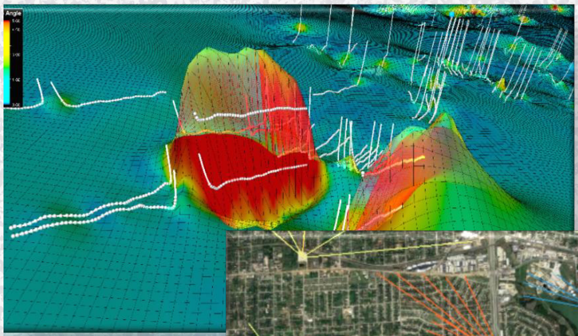
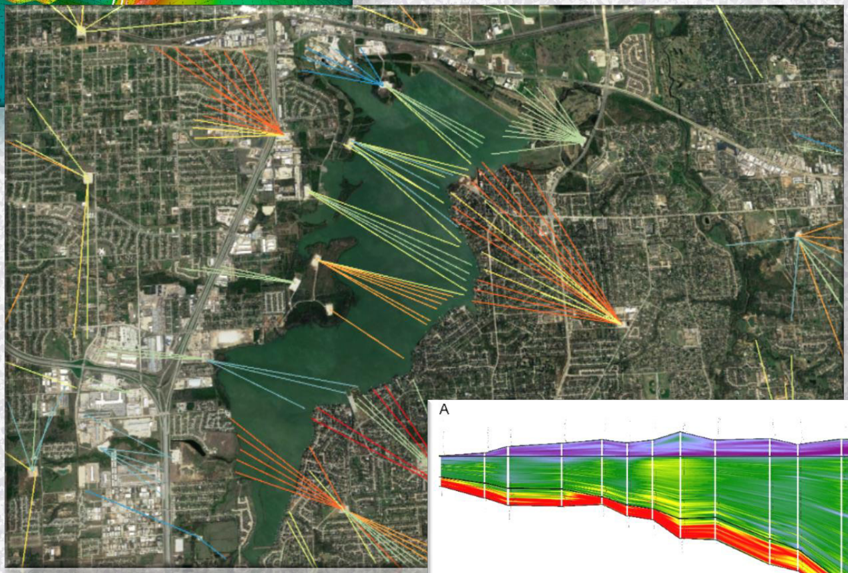
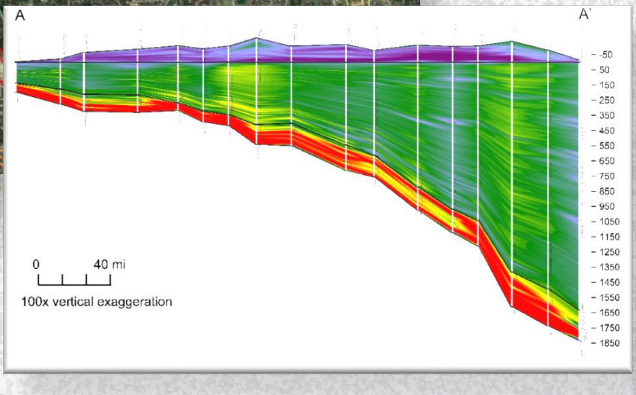
Final Report Prepared for the U.S. Department of Energy

Update and Enhancement of Shale Gas Outlooks

Barnett Shale
Haynesville Shale
Fayetteville Shale
Marcellus Shale







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Disclaimer: This report summarizes *research* conducted at the Bureau of Economic Geology at The University of Texas at Austin. As *research*, analyses contained in this report (including, but not limited to, estimates of gas in place and productivity outlooks) are prepared using a specific set of assumptions and are subject to change. Please contact the editors (S. Ikonnikova: svetlana.ikonnikova@beg.utexas.edu and K. Smye: katie.smye@beg.utexas.edu) for details on methodology, citations, and any updates on the materials presented herein.

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Contents

Executive Summary

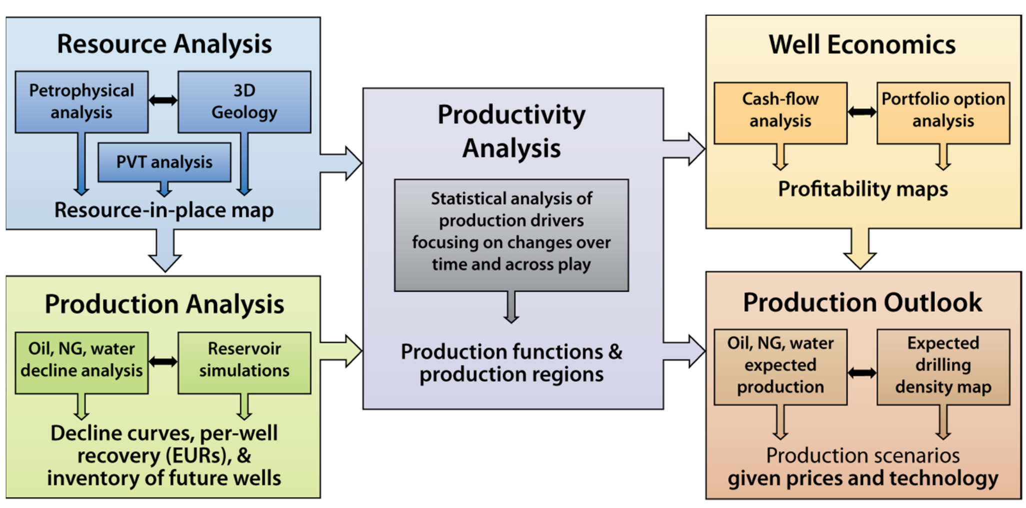
The continued growth of natural gas production from shale formations has led to major transformations in the U.S. energy landscape. The share of coal in primary energy consumption has decreased by almost 40 percent since 2005, having been replaced by environmentally preferable natural gas, especially in power generation. The abundance of shale gas has resulted in falling imports and increasing exports.

The prospect of ever-increasing liquefied natural gas (LNG) exports changes the role of the U.S. in the international energy trade. While most experts agree on the abundance of the resource, discussions continue about technical capabilities to recover that resource economically. Concerns include industry's ability to sustain production in future decades and the cost of doing so as domestic reliance on shale gas grows and the most attractive locations are drilled out.

Our research team at the Bureau of Economic Geology (Jackson School of Geosciences, The University of Texas at Austin) has aimed to update and improve production outlook assessments for the major U.S. shale gas plays, including the Barnett, Fayetteville, Haynesville, and Marcellus. In the course of our work, our team of geoscientists, engineers, statisticians, and economists has reviewed and analyzed developments in the understanding of geologic, production-technology, and economic factors. Following our integrated workflow (figure below), we focused on improvements in data quality and resolution, enabling further improvements in methodology in order to enhance the following:

- Geologic reservoir characterization
- Individual well decline and recovery analysis
- Statistical analysis of well productivity drivers
- Economically recoverable resource assessment

With these improvements, we present a more comprehensive production outlook model set up to run various scenarios with respect to energy prices, costs, technological advances, changes in geologic attributes, and physical and regulatory constraints.



Workflow for shale resources and production outlook studies.

The new assessment led to an ~5 percent increase in the free original-gas-in-place (OGIP) estimate, which is now about 3,100 trillion cubic feet (Tcf) of natural gas. However, expectations about technically recoverable resources increased by almost 25 percent. Recovery of ~800 Tcf is considered possible with new advances in drilling, such as stacked and staggered well drilling, which allow for higher recovery per unit of surface area. The increased density of drilling is, in many cases, combined with economies of scale from drilling of longer laterals and further cost improvements associated with simultaneous drilling of multiple wells. The correlation between drilling costs and energy prices led to even greater increases in the expected production outlook for a similar price scenario. At the constant real price of natural gas at Henry Hub of 3$/MMBtu, the new model yields over 100 Tcf more production by 2045. At 4$/MMBtu, ~200 Tcf more is recovered. However, further price increases would have diminishing returns owing to location availability and infrastructure constraints.

Note that the analysis does not rule out higher recovery factors if new technology, beyond incremental and economies-of-scale improvements, shifts the productivity of lower-quality rock to commercial levels. This kind of step change in technology may be necessary to preclude production decline after 2035.

This report is organized in accordance with the workflow and focuses on the comparison of the original and updated (1) resource-in-place estimates; (2) technically recoverable resources, with some details regarding new observed drilling techniques and completion practices; and (3) production outlooks under different price scenarios. The comparison for each component consists of three steps: changes in input data, improvements in methodology, and update of assessments.

In line with the proposed scope, the study covers the major shale gas plays. However, as discussed in more detail in **Chapter 1**, in some plays the stratigraphic analysis was extended to allow more comprehensive characterization of additional target formations. Formations correlated in the course of the analysis are shown in the table below, with resource assessments for formations in bold type. We discuss the extent and details of the geologic analysis, including stratigraphic and petrophysical characterization and construction of the 3D geocellular model.

Correlated formations. Formations in parentheses were correlated locally, and resource assessments were carried out for formations in bold.

Barnett	Haynesville	Fayetteville	Marcellus
(Marble Falls)	(Bossier)	**Fayetteville**	(Upper Devonian)
Upper Barnett	**Haynesville**	**Lower Fayetteville**	Tully Limestone
Forestburg	Smackover	Hindsville LS / Batesville SS	Mahantango
Lower Barnett			**Upper Marcellus**
Viola/Simpson			Cherry Valley/ Purcell Limestone
Ellenburger			**Lower Marcellus**
(Precambrian			Onondoga

Geologic reservoir attributes are used in the well decline analysis presented in **Chapter 2**. The decline analysis has been updated and enhanced by (1) improved granularity of geologic description, (2) increased collection of wells with longer production histories, and (3) additional completion details such as landing zones and drilling patterns. With the updates in geologic characterization and estimated recovery—and inclusion of additional completion data, such as for volumes of treatment fluid and proppant, landing zones, and drilling patterns—we were able to exploit and benefit from capabilities provided by the machine-learning algorithms for statistical analysis.

In **Chapter 3** we discuss the productivity analysis used to understand the role of geology and technology in resource recovery, track changes in technology, and build expectations about productivity of the undrilled locations leading to the technical recoverable resource assessment.

The findings and results of the geologic well-production and productivity analyses are combined to provide inputs for the individual well economics model, and to build production outlooks, as discussed in **Chapter 4**. The upgraded well economics incorporated into the outlook model capture important features of well and play development as well as industry dynamics. In particular, well economics takes into account positive correlation between energy price and drilling costs, along with improve-ments in drilling efficiency, economies of scale associated with drilling and completion of multiple wells and longer wells, and costs associated with differences in use of key input factors such as water for hydraulic fracturing and proppant. The production outlook model is set to be sensitive to market drivers such as financial costs of capital and has the ability to test differences in resource development if industry firm concentration changes from many mid-sized companies to fewer larger-sized firms.

Discussion highlights major conclusions and discusses prospective avenues for further research. With limitations, mainly related to data, we find that our study is the most robust and comprehensive in depth and scope, and offers great value to any stakeholder interested in understanding the resiliency of U.S. production in the face of increased volatility in energy prices, as well as the emerging new natural gas trade relationships between U.S. producers and foreign importers such as China and Mexico.

In this final chapter, we summarize all of the key findings and provide an extended discussion on directions for further research based on the limitations of the current study. We talk about the necessity of continuing the effort to update outlooks on a regular basis, taking into account new advances in technology, which are difficult to predict, particularly under the current market uncertainty. Finally, we relate the results of the current study to potential macroeconomic implications that may affect economic developments in the U.S.

Chapter 1. Geologic Analysis

1.1 Study Questions

Geologic assessment of shale oil and gas plays is the basis for understanding resource in place and geologic factors influencing productivity. Our previous studies reported gas-in-place assessments, which revealed a need for continued updates of both data and approach. Continued geologic assessment of shale gas plays reflects improving methodology, updated log and core data availability, changes in our understanding of what portion of resource is currently being produced, and the prospectivity of adjacent formations. These updates require a "living model" where changes in input parameters feed through all parts of the analysis. Here, we present our approach to and results of stratigraphic and petrophysical interpretation for each basin, highlighting the added granularity and more sophisticated methodology relative to previous studies.

As unconventional oil and gas plays mature, additional well logs are released and provide critical control points in areas with little data. Furthermore, over time, our approach to stratigraphic and petrophysical analysis has improved, acknowledging that while a consistent model is optimal, the character of gas shales varies and, therefore, the most appropriate methods of assessment may vary between plays.

Maturing plays have also revealed the importance of considering adjacent formations in observed production and drilling trends (e.g., the Upper Devonian in the Marcellus play, and the Bossier in the Haynesville play). As adjacent formations become attractive through stacked horizontal wells and multiple landing zones, the economics of a given acreage are impacted. This updated assessment includes an overview of related pay zones and their implications for drilled wells. However, as plays continue to mature and stacked wells become more attractive, complete resource assessment of these formations will be necessary.

Furthermore, as plays continue to develop, we observe a need for a new understanding of "net pay" cutoffs. Previous studies utilized a more conventional assessment approach that implements net-pay cutoffs—e.g., a minimum porosity or total organic carbon (TOC)—to identify potentially productive zones. However, high recovery factors in some plays (e.g., Haynesville) reveal that operators are able to overcome challenges that may have previously prohibited production and are now able to access additional oil or gas with improved technology. To account for this, we consider the total gas in place to understand recovery factors, but also implement net-pay cutoffs to understand the resource that is currently driving productivity of an average well.

This assessment also includes the development of 3D geocellular models with multiple applications: well landing formations and zones can be determined, providing a quality control check of publicly available data; structural features such as folds and faults can be mapped in 3D; horizontal well paths can be incorporated to add detail to structural surfaces; near-wellbore properties can be assessed on a 3D basis; and properties can be distributed in a more sophisticated way utilizing variograms.

Major questions addressed in this updated geologic assessment fall under two themes:

1. What is the gas in place of the major U.S. shale gas plays?
2. What are the major geologic properties driving productivity?

Specific to this study, within the gas-in-place assessments we include a discussion of how we can improve the precision of our estimates. While gas in place in a given play is "fixed," our estimates of

the resource and our assumptions about what portion of the resource is accessible improve with the addition of data and refinement of methodology.
Within the second theme, we investigate how the properties affecting productivity vary spatially and vertically through the use of a 3D geocellular model. We also improve our understanding of how best to utilize available wireline well logs to gain insight into geologic variability.

1.2 Data

Geologic assessment of shale plays relies primarily on subsurface data including petrophysical well logs and, when available, core analyses. The spatial resolution of data types varies, with a general assessment of the entire play possible while small windows with additional data allow for calibration of interpreted properties with rock data (Fig. 1.1).

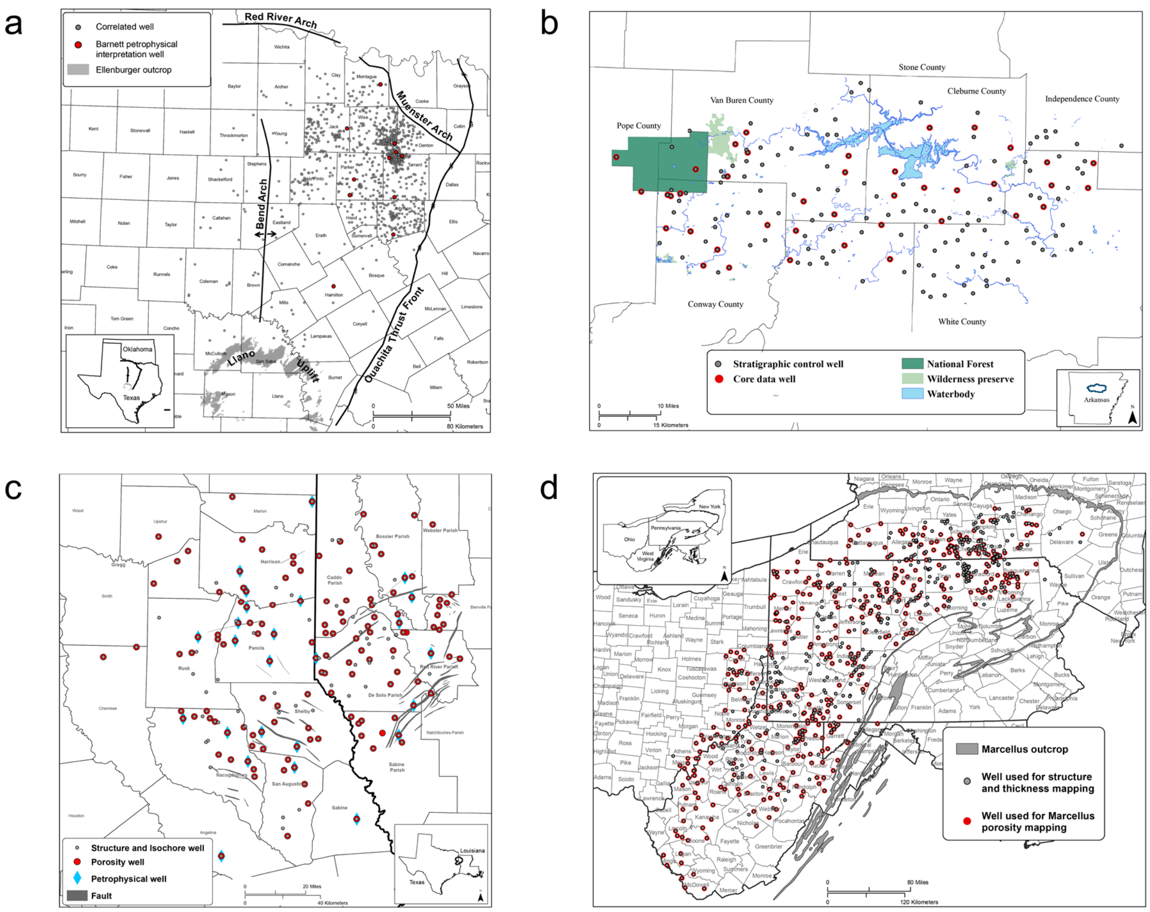


Figure 1.1 Distribution of log data for (a) Barnett, (b) Fayetteville, (c) Haynesville, and (d) Marcellus Shale plays.

Digital well logs for this study were acquired through commercial and state databases. Access to digital well logs for regions in Texas (Barnett and TX Haynesville) was provided by IHS. Well-log and core data were also acquired from the Bureau of Economic Geology (Bureau) Core Research Center and Geophysical Log Library, as well as from the Texas Railroad Commission. Data for assessment of the Marcellus Shale were acquired through the Pennsylvania Department of Conservation and Natural Resources (PA DCNR); West Virginia Geological and Economic Survey (WVGES); Ohio Department of Natural Resources, Division of Oil and Gas; and the Empire State Oil and Gas Information System (ESOGIS). Where additional control is needed (e.g., for Barnett, Fayetteville, and Marcellus), data are sourced from operators.

The minimum logs required for resource-in-place estimates are gamma-ray, density, neutron porosity +/- resistivity, and a caliper log to assess borehole quality. The usefulness of each log type differs by play; for example, in the Marcellus, the gamma-ray log is indicative of TOC, while in the Haynesville, gamma-ray values are comparable to overlying nonproductive shales but neutron and density reflect the presence of gas (Fig. 1.2).

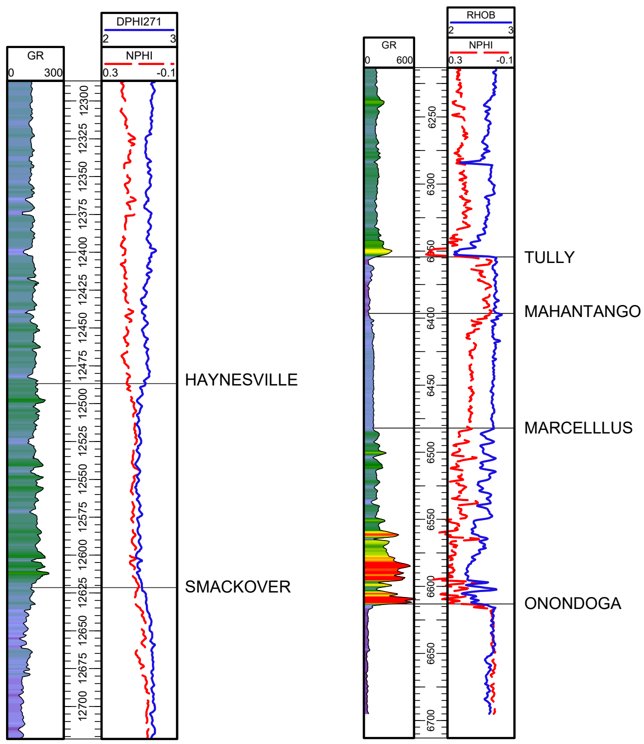


Figure 1.2 Type logs for (a) Haynesville, and (b) Marcellus Shales, showing that the usefulness of each log varies by play. Gamma-ray is shown in track 1, and neutron and density porosity are shown in track 2.

Previously published work is also incorporated into the study, including thermal-maturity data, structural features and cross sections, and temperature sourced from the aggregated National Geothermal Data System (NGDS) operated by the SMU Geothermal Laboratory and Cornell Energy Institute.

1.3 Methodology

1.3.1 Geology

Within each study area, digital and raster logs were sourced with a focus on (1) core production areas within the basin, (2) well depth and intervals logged, and (3) log curve type and quality. Formation tops were correlated for producing and adjacent formations (Summary table) in IHS Petra® v3.8.9.

In the Barnett study, 1,286 wells with digital logs across the Fort Worth Basin (Fig. 1.1) were correlated; formation tops include the Marble Falls, Barnett Shale (and Forestburg Limestone, separating the Upper and Lower Barnett), Viola–Simpson, and Ellenburger. All wells utilized log some of the Barnett interval, while 1,023 penetrate Ordovician units (Viola–Simpson and/or Ellenburger). The Ellenburger consists of alternating limestone and dolomite; in some places it is heavily karsted and water-bearing with appreciable porosity, affecting the water cut of Barnett producing wells. In contrast, the Viola Limestone is a tight (low porosity) formation. The presence of the Viola–Simpson separating Barnett wells from the water-bearing Ellenburger is an important component of the statistical analysis.

In the Fayetteville Shale play, 159 wells were correlated. The lithology of the rocks underlying the Fayetteville is also thought to affect vertical fracture propagation, so the lithology (sandstone vs. limestone) was determined and mapped (Fig. 1.3) and used as
a binary indicator in the statistical analysis.

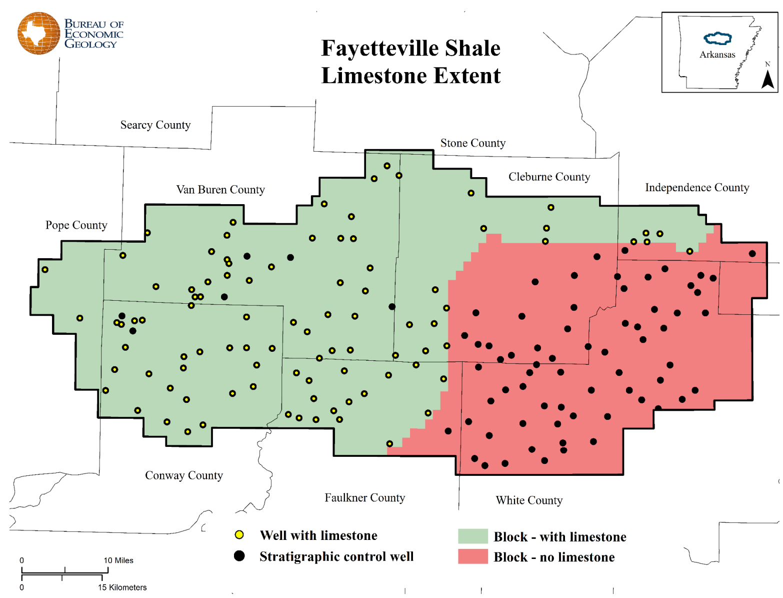


Figure 1.3 Lithology (sandstone vs. limestone) of the formation present beneath the Fayetteville Shale. The underlying formation's lithology is thought to affect vertical fracture propagation and, therefore, productivity.

In the Haynesville Shale play, 198 wells were correlated. The overlying Bossier Shale can be productive, exhibiting a similar gas effect in the neutron and density log curves as is seen in the Haynesville; the Bossier pay zone was identified and mapped across much of the Haynesville Shale play trend.

In the Marcellus Shale, 838 wells were correlated. The Upper and Lower Marcellus are separated by a limestone (here called the *Cherry Valley*; also often correlated with the Purcell Limestone); its thickness was mapped to be used as an indicator of whether or not fractures would propagate through it to access both Upper and Lower Marcellus, or whether drilling of separate stacked horizontal wells would be possible. The Upper Devonian (overlying the Tully Limestone) consists of shales that are also locally productive. The proximity to potentially productive Upper Devonian formations is indicated by the thickness of the Tully Limestone and Mahantango Group, which increases toward the east and northeast portions of the play (Fig. 1.4).

Using a high resolution Digital Elevation Model (DEM), ground elevation values were sampled to points along outcrop lines for Barnett and Marcellus formations and merged with formation top data sets for interpolation. Surface layers were interpolated using a Natural Neighbor (NN) algorithm in Arc Map 10.3. The NN algorithm only interpolates surfaces to the spatial extent of the data; in order to extrapolate to the full extent of the study area, a grid of points was created by sampling the NN raster values every 2,000 ft. The grid values were then extrapolated to the extent of the play boundary using an Inverse Distance Weighted (IDW) algorithm.

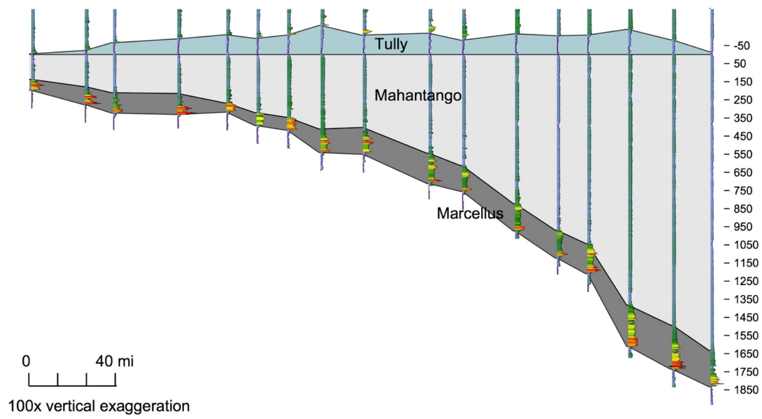


Figure 1.4 Marcellus Shale stratigraphic cross section (SW to NE) with top of Mahantango (top of Hamilton Group) datum, showing the increasing thickness of the Hamilton Group from SW to NE.

1.3.2 Petrophysics

The purpose of the petrophysical analysis in each play is to quantify reservoir properties, specifically porosity, TOC, and other factors affecting resource-in-place estimates and productivity. In the Barnett, porosity was computed from bulk density logs (ρ_{bulk}). A set of wells (n=8) with a core-calibrated petrophysical interpretation showed an average grain density (ρ_{matrix}) of 2.63 g/cc, reflecting the mineralogical constituents present. Combined with a fluid density (ρ_{fluid}) of 0.7 g/cc (corresponding to 25 percent water saturation; water density of 1.0 g/cc; and gas/oil densities of 0.28 and 0.38 g/cc, respectively), porosity (Φ) was calculated as follows:

$$\phi = \frac{\rho_{matrix} - \rho_B}{\rho_{matrix} - \rho_{fluid}} \qquad (1)$$

Haynesville Shale porosity was calculated for 135 wells with digital logs (Fig. 2) using the density log (Eq. 1). A detailed petrophysical model for a subset of the porosity wells (n=25, 9 with core data) computed volumes of calcite, kerogen, porosity, quartz, and clay with a fixed quartz/clay ratio of 55:45. Density-derived porosities were calibrated to modeled porosities. The separation between neutron and density logs was used as a proxy for clay volume and employed in net-pay thickness and porosity mapping to exclude nonproductive clay-rich areas.

Fayetteville Shale porosity was calculated from density logs (Eq. 1) using standard matrix and fluid densities and calibrated using gas-filled core porosity for a subset of wells (n=40) provided by an operator (Fig. 1.4). The calibration factor ranges from 0.66 to 1.13, reflecting variation in volume of TOC, which lowers the density log reading. TOC was computed from the bulk density log using the Schmoker method (Schmoker and Hester, 1983). The average core water saturation is ~30 percent, and average core gas-filled porosity, 4.2 percent.

Marcellus petrophysical analysis included computation of porosity (Eq. 2) and TOC. Quality control was performed on digital gamma-ray (GR) and bulk density (RHOB) log curves. Gamma-ray logs were identified as cased or uncased at the depth of the intervals of interest. Bulk density log curve quality was assessed through the use of histograms and mapping of mean and standard deviation values. Subsets of wells for Marcellus porosity mapping (495 wells) and Hamilton Group porosity mapping (350 wells) were identified (Fig. 1.4). To compute TOC, uranium (U) content was estimated using an exponential function relating U to gamma-ray log (Fig. 1.5a). TOC was calibrated to U core data for wells sourced from NY ESOGIS and PA DCNR using a linear regression. Porosity (Φ) was computed from the bulk density log (ρB) using the TOC volume (TOC), density of TOC (ρ_{TOC}) derived from relation to thermal maturity values (R_o×0.342+0.972) (Guidry, 1994; Ward, 2010), and matrix density (ρ_{matrix}) of 2.71 g/cc:

$$\phi = \frac{\rho_{matrix} - \rho_B\left(\frac{\rho_{matrix}TOC}{\rho_{TOC}} - TOC + 1\right)}{\rho_{matrix} - \rho_{fluid}} \qquad (2)$$

Porosity distributions were compared to operator-provided Elan-derived total porosities for a subset of wells (Fig. 1.5b).

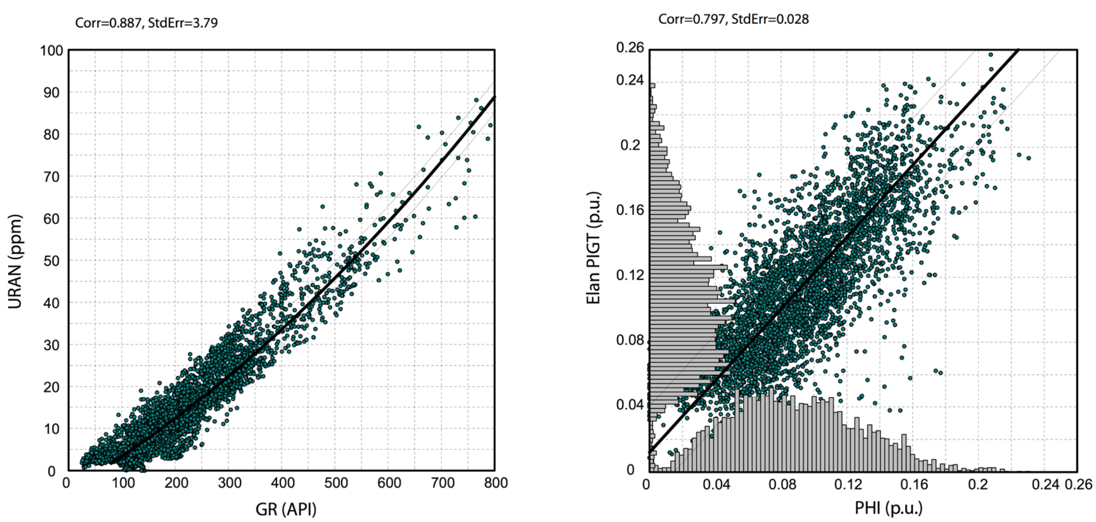


Figure 1.5 (a) 16 wells with spectral gamma ray, showing that gamma ray primarily reflects uranium. (b) Quality check of porosity values computed using Eq. 2 (PHI) and Elan-computed porosity values.

1.4 Geology and Petrophysics into 3D

The purpose of the 3D model creation in each play is to combine the results of the geologic interpretation with those of the petrophysical and engineering analysis into an integrated, three-dimensional geocellular model (Fig. 1.6) capable of yielding insights into both basinwide geology and detailed per-well production behavior. All knowledge of the geology, rock properties, drilling and well completions, and past-production performance were incorporated into a single basinwide 3D model for each of the shale basin studies. The role of the 3D model is to provide a more accurate description of the reservoir, thus minimizing the uncertainties associated with horizontal-well locations and classification of production-formation zones in relation to actual subsurface stratigraphy. Advances in performance and scalability of modern 3D geologic modeling software solutions, in combination with more powerful computing and visualization technology, have enabled us to build detailed models encompassing regional basins.

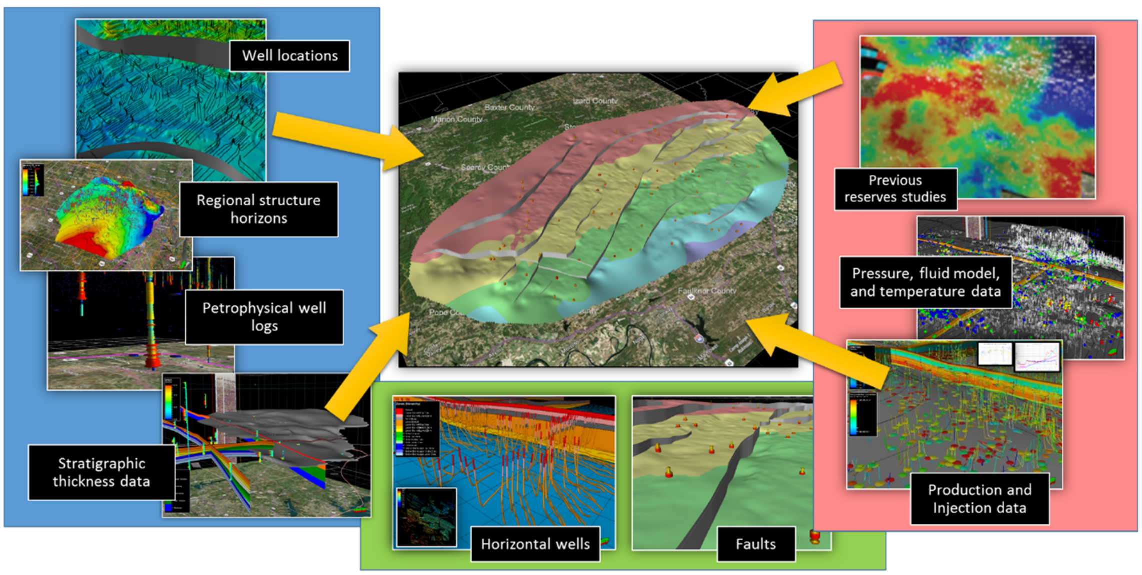


Figure 1.6 Example of data and interpretations integrated into a regional shale basin 3D geocellular model.

An important initial step in building the 3D models is to generate surface models of the stratigraphic horizons for the stratigraphic tops interpreted during the geology phase. The next step in structural-surface quality improvement involves a process known as *conformable mapping*. Conformable mapping starts with building a surface from well tops with the most numerous data distribution. This well-defined horizon functions as the control surface. The technique then transfers the shape of the control surface to a new horizon data set with fewer points, using an intermediate thickness-distribution grid, while honoring all well tops of the new surface. This conformable-mapping method was used to improve the accuracy for deeper surfaces in the shale basin study areas, where fewer well tops were available.

In the absence of 3D seismic data or interpretations, horizontal well position logs were used to calculate trend surfaces, which correct local stratigraphic strike-and-dip characteristics of the stratigraphic horizons, resulting in more accurate structural and stratigraphic frameworks utilized by the 3D model (Fig. 1.7). The resulting structural surfaces were then used to build a more accurate stratigraphic framework for the 3D geocellular model.

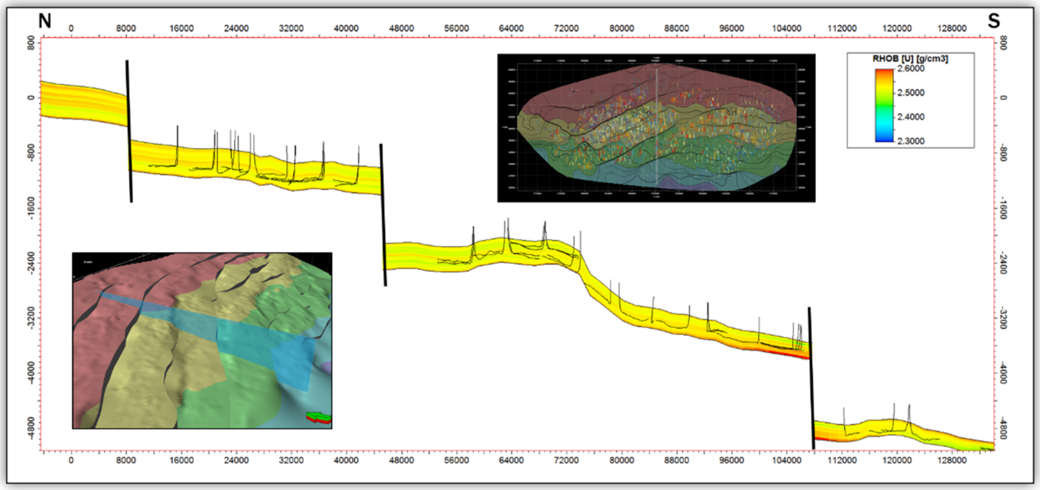


Figure 1.7 Example of structural and stratigraphic interpretations corrected using producing horizontal well trend analysis in the absence of available 3D seismic data.

Modeling horizontal wells in a 3D interpretation environment yielded the ability to analyze true spatial relationships between wells, providing better insight into field-development strategies used by various operators. This is especially important since this study shows how well interference for hydraulically fractured horizontal wells in shale basins is related to both lateral well spacing and vertical well positioning.

A recurring problem with operator-reported horizontal-well completion records is misclassification of the production-formation zone. Using well trajectories in conjunction with the 3D geocellular model enables us to reclassify the actual landing zone and producing formation more accurately for the horizontal wells, so as to assist in subsequent analysis of the production histories of these wells (Fig. 1.8).

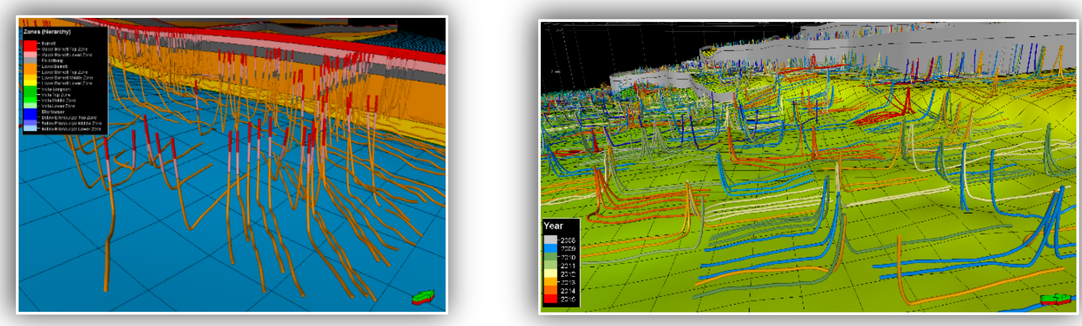


Figure 1.8 Image on left is a 3D representation of base of Lower Barnett zone showing well trajectories colored by formation in Barnett study area. Image on right shows Fayetteville horizontal producers colored by completion date.

Well-log curves were imported into the model using files in log ASCII standard (LAS) format. These files included both originally logged curves and calculated petrophysical curves. Well-log curves for wells are sampled at half-foot increments. Vertical thickness of individual layers in the 3D geocellular models is approximately 5 ft. Before the well-log curves can be distributed along the layers of the model, the multiple log-curve values that fall within the volume of a single geocellular cell are averaged into a single value, a process known as *upscaling* of log curves. Different petrophysical properties were upscaled using different vertical averaging techniques, ranging from thickness-weighted arithmetic averaging used for porosity to harmonic averaging used to upscale vertical permeability.

After application of these two surface-modeling quality-control methods, the resulting more detailed structural surfaces were then used to build a more accurate stratigraphic framework for the 3D geocellular model. The 3D models for the shale basins use structural horizons mapped with a lateral X and Y increment ranging from 500 to 750 ft and a vertical layer thickness of approximately 5 ft, resulting in total model sizes ranging between 300 million and 1 billion cells.

The upscaled well-log-curve attributes were then distributed along the layers of the model using the sequential Gaussian simulation (SGS) method (Fig. 1.9). SGS is used to simulate continuous variables such as petrophysical properties and well-log curves. Multiple equally probable realizations were run and post-processed to quantify the range of uncertainty for each geometrical, petrophysical, or fluid property. In its ability to reproduce the input data variance, as well as the spatial-correlation structure, of the attribute, SGS provides more realistic reservoir-attribute distributions than smoother, more deterministic-based techniques such as inverse-distance or co-kriging.

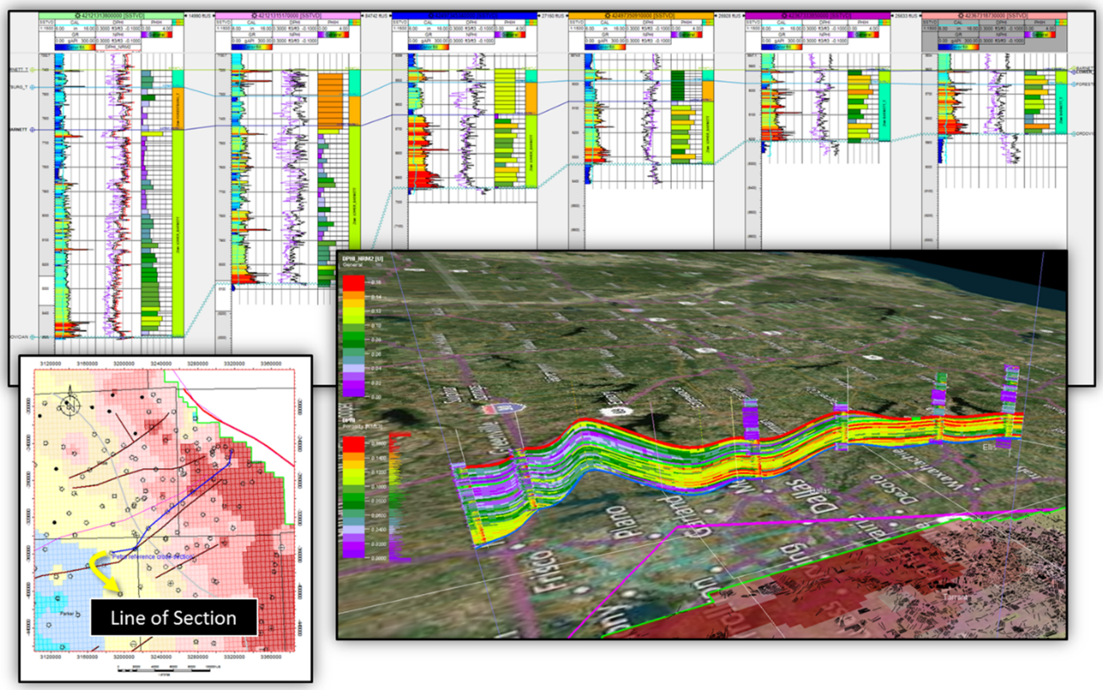


Figure 1.9 Cross section showing gamma-ray, density-porosity, and upscaled porosity thickness logs. Remaining images show line-of-section key map and 3D cross section indicating density- porosity log curves and 3D model distribution using sequential Gaussian simulation.

Landing zones for the wells targeting the producing shale interval were determined by calculating the intersection between well trajectories and the 3D model zones on a foot-by-foot basis to yield the most-abundant stratigraphic zone traversed by the horizontal wells. On average, we observed a 30 percent difference between landing zones reported by operators when compared to the landing zones determined using the 3D model.

Production-history data in the form of monthly oil, water, and gas production for all horizontal producing wells in the shale studies were imported in the 3D model, allowing for the visualization of production bubble maps and pie charts in both map and 3D views (Fig. 1.10).

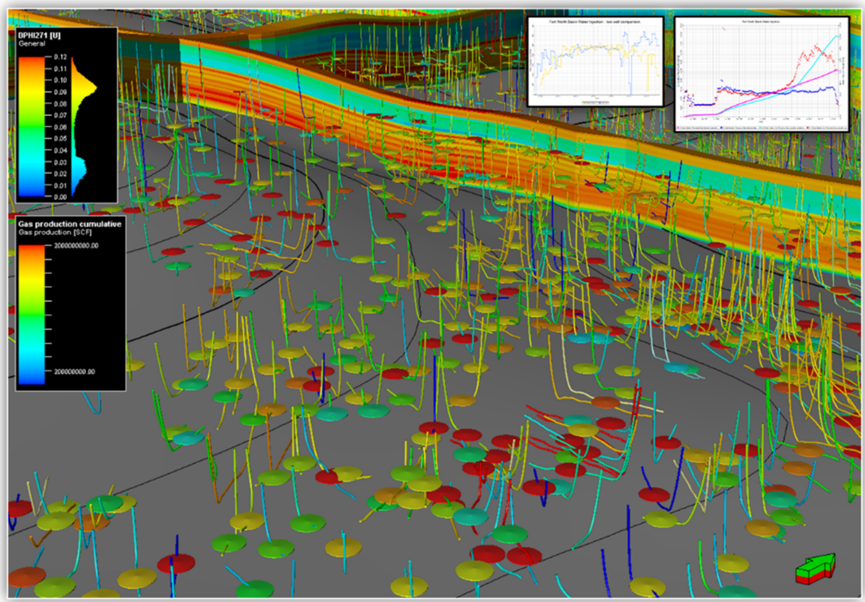


Figure 1.10 3D representation of Barnett horizontal-well producers showing cumulative-gas- production colored symbols. Color of well trajectory represents year in which well was drilled. Fence diagram in background shows a 3D distribution of density–porosity.

1.4.2 Model Capabilities and Outputs

The 3D geocellular models for the shale basins yield the following capabilities and output:

- High-resolution, basinwide, geologic stratigraphic framework based on correlated horizon surfaces
- Quality control and resolution of data inconsistencies for well headers, directional surveys, well logs, and producing-formation reporting
- Identification of contradictions in stratigraphic interpretations from different sources
- More accurately modeled stratigraphy to assist in engineering interpretation of horizontal-well landing zones and production intervals

- Distribution of petrophysical and fluid parameters, including original well logs, porosity, and gas and water saturation, using deterministic and geostatistical distribution techniques
- Calculation of vertical distances of well trajectories to their target zones as well as of distances between producing horizontal wells
- Time-based visualization of production-history data using 3D pie charts showing watercut , cumulative production, and estimated ultimate recovery values
- Individual well-trajectory cross sections showing well-bore locations relative to stratigraphic-zone interpretations
- Calculation of original oil- and gas-in-place volumes for the reservoir zones
- Export of zone, fluid, and petrophysical parameters to fluid-flow simulators

1.5 Results and Discussion

Geologic assessment of the four shale gas plays results in a comprehensive data set that includes formation tops for correlated wells; reservoir properties on a per-well, square-mile-block (2D mapping) and cell (3D geomodel) basis; shape files of important structural features; and maps of structure, thickness, and reservoir properties. Estimates of gas in place are calculated in both 2D and 3D and compared.

While 2D and 3D model-derived maps are based on the same formation top data set, the 3D model incorporates additional data such as horizontal well paths and faults. In the Barnett Shale, maps of depth to top of Ordovician (base of Barnett) show deepening toward the Ouachita Thrust Front and Red River Arch. However, the structure contours of the 3D model-derived surface are offset by faults, which cut the top of the Ordovician surface (Fig. 1.11).

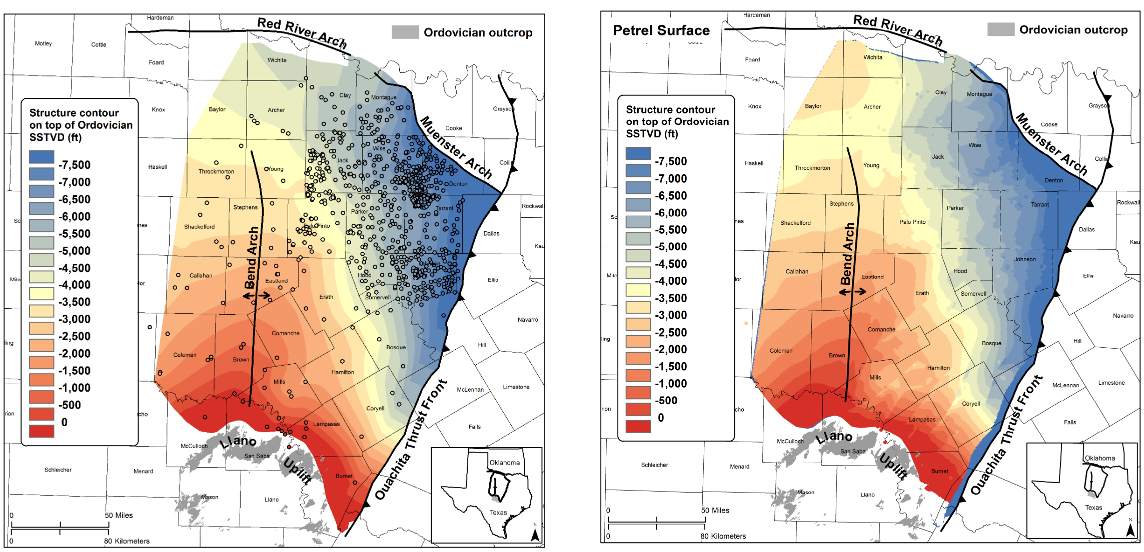


Figure 1.11 Comparison of structure on base of Barnett (top of Ordovician) based on (left) 2D mapping of vertical well-log data, and (right) incorporating faults in 3D geomodel.

Increased granularity is also observed in updated Haynesville Shale structure maps (Fig. 1.12), in which the 3D model-derived surface incorporates the trend of the horizontal well paths. By utilizing the directional surveys of the horizontal wells, in addition to the formation top depths based on vertical well-log data, the detailed structure of the formation is revealed. In particular, the horizontal well paths reveal the detailed structure around faults not observed by utilizing only vertical wells.

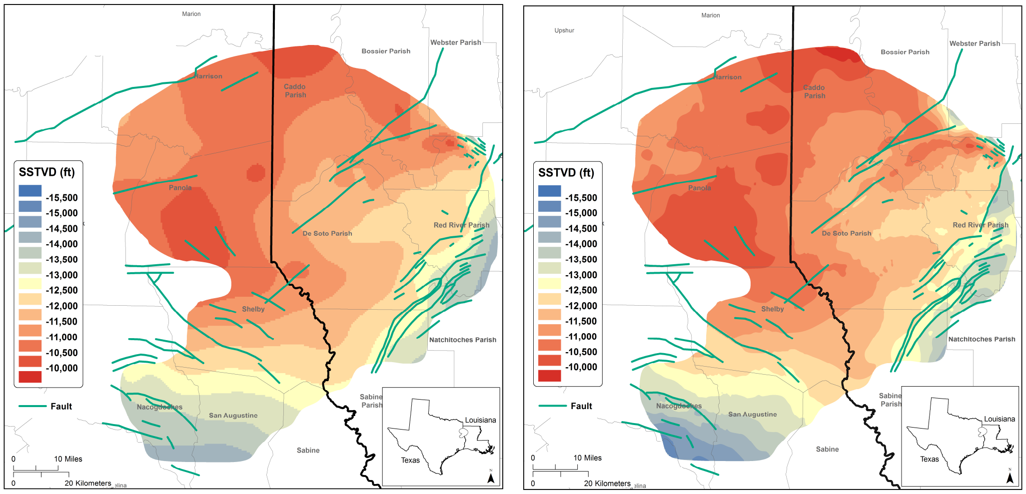


Figure 1.12 Comparison of structure on top of Haynesville Shale from (left) vertical well logs mapped in 2D, and (b) vertical well logs and horizontal well paths mapped in 3D.

Another method implemented to increase granularity is to include information such as location of outcrop in assessment. In the Marcellus Shale, a sharp change in dip associated with the Allegheny structural front cannot be captured with the resolution of vertical well- log placement, but by constraining the structural contours using outcrop data we are able to more accurately map the structure.

1.5.1 Gas-in-Place Estimates

Geologic and petrophysical characteristics of each play allow for updating our OGIP estimations. We used a volumetric approach to calculate OGIP in every given geomodel cell and then aggregated on a square-mile basis. The OGIP formula (Eq. 3) includes the porosity (ϕ), thickness (H), and water saturation (S_w) values and formation volume factors for gas (B_g) or oil (B_o):

$$OGIP = \frac{27878400 \times \phi\, H\, (1-S_w)}{5.615 \times B_g} \tag{3}$$

The original studies paid little attention to the liquids-producing regions, because low production of both natural gas and oil made those areas commercially unattractive. However, increase in oil and natural-gas liquids prices over time suggested that those areas could be developed. In the current update, we included areas producing oil and gas condensate in the Barnett and Marcellus plays, which attracted increasing attention as oil prices spiked in recent years.

In line with the proposal, we collected available data on well API gravity and gas-to-oil ratio to determine liquid type, enabling us to

- improve OGIP estimates, and
- add estimations of original liquids in place.

In both the Barnett and Marcellus plays, data on liquids indicate several fluid regions ranging from lean to rich condensate and, finally, light sweet oil. To study fluids one would have to develop fluid characterization models; however, the lack of data does not allow for such analysis. To overcome the limitations in data, we refer to our Eagle Ford play analysis (Gherabati et al., 2016).

Formation volume factors present a relationship between the volumes taken by a fluid vs. natural gas given pressure and temperature conditions. The amount of surface oil, condensate, and gas produced from a unit volume of reservoir fluid is the output of fluid modeling. Thus, to calculate liquids in place (LIP) to account for the part of hydrocarbon pore volume taken by the liquids, we apply the following approach:

$$LIP=(27878400\times(1-Sw)\varphi h)/(5.615\ Bo) \tag{4}$$

Oil-formation volume factor increases with the increase in specific gravity and gas-to-oil ratio (GOR), which vary geographically but are taken to be constant within a vertical interval. Solution GOR, typically used to classify fluid type, is difficult to measure because GOR in unconventional low-permeability reservoirs may change dramatically over a short period of time, with an initial quick pressure drop around the well once production starts. Liberated gas in the reservoir, which evolves after reservoir pressure drops below saturation pressure, flows more easily than oil and increases producing GOR. Therefore, we chose to rely on API gravity data, which is not a function of the difference between initial and reservoir pressure as an indicator for a well fluid type. Solution GOR and API gravity increase for lighter oil and are directly related. The relation changes from one shale play to another (Fig. 1.13).

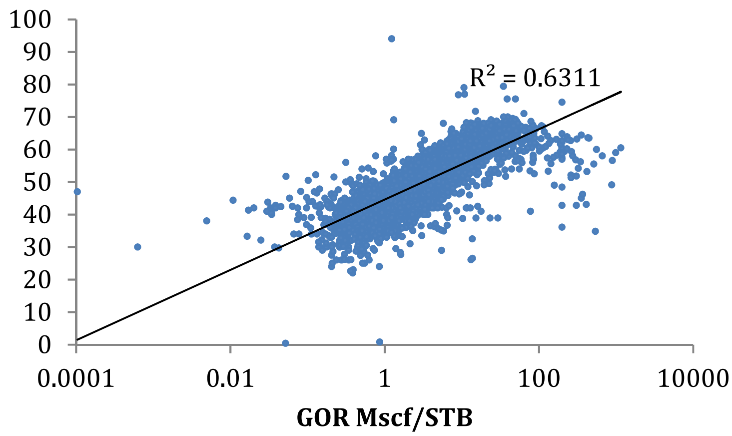


Figure 1.13 GOR and API gravity correlation in Eagle Ford play.

In the Barnett fluid analysis, the major difficulty was that a clear relationship between GOR and API gravity was not observed. Low reservoir pressure in the Barnett has liberated more gas and resulted in a high GOR across the play. Except for Montague County in the north, producing GOR is higher than 50,000 scf/STB in all liquid-producing areas (Fig. 1.14). Study of the relationship between API gravity and solution GOR in other shale plays shows that 40 to 50 degrees API is the API gravity of light oil and volatile oil. Such fluids have a solution GOR of 500 to 3000 scf/STB. However, based on the extracted PVT reports in Barnett, 40 to 50 degrees API gravity fluid produces between 10,000 to 100,000 scf/STB GOR.

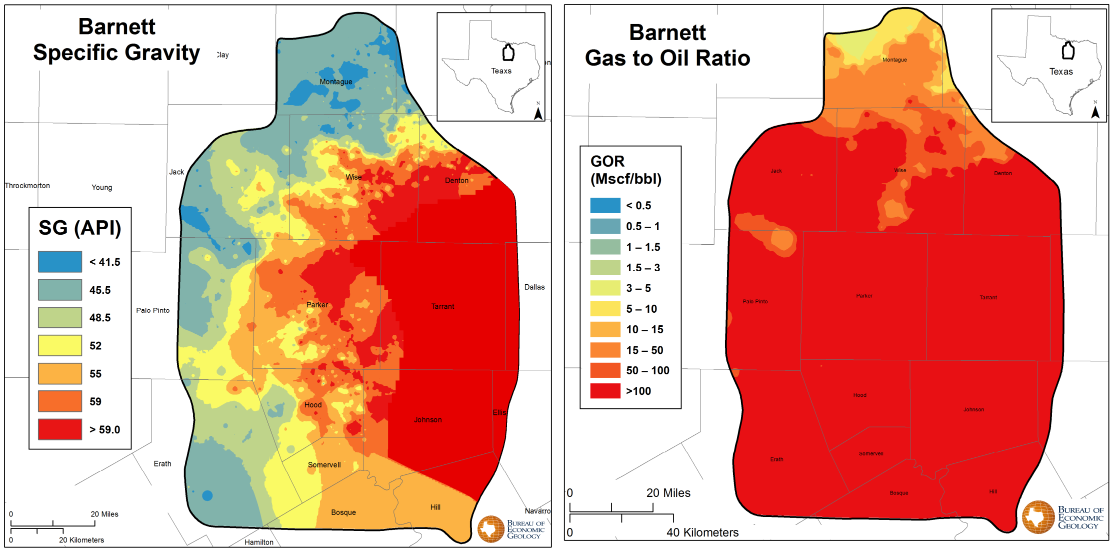


Figure 1.14 API gravity (left) and GOR (right) maps for the Barnett play used in fluids analysis.

We therefore conclude that GOR range doesn't represent a solution GOR of the reservoir fluid. Information about the saturation pressure and solution GOR of the Barnett fluid is very limited, which makes it difficult to estimate original oil and gas in place. Using Barnett high-producing GOR to specify reservoir fluid, which indicates the existence of lean condensate and dry gas, leads to underestimating the amount of liquid in place. Using API gravity, on the other hand, indicates the existence of oil and rich condensate in addition to lean condensate and dry gas. Because of high uncertainties in determining the nature of the reservoir fluid, we specify richer and leaner fluid properties for each point in the Barnett. Richer fluid properties use API gravity, which indicates the existence of large areas of volatile oil and rich condensate. Richer fluid properties have five regions: volatile oil, two rich condensates, lean condensate, and dry gas. The leaner fluid properties are based on the producing GOR map and have two regions: lean condensate and dry gas. Under those assumptions, we estimate liquids in place of ~ 90 billion barrels.

Presented to key operators in the play, the methodology was approved as an approximation. Without data on API gravity in the Marcellus play and similar challenges in relying on scarce GOR data, we could not assign fluid type and, therefore, do not provide LIP estimates. However, we did use GOR data in our decline analysis to approximate viscosity matching that derived for the Barnett play, which gave reasonable results. We also used GOR data in our economic analysis to assign expected fluids-related profits.

After liquids analysis in mixed plays and solely gas evaluation in others, we produce estimates of the total free gas in place (Table 1.1), as well as gas-in-place numbers that reflects the resource being accessed by current completions technology. In the Haynesville, for example, total gas in place does not reflect productivity; however, including only resource with clay content below a certain cutoff reflects current production trends (Fig. 1.15).

Table 1.1 Gas in place calculated for four shale gas plays

	OGIP^{free} (Tcf)		Adsorbed Gas (Tcf)
	Gross	**Net OGIP** *driving current production*	
Barnett	508		
Fayetteville	75		43
Haynesville	700	455	
Marcellus	1813	1448	414

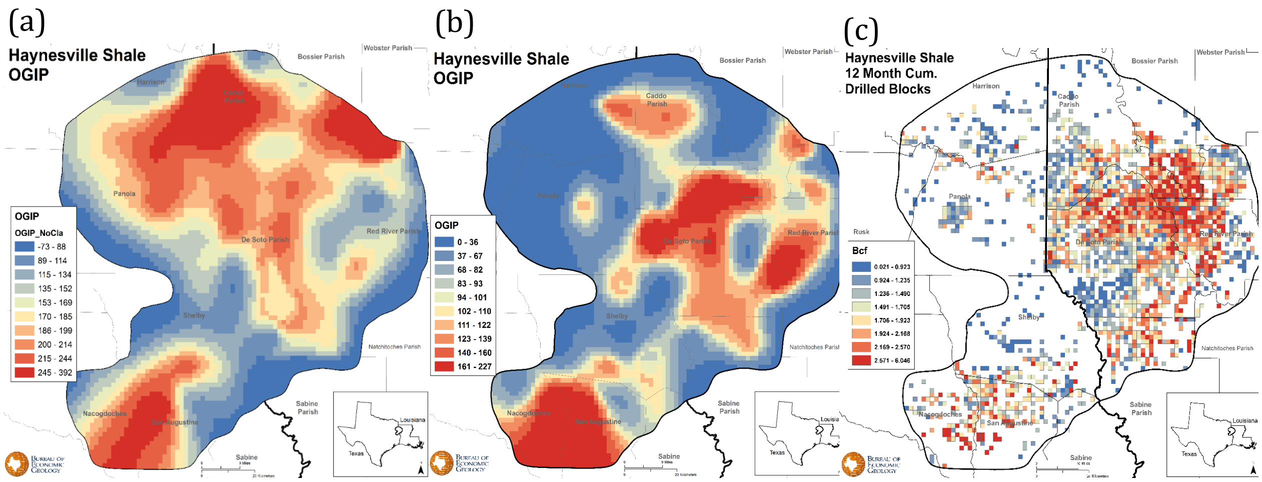


Figure 1.15 Haynesville Shale (a) total free gas in place, (b) gas in place calculated after application of cutoff excluding clay-rich zones, and (c) current 12-month cumulative production for drilled blocks.

Similar exercises were carried out in the Marcellus Shale based on TOC content (e.g., >2%) and in the Barnett Shale based on gamma-ray signature to exclude limestone-rich layers toward the Muenster Arch that do not significantly contribute to productivity. Estimating gas in place in the Marcellus is particularly complex, with multiple cases—e.g., Lower Marcellus only, Upper and Lower Marcellus combined (Fig. 1.16), Marcellus and Mahantango Group, and 300 ft from the base of Marcellus—required to calculate how much gas may be accessed by a single horizontal well.

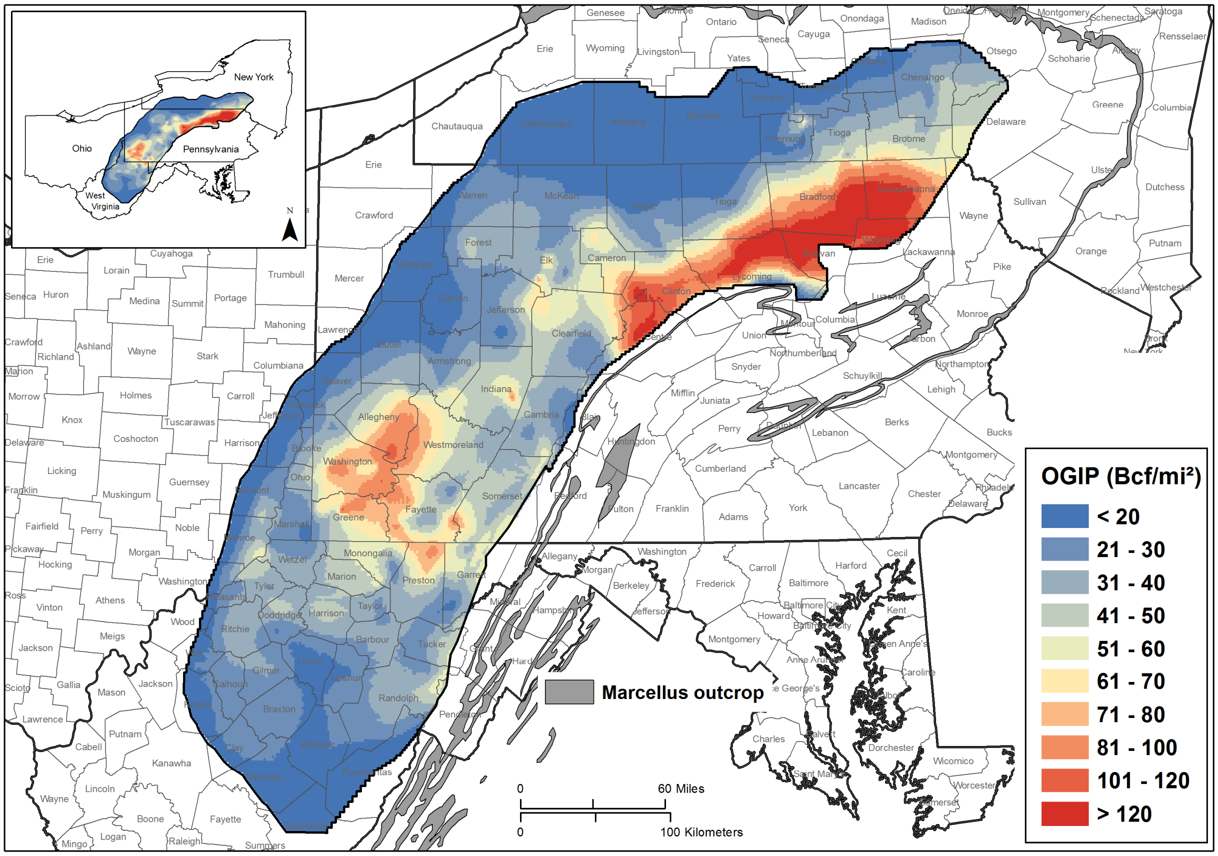


Figure 1.16 Marcellus Shale total free gas in place.

Chapter 2. Well Production-Decline Analysis

2.1 Overview

Estimation of resource in place, although helpful, lacks practical significance because most resources, and natural gas in particular, cannot be fully recovered. Therefore, the geologic characterization is complemented by the assessment of technically possible recovery. Such an estimate changes as technology changes and production techniques improve, so most assessments by definition are conservative, being based on past data. Production data from existing projects are used to determine the efficiency in recovery of the current technology. Based on that, estimations are done on how much resource can be extracted, assuming a similar approach to production.

The objective of the production analysis reviewed in this section is first to predict future production from existing individual wells and then to define production-decline profiles for potential future wells (Table 2.1). The former would allow estimation of technically recoverable resources for the drilled area. The latter would be coupled with results of the statistical analysis of productivity to determine expected per well recovery of potential future wells and, thus, future technically recoverable resources.

Table 2.1 Summary table for production-decline analysis

	N of wells analyzed	Estimated EUR, Tcf
Barnett	18,528	27.7
Fayetteville	5,825	10.7
Haynesville	3,560	15.2
Marcellus	10,394	52.7

The specified task is complicated by the fact that reservoir properties and, thus, decline profiles vary within each play and across the plays, raising numerous debates about which decline-analysis approach is the most appropriate. Studies also reveal that decline curves may change with different drilling and completion technologies applied (Griffin et al, 2013). The spatial and temporal variability in declines identified in the original Bureau study prevents us from deriving a single, e.g., average, production profile for any play, instead suggesting identification of a set of representative decline curves. Our goal is to investigate what determines the expected ultimate recovery beyond the physical flow model, e.g., how a decline curve may change as a function of technology, completion design, or related parameters. The answer to that question may play an important role in the discussion of economic value of production under different technology and price assumptions.

This more in-depth analysis reveals several very important factors that we attempt to take into account, but uncertainty could be decreased further were more accurate data available. First, taking into account natural gas liquids and co-produced oil and water is important for the decline analysis. Yet most states do not provide accurate data for these items, forcing us to make approximations and assumptions. Second, pressure data are still very scarce, again making our predictions in some cases less accurate. We also find it hard to make good estimates of adsorption, though improvements in petrophysical analysis and core data help that discussion.

Finally, the presented analysis reveals a challenge in understanding decline of younger wells as bottlenecks in the infrastructure induce producers to choke the wells; thus, a true decline has not been seen in a number of wells. The fraction of these wells is greatest in the most important high-production play, the Marcellus.

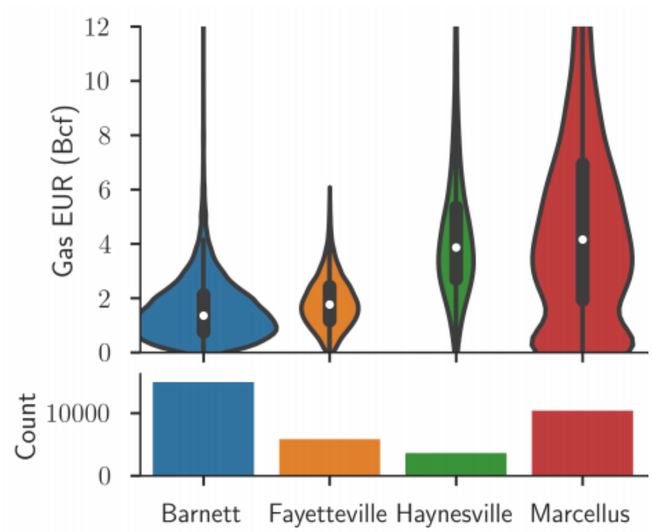


Figure 2.1 Summary statistics on estimated ultimate recovery (EUR) for horizontal wells drilled in the four shale gas plays between 2005 and 2016 and used in the study.

In summary, we estimate production from about 38,000 gas wells (of which about 35,000 are horizontal). Although for our analysis we can use only wells with at least 12 months of production history, we find that, overall, we can rank the plays: Haynesville and Marcellus exhibit the highest per-well and per-foot production (Fig. 2.1). Those plays benefit from higher pressures and higher resource in place in the areas that have received most of the drilling attention to date.

We estimated about 106 Tcf of natural gas expected to be recovered by wells drilled through the end of 2016, which is about 3 percent of total in place. However, the highest average per total acreage drilled is only about 30 percent—in the Fayetteville play, which benefited from natural fractures, adsorbed gas, and advanced drilling techniques. With the majority of the best acreage drilled, the per-play recovery factor is expected only to decrease unless significant improvements in technology are shown. To evaluate these wells, we may still need better data resolution.

2.2 Data

As in the proposal, this analysis starts with an update of well production-history data used in the previous analysis and includes new wells drilled since the previous study. In our current analysis, similar to the past analysis, we rely on the IHS database for production, completion, and well directional survey data. Differences in drilling dynamics led to uneven expansion of well databases:

fewer wells were added to older and more drilled-out plays like Barnett and Fayetteville or to those more expensive to drill, like Haynesville. The greatest increase in the number of wells was for the Marcellus play, where the number of wells almost doubled. (Marcellus data has also improved recently: since 2015, Pennsylvania requires a monthly report of production, as compared to previously required bi-annual production reports.)

The database includes all existing wells, but the decline analysis was performed only on wells that have at least 12 months of production history. Decline analysis includes a forecast of natural gas, liquids, and water production out to a 25-year lifetime.

To improve the decline analysis, characteristics relevant to the reservoir have been extracted from the updated geologic analysis presented in the previous chapter. All existing wells in each play in the scope of our study were assigned based on their location attributes, which are essential in production-decline analysis. The list of attributes used in our analysis of estimated ultimate recovery includes the following:

- Estimates of resource in place
- Fluid properties, such as GOR and API gravity, serving as a proxy for viscosity (used only in Barnett and Marcellus plays in liquid-producing areas)
- Water saturation and water cut
- Pressure and porosity, used also to approximate adsorbed gas

Note that the only wells included in the analysis are those that fall into the established play boundaries and belong to the appropriate vertical interval. We identified some wells originally incorrectly assigned to Barnett, Haynesville, or Marcellus formations based on our updated stratigraphic interpretations and 3D modeling, and given the directional survey data reported for the horizontal legs of the wells. The locations for future wells have also been assigned a similar set of attributes, used in the analysis to form expectations about potential well decline.

2.3 Methodology

This part of our analysis consists of two major tasks: (1) Testing how accurately we predicted the estimated ultimate recovery (EUR) of wells in the original study and, with that, discussing uncertainties involved in the decline analysis; and (2) developing an improved model to analyze production from wells drilled in the Barnett, Fayetteville, Haynesville, and Marcellus plays. The original decline approach employed to calculate EUR for the shale gas wells was based on the physical flow model developed by Patzek et al. (2013). The model suggested the procedure to identify and predict decline for wells in boundary-dominated flow (BDF), but with no formal suggestions on how to estimate expected time to BDF for noninterfering wells, leading to debate on how to assign EURs to a large population of younger wells having not yet reached BDF. We thus faced difficulty analyzing productivity of the younger wells and new developments in technology—detrimental for the production outlook analysis because of the bias to underestimations.

Another issue with the original approach was its focus solely on natural gas production, with little attention paid to either the effect of adsorption and variation in fluid properties or production of liquids and water. The later was found to be particularly important in the analysis of the Barnett and Marcellus wells from liquid-rich regions.

To address past limitations, an updated approach was developed that offers several methodological improvements to help understand the effects of various rock properties and explore impact from drilling and completion practices.

The steps of the production-decline analysis were as follows:

1. Rebuild physical model representing production as a rectilinear flow with boundary conditions having geologic attribute inputs (Male et al., 2016).
2. Add a flow parameter capturing compressibility effects (diffusivity affected by pressure).
3. Update fitting procedure (allowing processing of thousands of wells per minute) to find whether a well is in BDF, or interfering.
4. Provide stimulated rock volume (SRV) and terminal decline rate as outputs per well (Male et al., 2015).
5. Separate wells in BDF from noninterfering wells to perform statistical analysis of variability in production decline beyond that geologically suggested, to test how completion parameters may explain residual error.
6. Apply statistically suggested variations in decline profiles (from what would be expected based purely on the physical model) to suggest time to BDF in noninterfering wells.
7. Perform hindcasting (hiding the last 6, 12, and 24 months of production) to test the robustness of predictions and thereafter check the deviation of new estimations from the original estimations by the Bureau team.
8. Detect wells with production errors, for further uncertainty analysis.
9. Use the physical model–based declines with suggested completion-driven deviations to estimate production-decline profiles for locations left for future drilling.

We model how production-decline curves change with fluid properties and spacing between wells by enhancing the physical flow model and using parameters for fluid viscosity and SRV.

Under rectilinear flow assumption we apply Darcy's law using pseudo-gas pressure (m) with pressure diffusion through porous media (see Male et al., 2016, for further technical details):

$$\frac{\partial \tilde{m}}{\partial \tilde{t}} = \frac{\alpha}{\alpha_i} \tilde{\nabla}^2 \tilde{m} \tag{5}$$

where α is the diffusivity, and α_i is at initial reservoir conditions.

$$\alpha = \frac{k}{(S_g \phi + (1-\phi) K_a)\mu c} \tag{6}$$

S_g :	gas saturation	μ :	viscosity
c :	isothermal compressibility	k :	rock permeability
ϕ :	rock porosity	K_a :	desorbing gas

We determine time to boundary dominated flow gas in place through:

$$\tau = \text{Time to BDF} \quad = \frac{(\text{interfracture distance})^2}{\text{reservoir diffusivity}} \quad = \frac{d^2}{\alpha_i} \tag{7}$$

$\tilde{t} = t/\tau$ is dimensionless time. At $\tilde{t} \approx 0.6$, production deviates from square root time and begins to transition to exponential decline.

$$\begin{aligned}\mathcal{M} &= \text{Original gas in the Stimulated Reservoir Volume (SRV)} \\ &= \underbrace{(N+1)4LHd}_{\text{size of SRV}} \left[\underbrace{\phi S_g \rho_g}_{\text{free gas}} + \underbrace{(1-\phi)\rho_a}_{\text{adsorbed gas}} \right]_{p_i}\end{aligned} \tag{8}$$

Using Fortran and Python, the developed procedure to fit the entire collection of wells allows discovery of exit decline rates for all individual interfering wells, as well as using scaling to compare the curves to reveal irregulaties (Fig. 2.2).

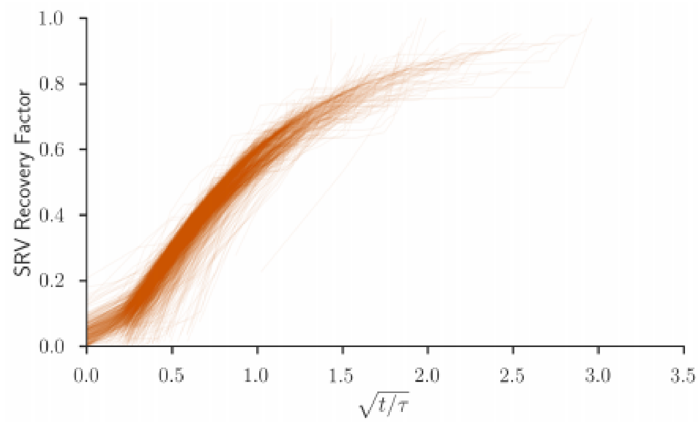


Figure 2.2 Individual well production-decline data for Marcellus wells that have experienced interfracture interference.

Next, in case of the presence of adsorbed gas, we use data on Langmuir isotherms to help us explain changes in production decline in the later lifetime of the well (Fig. 2.3). The effect of adsorption was particularly important in the analysis of the Fayetteville and Marcellus wells. We also tried to take some adsorption into consideration while analyzing the Barnett wells.

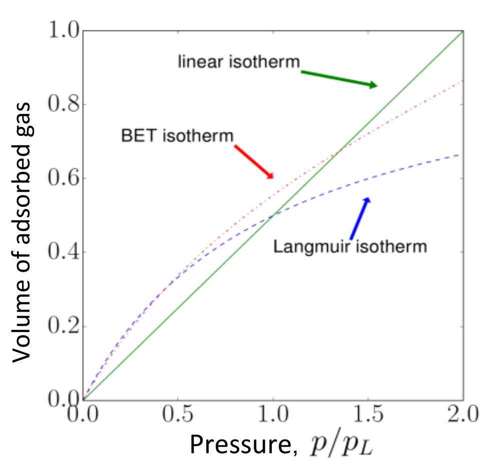


Figure 2.3 Types of adsorbtion isotherms with Langmuir isotherm used in the presented calculations.

In addition to those for the Barnett and Marcellus, we also produce estimations taking into account API gravity and fluid properties (Fig. 2.4). Results suggest that in the presence of other liquids, production of natural gas declines more quickly.

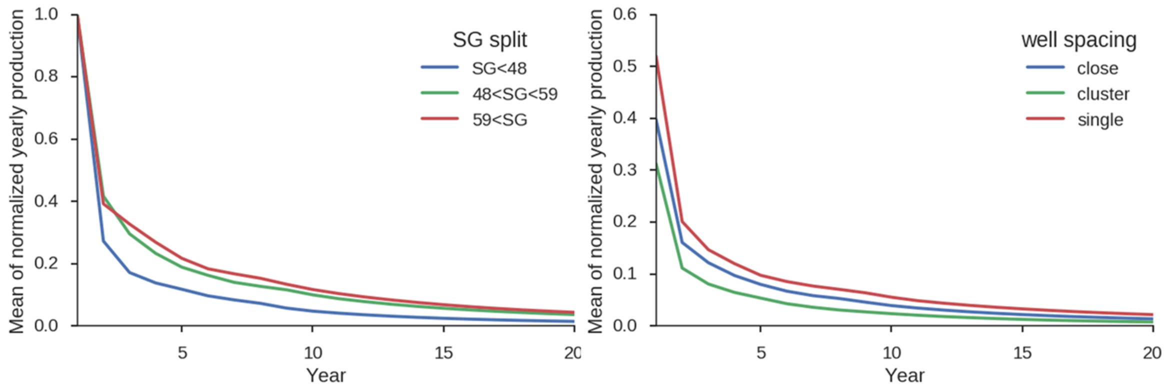


Figure 2.4 Changes in normalized decline profiles of the Barnett wells depending on fluid composition of production and well spacing.

In the original analysis, we treated all wells as dry gas wells that decline identically. We did not look at the differences in decline and initial productivity for close-spaced and cluster-drilled wells. Observations of high variation in well spacing (proximity of lateral legs to each other) led us to the development of a procedure to assign each well a drilling type based on well completion, with respect to the date of completion of offsetting wells and the distance between lateral legs of adjacent wells.

As of 2008–2009, about 75 percent of the developable locations in the high-producing dry gas region have been drilled. To cope with low prices and extend the life of their good acreage, producers turned to experimenting with well spacing and completion design. Over time, an increasing percentage of wells drilled were close-spaced (<400 ft spacing), infill, and cluster wells (Fig. 2.5).

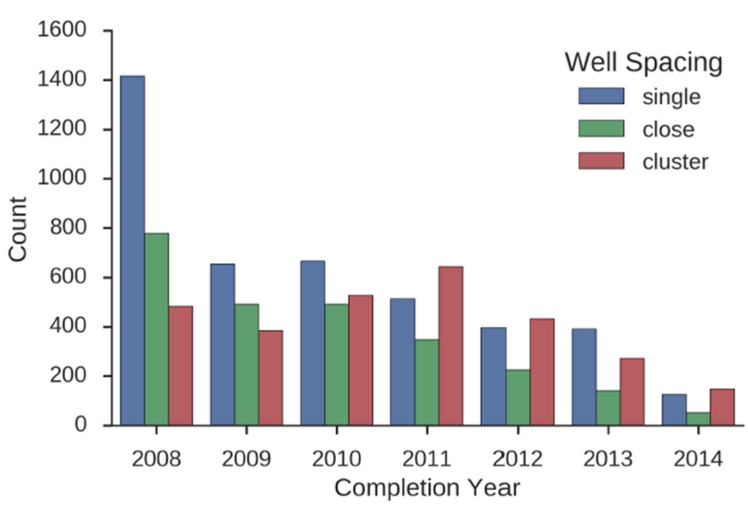


Figure 2.5 Changes in frequency of different drilling patterns for the Barnett horizontal wells.

The derived indicator for whether any given well is drilled as close-spaced, cluster, infill, or single/stand-alone allows classification of wells with respect to spacing and investigation of the link between decline and drilling pattern. The observed bimodal and, in some cases, tri-modal shapes of the EUR distribution suggested that we should look further for potential reasons for these shapes (Fig. 2.6). When splitting the mixture distributions and analysis properties of wells, we found that the reason for the phenomenon lies in completion and drilling strategies.[1]

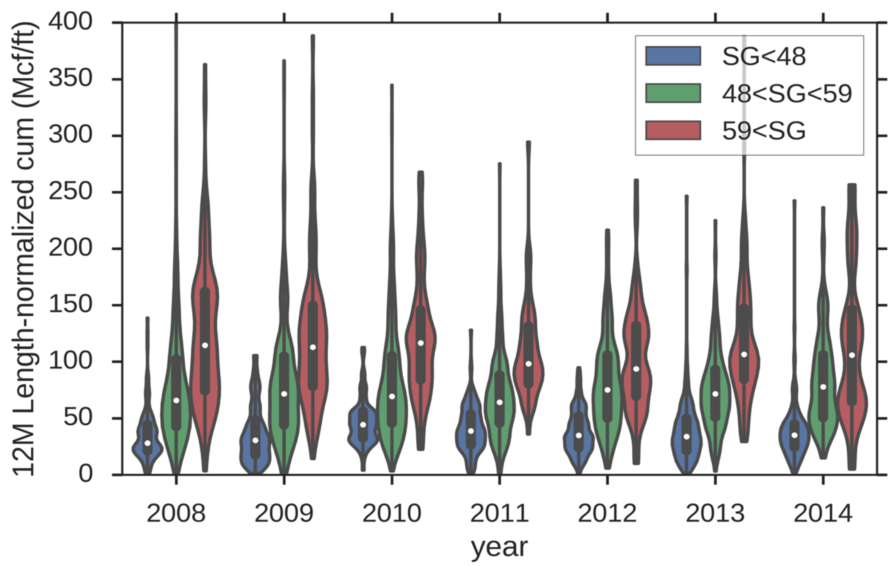


Figure 2.6 Changes in the normalized first year production of natural gas over time and across different fluid regions.

Finalized models combining all listed features were used to assign expected EUR to all wells in our database. With these models, we were able to proceed with the hindcasting exercise (Fig. 2.7), where we look at both well-by-well comparison and a change in the distribution of the previous run results versus the new ones.

[1] Because production behavior and completion inputs, such as treatment fluid and proppant volume, were found to be statistically similar for infill and cluster wells, we refer to them all as *cluster*.

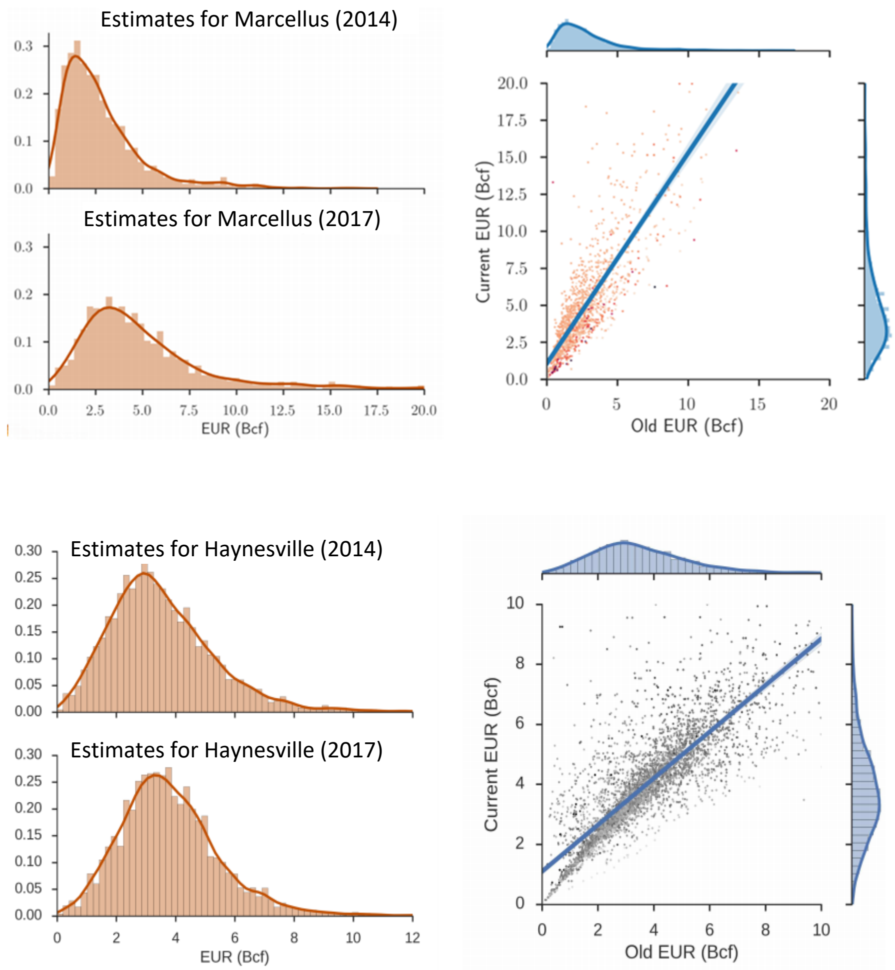


Figure 2.7 Comparison of previous study EUR estimations vs. results from the updated decline analysis for the Marcellus (upper) and Haynesville (lower) wells.

We conclude with several observations. First, we find that our estimations were more accurate for plays with 90–95 percent of wells being older than 24 months, namely Barnett and Fayetteville, where over 75 percent of wells had change in their EURs of less than 10 percent. Apart from this statistic, in the abovementioned plays, per-well EURs are smaller in absolute values and, thus, the uncertainty can be called small. Younger plays and higher-producing wells, which may also have a larger fraction of wells choked in their early lifetime, suggested higher uncertainty and variability. Thus, results presented for the Marcellus play show that some wells have reassigned EURs increased by 30 percent. We believe that with higher-resolution (e.g., daily) data and important information such as pressure availability, our analysis would have better accuracy.

Our analysis outside this study also suggests that further improvements in EUR analysis could be made if physical modeling were combined with numerical reservoir simulations, which in turn could benefit greatly from our 3D modeling effort.

Chapter 3. Statistical Productivity Analysis

3.1 Overview and Questions

With hydraulic fracturing and horizontal drilling responsible for the current U.S. abundance of natural gas and tight oil, technology was and is the most important driver of shale industry development. Improvements in technological capabilities and efficiency in extracting natural gas from shale formations have become even more important in the current low natural gas environment as producers continue to exhaust their best locations and move to less attractive areas in terms of resource in place. However, the original Bureau study showed that the relationship between production (recovery factor) and reservoir properties (such as porosity, thickness, pressure) is not straightforward. Other factors such as completion design (treatment fluid and proppant volumes, lateral length, spacing), well landing, and drilling patterns also matter.

Moreover, owing to energy price uncertainties, the ability to control costs while experimenting with technologies to enhance recovery is of utmost importance, especially in a capital funding environment that is more disciplined than in the formerly more consolidated industry. A strong component of the Bureau's future research on shale economics focuses on understanding the delicate balance between capital markets and their return expectations, the robustness of returns to energy price volatility, and technological advances with cost control.

This chapter reviews the statistical analysis of individual well productivity we performed to improve our understanding of (1) the drivers of spatial and temporal production heterogeneity; and (2) the relationship between rock properties, well-completion design details, time (proxy for unobservable technological changes), and well-production performance.

The goal of the statistical analysis is to update our productivity model to estimate the performance of potential wells and to explore the uncertainty related to the choice of input factors. We originally developed the production model in 2012 and continuously improved it as we expanded our analysis to other plays, accumulated more data, and improved our understanding through more sophisticated methodologies such as geocellular modeling. The intended result of this analysis is the ability to map expected individual production in each square mile of each play depending on technology assumptions. Such a map will be utilized in the next step of the production-outlook analysis, when we assess well economics in order to determine locations likely to be drilled and calculate technically recoverable resources (TRR).

Some by-products of our analysis that are especially worth mentioning include

- testing the sensitivity of TRR to uncertainty in data, which is particularly valuable in discussions about the value of new, more accurate, and/or higher-resolution data and information; and
- verifying the validity of our geologic and petrophysical analysis, which is beneficial in light of the unsuitability of some conventional resource-assessment metrics and practices in the analysis of unconventional reservoirs. Questions include whether the standard logs are sensitive enough to correctly measure porosity and whether we understand water saturation.

In this study, we tested parametric and nonparametric statistical models and compared their performance based on the generalizability of functional relationships, robustness of performance, and tractability of results. The latter was a particular challenge, given the number of attributes and the scope of each study with respect to time and geography.

The key findings of our statistical analysis can be summarized as follows.

- Evidence for multidimensional heterogeneity for each play suggests that using a single model to describe the productivity relationship in the entire play would be suboptimal.
- Application of advanced statistical techniques, such as model-based recursive partitioning and random forest, helps to capture and account for heterogeneity in the data.
- It is possible to derive functional relationships between well performance and a set of geologic and technical attributes for use in the well economics analysis.
- Nonparametric machine-learning methods, however, appear to provide more-accurate predictions in areas with better data coverage.

Based on our statistical analysis, the calculated aggregate TRR for the four plays increased by about 20 percent; the Barnett play was the oldest shale gas play. The key driver for improvements in statistics for all four plays is the contribution from the formations above the Marcellus; substantial changes in the Barnett assessment were driven by the capability to drill stacked wells and thus extract resources previously considered nonproducible.

3.2 Data

Our analysis was built on the study of geologic attributes including porosity, water saturation, thickness, pressure, and API gravity (in the Barnett and some areas of the Marcellus plays), complemented by IHS data on well locations (X, Y, Z); length of lateral or horizontal leg; and completion details such as volume of treatment fluid and proppant used for hydraulic fracturing and year of completion. We use different time resolutions, testing months, quarters, and years. In addition, the complete database includes the identity of the drilling and current operator to test for missing variables. We again used the variable specifying the type of drilling pattern, which appeared to matter in the Barnett and Fayetteville studies (Figs. 3.1, 3.2). Our database on multiple plays throughout their lifetimes equipped us to proceed with the analysis of productivity in shales, hailed as the one of most comprehensive publicly available studies (Montgomery and O'Sullivan, 2017).

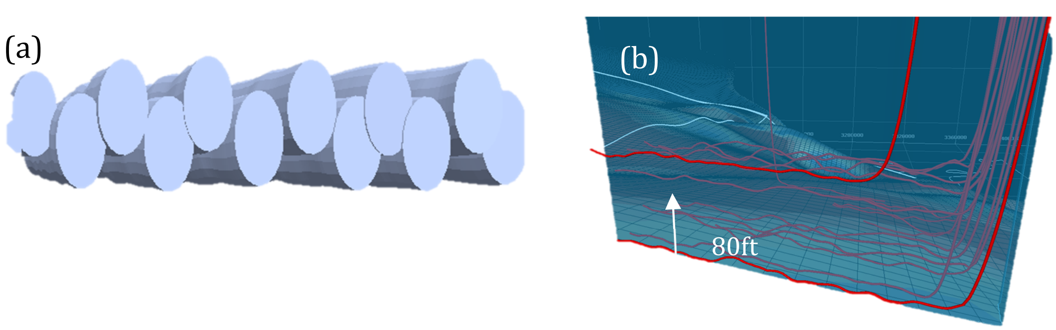


Figure 3.1 Extracts from Barnett 3D model: (a) Drilling patterns for horizontal wells with 200-ft-radius buffers; (b) side view on drilling paths of stacked wells.

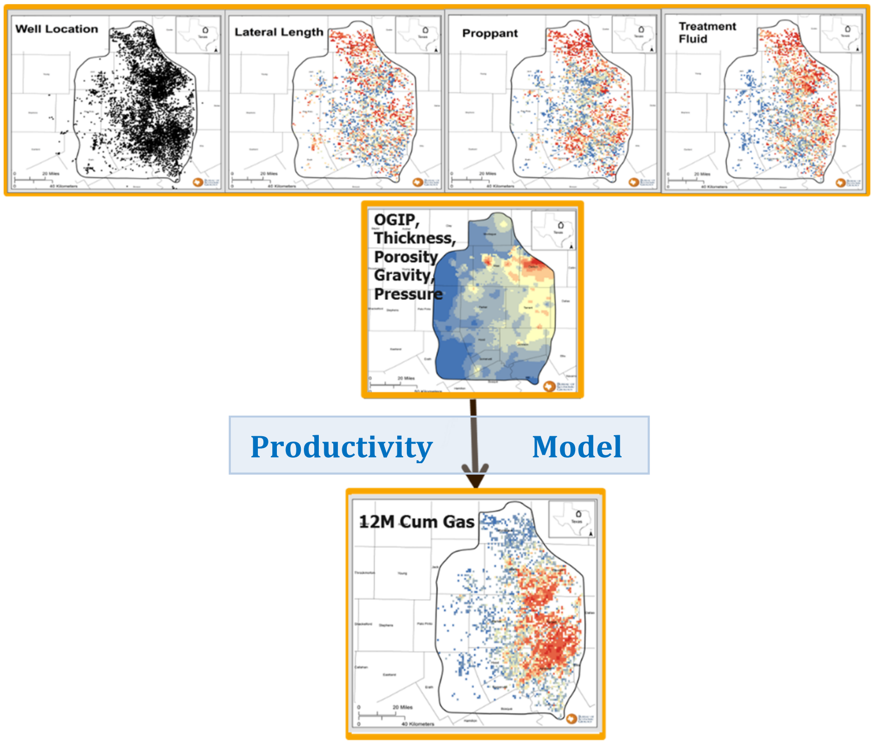


Figure 3.2 Schematic representation of data set used in statistical analysis of per-well production in the original Bureau study and complemented in the current study by well spacing and drilling pattern marker.

3.3 Methodology

For the statistical analysis we selected two models: model-based recursive partitioning (MBRP), which is a parametric model, and random forest (RF), which is a nonparametric model. The advantages of the first model are (1) the possibility of testing for and using a functional form, (2) the ability to detect and capture potentially important properties such as diminishing returns of the production on input factors, and 3) tractability of results and parameters. We choose a Cobb–Douglas functional form that allows for linearization and explicit analysis of marginal productivity of the input factors of production. More specifically:

$$12mCum \sim A(t) \cdot ORIP^{a} \cdot TF^{b} \cdot PP^{c} \cdot LL^{d} \tag{9}$$

The dependent variable, the first 12 months of cumulative production, is defined to depend on technology factor (A) that changes with time, original resource in place (ORIP), treatment fluid (TF), volume of proppant (PP), and lateral length (LL). In the course of the analysis we tested both ORIP and a set of its components as independent variables. The production function expression can be readily interpreted and used in economic analysis.

One of the advantages of model-based recursive partitioning over standard regression techniques is the former's ability to account for heterogeneity in the data via a user-specified set of splitting variables to divide the data into groups. A production function is assigned to each group. The model provides flexibility in capturing spatial geologic trends, when the splitting variables include geologic attributes, e.g., API gravity (Fig. 3.3). Each region is assigned a unique production function. In addition, if a temporal dimension is added to the set of splitting variables, such a map of regions may change over time and allow for detection of technological shifts.

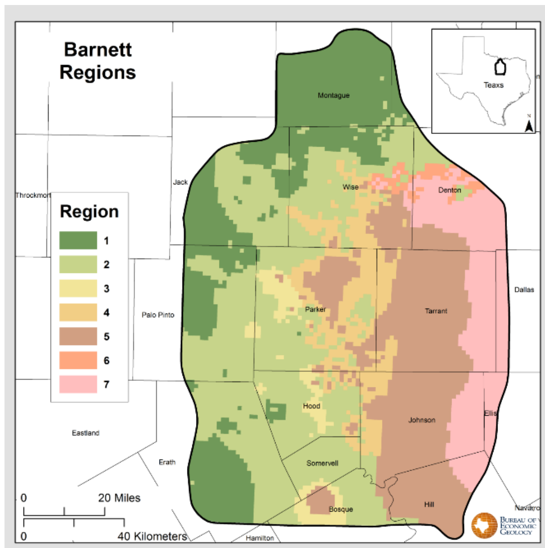


Figure 3.3 Map showing geographic extent of production-function regions for the Barnett play, with splits based on oil gravity, thickness, formation depth, and time as suggested by MBRP model.

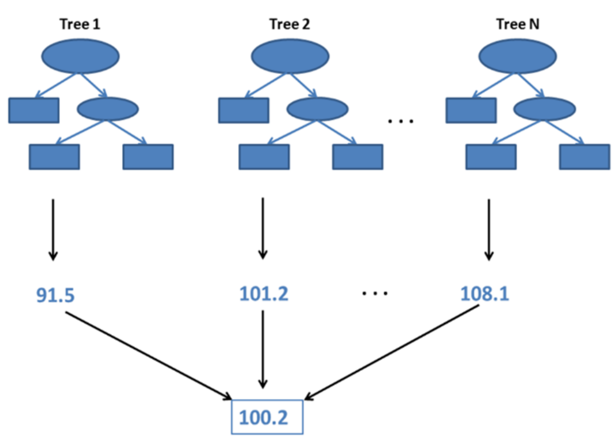


Figure 3.4 Example of forest consisting of individual-run trees resulting from RF model.

The MBRP is a binary tree algorithm that provides one tree and a set of functions calibrated for the split groups of data. The alternative model tested, RF, does not require a pre-specified set of splitting variables, regression variables, or functional form relating productivity to geology and operator completion practices. RF-like algorithms suggest variables for splits producing multiple trees, averaging the final result based on the given criteria (Fig. 3.4). Such approaches are known to decrease variance and allow for bootstrapping of the sample with replacement for testing the reliability of predictions.

In our analysis we compare results from both models to assess performance (Fig. 3.5). Our results suggest that maps built based on MBRP models exhibit less gradation in values. Moreover, the model-based recursive-partitioning algorithm provides functional relationships that can be extended beyond the range of the observed data when predicting new observations. The RF algorithm tends to perform better when the new observations fall within the range of the observed ones used to train the algorithm.

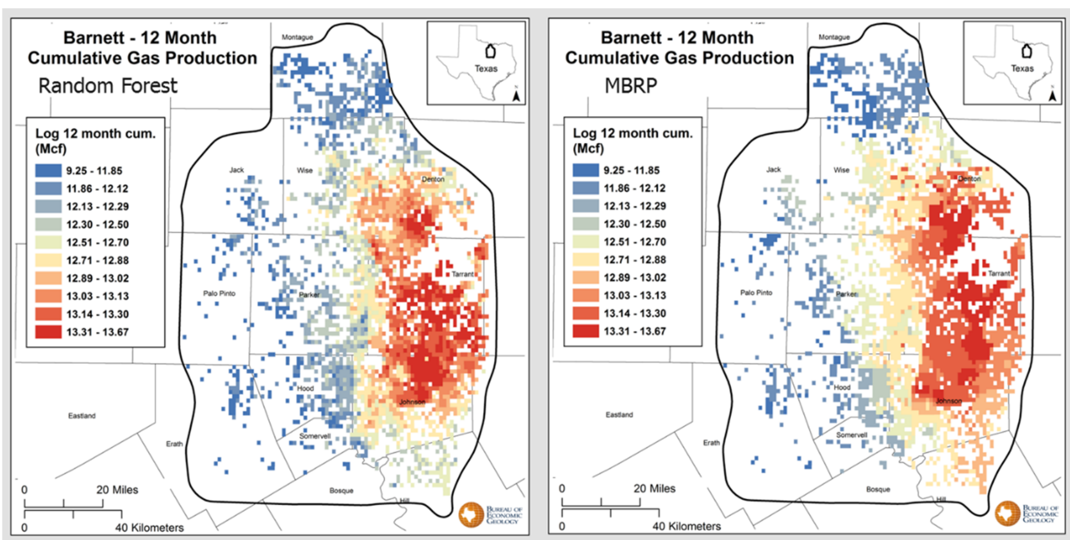


Figure 3.5 Comparison of RF and MBRP model projections of 12-month cumulative production of natural gas for all drilling blocks in the Barnett play, assuming for all wells a lateral length of 4,500 ft, and TF and PP of about 5,000,000 gallons and pounds, respectively.

In addition to testing the differences in predictions, we are particularly interested in examining whether the models can differentiate technological innovations such as changes in drilling patterns. Both models appear to be sensitive to the patterns, along with the completion choice, showing finer variations (Fig. 3.6).

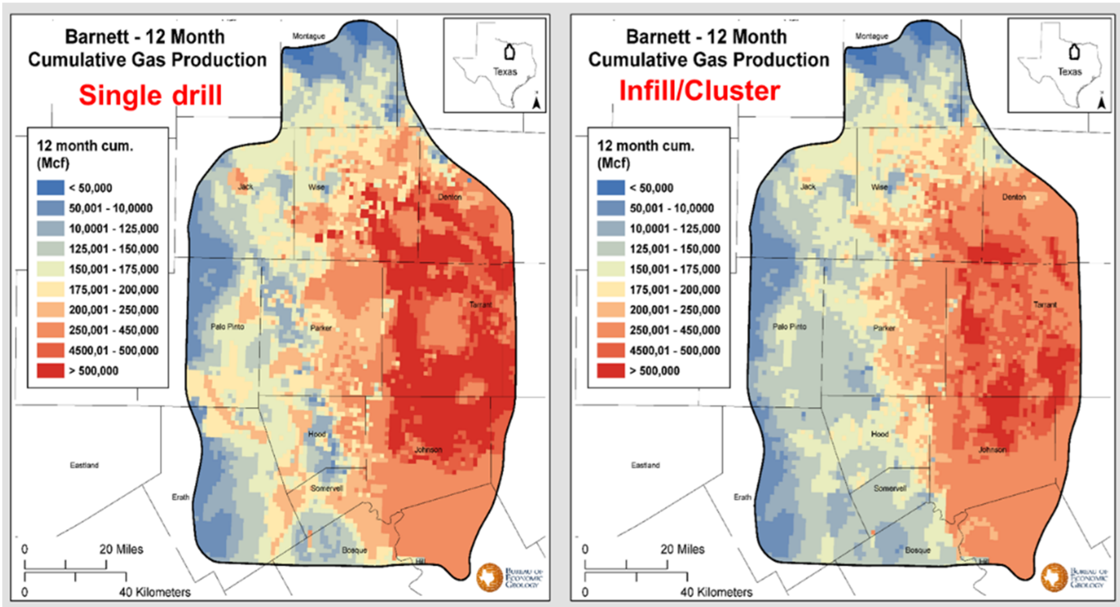


Figure 3.6 Maps with RF model projections for 12-month cumulative production for each square-mile block of the Barnett play, using the completion details prevailing in a given region in 2016.

Because of the temporal structure of productivity and operator-completion practice data (Fig. 3.7), we tested the ability of our models to predict productivity via forward validation. In particular, we constructed our training data with wells older than the wells included in our test set. Doing so allowed us to preserve the temporal structure of the data and to generate forward-looking productivity predictions.

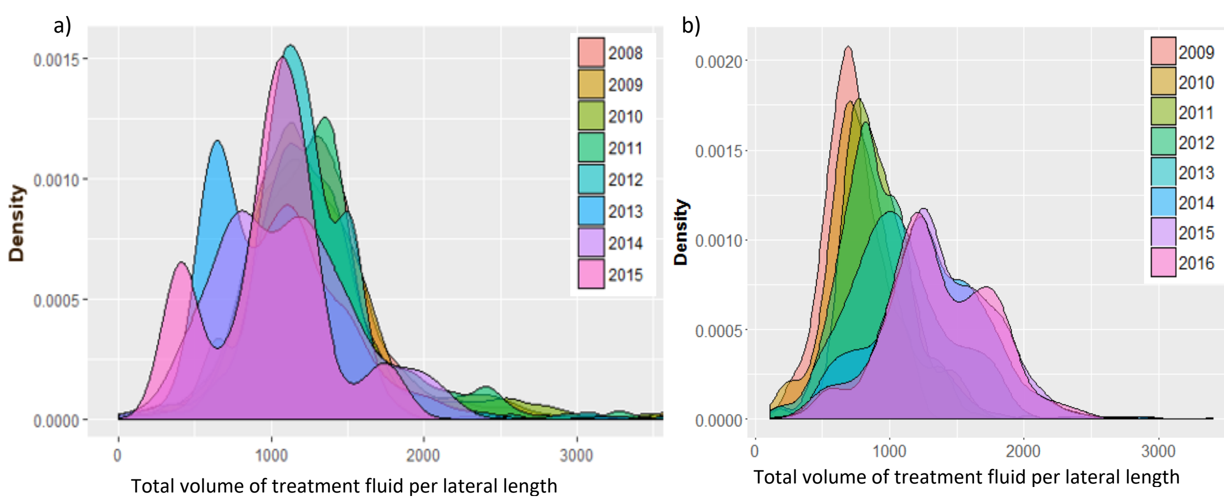


Figure 3.7 Probability density plots for (a) Barnett and (b) Marcellus wells showing changes in intensity of hydraulic fracturing fluid use over time.

Once the models' predictive performance was assessed, we tested the ability of the algorithms to accurately predict productivity given the uncertainty in operator-completion-practice inputs. In particular, while future drilling locations can be characterized by mostly static geology and location, operator completion practices change over time. To quantify the impact of those changes to the overall performance of the algorithms, we generated a set of scenarios of possible future completion practices and used them to study their impact on productivity predictions (Fig. 3.8).

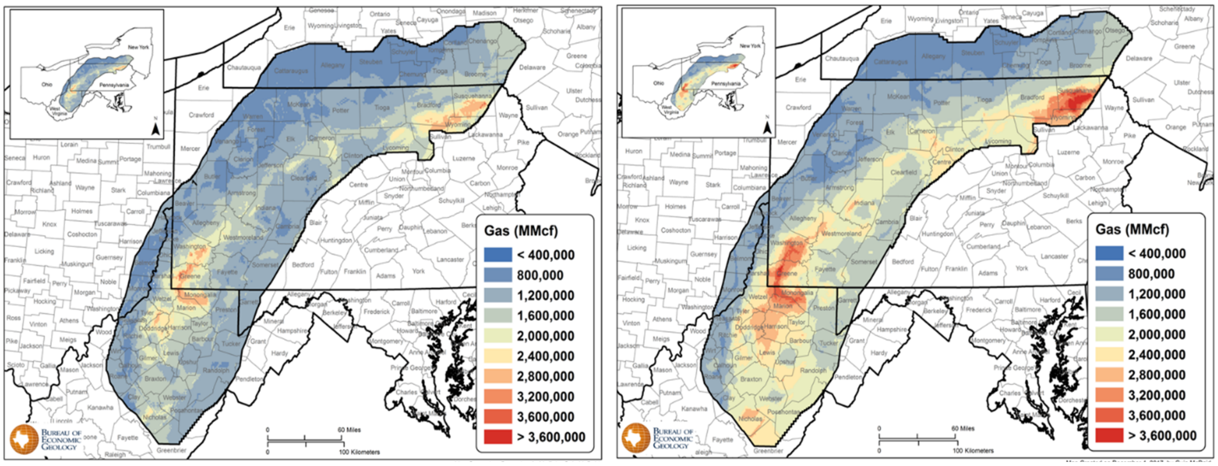


Figure 3.8 Estimates for the first-year cumulative production per well if drilled in 2018 in any given 1 mi^2 block under the assumption of variable (suggested by RF imputations) lateral length (left) and fixed 12,000-ft lateral length (right).

Each play has its own pace of changes, yet in some cases we found possible overlaps and potential interaction between, for example, changes in lateral length and fluid volume per foot of lateral. Furthermore, with operators being prone to drill fewer wells and to focus on more productive areas in the low-price environment, we had to test for "sample bias."

We created two forward validation experiments (Table 3.1). In the first, we used a 2-year sliding window to train the data and the year immediately following to test the predictive ability of the models. The second experiment consisted of aggregating the training data through time, adding every year to the training set after it was predicted by the model, and predicting the following year. To determine any possible effects of historical or time-related bias, we compared the two validation approaches across time. For the Marcellus play (Table 3.1 lower panel), the mean squared error values from the two forward validation approaches indicated that training the model on large historical data deteriorates the predictive performance of the algorithms. For the Barnett play (Table 3.1 upper panel), the predictions of the RF algorithms may be biased when trained with older historical data.

Table 3.1 Results of validation tests for RF and MBRP models for the (top) Barnett and (bottom) Marcellus plays, reporting the mean square error for 2-year and accumulated history trainings.

Train	Test Year	RF	MBRP	Train	Test Year	RF	MBRP
2007-2008	2009	0.37	0.45	2007-2008	2009	0.37	0.45
2008-2009	2010	0.46	0.58	2007-2009	2010	0.45	0.56
2009-2010	2011	0.33	0.41	2007-2010	2011	0.34	0.40
2010-2011	2012	0.25	0.30	2007-2011	2012	0.25	0.30
2011-2012	2013	0.34	0.36	2007-2012	2013	0.33	0.35
2012-2013	2014	0.23	0.31	2007-2013	2014	0.30	0.24
2013-2014	2015	0.47	0.65	2007-2014	2015	0.76	0.45

Train	Test Year	RF	MBRP	Train	Test Year	RF	MBRP
2008-2009	2010	0.94	0.83	2008-2009	2010	0.93	0.83
…	…	…	…	…	…	…	…
2008-2014	2015	0.27	0.32	2013-2014	2015	0.26	0.32
2008-2015	2016	0.26	0.31	2014-2015	2016	0.25	0.31

With the robustness of the predictions and potential biases of the models tested, we next turned to analysis of productivity. First, comparing expected per-well first-year production values across all drilled blocks in the Barnett play, we found that wells drilled after 2008 have on average almost 10 percent higher production. If, however, we compare the change in well performance over time—taking into account changes in well completions, including changes in average well length from about 3,000 ft in 2010 to roughly 4,800 ft in 2016—we find that per-well first-year production increased on average by about 40 percent (Fig. 3.7).

Improvement in per-well performance is higher in lower-producing areas, although, in some cases, per-well production increases thanks to longer laterals. Such observed improvements in certain statistical measures on a well basis, however, ignore other considerations such as the spacing between wells or well density. Apparent per-well productivity improvement may have a negative effect on recovery factors under the multidimensional normalization.

With values of input factors (TF, PP, LL) dramatically increasing over time, and with geologic knowledge and data resolution improving over time, it is natural to expect recovery factors to increase over time. However, the technical literature suggests that even advanced drilling and completions still result in recovery decreasing with distance from a wellbore since fracture density decreases further away from the wellbore. This belief encouraged operators to experiment with well spacing: with closer drilling, an overlap in the stimulated volumes may lead to an increase in recovery factor per total volume drained by offsetting wells (Fig. 3.9). Such super-additivity, when the recovery factor over two wells is greater than the recovery factor of each individual well, could motivate extraction of resources from areas originally considered to be drilled out.

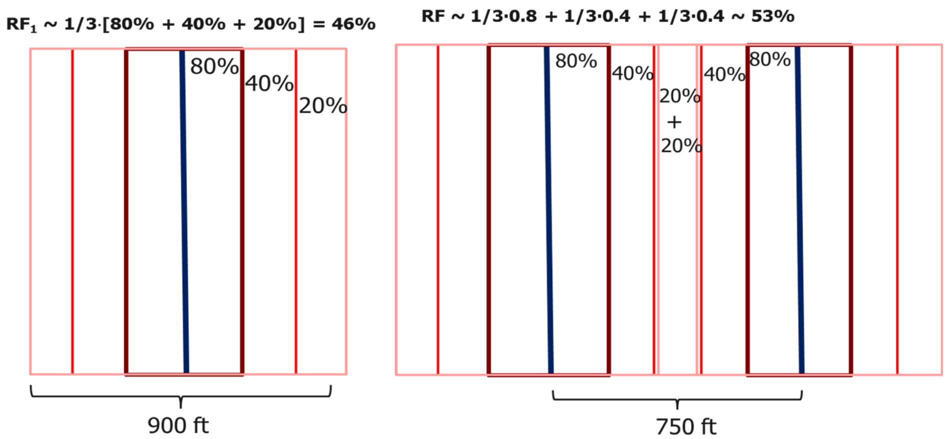


Figure 3.9 Schematic representation of possible uneven distribution of recovery factors with distance from wellbore (left), and a possible increase in recovery factor in the case of offsetting drainage volumes with closer spacing (right).

Along with the increased recovery rationale for density of drilling could be the rationale based on economics: while smaller spacing translates to more wells per area, if completed at the same time and with smaller volumes of completion inputs, the wells are often cheaper and could suggest a higher return (Ikonnikova and Jang, 2017) when measured per surface area. Thus, the statistically derived observations matter in the later economic analysis and the ability to integrate them within one workflow is essential.

3.4 Results and Conclusions

Our statistical analysis allows us to estimate

- the expected number of wells, based on projections regarding drilling patterns, including stacked wells;
- expected future completion inputs per location (TRR estimate based on 2018);
- expected first-year production for each potential future well; and
- the remaining technically recoverable resource.

The results presented in Table 3.2 are used for the base-case production outlook in the next chapter. However, numerous simulations suggest uncertainty in these values, particularly regarding the future completion advances and drilling patterns.

Table 3.2 Summary results for recoverable resources in the four shale gas plays.

	Total Studied Area *mi^2*	**Remaining* Developable** *mi^2*	**Potential** Future wells**	**Remaining TRR** *Tcf*
Barnett	8,000	~6,300	62,000	72
Fayetteville	2,700	~ 1,600	12,500	12
Haynesville	5,200	~4,800	27,600	127
Marcellus	42,600	~39,400	175,500	560

* only drilled acreage and faults are excluded

** lateral length and well spacing assumptions vary within and across plays

In summary, our statistical analysis suggests that projections of per-unit surface recovery estimates may be a more suitable measure in future discussions regarding resource recovery. The production outlook in this case should be related to geographical regions, rather than individual plays, which have uncertain boundaries.

The following results should be highlighted:

- Productivity of blocks with high initial per-well production (top 30 percent of wells with respect to 12mCum/LL as of 2010) has seen an increase in per-block TRR of up to ~50 percent in the Barnett play, owing to infill and stacked well drilling, and up to ~30 percent in the Haynesville and Marcellus plays, owing to more efficient recovery through optimized spacing and use of treatment fluid and proppant.
- On a per-well basis, the incremental recovery is higher in lower-producing areas, primarily associated with an increase in lateral length and the use of intensive completions.
- Plays with a shorter drilling history and hence, larger undeveloped areas, such as the Marcellus and Haynesville, show a greater shift in inputs such as TF and LL allowing for gains through economics of scale.
- Across all plays, it takes up to 2 years to achieve the highest performance in wells after a structural shift in completion design, particularly lateral length, treatment fluid, and proppant use, etc. We interpret this as being due to gaining experience or learning-by-doing improvements as opposed to structural shifts related to technological advances.
- Data suggest that wells with longer laterals rarely result in increased TRR/ft; improvements are greater in shorter wells (all else being equal).
- Finally, across all basins we found that total TRR is increasing over time as operators improve their drilling and completion (D&C) practices.

The key differences between these findings and those of the previous study are (1) changes in recovery with inputs and over time; (2) addition of vertical resolution, e.g., well stacking; (3) differentiation of uncertainty related to inputs (which also represent costs) and our ability to predict the relationship between inputs and outputs (technology function); (4) inclusion of faults and other technical challenges for drilling, changing the developable area; and (5) critiques related to potential time and geographic sample bias.

Overall, the new assessment of technically recoverable resources is more comprehensive and technically sophisticated than that of the previous study, this time providing insights into possible biases in data interpretations and classifying uncertainties. For instance, we find evidence of correlation in the choice of inputs across the plays, suggesting that uncertainty in input predictions could be reduced if, for example, we expand the scope to include all of the major basins in our sample.

Chapter 4. Well Economics and Production-Outlook Analysis

4.1 Overview

High energy prices, low interest rates, technological advances, and experimentation fueled the development of, first, shale gas and, then, tight oil resource plays around the United States. However, the industry's own success caused the fall of natural gas prices as early as 2010. The price of natural gas remained low since then because demand, though increasing, could not catch up with supply, which also increased owing to associated gas from liquids-rich plays. The oil price collapse in 2015 and 2016 can also be explained, at least partially, by the success of tight-oil production increase in the U.S. As important as the increased production was, the nimbleness of U.S. operators to adjust drilling and, thus, production in much shorter periods than can be done with conventional resources changed the nature of the global oil market.

Although the oil price has increased since mid-2017, it remains significantly below the \$80–\$90/bbl range that was the norm before 2014. Nevertheless, lower costs of drilling and completion, improved operational efficiency, lease-development obligations, and consolidation and rationalization in the industry—which is probably key to the continued interest of investors—allowed for quick and significant recovery of tight oil drilling. Associated gas production increased along with liquids production, impacting the economics of dry-gas drilling as well as the natural gas market overall.

In the future, natural-gas demand growth may finally shift to higher gear between 2018 and 2020 with the completion of liquefied natural gas (LNG) export facilities; pipelines to Mexico; and methanol, fertilizer, and other industrial facilities using methane or natural gas liquids (NGLs) as feedstock and increasing gas burn for power generation, especially if more coal plants retire. Between 2020 and 2030, natural gas demand may become even stronger if some nuclear plants, in addition to more coal plants, retire and a second wave of LNG export and petrochemicals facilities are built.

Fully cognizant of this dynamic demand/supply context, we reassess our approach to well economics and production outlook analyses and ask the following questions:

1. Can shale gas production match expected demand growth? So far, economics of dry-gas plays have been challenging in many locations. Oil price influences D&C costs to a great extent, as does overall natural gas supply because of associated gas production. Consolidation in the industry may lead to more-disciplined drilling.
2. What production can we expect from each play? The location of each play with respect to demand growth is important. For example, most LNG and pipeline export capacity, as well as petrochemicals demand, is materializing in the Gulf Coast while demand for gas-fired power is also strong in the Marcellus region and the southeastern U.S. Development of midstream infrastructure for both natural gas and NGLs (processing, pipelines, storage) will determine basis differentials and impact production economics. At the same time, each location's geology will determine productivity and, thus, unit cost, which will also be a function of D&C technology that operators implement.

Well economics is an important building block of production-outlook analysis. We conclude with production-outlook projections for different scenarios. Views on the future of energy prices, technology, and costs vary greatly among experts. Given the uncertainties around each of these elements, as we have been discussing, this divergence is to be expected. We do not espouse any particular view but consider reasonable ranges for our key inputs. Accordingly, we present a range of possible outlooks around what we call a “base case,” calling the bounding cases “high” and “low” scenarios. These outlooks are subject to change as drilling continues and we gather more data to analyze, and as market conditions evolve. Our modeling tools allow for testing a variety of possible combinations of economic and technical input parameters and assumptions.

Here, we describe new features implemented for the DOE-funded research and discuss results. Our models have been continuously enhanced since 2012 to allow for more-realistic representation of operator decision-making and to increase the granularity of outlook projections. We highlight the most important new features added in this round of updates, which vary depending on the characteristics of each play. In particular, we discuss the following:

1. Updated cost assumptions, including redefinition of D&C cost as a function of drilling depth, lateral length, and volumes of treatment fluid and proppant. This update allows us to establish a link between costs and technology/efficiency improvements over time. We also added a scaling factor to our cost function to capture the correlation between D&C cost and oil price.
2. Reassessment of existing-well profitability. We now separately take into account basis differentials and transportation costs; capture energy-price expectations, using forward curves rather than spot price as a driver of drilling decisions; and model co-production of liquids and water as part of the decline curve rather than of fixed parameters, allowing us to represent more accurately the value of liquids and the cost of water treatment.
3. Analysis of the relationship between energy prices, capital spending, and drilling portfolio, particularly the choice of drilling locations with respect to their expected profitability and the total number of wells.
4. Modeling and mapping of future expected drilling based on expected profitability and available inventory of wells, calculated on a square-mile basis and taking into account the ability to drill multiple wells per location and proximity for already developed sites with infrastructure.

Table 4.1 Summary of changes in resource assessment and outlook results for shale gas plays studied: Barnett, Fayetteville, Haynesville, and Marcellus.

	Update	**Original**	**% change**
OGIP	3100	2950	5%
TRR	780	650	20%
Cum production by 2045			
@ $3/MMBtu	160	185	-14%
@ $4/MMBtu	320	215	49%
@ $6/MMBtu	475	330	44%

Overall, in relation to our previous studies, we improved both the granularity of our analysis and our modeling. Improved understanding of the rationale behind operator-drilling decisions was of particular importance to enhance the "reality" of the model. In particular, we highlight the importance of investment financing for supply sustainability under low prices and growth under high prices.

In summary, production-outlook results suggest that, despite a relatively minor change in the total OGIP estimate, TRR increases notably. More striking is the difference in cumulative production from previous studies, especially at higher prices. In a constant $4/MMBtu scenario, aggregate cumulative production by the end of 2045 in the four plays studied is 49 percent greater.

Our past analysis was by design conservative and, indeed, yielded lower aggregate EUR estimates when actual prices and costs are used. However, this observation does not hold true at the individual play level. For example, our original Barnett production outlook now appears optimistic while we seem to have accurately estimated Fayetteville production.

In contrast, we underestimated Marcellus production, likely because of relative financial attractiveness shifting investment-capital distribution across plays, which was not accounted for in our previous analysis. Over the period since our early analysis (2011–12), financial and drilling attention shifted to plays with greater potential, such as the Marcellus and Permian basins. This investment environment remains dynamic as industry consolidation; oil, gas, and NGL prices; monetary policy of rising interest rates; and other developments continue to alter company decisions on where, when, and how many wells to drill. In this updated study, we take the first steps toward incorporating financial considerations into industry dynamics modeling.

4.2 Data

As can be seen from our integrated workflow presented earlier, the outlook analysis is built on findings from all study blocks. As presented in earlier chapters, outputs from companion studies on geology, engineering, and statistical characterization of the field that are used in well economics and production outlook include the following:

- Projected production-decline profiles for existing wells (natural gas and, where applicable, water and liquids) and representative decline curves for all locations left for future drilling
- First-year production estimates for all future well locations as a function of geologic and completion inputs, which, when multiplied by associated decline profiles, result in EUR estimation (for natural gas and, where applicable, water and liquids)
- Completion data for existing wells on treatment fluid, proppant, and lateral length and derived expectations for each potential future well location
- Number and position of locations left for future drilling in each square mile of a play, depending on the well-spacing assumption and assumed extent of the developable area (e.g., excluding regions with a ban on drilling)

In addition, we updated well-cost data with more recent data to capture changes in D&C costs due to both fluctuations in the oil price and evolution of completion practices. As mentioned before, we also improved the representation of D&C costs by adding details on the size of the completion and on oil price. For this purpose, we researched and compiled a database on trends in drilling and completion costs per unit of drilling depth and lateral length, volumes of hydraulic fracturing liquid and proppant, and other cost items. We collected these data from company investor presentations, industry publications, and WoodMac and other analysts, and subjected them to due diligence by our sponsors via personal communications and company visits.

We also updated data on spot and forward prices of natural gas, NGLs, oil, and basis differentials. For the Barnett, Fayetteville, and Haynesville plays we used SNL projections for basis differential to Henry Hub. For the Marcellus play, we created a map assigning each well location to a certain hub and used basis differential predictions for each hub from the GPCM model[2] (Figs. 4.1, 4.2). We relied on previously collected information on state taxation and regulations regarding depreciation and depletion schedules.[3]

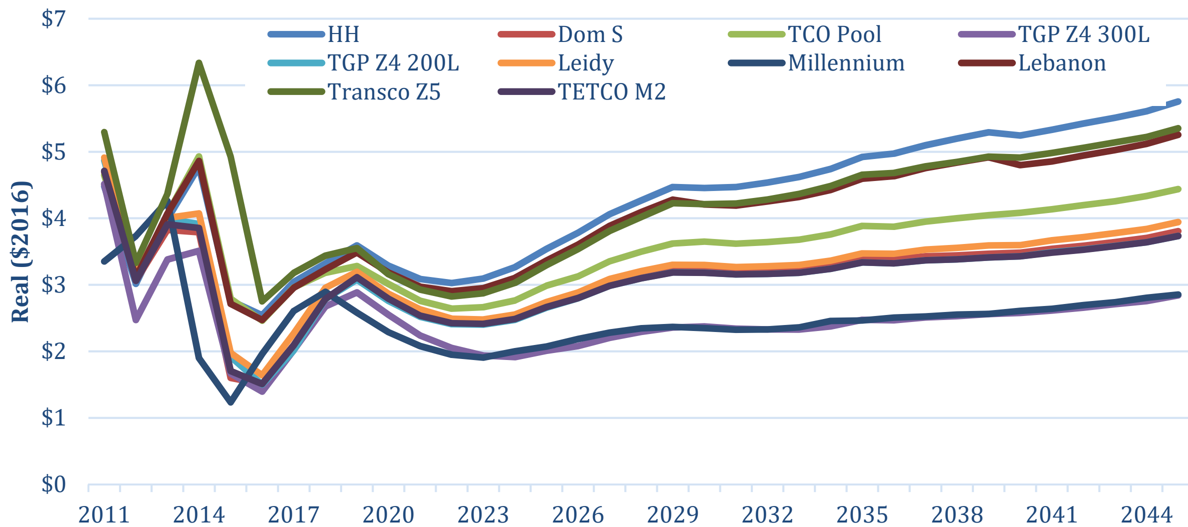


Figure 4.1 Past and future basis differentials in various hubs in or near the Marcellus play, based on our run of the GPCM® model.

2 GPCM® is one of the most widely used tools for developing forecasts and scenarios for North American natural gas flows, price, and basis. The Bureau of Economic Geology had a trial license for GPCM®. We are thankful to RBAC Inc. for granting this license.

3 Analysis of future play development presented below relies on the 35% income tax assumption.

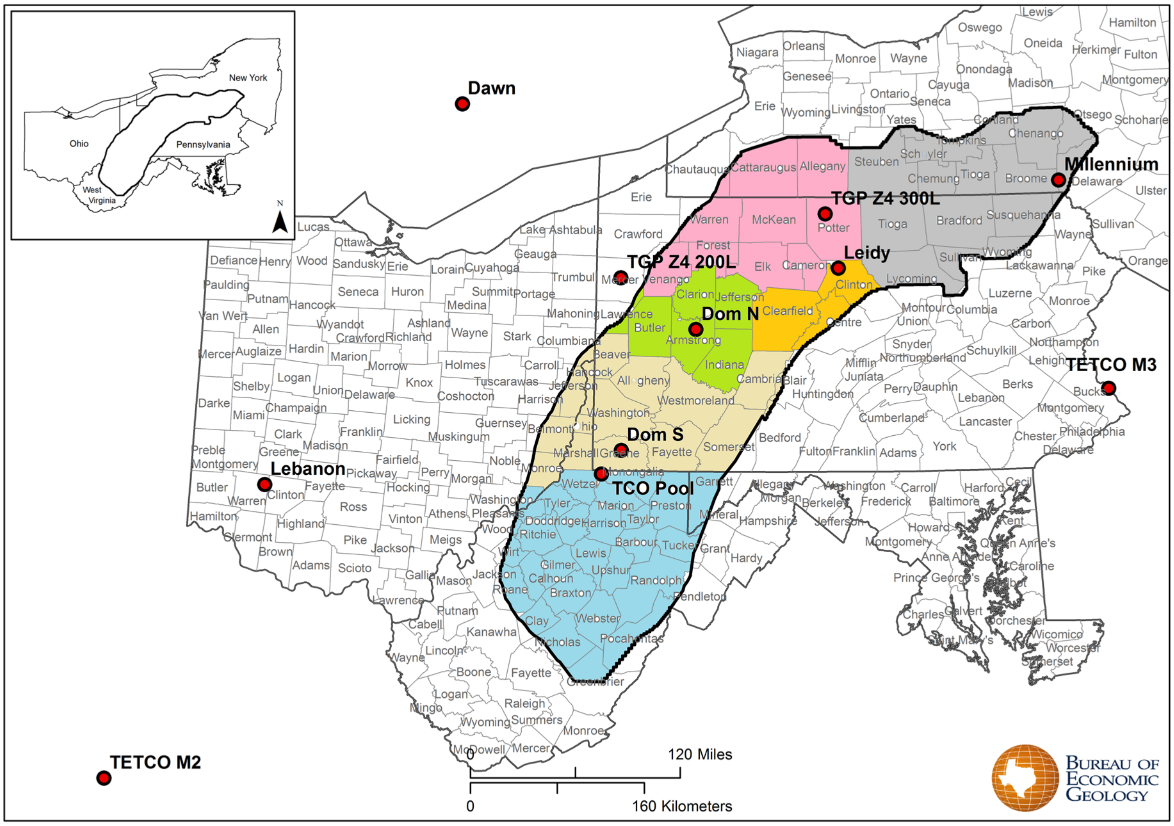


Figure 4.2 Marcellus play wells and pricing hubs used for their economics (map).

4.3 Methodology

Development of shale resources is driven by well profitability and location availability (Gulen et al., 2015; Ikonnikova et al., 2016). As before, we use a standard discounted cash-flow model to evaluate the economic viability of individual wells and to define how operational profits depend on oil and gas production; energy prices; and costs of processing, transportation, and water handling.

The model allows for the calculation of various measures of investment attractiveness, such as break-even prices, profitability index (PI), and net present value (NPV). PI, calculated as a ratio of discounted expected future profits and total drilling and completion (TDC) costs, stands as a particularly useful metric for several reasons. First of all, it allows for entry of a variable price profile for the entire well lifetime. Second, any correction in costs, prices, discounting, or other parameters of revenues or costs can be easily implemented through a multiplier. Formally, PI is defined as following:

$$PI = \frac{\sum(1+r)^{-t}((1-Royalty)\cdot q^{t}\cdot p^{at\ time\ of\ drilling} - Tax\_Payments - Operational\_Costs)}{TDC} \quad (10)$$

Here $\boldsymbol{q}^t$ is the vector of annual production of oil and natural gas; $\boldsymbol{p}$ is the vector of real prices corresponding to expectations at the time of drilling; and r is the real interest rate, set at 6 percent for the past until 2009 and at 8 percent thereafter. Thus, we estimate well profitability as it was seen at the time of drilling. Tax payments included state severance, and federal and state income taxes.

As mentioned before, TDC is scaled relative to oil price, based on the historical relationship between WTI oil price and Bureau of Labor Statistics Producer Price Index (BLS PPI) for drilling costs in the U.S. Based on investor reports, we also estimate that drilling costs are prone to decrease thanks to efficiency improvements. However, reports and discussions by the oilfield services sector suggest that drilling costs are unlikely to fall below 150$/ft (total vertical plus horizontal length). Changes in drilling costs are particularly dramatic in the case of the Haynesville and Marcellus plays (Table 4.2). In contrast, the lowest per-foot drilling costs have been observed in the Barnett and Fayetteville plays, where normal pressure and relatively "easy" drilling depths of ~5,000–6,000 ft allowed operators to bring costs to the lowest limit.

Table 4.2 Summary of changes in average drilling and completion costs ($ million) for a representative 4,500 ft horizontal well drilled at 12,000 ft of depth in Haynesville play over time.

Year	Haynesville
2009	11.3
2010	10.7
2011	10.0
2012	9.5
2013	9.0
2014	8.5
2015	8.2
2016	7.5
2017/2018	6.8

Cost structures are further complicated by the need to process NGLs and condensate and then transport them to markets. The cost of gathering, processing, and transportation will likely decline as infrastructure is developed, but it is difficult to estimate at what level they will settle and when. In Table 4.3, we offer a collection of cost components for the dry- and wet-gas producing regions in the Marcellus play. The data indicate the dependency of costs on location, highlighting differences in operator ability to connect to regional transportation systems (also see the basis differentials in Fig. 4.1). These data are based on a survey of industry publications and company presentations and have been vetted by some operators. Based on these historical data and conversations with operators, we make assumptions about the future of these components.

Table 4.3 Summary of major cost and revenue components for a Marcellus well based on its location, used in calculations for 2018.

	NEPA	SWPA wet	SWPA dry	WV wet	WV dry
Gathering	$0.40	$0.40	$0.40	$0.40	$0.40
Processing		$0.20		$0.20	
Transport to pool	$0.30	$0.40	$0.40	$0.50	$0.50
Condensate		5 bbl./mmcf		5 bbl/mmcf	
Liquids (no C_2)		55 bbl/mmcf		55 bbl/mmcf	
Btu of gas sold	1,040	1,140	1,040	1,140	1,040
Drilling cost	$150/ft	$270/ft	$270/ft	$290/ft	$290/ft
Completion cost*	$370/ft	$440/ft	$440/ft	$570/ft	$570/ft
* Average: 40–45 frac stages, 1,250 (WV) to 2,000 (SWPA) lbs/ft of proppant, 1,550 gal/ft of water					

In short, after a detailed and vigorous effort to collect data on components of costs and revenues associated with shale gas drilling and subjecting these data to a rigorous reality check, we use them as inputs in our analysis to obtain NPV, PI, and other metrics of financial viability. This structured approach also allows us to estimate the shut-down year, or lifetime, for each well as a function of input parameters such as price and costs. We stop production of a well when its operational expenses exceed operational profits. In the past, we used a static assumption on production as the economic limit. Given that abandonment costs can be significant, especially if many wells have to be abandoned within the same time frame, our analysis can be useful in planning for these abandonment "waves."

Next, we use the low model to estimate profitability of (1) all existing wells, and (2) potential future wells. We do the latter for every future year, taking into account price expectations, correlated costs, and assumptions on technology and completion inputs. We examine how uncertainty regarding inputs translates into uncertainty concerning profitability and, thus, drilling attractiveness. Completion assumptions are often found to have greater effect than prices on short-term economic attractiveness. For instance, forcing all 2018 wells in parts of the Marcellus play where our interdisciplinary team estimated an EUR greater than 3 Bcf to be drilled with 12,000-ft laterals boosts PI estimates by about 25 percent on average thanks to economies of scale, which is roughly equivalent to about $1/MMBtu price increase over the assumed $3.25/MMBtu (Fig. 4.3).

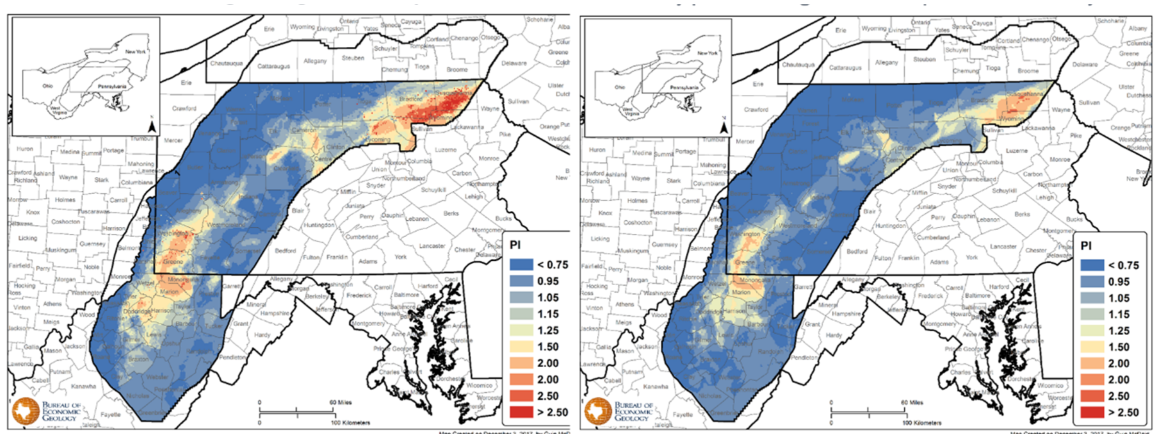


Figure 4.3 PI maps for Marcellus play under different well-completion assumptions: all future wells assumed to be drilled at 12,000-ft lateral with the 2016–2017 locally observed HF and proppant/ft (left); and based on RF imputations for well length, HF, and proppant volumes (right).

Mapping of estimated PI for past wells reveals drilling in commercially unattractive areas (Fig. 4.4). Further systematic analysis shows that drilling in economically unfavorable areas happened along the entire history of each play, although with some variation in the total percentage of wells drilled in unfavorable areas. To that end, to structure the future drilling model correctly, we had to analyze the relationship between drilling activity and PI distribution in the past. We examined (1) the change in total estimate of capital spending per play per year as a function of expected price and average cost change, and (2) change in a distribution of PIs across wells.

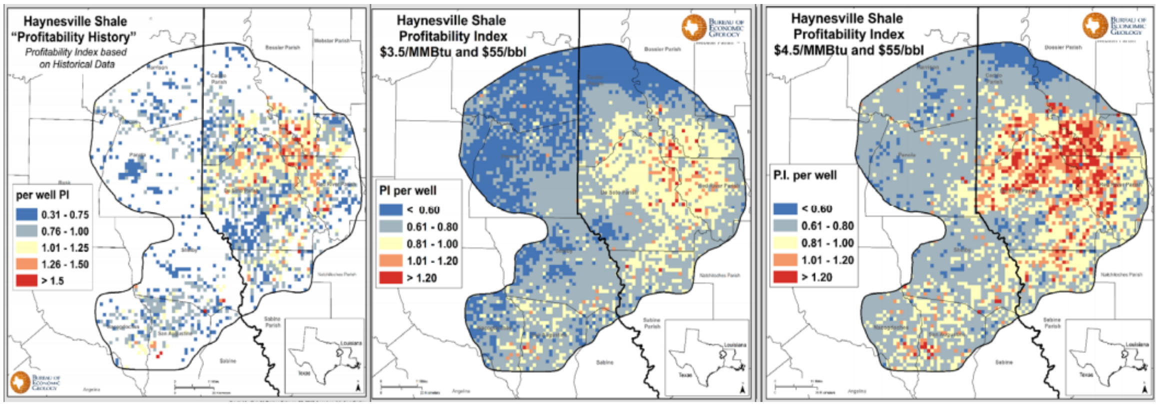


Figure 4.4 PI maps for Haynesville play showing distribution of locations for wells drilled in 2014–2016 (left), and profitability of locations remaining for drilling under $3.5/MMBtu (middle) and $4.5/MMBtu (right) natural-gas price assumptions.

Our analysis is complicated by the fact that—owing to changes in well productivity and input choices and the resulting total production, as well as changes in well costs—PI indicators of a play change over time. With drilling activity exhausting a developable area, the inventory of wells in any given PI range also changes. Moreover, at low prices, areas with high PI get exhausted quickly; yet, thanks to technological improvements, producers often manage to compensate for some losses and even increase their inventory in some PI ranges. As a result of this complicated but more-granular and realistic modeling of profitability, the number of locations that can be drilled at $4 almost quadrupled in the Haynesville play (Fig. 4.5)—consistent with the increased drilling activity observed in Haynesville despite lower prices.

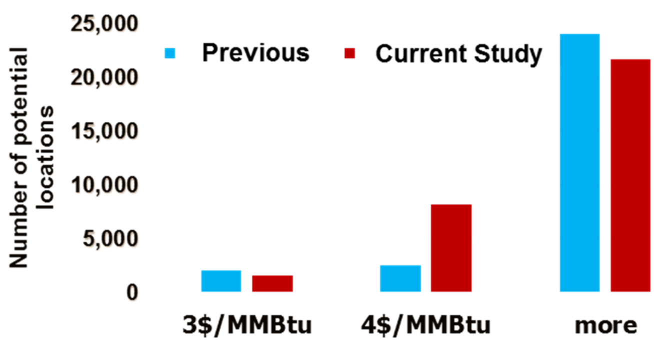


Figure 4.5 PI chart for the Haynesville play, showing the change in profitable drilling at different prices between previous and current analyses.

With the working hypothesis that drilling activity would expand if profit is expected to increase, and would shrink otherwise, we analyzed how investing in drilling changes over time, depending on energy prices, costs, and the inventory of drillable locations. We performed statistical analysis to relate capital spending to previous- year revenues and anticipated per-well profit for the next year based on costs and price expectations (Fig. 4.6). In this analysis, we found it beneficial to look separately at (1) expansion (shrinkage) of drilling in terms of capital spending depending on prices, costs, and expected production; and (2) changes in relative shares of wells drilled in different expected profitability ranges.

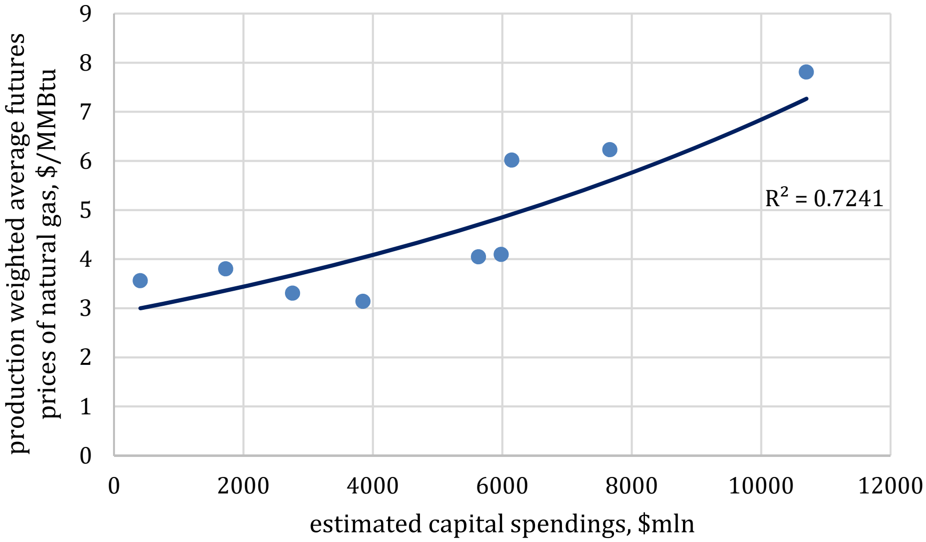


Figure 4.6 Correlation between capital spending and expected prices at time of spending for Barnett play.

Projections of future capital spending are translated into the expected number of wells to be drilled based on the cost of a median well. Window studies and analysis of individual companies and their reported capital return goals and development strategies performed on the Marcellus and Barnett plays suggest that such an approach is viable for the time being and useful to explain the historical trends. However, as the plays mature and operators exhaust economically viable locations—and financial goals of operators as well as capital market expectations in terms of returns from the sector also change—the derived relationships are also likely to change in the future. In financial economics literature, such changes are often related to industry evolution, including dynamics in the number and distribution of firms by size (e.g., in terms of internal capital). Thus, a more detailed examination would be required to keep the capital-spending model accurate for the projections.

Another important observation is the importance of oil price in drilling decisions. First, D&C costs are driven by global activity, which is decidedly dominated by liquids. As such, higher oil prices lead to higher D&C costs for all upstream operations. Second, the profitability of many gas wells is dependent on revenues that operators generate from NGLs, prices of which have historically been highly correlated with oil price, with the recent exception of ethane. Thus, we are careful to incorporate these relationships into our modeling as we analyze the distribution of wells by PI.

With drilling budgets and number of future wells defined, the question is where and which wells are likely to be drilled in each given year. To answer that question, we explore patterns in the distribution of wells with respect to profitability, or so-called drilling portfolios. In that analysis, we again include all major economic parameters such as energy prices, costs, inventory availability, and other possible drivers of location choice, such as the availability of take-away infrastructure capacity.

Each play is unique in its dynamics, although some similarities can be found. Thus, in Haynesville, drilling shifted to higher-profitability locations over time, although some drilling in the poorest locations continued and even increased from 2014 to 2015 (Fig. 4.5)—possibly due to depletion of highest-PI locations during a period of low prices and companies having to shift to lower-PI locations in their lease holdings. Note, however, that there are numerous drivers of profitability. Companies may have drilled experimental wells with different completion approaches in geologically more attractive areas, but at a higher cost—and the market price may have moved against them once they came online. Consolidation in the industry and the general switch from gas plays to liquids-rich plays may have influenced which companies drilled where. For example, higher-PI locations may be controlled by companies that are waiting for improved price signals or companies whose capital budgets are allocated to higher-PI drilling in other plays.

Similarly, drilling in the Barnett play moved to higher PI locations in both dry-gas and liquids-rich regions of the play (Fig. 4.7). Still, just like in the Haynesville play, drilling in lowest-PI locations continues. The same industry dynamics and rationale apply here, as well.

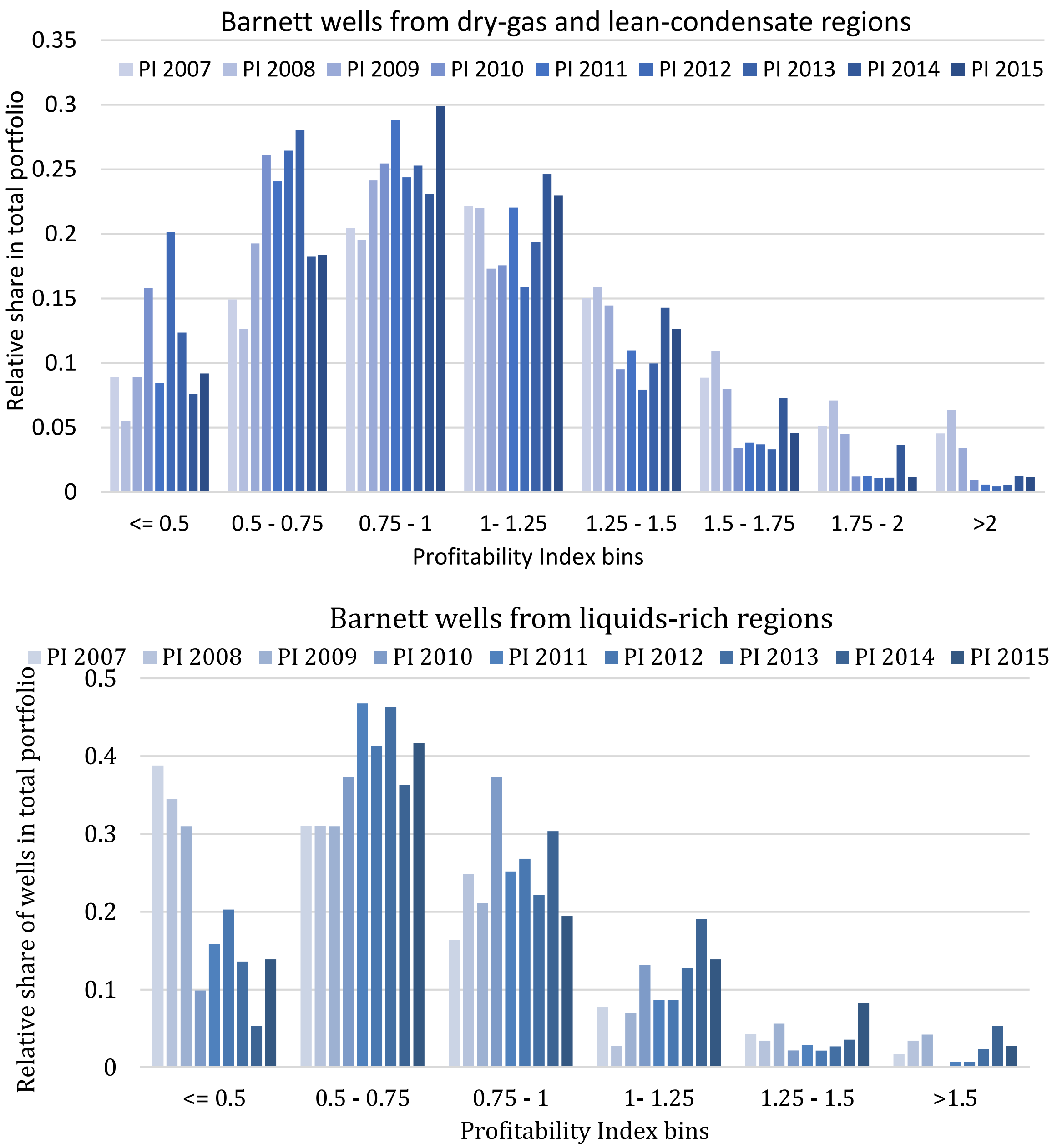


Figure 4.7 Relative shares of wells drilled in the Barnett dry (top) and wet (bottom) regions over time by PI bins. (Barnett and other play analysis relied on data collected through late 2017, but because results are reported only for wells with at least 12 month of production, we do not have data for all of 2016; thus 2015 is the last year shown here).

Quantitative and qualitative analysis of PI distributions across the plays suggests the following conclusions:

- Drilling in liquids-rich areas is driven primarily by oil rather than natural gas price. Oil price drives the price of NGLs with the exception of ethane, which has been "rejected" since 2013 or so. With increased exports of ethylene from ethane-only cracker and direct ethane exports, ethane rejection will decline and its price will rise, a trend we try to capture in our modeling.
- Price drops reduce drilling, especially in low-PI locations.
- Drilling in high-PI locations slows as they are depleted during low-price periods, especially if these locations were limited in number (e.g., best locations in dry Barnett).
- Drilling continues in areas with negative return expectations for a variety of reasons, including but not limited to lease obligations, anticipation of better prices, and experimental drilling to test different completions.

Although limited by the scope of the current project, the analysis we performed on profitability helped us to define future expected PI distributions as the percent of population of wells to be drilled each year with a given expected PI. Thus, capital budgeting modeling of financial incentives in future projects is a promising avenue for improving our modeling of future drilling and production outlook.

The combination of capital budgeting for future drilling and expected PI distributions allows us to assign a probability of drilling to each location. Thus, we generate expected drilling maps that are particularly useful in discussions of infrastructure constraints, e.g., gas or liquids pipelines or water recycling. Formally, we estimate the probability and therewith determine the locations for expected wells based on the total number of locations with the same profitability, $\bar{n}$, and estimated number of wells to be drilled in a given year in the given profitability bin, n^{PI}:

$$pr^{PI} = n^{PI}/\bar{n}^{PI} \tag{11}$$

Furthermore, drilling probabilities can be updated under the assumption that each year drilling extent spreads on average to about 2–3 miles away from the developed locations, as suggested by data (possibly related to the infrastructure and maintenance convenience).

Thus, we build a model that allows prediction of future drilling by location; given the assignment of production profiles to each individual location, we predict the entire play's expected-increment production profile for each year.

We always restricted the pace of drilling in any given area, typically by the historical pace of drilling. Even the most profitable regions will not be drilled "fully" in a year, even if the price signal is there. There are several reasons for controlling the pace of drilling, but lease holdings and limitations on capital and/or availability of equipment and crews are probably the most important. In our current modeling structure, we use 20 percent as the maximum number of locations to be drilled with profitability, even if economic indicators such as PI shows that they are all profitable.

4.4 Results

The outlook model combines the wells expected to be drilled in a given year, depending on the expected prices and costs, with the production estimates based on their locations. As the profitability of wells changes with energy prices, the expected total number of wells, their spatial distribution, and the estimated production volumes over time also change.

Over the years, as market conditions for both natural gas and oil changed, we have used a variety of natural-gas price assumptions for our sensitivity analyses to describe the lower and upper boundaries of expected drilling activity and the resulting production. For the current analysis, we use a natural gas price of $2.75/MMBtu and an oil price of $50/bbl for the lower boundary; $3.25/MMBtu and $65/bbl for the base, or reference, case; and $4.5/MMBtu and $80/bbl for the higher boundary. These scenarios are generally in line with the range of projections by the Energy Information Administration. However, it is important to realize that the history of oil and gas prices indicates that there will be volatility. One advantage of our modeling is that any combination of oil, natural gas, and NGL prices can be input. In fact, in the past, we tested scenarios with prices from the EIA AEO outlooks. However, for ease of comparison across our current scenarios and with past analyses, we present outlooks through 2045 with constant oil, gas, and NGL prices (Fig. 4.8).

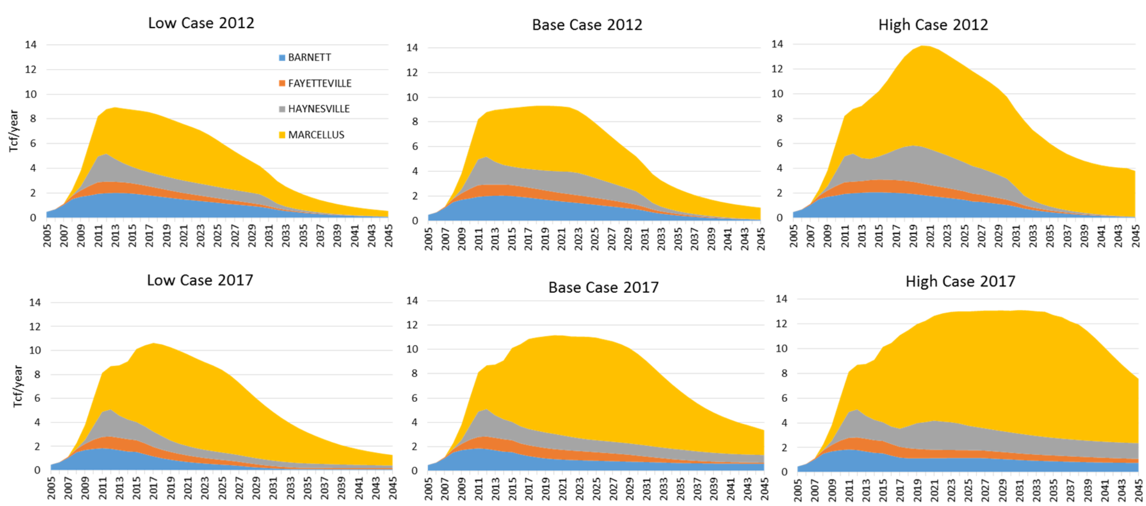


Figure 4.8 Production-outlook projections for major shale gas plays from the past, and updated analyses with varying assumptions on energy prices and likelihood.

The updated outlook analysis suggests several important results and conclusions:

- The current lower boundary has lower prices for both natural gas ($2.75/MMBtu vs. $3/MMBtu) and oil ($50/bbl vs. $80/bbl) than prices of our past analysis. Correspondingly, the current lower-boundary scenario results in lower production outlook: ~165 Tcf vs. ~ 185 Tcf. As can be seen in Fig. 4.8, production is lost primarily from Barnett and Haynesville.

- For the same price and for the base-case scenario, expected production increased by ~45 percent, mainly from the Marcellus play but also through extension of the life of drilling and production in the Haynesville and Barnett. The main reasons appear to be improvement in recovery; drop in D&C costs primarily owing to the recent drop in oil prices; and economies of scale associated with multi-well pad drilling and lengthening and staggering of wells.
- The high-case scenario also yields an increase in production of almost 45 percent in expected recovery, primarily from Marcellus but also from Haynesville. Barnett and Fayetteville do not add much to their performance in the base case. Nevertheless, the difference between TRR and cumulative production is over 30 percent, as some locations are expected to remain uneconomic even in this high case.
- Overall, we find that recent economic and technical changes allowed the industry to postpone the decline in aggregate production, but even in the high-price scenario, a decline is expected to happen by the late 2030s—but after a much longer period of "plateau" production.

Chapter 5. Discussion

Our understanding of shale gas drilling has been continuously improving since 2011, when we first started the work with an interdisciplinary team of geologists, engineers, and economists with funding from the Sloan Foundation. Importantly, our progress has been in parallel with the progress of the industry, which has also learned from every new well, horizon, and play drilled. There is no reason to expect that this progress will plateau any time soon. As the premier public resource for shale gas information, the Bureau intends to continue discovering, and sharing its findings with stakeholders.

Improvements to our analysis, made possible through funding from the DOE, yielded somewhat different results in terms of expected aggregate gas production from the four major shale gas plays than did our previous independent analyses of each play. However, as mentioned before, production outlooks are heavily dependent on the price of natural gas—as well as of oil and NGLs—in addition to D&C and operating costs, which are influenced by oil price and technological or efficiency improvements. Our results reflect current price and cost expectations, but further improvements in efficiency or technological breakthroughs cannot be ruled out, nor can higher oil and/or natural gas prices.

The Bureau has kept its shale resource assessment efforts evergreen by continuing to analyze geologic and production data, as well as increasingly important and more complex market and financial developments. We continually update our databases, improving our modeling with due diligence and reality checks from our operator and expert networks. We highlight the following areas of interest for our geologic future production economics and outlook analysis and modeling:

1. **Incorporation of additional factors that affect per-well recovery**. With development of stacked and staggered drilling, which expand play boundaries vertically, we intend to expand our modeling to capture productivity from all horizons. With high recovery factors from some areas (e.g., in liquids-rich Marcellus and clay-rich northern Haynesville), we seek to understand when and how operators overcome technical challenges to produce previously inaccessible resources that contributes to a well's recovery.
2. **Geologic properties of shales and their relation to productivity**. While all producing shales are similar, their varied depositional and tectonic histories create important differences. What are the important geologic factors affecting productivity (e.g., proportion of ductile minerals, vertical heterogeneity of formations, lithology of underlying formations), and how do they compare among shale plays?
3. **Per-play recovery**. As plays mature, what is the overall recovery factor for a given play? Which plays have been produced most efficiently, and why?
4. **Cross-play dynamics**. Drilling decisions in each play are not independent from those in other plays. Many operators hold acreage in more than one play. Consolidation in the industry and increasing demands by lenders for acceptable returns will likely increase investment discipline. On the other hand, newer players can go after less attractive acreage. We would like to improve capital allocation and investment decision-making aspects of our model.

5. **Role of technology**. Stacked and/or staggered drilling affect production economics, as do technological improvements. Separating their influences is an attractive area of further research. In particular, we are interested in identifying and modeling technologies that can lead to “step change” rather than incremental improvement.
6. **Role of related factors that may affect drilling, productivity, and economics of a given well or play**. For example, the production and disposal of water in shale plays may exert influence on play development. What geologic factors regarding water production (e.g., proximity to karsted, porous, water-bearing Ellenburger in the Barnett Shale) affect decisions about drilling location, and how does an operator’s ability to safely and economically dispose of hydraulic-fracturing wastewater affect the economics of a well, pad, or play?
7. **Granular understanding of inputs**. Uncertainty about inputs is greater than our ability to predict based on those inputs. In particular, length and water volumes require particular attention, but their use has intercorrelations across the plays.
8. **Abandonment**. Plays can be abandoned subject to economic conditions even when a significant portion of TRR is still underground. For example, we currently estimate that more than 50 percent of TRR will not be produced in Fayetteville and Barnett. The reserves unrecovered in the two plays due to economies represent a resource “buffer” for the U.S. that should lessen the extent of upward price excursions in the future.
9. **Uncertainties**. This approach produces a set of scenarios and uncertainty ranges are not explicitly explored for each scenario. A complete treatment of uncertainties from in-place estimates through production outlook scenarios would be a useful addition to the workflow.

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