ESTIMATE OF IMPACTS OF EPA PROPOSALS TO REDUCE AIR EMISSIONS FROM HYDRAULIC FRACTURING OPERATIONS

FINAL REPORT

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EXECUTIVE SUMMARY

On July 28, 2011, the U.S. Environmental Protection Agency (EPA) proposed a suite of regulatory requirements designed to reduce air emissions from the oil and natural gas industry (Federal Register, Vol. 76, No. 163, August 23, 2011, pp. 52738 - 52843). EPA has proposed new standards for several processes associated with oil and gas production that have not previously been subject to federal regulation.

Among these processes are well completions at new hydraulically fractured gas wells and at existing gas wells that are "re-fractured." For these wells, EPA proposes that emissions of volatile organic compounds (VOCs) would be minimized through the use of "reduced emissions completions" or RECs, which simultaneously reduce both VOC and methane emissions. When gas cannot be collected during well completion operations, emissions would be reduced through pit flaring, unless it is a safety hazard.

EPA's proposed rule imposes REC requirements on most unconventional gas wells, but requests comment on concerns that limited availability of REC equipment could adversely impact drilling and U.S. natural gas supplies necessitating a phase-in period to avoid disruptions. EPA estimates that only 3,000 to 4,000 of the 25,000 new and modified fractured gas wells completed each year currently employ RECs.

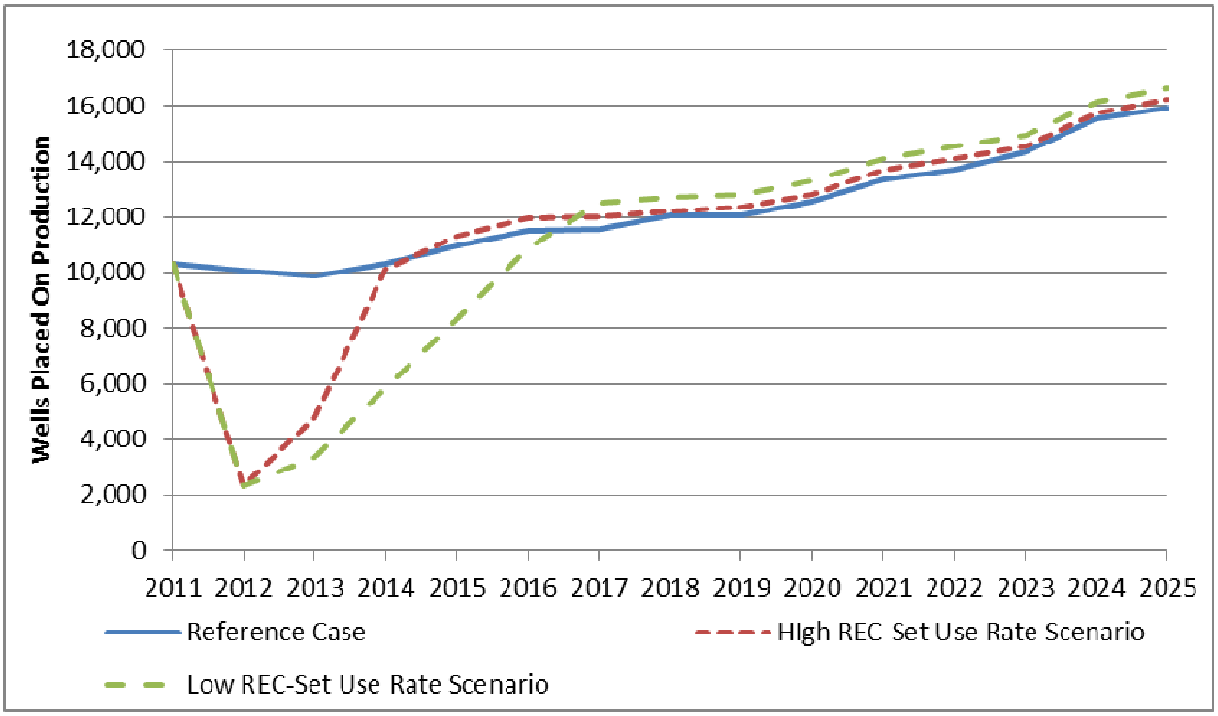
ARI's assessment of the potential impact of just the requirements for the use of RECs on hydraulically fractured wells included consideration of potential additional revenue from recovered methane and possible condensates, increased costs associated with implementing RECs on hydraulically fractured wells, and the impact of delays in unconventional resource development associated with the demand for REC equipment exceeding the supply.

Two scenarios were developed addressing the use-rate of REC equipment and the rate at which REC equipment supply could be expanded.

- The High REC-Set Use Rate scenario assumes 140 REC equipment sets and the necessary trained personnel to deploy this equipment are available in 2012, that 200 new REC equipment sets and the corresponding trained personnel are added per year, and each REC set can service 25 wells per year.
- The Low REC-Set Use Rate scenario assumes 292 REC equipment sets and the necessary trained personnel to deploy this equipment are available in 2012, that 200 new REC equipment sets and the corresponding trained personnel are added per year, and each REC set can service only 12 wells per year.

Overall, both scenarios indicate a phase-in period of REC requirements is needed to avoid disruption. In the High REC-Set Use Rate scenario, it takes approximately 3 to 4 years for REC equipment to become available to keep pace with unconventional resource development that would otherwise occur. In the Low REC-Set Use Rate scenario, it takes longer, on the order of 6 to 7 years for REC equipment to become available to allow unconventional oil and gas drilling to approach the pace and level that would otherwise occur, Figure ES-1.

Figure ES-1
IMPACT OF NEW REC REQUIREMENTS ON U.S. UNCONVENTIONAL DRILLING



Depending on the REC-Set Use Rate scenario assumed, the following impacts from base case levels are projected in the first 4 years after the requirements go into effect (through 2015):

- Overall well drilling for unconventional resources producing natural gas over 2012 - 2015 would be reduced by 31% to 52%, amounting to reductions in drilling ranging from 12,700 to 21,400 wells.
- 5.8 to 7.0 quadrillion Btu (Quads) of otherwise economic unconventional natural gas would not be developed and produced by 2015, a 9% to 11% reduction.
- 1.0 to 1.8 billion barrels of otherwise economic unconventional liquids would not be developed and produced by 2015, a 21% to 37% reduction.
- Federal royalties of $7.0 to $8.5 billion that would otherwise be collected would not be paid in the first 4 years after the requirements go into effect.
- State revenues from severance taxes amounting to $1.9 to $2.3 billion would be delayed beyond the first 4 years after the requirements go into effect.

Under either scenario of REC equipment availability, a significant slowdown in unconventional resource development would occur, resulting in less reserve additions, less production, lower royalties to the Federal government and private landowners, and lower severance tax payments to state governments. The delays in drilling results in delays in production, which result in the delays in the economic benefits associated with that production. This analysis did not attempt to estimate lost jobs associated with reduced drilling, oil and gas supply services, and indirect employment.

INTRODUCTION

On July 28, 2011, the U.S. Environmental Protection Agency (EPA) proposed a suite of regulatory requirements designed to reduce air emissions from the oil and natural gas industry (Federal Register, Vol. 76, No. 163, August 23, 2011, pp. 52738 - 52843). EPA is proposing new standards for several processes associated with oil and gas production that have not previously been subject to federal regulation.

Among these impacted processes are well completions at new hydraulically fractured gas wells and at existing gas wells that are "re-fractured." For these wells, EPA proposes that emissions of volatile organic compounds (VOCs) would be minimized through the use of "green completions," also called "reduced emissions completions" or RECs, which simultaneously reduce both VOC and methane emissions. When gas cannot be collected during well completion operations, emissions would be reduced through pit flaring, unless it is a safety hazard.

The REC requirements would not apply to exploratory wells or delineation wells (used to define the borders of an oil and/or gas reservoir), because generally they are not near a natural gas sales line. It should be recognized that a number of states now require the use of RECs, and a number of companies are voluntarily using this process, even when not required by state regulations.

In their November 30th comments to the proposed rule, API stated that:

> "The equipment prescribed to conduct Reduced Emission Completions will simply not be available in time to comply with the current final rule schedule. We believe it will take years to manufacture sufficient specialized equipment and adequately train operators how to safely conduct these operations."

If insufficient REC equipment is available to meet the demand for new fractured completions when EPA's proposed rules go into effect, it is feared that new well completions would be constrained until the supply of REC equipment catches up to the demand, with a broad range of adverse impacts.

Moreover, although the application of REC equipment could produce some additional revenue through the sale of captured methane, REC requirements would add additional costs to new well completions that involve hydraulic fracturing, potentially impacting the economic viability of some resource development.

OBJECTIVE

This report estimates the impacts of EPA's proposal to reduce VOC emissions through the required use of RECs, which also simultaneously reduce methane emissions. This includes assessing potential additional revenue from recovered methane and possible condensates, increased costs associated with implementing RECs on hydraulically fractured wells, and the impact of delays in unconventional resource development associated with the demand for REC equipment exceeding the supply. This information will help assess the dimensions of a possible REC requirement phase-in period referenced in EPA's proposed rule, and recommended in the API comments.

ESTIMATED COSTS ASSOCIATED WITH REQUIRING RECS ON HYDRAULICALLY FRACTURED WELLS

In the draft rule, EPA is proposing operational standards for completions of hydraulically fractured gas wells. Two subcategories of hydraulically fractured gas wells are identified for which well completions are conducted. The first is exploratory and delineation wells. These wells generally are not in close proximity to a gas gathering line or sales line that could collect recovered methane, so the proposed operational standard would require pit flaring.

The second category is for all hydraulically fractured gas wells excluding exploratory and delineation wells, where the proposed operational standards would require the use of RECs in combination with pit flaring of gas not suitable for entering the gathering line. This second category would include well completions conducted at newly drilled and fractured wells, as well as completions conducted following re-fracturing operations at various times over the life of the well.

EPA states that equipment required to conduct RECs may include tankage, special gas-liquids and separator traps, and gas dehydration. Though highly variable, they estimated that typical well completions last between 3 and 10 days, and the costs of performing RECs are between $700 and $6,500 per day, including a cost of approximately $3,523 per completion event for the pit flaring equipment. Based on these assumptions, EPA uses an estimated average incremental cost of $33,237 per completion for their EPA's Regulatory Impact Analysis (RIA) – "Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry."

EPA, in its Technical Support Document[1] (TSD) estimates the cost of doing a REC with the following equation:

> Total Cost Per Completion = [Average length of completion flowback * Cost per day] + [Fixed cost for Transportation and Set Up]

In their assessment, EPA assumes that the average length of completion flow back is 7 days. The data point comes from a Natural Gas STAR (NGS) document,[2] which found that "Well completions usually take between 1 to 30 days…." A subsequent table specified well clean-up time at 3 to 10 days. The average of 3 to 10 days is 6.5. EPA's TSD therefore assumed 7 days.

EPA assumes that the costs per day for using REC equipment are $4,146 based on the same NGS paper. It says that "REC vendors and Natural Gas STAR partners have reported the incremental cost of equipment rental and labor to recover natural gas during completion ranging from $700 to $6,500/day over a traditional completion." In the TSD, EPA updates these numbers and takes the average to arrive at $4,146/day.

However, in the NGS document, it stated that, "…A REC annual program may consist of completing 25 wells per year within a producer's operating region." This implies a set of REC equipment is on a site 14.6 days, on average. This is a more appropriate time period for estimating the well time costs associated with deploying REC equipment.

EPA also estimates transportation and set up costs to be $691. Again, this comes from the NGS paper, which states "The incremental cost associated with

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[1] EPA, (July, 2011) *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution*. EC/R Inc., EPA-453/R-11-002

[2] Natural Gas STAR, *(No Date) Lessons Learned from Natural Gas STAR Partners: Reduced Emissions Completions*.

transportation *between well sites in the operator's field* and connection of the REC equipment within the normal flow back piping from the wellhead to an impoundment or tank is generally around $600/completion" (emphasis added). The TSD updates this figure to $691.

Returning to the above equation, with EPA assumptions, gives:

Total Cost per completion = [7 days * $4,146/day] + $691 = $29,713 per well.

This is what EPA has on page 4-17 of the TSD, and is comparable to the $33,237 per completion estimate. However, correcting the first variable in the above equation to reflect 15 days from the NGS assessment, which is more appropriate since that is what operators likely would be paying for, then results in:

Total Cost per completion = [15 days * $4,146/day] + $691 = **$62,881**

This is the estimated cost per completion for using REC equipment that is assumed in this analysis.

However, as discussed below, this analysis develops two scenarios regarding the number of reduced emission completions per year for a set of reduced emission completion equipment. One scenario assumes 25 RECs per year (effectively the 15 day's per REC used in the above cost calculation) while the other assumes 12 RECs per year, or one every 30 days. Altering the above equation to reflect 30 days on-site for a set of REC equipment would increase the cost per completion to over $125,000. Because this analysis is focusing more on the question of REC set availability than REC set cost, this analysis keeps the REC cost at the lower $62,881 amount for both scenarios. Doing so necessarily underestimates the negative impact of the REC requirement for the 30 day scenario.

Additionally, it is important to note that while the REC cost assumptions in this analysis are based on EPA and NGS reports, those estimates have been criticized as severe underestimates. For example, API's docket comments (EPA-HQ-OAR-2010-0505, November 30, 2010, page 108) estimate that "a REC evolution to sales would add $180,000 to the cost of the well." To the extent that the cost assumptions in this analysis are unrealistically low, the impacts also are underestimated.

ESTIMATED EMISSIONS RECOVERY FROM THE USE OF RECS ON HYDRAULICALLY FRACTURED WELLS

Reduced emission completions may allow for the recovery and sale of additional quantities of natural gas and condensate. EPA's Regulatory Impact Analysis of July 2011 assumes that, on average, each well utilizing RECs can recover and sell 8,258 Mcf of methane and 34 barrels of condensate per REC application.

These estimates for hydrocarbon recovery associated with the application of RECs are assumed for this analysis.

ESTIMATED PROPORTION OF PRODUCING GAS WELLS THAT ARE REFRACTURED

The proposed rule requires that RECs be conducted at both newly drilled and fractured wells, as well as completions conducted during re-fracturing operations at various times over the life of the well. EPA's analysis assumes a 10% per year rate of re-fracturing for natural gas wells; that is, 1 in 10 producing wells is re-fractured in a given year. EPA states that it has received anecdotal information suggesting that re-fracturing could be occurring much less frequently, while others suggest that the percent of wells re-fractured in a given year could be greater. Thus, EPA is seeking comment and comprehensive data and information on the rate of re-fracturing and key factors that influence or determine re-fracturing frequency.

Consistent with EPA's regulatory proposal, this assessment assumes that 100% of unconventional wells producing natural gas (shale, coalbed methane, and low permeability tight gas sand wells) are hydraulically fractured. There are indications that some conventional gas wells also are hydraulically fractured while being completed, and therefore might also fall under a REC requirement. Because conventional gas well completions are not included in this analysis, this analysis may underestimate impacts such as reduced drilling because of REC availability problems.

Additionally, API's November 30th docket comments indicated that only about 1% of the currently producing gas wells in a given year are re-fractured, which is the assumption used in this analysis. However, if the frequency of re-fracturing operations is closer to EPA's estimate, the impacts resulting from the analyses in this assessment could be substantially underestimated.

ESTIMATED AVAILABILITY OF REC EQUIPMENT FOR USE WITH HYDRAULICALLY FRACTURED WELLS

EPA estimated the number of completions and recompletions already controlling emissions in absence of a Federal regulation based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations. Based on this criterion, 15% of natural gas completions with hydraulic fracturing and 15% of existing natural gas workovers with hydraulic fracturing were assumed to be controlled by either flare or RECs in absence of Federal regulations. Completions and recompletions without hydraulic fracturing were assumed as having no controls in absence of Federal regulations.

EPA's Federal Register Notice (page 52578) states that: "Of the 25,000 new and modified fractured gas wells completed each year, we estimate that approximately 3,000 to 4,000 currently employ reduced emission completions." The 25,000 gas well figure includes the impact of EPA's assumption that 10% of existing gas wells are re-fractured annually.

EPA's "Reduced Emissions Completions" document from "Lessons Learned from Natural Gas STAR Partners" includes an assumption that a REC-set completes 25 RECs per year. Using an estimate 3,500 RECs per year (mid-point of EPA's estimate) with a REC-set doing 25 RECs per year, then EPA information implies that 140 REC-sets currently are in use.

EPA does not project a rate at which new REC-sets might become available. However, EPA assumes that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, they acknowledge that energy availability could be affected if a shortage of REC equipment causes delays in well completions, and specifically requested comment on a phase-in period for REC requirements.

In an attempt to shed some light on this assumption, the API Clean Air Issues Group (CAIG) surveyed API members, and based on this survey, API believes that for a variety of reasons - including time to mobilize and demobilize equipment, difficulty in precise scheduling in use of RECs, and typical 30-day rental contracts for REC-sets - a more realistic estimate of REC-set productivity is one well per month, or 12 wells per year.

Using the mid-point of EPA's estimate of the number of RECs per year (3,500) and industry's estimate of 12 RECs per REC-set implies there are 292 REC's currently in use.

Also, based on this survey, for purposes of this assessment, after a one-year lag, an estimated 50 new REC-sets might be delivered per quarter, or 200 new REC-sets per year would be available starting in 2013. As noted in API's November 30th docket comments: "This equipment is fairly specialized, the shops licensed to make it are limited, and some of the components require a long lead time. It should be expected with today's demand for other pressure vessels that it will be on the order of one year before the first set of additional equipment can be delivered."

Based on these different assumptions, two REC-set availability scenarios are considered in this assessment. These two alternatives are summarized in Table 1.

Table 1
KEY ASSUMPTIONS FOR REFERENCE CASE AND TWO REC-SET AVAILABILITY SCENARIOS

	Reference Case	**High REC-Set Use Rate**	**Low REC-Set Use Rate**
# Covered Wells Fracked	Model dependent	# wells REC-completed depends on REC-set availability	
REC-Set Assumptions			
• RECs per REC-set per year	25	**25**	**12**
• RECs in 2012	3,500	3,500	3,500
• # REC-sets in 2012	140	140	292
• # New REC-sets/year starting in 2013	0	200	200

POTENTIAL SUPPLY IMPACTS ASSOCIATED WITH REQUIRING RECS ON HYDRAULICALLY FRACTURED WELLS

This assessment focuses only on the estimated potential costs and resulting impacts associated with performing RECs on unconventional resource wells producing natural gas that meet EPA's proposed requirements, and not the other emission reduction requirements established by the proposed rule. For purposes of this assessment, we have assumed that this will apply to all unconventional resources producing at least some natural gas, even if the primary product is liquids. In the model used in this assessment, all unconventional resources are assumed to produce at least some associated gas. Some wells produce only gas, but the rest, including predominantly liquids plays like the Bakken and Eagle Ford, produce both liquids and gas.

The key factors influencing these impacts are the estimated costs associated with using REC equipment on hydraulically fractured wells subject to the rule's requirements, and estimates of the timing of the availability of REC equipment necessary for complying with the proposed EPA requirements.

For this assessment, the Reference Case crude oil and natural gas price forecasts from the Energy Information Administration's (EIA) Annual Energy Outlook 2011 (AEO 2011) were assumed. In these forecasts, crude oil prices are forecast to rise from $86.23 per barrel in 2012 to $115.15 per barrel by 2025 (2009 dollars). Average wellhead natural gas prices are forecast to rise from $4.09 per Mcf in 2012 to $5.43 per Mcf in 2025. The price forecasts assumed in this assessment are summarized in Table 2.

Table 2
ENERGY INFORMATION ADMINISTRATION ANNUAL ENERGY OUTLOOK 2011 REFERENCE CASE OIL AND GAS PRICES

Oil and Gas Supply, Reference case (in 2009 dollars)						
	2010	2011	2012	2015	2020	2025
Lower 48 Average Wellhead Price (dollars per barrel)	$78.62	$84.00	$86.23	$94.99	$107.36	$115.15
Lower 48 Average Wellhead Price (dollars per thousand cubic feet)	$4.08	$4.09	$4.09	$4.24	$4.59	$5.43

However, it is important to note that EIA's price forecasts are used throughout this analysis even if REC equipment availability limits unconventional resource development and production, which might impact natural gas prices. Also important to note is that this analysis only assessed the impact on unconventional resource development (tight gas, CBM and shale wells). To the extent a REC requirement also applies to "conventional" wells that are hydraulically fractured, the phase-in requirement and impacts are underestimated.

Finally, this analysis does not attempt to assess impacts on the broader U.S. economy.

This assessment used Advanced Resources' unconventional resources supply system. The system was originally developed in 1997 as an internal analytic tool, and subsequently was used as the basis for DOE/EIA's unconventional gas module within their National Energy Modeling System (NEMS)

More information on the system can be found in Appendix A.

SUMMARY OF RESULTS

The new requirements for REC equipment on hydraulically fractured gas wells are assumed to incrementally cost $62,881 for all new unconventional wells. Between 2005 and 2010, on average, 7% of gas wells drilled was defined as exploratory, according to the Energy Information Association.[3] Therefore, for this analysis, it was assumed that 7% of new unconventional wells otherwise covered by the EPA proposed rule were "exploratory and delineation wells" and thus would be exempt from the proposed requirements, since presumably gas gathering systems for the flow back from these wells would not be in place. In addition, it was assumed that 1% of existing wells would be re-fractured annually, and thus would utilize some of the REC equipment that would otherwise be available for new hydraulically fractured wells.

The High REC-Set Use Rate scenario assumes that 140 REC equipment sets and the necessary trained personnel to deploy this equipment are available in 2012, and that each REC set can service 25 wells per year, resulting in 3,500 REC completions in 2012. The scenario also assumes that 200 new REC equipment sets and the corresponding trained personnel were added per year.

- *In this scenario, it is not until 2014 that REC equipment becomes available to almost keep pace with unconventional natural gas drilling that would otherwise*

[3] http://www.eia.gov/dnav/ng/ng_enr_wellend_s1_a.htm

occur. By 2015, the availability of REC equipment reaches the level that would allow unconventional well drilling to return to the Base Case level. .

The Low REC-Set Use Rate scenario assumes that 292 REC equipment sets and the necessary trained personnel to deploy this equipment are available in 2012, and each REC set can service only 12 wells per year, resulting in 3,500 REC completions in 2012. The scenario also assumes that 200 new REC equipment sets and the corresponding trained personnel were added per year.

- *In this scenario, it takes longer, until 2016 for REC equipment to become available to allow unconventional oil and gas drilling to approach the pace and level that would otherwise occur. By 2017, the availability of REC equipment reaches the level that would allow the Base Case level of unconventional oil and drilling to be reached.*

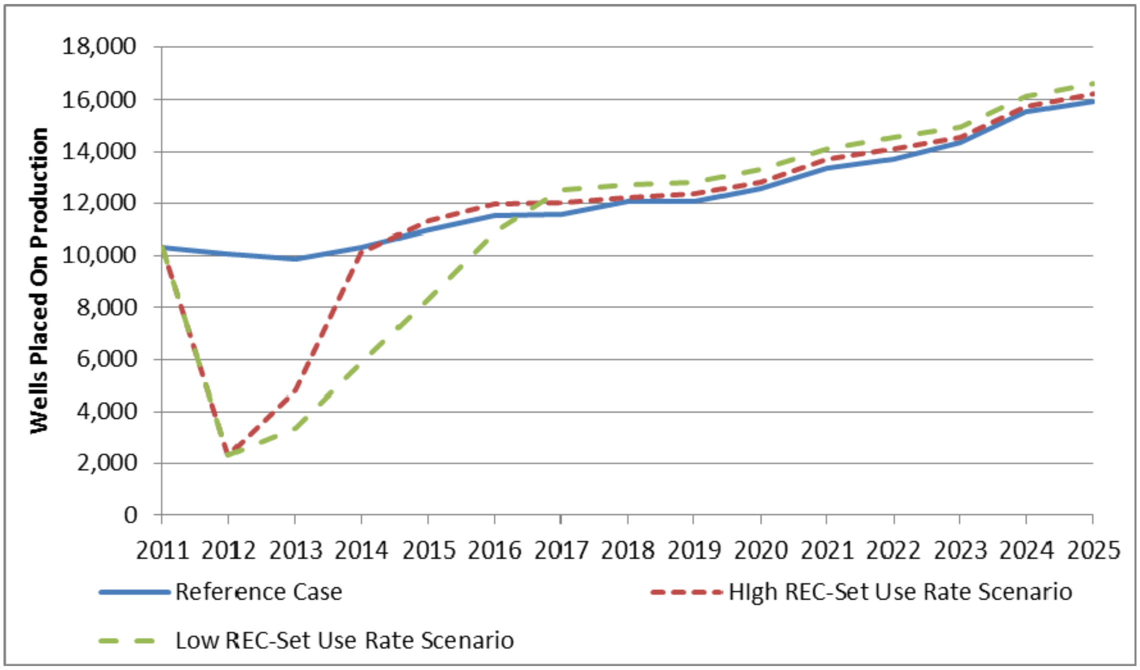
The REC-set assumptions and drilling are summarized in Table 3 for 2012-2017 and a longer term view of unconventional gas well drilling is illustrated graphically in Figure 1.

Table 3
REC-SET ASSUMPTIONS AND UNCONVENTIONAL WELL DRILLING 2012-2017

	2012	2013	2014	2015	2016	2017
Base Case Drilling	10,076	9,901	10,330	10,974	11,507	11,545
High REC-Set Use Rate Scenario (25 wells/yr per REC-set)						
· **REC-Sets Available**	140	240	440	640	840	1,040
· **Wells Drilled**	2,309	4,805	10,132	11,325	11,956	12,024
Low REC-Set Use Rate Scenario (12 wells/yr per REC-set)						
· **REC-Sets Available**	292	392	592	792	992	1,192
· **Wells Drilled**	2,313	3,390	5,870	8,329	10,876	12,527

Note: “Wells Drilled” includes exploratory and delineation wells that do not use REC equipment but excludes the re-fracturing of 1% of existing wells which does use REC equipment. During the first four quarters beginning one year after the rules go into effect, 50 new REC-sets per quarter are assumed to be delivered. However, the *average availability* of new REC-sets during the first four quarters would only be 100, hence the increase in REC-sets between 2012 and 2013 is 100. Additionally, the ARI model runs on a calendar year basis while the proposed reduced emission completion rule does not start on January 1. Conceptually, these annual impact estimates may be viewed as beginning with the implementation of the rule and covering each subsequent 12 month period.

Figure 1
IMPACT OF NEW REC REQUIREMENTS ON U.S. UNCONVENTIONAL DRILLING

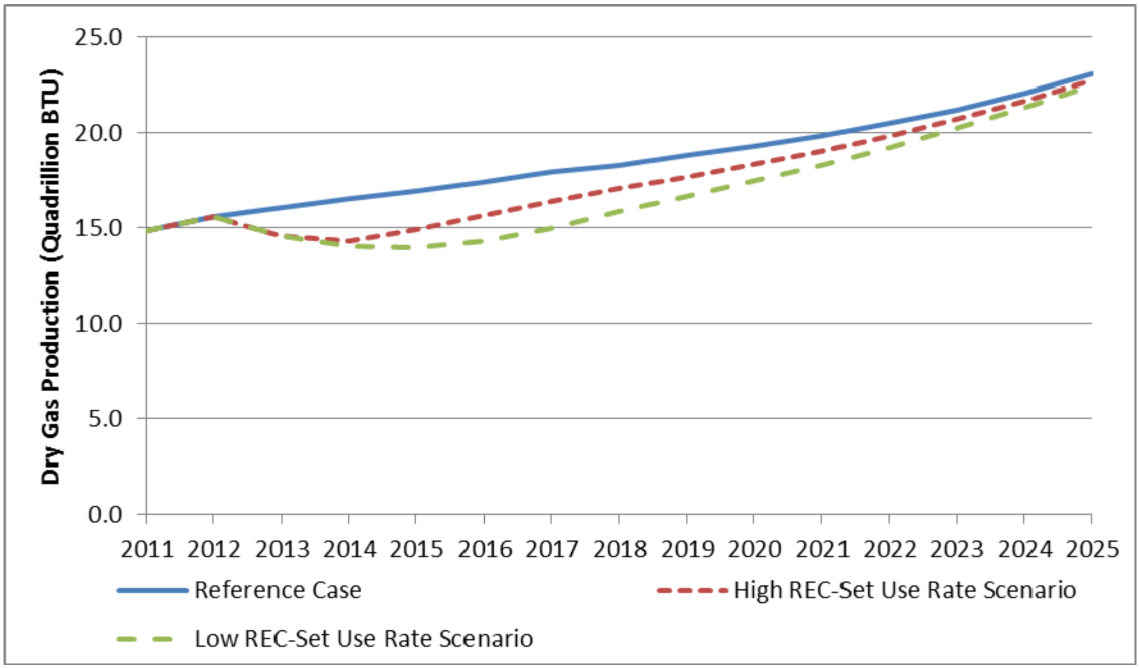


However, as shown in more detail in Figure 2, the impact of reduced drilling of unconventional resource wells producing natural gas results in fewer natural gas reserve additions and consequently lower natural gas production through at least 2025.

Also, apparent in Figure 1 is that in the later years, drilling in the two regulatory cases exceeds that in the Reference Case. This is because the pace of development in a given unconventional play is assumed to be a function of the potential profitability of the play, which will be a function of the prices for oil and gas, as well as the amount of undeveloped remaining resource in a play. Since in the later years, prices are higher, and under the regulatory cases, less of the resource has been developed at a given point in time, drilling levels naturally increase to compensate.

Production in the regulatory cases, on the other hand, does not ever exceed that in the Reference Case through 2025.

Figure 2
IMPACT OF NEW REC REQUIREMENTS ON U.S. UNCONVENTIONAL NATURAL GAS PRODUCTION



It is important to note that the model used in this analysis assumes a well drilled in one year does not commence production in the following year. Thus, while drilling levels are impacted in the year 2012 due to the new requirements, impacts on production are not realized until 2013.

Finally, any potential impact on national natural gas prices or other adverse impacts on the U.S. economy are not assessed in this analysis.

HIGH REC-SET USE RATE SCENARIO RESULTS

Comparing the High REC-Set Use Rate scenario compared to the reference case results in the following impacts in the first 4 years after the requirements go into effect (by 2015):

- Overall well drilling for unconventional gas from 2012 through 2015 would be reduced by 31%, or 12,711 wells.
- 5.8 Quadrillion Btu (Quads) of otherwise economic unconventional natural gas would not be developed and produced by 2015, a 9% reduction.

- 1.0 billion barrels of otherwise economic unconventional liquids would not be developed and produced by 2015, a 21% reduction.
- Royalties (public and private) of nearly $7 billion that would otherwise be collected would not be paid in the first 4 years after the requirements go into effect.
- State revenues from severance taxes amounting to nearly $1.9 billion would be delayed beyond the first 4 years after the requirement go into effect.
- The loss in royalties and severance tax revenues in the first 4 years amounts to a 12% reduction from the base case.

These results are summarized by category of unconventional gas resource in Table 4.

Table 4
SUMMARY OF IMPACTS OF NEW REC REQUIREMENTS ON U.S. UNCONVENTIONAL RESOURCE DEVELOPMENT TO 2015
High REC-Set Use Rate Scenario

Category	Units	Tight Gas	Coalbed Methane	Shale Gas	Total Unconventional
Total Gas Production - Base Case	**Quads**	25.5	4.0	33.9	**63.4**
Reduction in Gas Production	**Quads**	-1.4	-0.1	-4.2	**-5.8**
% Reduction		-6%	-4%	-12%	**-9%**
Total Liquids Production - Base Case	**Bbbls**	1.4	0.0	3.5	**4.9**
Reduction in Liquids Production	**Bbbls**	-0.2	0.0	-0.9	**-1.0**
% Reduction		-13%	0%	-24%	**-21%**
Foregone Gas Reserve Additions	**Tcfe**	-7.9	0.7	-20.7	**-27.8**
Total Drilling - Base Case	**Wells**	12,223	489	28,405	**41,117**
Reduction in Well Drilling	**Wells**	-3,985	-222	-8,504	**-12,711**
% Reduction		-33%	-45%	-30%	**-31%**
Foregone Royalties	**Million $**	1,673	96	5,202	**6,971**
Foregone State Sev Tax Revenues	**Million $**	446	26	1,387	**1,859**

Note: The Tcfe in the forgone natural gas reserve additions applies to both natural gas and associated liquids reserves. "Wells Drilled" includes exploratory and delineation wells that do not use REC equipment but excludes re-fracturing 1% of existing wells which does use REC equipment.

Comparing the High REC-Set Use Rate scenario to the Reference Case to the year 2025 results in the following:

- Overall drilling for unconventional gas would be reduced by 6%, or 9,635 wells.
- 15.0 Quads of otherwise economic unconventional natural gas would not be developed and produced, a 6% reduction.
- 2.2 billion barrels of otherwise economic unconventional liquids would not be developed and produced, an 8% reduction.
- Royalties of approximately $17.6 billion that would otherwise be collected would not be paid.
- State revenues from severance taxes of $4.7 billion would not be collected.
- The loss in royalties and severance tax revenues through 2025 amounts to a 6% reduction from the base case.

These results are summarized in Table 5.

LOW REC-SET USE RATE SCENARIO RESULTS

Comparing the Low REC-Set Use Rate scenario to the reference case results in larger impacts than the High REC Set Use Rate scenario in the first 4 years after the requirements go into effect:

- Overall well drilling for unconventional gas between 2012 and 2015 would be reduced by 52%, or 21,379 wells.
- 7.0 Quads of otherwise economic unconventional natural gas reserves would not be developed and produced by 2015, an 11% reduction.
- 1.8 billion barrels of otherwise economic unconventional liquids reserves would not be developed and produced by 2015, a 37% reduction.
- Royalties of approximately $8.5 billion that would otherwise be collected would not be paid in the first 4 years after the requirements go into effect.

Table 5
SUMMARY OF IMPACTS OF NEW REC REQUIREMENTS ON U.S. UNCONVENTIONAL RESOURCE DEVELOPMENT TO 2025
High REC-Set Use Rate Scenario

Category	Units	Tight Gas	Coalbed Methane	Shale Gas	Total Unconventional
Total Gas Production - Base Case	**Quads**	93.6	16.9	152.9	**263.4**
Reduction in Gas Production	**Quads**	-3.8	-0.9	-10.3	**-15.0**
% Reduction		-4%	-6%	-7%	**-6%**
Total Liquids Production - Base Case	**Bbbls**	6.8	0.0	21.0	**27.9**
Reduction in Liquids Production	**Bbbls**	-0.5	0.0	-1.7	**-2.2**
% Reduction		-7%	0%	-8%	**-8%**
Foregone Gas Reserve Additions	**Tcfe**	-4.7	1.6	-12.8	**-15.8**
Total Drilling - Base Case	**Wells**	51,120	11,518	111,252	**173,891**
Reduction in Well Drilling	**Wells**	-2,822	-2,030	-4,783	**-9,635**
% Reduction		-6%	-18%	-4%	**-6%**
Foregone Royalties	**Million $**	4,543	688	12,328	**17,559**
Foregone State Sev Tax Revenues	**Million $**	1,212	183	3,287	**4,682**

Note: “Wells Drilled” includes exploratory and delineation wells that do not use REC equipment but excludes re-fracturing 1% of existing wells which does use REC equipment.

- State revenues from severance taxes amounting to over $2.3 billion would be delayed beyond the first 4 years after the requirement go into effect.
- The loss in royalties and severance tax revenues in the first 4 years amounts to a 14% reduction from the base case.

These results are summarized by category of unconventional gas resource in Table 6.

Table 6
SUMMARY OF IMPACTS OF NEW REC REQUIREMENTS ON U.S. UNCONVENTIONAL RESOURCE DEVELOPMENT TO 2015
Low REC-Set Use Rate Scenario

Category	Units	Tight Gas	Coalbed Methane	Shale Gas	Total Unconventional
Total Gas Production - Base Case	**Quads**	25.5	4.0	33.9	**63.4**
Reduction in Gas Production	**Quads**	-1.8	-0.2	-5.0	**-7.0**
% Reduction		-7%	-5%	-15%	**-11%**
Total Liquids Production - Base Case	**Bbbls**	1.4	0.0	3.5	**4.9**
Reduction in Liquids Production	**Bbbls**	-0.8	0.0	-1.0	**-1.8**
% Reduction		-53%	0%	-30%	**-37%**
Foregone Gas Reserve Additions	**Tcfe**	-13.3	1.1	-34.3	**-46.4**
Total Drilling - Base Case	**Wells**	12,223	489	28,405	**41,117**
Reduction in Well Drilling	**Wells**	-6,395	-348	-14,636	**-21,379**
% Reduction		-52%	-71%	-52%	**-52%**
Foregone Royalties	**Million $**	2,062	117	6,310	**8,490**
Foregone State Sev Tax Revenues	**Million $**	550	31	1,683	**2,264**

Note: "Wells Drilled" includes exploratory and delineation wells that do not use REC equipment but excludes re-fracturing 1% of existing wells which does use REC equipment.

Comparing the Low REC-Set Use Rate scenario to the reference case to 2025 shows larger impacts that the High REC Set Use rate scenario, as follows:

- Overall drilling for unconventional gas would be reduced by 9%, or 15,379 wells.
- 24.5 Quads of otherwise economic unconventional natural gas reserves would not be developed and produced, a 9% reduction.
- 3.8 billion barrels of otherwise economic unconventional liquids reserves would not be developed and produced, a 13% reduction.
- Royalties of approximately $29.8 billion that would otherwise be collected would not be paid.
- State revenues from severance taxes amounting to $7.9 billion would not be collected.

- The loss in royalties and severance tax revenues through 2025 amounts to a 10% reduction from the base case.

These results are summarized in Table 7.

Table 7
SUMMARY OF IMPACTS OF NEW REC REQUIREMENTS ON U.S. UNCONVENTIONAL RESOURCE DEVELOPMENT TO 2025
High REC-Set Use Rate Scenario

Category	Units	Tight Gas	Coalbed Methane	Shale Gas	Total Unconventional
Total Gas Production - Base Case	**Quads**	93.6	16.9	152.9	**263.4**
Reduction in Gas Production	**Quads**	-6.3	-1.2	-17.0	**-24.5**
% Reduction		-7%	-7%	-11%	**-9%**
Total Liquids Production - Base Case	**Bbbls**	6.8	0.0	21.0	**27.9**
Reduction in Liquids Production	**Bbbls**	-0.8	0.0	-3.0	**-3.8**
% Reduction		-11%	0%	-14%	**-13%**
Foregone Gas Reserve Additions	**Tcfe**	-7.9	2.0	-22.1	**-28.1**
Total Drilling - Base Case	**Wells**	51,120	11,518	111,252	**173,891**
Reduction in Well Drilling	**Wells**	-4,491	-2,127	-8,761	**-15,379**
% Reduction		-9%	-18%	-8%	**-9%**
Foregone Royalties	**Million $**	7,678	852	21,257	**29,787**
Foregone State Sev Tax Revenues	**Million $**	2,048	227	5,668	**7,943**

Note: “Wells Drilled” includes exploratory and delineation wells that do not use REC equipment but excludes re-fracturing 1% of existing wells which does use REC equipment.

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The bottom line is that under either scenario of reduced emission completion equipment availability, a significant slowdown in unconventional resource development would occur compared to the Base Case. This slowdown in drilling results in less reserve additions, less production, lower royalties to the Federal government and private landowners, and lower severance tax payments to state governments. This analysis did not attempt to estimate lost jobs associated with reduced drilling, oil and gas supply services and indirect employment. The delays in drilling results in delays in production, which result in the delays in the economic benefits associated with that production.

APPENDIX A
OVERVIEW OF ADVANCED RESOURCES UNCONVENTIONAL RESOURCES SUPPLY ANALYSIS SYSTEM

This assessment used Advanced Resources' unconventional resources supply system as the basis of this assessment. The system was originally developed in 1997 as an internal ARI analytic tool, and then it was used as the basis for DOE/EIA's unconventional gas module within their National Energy Modeling System.

Currently, ARI has the capability of assessing the impact of proposed regulatory requirements on 139 unconventional oil and natural gas plays in the U.S., including new emerging oil plays such as the Bakken and the Eagle Ford shales.

This integrated database, economic model and forecasting system is resource-driven and includes play-specific economic modules that determine the profitability and development schedule for each of the unconventional resource plays. The main components are further discussed below:

- Resource Size. The system contains the results of periodically updated resource assessments prepared by ARI for each of the unconventional resource plays. Play area is determined via an independent geologic assessment of each play, as well as an assessment of what portion of the larger play outline is of sufficient quality for likely development. The number of possible well sites in the higher quality portion of the play area is based on actual (and projected) well spacing multiplied by the play's success rate (determined from detailed study of each play). The number of potential well locations is combined with the latest trend in recovery per well to estimate the size of the play. Past production and already developed cells are then subtracted to provide an assessment of the remaining technically recoverable resource.

- Well Distribution. Each unconventional resource play area and the well performance in each play area are divided into three groups. An average well, estimated to cover 30% of a play area, is the starting point for the model. The best 30% of the play area will have wells with estimated ultimate recoveries (EURs) about twice the "average" well in a play. (Wells that produce from a "fairway" – i.e., the best portion of a play – often show, as a group, estimated EURs substantially higher than the average well in the play.) The truly marginal 40% of the play area will have EURs between 25% and 30% of the average wells. This actual well distribution for each play is based on tabulation of extensive data on actual well performance. ARI periodically analyzes the changes in well productivity for each play to recalibrate play performance, well distributions and recovery estimates.

- Discounting Reserves. To facilitate discounted NPV economic analysis, well reserves for each performance category are discounted to time zero using a 15% annual discount factor. The production type curve for each play is plotted and discounted assuming a 25-year well life.

- Capital and O&M Costs. The system accounts for all direct costs associated with play development. These include drilling & completion, well stimulation, pumping & surface equipment, lease equipment, gas gathering and compression, water collection and disposal, G&A, operating costs and basin differential. When costs are matched with discounted production and a gas price, the profitability of each play is determined, on both a discounted (and undiscounted) basis.

- Forecast Drilling Schedule and Production. In the forecast mode, the system selects a drilling schedule based on the profitability of each play. The model accomplishes this by dividing the number of remaining undrilled well sites by a drilling schedule, depending on profitability. The more profitable the play, the more rapid the drilling schedule. The process repeats itself for subsequent years, accounting for changing costs and gas prices over time which will change profitability. The drilling schedule also determines how quickly reserves are replaced and the overall resource depleted.

- Technology Impact. The system also models the impact of both regular advances and step changes technology on production, well drilling and reserves. For example, it includes the effects of new technology such as horizontal wells for tight sands, advanced cavitation techniques for coalbed methane, and multilateral completions for gas shales by modifying the gas production profiles associated with these technology advancements, and thus play profitability.

- Access Restrictions. Drilling on public lands can be restricted for a variety of reasons, included sensitive habitat, endangered species, and terrain stability concerns. The model can account for these increasing restrictions by increasing development time and reducing overall recovery of these “off limits” and restricted areas.

Considerable effort is spent on keeping the data and analysis system current. ARI updates production, well drilling, and reserves data annually. Periodically, ARI undertakes a fundamental update of well performance and costs. During well performance updates, every producing well in our database for each of the plays is examined to extract trends in well productivity and technology effects. This involves examining tens of thousands of wells. Wells are grouped and analyzed by vintage, by performance, and by location within the play. Cost updates involve examining changes in drilling and completion costs, operating costs, basin differentials, along with other cost components. Using the above data, ARI periodically also updates the resource assessments for each play in the system, giving particular attention to changes in play area, changes in well spacing, and changes in well productivity and success rates.

Advanced Resources’ unconventional resources supply system has benefited from an extensive set of updates over the past year. An additional 15 plays have been added to reflect the additional resource potential of liquids rich shale and tight gas sand basins in the Rockies, Pennsylvania, Mid-Continent, and Texas. To ensure the value of higher value hydrocarbons is adequately represented in project economics, an industry-standard petroleum products pricing module was added. Based on play-specific gas composition data, this module accurately accounts for the separation and marketing of higher value hydrocarbons where adequate separation facilities are available. Additionally, all major plays within the model have been updated based on the most recent well performance, cost, and economics data available.