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Update and Enhancement of U.S. Shale Gas Outlooks

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Executive Summary

This report reviews fifth-quarter (first-quarter of the second year) progress on the "Update and Enhancement of U.S. Shale Gas Outlooks" study funded by the U.S. Department of Energy and conducted by the Bureau of Economic Geology. The study is progressing in accordance with the proposed calendar, so the plan for delivering results remains unchanged. The spending is below what was originally proposed due to a delay in resolving a potential conflict of interest by one of our researchers; however, no budget adjustments are planned for the second year of the study.

In the following, we review of results from the Marcellus Shale study, which has been evaluated over the past few months, and a brief look at the preliminary results, particularly related to the geologic characterization of the play. As described in this report, we performed the following analyses in the fifth quarter:

Marcellus Study
1. Set up a 3D geocellular model using the updated log database adding infill logs to improve data coverage and 3D geomodel setup for geologic description. 2. Expanded stratigraphic correlations to include other formations potentially contributing to productivity. 3. Updated production database and performed individual well decline analysis with a special focus on chocked wells. 4. Developed and started testing a statistical model combining model-based recursive partitioning and random forest features. 5. Developed a well economics model to understand differences in completion not explained by geologic characteristics or drilling patterns. Expanded the production outlook model to analyze the impact of infrastructure constraints, e.g. limited pipeline capacity.

The greatest improvements in the Marcellus play assessment update are: 1) 3D analysis, including a detailed description of the faulting system based on well directional surveys and well log correlations; 2) improvements in decline analysis, thanks to the increased dataset of wells and longer well production histories; 3) comprehensive statistical analysis based on almost 20 variables; and 4) inclusion of financial consideration regarding drilling along with the potential to test the impact of infrastructure constraints on play development. With data on about 9,600 wells we were able to identify rapid changes in the depth of the Marcellus and use that to confirm the location and depth of faults. This improved our mapping of other geologic and reservoir characteristics. We also are working on petrophysical analysis not conducted in the original play assessment due to a lack of data. Specifically, we are seeking to derive adsorption isotherms to quantify the absorbed gas and are quantifying free gas-in-place based on the pressure and hydrocarbon-pore-volume values.

Our understanding of ultimate recovery from wells drilled in the Marcellus has also improved with extensive statistics accumulated on wells drilled in clusters or in a stacked pattern. Three additional years of production history has allowed us to perform a detailed analysis of the changes in well production declines. We also note changes in well spacing and lateral well length trends over time to provide a range of per-well production results depending on the future completion details. Essentially, financial considerations are taken into account for the first time in this Marcellus analysis.

As before our study follows the established workflow (**fig. 1**).

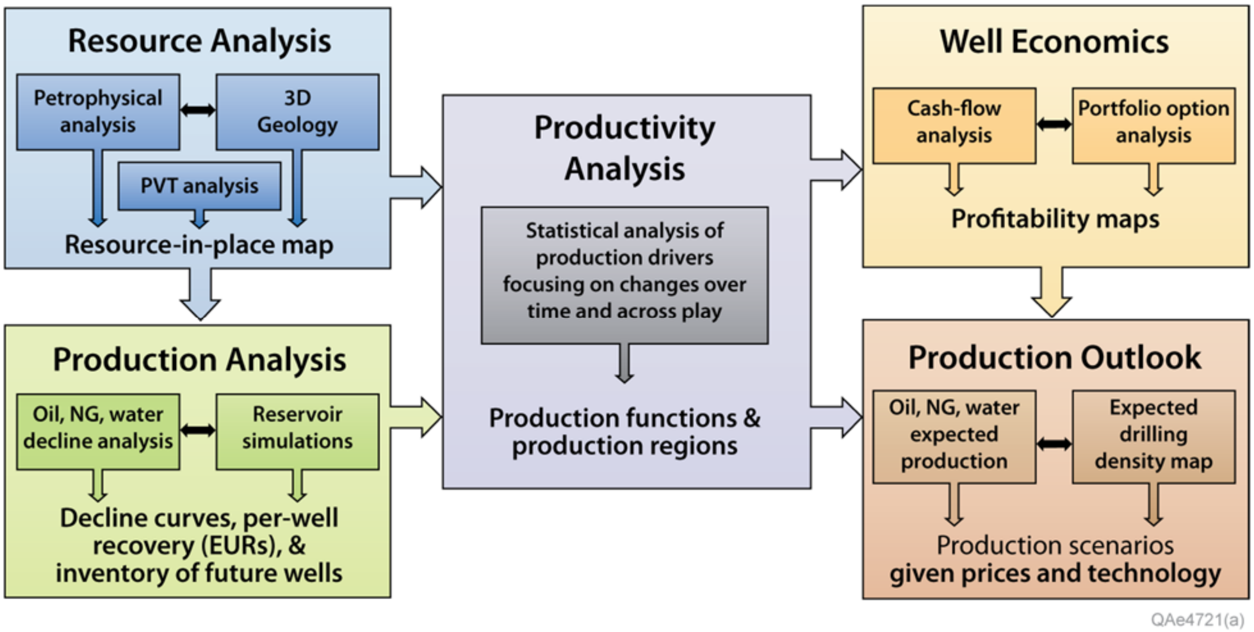

Figure 1. Workflow for shale resources and production-outlook studies.

The remainder of this report provides additional detail about the current analysis with some illustrations. The overview of the results of the study will be provided in the next report.

Details of Fifth-Quarter Analysis

Marcellus Play

Geologic Analysis

Digital and raster log data was acquired for the productive Marcellus area from the Ohio Department of Natural Resources, West Virginia Geological and Economic Survey, Pennsylvania Department of Conservation and Natural Resources, Empire State Organized Geologic Information System, and IHS LogNet®. Formation tops were correlated for 832 wells (Figure 1) in IHS Petra®, with correlated formations including the Tully Limestone, Mahantango Shale, Marcellus Shale (including differentiation of the Upper and Lower Marcellus and the intervening Cherry Valley Limestone), and Onondoga Limestone. Structure on the base of the Marcellus was mapped utilizing formation tops for 832 wells merged with outcrop surface elevation extracted values for added control. Thickness maps for the Tully

Limestone, Hamilton Group, Mahantango Shale, Marcellus Shale, and Cherry Valley Limestone were created using 832 correlated wells merged with outcrop surface elevation extracted values for added control. Thickness maps for the Tully Limestone, Hamilton Group, Mahantango Shale, Marcellus Shale, and Cherry Valley Limestone were created using 832 correlated wells.

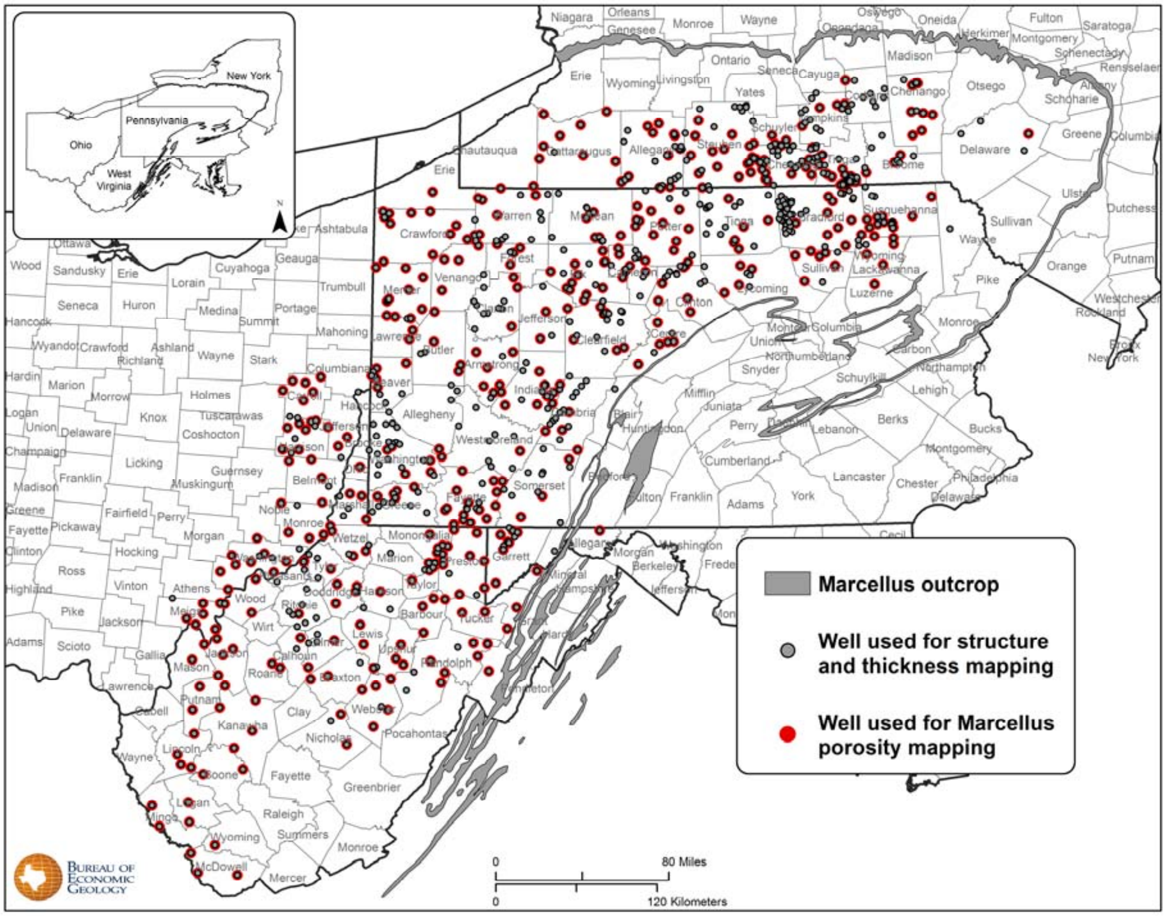

Figure 1. Marcellus base map showing distribution of digital log data for structure, thickness and porosity mapping, and the location of Marcellus outcrop.

To facilitate petrophysical interpretation including computation of porosity and total organic content (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.

Published interpreted faults were digitized for incorporation in the 3D model. Literature values for vitrinite reflectance (Ro), reflecting thermal maturity, were digitzed and a contour map was created to assess liquids-rich areas, and to aid in determination of kerogen density for computation of TOC.

Correlation of additional formations that are potentially productive in the Appalachian Basin (e.g. Upper Devonian units such as the Burket Shale) is in progress, due to be completed in November 2017.

Three Dimensional Geomodel

Digital log curves were imported into the 3D model, including both original wireline curves as well as calculated petrophysical curves. Correlated well log tops were used to map structural surfaces used to construct the 3D geocellular model. Following upscaling of log curve attributes to the vertical resolution of the 3D model, the petrophysical attributes were distributed along the layers of the model using both deterministic and stochastic methods. Horizontal well producers (10,119 wells) were imported into the model for the purpose of stratigraphic landing zone calculations. Monthly production rate data for these producing wells were added to the model, which was then used to explore relationships between production characteristics and geology at the well locations. A sealed, faulted framework model utilizing the newly available faults is in progress, due to be completed in November 2017.

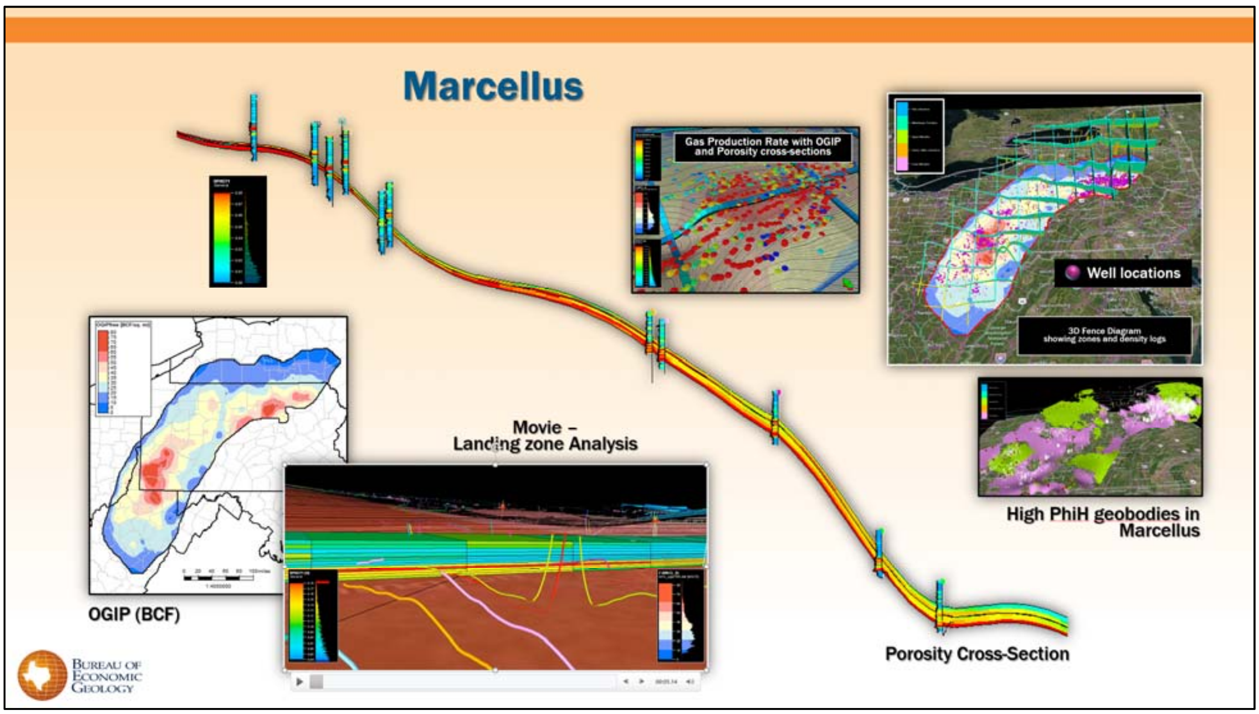

Figure 2. Porosity cross-section of the Marcellus shale with inset images showing production data, reservoir zones, porosity-thickness volumes, gas-in-place maps, and landing zone analysis.

Well Production Decline Analysis

In our initial study, Pennsylvania well production was reported at a semi-yearly basis. Since the study was completed, the state has switched to mandatory monthly production. In this quarter we wrote scripts to handle the transition between reporting schemes, then forecasted production and ultimate recovery from 9,627 Marcellus wells. We compared results from our 2014 study of the Marcellus to our most recent results and found that the transition to monthly production data greatly impacted ultimate recovery estimates for Pennsylvania wells. The median well is now expected to produce 3.45 Bcf over its first twenty years of life.

We also performed spacing analysis where we quantified the closeness of wells drilled from the same pad in order to perform regressions on productivity and late-life production characteristics of wells drilled at different spacings and with different completion strategies.

We plan to finish sensitivity analysis on the effects of gas maturity and adsorbed gas, and continue our study of the effects of close spaced well drilling in November and December.

Statistical Productivity Analysis

In the 2013 study we used production, well length, and OGIP^{free} data to predict per-well production assuming future wells to be drilled following the drilling patterns and recipes used at that time. In the updated study we extended our analysis including data on water and proppant use, drilling type (close-spaced, cluster, single or stacked) and operator identity to capture more attributes potentially affecting per-well productivity. We include pressure, hydraulic fracturing fluid, net and gross formation thickness and porosity, TOC, amount of proppant, and well location as potential productivity drivers. Additionally, we collect data on the 8 major producing companies and use their reports to guide us on expected completion types and details. The preliminary statistical analysis suggests that in the Marcellus play well completion details play the overriding role in the past two years, though pressure and other geologic attributes matter too. The penalized model based recursive partitioning model has been adopted to estimate expected well production in each given location under various price and technology assumptions. The model also allows to test sensitivity of the results to completion parameters and therewith to future technology. In combination with the results of the decline analysis, we can calculate expected EURs and technically recoverable resource (TRR). The preliminary results suggest that the remaining TRR estimate has increased since our previous analysis. (We will provide the exact new estimate in the next quarterly report after finalizing the 3D geomodel.)

Well Economics and Production-Outlook Analysis

Based on the results of the geologic, decline, and statistical analyses we develop a well economics model. Using a cash-flow model with past data on costs and energy prices we describe operators supply elasticity to price and define the drilling portfolio. These results will then be incorporated into our outlook model to project future drilling depending on energy prices, technologies and costs.

The novelty in the Marcellus play analysis apart from data update is that this time we also investigate how financial constraints, e.g. producers' ability to borrow, affects or constraints play development. In addition to that we use SNL data on the current and future pipeline capacities in the region to constraint production play in the region. The developed model will allow us to test the impact of new infrastructure investments and potentially test the effect LNG trade may have on the Marcellus play production.

Summary

To conclude, the study progresses in-line with the originally envisaged schedule. The analysis of the biggest shale gas play in the U.S., the Marcellus play, requires extra attention to geologic, technical, and economics / financial details. The details of the original resource in place, technically recoverable, and future production outlook will be provided in the next report.

Base Line Reporting	Budget Period 1				Budget Period 2
	Q1 6/15/2016 - 9/15/2016	Q2 9/15/2016 - 12/31/2016	Q3 01/01/2017 - 03/31/2017	Q4 04/01/2017 - 06/30/2017	Q4 07/01/2017 - 09/30/2017
Baseline Federal Share	$63,217	$63,217	$63,217	$63,217	$0
Baseline non-Federal Share	$22,500	$22,500	$22,500	$22,500	$0
Total Baseline Cost	$85,717	$85,717	$85,717	$85,717	$0
Actual Federal Share	$1,317.50	$45,462.28	$49,161.20	$33,600.02	$36,330.17
Actual non-Federal Share	$0.00	$18,000.00	$36,000.00	$9,220.00	$0.00
Total Actual Quarterly Cost	$1,317.50	$63,462.28	$85,161.20	$42,820.02	$36,330.17
Variance Federal Share	$61,899.50	$17,754.72	$14,055.80	$29,616.98	($36,330.17)
Variance non-Federal Share	$22,500.00	$4,500.00	($13,500.00)	$13,280.00	$0.00
Total Variance Cumulative	$84,399.50	$22,254.72	$555.80	$42,896.98	($36,330.17)