Response to Comments on Gas Development Scenarios

1. The statement that "no more than 10 wells per year will be drilled" is unreasonable and inconsistent with scenario 3.
The statement was a relic from an earlier draft and should have been deleted.

2. The use of F5 and F95 are confusing.
USGS used F95, F50 and F5 to indicate a 95%, 50% and 5% chance, respectively, that the amount associated with that fractile would be present. The text will be changed to reflect 95% instead of F5 to reduce confusion, although they are interchangeable

3. Eight wells per pad may be too high; also, it is unreasonable to assume that all planned wells will be drilled on a pad before another pad is constructed. Another commenter said that 8 wells per pad would be reasonable, but there may be a gap of time between drilling each well.
The scenarios have been revised so that there are 6 wells per pad and the drilling has been staggered so that not all wells will be drilled on a pad before the drill rig moves to another pad.

4. The scenarios of no drilling, extraction of 25% of the available gas, and extraction of 75% of the available gas over a 20 year period are flawed. Zero drilling is not a scenario, and 100% extraction should be run as an upper bound. More intermediate scenarios should be run. Are there data from Pennsylvania and West Virginia that would inform the scenarios?
The 0, 25 and 75 percent recovery assumptions are illustrative of scenarios associated with the pace of drilling (none, medium and high) rather than predictions about how much gas will ultimately be extracted, and are a reflection of the potential extraction that may occur within the region. The no drilling scenario reflects the lower-bound, or current drilling climate, and allows for a baseline of activity with which to compare the 25 and 75 percent scenarios. Impacts under an intermediary, or 50 percent scenario, could be measured, but will only reflect the marginal difference between the mid- and high-case scenarios. A scenario where 100 percent of reserves are extracted is unrealistic, if only because some owners of mineral rights will not lease those rights.

Pennsylvania's and West Virginia's experience would probably not be good predictors of extraction in Maryland. For example, Pennsylvania has leased gas rights in state forests, while Maryland's current position is not to lease those rights. Also, start-up in Maryland would be significantly different from start-up in Pennsylvania in 2008 because the industry has learned a great deal since then about improving operations. The pace of drilling is affected by many factors, including the availability of pipelines, the price of gas, and the availability of drill rigs.

5. Assuming a uniform pace of drilling for 10 years is not realistic. There is the potential for a boom and bust cycle or dramatic changes in demand for natural gas. There is no reason for well drilling to stop at 2026 – for a 20 year study – new wells should be drilled for ALL 20 years not just the first 10.

The scenarios have been revised so that they no longer include a uniform pace of drilling. The analysis uses a twenty year period to simulate a potential "boom/bust" cycle. All the wells called for in the scenarios are drilled in the first ten years, simulating a "boom" period. During the second 10 years, the wells are producing, but production is declining, simulating a potential "bust" period.

6. The price of natural gas should be a variable across a reasonable range because this could have a significant effect on the calculated economic impact. The Henry Hub forecast is for $3.57 per MMbtu in 2016 increasing to $6.69 per MMBtu in 2036 according to the EIA's Annual Energy Outlook 2013. The figure $3.25 is just for the year 2013 and is not relevant to this study. Using the historical average may be more reflective of the future.
RESI has decided to use cost projections for the reference case from the Energy Information Administration (EIA) as reported in the Annual Energy Outlook 2013 (AEO2013).[1] *EIA describes the reference case projection as "a business-as-usual trend estimate, given known technology and technological and demographic trends."*[2] *The Henry Hub spot price is the benchmark price for natural gas in the United States. EIA projects natural gas prices based in large part on Henry Hub spot prices. Multiple variables could cause the reference case estimates to be high or low; for example, whether economic activity is strong or weak, whether the prices for oil and coal rise or fall, and whether a carbon tax is imposed. Selecting different assumptions would introduce a bias into RESI's analysis*

RESI is not using a single figure, such as $3.25, as the price for gas for its study. RESI will use the projected future prices of gas from the EIA's Annual Energy Outlook 2013, which provides projections for each year to 2040.[3]

7. Consideration should be given to higher prices if liquefied natural gas is exported from Maryland. Using the Henry Hub data may underestimate the price. If the projection of Henry Hub prices diverges from projected Maryland prices because of different demand and supply commissions in Maryland as compared to the Henry Hub, then the prices used in the analysis will be incorrect.
It is true that if the price of gas in Maryland diverges dramatically from the Henry Hub price that the economic impact of shale gas development in Maryland may be overestimated or underestimated. Natural gas prices in the Mid-Atlantic have historically been higher than the Henry Hub price, reflecting the cost of moving natural gas from the Gulf region to consumers. That relationship began to change in 2011 when gas production increased from the Marcellus region. It is possible that this trend will continue, but there could be countervailing forces, such as increased export of natural

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[1] "Annual Energy Outlook 2013," U.S. Energy Information Administration, accessed on October 31 at http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf
[2] Ibid, pg. 55
[3] See U.S. Energy Information Administration Annual Energy Outlook 2013 Table using the Reference Case scenario for Henry Hub Spot Price, available at http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a

gas. The spot price can also be influenced by production, availability of infrastructure, and demand, e.g. an especially cold winter. RESI selected the EIA projections which are based on the Henry Hub price as the most reliable available.

8. State and County taxes should be considered separately, and it would be reasonable to assume that a State level severance tax between 1% and 2.5% would be imposed.
RESI will incorporate the existing county severance tax structure, as well as the proposed 2.5% severance tax into its economic model. Taxes at the State and County levels will be distinguished as part of the fiscal impact analysis. RESI will be able to scale the estimates from the analysis up or down to reflect possible changes in the severance tax rates for the State. Future analysis using the findings of the economic and fiscal impact analysis can be used by the State to evaluate proposed changes to the severance tax.

It should be noted that the most recent bill proposing a state level severance tax, SB 879 (2013), would have required that the proceeds be deposited in a special, nonlapsing fund. Until the balance in the fund exceeded $15 million, money could be used only to monitor for, mitigate, and remediate adverse impacts of gas exploration and production that could not be attributed to a specific actor, or that had to be corrected immediately to protect public health or safety, the environment, or natural resources, and the responsible actor did not address them within a reasonable time. The positive economic impact of the tax revenue would appear to be minimal until the balance exceeded $15 million. To the extent imposition of a state-level severance tax might discourage drilling in Maryland, it would be represented by the no drilling or low level drilling scenarios.

9. Are governmental expenses like the administrative costs of review of permits and CGDPs, inspections, and enforcement considered? Should the income MDE receives from permit fees be factored in?
It is difficult to estimate the cost to the County of participating in the CGDP process or negotiating Road Use Agreements, and these costs will not be considered. The statute authorizing MDE to assess permit fees is designed to be revenue neutral. That is, the Department is to collect enough money "solely to administer and implement programs to oversee the drilling, development, production, and storage of oil and gas wells, and other requirements related to the drilling of oil and gas wells." To reinforce this, the statute also says "In any fiscal year, if the fee schedule established by the Department generates revenue that exceeds the amount necessary to operate a regulatory program to oversee the drilling of oil and gas wells, the Department shall reduce the fees in the following fiscal year."

10. It is essential to look at the economic effects of shale gas drilling on tourism and the resort economy, including changes in property values.
The study will look at potential impacts to tourism and property values as follows:

- *RESI is reviewing existing tourism studies and gathering visitation figures pre- and post-drilling for regions similar to Western Maryland, which includes interviewing communities in Pennsylvania and West Virginia to quantify the potential impacts of gas development activity on visitation. RESI will determine the change in tourism associated with shale drilling using a time-series regression analysis. From this* *regression, RESI will determine an impact multiplier which will be applied to baseline Garrett County tourism data (based on the 2010 study) to determine the change in tourism to the region that may occur with respect to drilling.*

- *As part of the comprehensive study, RESI is conducting an analysis of property values pre- and post-drilling. The Hedonic Analysis will take into consideration the presence of natural gas wells, whether the property relies on ground water or public water, and proximity to potential well locations. RESI is using data on existing well locations, data from past permit applications for Marcellus wells (since withdrawn), lease information, and geographic analysis to determine potential locations where drilling may take place under the scenarios. The findings will be used as impact multipliers in the economic model, which will account for the potential change in property values in the region during the study time period.*
- *RESI conducted an in-person and online survey to evaluate the non-market impact of potential Marcellus shale natural gas exploration and production. The survey was intended to elicit values for environmental protection from residents and non-residents in Allegany and Garrett Counties. Responses will form one set of inputs into the economic model. Questions covered usage of environmental amenities, residence, a hypothetical drilling scenario, and demographics. Responses to a question on willingness to pay for environmental protection against potential damages from drilling will also be used to develop an input to help determine the total economic impact of drilling, should it occur.*

11. Maryland has 1.09% of the Marcellus, not 1.69%. The USGS estimates are considered low, but this will not matter much in a 20 year time frame. This study at the minimum should run the F50 estimate as one of the scenarios.
According to EIA, Maryland has approximately 1.09% of the areal extent of the Marcellus formation. Considering the three Assessments Units (Interior, Foldbelt, and Western Margin) separately, USGS estimates that Maryland has approximately 1.69% of the Interior AU, which contains 96% of the total undiscovered resource, 2.28% of the Foldbelt AU, and none of the Western Margin AU. The number chosen for the scenarios represents the Interior AU only (703 billion cubic feet). The number in the December 2011 report of MDE and DNR used the Interior and the Foldbelt AUs (711 billion cubic feet).

12. Given the timing of the report and the need to gather 2 years of baseline data before drilling, it would be more realistic to have the time period run from 2018 to 2028 rather than 2016 to 2026.
The scenarios now run for the 20 year period from 2017 to 2036, with the drilling occurring in the first 10 years.

13. The interest in development in Maryland has dramatically diminished, based on the acreage of leases that were not renewed. Any activity early on will more likely occur near the PA and WV borders because of where drilling has already occurred and the proximity to infrastructure.
The scenarios and revised scenarios reflect no drilling, moderate, and aggressive rates of drilling and therefore already simulate different levels of interest. The sites that were the

subjects of the original well drilling applications in Maryland (since withdrawn) were along the West Virginia and Pennsylvania borders, so it is likely that, if drilling occurs, it would start there.

14. The production decline curve is based on outdated information. Also, the document suggests a static production rate after 3 years, when it would be more accurate to identify a static decline rate (perhaps 15% to 20% per year). Relying on data from the Post Carbon Institute may undermine the credibility of the economic study because it is considered by some to be a biased source. An unbiased academic or government source could provide actual data.

Without actual Maryland data to measure production, RESI has opted to construct a curve reflecting elements of other curves derived from a mix of academic, government and industry sources. The curve was constructed using an initial production rate of approximately 2.19 mmcf (million cubic feet) per day. The well starts with a high production amount, which rapidly declines during the first year. The production rate declines in each successive year and at the end of the fourth year the production for that year is down to 26 mmcf, or a 90 percent decline.

A hyperbolic curve represents the decline rate over the first three years of production. After three years, the curve becomes an exponential decline curve. Beginning with an initial production amount of 395 mmcf, the marginal decline varies from 31 percent to 35 percent in the first three years. In that three-year period, 85 percent of the total EUR is assumed to be recovered. At the end of the 20-year period, approximately 98 percent EUR is assumed to be recovered.

The decline curve will be used when calculating the amount of gas produced, the price of natural gas, and resulting royalty rates.

Curve Comparison

	David Hughes	*Terry Engelder*	*RESI*
Assumptions for EUR	*1.22 EUR (bcf) Estimates are based on DI Desktop data from whole Marcellus region*	*3.75 EUR (bcf) PA Department of Environmental Protection Data*	*1.158 EUR (bcf) USGS*
Initial Production[4]	*270 mmcf*	*Ranges from 75 to 1700 mmcf*	*395 mmcf*
Initial Production per Day	*1.5 mmcf*	*Ranges from approximately 2 to 7 mmcf*	*2.19 mmcf*
Percentage Decline Rate (from initial	*95 percent*	*Ranges from approximately 70*	*85 percent*

[4] Initial production represents first six months of production.

production to third year)		*to 90 percent (depending on well and location)*	
Total Amount Recovered by Year Three	*Approximately 1,161 mmcf*	*Ranges from approximately 316.5 to 7,174 mmcf*	*984.3 mmcf*

15. It does not appear that any scenario considers refracking. The economic lifetime of a well may be much less than 20 years if it is not refracking
Because the occurrence and frequency of re-fracking are not sufficiently understood, the economic study is not incorporating refracking into the scenarios.

16. The USGS value for Estimated Ultimate Recovery (EUR) of 1.158 billion cubic feet (Bcf) per well is based on old data. The report was published in 2011 so the data are from 2009 or 2010. It would be better to use EIA assumptions of 2.065 Bcf per well. See the EIA Oil and Gas Supply Module document at http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf at page 123. The yield has been increasing as wells are getting longer.

RESI prefers to use USGS data and estimates, to the extent they are available, for all assumptions in its report for purposes of consistency. The scenarios were constructed to simulate the extraction of 25% and 75% of the available gas over a twenty year period, with all the wells drilled in the first ten years. The value used for the EUR will determine how many wells will be drilled to extract this amount, and how many pads will be constructed, but it will not affect the amount of gas extracted over the study period.