Resource Assessment of Potentially Producible Natural Gas Volumes From the Marcellus Shale, State of New York

Prepared for the League of Women Voters of New York State

By Labyrinth Consulting Services, Inc.

Arthur Berman and Lyndon Pittinger

April 10th, 2014

Table of Contents

1) Summary

Labyrinth Consulting Services, Inc. was contracted on March 26, 2014 by the League of Women Voters of New York State to provide a resource assessment of potential commercially producible natural gas volumes from the Marcellus Shale in the State of New York, which currently has a de facto moratorium on hydraulic fracturing. An analysis of production performance trends based on data from wells in Pennsylvania indicates that the Marcellus Shale in New York is not commercially viable at current gas prices near $4.00-4.50/MMBtu (Million British Thermal Units). Assuming the de facto moratorium on hydraulic fracturing is lifted, contingent resource volumes of natural gas from the Marcellus Formation in New York State are estimated to range from 0.8 to 2.4 trillion cubic feet of gas (Tcf) if natural gas prices rise to $6.00/MMBtu (gas price referenced to Henry Hub point of sale[1]), depending on the range of uncertainty in area accessible to development. If gas prices rise to $8.00/MMBtu, the resource estimate ranges from 2.0 to 9.1 Tcf, also depending on uncertainty about access to development. Currently, NYMEX futures prices for natural gas average $4.31/MMBtu (as of April 9, 2014) for the four-year period from 2015 to 2018, reflecting the market's expectations of stable gas prices at current levels. Substantial unforeseen changes in the natural gas supply/demand balance would need to occur for long-term gas prices to increase to $6.00 and $8.00/MMBtu. These gas volumes are likely to be dry gas based on analogous production from northeastern Pennsylvania.

These resource assessments are based on reasonable assumptions for commercially viable acreage accessible to hydraulically-fractured development wells, ultimate recovery per well and final well spacing. This analysis is based entirely on publicly available information, focusing on Marcellus production performance trends in Pennsylvania and published geologic information. Proprietary data may exist that would lead to significantly different conclusions.

Substantial uncertainty exists in forecasting access and gas prices as well as extrapolating production performance into New York given the lack of well control or production within the state. Labyrinth believes that estimates reflected in these forward-looking statements are reasonable. However, such statements involve risks and uncertainties, and no assurance can be given that actual results will be consistent with these forward-looking statements. Labyrinth shall assume no liability whatsoever for the use or reliance thereupon by the League of Women Voters of New York State. Labyrinth's compensation for preparing this report was at Labyrinth's normal hourly rates for such geotechnical due diligence. Labyrinth's consultants have no financial stake in leases or companies related to the Marcellus play.

2) Introduction

Existing assessments of natural gas resource volumes recoverable from the Marcellus Shale span a wide range of values as follows:

- Engelder (2009) estimated a median (P50) technically recoverable resource volume of 489 Tcf for the entire Marcellus, with 71.9 Tcf of that volume in New York State.

- The United States Geological Society (USGS) provided an estimate in 2011 of 84.2 Tcf of undiscovered technically recoverable resource for the entire Marcellus play.

[1] For additional information on Henry Hub pricing, (http://en.wikipedia.org/wiki/Henry_Hub)

- The EIA provided an estimate in 2011 of 410 Tcf of undeveloped technically recoverable reserves, and one year later reduced that estimate to 141 Tcf for unproved technically recoverable resource, a reduction of -65%. These estimates were for the entire Marcellus play.

Each of these studies addresses technically recoverable but not necessarily economically recoverable resource volumes. The USGS definition of technically and economically recoverable resources is provided below:

> "The (USGS) uses the terms *technically* and *economically* recoverable resources when making its petroleum resource assessments. Technically recoverable resources (TRR) represent that proportion of assessed in-place petroleum that may be recoverable using current recovery technology, without regard to cost. Economically recoverable resources are technically recoverable petroleum for which the costs of discovery, development, production, and transport, including a return to capital, can be recovered at a given market price."

The EIA has a similar definition of technically recoverable resource that does not consider economic viability as follows:

> "Undiscovered technically recoverable resources (UTRR)**.** Oil and gas that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability."

Despite these definitions, widespread misunderstanding and confusion exist about the distinction between resources and reserves. The public, press and policy makers mistakenly believe that oil and gas companies will drill and develop TRR when, in fact, they will only develop the small subset of those resources that can be booked as commercially producible, in other words, reserves.

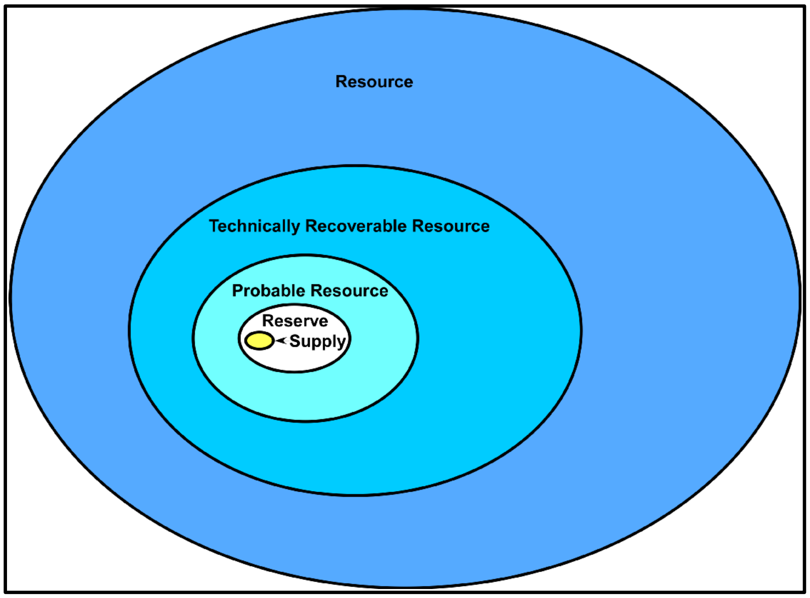
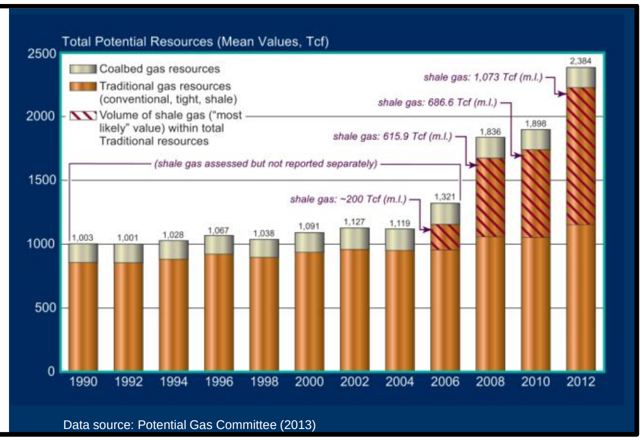


Figure 1. Relative Magnitude of Resources, Technically Recoverable Resources, Probable Resources, Reserves and Supply. Modified from Medlock (2010).

Furthermore, TRR are subdivided into speculative, possible and probable categories. Only probable TRR have been tested by drilling and are, therefore, known to be, in fact, technically recoverable. This category is generally about 25% of TRR, and perhaps 50% of probable TRR may become reserves. In other words, only about 12.5% of TRR are likely to become reserves.

This relationship underlies the common misperception that the United States has 100 years of natural gas supply. In fact, the entire TRR of the U.S. (Potential Gas Committee estimate) yields only 92 years of supply at current natural gas consumption.

SUMMARY OF POTENTIAL GAS COMMITTEE 2012 REPORT	
Technically Recoverable Resources (TRR)	**Tcf**
Probable including CBM (existing fields)	723
Possible (new fields)	1,001
Speculative (frontier)	655
Separately Aggregated Amount	6
Total	2,384
Years of Technically Recoverable Resources	**92**
Potential Reserves	**Tcf**
Proved Reserves	305
50% of Probable TRR	361
Total Potential Reserves	666
Years of Reserves (Total ÷ 2013 Consumption)	**26**



<u>Figure 2. The Myth of 100 years of Natural Gas Supply based on the Potential Gas Committee's current estimate of U.S. technically recoverable gas resources. Source: Report of the Potential Gas Committee (December 31, 2012)</u>

The Potential Gas Committee (PGC) estimates total U.S. TRR to be 2,384 Tcf in its most recent evaluation. Their probable component of TRR is 723 Tcf or 28 years of potential supply. This volume results in approximately 14 years of reserves and includes conventional and coal-bed methane sources in addition to shale gas. After including already proved reserves of 305 Tcf, total potential supply is for approximately 26 years.

Economic viability is the critical factor in determining whether a resource is eventually developed. Hence, this study will not consider technically recoverable volumes but instead will follow definitions of resources as defined by the industry-standard Petroleum Resource Management System (PRMS), which was sponsored in 2007 by the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), and Society of Exploration Geophysicists (SEG). These guidelines were enhanced in 2011 in part to address resource evaluation of shale gas plays. The following figure from the PRMS shows the progression from undiscovered Prospective Resources to discovered Contingent Resources to Proved, Probable and Possible Reserves. Although the chance of commerciality increases with this progression, commerciality is considered at each stage in determining project maturity. The following figure shows the classifications of reserves and resources as defined by the PRMS.

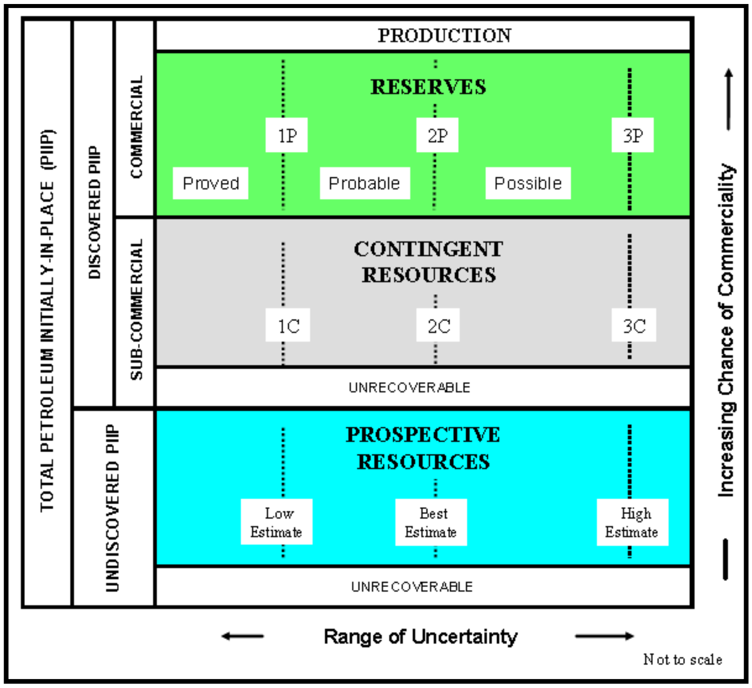


Figure 3: PRMS Classification of Reserves and Resources

Figure 4 from the PRMS adds detail on project maturity sub-categories.

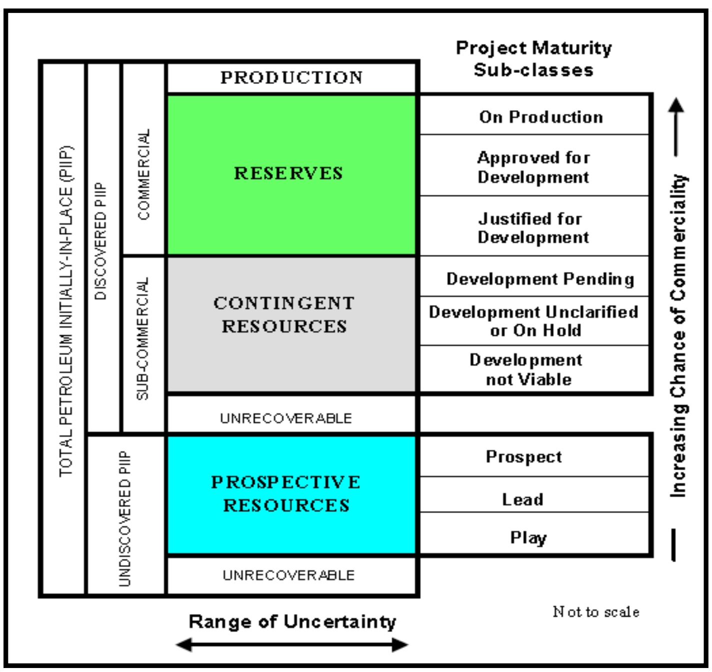


Figure 4: Sub-Classes of PRMS Classification System

The primary method used in this study to estimate the resource potential in New York State was to evaluate the actual production performance of Marcellus wells in Pennsylvania and extrapolate these production performance trends across the border into New York. Geologic trends such as depth, thickness, organic content and thermal maturity were also considered in extrapolating these performance trends.

Finally, natural gas pricing is a critical factor for evaluating commercially recoverable resources. The Henry Hub pipeline in Louisiana is the pricing point for natural gas futures on the New York Mercantile Exchange and provides the reference for most spot prices in the United States.

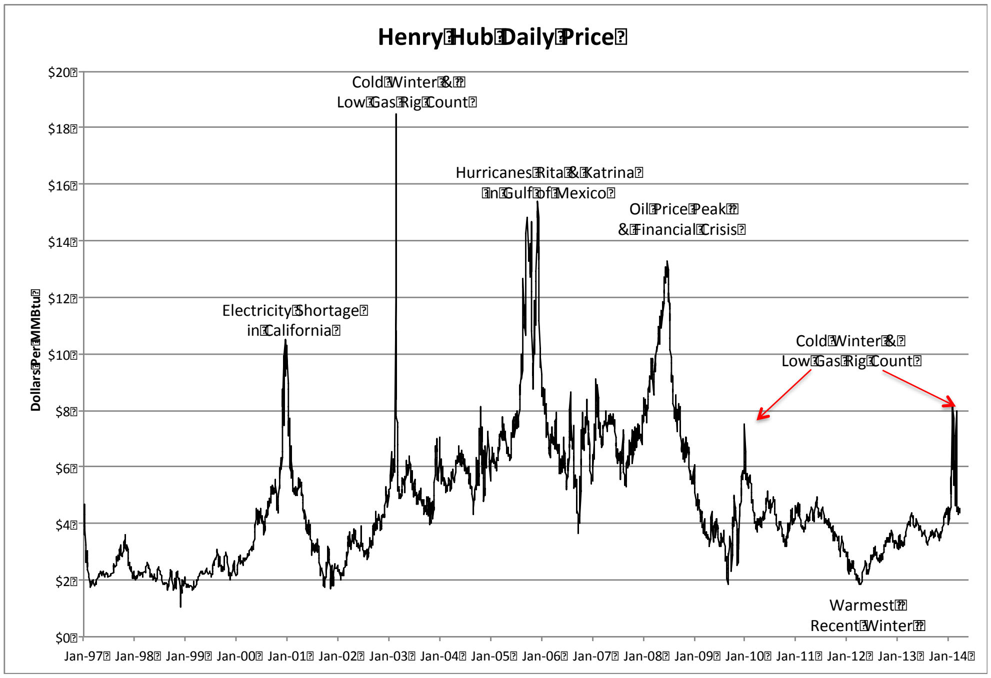


Figure 5: Henry Hub Daily Natural Gas Prices Since 1997. Source: EIA.

Natural gas prices have averaged \$4.70/MMBtu since January 1997 but have fluctuated between \$1.05 and \$18.48/MMBtu. The variance in price is related to the balance of supply, demand and the comparative inventory of volumes in underground storage. Historic price anomalies are most commonly related to weather but are also affected by oil and gas industry drilling activity or rig count levels. During the last several months, gas prices have been relatively high because of extremely cold weather. The U.S. Energy Information Administration predicts that prices will average \$4.44/MMBtu in 2014 and \$4.11/MMBtu in 2015.

3) Pennsylvania Production Performance Data

Since mid-2010, the Pennsylvania Department of Environmental Protection has publicly released total gas and condensate production volumes and days on-line for each semi-annual period. Based on the most recent data through the end of 2013, a total of 4,364 Marcellus horizontal wells in Pennsylvania have produced 6.1 Tcf of natural gas, averaging a rate of 9.2 Bcfd (billion cubic feet of gas per day) in the 2nd half of 2013, with 48% of the state's cumulative production from Bradford and Susquehanna counties. Unfortunately, Pennsylvania's six-month reporting periods provide lower resolution rate data compared to most other states for analyzing production decline trends, the primary tool used in evaluating reserves in shale gas plays. The PRMS guidelines (2011) state the following:

> "The most common way to assign Proved Reserves and Developed Producing Reserves in shale gas reservoirs is through the use of decline-curve analysis. (pg 158)"

Most hydrocarbon-producing states release production data on a monthly basis for severance tax purposes, providing detailed rate histories for analyzing decline trends. With Pennsylvania's semi-annual reporting, standard decline-curve analysis is a less reliable tool for quantifying well performance.

Lacking monthly production data, this analysis focuses instead on the cumulative production and days on-line for each well. Relative performance can be estimated using an arbitrary type well to compare the performance of wells with differing production lives. The type well serves simply as a comparison benchmark. For the purposes of this study, the type well is assumed to have an estimated ultimate recovery (EUR) of 4.2 Bcf, and is described using the hyperbolic equation as described by Arps (1945) with an initial rate of 4.5 MMscfd, a decline exponent of 1.45 and an exponential b-factor of 1.0. Each well is assigned a relative performance indicator (PI) based on the following equation:

$$PI = \text{Cumulative Production}_{\text{well}}\text{ (days on line)}/\text{Cumulative Production}_{\text{type well}}\text{ (same duration)} - 1$$

For example, a well that has produced twice as much cumulative volume of gas as the type well after 365 days on-line will have a PI value of 1. A well that has produced only one-half of the type well after a certain period will have a PI value of -0.5.

Figure 6 shows a contour map of PI values for 4,364 wells in Pennsylvania; areas shaded yellow to red are outperforming the type well and blue-shaded areas are underperforming the type well. The contour values represent an average PI value over a radius of 20,000 ft, effectively smoothing well-to-well variability. Two main core areas shaded in yellow to red are evident in the figure, one in northeastern Pennsylvania (southwestern Susquehanna, southeastern Bradford and northwestern Wyoming counties) and another in southwestern Pennsylvania (Green and Washington counties). The northeastern core area, which is dry gas production, is most relevant to assessing commercially viable resource in New York State.

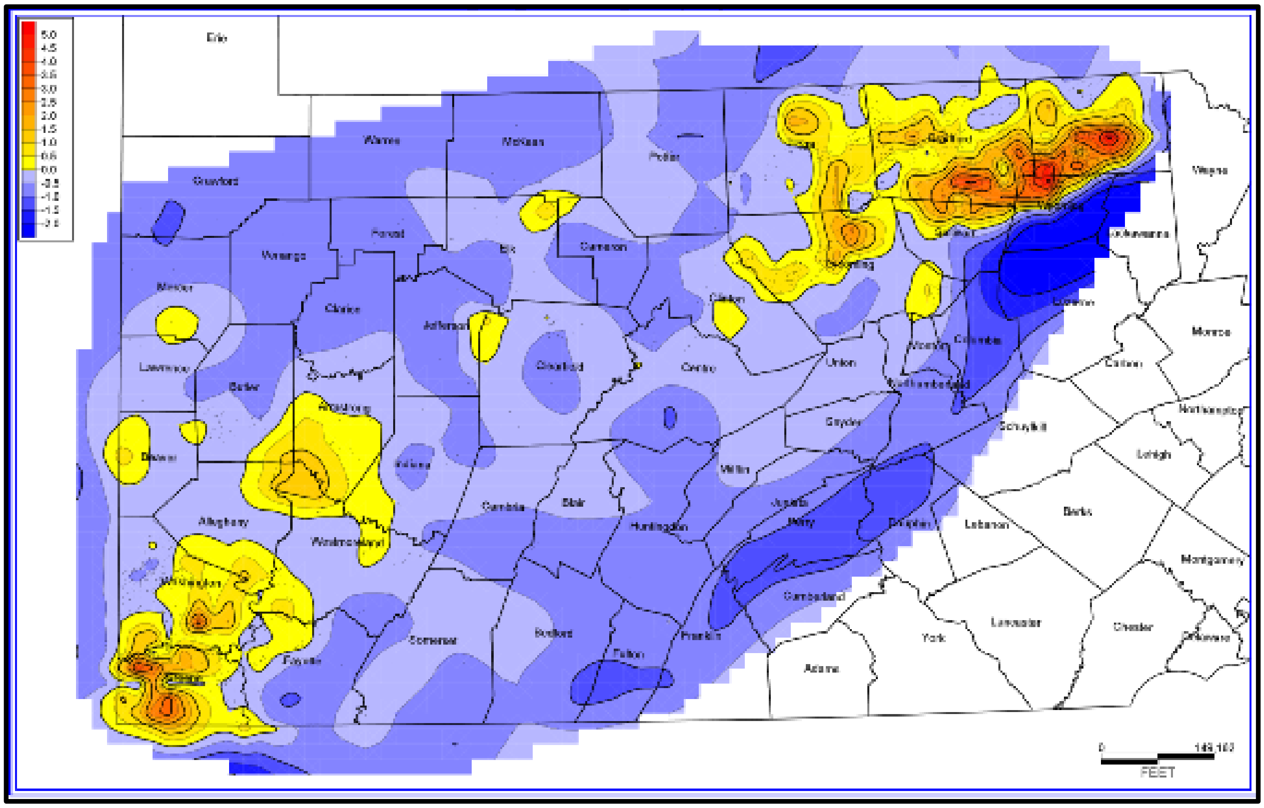


Figure 6 Marcellus Performance Indicator Map Based on production data through 2013 (Pennsylvania Department of Environmental Protection, March 2014). Yellow and red color-filled contours represent wells that out-performed our 4.2 Bcf type curve.

Figure 7 shows a more detailed view of the contour map of PI along with individual values of PI for each well to demonstrate how the outline of the core area is controlled by well data. In Susquehanna and Wyoming counties, the northern, northeastern and southeastern edges of the yellow to red area are defined by several wells with negative PI values. Well control is lacking along part of the eastern edge of the outperforming area. The geologic control to support this boundary between outperforming and underperforming production will be discussed in Section 3.1. The most positive evidence for potentially outperforming areas in New York State is a ridge of over-performance in the northeast quadrant of Bradford County that appears to trend WSW-ENE into Tioga and potentially Broome counties in New York. Farther west in Bradford and Tioga (PA) counties, the core area is surrounded by under-performing wells.

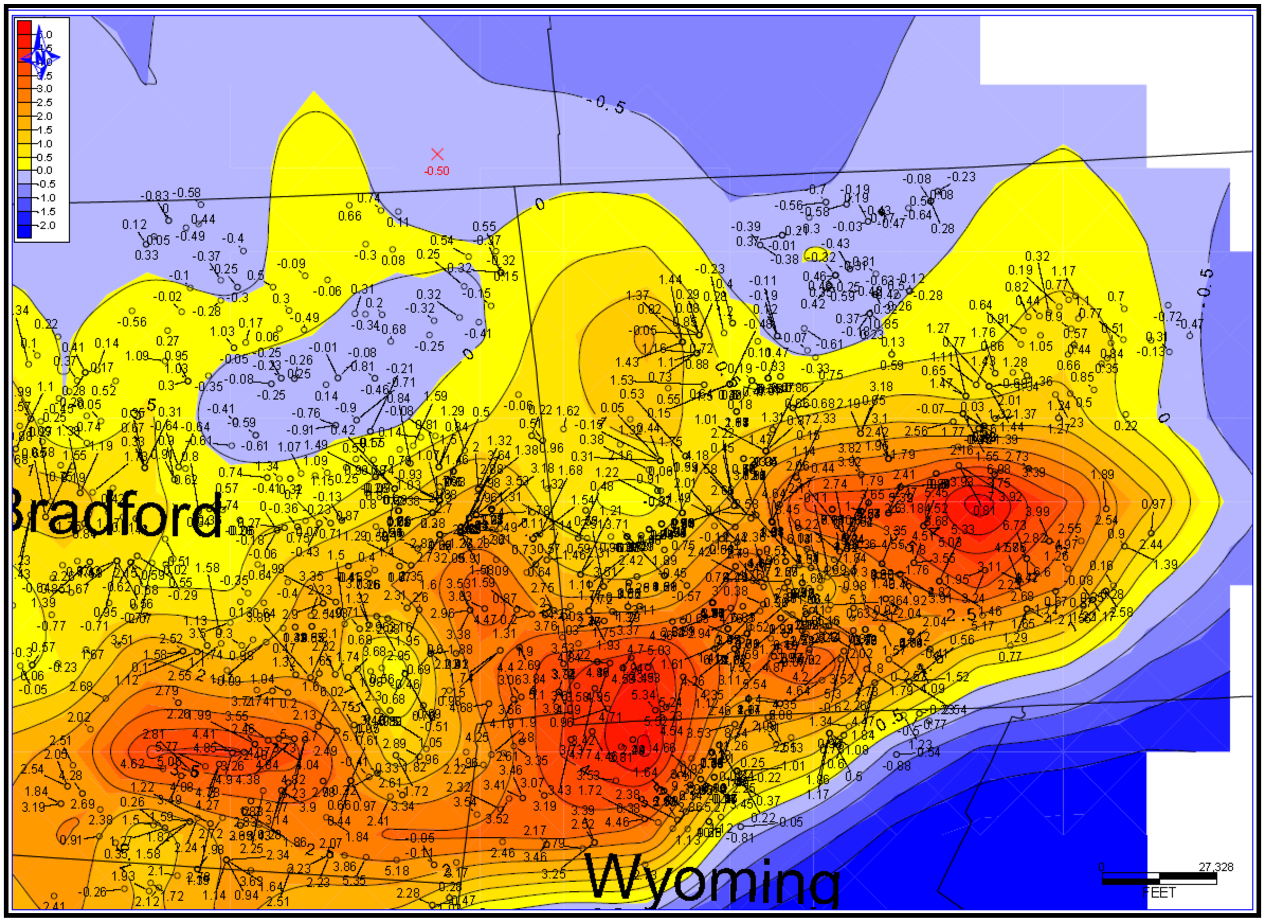


Figure 7: Contour Map of PI Focusing on Core Area in Northeast Pennsylvania

The eastern limit of over-performing wells in Susquehanna County appears to be corroborated by Figure 8, which shows acreage recently released by Chesapeake Energy, the most active driller in northeast Pennsylvania. Chesapeake released a substantial number of leases in northeastern and eastern Susquehanna County that lie in the blue shaded PI contours indicating poor well performance.

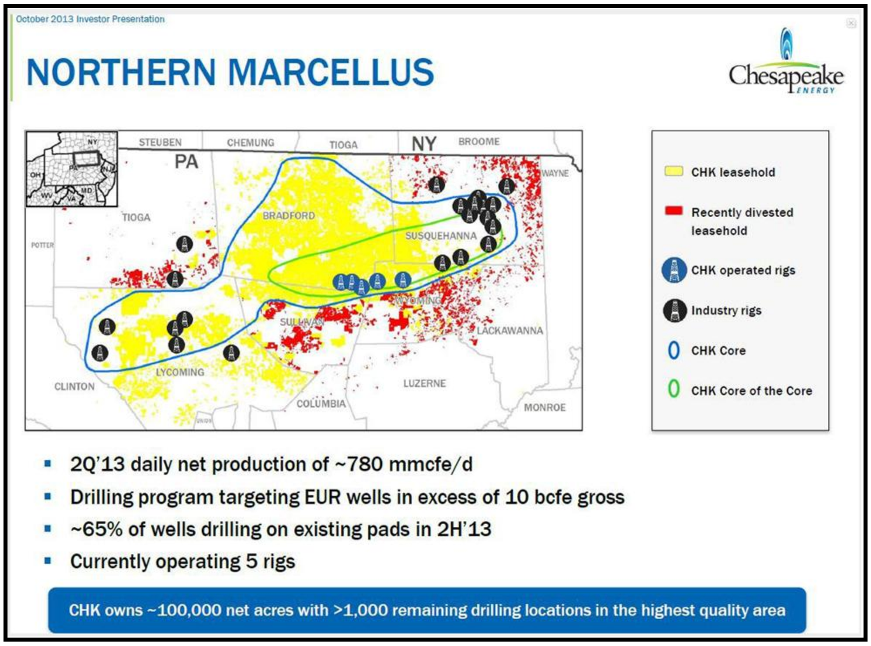


Figure 8: Acreage Released By Chesapeake (October 2013 Investor Presentation)

3.1) Geologic Control of Production Performance

The Marcellus Shale in Pennsylvania and adjacent New York consists of two organic-rich shale intervals, the Union Springs and Oatka Creek members, separated by the Cherry Valley Limestone (also called the Purcell Member), as shown in Figure 9.

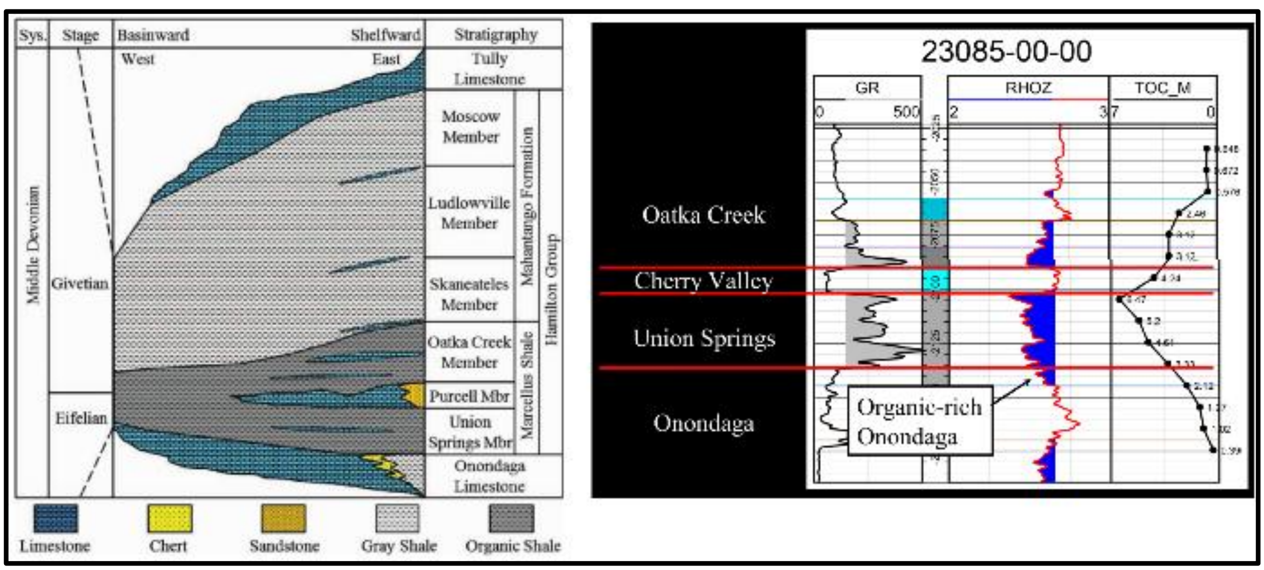


Figure 9. A stratigraphic column (left) showing Middle Devonian stratigraphy in Pennsylvania and New York (from Wang and Carr, 2013), and a well log section (right) showing well logs over the Marcellus Shale members and underlying Onandaga Limestone (from Smith and Leone, 2011).

Most natural gas production in northeastern Pennsylvania is from the Union Springs Member. The Union Springs Member was deposited in a trough with greatest thickness in Susquehanna, Bradford, Tioga (PA), Lycoming, and Wyoming counties, as shown in Figure 10. The Union Springs thins in all directions away from this trough and is 20-feet thick or less in Chemung, Tioga and Broome counties in New York. This geographic distribution limits the producing potential of the Marcellus Shale in New York. The overlying Oatka Creek Member has a similar geographic distribution and likewise limits the producing potential of the Marcellus in New York (Figure 12).

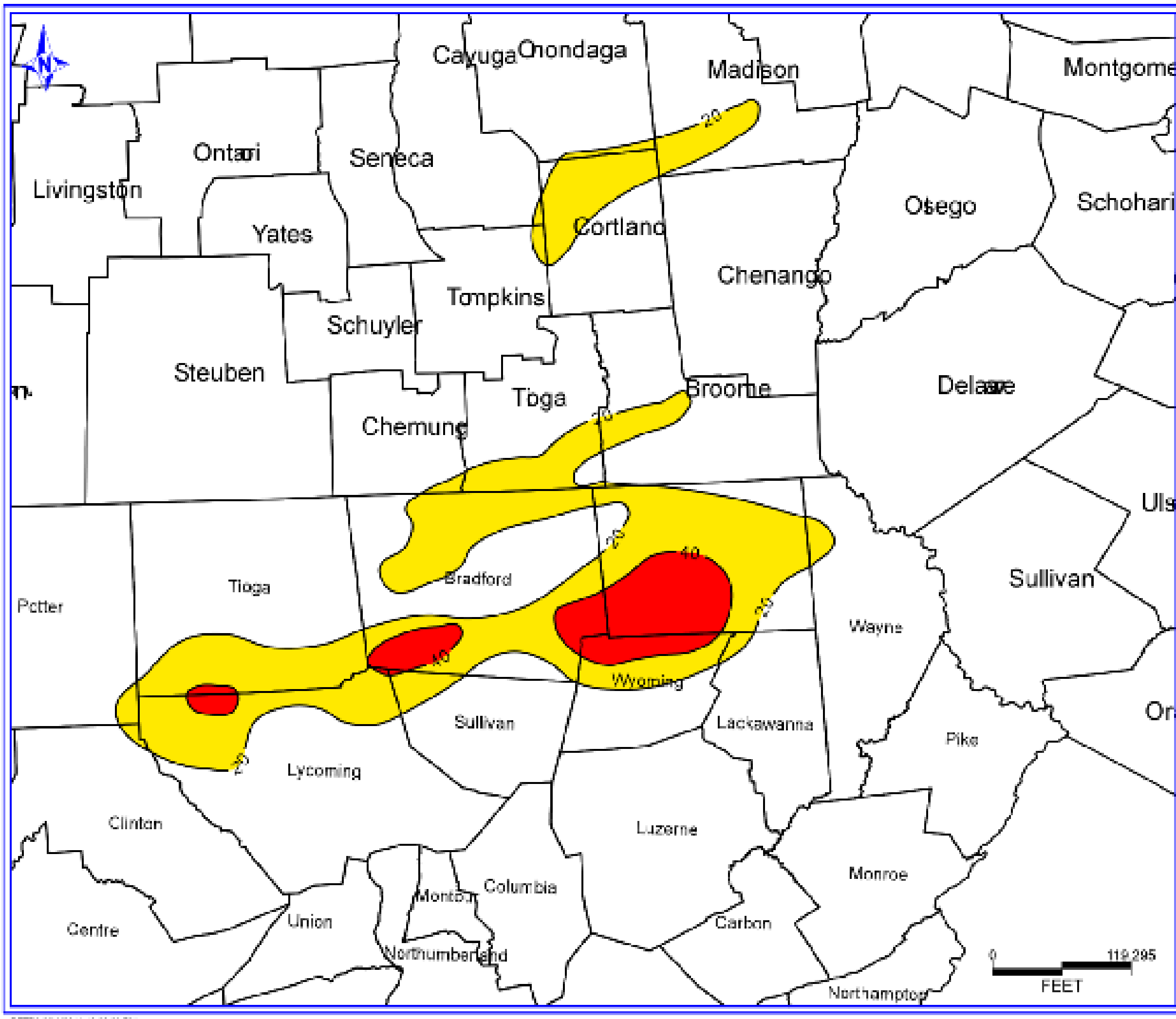


Figure 10. Distribution and Thickness of the Union Springs Shale Member of the Marcellus Shale (after Wang and Carr, 2013).

Figure 11 overlays the thickness of the Union Springs Shale Member with the PI contours, demonstrating that in the northeastern core area of the Marcellus Shale play in Pennsylvania, better well performance is highly correlated with the thickness of the Union Springs Shale.

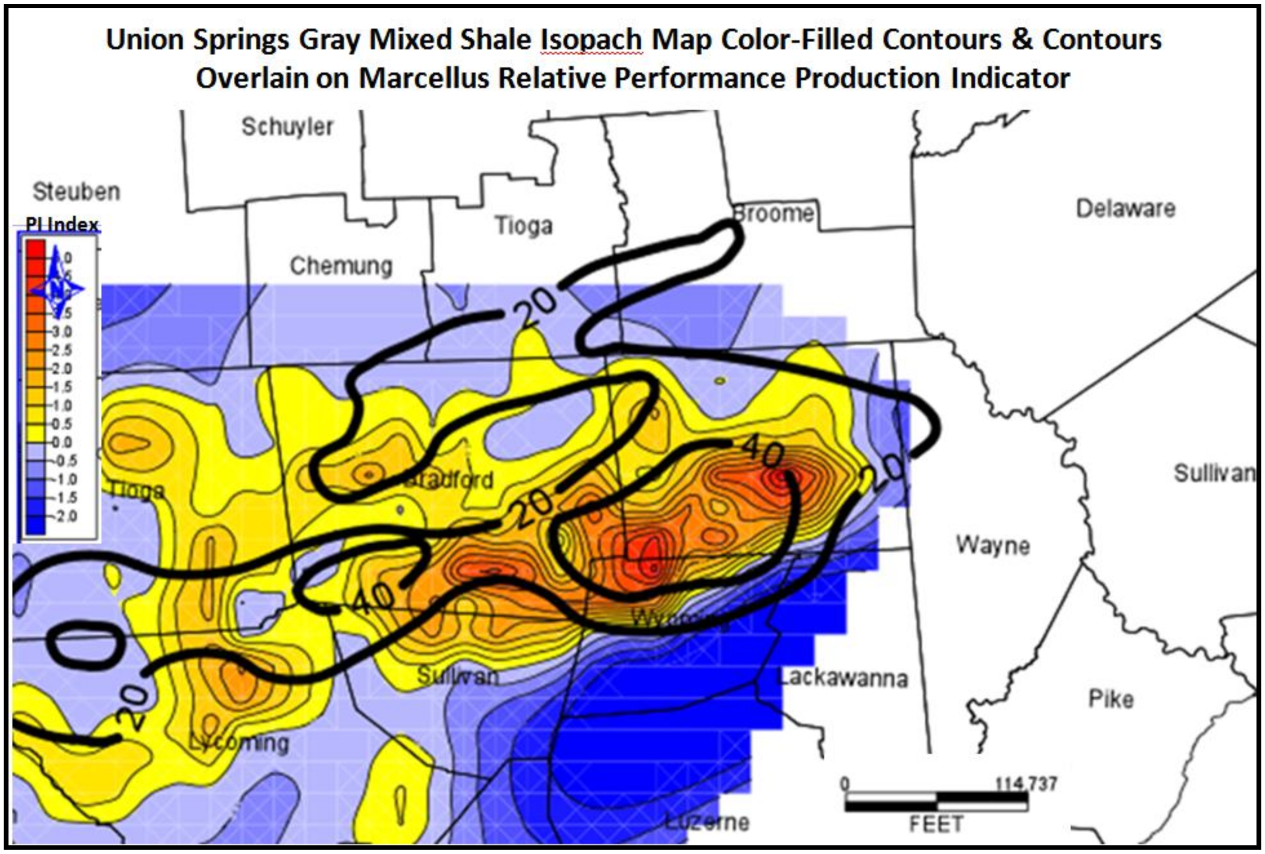


Figure 11. Isopach Contours of the Union Springs Member of the Marcellus Shale Superimposed on Marcellus Natural Gas Production (PI).

Figure 12 shows that production performance in northeastern Pennsylvania also appears to correspond to the thickness of the Oatka Creek Shale Member.

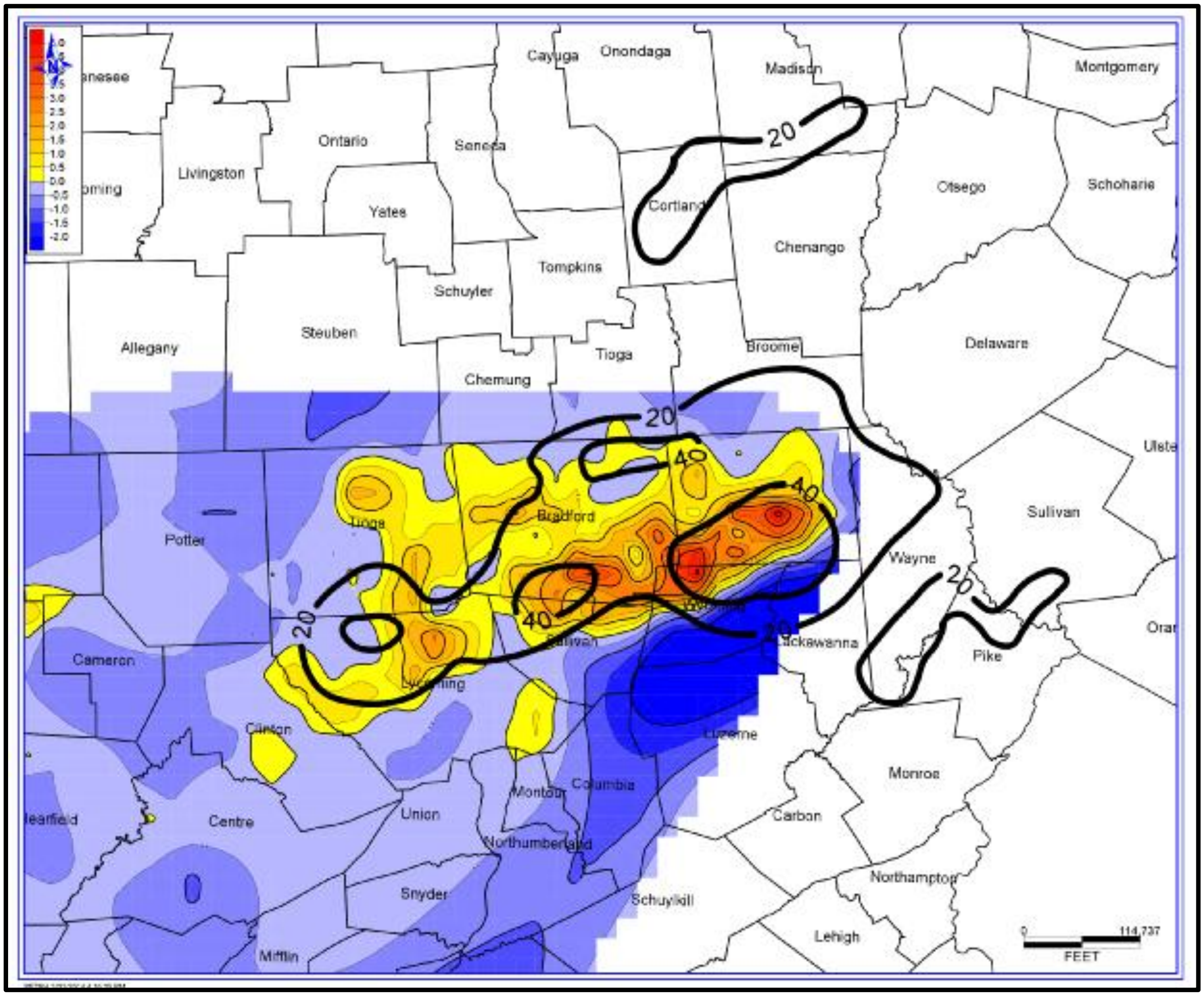


Figure 12. Isopach contours of the Oatka Creek Member of the Marcellus Shale after Wang and Carr (2013) Superimposed on Marcellus Natural Gas Production (PI).

Moreover, the thickness of the total Marcellus Shale interval is greatest in northeastern Pennsylvania and thins dramatically into New York, further limiting the production potential of New York.

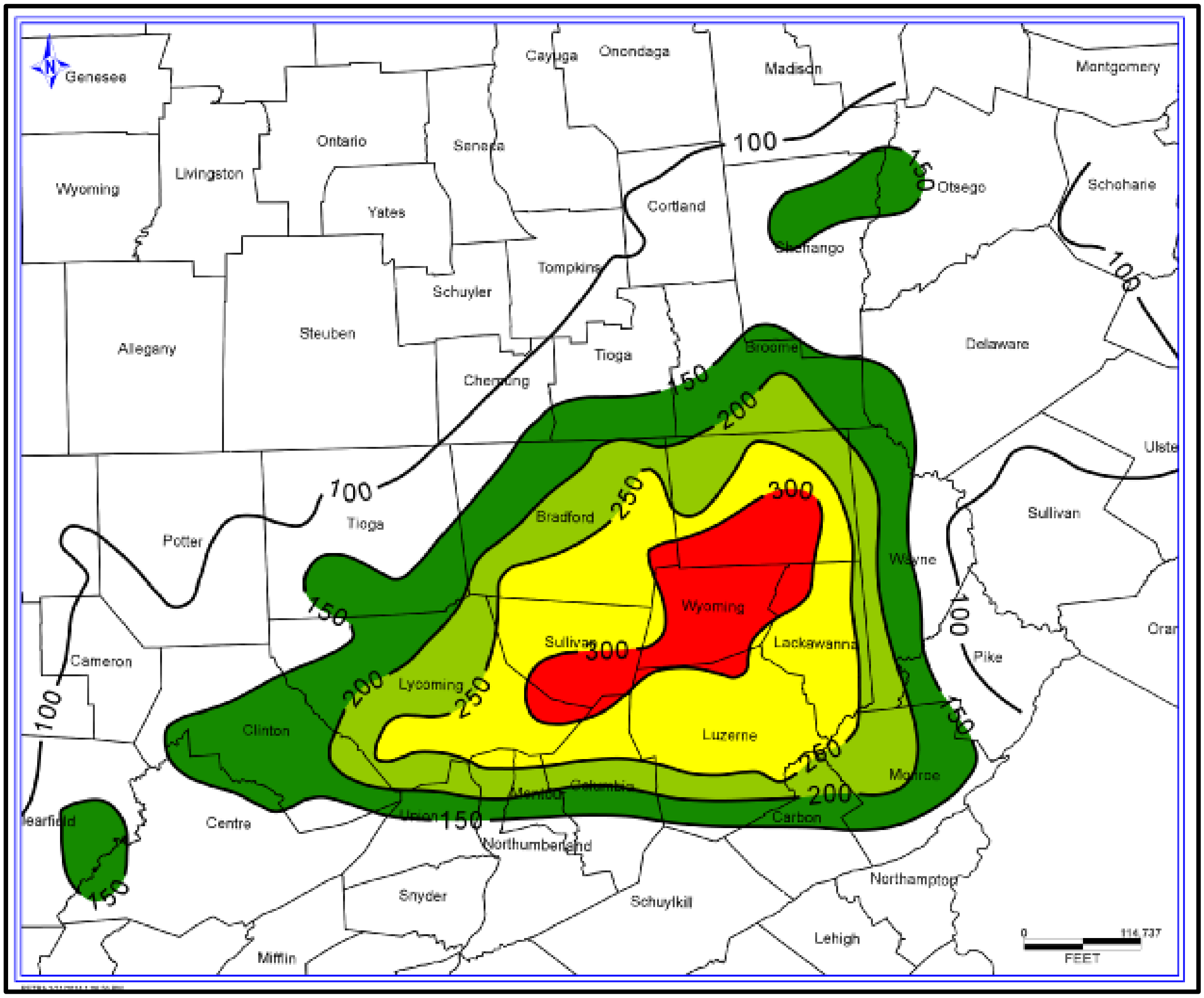


Figure 13. Distribution and thickness of the Marcellus Shale (after Wang and Carr, 2013).

Depth to the Marcellus Shale is also a factor in estimating the gas production potential in New York because depth correlates with sufficient reservoir pressure necessary to commercially produce natural gas. Figure 14 shows that most production to date in Pennsylvania is from reservoirs at least 4000 feet below the surface. It also shows that comparable depths in New York are limited only to the southern tier of counties further limiting the productive potential of the Marcellus Shale in New York.

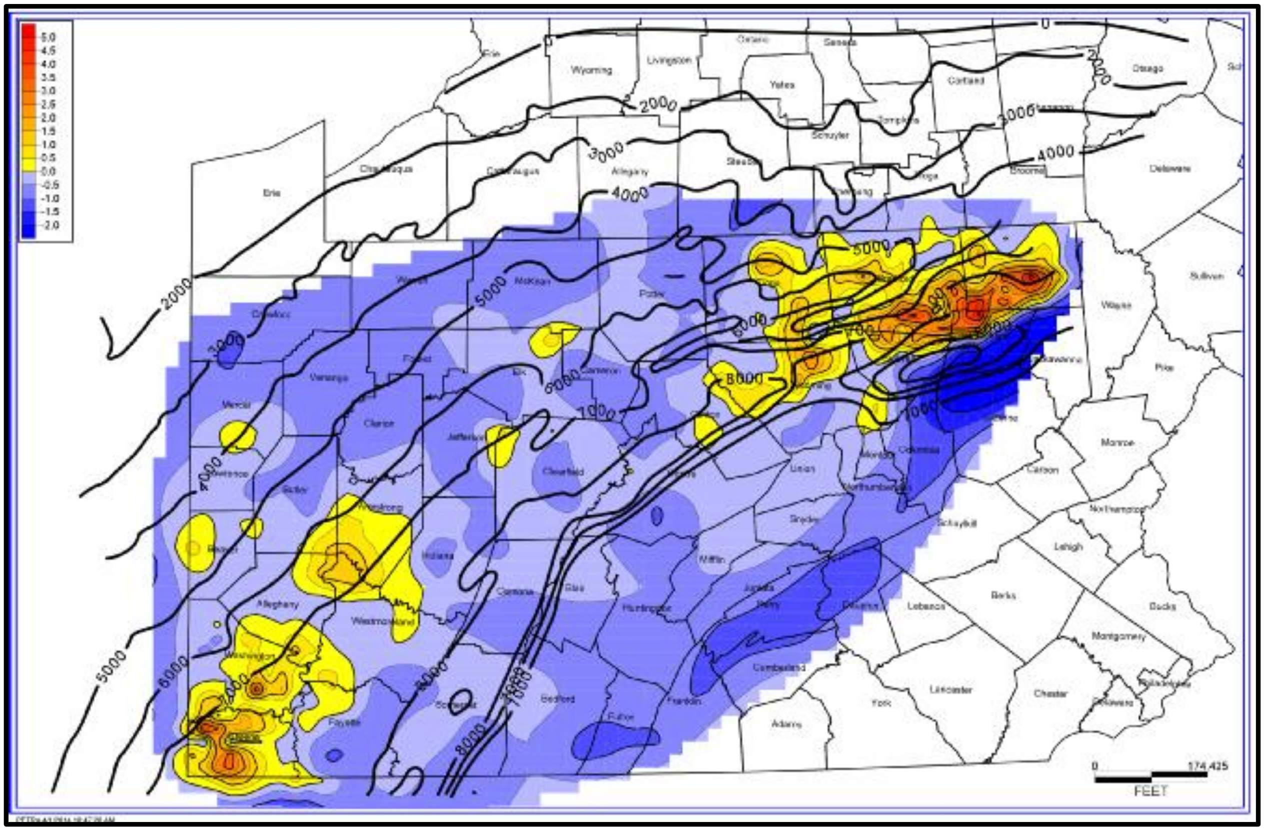


Figure 14: Marcellus Shale Drilling Depth (feet) after Wrightstone (2009).

4) Estimating Volumetric Resource Potential in New York State

Estimates for Contingent Resource volumes are based on the following formula:

Contingent Resource Volume (Bcf) = Commercially Viable Area (acres)
* Fraction of Area Accessible for Development
* EUR/well (Bcf/well)
/ spacing of wells (acres/well)

4.1) Commercially Viable Area

Commercially viable areas of horizontally drilled, fracture-stimulated wells in the Marcellus Shale is determined based on correlating results from decline-curve analysis to the PI index and evaluating threshold production volumes necessary to provide an economic return to the investor. Decline-curve analysis of various groups of wells provides estimates of EUR/well that can be correlated to the PI values of those same wells. Economic analysis of revenues and costs from an individual well are then used to determine the threshold EUR/well required to provide a minimum investment return for a range of gas prices. These threshold volumes are then correlated to PI values that outline the boundary of potentially commercial resource areas in New York.

4.1.1) Decline Curve Analysis

As mentioned earlier, "The most common way to assign Proved Reserves and Developed Producing Reserves in shale gas reservoirs is through the use of decline-curve analysis." (PRMS Guidelines (2011) pg 158). The use of trends in analogue EUR/well values provides the best means of extrapolating production performance trends into undeveloped and untested areas.

Normalized production decline curves were calculated based on semi-annual rates for each of the reporting periods for all wells completed in the 2nd half of 2010 grouped by the following counties - Bradford, Susquehanna, Greene, Tioga and Washington counties. Decline trends were also calculated for the core area in southwestern Susquehanna and southeastern Bradford counties to include the top-performing areas in the data base. In addition, decline curve-analysis was performed on normalized rates for groups of Marcellus wells located in West Virginia, which provides monthly production data. Although geographically distant from the New York area being evaluated, this monthly data provided important calibration for the b-exponent used in matching the decline trends for Pennsylvania data. Estimated ultimate recovery (EUR), which is the sum of cumulative production and remaining reserves, was estimated using industry-standard decline-curve analysis as described in Fetkovitch (1980). The decline curve-analysis plots and results are provided in Appendix B.

Table 1: Decline Curve Analysis Results and PI for Various Groups of Wells

Group of Wells	PI	EUR, Bcf
Antero Operated, Harrison Cty, WV 2010	61%	5.3
Antero Operated, Harrison Cty, WV 2011	125%	7.5
EQT Operated, Dodderidge Cty, WV 2009	-24%	2.6
EQT Operated, Dodderidge Cty, WV 2010	17%	4.5
Susquehanna Cty 2H 2010	176%	7.4
Bradford Cty 2H 2010	87%	8.3
Washington Cty 2H 2010	-14%	4.3
Tioga Cty 2H 2010	30%	4.4
Greene Cty 2H 2010	30%	4.1
Core Bradford&Susquehanna 1H 2011	210%	8.9
Core Bradford&Susquehanna 2H 2011	300%	10.5

The correlation between EUR/well and PI is shown in Figure 15.

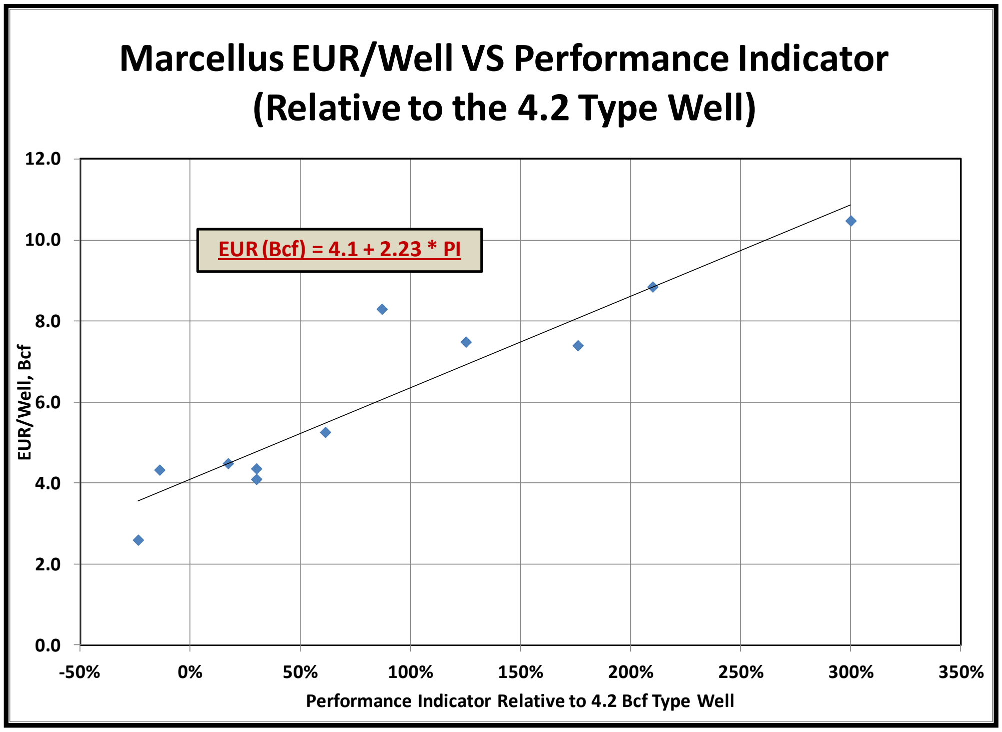


Figure 15: Correlation of EUR to PI

4.1.2) Economics

Conventional discounted cash-flow analysis was performed to determine commercially viable threshold values of EUR/well for outlining which parts of the Marcellus play are economic at various gas prices. The assumptions used in this analysis for well drilling and completion costs, expenses, sales volumes, prices, timing and taxes are provided in Table 2.

Table 2: Assumptions Used in Determining Threshold EUR/well Values

Assumptions	Marcellus (PA)
Royalty	17.5%
Drilling and Completion Well Cost, $MM/well	$6.50
Tie In Cost, $MM/well	$0.50
Expense, LOE+Gath.+Tax+G&A+ Differential to Henry Hub, $/net Mscf	$2.00
Breakeven EUR/well for 8% Return @ $4/MMBtu, Bcf/well	8.4 Bcf
Breakeven EUR/well for 8% Return @ $6/MMBtu, Bcfe/well	3.9
Breakeven EUR/well for 8% Return @ $8MMBtu, Bcfe/well	2.6
Breakeven EUR is calculated by scaling the type well (4.2 Bcf, 4.5 MMscfd IP, b = 1.0, Di = 1.49)	
to achieve 8% rate of return	

Total non-capital expenses for shales gas companies are estimated at $2.00/Mcf including all operating, gathering, transporting, marketing, general and administrative expense plus production taxes. It also includes the difference between the reported realized gas price versus the posted average Henry Hub spot gas price for the same reporting period. An analysis of costs reported by the largest shale gas companies shows an average total non-capital expense exceeding $2.00/Mcf as shown in the Figure 16. Drilling and completing wells and operating, transporting and marketing production from these shale gas wells are the main business of these companies. Hence, the full costs of running their business such as general and administrative costs are included as part of their ongoing business in determining commercial threshold volumes in terms of EUR/well.

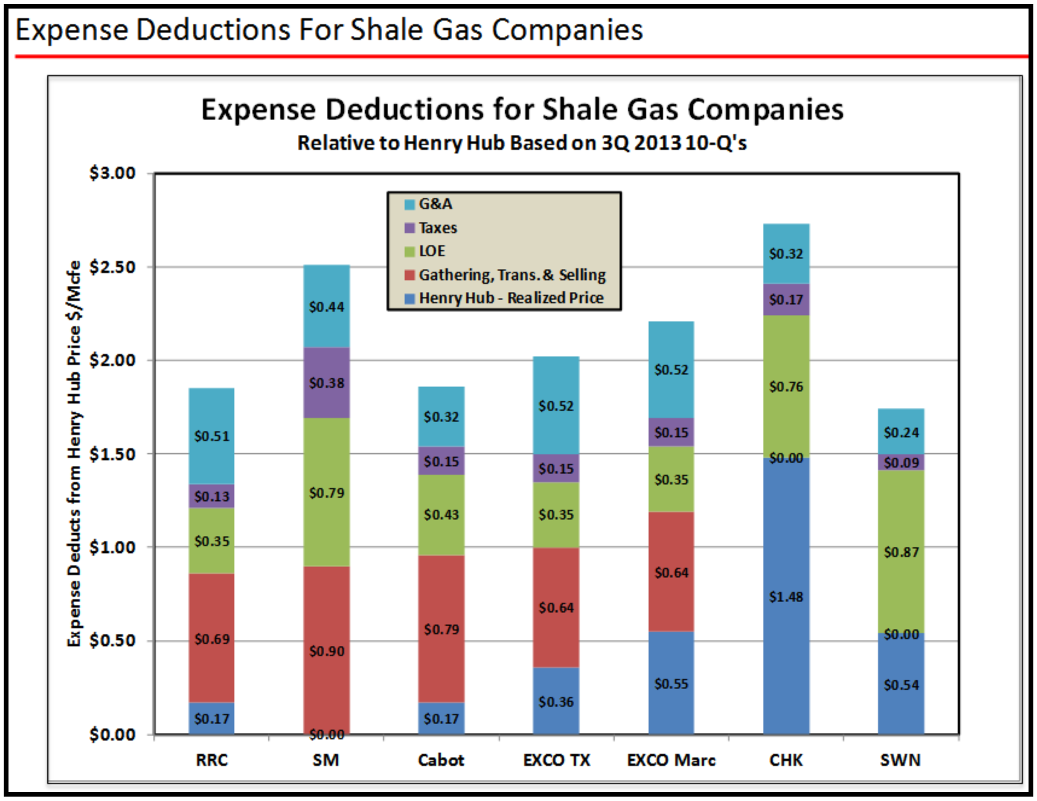


Figure 16: Expense Deductions Reported by Shale Gas Producers (Based on 3Q 2013 SEC Submissions)

The results of the discounted cash-flow analysis indicate that at $4.00/MMBtu (Henry Hub spot price), the minimum EUR/well for commercial development is 8.4 Bcf. At a higher gas price of $6.00/MMBtu, the minimum commercial EUR/well is 3.9 Bcf, and at $8.00/MMBtu, the minimum commercial EUR/well is 2.6 Bcf. Using the correlation in Figure 15, the threshold PI values are 2.1, -0.1 and -0.5 at gas prices of $4.00/MMBtu, $6.00/MMBtu and $8.00/MMBtu respectively.

4.1.3) Estimates of Commercially Viable Areas

With these threshold PI values, the contour map in Figure 17 shows our "best estimate" of the outlines of commercially viable areas of the Marcellus in New York for $6.00 and $8.00/MMBtu gas prices. Figure 16 includes contour values of PI with yellow-to-red shaded areas averaging a PI greater than zero. With the threshold PI for the $6.00/MMBtu case estimated at -0.1, the yellow-to-red shaded areas of Pennsylvania represent areas that are commercially viable at $6.00/MMBtu. The contouring projected into New York is extrapolated and has no data control, so these contours by themselves do not provide a reliable basis for estimating the viable area.

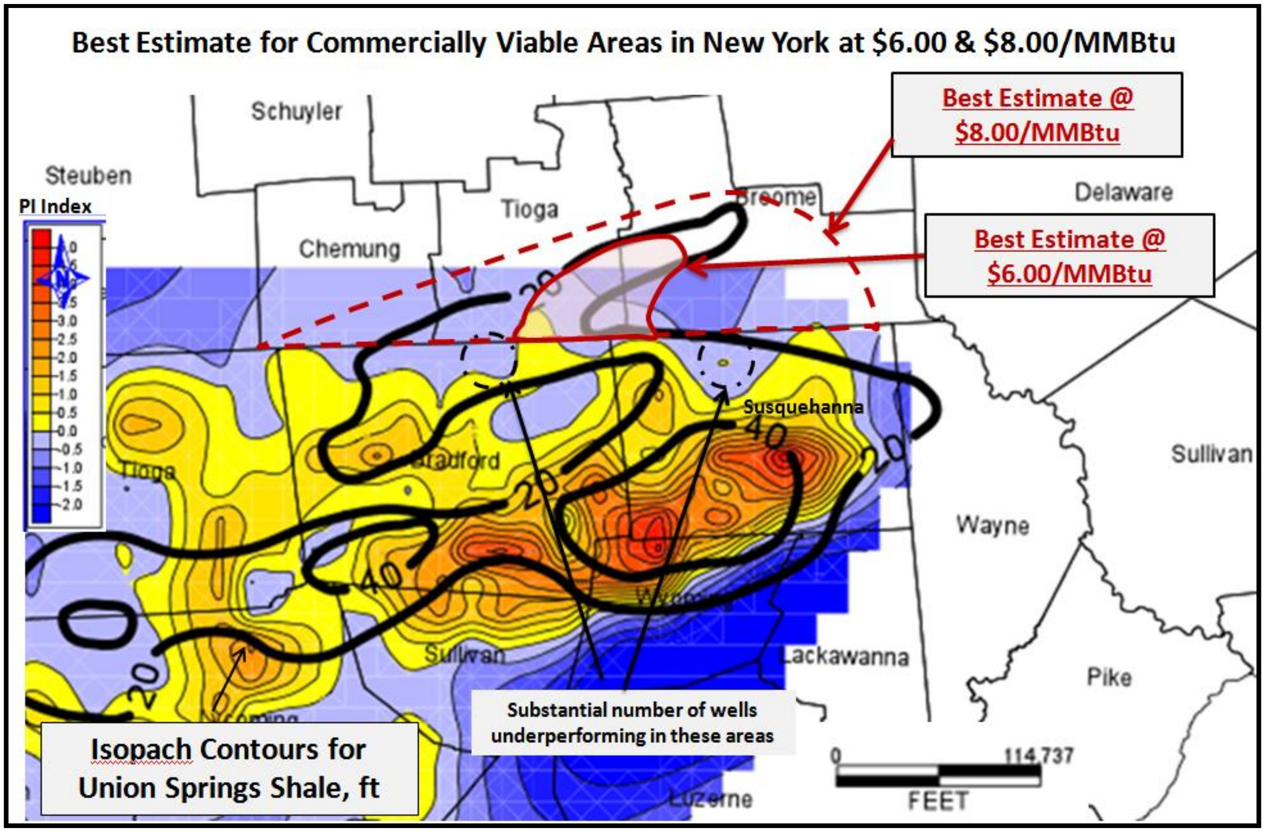


Figure 17: Best Estimates for Commercially Viable Areas in New York

At $4.00/MMBtu, only a small core area contained entirely inside Pennsylvania is commercially viable (approximately 300,000 acres), and no area of New York is considered commercially viable at these current gas prices. This conclusion may be considered controversial because large amounts of capital are being spent to develop the Marcellus formation in many counties in Pennsylvania. Some might take that as evidence of a much larger commercially viable area. We contend that analysis of actual production performance and economic analysis of threshold volumes is a more appropriate basis on which to establish commercially viable areas.

The commercially viable area at $6.00/MMBtu is estimated to be approximately 480,000 acres in New York and includes southeastern Tioga and southwestern Broome Counties. This area is based on an assumption that the trend of over-performing wells in northeastern Bradford counties extends along a WSW-ENE trend into Broome County. This trend is also supported by the 20-ft thickness contour of the Union Springs Shale, which also trends WSW-ENE. These contours do not include all of the 20 ft contour of the Union Spring thickness because substantial areas within the 20-ft contour are underperforming in Pennsylvania. The prospective area is bounded to the west by underperforming wells in north-central Bradford County and to the east by underperforming wells in north-central Susquehanna County.

The commercially viable area at $8.00/MMBtu in New York is estimated at approximately 1,000,000 acres and extends west, north and east from the $6.00/MMBtu area. The northern extent of potentially commercial production is probably constrained by the two key trends – the Union Springs Shale both thins and is shallower toward the northeast. With no well control in New York to define the PI contouring, however, the extent of this area is uncertain. Our intent in drawing the outline for the "best estimate" is to have a balance of upside as well as downside potential based on the data available. In both the $6.00 and $8.00/MMBtu cases, the commercially viable core area is not projected to extend into Delaware and Sullivan counties in New York.

4.2) Fraction of Area Accessible to Development

Proposed regulations for shale gas development have been in a state of flux for some time. There is currently no government study which definitively shows the area that can potentially be developed in New York; however, because access to development is a key component of estimating reserves, we will present three possible scenarios. There is the study by Blohm et al (2012) which provides rough estimates of the fraction of land area that might be available under the proposed regulations for gas development if the state-wide de facto moratorium is lifted. Blohm et al estimate that 83% of New York State is likely to be off limits to drilling compared to only 32% of Pennsylvania. This study provides estimates of excluded areas by county, yet it should be noted that Blohm assumes that the "fairway" of shale gas development in New York State extends over all of the counties in the Southern Tier; when industry reports indicate potential in no more than 6 counties, namely Chemung, Tioga, Broome, Chenango, Delaware and Sullivan County. The effect, on the one hand, is to apply their methodology to areas that have no demonstrable potential to arrive at the gross assumption of 83% as the excluded area. On the other hand, the Blohm methodology assumes that population density is uniformly distributed over each county, which is by no means the case. For example, the authors assume that the population of Broome County, which includes the Binghamton metro area, is uniformly dispersed over the county for purposes of calculating the impact of setbacks from housing. This methodology has the effect of eliminating all access in Broome County, even though Broome is the one county with clear shale gas potential.

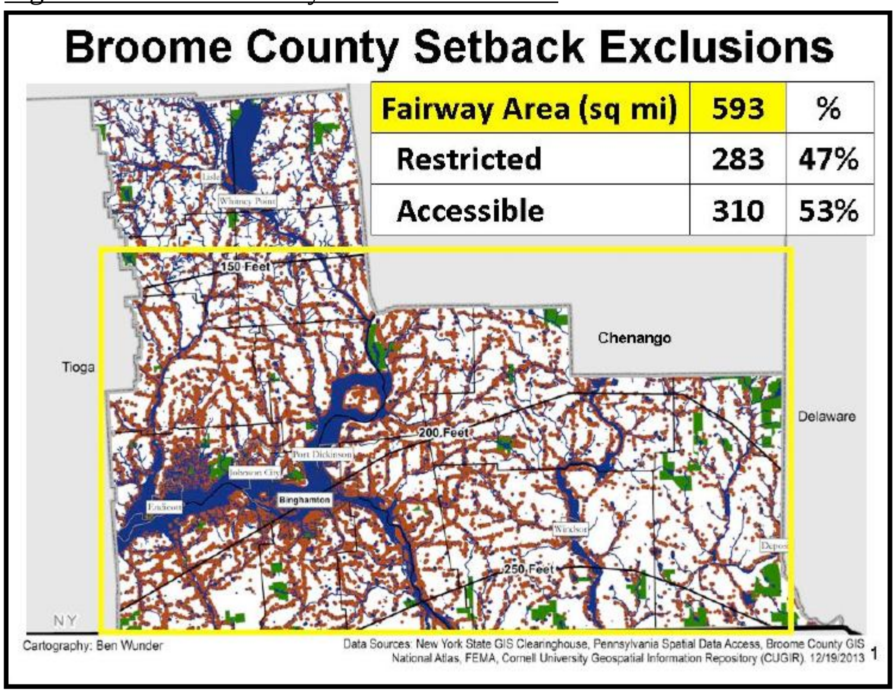
Subsequent to the Blohm study, Acton and Wunder estimated the impact of the proposed regulations using GIS data for the fairway areas. Acton and Wunder mapped setbacks from data on housing and housing clusters, streams, rivers and other topographical features. They estimated that the regulations would remove an average of 39% of the fairway, from a high of 47% in Broome County, to a low of 24% in Chenango County. Table 3 shows the assumptions used in this study for setback regulations in New York, and Figure 18 shows these setbacks applied to Broome County.

Table 3: New York Setback Regulations

NYS Setback Regulations

	Protected Feature	Setback (ft)
Water	FAD Watershed NYC	4000
	Public Water Supply / Reservoir Natural Lake / Man-made Impoundment	2000
	100 Year Floodplain	Within
	Primary Aquifer, Residential Water Well, Livestock / Crop Water Source	500
	Perennial or Intermittent Stream Lake, Pond, Storm Drain	150
Land	State Land, State Park Wildlife Mgmt Area	Within
Buildings	Inhabited Dwelling, Public Building	500

Figure 18: Broome County Setback Exclusions



Three access scenarios described as follows are used in estimating resource volume:

> Scenario 1: Based on exclusion estimates for each county by Blohm (2012), 76%, 72% and 100% of Chemung, Tioga and Broome Counties, respectively, are excluded from gas development,
>
> Scenario 2: Based on Acton and Wunder but modified for edge effects and topography, 75% of county areas are excluded from gas development, and

Scenario 3: Based directly on Acton and Wunder, 39% of Chemung and Tioga Counties and 47% of Broome County are excluded from gas development.

4.3) EUR/Well

The EUR/well is simply an estimate of the average value likely to occur within the commercially viable boundaries. Higher gas prices result in a lower threshold, so the expected average EUR/well will decrease as the developed area expands into lower quality resource. The average EUR/well is estimated to be in the range of 5 Bcf for the $6.00/MMBtu scenario, and 4 Bcf for the $8.00/MMBtu scenario.

4.4) Final Well Spacing

With an estimate for the commercially viable area and the fraction of that area accessible for development, final well spacing determines the number of wells to be drilled. Final well spacing is a complex engineering and geologic optimization issue requiring substantial analysis by each operator. As wells are drilled closer to each other, the potential for interference increases, potentially reducing EUR/well and, therefore, degrading the economic potential of these areas.

The Union Springs Shale Member is believed to be extensively naturally fractured, which may be the primary reason why the core area of the Marcellus formation is the best performing shale gas play in the country. Parts of the Marcellus core area may have average EUR/well values exceeding 10 Bcf, compared to less than 5 Bcf in the Haynesville play and less than 2 Bcf in the Barnett play. These natural fracture networks may also enable these wells to drain larger areas, hence enabling the higher EUR/well. Therefore, the estimated final optimum well spacing for the Marcellus may be in the range of 120 acres/well, which is higher than that estimated for other shale plays. The optimum final well spacing can only be determined by careful monitoring of pilot tests of multiple wells spaced at various distances, and such data is typically proprietary.

4.5) New York State Resource Volumes

Based on assumptions for commercially viable area, access, EUR/well and well spacing discussed above, total contingent resource potential for potential Marcellus wells in New York is as follows:

1) Zero at current gas prices, regardless of which access scenario is assumed,
2) 0.8 Tcf at $6.00/MMBtu and 2.0 Tcf at $8.00/MMBtu assuming access Scenario 1 based on estimates by Blohm (2012),
3) 1.0 Tcf at $6.00/MMBtu and 4.0 Tcf at $8.00/MMBtu assuming access Scenario 2 based on Acton and Wunder but modified for edge effect and topography,
4) 2.4 Tcf at $6.00/MMBtu and 9.1 Tcf at $8.00/MMBtu assuming access Scenario 3 based on Acton and Wunder without adjustment.

These resource volumes are classified as “2C” Contingent Resource Volumes based on the PRMS (2007) guidelines. The following table provides assumptions and resource volumes by county.

Table 4: Marcellus Resource Estimates for New York State

$6/MMBtu Case Best Estimate											
	1,000 acres	%	Exclusion %			1,000 acres	Bcf/well	acres/well	Contingent Resource, Bcf		
County	Total Area	Commercially Viable	Scenario 1	Scenario 2	Scenario 3	Open Area	EUR/well	Spacing	Scenario 1	Scenario 2	Scenario 3
Chemung	263	0%	-76%	-75%	-39%	0	5	120	0	0	0
Tioga	335	20%	-72%	-75%	-39%	19	5	120	775	692	1,688
Broome	459	7%	-100%	-75%	-47%	0	5	120	0	356	756
								Total =	775	1,048	2,444

$8/MMBtu Case Best Estimate											
	1,000 acres	%	%			1,000 acres	Bcf/well	acres/well	Contingent Resource, Bcf		
County	Total Area	Commercially Viable	Scenario 1	Scenario 2	Scenario 3	Open Area	EUR/well	Spacing	Scenario 1	Scenario 2	Scenario 3
Chemung	263	22%	-76%	-75%	-39%	14	4	120	461	480	1,171
Tioga	335	49%	-72%	-75%	-39%	46	4	120	1,523	1,360	3,318
Broome	459	56%	-100%	-75%	-47%	0	4	120	0	2,160	4,578
								Total =	1,984	3,999	9,067

Considerable uncertainty exists in this resource assessment. This study is based entirely on publicly available information, and proprietary information may exist that would lead to significantly different findings. Access restrictions to development are perhaps the most important uncertainty affecting the potential range of final outcomes. In addition, the lack of well control in New York limits the reliability of extending actual production performance trends into the state.

References:

Acton, J. and Wunder,, B., "Impact of Proposed Environmental and Drilling Regulations on Recoverable Shale Gas Reserves in New York State", (http://www.scribd.com/doc/216907402/New-York-Drilling-Restrictions)

Arps, J.J.(1945). Analysis of Decline Curves. Transactions AIME 160:228-247.

Blohm, A. et al, (2012), The Significance of Regulation and Land Use Patterns on Natural Gas Resource Estimates in the Marcellus Shale, Energy Policy 50 (2012), pg 359-369. (http://www.scribd.com/doc/172872710/Shale-Gas-and-Land-Use-in-New-York)

Coleman, J.L., et al,(2011). 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, 2 p, (http://pubs.usgs.gov/fs/2011/3092/S).

Guidelines for Application of the Petroleum Resources Management System (2011). Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers.

Fetkovitch, M.J., 1980. Decline Curve Analysis Using Type Curves. JPT 32(6): 1065-1077.

Medlock, K. B. III, 2010, The Shale Gas Revolution and What It Means for Global Energy Markets: Presentation at the Baker Institute Roundtable: Energy Market Consequences of an Emerging U.S. Carbon Management Policy.

Petroleum Resource Management System. (2007). Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers.

Potential Gas Committee *Report of Potential Supply of Natural Gas in the United States (2013)*; U.S. Energy Information Administration *Annual Energy Outlook 2012;* National Petroleum Council *Prudent Development Report 2011*.

United States Energy Information Administration (EIA), (2011). Annual Energy Outlook (www.eia.gov)

Wang, G., and T.R. Carr (2014), Organic-rich Marcellus Shale Lithofacies Modeling and Distribution Pattern Analysis in the Appalachian Basin, AAPG Bulletin, v. 97, no. 12 (December 2013), pp. 2173–2205.

Wrightstone, G, 2009, Marcellus Shale – Geologic Controls on Production: Search and Discovery Article #10206 (2009).

Appendix A: PRMS Definitions of Reserves (2007)

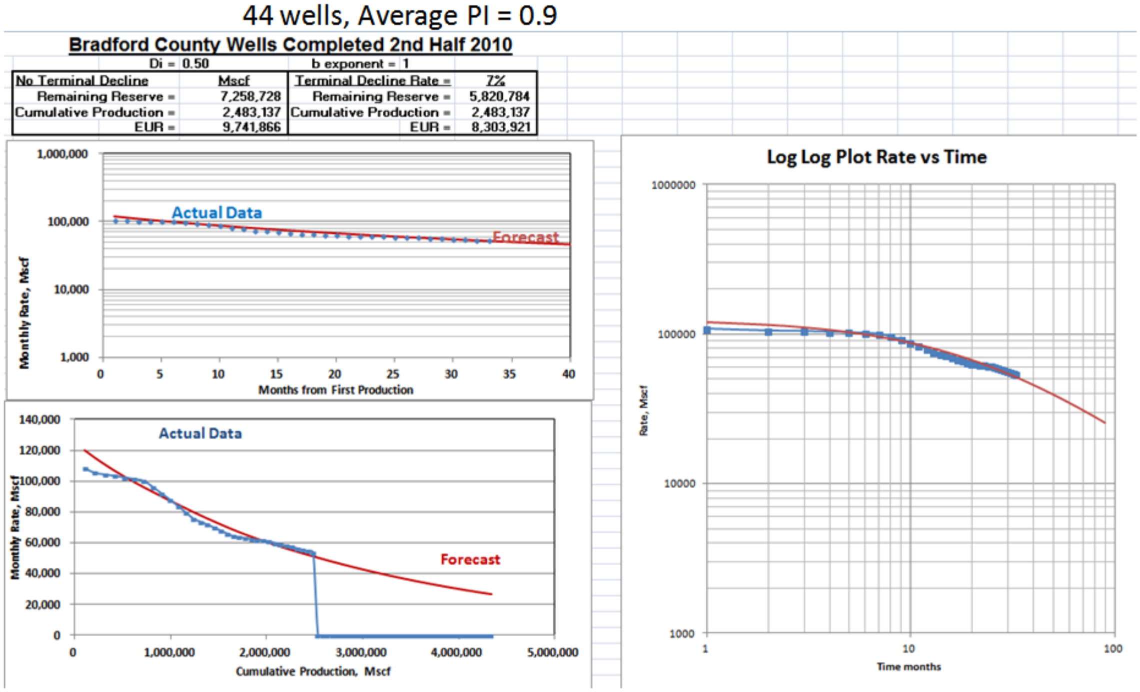
Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must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

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

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

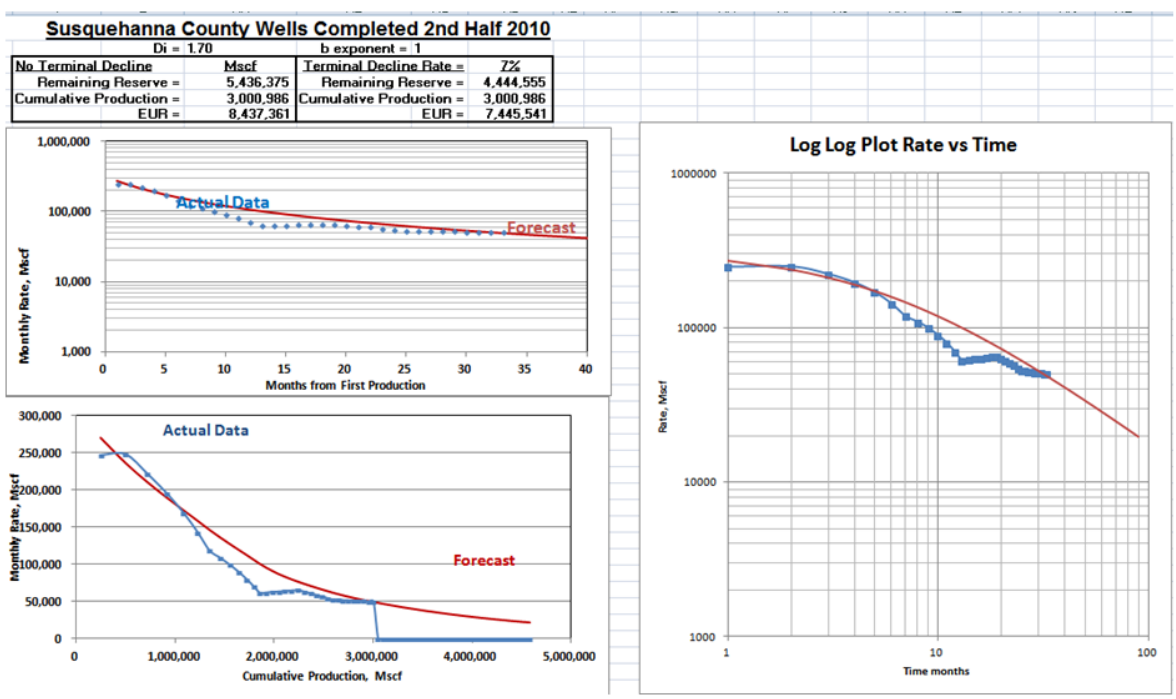
Appendix B: Decline Curve Analysis Results for Marcellus Wells

44 wells, Average PI = 0.9



Pennsylvania Marcellus Production Reported for Each Half Year
Is Used to Estimate Monthly Production Rates

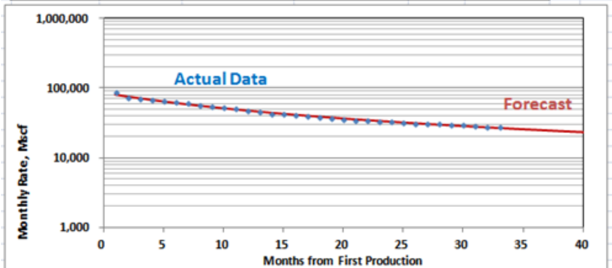
Poor Quality DCA Match, 61 wells, Average PI = 1.76

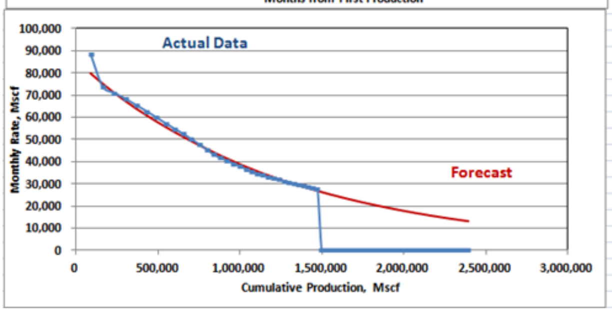


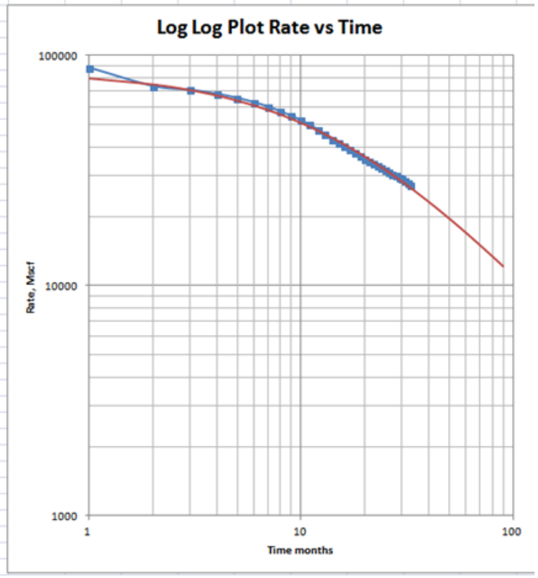
35 wells, Average PI = 0.3

Greene County Wells Completed 2nd Half 2010

Di = 0.75		b exponent = 1	
No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	3,406,862	Remaining Reserve =	2,640,363
Cumulative Production =	1,471,955	Cumulative Production =	1,471,955
EUR =	4,878,816	EUR =	4,112,318



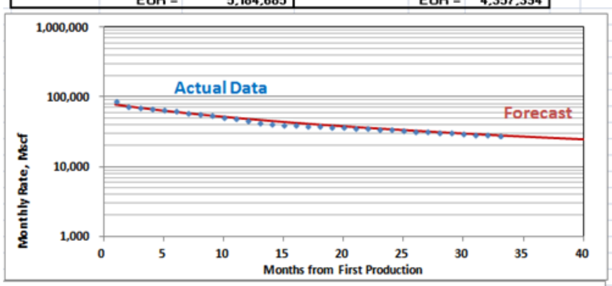


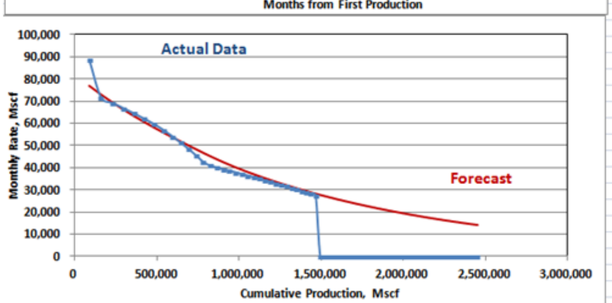


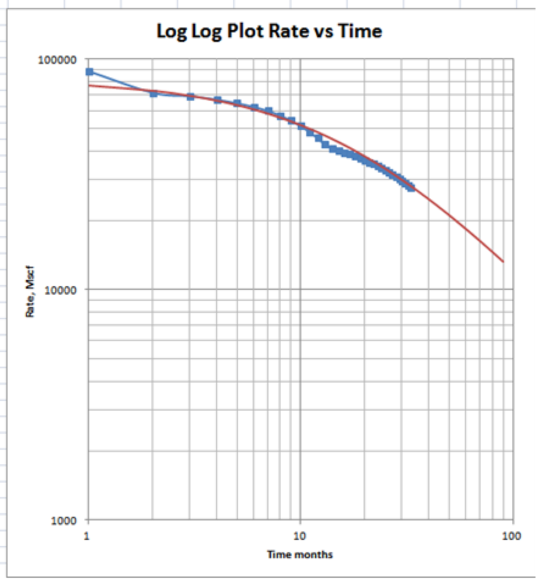
22 wells, Average PI = 0.3

Tioga County Wells Completed 2nd Half 2010

Di = 0.65		b exponent = 1	
No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	3,718,237	Remaining Reserve =	2,890,947
Cumulative Production =	1,466,448	Cumulative Production =	1,466,448
EUR =	5,184,685	EUR =	4,357,394





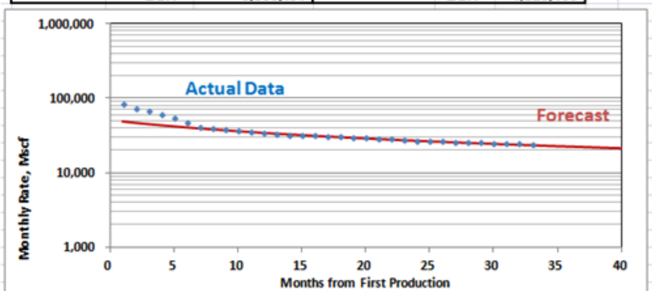


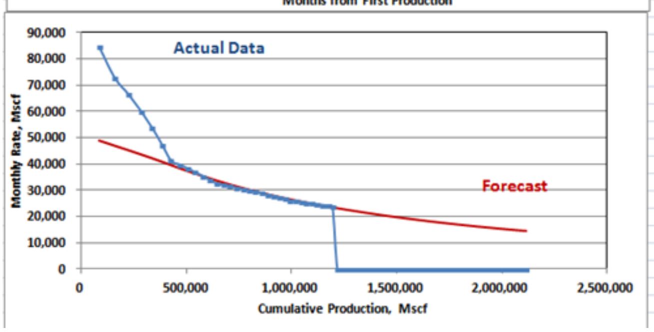
37 wells, Average PI = -0.1

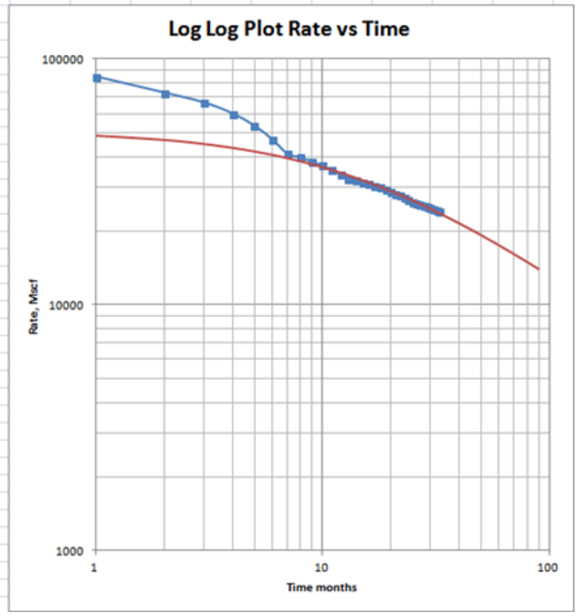
Washington County Wells Completed 2nd Half 2010

Di = 0.50 b exponent = 1.5

No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	4,861,939	Remaining Reserve =	3,135,234
Cumulative Production =	1,194,256	Cumulative Production =	1,194,256
EUR =	6,056,194	EUR =	4,329,489



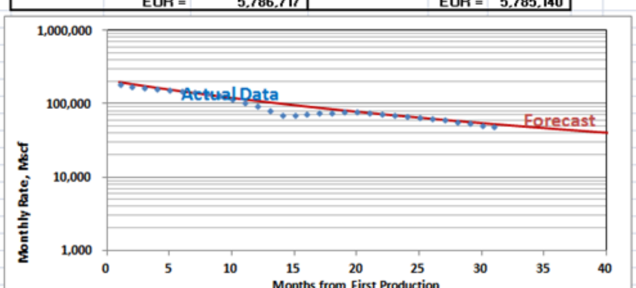


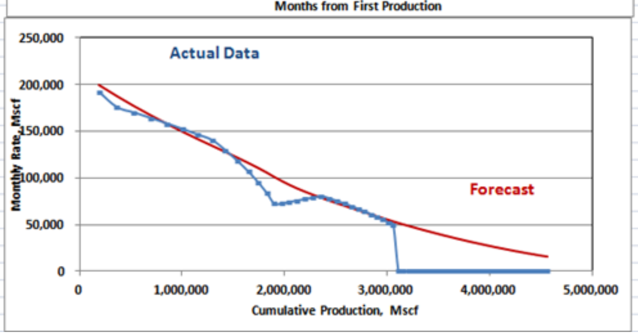


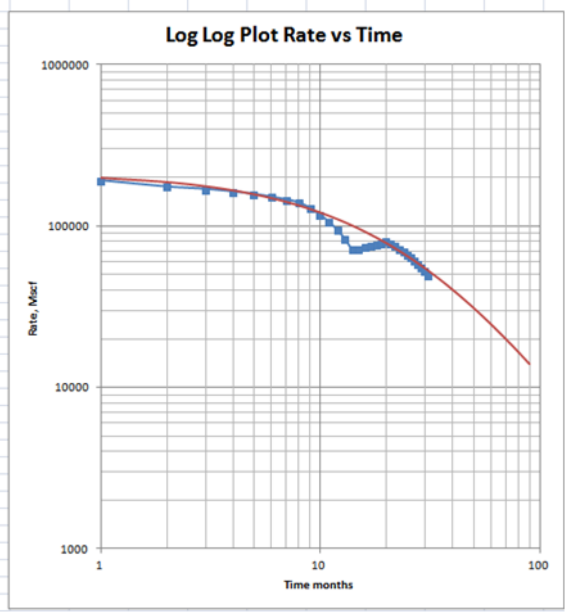
Average Susquehanna Compl 2nd Half 2010 SW Quadrant of County

Di = 0.75 b exponent = 0.5

No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	2,723,964	Remaining Reserve =	2,722,388
Cumulative Production =	3,062,753	Cumulative Production =	3,062,753
EUR =	5,786,717	EUR =	5,785,140





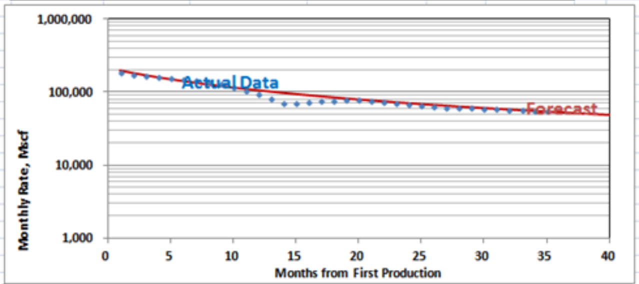


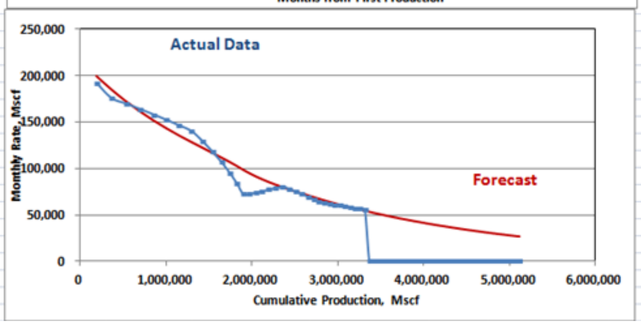
107 Wells, Avg PI = 2.1

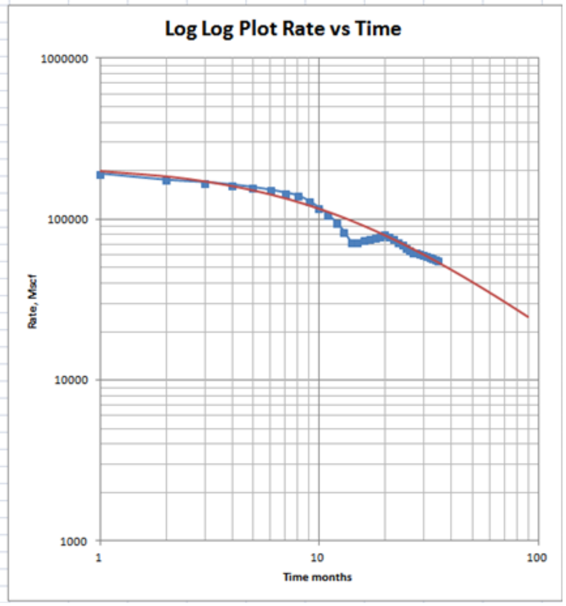
Average SW Susquehanna & SE Bradford Well Compl 2nd Half 2010

Di = 0.95 b exponent = 1

No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	6,784,088	Remaining Reserve =	5,532,674
Cumulative Production =	3,318,158	Cumulative Production =	3,318,158
EUR =	10,102,246	EUR =	8,850,832





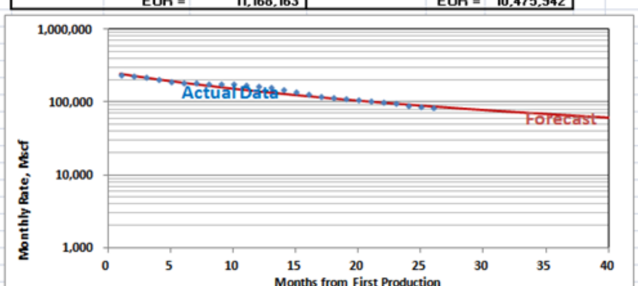


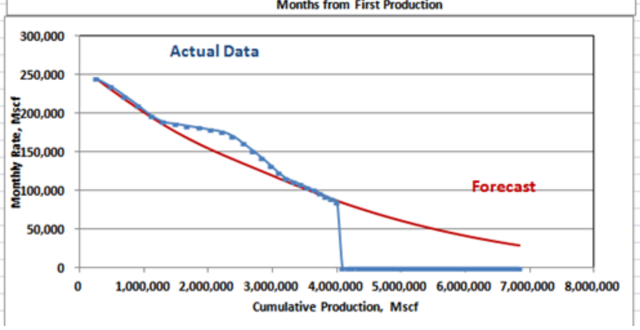
70 Wells, Avg PI = 3.0

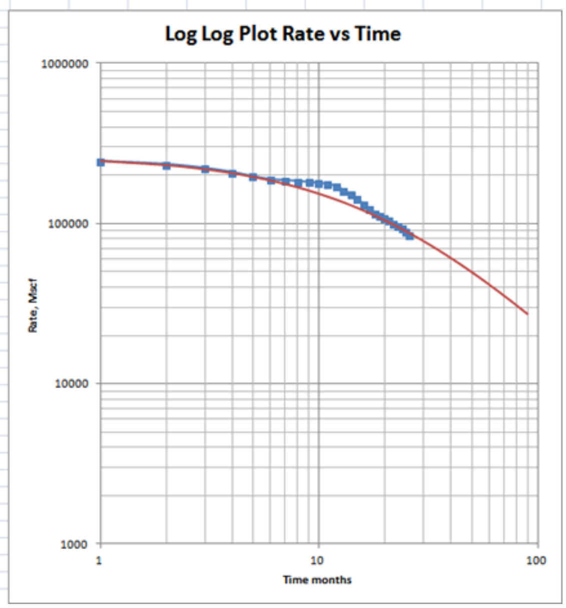
Average SW Susquehanna & SE Bradford Well Compl 1st Half 2011

Di = 0.75 b exponent = 0.75

No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	7,166,354	Remaining Reserve =	6,474,133
Cumulative Production =	4,001,809	Cumulative Production =	4,001,809
EUR =	11,168,163	EUR =	10,475,942



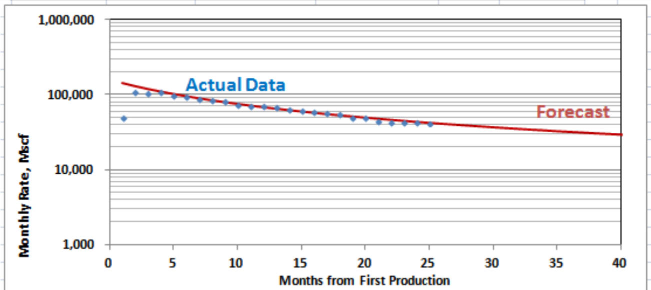


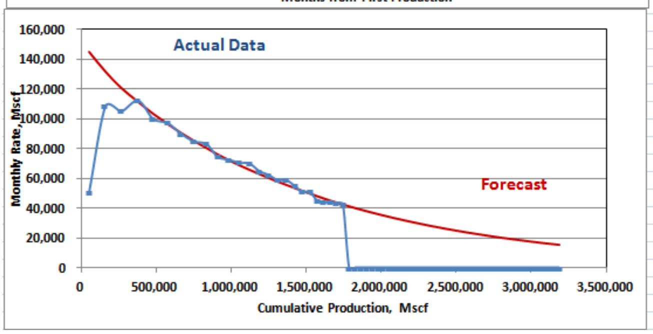


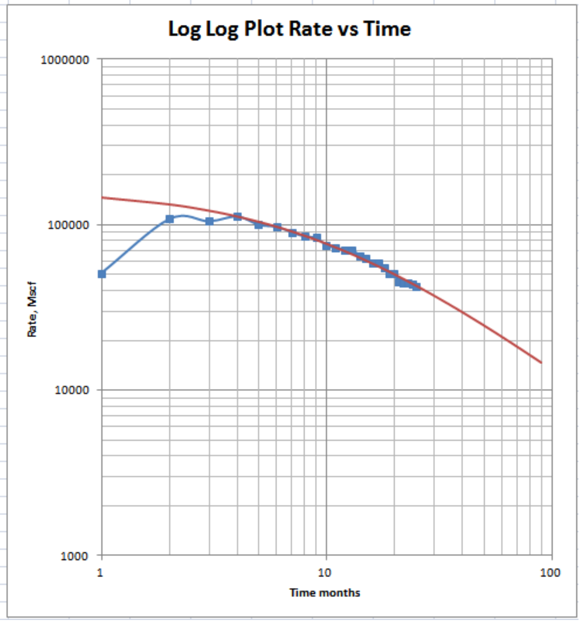
Decline Curve Analysis of West Virginia Wells Using Public Data for Monthly Production (Grouped by operator, year of completion and county)

Antero 2010 Avg

Di = 1.20		b exponent = 1	
No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	4,340,606	Remaining Reserve =	3,518,290
Cumulative Production =	1,745,413	Cumulative Production =	1,745,413
EUR =	6,086,018	EUR =	5,263,703

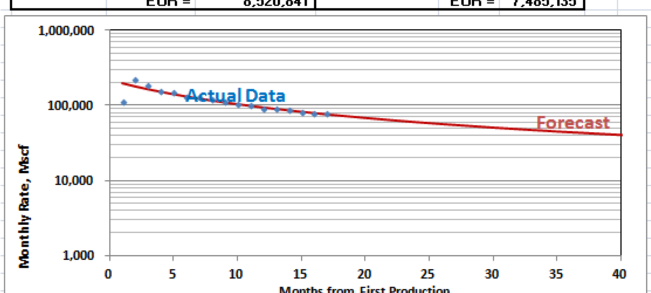


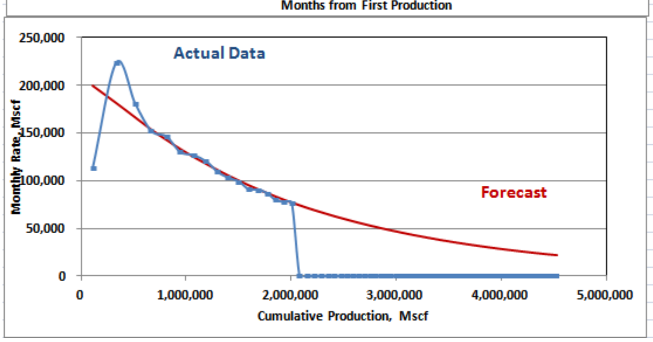


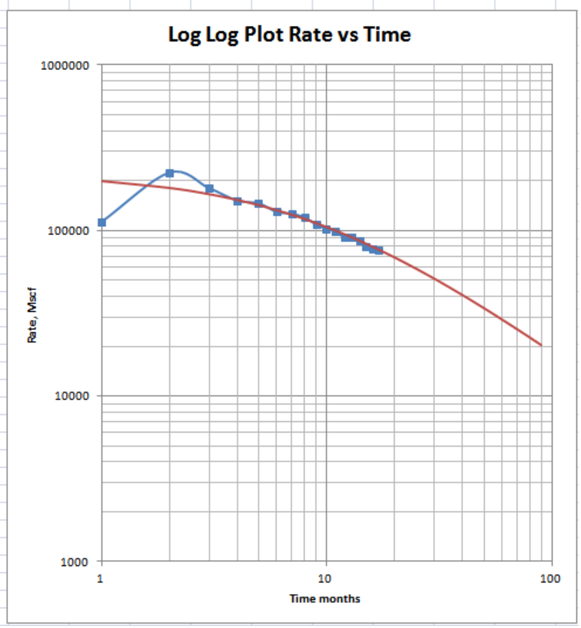


Antero 2011 Harrison Average

Di = 1.20		b exponent = 1	
No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	6,514,623	Remaining Reserve =	5,478,917
Cumulative Production =	2,006,218	Cumulative Production =	2,006,218
EUR =	8,520,841	EUR =	7,485,135



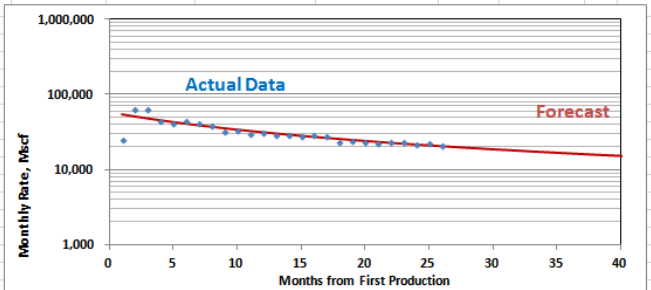


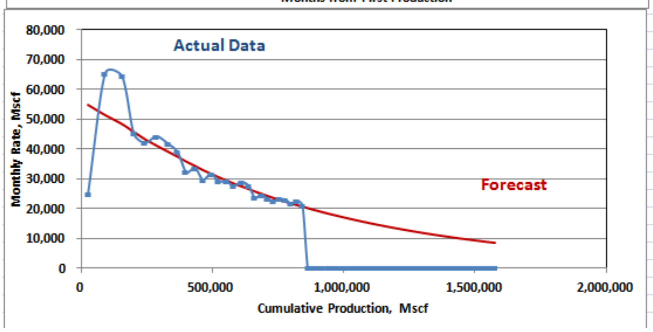


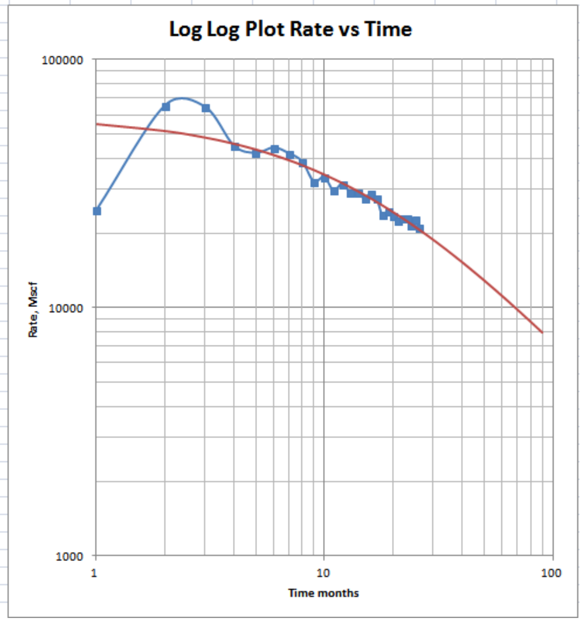
EQT 2009 Dodderidge Avg

Di = 0.80 b exponent = 1

No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	2,152,837	Remaining Reserve =	1,760,038
Cumulative Production =	842,110	Cumulative Production =	842,110
EUR =	2,994,947	EUR =	2,602,148



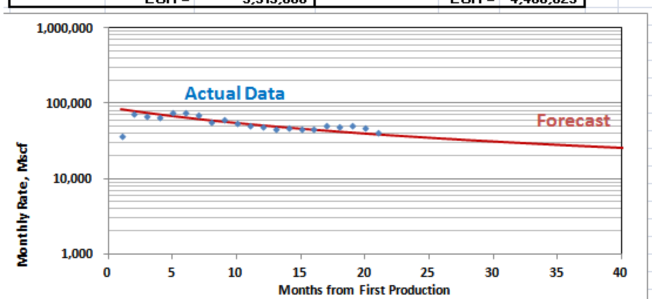


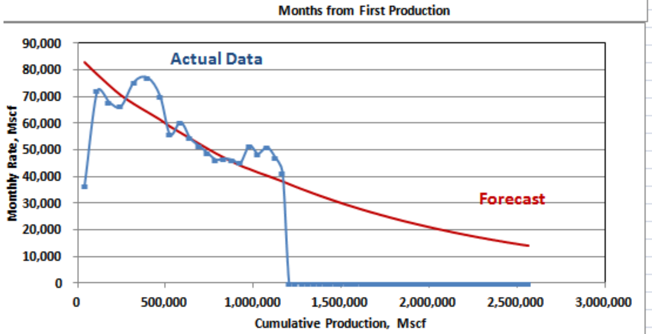


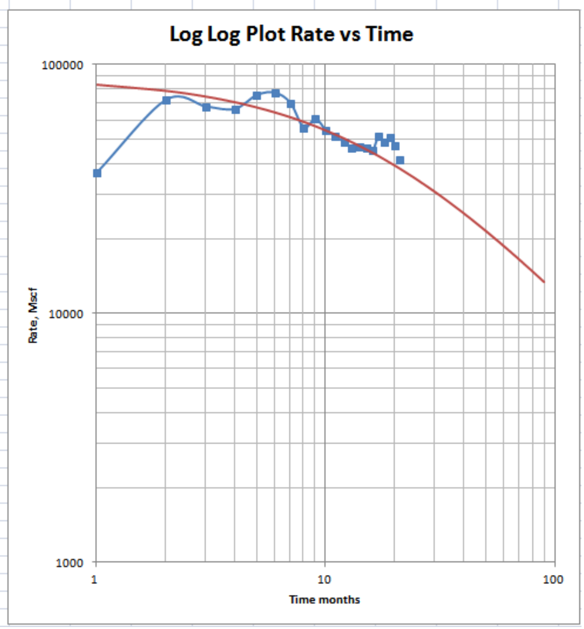
EQT 2011 Avg Dodderidge

Di = 0.70 b exponent = 1

No Terminal Decline	Mscf	Terminal Decline Rate =	7%
Remaining Reserve =	4,149,996	Remaining Reserve =	3,324,159
Cumulative Production =	1,163,870	Cumulative Production =	1,163,870
EUR =	5,313,866	EUR =	4,488,029







Appendix C: Author Publications & Presentations

Publications

1. Berman, A. E., 2013, British Geological Survey Bowland Shale Gas Assessment: The Oil Drum (March 2013): http://www.theoildrum.com/node/10088 .

2. Berman, A. E., 2013, Say It LOUD: A Few Words About Peak Oil: AAGP Explorer, Vol. 34, No. 2 February 2013: http://petroleumtruthreport.blogspot.com/

3. Berman, A. E., 2013, The Illusion of U.S. Energy Independence: Economic Straight Talk: http://www.economicstraighttalk.com/NewsArticles/Commentary.aspx?Id=910.

4. Berman, A. E., 2013, Lessons From Past Natural Gas Import Fiascos Suggest A Cautious Approach to Natural Gas Exports: The Oil Drum (February 2013): http://www.theoildrum.com/node/9828.

5. Berman, A. E., 2012, U.S. Shale Gas: A Different Perspective on Future Supply and Price: Bulletin of the South Texas Geological Society (February, 2012) v. 52, no. 6, p. 19-44.

6. Berman, A. E., 2011, After The Gold Rush: A Perspective on Future U.S. Natural Gas Supply and Price: The Oil Drum : http://www.theoildrum.com/node/8212.

7. Berman, A. E. and L. F. Pittinger, 2011, U.S. Shale Gas: Less Abundance, Higher Cost: The Oil Drum (August 5, 2011), http://www.theoildrum.com/node/8212.

8. Berman, A. E., 2010, EIA Annual Energy Outlook 2011: Don't Worry, Be Happy: The Oil Drum December 29, 2010: http://www.theoildrum.com/node/7285.

9. Berman, A. E., 2010, Shale Gas—Abundance or Mirage? Why The Marcellus Shale Will Disappoint Expectations: The Oil Drum October 29, 2010: http://www.theoildrum.com/node/7075#more.

10. Berman, A. E., 2010, BP's Deepwater Horizon - Static Top Kill vs. Bottom Kill: Weighing the Risks: The Oil Drum July 30, 2010: http://www.theoildrum.com/node/6790.

11. Berman, A. E., 2010, Estimated Oil Flow Rates From the BP Mississippi Canyon Block 252 "Macondo" Well: The Oil Drum June 29, 2010: http://www.theoildrum.com/node/6644.

12. Berman, A. E., 2010, What caused the Deepwater Horizon Disaster?: The Oil Drum May 21, 2010: http://www.theoildrum.com/node/6493#more

13. Berman, A. E., 2010, ExxonMobil's Acquisition of XTO Energy: The Fallacy of the Manufacturing Model in Shale Plays: The Oil Drum: http://www.theoildrum.com/node/6229

14. Berman, A. E., 2010, McMoRan Davy Jones Gas Discovery: The Oil Drum: http://www.theoildrum.com/node/6135#more

15. Berman, A.E., 2009, Facts are Stubborn Things: Association for the Study of Peak Oil: http://www.aspousa.org/index.php/2009/11/facts-are-stubborn-things-arthur-e-berman-november-2009/

16. Berman, A. E., 2009, A Haynesville Shale symposium: World Oil, v. 230, no.10, p. 15.

17. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 10, p. 17.

18. Berman, A. E., 2009, Realities of shale play reserves: examples from the Fayetteville Shale: World Oil, v. 230, no.9, p. 17.

19. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 9, p. 17.

20. Berman, A. E., 2009, Lessons from the Barnett Shale imply caution in other shale plays: World Oil, v. 230, no. 8, p. 17.

21. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 8, p 19.

22. Berman, A. E., 2009, Mozambique heats up: World Oil, v. 230, no.7, p. 17.

23. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 7, p. 19.

24. Berman, A. E., 2009, A long recovery for gas prices: revisiting the Haynesville Shale: World Oil, v. 230, no. 6, p. 15.

25. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 6, p. 17.

26. Berman, A. E., 2009, Papua New Guinea emerging as a natural gas province: World Oil, v. 230, no.5, p. 15.

27. Berman, A. E., 2009, Haynesville sizzle could fizzle: World Oil, v. 230, no.4, p. 19.

28. Berman, A. E., 2009, Independents discover major oil reserves in Uganda: World Oil, v. 230, no.3, p. 15-70.

29. Berman, A. E., 2009, Independents discover major oil reserves in Uganda: World Oil, v. 230, no.3, p. 15-70.

30. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 3, p. 17.

31. Berman, A. E., 2009, Low oil prices and the future of exploration—en aguas revueltas: World Oil, v. 230, no.2, p. 21.

32. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 2, p. 23.

33. Berman, A. E., 2009, Shale Plays and Lower Natural Gas Prices: A Time for Critical Thinking: World Oil, v.230, no. 1, p. 15.

34. Berman, A. E., 2009, Exploration Discoveries: World Oil, v. 230, no. 1, p. 17.

35. Berman, A. E., 2008, Oil and politics in Sudan: World Oil, v. 229, no.12, p. 15.

36. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 12, p. 17.

37. Berman, A. E., 2008, 50 Years of Exploration in the Tarim Basin, v. 229, no. 11, p. 21.

38. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 11, p. 23.

39. Berman, A. E., 2008, Geology matters in the Austin Chalk play, v. 229, no. 10, p. 21.

40. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 10, p. 23.

41. Berman, A. E., 2008, The Haynesville Shale sizzles while the Barnett cools, v. 229, no. 9, p. 23.

42. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 9, p. 25.

43. Berman, A. E., 2008, The High Price of Oil: World Oil, v. 229, no. 8, p. 23.

44. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 8, p. 25.

45. Berman, A. E., 2008, Re-examining peak oil: An interview with Nansen G. Saleri: World Oil, v. 229, no. 7, p. 25.

46. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 7, p. 27.

47. Berman, A. E., 2008, The limits of global gas supply: World Oil, v. 229, no. 6, p. 23.

48. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 6, p. 25.

49. Berman, A. E., 2008, Another Discovery in Belize: World Oil, v. 229, no. 5, p. 23-24.

50. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 5, p. 27.

51. Berman, A. E., 2008, Winners Curse: The end of exploration for ExxonMobil: World Oil, v. 229, no. 4, p. 23-24.

52. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 4, p. 25.

53. Berman, A. E., 2008, NAPE exhibitors miss the mark: World Oil, v. 229, no. 3, p. 23.

54. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 3, p. 25.

55. Berman, A. E., 2008, Three Super-giant fields discovered offshore Brazil: World Oil, v. 229, no. 2, p. 23-24.

56. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 2, p. 27.

57. Berman, A. E., 2008, The paradigm and the anomaly: World Oil, v. 229, no. 1, p. 20.

58. Berman, A. E., 2008, Exploration Discoveries: World Oil, v. 229, no. 1, p. 21.

59. Berman, A. E., 2007, Peaking in Tongues: World Oil, v. 228, no. 12, p. 20.

60. Berman, A. E., 2007, Exploration Discoveries: World Oil, v. 228, no. 12, p. 25.

61. Berman, A. E., 2007, Revisiting the Barnett Shale: World Oil, v. 228, no. 11, p. 20.

62. Berman, A. E., 2007, Exploration Discoveries: World Oil, v. 228, no. 11, p. 21.

63. Berman, A. E., 2007, Readers respond to the Fayetteville Shale: World Oil, v. 228, no. 10, p. 20.

64. Berman, A. E., 2007, Exploration Discoveries: World Oil, v. 228, no. 10, p. 21.

65. Berman, A. E. and J. H. Rosenfeld, 2007, Deep-water Gulf of Mexico Wilcox play: a new paradigm for the Gulf Coast Paleogene: Petroleum Frontiers, v. 21, no. 1, IHS, Inc., 54p.

66. Berman, A. E., 2007, Will LNG imports hurt US natural gas exploration?: World Oil, v. 228, no. 9, p. 20.

67. Berman, A. E., 2007, Exploration Discoveries: World Oil, v. 228, no. 9, p. 19.

68. Berman, A. E., 2007, The Fayetteville Shale play: An early evaluation: World Oil, v. 228, no. 8, p. 20.

69. Berman, A. E., 2007, Exploration Discoveries: World Oil, v. 228, no. 8, p. 25.

70. Berman, A. E., 2007, Giant Nanpu field discovery: A lesson in reserve calculation: World Oil, v. 228, no. 7, p. 19.

71. Berman, A. E., 2007, Exploration Discoveries: World Oil, v. 228, no. 7, p. 21.

72. Berman, A. E., 2007, The impending natural gas supply crisis: Why prices will rise: World Oil, v. 228, no. 6 (June 2007), p.21.

73. Berman, A. E. and J. H. Rosenfeld, 2007, A new depositional model for the deepwater Wilcox-equivalent Whopper Sand—changing the paradigm: World Oil, v. 228, no. 6 (June 2007), p.77-82.

74. Berman, A. E., 2007, The end of exploration: World Oil, v. 228, no. 5 (May 2007), p.21.

75. Berman, A. E., 2007, Plank road fever and the Barnett Shale: World Oil, v. 228, no. 4 (April 2007), p.23-24.

76. Berman, A. E., 2007, Deepwater Wilcox play in the Gulf of Mexico: Paradigm lost: World Oil, v. 228, no. 3 (March 2007), p.19.

77. Berman, A. E., 2005, The Great Sumatra-Andaman Earthquake of December 26, 2004: New Insights That Will Change the Next 40 Years and the Plate Tectonic Paradigm: Houston Geological Society Bulletin, v. 48, no. 4, p. 31-41.

78. Berman, A. E., 2005, The Debate Over Subsidence in Louisiana and Texas: Houston Geological Society Bulletin, v. 48, no. 1, p. 47-54.

79. Berman, A. E., 2005, Ideas Are Like Stars: The Current Oil Boom: Houston Geological Society Bulletin, v. 47, no. 10, p. 9-23.

80. Berman, A. E., 2005, The Oil Boom, 1973-1986: A Simple Story? Houston Geological Society Bulletin, v. 47, no. 9, p. 9-21.

81. Berman, A. E., 2005, An Interview with Joel Bartsch, President of the HMNS: Gold, Re-opening of the Weiss Energy Hall and Hall of Gems and Minerals, and Distinguished Lectures on Earthquakes and Tsunamis: Houston Geological Society Bulletin, v. 47, no. 9, p. 53-55.

82. Berman, A. E., 2005, Letters from Jakarta: Indian Ocean Nations Select a Tsunami Warning System: Houston Geological Society Bulletin, v. 47, no. 8, p. 9-19.

83. Berman, A. E., 2005, An Interview with Jim Hackett, Anadarko Petroleum CEO, January 7, 2005: Houston Geological Society Bulletin, v. 47, no. 7, p. 25-36.

84. Berman, A. E., 2005, The Northern Sumatra Earthquake of 2004:Forty Years of Ignoring Plate Tectonics: Houston Geological Society Bulletin, v. 47, no. 6, p. 9-19.

85. Berman, A. E., 2005, Anatomy of a Silent Disaster: Ongoing Subsidence and Inundation of the Northern Margin of the Gulf of Mexico: Houston Geological Society Bulletin, v. 47, no. 6, p. 31-47.

86. Berman, A. E., 2004, Technology in the Post-Modern Age: A Conversation with John Lienhard: Houston Geological Society Bulletin, v. 47, no. 5, p. 9-17.

87. Berman, A. E., 2004, New ideas and their diffusion: Houston Geological Society Bulletin, v. 47, no. 4, p. 9-17.

88. Berman, A. E., 2004: Election issues in the context of petroleum and history part 2. United States Energy Dependence: Houston Geological Society Bulletin, v. 47, no. 3, p. 9-13.

89. Berman, A. E., 2004: Election issues in the context of petroleum and history: Houston Geological Society Bulletin, v. 47, no. 2, p. 9-13.

90. Berman, A. E., 2004: A lesson about predictions: Houston Geological Society Bulletin, v. 47, no. 1, p. 9-11.

91. Berman, A. E., 2004: The war on terror and strategic oil supplies: Rigzone, June 11, 2004.

92. Berman, A. E., 2004: Proven reserve reductions: a geologist's perspective—Is certification necessary?: Houston Geological Society Bulletin, v. 46, no. 10, p. 67-73.

93. Berman, A. E., 2004: Oil and gas proven reserve reductions: a geologist's perspective: Houston Geological Society Bulletin, v. 46, no. 9, p. 55-60.

94. Berman, A. E., 2004: Pemex makes gas discoveries in the Sabinas basin: Rigzone, March 4, 2004.

95. Berman, A. E., 2004: Academic Liaison Committee adds resources and goes on the HGS Website: Houston Geological Society Bulletin, v. 46, no. 7, p. 31-39.

96. Berman, A. E., 2004: The HGS Website: a closer look: Houston Geological Society Bulletin, v. 46, no. 5, p. 37-51.

97. Berman, A. E., 2004: The Bureau of Economic Geology—an interview with Director Scott Tinker and staff and a new Houston research center: Houston Geological Society Bulletin, v. 46, no. 6, p. 37-45.

98. Berman, A.E. and V. Schmidt, 2003, Africa: New Plays, New Perspectives: Houston Geological Society Bulletin, v. 46, no. 3, p. 37-45.

99. Berman, A. E., 2003: Eyes on planet Earth: monitoring our changing world: Houston Geological Society Bulletin, v. 46, no. 4, p. 23-28.

100. Haldar, J. K., C. J. O'Byrne, A. E. Berman, and J. Gamber, 1999, Dynamic Response of Deepwater Depositional Systems to Growth of the Mississippi Fan Fold Belt, Gulf of Mexico (abstract): in W. C. Terrell and L. Czerniakowski, eds., Transactions Gulf Coast Association of Geological Societies, vol. 49, p. 2.

101. O'Byrne, C. J., J. K. Haldar, R. Klecker, A. E. Berman, and J. Martinez, 1999, Dynamic Response of Deepwater Depositional Systems to Growth of the Mississippi Fan Fold Belt, Gulf of Mexico: in W..C. Terrell and L. Czerniakowski, eds., Transactions Gulf Coast Association of Geological Societies, vol. 49, p. 404-417.

<u>Presentations</u>

1. South Texas Geological Society, Assessing The Business Performance of U.S. Shale Plays (San Antonio, March 25, 2014).
2. Reagan High School, Energy Independence: Fact or Fiction (San Antonio, March 25, 2014).
3. NACE Investment Forum, Energy Independence: Fact or Fiction (Palm Beach, March 18, 2014).
4. The Energy Authority Energy Symposium, Separating The Signal From The Noise in U.S. Shale Gas Plays (Jacksonville, March 13, 2014).

5. Industrial Energy Consumers of America Quarterly Meeting, Assessing The Business Performance of U.S. Shale Plays (Arlington, March 11, 2014).
6. Total Strategy Committee, Assessing The Business Performance of U.S. Shale Plays (Houston, March 10, 2014).
7. GLG New York Client Seminar: Assessing the Quality of Shale Play Reserves and Operator Performance (New York, February 26, 2014).

8. Lafayette Geological Society: Reflections on A Decade of Shale Plays (Lafayette, February 19, 2014).

9. Coleman Research Group: Update on Shale Depletion Rates, Estimated Ultimate Recovery & North American Energy Independence (New York, January 31, 2014).

10. International Association for Energy Economics Annual Meeting: Panel Discussion on Shale Gas with Adam Sieminski, EIA Administrator (Philadelphia, January 3, 2014).

11. Shreveport Geological Society: Reflections on A Decade of Shale Plays (Shreveport, December 17, 2013).

12. Macquarie Capital (USA) Key Client Meeting: Reflections on A Decade of Shale Plays (Houston, December 12-13, 2013).

13. Kinnear Financial Limited Autumn Investment Conference: Shale: what happens if the capital goes away? (Southampton, Bermuda, November 22, 2013).

14. GLG Research Client Seminar: Shale: what happens if the capital goes away? (Hong Kong, November 18, 2013).

15. Houston Geological Society Joint International & North American Dinner: Reflections on A Decade of Shale Plays (Houston, September 30, 2013).

16. American Association of Appraisers Houston 2013 Energy Valuation Conference: Let's Be Honest About Shale Gas (Houston, April 25, 2013).

17. AMGP-IMP Conferencia Tecnológica Temática para la Exploración y Explotación de Aceite y Gas en Lutitas: Shale Gas en EEUU: Seamos Sinceros Sobre Shale Gas (Mexico City, April 4, 2013).

18. Indiana State Legislature Testimony: Let's Be Honest About Shale Gas (Indianapolis, March 27, 2013).

19. Corpus Christi SIPES, : Let's Be Honest About Shale Gas (Corpus Christi, TX, March 26, 2013).

20. The Energy Authority Energy Symposium 2013: Let's Be Honest About Shale Gas (Jacksonville, FL, March 14, 2013).

21. University of Texas School of Law Renewable Energy Institute: After The Gold Rush: A Different Perspective on Future Gas Supply and Price (Austin, TX, January 29, 2013).

22. Association for the Study of Peak Oil 2012 Conference: Oil-Prone Shale Plays: The Illusion of Energy Independence (Austin, November 30, 2012).

23. Houston SIPES Continuing Education Seminar: Oil-Prone Shale Plays: The Illusion of Energy Independence (Houston, October 19, 2012).

24. Austin SIPES: After The Gold Rush: A Perspective on Future U.S. Natural Gas Supply and Price (Austin, October 4, 2012).

25. American Public Power Association: Will Natural Gas Be There When We Need It (and at What Price)? (Seattle, June 19, 2012).

26. South Texas Money Management Seventh Annual Energy Symposium: After The Gold Rush: A Perspective on Future U.S. Natural Gas Supply and Price (San Antonio, May 16, 2012).

27. Society of Professional Evaluation Engineers: A Perspective on Future U.S. Natural Gas Supply and Price (Midland, May 8, 2012).

28. Accenture Upstream Major Capital Projects Supply Chain Forum: A Perspective on Future U.S. Natural Gas Supply and Price (Houston, April 25, 2012).

29. West Texas Geological Society: U.S. Shale Oil: Expectation and Experience (Midland, April 10, 2012).

30. Middlefield Investment Conference: U.S. Shale Oil (Toronto, March 21-22, 2012).

31. Kinnear Financial Spring Investment Conference: U.S. Shale Oil (Banff, March 17, 2012).

32. The Energy Authority: Shale Panel Discussion with Jen Snyder, Wood Mackenzie (Jacksonville, FL March 15 and February 21, 2012).

33. South Texas Geological Society Luncheon Meeting: U.S. Shale Oil (San Antonio, March 14, 2012).

34. Large Public Power Council: A Perspective on Future U.S. Natural Gas Supply and Price (San Juan, PR, February 12, 2012).

35. Houston Geological Society: U.S. Shale Gas: Magical Thinking (Houston, TX, January 25, 2012).

36. Society of Petroleum Evaluation Engineers (SPEE) Dallas Chapter: U.S. Shale Gas: Magical Thinking (Dallas, TX, January 19, 2012).

37. Alaska Alliance: U.S. Shale Gas: Magical Thinking (Anchorage, AK, January 6, 2012).

38. BP Energy Company, North American Gas & Power: U.S. Shale Gas: Magical Thinking (Houston, TX, December 14, 2011).

39. Gerson Lehrman Shale Gas Panel Discussion (San Francisco, December 7, 2011).

40. Energy Utility Consultants, Inc. Conference Panel Discussion: The Future of Fossil-Fired Plants: Risks and Opportunities in Light of Regulatory and Economic Uncertainty (Arlington, VA, December 5, 2011).

41. National Association of Regulatory Utility Commissioners Annual Meeting: The Great Frontier panel discussion (St. Louis, November 14, 2011).

42. American Public Power Association Annual Member CEO Meeting: Shale Gas—Magical Thinking (Washington, D.C., October 26, 2011).

43. Corpus Christi Society of Independent Earth Scientists: Shale Gas—Magical Thinking (Corpus Christi, October 25, 2011.

44. Kinnear Financial Limited Fall Investment Conference: Shale Gas—Magical Thinking (Southampton, Bermuda, October 21, 2011).

45. Gerson Lehrman Shale Gas Panel Discussion (New York, October 18, 2011).

46. Middlefield Investment Conference: Shale Gas—The Eye of the Storm (Calgary, July 14, 2011).

47. Natural Resources Partnership: Shale Gas—A View from the Bottom of the Resource Pyramid (Houston, TX, May 26, 2011).