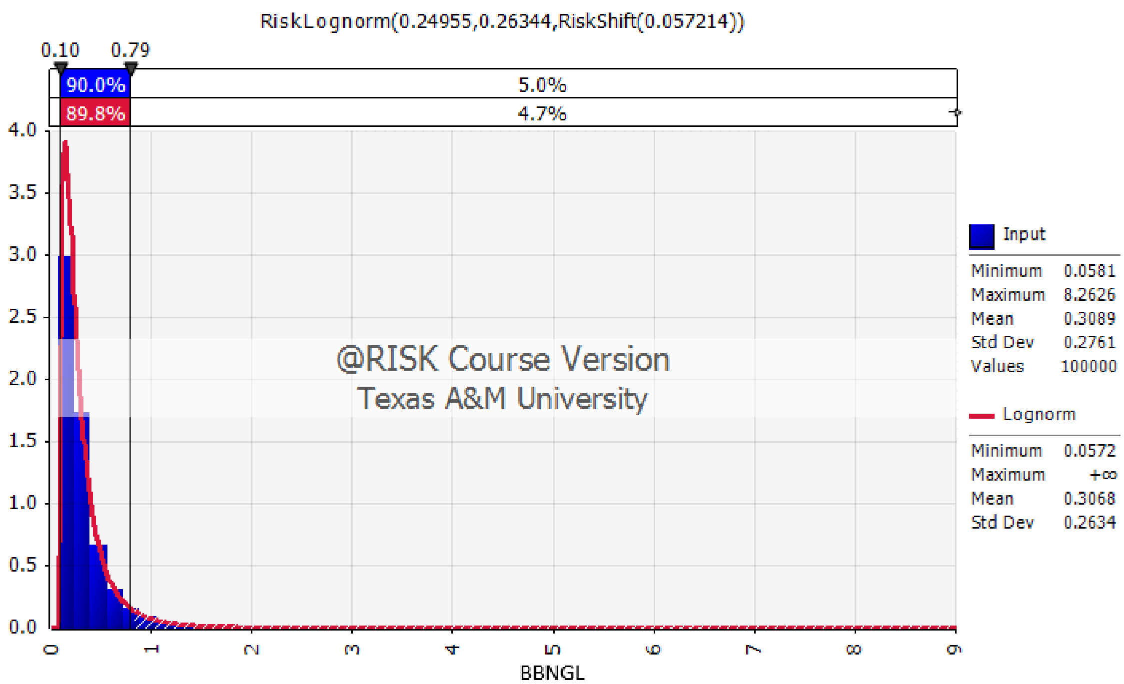

Fig. 54—Total NGL reserves plus resources estimates of the WV Marcellus shale play follow a lognormal distribution.

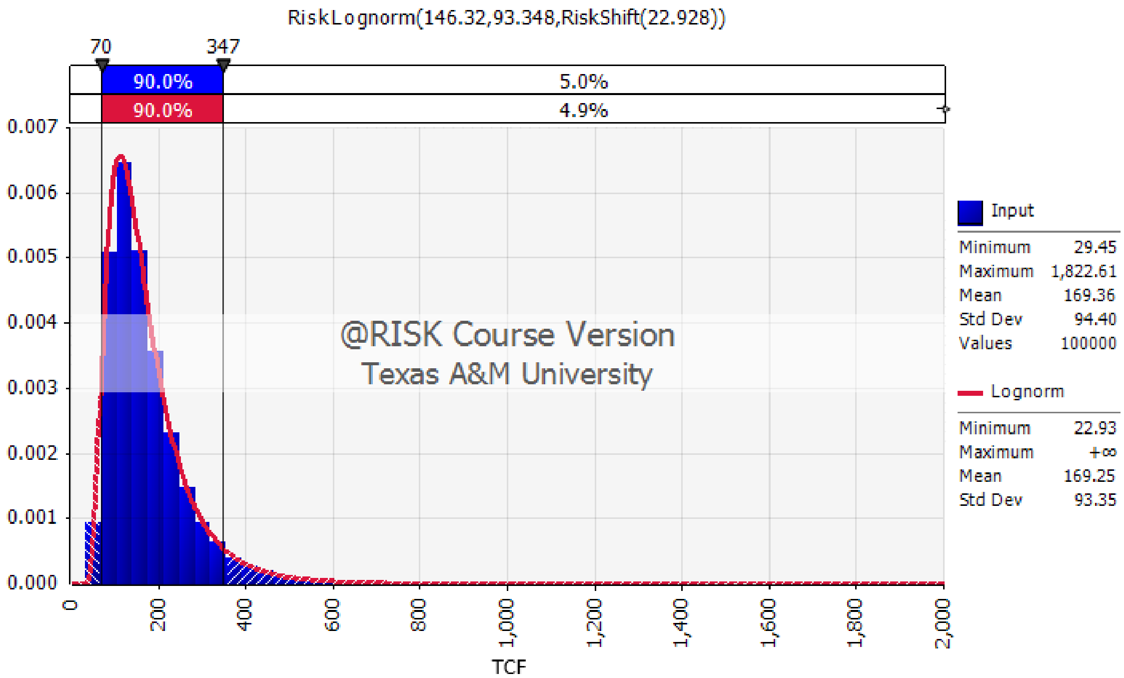

Fig. 55—Total gas reserves plus resources estimates of the WV Marcellus shale play follow a lognormal distribution.

Table 40—P90-to-P10 ratio for the WV Marcellus shale play reserves estimates for every AU.

	Existing Reserves			Undeveloped Reserves		
P90-to-P10 Ratio	Liquid-Rich Region		Dry Gas Region	Liquid-Rich Region		Dry Gas Region
	NGL	Gas	Gas	NGL	Gas	Gas
Western AU	N/A	N/A	8.59	12.44	10	10.03
Interior AU	25.99	18.56	17.83	5.57	5.73	4.65
Foldbelt AU	N/A	N/A	N/A	N/A	N/A	N/A

Table 41—P90-to-P10 ratio for the WV Marcellus shale play resources estimates for every AU.

P90-to-P10 Ratio	Contingent Resources			Prospective Resources		
	Liquid-Rich Region		Dry Gas Region	Liquid-Rich Region		Dry Gas Region
	NGL	Gas	Gas	NGL	Gas	Gas
Western AU	N/A	N/A	12.56	16.60	13.85	16.02
Interior AU	8.04	8.18	4.54	7.16	7.28	6.07
Foldbelt AU	N/A	N/A	N/A	N/A	N/A	7.58

Table 42— P90-to-P10 ratio for the WV Marcellus shale play reserves and resources estimates for every AU.

	WV P90/P10	
	NGL	Gas
Existing Reserves	25.99	7.85
Undeveloped Reserves	4.97	3.35
Total Reserves	5.10	3.4
Contingent Resources	8.04	3.69
Prospective Resources	5.73	4.48
Total Resources	6.92	3.67
Total Reserves + Resources	5.07	3.48

As explained earlier in this subchapter, Gong *et al.* (2013) stated that the true correlation between future wells is unknown; however, the correlation should neither be 100% independence nor 100% dependence. Assuming the wells to be 100% independent will result in underestimating uncertainty, with a narrower range between P10 and P90 than the 100% dependency assumption. Having reserves and resources estimates with more reliable uncertainty quantification is best, but given the subjectivity in the minimum decline rates in the type probabilistic decline curves and the lack of long-term production data in the Marcellus shale play, overestimating the uncertainty is safer and preferable to underestimating it.

Since these reserves and resources estimates were calculated assuming complete dependency between the wells, theoretically the results will tend to overestimate uncertainty. As explained in Subchapter 3.5, a P90-to-P10 ratio in the 6-to-10 range was deemed to be a reasonable expression of the uncertainty in the long term. Tables 40 and 41 show that only a small portion (4 out of 21 ratios) of the estimates have P90-to-P10 ratio smaller than 6, thereby likely underestimating uncertainty. There are 9 out of 21 ratios greater than 10, due to the complete dependence assumption between the wells. The rest of the P90-to-P10 ratios fall into the reasonable range of 6 to 10.

The aggregation of reserves and resources estimates across AUs and production regions was performed within the same Monte Carlo simulation. This means that the aggregation was performed under the assumption of complete independence among the reserves and resources between AUs and production regions. It is not surprising that the P90-to-P10 ratios for the aggregated results (Table 42) were dominantly smaller than 6, indicating possible underestimation of uncertainty.

CHAPTER IV

DISCUSSION

This chapter discusses the extrapolation of the WV Marcellus shale reserves and resources estimates to the rest of the Marcellus shale play. This chapter also shows the comparison of this work's reserves and resources estimates of the WV Marcellus shale play with the other five previously published estimates: USGS (2003), Engelder (2009), EIA (2011), USGS (2011a), and EIA (2012a) estimates.

4.1. Extrapolation of the WV Marcellus Shale Play Reserves and Resources Estimates to the Rest of the Marcellus Shale Play

In order to extrapolate the WV Marcellus shale play reserves and resources estimates to the rest of the Marcellus shale play, the boundary between liquid-rich region and dry-gas region needs to be extended. The initial GLR analysis based on McCain (1994) guideline was performed again for the wells in the rest of the Marcellus shale play with the same criteria as the wells selected in the WV Marcellus shale play. **Table 43** shows the results of initial GLR analysis for the Marcellus wells outside of WV. **Fig. 56** shows the wells location on the Marcellus shale play.

Table 43—Results of initial GLR analysis for the Marcellus wells outside of WV.

Fluid Type	Number of Wells
Black Oil	2
Volatile Oil	0
Retrograde Gas	45
Wet Gas	241
Dry Gas	3516
Total	3804

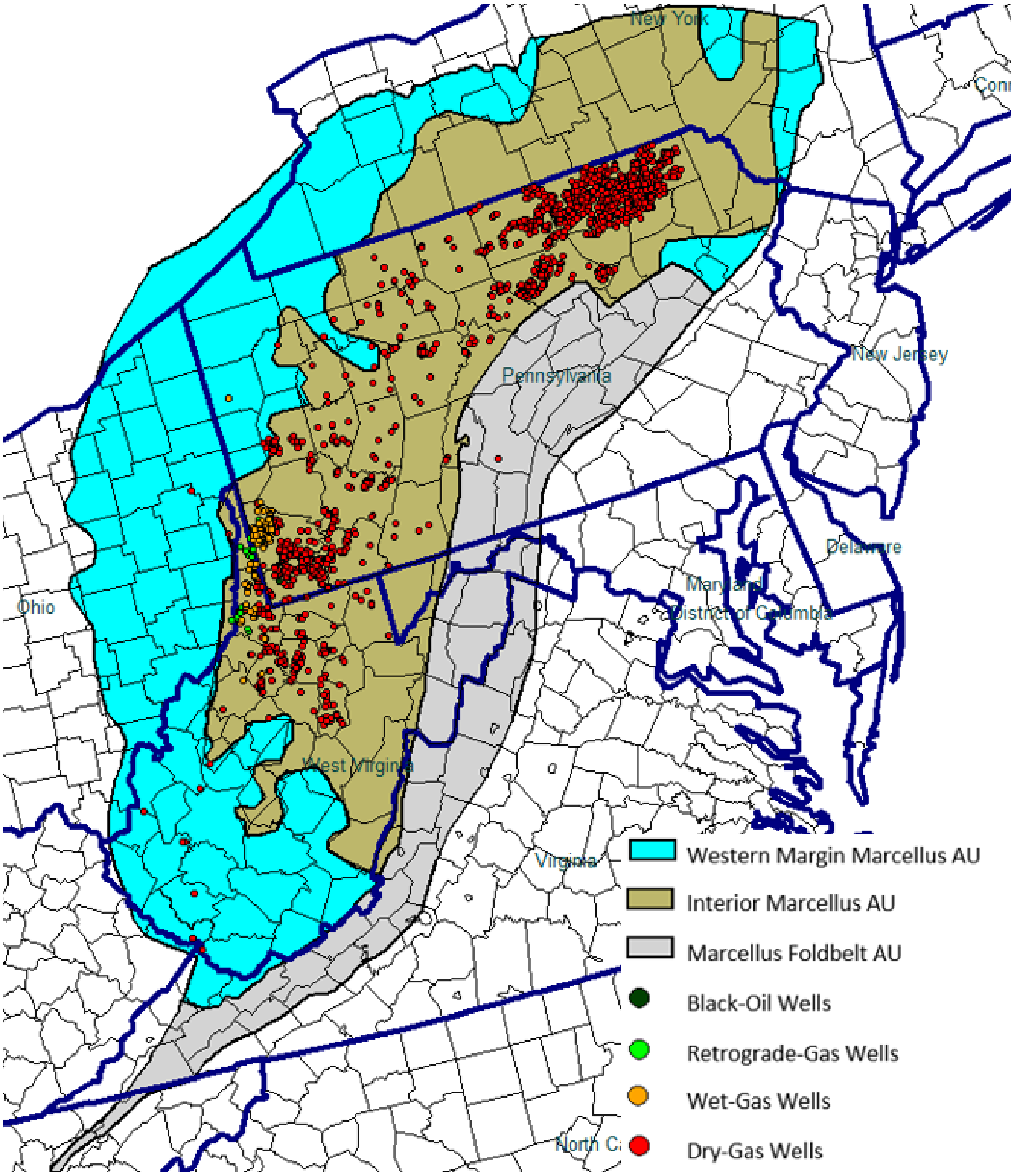

Fig. 56—All type of wells in the Marcellus shale play.

Outside of WV, the Marcellus shale play only has horizontal wells in PA and OH. There are no horizontal Marcellus wells in NY, VA, and MD. There was a temporary high-volume hydraulic fracturing moratorium in NY that existed for more than six years pending studies on the possible health consequences of fracturing in the Marcellus shale play (Dittrick 2015). NY officially prohibited high-volume hydraulic fracturing in the state on June 29, 2015, by issuing its formal finding statement, completing the state's seven-year review of this activity (DEC 2015). MDE (2015) stated that Maryland has just published its oil and gas exploration and production regulations regarding Marcellus shale safe-drilling initiative on January 9, 2015, and is currently reviewing the comments that it received. DMME (2012) explained that the VA Marcellus shale is present in relatively shallow belts of folded and faulted rock. This tectonic disturbance causes much of the natural gas once present in the Marcellus shale to have probably escaped. DMME (2012) also stated that the VA Marcellus shale play is thermally overmature, meaning that the shale play was most likely heated to too high a temperature in the past to preserve economic quantities of gas or oil. These are the reasons why there is no Marcellus well in NY, VA, and MD.

Using the initial GLR analysis results, the boundary between the liquid-rich and dry-gas regions was extended to the rest of the Marcellus shale play. Since there are no wells in the NY Marcellus shale, the boundary between the liquid-rich and dry-gas regions was inferred from the contour map of the depth of Marcellus shale base (PSU 2010). By doing this, there is a lot of subjectivity in drawing the boundary in the NY Marcellus shale. Therefore, the boundary line for the NY part was drawn with a dashed line. It means that the boundary was inferred from means other than the control that was used in the other parts, which is the initial GLR analysis results. **Fig. 57** shows the contour map of the depth of Marcellus shale base from PSU (2010). **Fig. 58** shows all the Marcellus shale wells on top of the PSU (2010) contour map, along with the boundary between the liquid-rich and dry-gas regions. The boundary on the Marcellus shale AUs map is shown in **Fig. 59.**

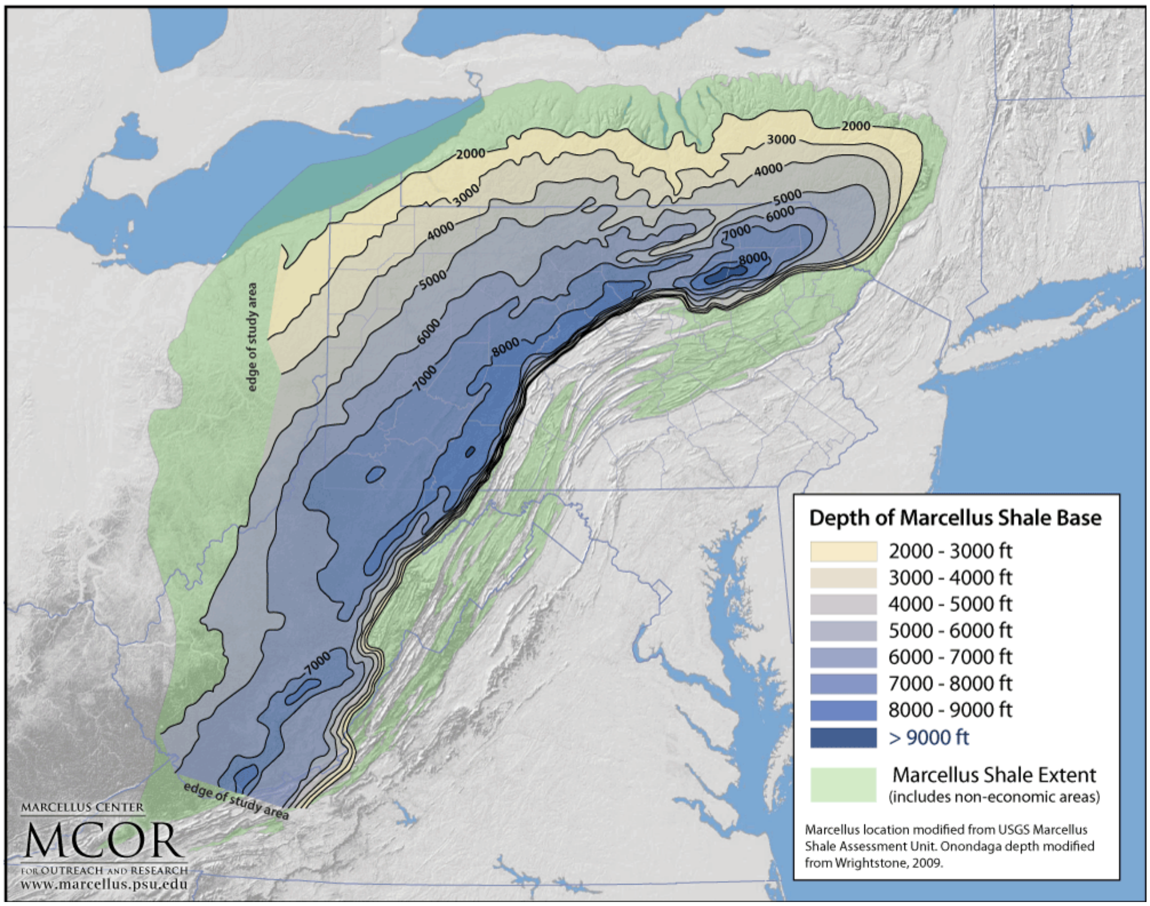

Fig. 57 —The depth of Marcellus shale base contour map (PSU 2010).

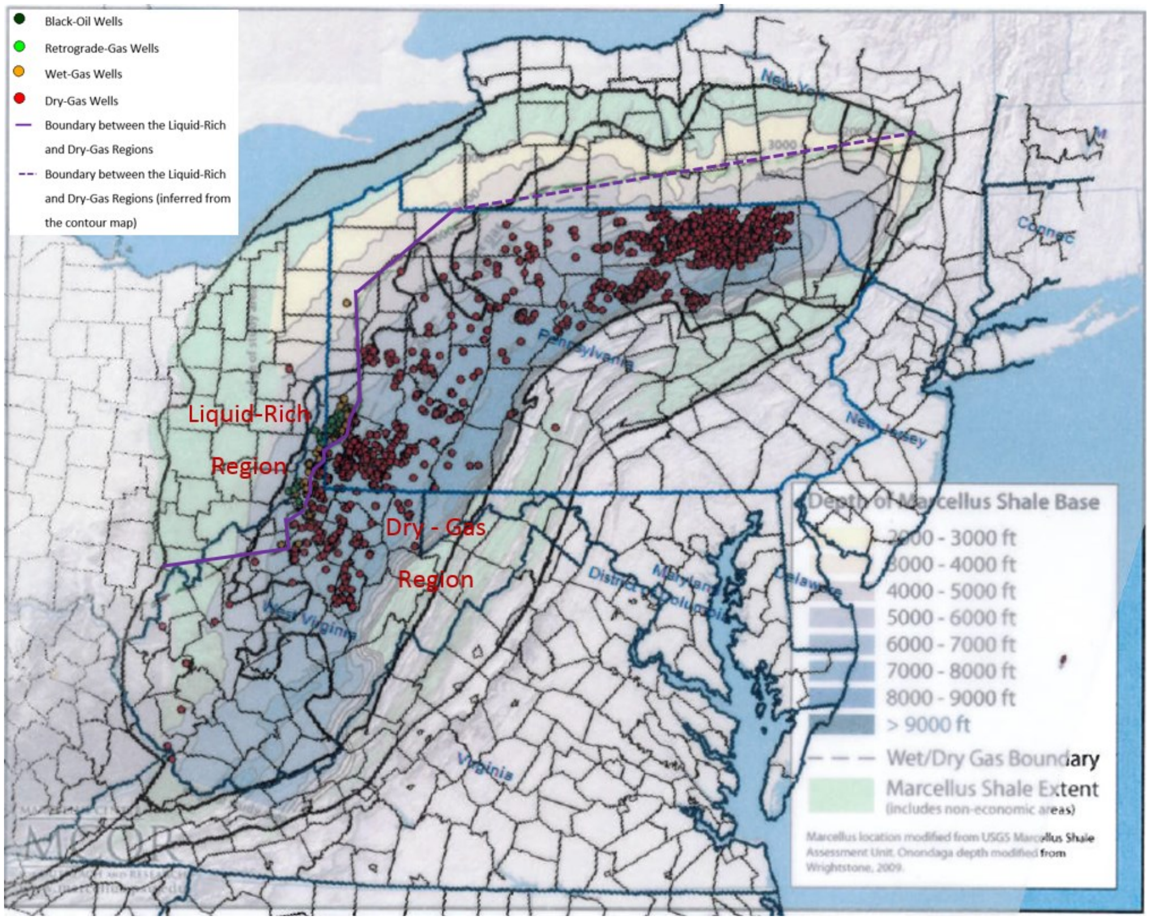

Fig. 58—The boundary between the liquid-rich and dry-gas regions in the Marcellus shale play drawn on top of the PSU (2010) contour map.

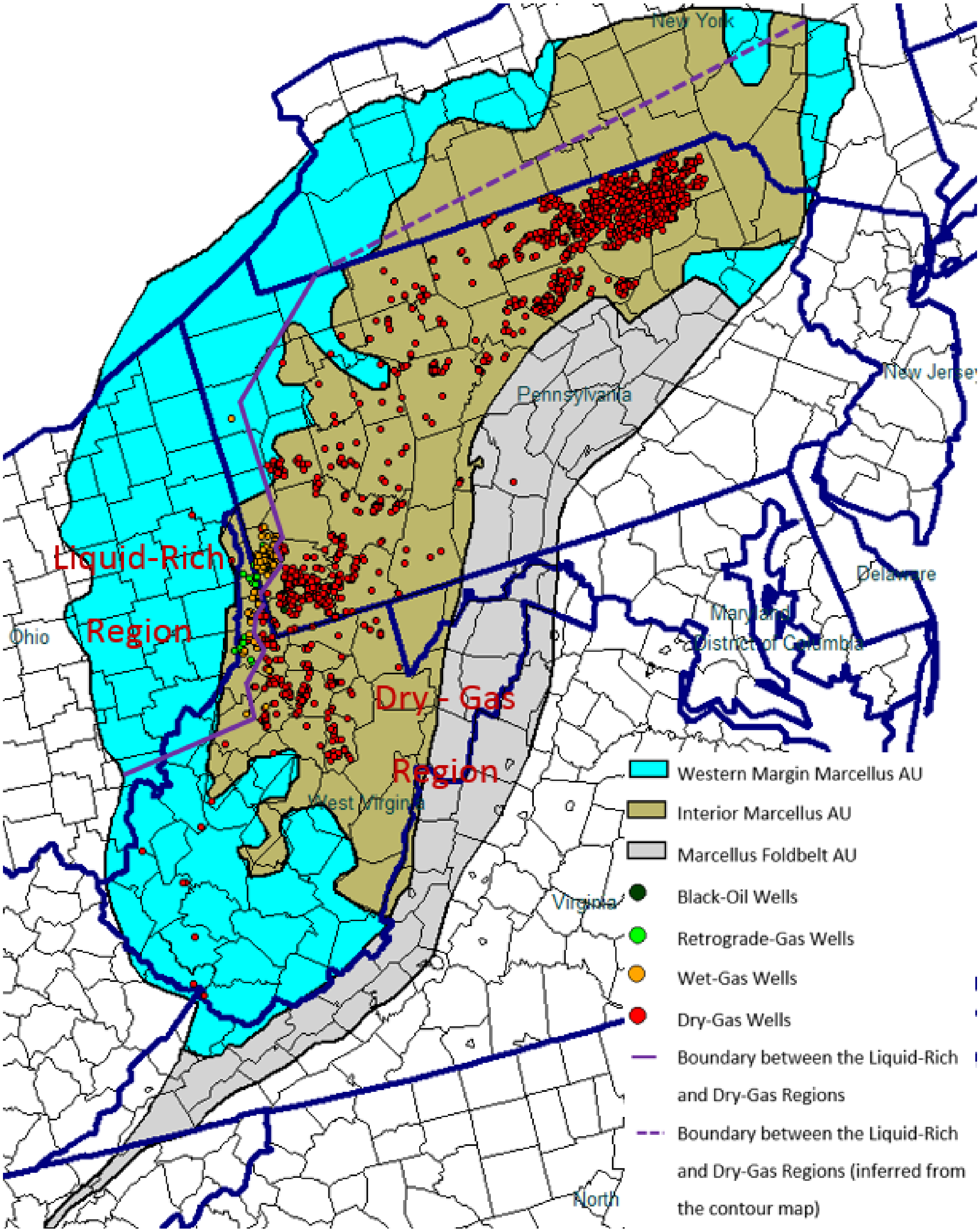

Fig. 59—The boundary between the liquid-rich and dry-gas regions for the rest of the Marcellus shale play. To the left of the purple line is the liquid-rich region, while to the right of the purple line is the dry-gas region.

The 12-mile radius that was used to determine the discovered and undiscovered areas in the WV Marcellus shale play was also used for the rest of the Marcellus shale play. **Table 44** shows the discovered and undiscovered areas for every AU in PA, OH, and the rest of the Marcellus shale play (RoP) where there are no Marcellus wells that have been drilled.

Table 44—Discovered and undiscovered areas for every AU in the rest of the Marcellus shale play.

PA, OH, and the Rest of the Marcellus Shale Play		PA Area (acres)	OH Area (acres)	The rest of the play Area (acres)
Liquid-Rich Region		2,521,727	8,882,087	9,598,037
Western AU	Discovered	364,730	541,627	-
	Undiscovered	1,757,508	8,022,006	5,757,234
	Total	2,122,238	8,563,632	5,757,234
Interior AU	Discovered	315,926	256,496	-
	Undiscovered	83,562	61,959	3,840,802
	Total	399,489	318,454	3,840,802
Dry-Gas Region		24,418,061	411,471	12,156,891
Western AU	Discovered	658,125	52,876	110,238
	Undiscovered	1,420,193	358,596	1,621,471
	Total	2,078,317	411,471	1,731,709
Interior AU	Discovered	12,974,169	N/A	666,356
	Undiscovered	3,582,346	N/A	3,694,062
	Total	16,556,515	N/A	4,360,418
Foldbelt AU	Discovered	531,669	N/A	-
	Undiscovered	5,251,560	N/A	6,064,764
	Total	5,783,229	N/A	6,064,764

Table 44 shows that there are discovered areas for the rest of the Marcellus shale play where there are no Marcellus wells that have been drilled. The reason for this is because there are wells in the PA Marcellus shale play near the boundary of PA-NY and PA-MD that have the 12-mile-radius circles around them spread to the NY and MD areas. The area inside the 12-mile-radius circles is categorized into discovered area. That is why even though there are no wells in the rest of the Marcellus shale play, it still has discovered areas. However, since there is no drilling activity in the rest of the Marcellus shale play due to the fracturing ban, the process of reviewing regulations, or economical reasons, this part of the Marcellus shale play only has contingent resources in the discovered area.

The discovered area that is created by the spreading of the 12-mile-radius circles outside a boundary was also applied between AUs. Any area in an AU that is covered by the spreading circles from the wells in the neighboring AU, but has not been covered inside the 12-miles-radius circles of its own existing wells, will add to the discovered area. For example, there is only one existing well in the Marcellus foldbelt AU in the dry-gas region, and the 12-mile-radius circle around this well does not spread outside the boundary of the AU. The discovered area should only be the area of a circle with 12-mile radius. However, since there are some parts of the Marcellus foldbelt AU that is covered by the spreading circles from the existing wells in the interior Marcellus AU, this will add to the discovered area for the Marcellus foldbelt AU. **Fig. 60** illustrates this example.

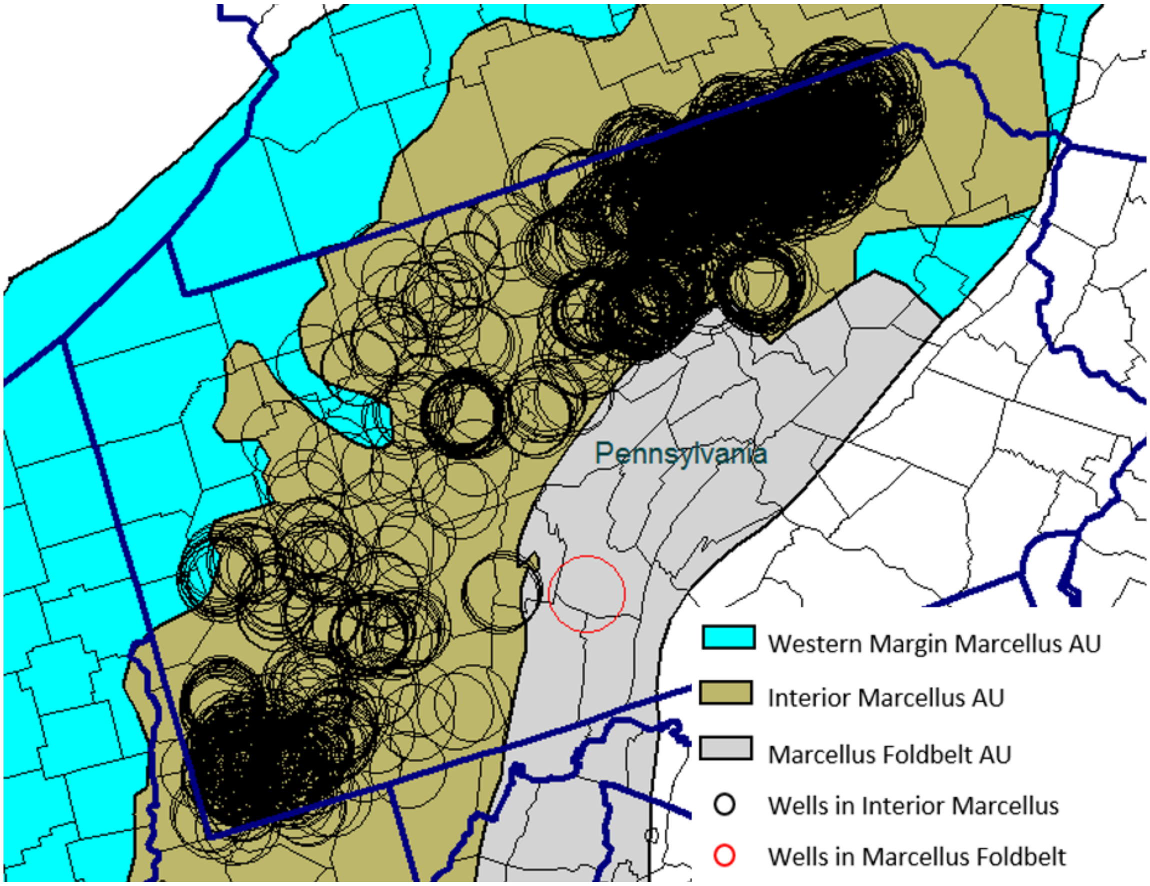

Fig. 60—Example on the discovered area in the Marcellus foldbelt AU becomes the summation of the red circle from the existing well in the AU and parts of the black circles that cover some parts of the Marcellus foldbelt AU.

These discovered and undiscovered areas were used in calculating reserves and resources estimates for the rest of the Marcellus shale play. The Monte Carlo simulation to calculate reserves and resources estimates for PA, OH, and the rest of the Marcellus shale play were actually performed together along with the reserves and resources estimation of the WV Marcellus shale play. The estimation parameters and TRR20 distributions for PA, OH, and the rest of the Marcellus shale play were the same as in the

WV Marcellus shale play, except for the drilling rate. The drilling rates for the PA and OH were the 2013 drilling rates, which were 1304 wells/year for PA and 1 well/year for OH. No drilling rate parameter for the rest of the Marcellus shale play was used, because there has been no drilling activity. There were only contingent and prospective resources in the rest of the Marcellus shale play. The calculations for the reserves and resources estimates for the rest of the Marcellus shale play were performed by using similar Excel® sheets shown in Fig. 52 and 53. The reserves and resources estimates for the whole play were also calculated by summing the total reserves and resources estimates from the WV, PA, OH, and the rest of the Marcellus shale play. **Table 45 through 55** shows the reserves and resources estimates results for the PA, OH, the rest of the Marcellus shale play (RoP), and for the whole Marcellus shale play. **Table 56** shows the P90-to-P10 ratios of the Marcellus shale play reserves and resources estimates.

Table 45—The reserves estimates results for the PA Marcellus shale play.

PA	Existing Reserves		Undeveloped Reserves		Total Reserves	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.0014	3.92	0.0767	23.75	0.081	29.08
P50	0.0088	10.96	0.1637	43.38	0.175	54.97
P90	0.0335	25.88	0.3929	79.56	0.423	103.19

Table 46—The resources estimates results for the PA Marcellus shale play.

PA	Contingent Resources		Prospective Resources		Total Resources	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0	58.4	0.0128	10.95	0.0129	71.35
P50	0	193.98	0.0331	27.46	0.0337	222.54
P90	0	512.06	0.0975	68.73	0.1053	576.92

Table 47—Total reserves and resources estimates results for the PA Marcellus shale play.

PA	Total Reserves and Resources	
	NGL (BBNGL)	Gas (TCF)
P10	0.0966	105.15
P50	0.2125	278.99
P90	0.5252	674.40

Table 48—The reserves estimates results for the OH Marcellus shale play.

OH	Existing Reserves		Undeveloped Reserves		Total Reserves	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.00001	0.00423	0.00017	0.01255	0.00019	0.0179
P50	0.00006	0.00933	0.00036	0.02569	0.00043	0.0356
P90	0.00023	0.02113	0.00087	0.05246	0.00109	0.0718

Table 49—The resources estimates results for the OH Marcellus shale play.

OH	Contingent Resources		Prospective Resources		Total Resources	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.0862	4.95	0.03	1.93	0.126	7.48
P50	0.1929	10.51	0.1	5.85	0.302	16.76
P90	0.4838	24.07	0.37	19.43	0.834	42.44

Table 50—The total reserves and resources estimates result for the OH Marcellus shale play.

OH	Total Reserves and Resources	
	NGL (BBNGL)	Gas (TCF)
P10	0.126	7.5
P50	0.303	16.8
P90	0.835	42.5

Table 51—The resources estimates results for the rest of the Marcellus shale play.

RoP	Contingent Resources		Prospective Resources		Total Resources	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	N/A	4.87	0.16	25.47	0.16	32.98
P50	N/A	13.27	0.43	54.56	0.43	69.29
P90	N/A	31.75	1.26	119.73	1.26	147.69

Table 52—The total reserves and resources estimates result for the rest of the Marcellus shale play.

RoP	Total Reserves and Resources	
	NGL (BBNGL)	Gas (TCF)
P10	0.16	32.98
P50	0.43	69.29
P90	1.26	147.69

Table 53—The reserves estimates results for the whole Marcellus shale play.

Total Marcellus	Existing Reserves		Undeveloped Reserves		Total Reserves	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.0041	5.35	0.159	36.98	0.1659	44.03
P50	0.0138	12.65	0.285	58.97	0.3008	72.14
P90	0.04023	27.59	0.5664	96.54	0.6027	121.83

Table 54—The resources estimates results for the whole Marcellus shale play.

Total Marcellus	Contingent Resources		Prospective Resources		Total Resources	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.1745	178.03	0.33	89.21	0.593	287.5
P50	0.3394	336.50	0.68	142.13	1.076	486.67
P90	0.7252	664.36	1.596	232.44	2.176	866.71

Table 55—The total reserves and resources estimates result for the rest of the Marcellus shale play.

Total Marcellus	Total Reserves and Resources	
	NGL (BBNGL)	Gas (TCF)
P10	0.858	339.1
P50	1.432	560.3
P90	2.623	980.9

Table 56—P90-to-P10 ratios of the Marcellus shale play reserves and resources estimates.

	WV P90/P10		PA P90/P10		OH P90/P10		RoP P90/P10		Total Marcellus P90/P10	
	NGL	Gas	NGL	Gas	NGL	Gas	NGL	Gas	NGL	Gas
Existing Reserves	25.99	7.85	23.26	6.60	23.48	4.995	N/A	N/A	9.81	5.16
Undeveloped Reserves	4.97	3.35	5.12	3.35	5.04	4.18	N/A	N/A	3.56	2.61
Total Reserves	5.10	3.4	5.25	3.5	5.67	4.02	N/A	N/A	3.63	2.8
Contingent Resources	8.04	3.69	N/A	8.77	5.61	4.86	N/A	6.52	4.16	3.73
Prospective Resources	5.73	4.48	7.62	6.28	12.34	10.07	7.89	4.7	4.84	2.61
Total Resources	6.92	3.67	8.16	8.09	6.62	5.67	7.89	4.48	3.67	3.01
Total Reserves + Resources	5.07	3.48	5.44	6.41	6.63	5.67	7.89	4.48	3.06	2.89

It should be noted that the estimates for the PA and OH Marcellus shale play were calculated based on the WV Marcellus shale play analysis, not from the actual production data analysis from the existing wells in the PA and OH Marcellus shale play. As stated in Subchapter 3.6.4, the summation of the reserves and resources estimates for all of the Marcellus shale play were performed within one run of Monte Carlo simulation, which means that it was performed by assuming complete independence among the reserves and resources between AUs and production regions. Table 56 shows that about 65% of the P90-to-P10 ratios are smaller than 6, which means that the results tend to underestimate the uncertainty.

4.2. The Comparison with USGS (2003) and USGS (2011a) Estimates

USGS (2003) and USGS (2011a) estimates were intended for the undiscovered resources of the Marcellus shale play and were published for the whole Marcellus shale play. Therefore, this work's prospective resources estimates for the whole Marcellus shale play were used in this comparison. Instead of using P10, P50, and P90, USGS (2003) and USGS (2011a) used P5, P50, and P95. **Table 57** shows the comparison of the estimation parameters used in these three estimates. **Table 58** shows the comparison between USGS (2003), USGS (2011a) and this work's Marcellus shale play reserves and resources estimates. **Fig. 61 and 62** show the graphical comparison between these three estimates.

Table 57—The comparison of estimation parameters used in USGS (2003), USGS (2011a), and this work's gas and NGL estimates.

	USGS (2003)	USGS (2011a)	This Work
Discovered (acres)	N/A	666,029	21,915,930
Undiscovered (acres)	N/A	65,936,851	52,971,924
Total Area (acres)	N/A	Triangular distribution with overall mean of 66,602,880	74,887,854
Well Spacing (acres/well)	N/A	Triangular distribution shown in Table 32, with the overall mean value of 132	Triangular distribution shown in Table 32, with the overall mean value of 132
End of forecast (years)	30	30	20

Table 58—The comparison between USGS (2003), USGS (2011a) and this work's gas and NGL Marcellus shale play estimates.

Whole Marcellus Shale Play Estimates	USGS (2003)		USGS (2011a)		This Work's	
	NGL Undiscovered Resources (BBNGL)	Gas Undiscovered Resources (TCF)	NGL Prospective Resources (BBNGL)	Gas Prospective Resources (TCF)	NGL Prospective Resources (BBNGL)	Gas Prospective Resources (TCF)
P5	0.0045	0.822	1.554	42.95	0.27	78.56
P50	0.0102	1.736	3.095	78.68	0.68	142.13
P95	0.0231	3.668	6.162	144.15	2.08	269.33

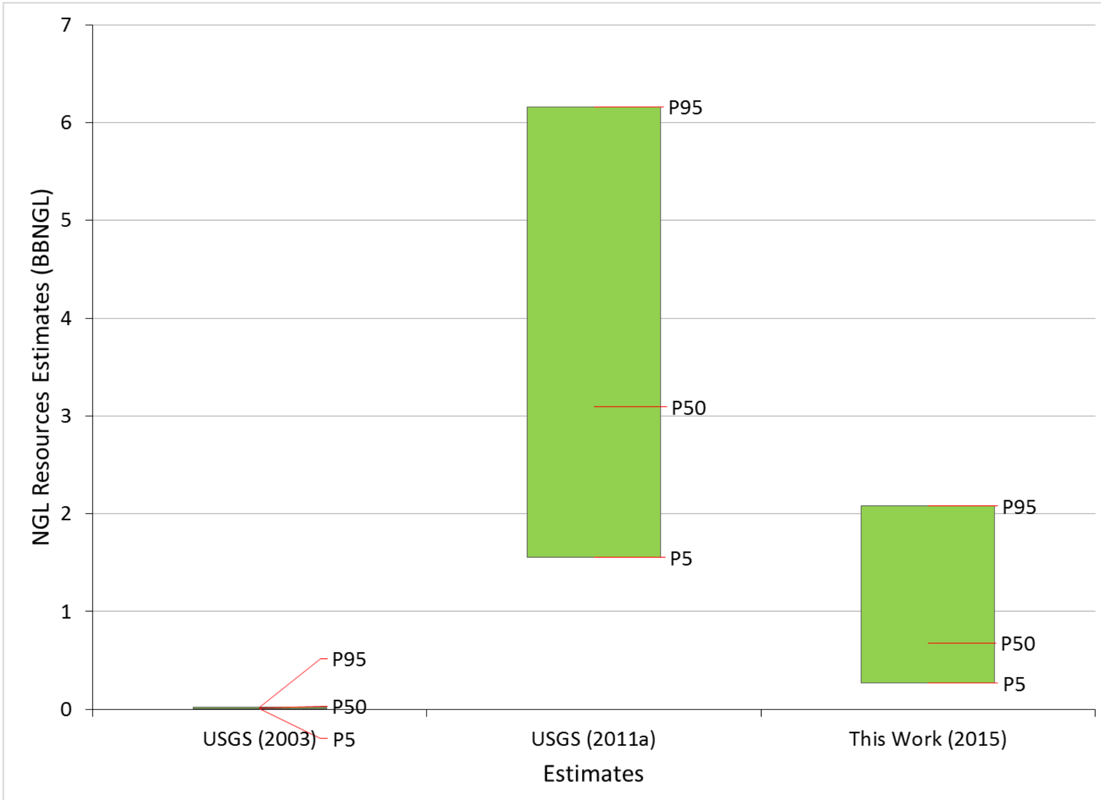

Fig. 61—The graphical comparison of USGS (2003), USGS (2011a), and this work's NGL estimates of the Marcellus shale play.

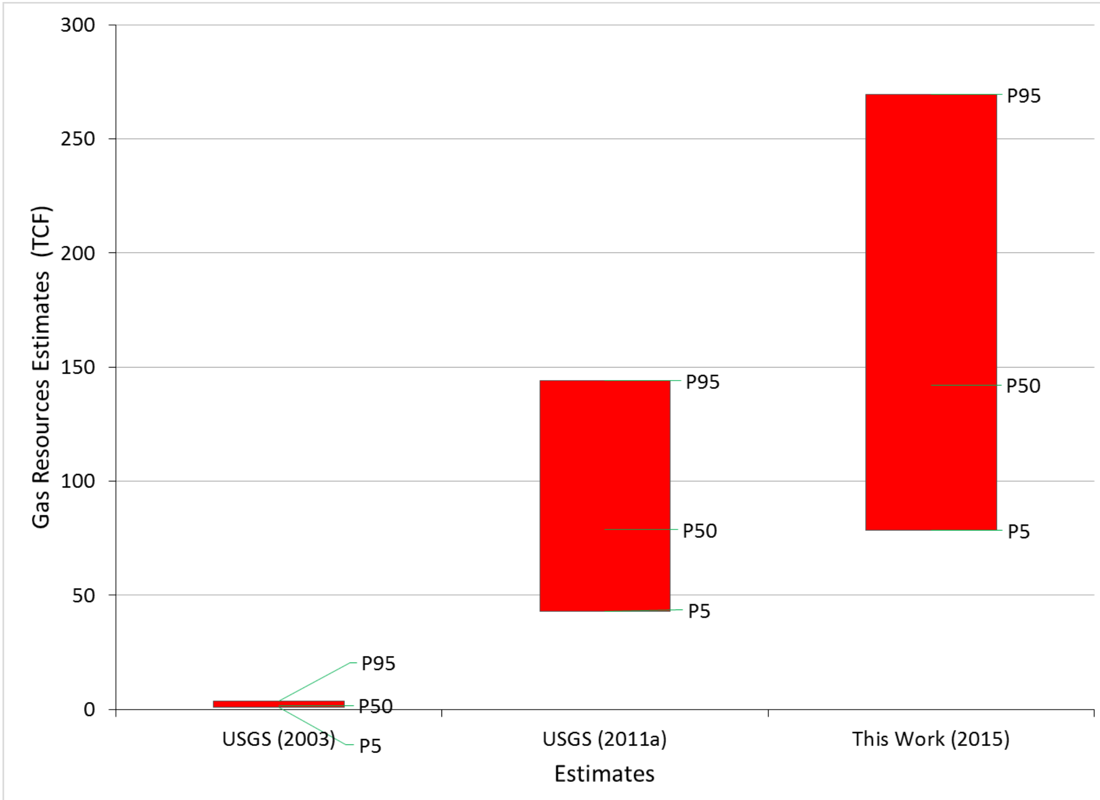

Fig. 62—The graphical comparison of USGS (2003), USGS (2011a), and this work's gas estimates of the Marcellus shale play.

Table 57 shows that the only information about estimation parameters that is available from USGS (2003) is the end of forecast time, which was the common time used by the USGS (30 years). It is the same as in USGS (2011a) and 10 years longer than this work's end of forecast time. Table 57 also shows that the undiscovered area in USGS (2011a) estimates is higher than this work's undiscovered area, but USGS (2011a) discovered area is much lower than this works'. This work's total area is higher than USGS (2011a) total area. The well spacing parameters is the same for both of estimates since this work based its well spacing on USGS (2011a) assessment. It should be noted that there is a 4-year gap between USGS (2011a) and this work's estimates. During this 4-year gap the drilling and production activities in the Marcellus shale play continued to increase, which makes some of the undiscovered area in the USGS (2011a) estimates shifted to the discovered area. That is why the discovered area in this work's estimates is higher and the undiscovered area in this work's estimates is lower than USGS (2011a).

Table 58, Fig. 61, and Fig. 62 show that USGS (2003) has the lowest estimates for both NGL and gas among the three estimates. As explained in Subchapter 1.4.2, the limitation in public production data available and also the limitation in technology were the causes for these low estimates. Most of the wells' production data in USGS (2003) estimates came from vertical wells drilled in WV. PA maintained a 5-year embargo on the release of well-level production data until 2010 (EIA 2012a). Since 2003, technological improvements have led to more-productive and less-costly wells. The newer horizontal wells have higher EURs than the older vertical wells. As a result, the cumulative production of the Marcellus shale play was on a path to exceed this USGS (2003) estimates within a year or two (EIA 2012a). Therefore, the USGS updated its Marcellus shale play assessment with USGS (2011a) estimates.

Table 58, Fig. 61 and Fig. 62 show that the gas undiscovered resources estimates from USGS (2011a) are lower than this work's gas prospective resources, but USGS (2011a) NGL undiscovered resources estimates are higher than this work's NGL prospective resources. USGS (2011a) undiscovered resources estimates were published in 2011. Since the development of the Marcellus shale play continues to rise, there must be more production data available to be included in the reserves/resources assessments.

This work shows that the type probabilistic decline curves that were used in the estimation were able to bracket the production data quite well (Fig. 32, 35, and 39). In Table 7 where EIA (2012a) compared USGS (2011a) estimates with its estimates from 2011 and 2012, it is shown that the average EUR used in the USGS (2011a) estimates was 0.93 BCF/well. On the other hand, Table 30 shows that the mean values of the TRR20 from the gas type probabilistic decline curves for both production regions in this work are more than 3 BCF/well. It is more than three times the average EUR value in USGS (2011a) estimates. This is the main reason why this work's gas prospective resources estimates are higher than USGS (2011a) gas undiscovered estimates. There is no information about the average EUR/well for USGS (2011a) NGL undiscovered resources estimates. However, the NGL type probabilistic decline curves in this work (Fig. 39) are able to bracket the production data quite well. This provides support for the reasonableness of this work's NGL prospective resources estimates.

In order to check whether the USGS quantified the uncertainty well in its estimates in 2003 and 2011, the ranges of USGS (2003) and USGS (2011a) estimates were compared. The P95-to-P5 ratios and ranges from USGS (2003) and USGS (2011a) estimates are shown in **Table 59.**

Table 59—The P95-to-P5 ratios and ranges from USGS (2003) and USGS (2011a) gas and NGL estimates.

Whole Marcellus Shale Play Estimates	USGS (2003)		USGS (2011a)	
	NGL Undiscovered Resources	Gas Undiscovered Resources	NGL Prospective Resources	Gas Prospective Resources
P95-to-P5 ratio (dimensionless)	5.14	4.46	3.97	3.36
P95 - P5 (NGL in BBNGL, Gas in TCF)	0.02	2.85	4.61	101.19

Good uncertainty assessment practices should result in uncertainty decreasing as more information is obtained. That is, one would expect P95-minus-P5 ranges and/or P95-to-P5 ratios to be smaller in later estimates than earlier estimates. In addition to that, the updated range should ideally lay inside the previous range, or there should at least be considerable overlap. Table 59 shows that the later USGS estimates have narrower P95-to-P5 ratios, but Figs. 61-62 show that ranges fail to overlap. The range of the USGS (2011a) estimates are nowhere near the range of USGS (2003) estimates. Even though the P95-to-P5 ratios of USGS (2003) estimates are wider than in USGS (2011a) estimates, the P95-minus-P5 ranges of USGS (2011a) estimates are much wider than in the USGS (2003) estimates. It appears that the USGS did not perform a good uncertainty quantification in its USGS (2003) estimates. Although uncertainty quantification in USGS (2011a) estimates is better than USGS (2003) estimates, the P95-to-P5 ratios of USGS (2011a) estimates are smaller than 6 (in the 3-to-4 range), indicating they may still be underestimating uncertainty.

4.3. The Comparison with Engelder (2009) Estimates

As explained in Subchapter 1.4.2, Engelder (2009) graded the 117 counties that contain the Marcellus shale into a six-tier system based on several geological parameters and gas production data from the play through May 15, 2009. Tier 1 is for the counties that have proven horizontal wells producing with P50 of initial production rate > 4 MMCFe/day or less than 10 miles from such wells. It means that there are some existing wells in Tier 1, which also means that Tier 1 contains discovered area within. As a result, there will be existing reserves, undeveloped reserves, and contingent resources for the discovered area, and prospective resources for the undiscovered area in Tier 1. The other 5 tiers are not adequately tested by production and thus graded downward from Tier 2 to 6 based on geological conditions. It means that these 5 tiers contain only prospective resources. Engelder (2009) did not separate his estimates into reserves or resources category. Therefore, Engelder (2009) estimates are the summation of the total reserves and total resources of the play. Engelder (2009) Marcellus shale play estimates were published by state. Engelder (2009) estimates were also for gas production and gas equivalent from NGL production. USGS (2005a) defines 1 barrel of oil equivalent (BOE) equals 6,000 cubic feet. Using this BOE definition, the total of gas and NGL reserves and resources of this work's WV Marcellus shale play estimates were compared to Engelder

(2009) WV estimates. **Table 60** shows the comparison of the estimation parameters used in Engelder (2009) and this work's reserves and resources estimates for the WV Marcellus shale play. **Table 61** and **Fig. 63** show the comparison between Engelder (2009) WV estimates and this work's estimates.

Table 60—The comparison of estimation parameters used in Engelder (2009) and this work's gas equivalent estimates for the WV Marcellus shale play.

	Engelder (2009)	This Work
Discovered (acres)	N/A	5,443,720
Undiscovered (acres)	N/A	11,455,862
Total Area (acres)	15,406,629	16,899,581
Well Spacing (acres/well)	80	Triangular distribution shown in Table 32, with the overall mean value of 132
End of forecast (years)	50	20

Table 61—The comparison between Engelder (2009) and this work's gas equivalent WV Marcellus shale play estimates.

WV Estimates	Engelder (2009) Total Reserves and Resources (TCFe)	This Work's Total Reserves and Resources (TCFe)
P10	35.02	82.23
P50	77.59	147.26
P90	136.81	287.32

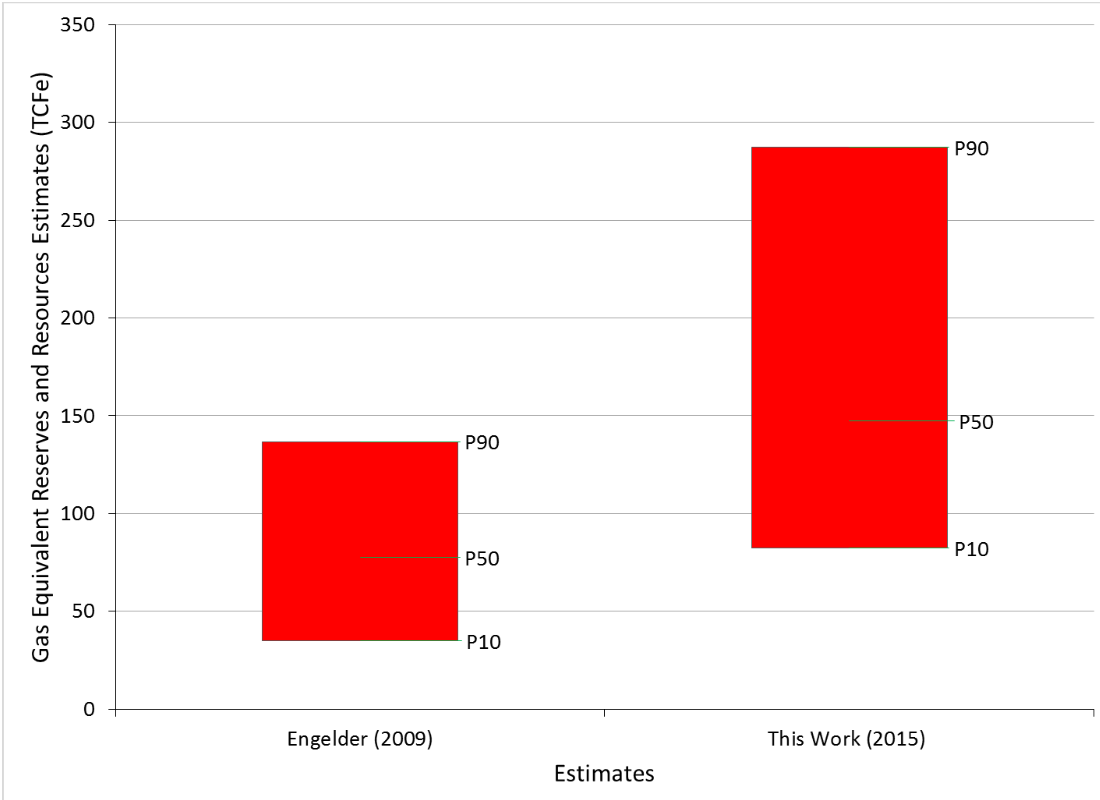

Fig. 63—The graphical comparison of Engelder (2009) and this work's gas equivalent WV Marcellus shale play estimates.

Table 60 shows that this work has larger area than Engelder (2009). In its estimates, Engelder (2009) assumed that only 70% of the play's area was accessible. This work, on the other hand, instead of using one single value, takes uncertainty into consideration by adopting USGS' (2011a) triangular distribution of the fraction/percent area-with-potential parameter. In terms of well spacing, this work has a larger overall mean value of well spacing than Engelder's (2009) well spacing, which is 132 acres/well compared to 80 acres/well. It also shows that the end of the forecast time in Engelder (2009) is longer than this works', which is 50 years compared to 20 years.

Table 61 and Fig. 63 show that this work's estimates are higher than Engelder's (2009) estimates. It should be noted that Engelder (2009) estimates were published in 2009 and also dealt with limited production data. The estimates are outdated because it was published about five years ago. A lot can happen in the play during five years, particularly in the availability of production data.

4.4. The Comparison with EIA (2011) and EIA (2012) Estimates

EIA (2011) estimates were conducted by an independent consultant hired by the EIA after the cumulative production in the Marcellus shale play was on a path to exceed the USGS (2003) estimates within a year or two (EIA 2012a). The USGS also updated its assessment in USGS (2011a) estimates. The EIA adopted this USGS (2011a) assessment, and updated its estimates in EIA (2012a).

Table 7 shows that the total of EIA (2011) estimates is 410.374 TCF for the whole Marcellus shale play. Table 6 shows EIA (2012a) estimates for the WV Marcellus shale play for each Marcellus shale AU. The total of EIA (2012a) estimates for the WV Marcellus shale play is 8.86 TCF. Both of the estimates are unproved TRR for gas production. As explained in Subchapter 1.4.2, unproved TRR equals the total technically recoverable resources minus the proved oil and gas reserves EIA (2014b). Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced (EIA 2014b).

There are two categories of reserves according to the PRMS: existing reserves and undeveloped reserves. EIA (2014b) explanation about the term proved reserves is unclear regarding whether it includes both existing and undeveloped reserves or not. The EIA (2014b) proved-reserves explanation is also ambiguous because drilling a new well will shift some amount of the undeveloped reserves into the existing reserves, but it does not necessarily mean that the proved reserves will increase. If the drilled well's circle that defines the discovered area around that well does not add to the existing discovered area, i.e., inside the existing discovered area, it will not increase the proved reserves. However, if the drilled well is located outside or near the border of the existing discovered area, its circle will add to the existing discovered area, hence increasing the proved reserves. Since the EIA (2014b) definition about proved reserves is not quite clear, it is assumed that the drilled wells will add to the proved reserves, which means the proved reserves is the summation of existing and undeveloped reserves. Therefore, unproved TRR is comparable to the total resources in the PRMS definition.

EIA (2011) unproved TRR was compared to this work's total resources for the whole Marcellus shale play. EIA (2012a) estimates for the WV Marcellus shale play was compared to this work's total resources for the WV Marcellus shale play. **Table 62** shows the comparison of the estimation parameters used in EIA (2011) and this work's reserves and resources estimates for the whole Marcellus shale play. **Table 63** and **Fig. 64** shows the comparison between EIA (2011) estimates and this work's estimates. **Table 64** shows the comparison of the estimation parameters used in EIA (2012a) and this work's reserves and resources estimates for the WV Marcellus shale play. **Table 65** and **Fig. 65** show the comparison of EIA (2012a) and this work's WV Marcellus shale play estimates.

Table 62—The comparison of estimation parameters used in EIA (2011) and this work's gas estimates for the whole Marcellus shale play.

	EIA (2011)	This Work
Discovered (acres)	N/A	21,915,930
Undiscovered (acres)	N/A	52,971,924
Total Area (acres)	60,731,520	74,887,854
Well Spacing (acres/well)	80	Triangular distribution shown in Table 32, with the overall mean value of 132
End of forecast (years)	30	20

Table 63—The comparison result between EIA (2011) estimates and this work's gas estimates for the whole Marcellus shale play.

Whole Marcellus Shale Play Estimates	EIA (2011) Unproved TRR (TCF)	This Work's Total Resources (TCF)
P10	410.37	287.5
P50		486.7
P90		866.7

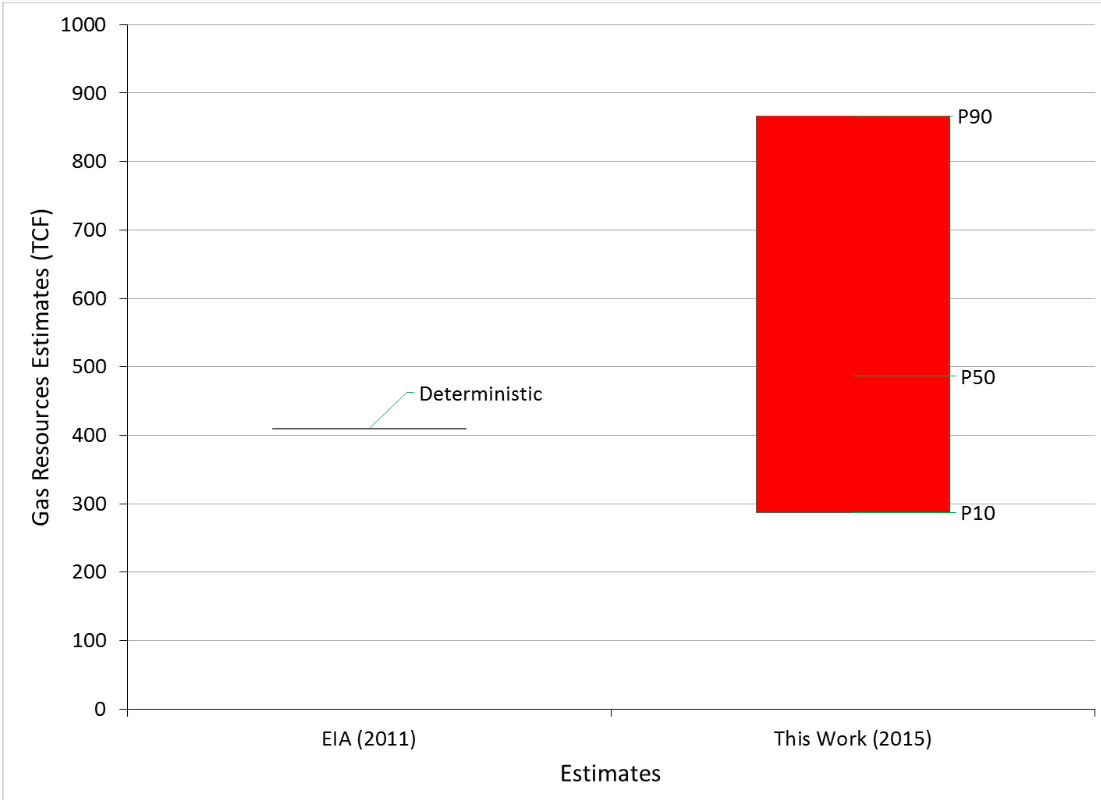

Fig. 64—The graphical comparison of EIA (2011) and this work's gas estimates for the whole Marcellus shale play.

Table 64 —The comparison of the estimation parameters used in EIA (2012a) and this work's gas estimates for the WV Marcellus shale play.

	EIA (2012)	This Work
Discovered (acres)	151,827	5,443,720
Undiscovered (acres)	15,030,893	11,455,862
Total Area (acres)	15,182,720	16,899,581
Well Spacing (acres/well)	132	Triangular distribution shown in Table 32, with the overall mean value of 132
End of forecast (years)	30	20

Table 65—Comparison between EIA (2012a) estimates and this work's gas estimates for the WV Marcellus shale play.

Whole Marcellus Shale Play Estimates	EIA (2012a) Unproved TRR (TCF)	This Work's Total Resources (TCF)
P10	8.86	81.5
P50		145.9
P90		283.8

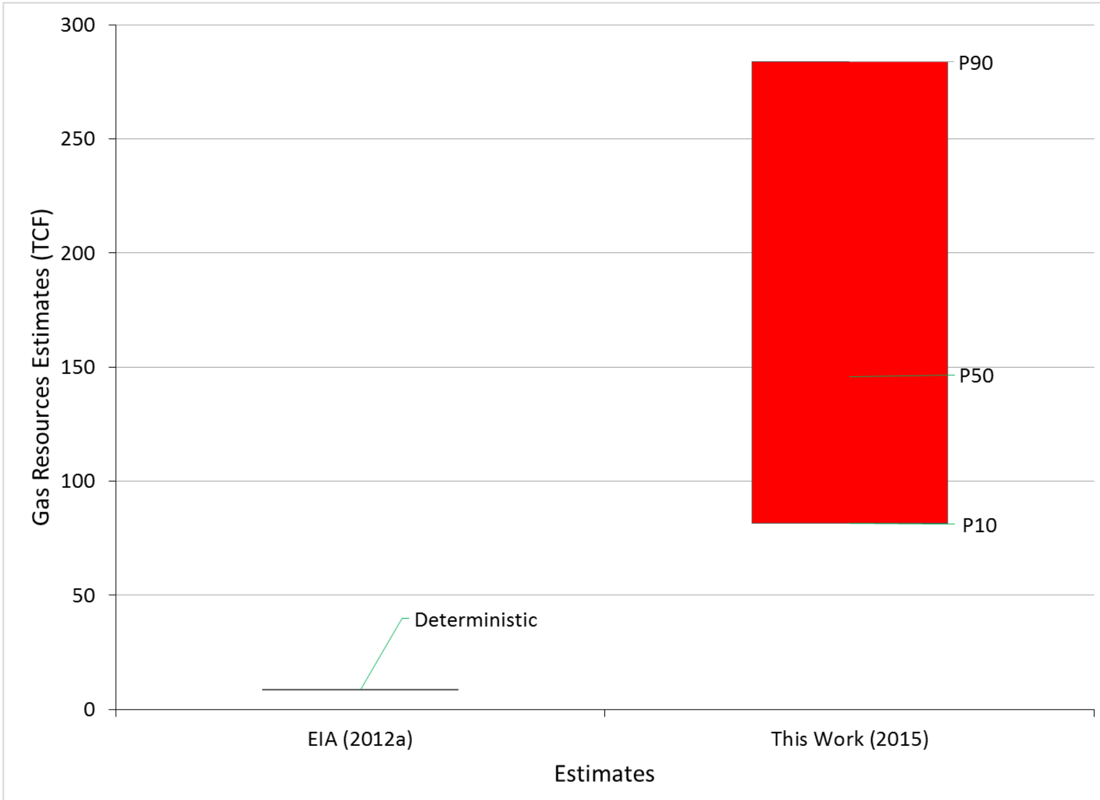

Fig. 65—The graphical comparison of EIA (2012a) and this work's gas estimates for the WV Marcellus shale play.

Table 62 shows that this work has larger total area than EIA (2011). EIA (2011) divided its area into active and undeveloped area based on company leases. The active area is the acreage reportedly under lease by oil and gas companies, while the undeveloped area is the remaining area that has not been leased. This definition is not the same as the discovered and undiscovered areas in this work because some areas can be categorized discovered even though they are not under company lease. Therefore, the comparison for this work's reserves/resources category in the discovered and undiscovered areas cannot be compared with EIA (2011) estimates for its active and undeveloped areas. The total of

EIA (2011) estimates in Table 7 was instead used in this comparison. EIA (2011) used 80 acres well spacing, while this work used the overall mean value of 132 acres well spacing. The end of the forecast time in EIA (2011) is longer than this works', which is 30 years compared to 20 years. Table 63 and Fig. 64 show that EIA (2011) estimates are inside the range of this work's total resources estimates, and quite close to this work's P50 estimate.

Table 64 shows that this work's discovered area is higher than EIA (2012a) discovered area, and this work's undiscovered area is lower than EIA (2012a) undiscovered area. It is understandable since the as-of-date data used in EIA (2012a) is 1/1/2010 (Table 8).Between the EIA (2012a) as-of-date and this work as-of-date (12/1/2013), the drilling and production activities in the Marcellus shale play continued to increase, which makes some of the undiscovered area in the USGS (2011a) estimates shifted to the discovered area. The same as in EIA (2011), the end of forecast time in EIA (2012a) is also 30 years. EIA (2012a) used 132 acres well spacing, which is the same as this work's mean well spacing. Table 65 and Fig. 65 show that this work's total resources estimates are much higher than EIA (2012a) estimates.

The same as the comparison with the USGS (2011a) estimates in Subchapter 4.2, this work's TRR20/well is also higher than EIA (2011) and EIA (2012a) average EUR/well. Table 7 shows that EIA (2011) has 0.93 BCF average EUR/well, and EIA (2012a) has 1.56 BCF average EUR/well. Table 30 shows that the mean values of the TRR20 from the gas type probabilistic decline curves for both production regions in this work are more than 3 BCF/well. It is more than twice the average EUR/well values in EIA (2011) and EIA (2012a) estimates. The obvious advantage that this work has over EIA

(2011) and EIA (2012a) estimates is the greater availability of production data in the Marcellus shale play, since this work was conducted later than both of the EIA estimates. Since EIA (2011) and EIA (2012a) were deterministic, they do not consider uncertainty quantification.

CHAPTER V

CONCLUSIONS

5.1. Conclusions

- The WV Marcellus shale play reserves and resources estimates are as follows.

WV	Total Reserves		Total Resources		Total Reserves and Resources	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.048	8.19	0.0517	70.65	0.1154	81.54
P50	0.095	14.91	0.1263	130.13	0.2252	145.91
P90	0.245	27.88	0.3579	259.51	0.5846	283.81

- This work's reserves and resources estimates are generally higher than those previously published by USGS (2003), Engelder (2009), EIA (2011), USGS (2011a), and EIA (2012a).
- The estimates of the whole Marcellus shale play that are extrapolated from the WV Marcellus shale play analysis are as follows.

Total Marcellus	Total Reserves		Total Resources		Total Reserves and Resources	
	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)	NGL (BBNGL)	Gas (TCF)
P10	0.1659	44.03	0.593	287.5	0.858	339.1
P50	0.3008	72.14	1.076	486.67	1.432	560.3
P90	0.6027	121.83	2.176	866.71	2.623	980.9

The PA and OH estimates were extrapolated from the WV Marcellus shale play analysis, and were not based on actual production data analysis in these areas.

- Based on the hindcast study results, the MCMC PDCA method proves its reliability once again in forecasting production and estimating reserves with the WV Marcellus shale play production data. The hindcast results show that the Duong (2011) DCA method is well calibrated and consistently outperforms the other DCA models used in this work.
- This work offers the industry an update of the reserves and resources estimates of the Marcellus shale play in WV. These estimates reliably quantify the uncertainty in the play and can help in decision making regarding continued development of the play.

5.2. Limitations and Future Work Recommendation

As stated in Subchapter 3.2, this work focused on reserves and resources estimates for only the WV Marcellus shale play. This was because as of November 2, 2014, which was the date the production data was taken from the DI Desktop application, only WV had monthly production data out of six states that cover the Marcellus shale play. The reserves and resources estimation for the Marcellus shale play beyond WV was extrapolated from the WV Marcellus shale play reserves and resources analysis.

In imposing minimum decline rate, this work used a D_{min} distribution from the Eagle Ford play, since there was no long-term production data on which to base the analysis for selecting D_{min} from Marcellus shale play production data. This work also assumed that all the wells in the play are completely independent while in reality they should neither be 100% independent nor 100% dependent. There was also subjectivity in extending the boundary between the liquid-rich and dry-gas regions in the NY part because there were no existing wells there from which to get an initial GLR analysis. The boundary was based on the contour map of depth to the Marcellus shale base.

A P90-to-P10 ratio in the 6-to-10 range was deemed to be a reasonable expression of the uncertainty in the long term. The P90-to-P10 ratios for this work's WV Marcellus shale play reserves and resources estimates within each AU are mostly greater than or fall inside this range due to the complete dependence assumption between the wells. The summation of reserves and resources estimates was performed within the same Monte Carlo simulation, which means that the summation was performed under the assumption of complete independence among the reserves and resources between AUs and production regions. Because of this, this work's total reserves and resources estimates of the Marcellus shale play tend to underestimate the uncertainty.

Reserves and resources estimation for the Marcellus shale play as a whole will be interesting to pursue, now that PA has implemented a new rule requiring monthly production reporting for unconventional wells effective January 2015 (DEP 2015). The reserves and resources estimates for the Marcellus shale play will be more reliable because the analysis for the play outside WV, especially in PA, will be based on monthly production data from the play itself, and there will be more production data available for the WV Marcellus shale play. It will be better to start performing the estimation next year in 2016 when there will be at least 12 months monthly production data for each producing well in the play outside WV. As more production data become available, it may be possible to perform D_{min} analysis using Marcellus shale play production data. There is also a need for research on how to model dependency between the wells in reserves and resources estimation for the Marcellus shale play.

NOMENCLATURE

a	Duong intercept constant, 1/month
b	Decline exponent for Arps' model, dimensionless
BBNGL	Billion barrels of NGL
BCF	Billion cubic feet
BCFe	Billion cubic feet equivalent
c_t	The percent correct
D_i	Initial decline rate, 1/year
D_{min}	Minimum decline rate, 1/year
D_∞	Power-law decline at infinite time constant, 1/year
EIA	The U.S. Energy Information Administration
GLR	Gas Liquid Ratio, MCF/STB
m	Duong slope constant
MBM	Modified bootstrap method
MCF	Thousand cubic feet
MCMC	Markov Chain Monte Carlo
n	Decline exponent in power-law and SEPD model
n_t	The number of assessment for the response probability r_t
N	Total number of assessments
NGL	Natural Gas Liquid
OH	Ohio

PA	Pennsylvania
PDCA	Probabilistic decline curve analysis
PRMS	Petroleum resources management system
P5	Value at 5th percentile
P10	Value at 10th percentile
P50	Value at 50th percentile
P90	Value at 90th percentile
P95	Value at 95th percentile
r_t	The response probability assigned to an assessment
SEPD	Stretched exponential decline model
SPE	Society of petroleum engineers
STB	Stock Tank Barrel
T	Total number of different response probabilities (e.g., 3 for 10%, 50%, 90%)
TRR20	Technically Recoverable Resources at 20 years, STB or BCF
TCF	Trillion cubic feet
WV	West Virginia
α	Acceptance probability in MCMC, dimensionless
θ	Decline curve parameters
ϑ	One of the decline curve parameters
θ_j	Parameters of step j in MCMC
θ_{lower}	Lower boundary of proposal distribution

θ_{upper}	Upper boundary of proposal distribution
$\theta_{proposal}$	Parameters drawn from proposal distribution
σ	Sample variance from best fit
$\sigma_{proposal}$	Sample variance from proposal parameters
σ_j	Sample variance from step j in MCMC
σ_{ϑ}	Standard deviation of proposal distribution of parameter ϑ
Φ	Cumulative density function of standard normal distribution
τ	Characteristic time parameter for SEPD model, month
c_t	The percent correct

REFERENCES

Arps, J.J. 1945. Analysis of Decline Curves. *AIME* **160** : 228–247. http://dx.doi.org/10.2118/945228-G.

Bloomberg. 2015. Energy & Oil Prices. *bloomberg.com*, www.bloomberg.energy (accessed 22 January 2015).

Capen, E.C. 1976. The Difficulty of Assessing Uncertainty (Includes Associated Papers 6422 and 6423 and 6424 and 6425). *SPE Journal of Petroleum Technology* (8): 843–850. http://dx.doi.org/10.2118/5579-PA.

Cheng, Y., Wang, Y., McVay, D.A. *et al*. 2010. Practical Application of a Probabilistic Approach to Estimate Reserves Using Production Decline Data. **2** (1). http://dx.doi.org/10.2118/95974-PA.

DEP, Pennsylvania. 2015. Monthly Reporting of Unconventional Well Production Data. *files.dep.state.pa.us*, 5 February 2015, http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/industryResources/2015/Unconventional%20Monthly%20Production%20Reporting%20Letter.pdf (accessed 10 June 2015).

DEC, New York. 2015. New York State Officially Prohibits High-Volume Hydraulic Fracturing. *dec.ny.gov*, 29 June 2015, http://www.dec.ny.gov/press/102337.html (accessed 7 July 2015).

Dittrick, P. 2015. New York State Decides to Ban Hydraulic Fracturing. *ogj.com*, 10 February 2015, http://www.ogj.com/ales/uogr/print/volume-3/issue-1/new-york-state-decides-to-ban-hydraulic-fracturing.html (accessed 10 June 2015).

DMME, Virginia. 2012. Hydraulic Fracturing in Virginia. *dmme.virginia.gov*, 2012, http://www.dmme.virginia.gov/dgo/HydraulicFracturing.shtml (accessed 7 July 2015).

Dugan, T. 2014. CONSOL Energy. *Iogawv.com*, http://www.iogawv.com/Resources/Docs/WinterMeeting/2014_ConsolWinterMeeting.pdf (accessed 9 June 2015).

Duong, A.N. 2011. Rate-Decline Analysis for Fracture-Dominated Shale Reservoirs. *SPE Reservoir Evaluation & Engineering* (06). http://dx.doi.org/10.2118/137748-PA.

EIA. 2011. Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays. U.S. Department of Energy, Washington, DC20585. http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf.

EIA. 2012a. Annual Energy Outlook 2012 with Projections to 2035. Department of Energy, Washington, DC20585. http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

EIA. 2012b. Geology and technology drive estimates of technically recoverable resources. *eia.gov*, 20 July 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=7190 (accessed 18 May 2015).

EIA. 2013. Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. U.S. Department of Energy, Washington, DC20585. http://www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf.

EIA. 2014a. Oil and Gas Outlook. *eia.gov*, 13 November 2014, http://www.eia.gov/pressroom/presentations/sieminski_11132014.pdf (accessed 19 May 2015).

EIA. 2014b. Oil and natural gas resource categories reflect varying degrees of certainty. e*ia.gov*, 17 July 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=17151 (accessed 19 May 2015).

EIA. 2015. Drilling Productivity Report for Key Tight Oil and Shale Gas Regions. Department of Energy, Washington, DC20585. http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf

Engelder, T. 2009. Marcellus. *Fort Worth Basin Oil&Gas Magazine*: 18–22. http://www.marcellus.psu.edu/resources/PDFs/marcellusengelder.pdf

Gong, X.2013. *Assessment of Eagle Ford Shale Oil and Gas Resources*. PhD Dissertation, Texas A&M University, College Station, Texas, (August 2013).

Gong, X., Gonzalez, R.A., McVay, D.A. *et al*. 2011. Bayesian Probabilistic Decline Curve Analysis Quantifies Shale Gas Reserves Uncertainty. *SPE J*. SPE-147588-PA. (in press; issued 1 May 2014). http://dx.doi.org/10.2118/147588-PA.

Gong, X., Tian, Y., McVay, D.A. 2013. Assessment of Eagle Ford Shale Oil and Gas Resources. Paper presented at the SPE Unconventional Resources Conference, Calgary, Alberta, Canada. Society of Petroleum Engineers SPE-167241-MS. http://dx.doi.org/10.2118/167241-MS.

Gonzalez, R.A., Gong, X., McVay, D.A. 2012. Probabilistic Decline Curve Analysis Reliably Quantifies Uncertainty in Shale Gas Reserves Regardless of Stage Depletion. Paper presented at the SPE Eastern Regional Meeting, Lexington, Kentucky, USA. Society of Petroleum Engineers SPE-161300-MS. http://dx.doi.org/10.2118/161300-MS.

Gonzalez, R.A. 2012. *Using Decline Curve Analysis, Volumetric Analysis, and Bayesian Methodology to Quantify Uncertainty in Shale Gas Reserves Estimates*. MS Thesis, Texas A&M University, College Station, Texas, (December 2012).

Holditch, S.A. 2006. Tight Gas Sands. *J Pet Technol* **58** (6): 86–93. SPE-103356-JPT. http://dx.doi.org/10.2118/103356-JPT.

Holditch, S.A. and Ayers, W.B. 2009. How Technology Transfer will Expand the Development of Unconventional Gas, Worldwide. *Proc.*, 29th Annual Gulf Coast Section SEPM Foundation Bob F. Perkins Research Conference, Houston, Texas, 6–8 December, 150–180. http://www.bergan.com/Downloads/HoldAyrs.pdf.

Ilk, D., Rushing, J.A., Perego, A.D. *et al*. 2008. Exponential Vs. Hyperbolic Decline in Tight Gas Sand — Understanding the Origin and Implications for Reserve Estimates Using Arps' Decline Curves. Paper presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA. Society of Petroleum Engineers SPE-116731-MS. http://dx.doi.org/10.2118/116731-MS.

Jochen, V.A. and Spivey, J.P. 1996. Probabilistic Reserves Estimation Using Decline Curve Analysis with the Bootstrap Method. Paper presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA. Society of Petroleum Engineers SPE-36633-MS. http://dx.doi.org/10.2118/36633-MS.

Lee, W.J. and Sidle, R. 2010. Gas-Reserves Estimation in Resource Plays. SPE Economics & Management 2 (2): pp. 86–91. http://dx.doi.org/10.2118/130102-PA.

McCain Jr., W.D. 1994. Heavy Components Control Reservoir Fluid Behavior. *J Pet Technol* **46** (09): 746–750. SPE-28214-PA. http://dx.doi.org/10.2118/28214-PA.

McCown, M. 2014. GASTAR Expanding Our Horizons. *iogawv.com*, February 2014, http://www.iogawv.com/Resources/Docs/WinterMeeting/2014_GastarWinterMeeting.pdf (accessed 9 June 2015).

McVay, D.A. and Dossary, M. 2014. The Value of Assessing Uncertainty. *SPE Econ & Mgmt* **6** (02): 100–110. SPE-160189-PA. http://dx.doi.org/10.2118/160189-PA.

MDE, Maryland. 2015. Marcellus Shale Safe Drilling Initiative. *mde.state.md.us*. 2015, http://www.mde.state.md.us/programs/land/mining/marcellus/pages/index.aspx (accessed 7 July 2015).

SPE, AAPG, WPC *et al*. 2007. Petroleum Resources Management System. http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf.

PSU. 2010. Marcellus Center for Outreach & Research (MCOR). *marcellus.psu.edu*, 2010, http://marcellus.psu.edu/images/Marcellus_Depth.gif (accessed 19 May 2015).

Toon, Steve. 2015. West Virginia Rising. *oilandgasinvestor.com*, 13 February 2015, http://www.oilandgasinvestor.com/west-virginia-rising-783086# (accessed 9 June 2015).

USGS. 2002. U.S. Geological Survey Input-Data Form and Operational Procedure for the Assessment of Continuous Petroleum Accumulations, 2002, Chapter 18 of Petroleum Systems and Geologic Assessment of the Southwestern Wyoming Province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series DDS-69-D. http://pubs.usgs.gov/dds/dds-069/dds-069-d/REPORTS/69_D_CH_18.pdf.

USGS. 2003. Assessment of Undiscovered Oil and Gas Resources of the Appalachian Basin Province, 2002. U.S. Geological Survey Fact Sheet FS-009-03. http://pubs.usgs.gov/fs/fs-009-03/FS-009-03-508.pdf.

USGS. 2005a. Glossary, Chapter 25 of Petroleum Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series DDS–69–D. http://pubs.usgs.gov/dds/dds-069/dds-069-d/REPORTS/69_D_CH_25.pdf.

USGS. 2005b. U.S. Geological Survey Assessment Concepts for Continuous Petroleum Accumulations, Chapter 13 of Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and

Utah: U.S. Geological Survey Digital Data Series DDS–69–D. http://pubs.usgs.gov/dds/dds-069/dds-069-d/REPORTS/69_D_CH_13.pdf.

USGS. 2011a. Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011. U.S. Geological Survey Fact Sheet 2011-3092. http://pubs.usgs.gov/fs/2011/3092/.

USGS. 2011b. Information Relevant to the U.S. Geological Survey Information Relevant to the U.S. Geological Survey Assessment of Middle Devonian Marcellus Shale of the Appalachian Basin Province, 2011. U.S. Geological Survey Open-File Report 2011-1298. http://pubs.usgs.gov/of/2011/1298/.

USGS. 2014. Appalachian Basin. *energy.usgs.gov*, 3 December 2014, http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment/USBasinSummaries.aspx?provcode=5067 (accessed 19 May 2015).

Valko, P.P. and Lee, W.J. 2010. A Better Way to Forecast Production from Unconventional Gas Wells. Paper presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, USA. Society of Petroleum Engineers SPE-134231-MS. http://dx.doi.org/10.2118/134231-MS.

Wrightstone, G. 2011. The Marcellus Experience (Part2). *wrightstoneenergy.com*, 2011, http://nebula.wsimg.com/c27249323a1d01133c201c6a13c3e5a0?AccessKeyId=C3A20ED6871E9474D0BE&disposition=0&alloworigin=1 (accessed 19 May 2015).