SHALE GAS REALITY CHECK

REVISITING THE U.S. DEPARTMENT OF ENERGY PLAY-BY-PLAY FORECASTS THROUGH 2040 FROM ANNUAL ENERGY OUTLOOK 2015

J. DAVID HUGHES

post carbon institute

SUMMER 2015

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About the Author

David Hughes is a geoscientist who has studied the energy resources of Canada for four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He developed the National Coal Inventory to determine the availability and environmental constraints associated with Canada's coal resources. As Team Leader for Unconventional Gas on the Canadian Gas Potential Committee, he coordinated the publication of a comprehensive assessment of Canada's unconventional natural gas potential.

Over the past decade, Hughes has researched, published and lectured widely on global energy and sustainability issues in North America and internationally. His work with Post Carbon Institute includes a series of papers (2011) on the challenges of natural gas being a "bridge fuel" from coal to renewables; *Drill, Baby, Drill* (2013), which took a far-ranging look at the prospects for various unconventional fuels in the United States; *Drilling California* (2013), which critically examined the U.S. Energy Information Administration's (EIA) estimates of technically recoverable tight oil in the Monterey Shale, which the EIA claimed constituted two-thirds of U.S. tight oil (the EIA subsequently wrote down its resource estimate for the Monterey by 96%); and *Drilling Deeper* (2014), which challenged the EIA's expectation of long-term domestic oil and natural gas abundance with an in-depth assessment of all drilling and production data from the major shale plays through mid-2014. Separately from Post Carbon, Hughes authored *BC LNG: A Reality Check* in 2014 and *A Clear View of BC LNG* in 2015, which examined the issues surrounding a proposed massive scale-up of shale gas production in British Columbia for LNG export.

Hughes is president of Global Sustainability Research, a consultancy dedicated to research on energy and sustainability issues. He is also a board member of Physicians, Scientists & Engineers for Healthy Energy (PSE Healthy Energy) and a Fellow of Post Carbon Institute. Hughes contributed to *Carbon Shift*, an anthology edited by Thomas Homer-Dixon on the twin issues of peak energy and climate change, and his work has been featured in *Nature*, *Canadian Business*, *Bloomberg, USA Today*, as well as other popular press, radio, and television.

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Shale Gas Reality Check: Revisiting the U.S. Department of Energy Play-by-Play Forecasts through 2040 from Annual Energy Outlook 2015
By J. David Hughes
In association with Post Carbon Institute

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"These predictions are made by the Energy Information Administration...
But in truth, some experts say, we'd have better luck calling Miss Cleo."
—Alan Neuhauser[1]

Like the author of the quote above, many are skeptical of the "projections" made by the U.S. Energy Information Administration (EIA) regarding future shale gas production. Nonetheless, these are commonly viewed by industry and government as the best available assessment of what to expect in the future, with the EIA's reference case typically viewed as the most likely scenario for future production. In my *Drilling Deeper*[2] report published last October, I developed alternate production forecasts for each of the major shale gas plays based on fundamental play characteristics and assumed drilling rates (see http://shalebubble.org/drilling-deeper). The EIA 2014 reference case projections overstated likely gas recovery through 2040 for these plays by 56% compared to my "Most Likely" drilling rate forecasts. The EIA projections are likewise considerably more optimistic than those of the University of Texas Bureau of Economic Geology (UTBEG) for the four plays it has assessed.[3]

Key fundamentals used in projecting future production of shale gas plays *in Drilling Deeper* were:

- **Rate of well production decline:** Shale gas plays have high well production decline rates, typically in the range of 75-85% in the first three years.
- **Rate of field production decline:** Shale gas plays have high field production declines, typically in the range of 30-45% per year, which must be replaced with more drilling to maintain production levels.
- **Average well quality:** All shale gas plays invariably have "core" areas or "sweet spots" where individual well production is highest and hence the economics are best. Sweet spots are targeted and drilled off early in a play's lifecycle, leaving lesser quality rock to be drilled as the play matures (requiring higher gas prices to be economic); thus the number of wells required to offset field decline inevitably increases with time. Although technological innovations including longer horizontal laterals, more fracturing stages, more effective additives, and higher volume treatments have increased well productivity in the early stages of the development of all plays, they have provided diminishing returns over time and cannot compensate for poor quality reservoir rock.
- **Number of potential wells:** Plays are limited in area and therefore have a finite number of locations that can be drilled. Once the locations run out, production goes into terminal decline.
- **Rate of drilling:** The rate of production is directly correlated with the rate of drilling, which is determined by the level of capital investment.

[1] Alan Neuhauser, "Wasted Energy: The pitfalls of the EIA's policy-neutral approach", *US News and World Report*, May 28, 2015; http://www.usnews.com/news/articles/2015/05/28/wasted-energy-the-pitfalls-of-the-eias-policy-neutral-approach.
[2] David Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Tight Oil & Shale Gas Boom* (Santa Rosa, CA: Post Carbon Institute, 2014); http://shalebubble.org.
[3] For an overview of the UTBEG analysis, see David Hughes, "Fracking Fracas: The Trouble with Optimistic Shale Gas Projections by the U.S. Department of Energy", December 23, 2014; http://www.postcarbon.org/fracking-fracas/

So how have the EIA's projections changed in 2015? The EIA kindly provided its play-by-play shale gas projections used for the reference case for its *Annual Energy Outlook 2015* (AEO2015). In Figure 1 I compare these new projections to my "Most Likely" drilling rate forecasts in *Drilling Deeper* and to the EIA's 2014 projections (AEO2014).

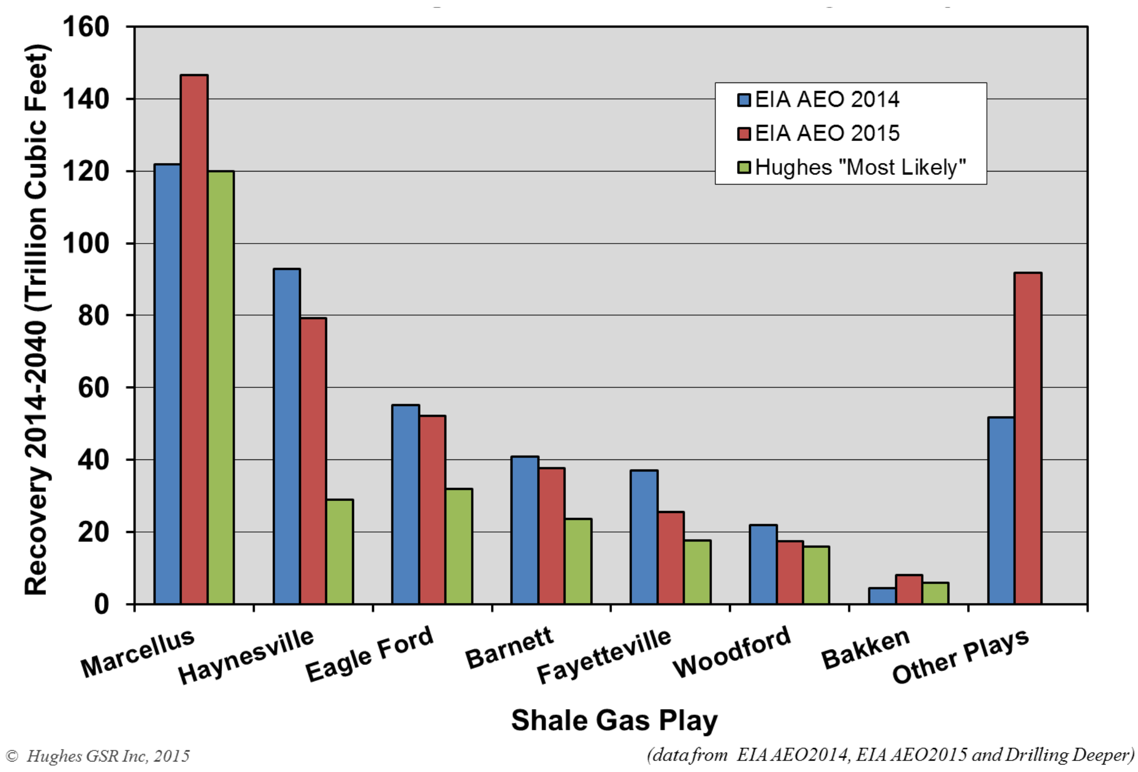


Figure 1. Cumulative recovery by play from 2014 to 2040 comparing AEO2014, AEO2015 and Drilling Deeper "Most Likely" projections.

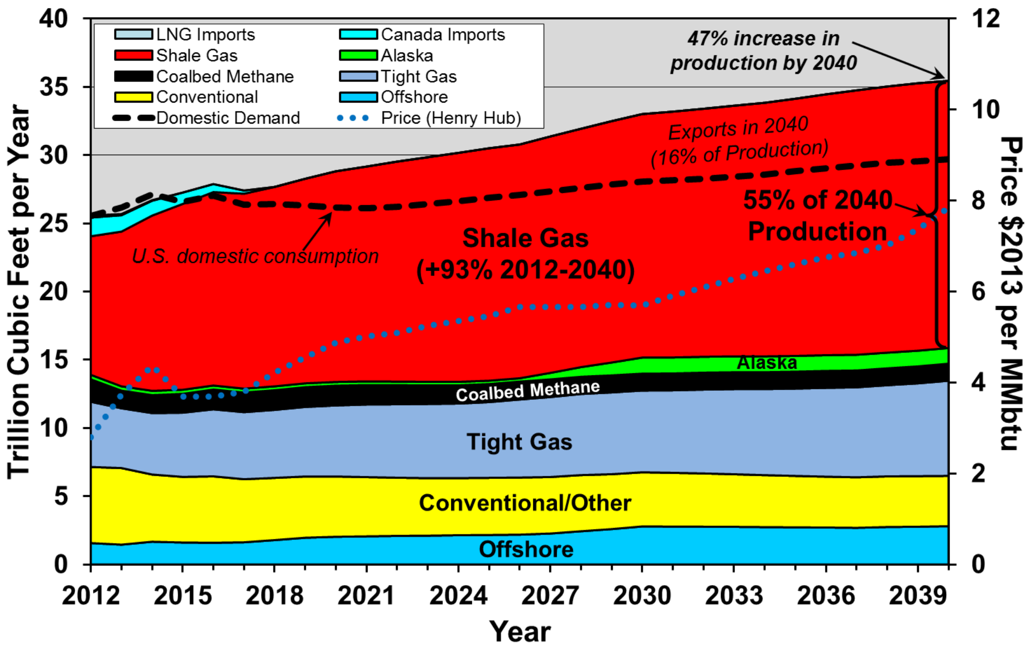
Significant increases occur in the Marcellus, Bakken and "other" plays, whereas all others are downgraded.

Some general observations with respect to the assumptions and projections in AEO2015:

- EIA assumes natural gas prices will remain low and will not exceed $6/MMbtu until 2032.
- EIA assumes production from shale gas will grow even faster than projected in AEO2014, with 2014-2040 production increasing by 36 trillion cubic feet (tcf) over the 2014 projection.
- The seven major plays analyzed in *Drilling Deeper*, which constituted 89% of AEO2014 projected shale gas production through 2040, amount to just 80% of the AEO2015 projection. Production is projected to grow aggressively in the Utica and other unnamed plays.
- One third of production through 2040 is projected to come from the Marcellus and 60% from just three plays—the Marcellus, Haynesville and Eagle Ford—highlighting yet again that high quality shale gas plays are not ubiquitous.
- Considering that AEO2014 and AEO2015 are just 12 months apart, there is a lot of change in projected production profiles for individual plays, which raises questions about the robustness, or lack thereof, of the EIA's forecasting methods.

1.1 PRODUCTION AND PRICE PROJECTIONS

Figure 2 illustrates the AEO2015 reference case for U.S. natural gas production by source and price projections. Most eggs are in the shale gas basket, with production forecast to grow by 93% over 2012 levels by 2040, when it will constitute 55% of production. Overall U.S. gas production is forecast to grow by 47% over the period, with 16% of production available for export by 2040. All other sources of gas are essentially flat to slightly increasing over the period. Prices will remain low, rising to $6/MMbtu by 2032 and just under $8/MMbtu by 2040.



© Hughes GSR Inc, 2015 (data from EIA Annual Energy Outlook 2015, Tables 13 and 14, http://www.eia.gov/forecasts/aeo/er/excel/yearbyyear.xlsx)

Figure 2. AEO2015 reference case forecast of gas production by source from 2012-2040.

Also shown is projected price (Henry Hub in 2013 dollars per MMbtu) and projected domestic consumption.

This is a good-news forecast, which even includes the construction of an Alaska gas pipeline by 2030 in the face of low prices. Too good to be true? Very probably, given that the most economic parts of shale gas plays are being drilled now (core areas or sweet spots) leaving the highest-cost parts of these plays for later—which will require higher prices and a much higher drilling rates to maintain, let alone grow, production. A look at the shale gas forecast by individual play gives a better perspective on the credibility of these projections.

2 Shale Gas Production by Play

Figure 3 illustrates the AEO2015 reference case forecast by shale gas play compared to AEO2014. Half of projected production comes from two plays, the Marcellus and Haynesville, and production from 2014-2040 is 36 tcf, or 9%, higher than AEO2014. The AEO2014's near-term underestimate of actual production, highlighted in *Drilling Deeper,* has been corrected in AEO2015 and shale gas production exits 2040 at the level projected in AEO2014.

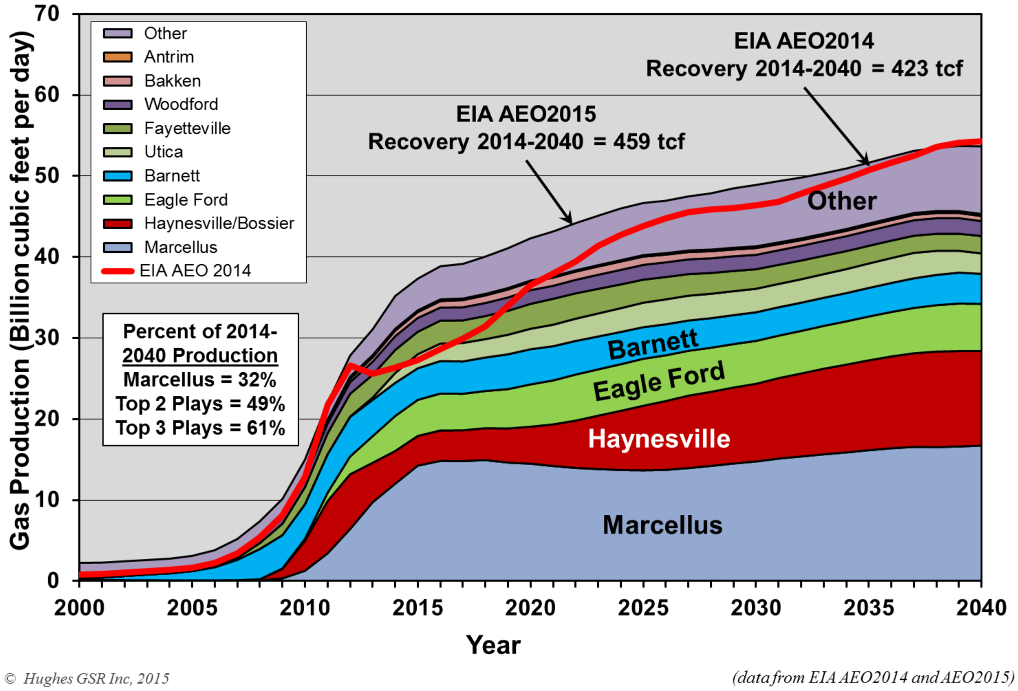


Figure 3. AEO2015 reference case forecast of gas production by shale gas play from 2012-2040, compared to AEO2014.

The EIA is even more bullish overall than last year and has corrected the near-term production underestimate in AEO2014. Sixty percent of 2014-2040 production is from just three plays.

2.1 MARCELLUS PLAY

Figure 4 illustrates the AEO2015 reference case forecast for the Marcellus compared to AEO2014 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2015, the Marcellus is forecast to produce 32% of all shale gas production from 2014 to 2040.

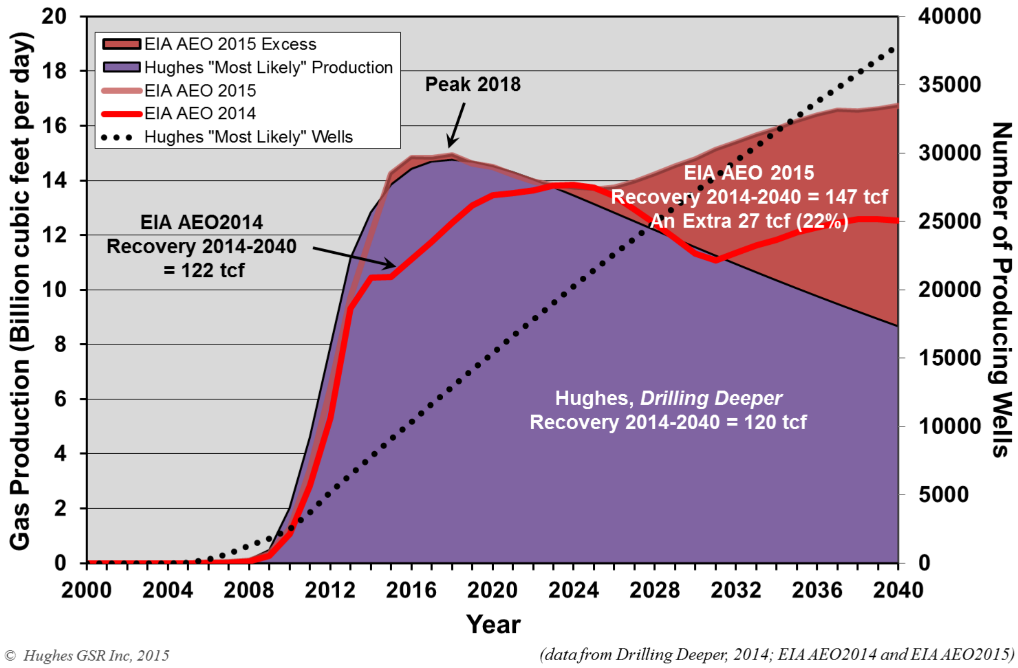


Figure 4. Marcellus Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative wells that would have to be drilled for the "Most Likely" drilling rate.

The AEO2015 projection almost perfectly parallels my "Most Likely" forecast until 2023, when it ramps up to a new all-time high in 2040. Total projected production is up 20% over AEO2014 and 22% above my "Most Likely" forecast. Some observations:

- Given that the average well quality in the Marcellus has been shown to be in decline in the sweet spots, as well as in the Marcellus play as a whole, the AEO2015 forecast lacks credibility, especially at the EIA's forecast gas prices.
- The only way production could begin to grow post-2023 is with a massive ramp up in drilling which, given declining well quality, would require much higher prices.
- Drilling rates in my "Most Likely" forecast, which projects a 4-fold increase in producing wells, would see some 25,000 remaining drilling locations by 2040, although these would be the lowest-productivity locations in the play. Ramping up production as projected by AEO2015 would see locations exhausted by this time, given the drilling rates required, setting the stage for a production collapse.
- The drop in rig counts in the Marcellus (63 in June 2015 vs. 143 in January 2012) has impacted drilling rates, despite greater efficiencies, and hence may cause the Marcellus to peak sooner at a lower rate than my "Most Likely" forecast. A wild card, however, is the large number of drilled but not connected locations, which will provide a buffer from falling rig counts for a few months.

2.2 HAYNESVILLE PLAY

Figure 5 illustrates the AEO2015 reference case forecast for the Haynesville compared to AEO2014 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2015, the Haynesville is forecast to produce 17% of all shale gas production from 2014 to 2040.

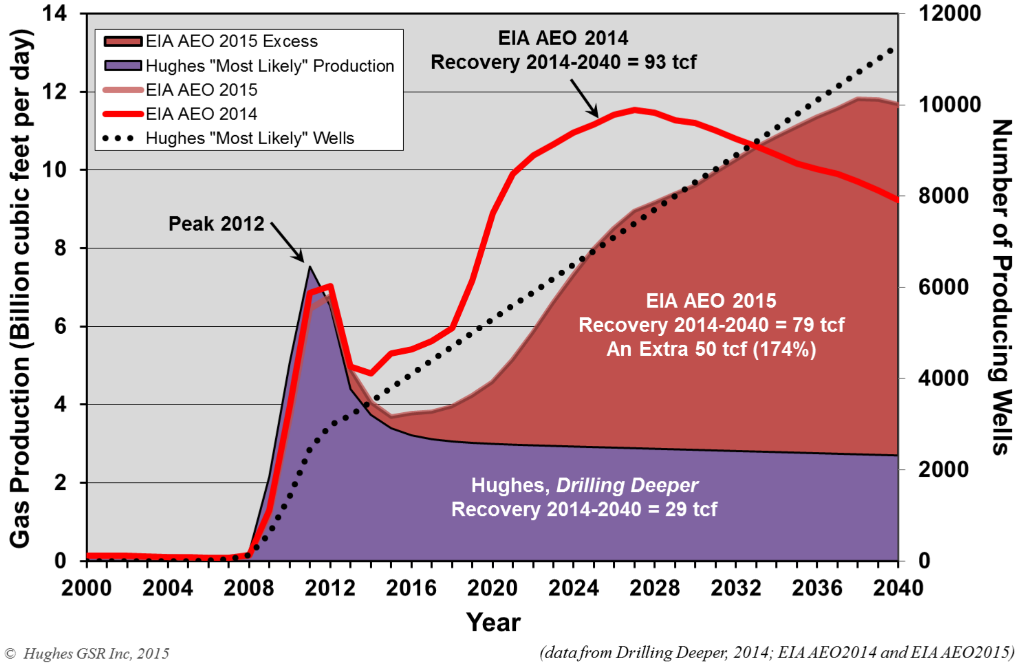


Figure 5. Haynesville Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative wells that would have to be drilled for the "Most Likely" drilling rate.

The AEO2015 projection parallels my "Most Likely" forecast until 2016, when it ramps up to a new peak in 2038. Total projected production is down 15% over AEO2014 but is 174% above my "Most Likely" forecast. Some observations:

- The only way production could begin to grow post-2016 to triple current production is with a massive ramp-up in drilling, which would require much higher prices.
- Drilling rates in my "Most Likely" forecast, which projects a 3-fold increase in producing wells, would see some 9,000 remaining drilling locations by 2040, although these would be the lowest productivity locations in the play. Ramping up production as projected by AEO2015 would see available locations exhausted before 2040, given the drilling rates required, setting the stage for a production collapse.
- The drop in rig counts in the Haynesville (26 in June 2015 vs. 161 in February 2011) has caused a major drop in Haynesville production, although the rig count did remain fairly consistent from mid-2012 until February 2015 at about 45. Even considering greater efficiency and better technology, the rig count would have to go far above the maximum rate in 2011 to achieve the AEO2015 forecast. Hence the AEO2015 forecast has little credibility, especially with forecast prices and available locations.

2.3 EAGLE FORD PLAY

Figure 6 illustrates the AEO2015 reference case forecast for the Eagle Ford compared to AEO2014 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2105, the Eagle Ford is forecast to produce 11% of all shale gas production from 2014 to 2040.

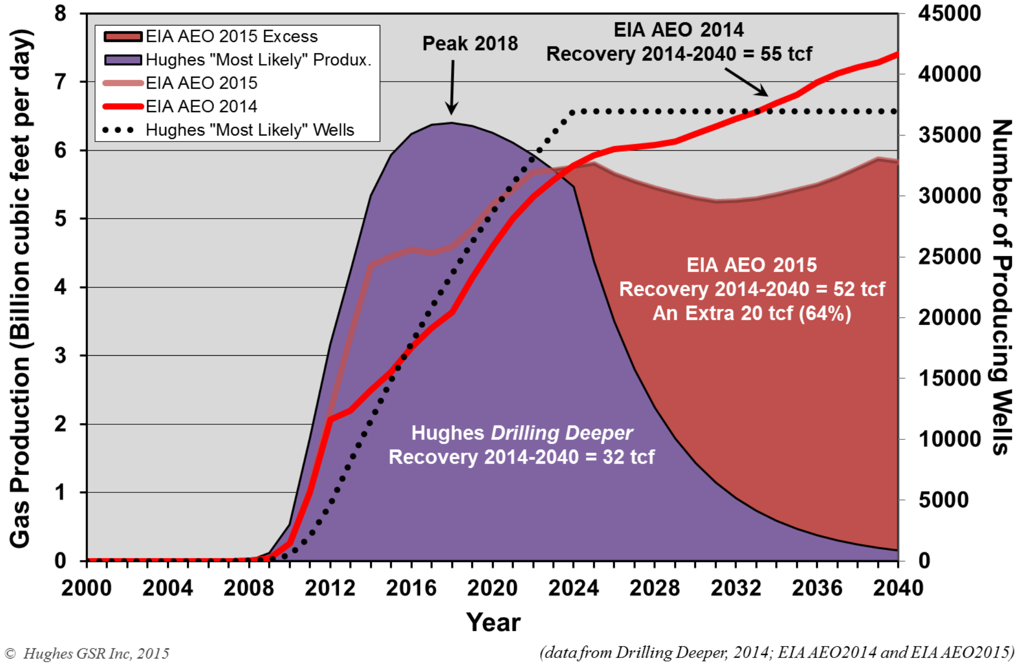


Figure 6. Eagle Ford Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative wells that would have to be drilled for the "Most Likely" drilling rate.

The AEO2015 projection has partially corrected EIA's original underestimate of near-term gas production in AEO2014, but is still below actual production of 5.6 bcf/d in January 2015. AEO2015 rises to a plateau in 2024 at about the current production level, drops only marginally, and then rises to an all-time peak in 2039. Total projected production is down 5% over AEO2014 but is 64% above my "Most Likely" forecast. Some observations:

- Due to the drop in oil prices (much Eagle Ford gas is produced in association with oil) drilling rates are currently below my "Most Likely" rate forecast, hence production will likely peak sooner at a lower rate, and drilling may continue an extra year or two before locations run out. The AEO2015 forecast of a high-production plateau beginning in 2024 and rising to an all-time high in 2039 belies the fact that there is a finite number of drilling locations in the Eagle Ford and hence is extremely optimistic.

- Drilling rates in my "Most Likely" forecast, which projects a 3-fold increase in producing wells from current levels to nearly 37,000, would see drilling locations exhausted by 2024. If the current drilling rate continues at reduced levels this may extend drilling somewhat, but will not change the recovery of gas by 2040 significantly.

- The drop in rig counts in the Eagle Ford (110 in June 2015 vs. 239 in February 2011, of which 20 and 36 were classified as "gas" rigs, respectively) has caused a slowdown in production growth. Even considering greater efficiency and better technology, the rig count would have to return to higher levels and the drilling rate would have to grow through 2040 to meet the AEO2015 forecasts. This would have to happen in the face of low prices and declining well quality as sweet spots were exhausted. There are nowhere near enough drilling locations to allow this to happen, hence the AEO2015 forecast has little credibility.

2.4 BARNETT PLAY

The Barnett Play is where modern fracking got started in earnest and is the most mature shale play in the U.S. Figure 7 illustrates the AEO2015 reference case forecast for the Barnett compared to AEO2014 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2015, the Barnett is forecast to produce 8% of all shale gas production from 2014 to 2040.

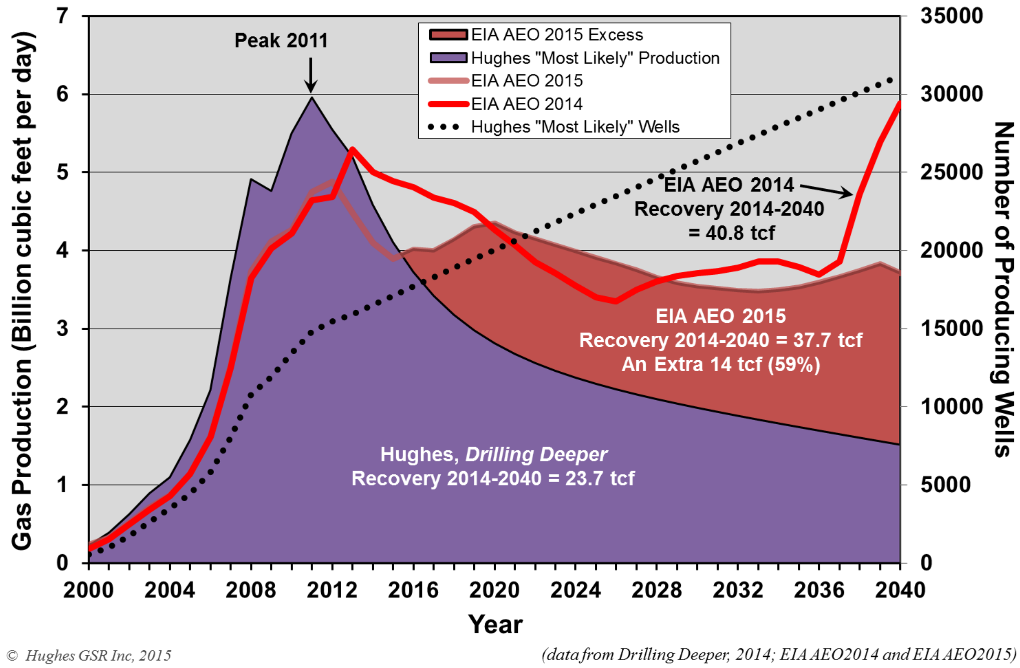


Figure 7. Barnett Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative wells that would have to be drilled for the "Most Likely" drilling rate.

AEO2015 projects Barnett production to begin growing in 2016 from the level in my "Most Likely" drilling rate forecast and remain at much higher levels through 2040. It is somewhat more reasonable than AEO2014, which projected a new all-time high in 2040. Total projected production is down 8% over AEO2014 but is 59% above my "Most Likely" forecast. Some observations:

- The only way production could begin to grow post-2016 is with a very considerable ramp up in drilling, given that sweet spots in the Barnett are nearing saturation and new well productivity is falling (down 18% from 2011 levels in 2013). Prices would have to be higher to justify this—considerably higher than forecast by AEO2015.

- Drilling rates in my "Most Likely" forecast, which projects a doubling in the number of producing wells, would see some 5,000 drilling locations remaining in 2040, although these would be the lowest-productivity locations in the play. Ramping up production as projected by AEO2015 would see available locations exhausted before 2040, given the drilling rates required, setting the stage for a production collapse.

- The drop in rig counts in the Barnett (5 in June 2015 vs. 60 in November 2011) has caused a major drop in production, although the rig count did remain between 25 and 40 from January 2013 to January 2015. Even considering greater efficiency and better technology, the rig count would have to go an order of magnitude above today's levels, and higher than the maximum rate in 2011, to achieve the AEO2015 forecast. Given that this would have to occur at low prices and amid falling well productivity, and that there are not enough available locations to do this, the AEO2015 forecast has little credibility.

2.5 FAYETTEVILLE PLAY

Figure 8 illustrates the AEO2015 reference case forecast for the Fayetteville compared to AEO2014 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2015, the Fayetteville is forecast to produce 6% of all shale gas production from 2014 to 2040.

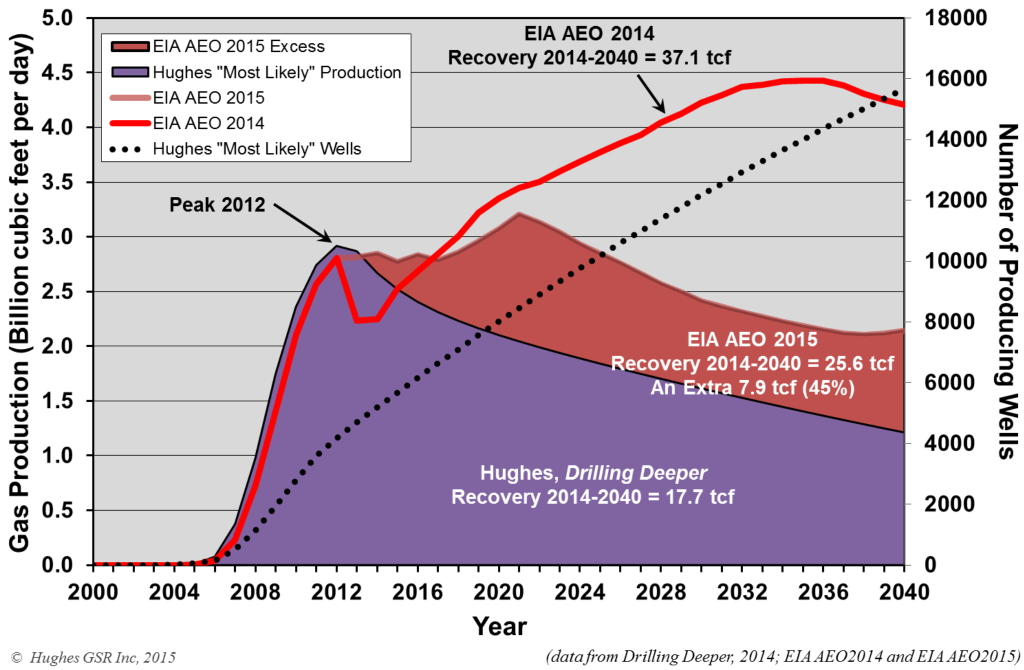


Figure 8. Fayetteville Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative wells that would have to be drilled for the "Most Likely" drilling rate.

AEO2015 projects Fayetteville production to maintain a plateau at its peak levels through 2017 and then rise to a new peak in 2021, followed by a gradual decline. This projection is much more reasonable than AEO2014, which projected a peak at nearly double current production in 2036. Total projected production is down 31% over AEO2014 but is 45% above my "Most Likely" forecast. Some observations:

- The only way production could begin to grow post-2017 is with a considerable ramp up in drilling, Prices would have to be higher to justify this—considerably higher than forecast by AEO2015.
- Drilling rates in my "Most Likely" forecast, which projects a tripling in the number of producing wells, would see less than 1,000 drilling locations remaining in 2040, and these would be the lowest productivity locations in the play. Ramping up production to a new peak in 2021 and maintaining production at levels 50% higher than my "Most Likely" forecast, as projected by AEO2015, would see available locations exhausted well before 2040, given the drilling rates required, setting the stage for a production collapse.
- The drop in rig counts in the Fayetteville (6 in June 2015 vs. 32 in January 2012) has caused a gradual drop in Fayetteville production, although the production data have yet to reflect the full impact of the drop in rig count as they are current only through January 2015. Even considering greater efficiency and better technology, the rig count would have to go considerably higher to meet the near term AEO2015 forecast. Given that this would have to occur at low prices, and that there are not enough available locations to meet its long term projection, the AEO2015 forecast is overly optimistic at best.

2.6 WOODFORD PLAY

Figure 9 illustrates the AEO2015 reference case forecast for the Woodford compared to AEO2014 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2015, the Woodford is forecast to produce 4% of all shale gas production from 2014 to 2040.

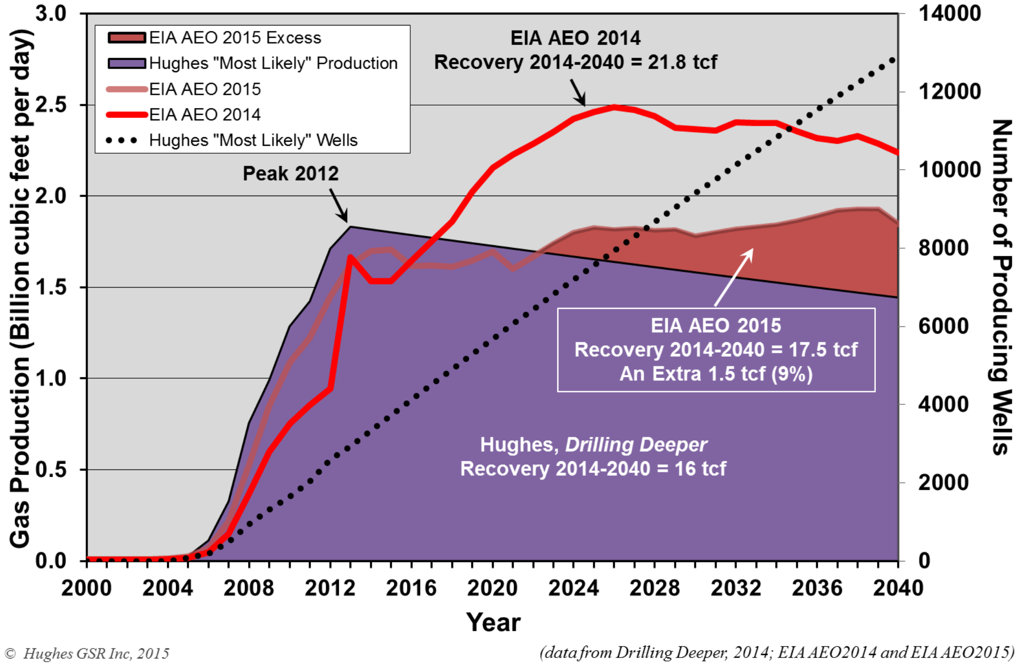


Figure 9. Woodford Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative wells that would have to be drilled for the "Most Likely" drilling rate.

AEO2015 projects Woodford production to grow gradually to a peak in 2039. This projection is much more reasonable than AEO2014 which projected a peak at 50% above the current production level in 2026. Total projected production is down 20% over AEO2014 but is 9% above my "Most Likely" forecast. Some observations:

- The AEO2015 projection is certainly possible but would require higher drilling rates than assumed in my "Most Likely" forecast. Prices would have to be higher to justify this.
- Drilling rates in my "Most Likely" forecast, which projects nearly a 4-fold increase in the number of producing wells, would see 6,000 drilling locations remaining in 2040, or about a third of the total number of locations in the play. Ramping up drilling rates to the level needed to meet the AEO2015 forecast is possible and there would still be some locations remaining in 2040.
- The drop in rig counts in the Woodford (40 in June 2015 vs. 74 in January 2012) has caused a gradual drop in Woodford production, although the rig count has held up much better in the Woodford than some of the other shale gas plays. Considering greater efficiency and better technology, the rig count would have to go somewhat higher to meet the near term AEO2015 forecast than assumed in my "Most Likely" case, but this is feasible.
- The EIA has improved its forecast for the Woodford compared to AEO2014, and hence this projection is rated as only slightly optimistic.

2.7 Bakken Play

Figure 10 illustrates the AEO2015 reference case forecast for the Bakken compared to AEO2014 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2015, the Bakken is forecast to produce 2% of all shale gas production from 2014 to 2040.

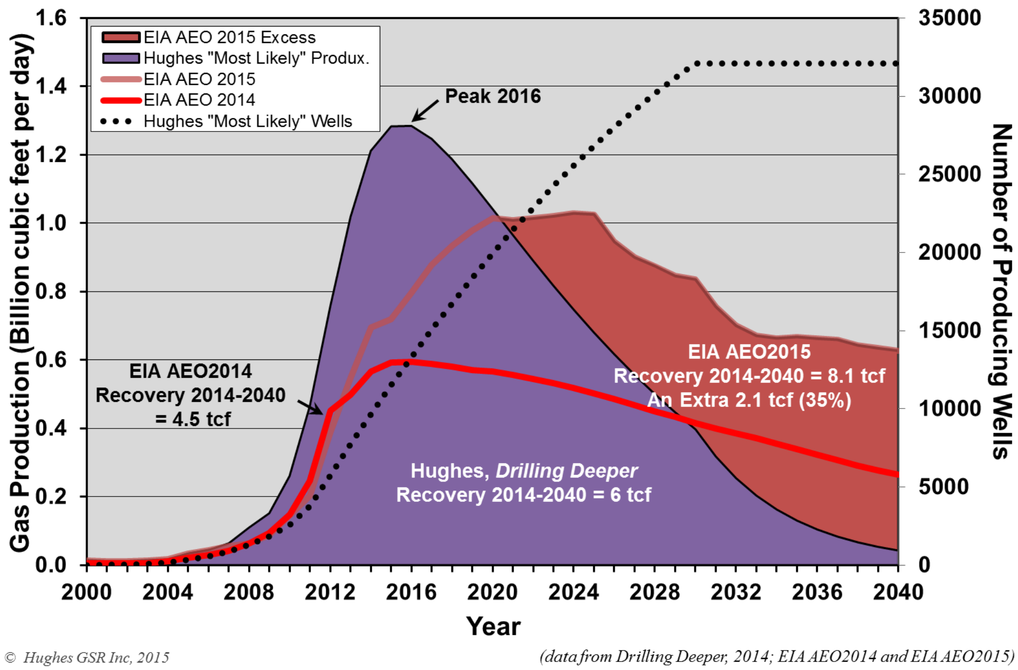


Figure 10. Bakken Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative wells that would have to be drilled for the "Most Likely" drilling rate.

The AEO2015 projection has partially corrected the underestimate of near term gas production in AEO2014 but is still below actual production of 1.3 bcf/d in January 2015. The AEO2015 projection rises to a peak in 2025 that is below the current production level and then declines. Total projected production is up 80% over AEO2014 and is 35% above my "Most Likely" forecast. Some observations:

- Due to the drop in oil prices (most Bakken gas is produced in association with oil) drilling rates have dropped to below my "Most Likely" rate forecast, and hence production is likely close to peak now. Drilling at a slower rate now will conserve additional locations for later, but the AEO2015 forecast implies that drilling rates will still be fairly high in 2040, well past the time locations will have run out.

- Drilling rates in my "Most Likely" forecast, which projects a 3-fold increase in producing wells from current levels to nearly 33,000, would see drilling locations exhausted by 2030. If the current drilling rate continues at reduced levels this may extend drilling somewhat, but will not change the recovery of gas by 2040 significantly.

- The drop in rig counts in the Bakken (77 in June 2015 vs. 198 in October 2014) has caused a decline in production. Gas is a by-product of oil production in the Bakken, hence its production will closely parallel that of oil (but may increase as a proportion of total production somewhat as flaring is brought under control). "Most Likely" drilling rates would see locations running out by 2030, hence projecting relatively high levels of gas production out to 2040, as in AEO2015, must be viewed as optimistic and not based on play fundamentals.

- Although AEO2015 is more realistic in total gas recovery for the Bakken than AEO2014, which was rated as too conservative in *Drilling Deeper*, it doesn't represent what is going on in the near term and it projects unrealistically high levels of gas production in the long term.

2.8 "OTHER" PLAYS

"Other" plays account for 20% of projected 2014 to 2040 shale gas production in AEO2015, up from 11% in AEO2014. These include the old and declining Antrim play of Michigan, and the emerging Utica play of Ohio and western Pennsylvania, estimated at 0.4% and 5.8% of 2014 to 2040 production, respectively. Figure 11 illustrates the AEO2015 reference case forecast for "other" plays compared to AEO2014.

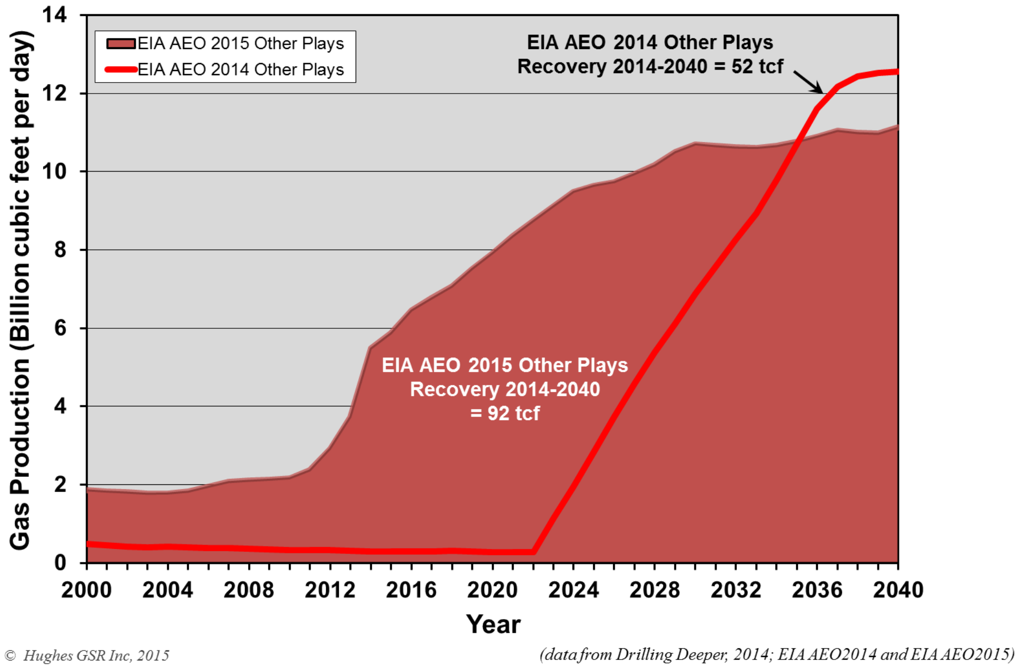


Figure 11. Other plays production in the AEO2014 and AEO2015 forecasts.
AEO2015 has nearly doubled the estimated 2014 to 2040 recovery from these plays.

The AEO2015 projection more accurately represents actual production from other plays in the near term than AEO2014 and has reduced their contribution to 2040 shale gas production to 16% compared to 23% for AEO2014. Nonetheless, the AEO2015 projection rises continually and exits 2040 at an all-time high. This would require aggressive development of other plays given that the Utica play, which is being intensely developed, is projected to be less than one-third of 2040 "other" play production, and the Antrim play is in decline. Total projected production from "other" plays over the 2014 to 2040 period is up 77% over AEO2014.

The AEO2015 projection for "other" plays must be rated as very optimistic, given that there are no emerging plays on the scale of the Utica despite an intensive exploration effort in recent years.

3 All Plays Comparison

Figure 12 illustrates the comparison of the major plays evaluated in *Drilling Deeper* compared to forecasts for the same plays from AEO2014 and AEO2015. Also shown is total shale gas production projected in AEO2015's reference case and the cumulative number of producing wells needed to meet the "Most Likely" forecast from *Drilling Deeper*. Despite considerable changes in the production forecasts for individual plays, AEO2015 has reduced its aggregate production from 2014-2040 for major plays by just 2% compared to AEO2014, and production in 2040 is virtually identical to AEO2014. Instead of reaching a plateau in 2024, as projected by AEO2014, AEO2015 forecasts a continuous increase in major play production through 2040, and a continuous growth in total production including "other" plays.

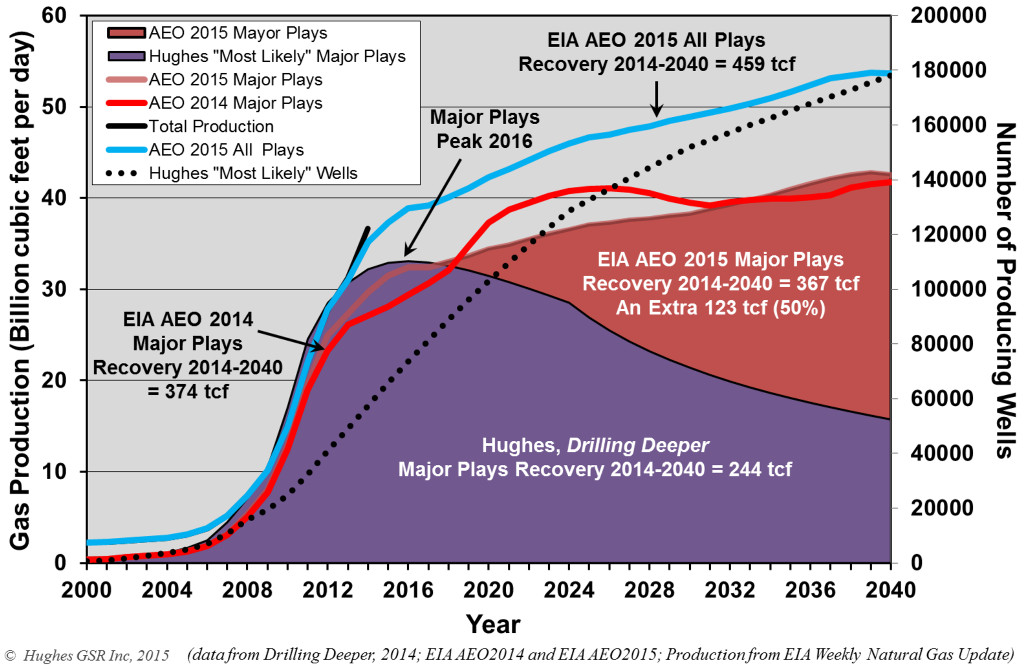


Figure 12. Comparison of the AEO2014 and AEO2015 forecasts for major plays compared to the "Most Likely" forecast for these plays in *Drilling Deeper*.

Also illustrated is the total production forecast for AEO2015 including "other" plays and the cumulative number of producing wells required to meet the "Most Likely" forecast. AEO2015 projects recovery of 50% more gas from major plays than forecast in the "Most Likely" case in *Drilling Deeper*.

The AEO2015 projections represent a good news story for those hoping for a lasting shale gas boom at low prices. Notwithstanding the major changes in outlook for individual plays between AEO2014 and AEO2015, the overall forecast is even more optimistic than AEO2014—but it is not supported by an analysis of key play fundamentals and an assessment of likely drilling rates. Given that the AEO2015 projections for individual plays range in the "very optimistic" to "little credibility" categories, the overall rating for AEO2015 has to be extremely optimistic, considering the fundamentals of these plays and their advancing state of drilling maturity.

3.1 VOLATILITY OF EIA PLAY LEVEL FORECASTS

One measure of the potential reliability of future production estimates from the EIA is how much successive forecasts change over time. Certainly everyone is entitled to change their mind, but the geological fundamentals of shale gas plays are now relatively well known and don't change wildly from year to year. Wild swings in projected production rates and cumulative recovery indicate a basic lack of robustness in the methodology used for estimation, unless there is significant new information to account for it.

Despite the fact that the EIA projections by play examined herein were made only 12 months apart, they exhibit major differences in future production rates and in estimated gas recovery. Figure 13 illustrates the magnitude of production rate differences between AEO2014 and AEO2015 by play in percentage terms. Plays have been revised both upward and downward by amounts exceeding 40 percent in some plays/years.

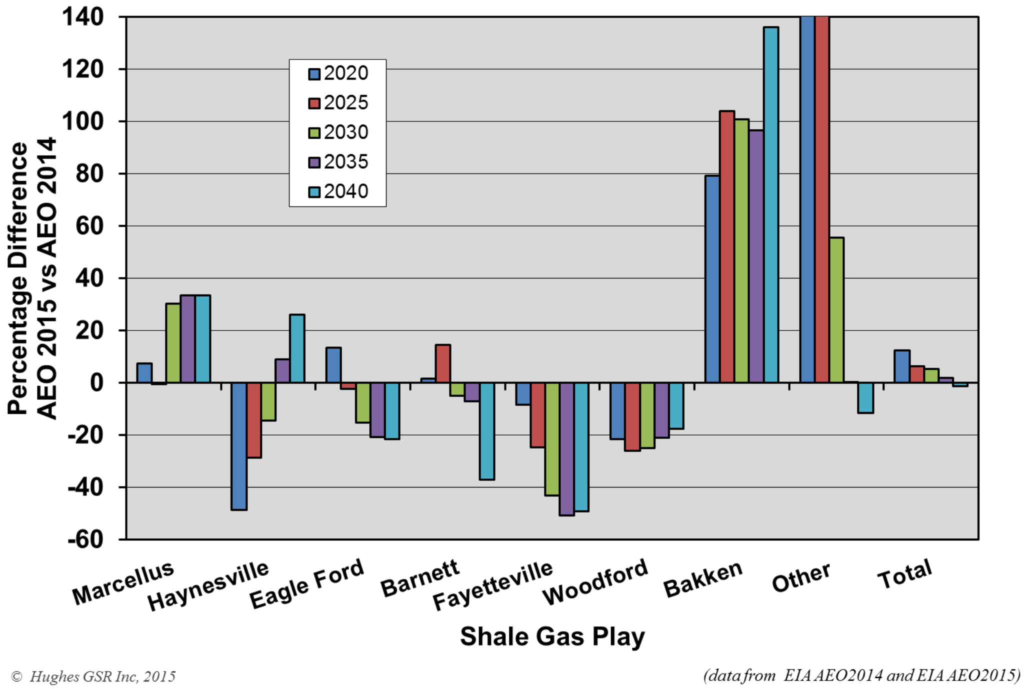


Figure 13. Comparison of projections by play from AEO2015 and AEO2014.

Comparison is made in terms of the percentage difference in production rates for the years 2020, 2025, 2030, 2035 and 2040. The 2020 and 2025 values for "Other" are literally off the chart, at 2,724% and 238% respectively.

Figure 14 illustrates the changes in total gas recovery from 2014 through 2040 between AEO2014 and AEO2015. Although 5 of the 7 major plays have been revised downward, the upward revisions of the Marcellus and "other" plays results in a total increase in production of 36 tcf, or 9% more in AEO2015 than AEO2014. Upward revisions in the Marcellus and "other" plays amount to 20% and 78% respectively.

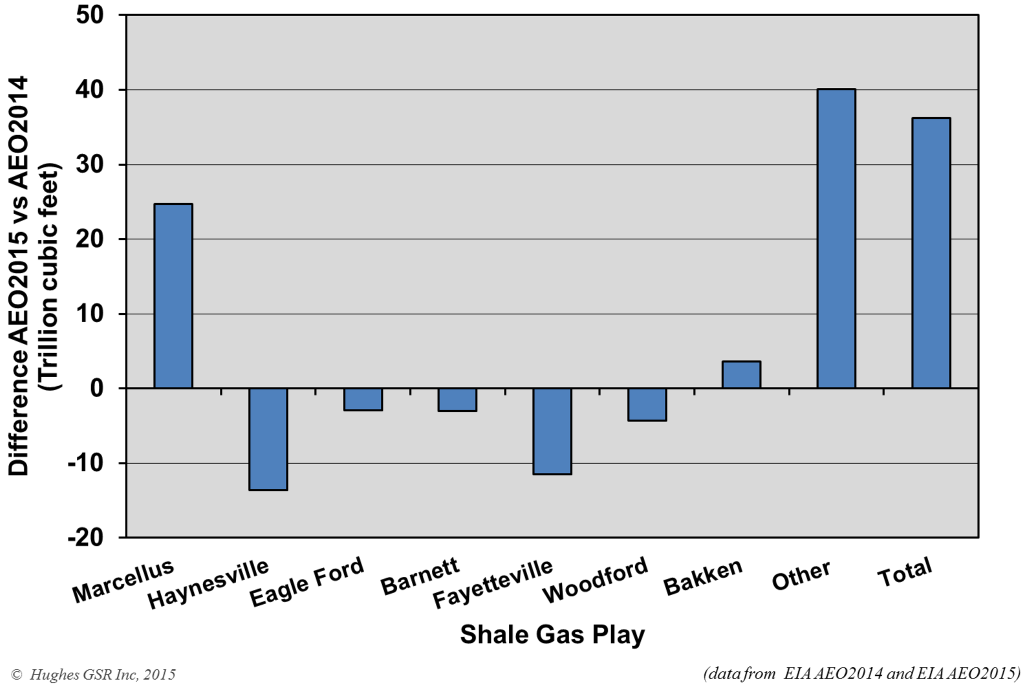


Figure 14. Comparison of projections by play from AEO2015 and AEO2014 in terms of total gas production from 2014 through 2040.

Overall production has increased by 36 tcf, or 9%, in AEO2015 compared to AEO2014.

The EIA offers no explanations for the volatility and optimism of its projections. Geological fundamentals appear to have little to do with it, given that major plays are now quite well understood. Assumptions of vastly improved technology in the future may be a factor, although improvement in average well quality has stagnated or is falling in sweet spot counties of major plays like the Bakken, Eagle Ford and Marcellus—as expected as sweet spots are drilled off. The volatility cannot be attributed to changes in future gas price assumptions either, given that prices are similar between the two forecasts, and in fact decrease by an average of 14 cents over the 2014 to 2040 period in AEO2015.

The volatility, optimism, and lack of transparency in EIA play-level shale gas production projections inspire little confidence in their reliability. This is a major concern for future energy policy decisions given the weight that many in government and industry place on them.

4 Summary and Implications

The future production of shale gas plays is a function of well quality variation by area, drilling rates, decline rates and number of available drilling locations.

Although much is made by industry of the role of technological improvements in increasing the amount of gas recovered per well, an analysis of the country's largest shale gas play, the Marcellus, shows that after a period of growth in the 2012 to early 2014 period, well productivity is declining in the play overall and in the sweet spot counties.

A rule of thumb is that companies, given the choice, always drill their best locations first. Drilling in the Marcellus has been concentrated in top dry gas counties like Susquehanna and Bradford, and wet counties like Washington. These counties can only absorb a finite number of wells before drilling must move out into lower quality parts of the reservoir. Further, wells spaced too close together will exhibit interference, reducing their ultimate output. Both these phenomenon appear to be happening in the Marcellus. In the Barnett, the most mature shale gas play, sweet spots are nearly saturated and average well productivity has declined by 17% since 2011.

The forecasting methods used in *Drilling Deeper* evaluated well quality, decline rates and available locations by subarea and built them into the modelling process. Given that trying to predict prices (and their inevitable effect on drilling rates) is a mug's game, as we have seen in recent months, several cases assuming different drilling rates over time were presented. The bottom line is that although changing drilling rates has a considerable effect on near-term production, it doesn't significantly change the total recovery through 2040, with the possible exception of the Marcellus, which will still have a significant number of remaining locations by then at projected drilling rates.

The EIA uses a system known as the National Energy Modelling System (NEMS) for forecasting which, although purported to be based on a county-level analysis for shale, is complex and is not transparent; its outputs for future shale play production at times defy logic. A statement at the EIA's NEMS link says: "Most people who have requested NEMS in the past have found out that it was too difficult or rigid to use."

This raises some important questions: If NEMS is truly a robust system for forecasting, why is there so much difference at the play level between AEO2014 and AEO2015? Why does Marcellus production surge post-2025, rising to a new all-time high by 2040? Why does Haynesville production surge beginning in 2016, rising to a new high that is triple current production rates in 2038? How can Eagle Ford production reach a plateau in 2021 and remain on it for the next two decades? Together these three plays make up 61% of the EIA's projected 2014-2040 production.

The EIA forecasts for these plays belie the fundamentals given what is known from an analysis of all available well production data. What is the EIA thinking? Do they assume an as-yet unknown spurt of technology will somehow overcome the geological realities of these plays? If that is the case, it would behoove them—and benefit the American public and policymakers who determine critically important energy and related investments and policies—to be candid about such assumptions.

Ratings for the EIA's projections for the largest shale gas plays described herein range from "little credibility" to "highly optimistic". Yet we are led to believe that shale gas will be even more abundant in the future than projected just a year ago, setting the stage for a robust LNG export industry, and greater industrial and power sector use, all at relatively low prices. Getting it wrong has very serious implications for energy policy and future energy security, considering that the EIA is the country's premier source for future production projections.