SPILMAN THOMAS & BATTLE, PLLC
ATTORNEYS AT LAW

James D. Elliott
(717) 791-2012
jelliott@spilmanlaw.com

August 18, 2014

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

**VIA ELECTRONIC MAIL**

**RE: Comments of the Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association and the Virginia Oil and Gas Association -- Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards; Docket ID No. EPA-HQ-OAR-2010-0505.**

Dear Administrator McCarthy:

The Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association, and the Virginia Oil and Gas Association (collectively, the "Independent Producers") appreciate the opportunity to submit comments on the proposed rule entitled "Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards" ("Proposed Rule") and published in the Federal Register on July 7, 2014 (79 Fed. Reg. 41752).

The Independent Petroleum Association of America ("IPAA") is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies.

The Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV") is a statewide nonprofit trade association that represents companies engaged in the extraction and production of natural gas and oil in West Virginia, and the companies that support these extraction and production activities. IOGA-WV was formed to promote and protect a strong, competitive and capable independent natural gas and oil producing industry in West Virginia, as well as the natural environment of the state.

The Kentucky Oil & Gas Association, Inc. ("KOGA") was formed in 1931 to represent the interests of Kentucky's crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators, as well as the businesses that support the industry. KOGA is comprised of 220 companies which consist of over 600 member representatives that are directly related to the crude oil and natural gas industry in Kentucky.

The Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Through the years PIOGA's membership has grown to nearly 1,000 members: oil and natural gas producers, drilling contractors, service companies, engineering companies, manufacturers, marketers, Pennsylvania Public Utility Commission-licensed Natural Gas Suppliers ("NGSs"), professional firms and consultants, and royalty owners. PIOGA promotes the interests of its members in environmentally responsible oil and natural gas operations in both conventional geologic formations and unconventional shale formations, and the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

The Ohio Oil & Gas Association ("OOGA") is a trade association with over 2,600 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources within the State of Ohio. OOGA represents the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio.

Indiana Oil and Gas Association, Inc. ("INOGA") has a rich history of involvement in the exploration and development of hydrocarbons in the State of Indiana. INOGA was formed in 1942 and historically has been an all-volunteer organization principally made up of representatives of oil and gas exploration and development companies (operators), however, it has enjoyed support and membership from pipeline, refinery, land acquisition, service, supply, legal, engineering, and geologic companies or individuals. INOGA has been an active representative for the upstream oil and gas industry in Indiana and provides a common forum for this group. INOGA represents its membership on issues of state, federal, and local regulation/legislation that has, does, and will affect the business of this industry

The Illinois Oil & Gas Association ("IOGA") was organized in 1944 to provide an agency through which oil and gas producers, land owners, royalty owners, and others who may be directly or indirectly affected by or interested in oil and gas development and production in Illinois, may protect, preserve and advance their common interests.

Formed in 1977 the Virginia Oil & Gas Association ("VOGA") is a non-profit trade association representing the interests of companies, partnerships, individuals, or other entities having an interest in the oil and gas industry and who are primarily engaged in the exploration, production, development, transportation, and distribution of natural gas and oil in Virginia.

The above associations came together, in large part, to comment on the original rule (individually, or as a member of IPAA), published on August 16, 2012; petition the United States Environmental Protection Agency ("USEPA") for reconsideration on October 15, 2012; and file a legal challenge in the United States Court of Appeals for the District Circuit to the August 16, 2012 final rule because there are aspects of the final rule and Proposed Rule that disproportionally impact conventional wells and energized wells – particularly as it relates to reduced emission completions ("RECs"). The history and activities of the above associations are relevant because of the depth of knowledge and unique position that many of their members have within the industry. The Independent Producers appreciate that the USEPA has recognized the proposed definition of a "low pressure well" proffered by the Independent Producers, but we are concerned that the USEPA continues to misunderstand our concerns and has not justified its definition of a low pressure well.

USEPA's preamble discussion of the low pressure well definition misses the point. It states in relevant part:

> [T]he three parameters discussed above and used in the EPA definition are known by operators in advance of flowback and that the relatively simple calculation called for in the EPA definition could be performed with a basic hand-held calculator and should not pose difficulty or hardship for the smaller operators.

79 Fed. Reg. 41758. The "hardship" is not the calculation. The hardship is being required to perform RECs on marginally cost-effective wells that industry has historically recognized as low pressure wells. While the ultimate calculation may be completed on a "basic hand-held calculator," it does not mean that the derivation of the formula or the results of the calculation accurately depicts what constitutes a low pressure well.

Additionally, the preamble takes issue with the Independent Producers petition for reconsideration because it "did not include any details on which of EPA's assumptions is questionable . . .." *Id.* While we provide details in these comments, USEPA's statement requires that we emphasize that the burden to justify the rule is on USEPA, not the Independent Producers or any other commenters. One of the key assumptions to the USEPA's definition is its reliance on the Turner equation to calculate the minimum gas velocity needed to lift a droplet.[1] This equation is used to predict the velocity needed to lift to the surface the proppant used to hydraulically fracture the well. The Turner equation is from a 1969 article in the Oil and Gas Journal.[2] The equation is based on a droplet reversal model. Independent Producers are not aware of the oil and gas industry using the Turner equation for any practical applications (unlike Independent Producers' proposed definition which relies on industry accepted calculations).

---

[1] Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Supplemental Technical Support Document for the Final New Source Performance Standards, pp. 34-37 (April 2012).

[2] Turner, R. G., *et. al.*, *Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells*, Journal of Petroleum Technology, Nov. 1969, Equation 4, at 1476.

Independent Producers site a *recent* engineering doctoral dissertation at the Tulsa University that compared several methods of calculating liquid loading in a well, which it is relevant as it pertains to the equations used by USEPA to develop a definition of a low pressure well. The dissertation was delivered by Dr. Shu Luo, a graduate student at Tulsa University, in 2013. His advisor was Dr. Mohan Kelkar, head of the Petroleum Engineering Department. Dr. Lho's abstract follows.

> When natural gas is produced from gas wells, it is always accompanied by liquid. At the later stages of a well's life, the gas is unable to carry liquid to the surface, resulting in liquid accumulation at the bottom of the well; this is called "Liquid Loading". Knowing when the liquid loading will occur is important because by using certain artificial lift methods the well can be produced under stable conditions even after the transition. The most popular method in the literature for determining the onset of liquid loading is the equation developed by Turner et al. This equation is a droplet model and is based on the terminal velocity of liquid droplet in single phase gas column. Many modifications have been proposed to this equation to improve the prediction of liquid loading. Recently, Veeken et al. have shown that in many inclined and some vertical wells, Turner's equation under-predicts the true critical flow rate (the flow rate at which liquid loading starts). This may be due to angle of deviation as well as the fact that inception of liquid loading is more likely due to liquid film reversal in annular flow rather than droplet fall back.
>
> In this dissertation, the inception of liquid loading is defined using the liquid film reversal model based on experimental observation. Also, a new liquid loading model which is based on liquid film reversal is proposed. We base our model on Barnea's model and make several improvements to that model for better prediction of liquid loading. The improvements include: (i) development of variable film thickness model to account for the deviation angle of the well; (ii) development of equation to account for annular flow; and (iii) improvement of the friction factor equation at the interface between the liquid film and the gas core. We validated our model against all the available data from the literature as well as additional data collected from various operators. The results show remarkable improvement over Turner's original method as well as various ad hoc modifications made to that equation. A method which determines the unloading of a gas well after shut in will also be discussed.
>
> In this dissertation, we also explore one possible method to eliminate liquid loading. Injection of surfactant is one of the common methods used for avoiding liquid loading in gas well. Using our definition of liquid loading, the stability of foam flow can be predicted. We also propose a correlation for liquid holdup in foam flow and compare the predictions with experimental data. Based on the large scale experimental data, we

> provide a preliminary model for predicting foam flow and articulate reasons why the foam works in preventing liquid loading.[3]

In relevant part, according to the recent research, the Turner equation typically under-predicts the velocity necessary to unload the well. Since the Turner equation under-predicts velocity, the resulting USEPA low pressure well formula then also under-predicts the pressure necessary for a well to flowback without assistance. For instance, to increase velocity in the well tubing, which has a fixed flow area, the flow rate of gas must be increased to carry the liquid up the tubing. To increase the flow rate within a given pipe size, pressure must increase. Operators will sometimes install smaller tubing to decrease flow area, which also increases velocity. This is one example of where USEPA's derivation of a complex equation to define low pressure well is flawed. A more accurate low pressure well definition should rely on the liquid film reversal model versus the Turner equation, and result in a higher pressure threshold than currently proposed by the USEPA. Again, the burden is on USEPA to justify its definition and not to simply question the alternative definition proposed by the Independent Producers. USEPA's reliance on an outdated equation not recognized or utilized by the industry is inappropriate.

As to the Independent Producers' alternative definition of a low pressure well, Independent Produce proposed the following more simple definition for "low pressure well."

> "A well where the field pressure is less than 0.433 times the vertical depth of the deepest target reservoir and the flow-back period will be less than three days in duration."

This definition was based on the weight of fresh water (8.33 lbs/gal) which is stacked on top of itself, and is known as hydrostatic pressure. Converting the density of fresh water to a pressure gradient results in 8.33 lb/gal being equal to 0.433 psi/ft. Therefore, the pressure of fresh water in the well bore is 0.433 psi/ft times the vertical well depth.

In reality, the fluid flowing to the surface could be fresh water, re-used hydraulic fracturing water, re-used produced water, or a mixture. Additionally, in the beginning of the operation, the initial fluids flowing to the surface are essentially the fracturing fluids put down hole. At the end of the operation, the fluids flowing to the surface will mainly consist of reservoir fluids, and the water will be more of a brine water and not fresh water. Brine water has a greater density, and more reservoir pressure will be required to lift the fluid to the surface. The use of a fresh water gradient of 0.433 psi/ft should be used to keep the definition conservative and simple.

As an alternative – or in addition – to a fresh water gradient, the density of brine water influenced by sand or proppant should be used to more accurately reflect the pressure of the water column in the well bore. In fact, USEPA appears to have utilized a gradient of 0.4645 psi/ft in the "Lessons Learned from Natural Gas STAR Partners; Reduced Emissions

---

[3] Luo, Shu, Inception of liquid loading in gas wells and possible solutions, Ph.D. diss., The University of Tulsa, 2013.

Completions for Hydraulically Fractured Natural Gas Wells" paper developed as a part of USEPA's Natural Gas STAR Program.[4] This is evidenced by the gradients listed in Exhibit 5 of the paper. A copy of this paper is provided as Attachment 1. Additionally, to perform a REC, the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough back pressure for it to get into the natural gas gathering line. To combust flowback emissions, the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough back pressure to flow to a flare or enclosed combustion device.

To reflect these realities, Independent Producers proposes to the USEPA that no emission control be required when the following scenario exists:

> "A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir."

At reservoir pressures below this value, enough pressure does not exist for any gas to flow to a flare, enclosed combustion device or the process. Consequently, the Independent Producers propose to the USEPA that combustion through a flare or enclosed combustion device be required when the following scenario exists:

> "A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir plus the gathering or sales line pressure."

At reservoir pressures less than the sum of the water column pressure and the sales line pressure, the recovered gas will not naturally flow into the sales line. The Proposed Rule does not require compression of recovered gas into the sales line. USEPA has recognized this type of simpler approach in estimating the level of pressure necessary for recovered gas to flow into a gathering or sales line in their "Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells" paper developed as a part of USEPA's Natural Gas STAR Program.[5] In this paper, USEPA provides a table (Exhibit 5) with pressures necessary for various well depths. For instance, USEPA indicates that the reservoir pressure necessary to flow recovered gas into a sales line for a 10,000-foot well would be 4,645 psig plus the sales line pressure.

The definition of a low pressure well is relevant to the revised stages of flowback and helps illustrate the problem and concern of those drilling low pressure wells. The Independent Producers generally support USEPA's proposed definitions for the stages of flowback from a

---

[4] USEPA; Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells; 2011. http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf
[5] *Id.*

well. In the USEPA proposal for the second round of reconsideration rulemaking,[6] three (3) new terms are proposed:

- Initial flowback stage
- Separation flowback stage
- Production stage

During the initial flowback stage, USEPA has indicated that there is not enough gas to operate a separator. Gas generated during the initial flowback stage would not be controlled under the proposal. USEPA acknowledges that during the separation flowback stage there may not be enough gas to operate a separator, with the gas either combusted or recovered depending on the well type according to the proposal. For certain lower pressure wells (that most likely would not meet the USEPA proposed definition of a low pressure well), the overall flowback period (all three stages) is so short that there is an insufficient amount of gas generated during the separation flowback stage to be able to operate or utilize a separator for a meaningful time period.

The Independent Producers proposed definition of a low pressure well that focused on the "three day" flowback period attempted to recognize this point. The dynamics of most vertical wells and energized wells are such that RECs or combustion by way of a separator is not feasible. The Independent Producers request that USEPA address this issue in their final rule to acknowledge that not every well will have the three flowback stages clearly defined, and in certain instances, the separation flowback stage is so short that RECs are not feasible or required, *i.e.*, that a well can essentially go from the initial flowback state to the production stage. There is a subjective element to this evaluation, which USEPA has acknowledged, so the final rule should not prevent those drilling low pressure wells from continuing their operations. As noted before in various comments, the economic incentive to undertake RECs exists. USEPA's proposed low pressure well definition forces controls on a segment of the industry that have no or minimal beneficial impact on the environment while imposing significant additional costs that will make drilling and operating such wells uneconomical. The Independent Producers request that the definition of a low pressure well be revised as suggested above or that USEPA acknowledge the separation flowback stage can be so short in duration that RECs are not necessary.

In addition to the comments above, the Independent Producers support and incorporate by reference the comments file by the American Exploration and Production Council ("AXPC")[7] on this proposed rule.

---

[6] Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards; Proposed Rule, 79 Fed. Reg. 41752 (July 17, 2014).

[7] AXPC is a national trade association representing 34 of the largest United States independent natural gas and crude oil exploration and production companies.

If the USEPA has any questions or concerns regarding the comments, please do not hesitate to contact me.

Sincerely,

James D. Elliott

cc: Bruce Moore
Amy Branning
Lee Fuller, IPAA Vice President of Government Relations
Charlie Burd, IOGA-WV Executive Director
Andrew V. McNeill, KOGA Executive Director
Lou D'Amico, PIOGA Executive Director
Thomas A. Stewart, OOGA Executive Vice President
Matt Stone INOGA President
Brad Richards, IOGA Executive Vice President
Greg Kozera, VOGA President

# **ATTACHMENT 1**

# Lessons Learned
from Natural Gas STAR Partners

# Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells

## Executive Summary

In recent years, the natural gas industry has developed more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involve hydraulic fracturing of the reservoir to increase well productivity. Industry reports that hydraulic fracturing is beginning to be performed in some conventional gas reservoirs as well. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and therefore methane emissions to the atmosphere. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990 - 2009* estimates that 68 billion cubic feet (Bcf) of methane are vented or flared annually from unconventional completions and workovers.

Reduced emissions completions (RECs) – also known as reduced flaring completions or green completions – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the sales pipeline. RECs help to reduce methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of thirteen different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2009 emissions reductions from RECs (as reported to Natural Gas STAR) have increased from 200 MMcf (million cubic feet) to over 218,000 MMcf. Capturing an additional 218,000 MMcf represents additional revenue from natural gas sales of over $1.5 billion from 2000 to 2009 (assuming $7/Mcf gas prices).

## Technology Background

High demand and higher prices for natural gas in the U.S. have resulted in increased drilling of new wells in more expensive and more technologically challenging unconventional gas reservoirs, including those in low porosity (tight) formations. These same high demands and

### Economic and Environmental Benefits

| Method for Reducing Natural Gas Losses | Volume of Natural Gas Savings (Mcf) | Value of Natural Gas Savings ($) | | | Additional Savings ($) | Implementation Cost ($) | Other Costs ($) | Payback (Months) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | $3 per Mcf | $5 per Mcf | $7 per Mcf | | | | $3 per Mcf | $5 per Mcf | $7 per Mcf |
| Purchased REC Equipment Annual Program | 270,000 per year | $810,000 per year | $1,350,000 per year | $1,890,000 per year | $175,000 per year | $500,000 | $121,250 per year | 6 | 4 | 3 |
| Incremental REC Contracted Service | 10,800 per completion | $32,400 per completion | $54,000 per completion | $75,600 per completion | $6,930 per completion | $32,400 | $600 per completion | Imme-diate | Imme-diate | Imme-diate |

General Assumptions:
[a] Assuming 9 days per completion, 1,200 Mcf gas savings per day per well, 11 barrels of condensate recovered per day per well, and cost of $3,600 per well per day for contracted services.
[b] Assuming $70 per barrel of condensate.
[c] Based on an annual REC program of 25 completions per year.

prices also justify extra efforts to stimulate production from existing wells in tight reservoirs where the down-hole pressure and gas production rates have declined, a process known as well workovers or well-reworking. In both cases, completions of new wells in tight formations and workovers of existing wells, one technique for improving gas production is to fracture the reservoir rock with very high pressure water containing a proppant (generally sand) that keeps the fractures "propped open" after water pressure is reduced. Depending on the depth of the well, this process is carried out in several stages, usually completing one 200- to 250-foot zone per stage.

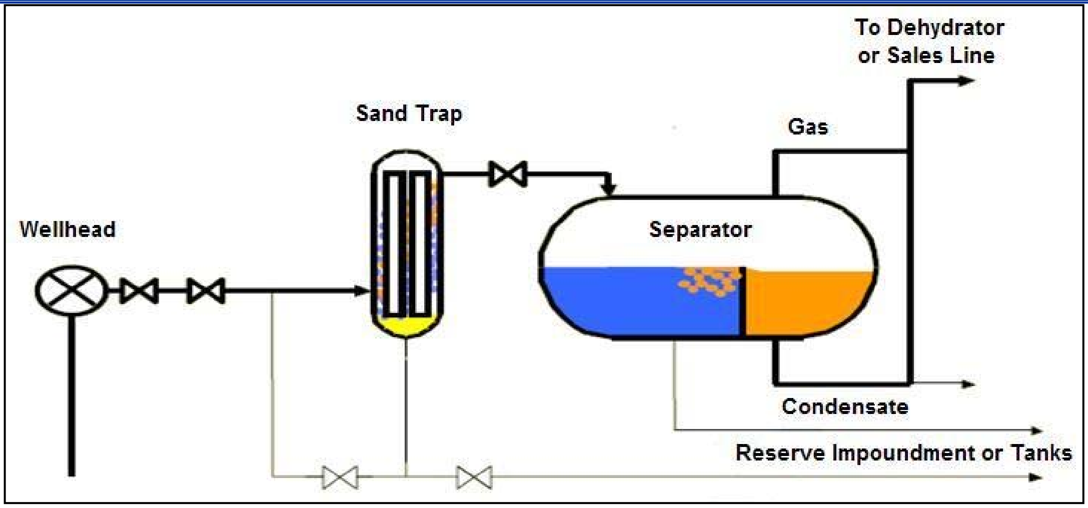
These new and "workover" wells are completed by producing the fluids at a high rate to lift the excess sand to the surface and clear the well bore and formation to increase gas flow. Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids and sand are captured and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from one day to several weeks during which time a substantial amount of gas may be released to the atmosphere or flared. Testing of production levels occurs during the well completion process, and it may be necessary to repeat the fracture process to achieve desired production levels from a particular well.

Natural gas lost during well completion and testing can be as much as 25 million cubic feet (MMcf) per well depending on well production rates, the number of zones completed, and the amount of time it takes to complete each zone. This gas is generally unprocessed and may contain volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) along with methane. Flaring gas may eliminate most methane, VOC and HAP emissions, but open flaring is not always a preferred option when the well is located near residential areas or where there is a high risk of grass or forest fires. Moreover, flaring may release additional carbon dioxide and other criteria pollutants (SOx, NOx, PM and CO) to the atmosphere.

Natural Gas STAR partners have reported performing RECs that recover much of the gas that is normally vented or flared during the completion process. This involves installing portable equipment that is specially designed and sized for the initial high rate of water, sand, and gas flowback during well completion. The objective is to capture and deliver gas to the sales line rather than venting or flaring this gas.

Sand traps are used to remove the finer solids present in the production stream. Plug catchers are used to remove any large solids such as drill cuttings that could damage the other separation equipment. The piping configuration to the sand traps is critical as the abrasion from high velocity water and sand can erode a hole in steel pipe elbows, creating a "washout" with water, sand,

**Exhibit 1: Reduced Emissions Completion Equipment Layout**




Adapted from BP.

hydrocarbon liquids and gas in an uncontrolled flow to the pad. Depending on the gas gathering system, it may be necessary to dehydrate (remove water from) the produced gas before it enters the sales pipeline. The gas may be routed to the permanent glycol unit for dehydration or a portable desiccant/glycol dehydrator used for dehydration during the completion process.

Free water and condensate are removed from the gas in a three phase separator. Condensate (liquid hydrocarbons) collected during the completion process may be sold for additional revenue. Temporary piping may be used to connect the well to the REC skid and gathering system if the permanent piping is not yet in place. Exhibit 1 shows a typical layout of temporary REC portable equipment, and Exhibit 2 explains some alternate, emerging, and/or experimental procedures for a well completion and REC.

The equipment used during RECs is only necessary for the time it takes to complete the well; therefore, it is essential that all the equipment can be readily transported from site to site to be used in a number of well completions. A truck mounted skid, as shown in Exhibit 3, is ideal for transporting the equipment between sites. In a large basin that has a high level of drilling activity it may be economic for a gas producer to build its own REC skid. Most producers may prefer contracting a third party service to perform completions.

When using a third party to perform RECs, it is most cost effective to integrate the scheduling of completions with the annual drilling program. Well completion time is another factor to consider for scheduling a contractor for RECs. Some well completions, such as coal bed methane, may take less than a day. On the other hand, completing wells which fracture various zones, such as shale gas wells, may take several weeks to complete. For most wells, it takes about 3 to 10 days to perform a well completion following a hydraulic fracture, based on partner experiences.

**Exhibit 2: Alternate Completion Procedures**

Energized Fracturing

Based on Natural Gas STAR partner experiences, RECs can also be performed in combination with energized fracturing, wherein inert gas such as $CO_2$ or nitrogen is mixed with the frac water under high pressure to aid in the process of fracturing the formation. The process is generally the same with the additional consideration of the composition of the flowback gas. The percent of inert gases in the flowback gas is, at first, unsuitable for delivery into the sales line. As the fraction of inerts decreases, the gas can be recovered economically. A portable membrane acid gas separation unit can further increase the amount of methane recovered for sales after a $CO_2$ energized fracture.

Compression

Two compressor applications during an REC have been identified or explored by Natural Gas STAR partners.

1) Gas Lift. In low pressure (i.e. low energy) reservoirs RECs are often carried out with the aid of compressors for gas lift. Gas lift is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the frac fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during an REC.

2) Boost to Sales Line. When the gas recovered in the REC separator is lower pressure than the sales line, some companies are experimenting with a compressor to boost flowback gas into the sales line. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate. Coal bed methane well completion is an example where additional compression might be required.

**Exhibit 3: Truck Mounted Reduced Emissions Completion Equipment**

Source: Weatherford

### Economic and Environmental Benefits

- ★ Gas recovered for sales
- ★ Condensate recovered for sales
- ★ Reduced methane emissions

- ★ Reduced loss of a valuable hydrocarbon resource
- ★ Reduced emissions of criteria and hazardous air pollutants

Emissions from well completions can contribute to a number of environmental problems. Direct venting of VOCs can contribute to local air pollution, HAPs are deemed harmful to human health, and methane is a powerful greenhouse gas that contributes to climate change. Where it is safe, flaring is preferred to direct venting because methane, VOCs, and HAPs are combusted, lowering pollution levels and reducing global warming potential (GWP) of the emissions as $CO_2$ from combustion has a lower GWP than methane. RECs allow for recovery of gas rather than venting or flaring and therefore reduce the environmental impact of well completion and workover activities.

RECs bring economic benefits as well as environmental benefits. The incremental costs associated with the rental of third party equipment for performing RECs can be offset by the additional revenue from the sale of gas and condensate. As this technology is being perfected and equipment becomes commonplace, the revenues in gas and condensate sales often exceed the incremental costs.

## Decision Process

### *Step 1: Evaluate candidate wells for Reduced Emissions Completions.*

When setting up an annual RECs program it is important to examine the characteristics of the wells that are going to be brought online in the coming year. Wells in conventional reservoirs that do not require a reservoir fracture (frac job) and will produce readily without stimulation can be cleared of drilling fluids and connected to a production line in a relatively short period of time with minimal gas venting or flaring, and therefore usually do not economically justify REC equipment. Wells that undergo energized fracture using inert gases require special considerations because the initial produced gas captured by the REC equipment would not meet pipeline specifications due to the inert gas content. However, as the amount of inerts decreases, the quality of the gas will likely meet pipeline specifications. In the case of $CO_2$ energized fracks, the use of portable acid gas removal membrane separators will improve gas quality and make it possible to direct gas to the pipeline (see Partner Experiences section for more information).

**Decision Process**
Step 1: Evaluate candidate wells
Step 2: Determine costs
Step 3: Estimate savings
Step 4: Evaluate economics

**State and Local Regulations**
The States of Wyoming and Colorado have regulations requiring the implementation of "flareless completions". Operators of new wells in this region are required to complete wells without flaring or venting. These completions have reduced flaring by 70 to 90 percent.

For more information, visit:
http://deq.state.wy.us
http://www.cdphe.state.co.us

Exploratory and delineation wells in areas that do not yet have sales pipelines in close proximity to the wells are not candidates for RECs as the infrastructure is not in place to receive the recovered gas. In depleted or low pressure fields with low energy reservoirs, implementing a RECs program would most likely require the addition of compression to overcome the sales line pressures–an approach that is still under development and may add significant cost to implementation.

Wells that require hydraulic fracturing to stimulate or enhance gas production may need a lengthy completion, and therefore are good candidates for RECs. Lengthy completions mean that a significant amount of gas may be vented or flared that could potentially be recovered and sold for additional revenue to justify the additional cost of a REC. If newly drilled wells are in close proximity, they could share the REC equipment to minimize transport, set-up, and equipment rental costs.

**Selecting a Basis for Costs and Savings**
- ★ Estimate the number of producing gas wells that will be drilled in the next year
- ★ Evaluate well depth and reservoir characteristics
- ★ Determine whether additional equipment is necessary to bring recovered gas up to pipeline specifications
- ★ Estimate time needed for each completion

### *Step 2: Determine the costs of a REC program.*

Most Natural Gas STAR partners report using third party contractors to perform RECs on wells within their producing fields. It should be noted that third party contractors are also often used to perform traditional well completions. Therefore, the economics presented deal with incremental costs to carry out RECs versus traditional completions.

Generally, the third party contractor will charge a commissioning fee for transporting and setting up the equipment for each well completion within the operator's producing field. Some RECs vendors have their equipment mounted on a single trailer while others lay down individual skids that must be connected with temporary piping at each site. The incremental cost associated with transportation between well sites in the operator's field and connection of the REC equipment within the normal flowback piping from the wellhead to an impoundment or tank is generally around $600/completion.

In addition to the commissioning fee, there is a daily cost for equipment rental and labor to perform each REC. As mentioned above, when evaluating the costs of well completions, it is important to consider the incremental cost of a REC over a traditional completion rather than focusing on the total cost. 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. Equipment costs associated with RECs will vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment such as a glycol dehydrator is already installed at the well site, REC costs may be reduced as this equipment can be used rather than bringing a portable dehydrator on-site, assuming the flow-back rate does not exceed the capacity of the equipment. Some operators report installing permanent equipment that can be used in the RECs as part of normal well completion operations, such as oversized three-phase separators, further reducing incremental REC costs. Well completions usually take between 1 to 30 days to clean out the well bore, complete well testing, and tie into the permanent sales line. Wells requiring multiple fractures of a tight formation to stimulate gas flow may require additional completion time. Exhibit 4 shows the typical costs associated with undertaking a REC at a single well.

**Exhibit 4: Typical Costs for RECs**

| One-time Transportation and Incremental Set-up Costs | Incremental REC Equipment Rental and Labor Costs | Well Clean-up Time |
|---|---|---|
| $600 per well | $700 to $6,500 per day | 3 to 10 days |

For low energy reservoirs, gas from the sales line may be routed down the well casing to create artificial gas lift, as mentioned in Exhibit 2. Depending on the depth of the well, a different quantity of gas will be required to lift the fluids and clean out the well. Using average reservoir depths for major U.S. basins and engineering calculations, Exhibit 5 shows various estimates of the volume of gas required to lift fluids for different well depths.

A REC annual program may consist of completing 25 wells/year within a producer's operating region. Exhibit 6 shows a hypothetical example of REC program costs based on information provided by partner companies.

**Exhibit 5: Sizing and Fuel Consumption for Booster Compressor**

| Well Depth (ft) | Pressure Required to Lift Fluids (psig) | Gas Required to Lift Fluids (Mcf)[a] | Compressor Size (horsepower)[a] | Compressor Fuel Consumption (Mcf/hr)[a] |
|---|---|---|---|---|
| 3,000 | 1,319 + Sales line pressure | 195 to 310 | 195 to 780 | 2 to 7 |
| 5,000 | 2,323 + Sales line pressure | 315 to 430 | 400 to 1,500 | 3 to 13 |
| 8,000 | 3,716 + Sales line pressure | 495 to 610 | 765 to 2,800 | 7 to 24 |
| 10,000 | 4,645 + Sales line pressure | 615 to 730 | 1,040 to 3,900 | 9 to 33 |

[a] Based on sales line pressures between 100 to 1,000 psig.

### Exhibit 6: Hypothetical Example Cost Calculation of a 25 Well Annual REC Program

**Given**

W = Number of completions per year
D = Well depth in feet (ft)
$P_s$ = Sales line pressure in pounds per square inch gauge (psig)
$T_s$ = Time required for transportation and set-up (days/well)
$T_c$ = Time required for well clean-up (days/well)
O = Operating time for compressor to lift fluids (hr/well)
F = Compressor fuel consumption rate (Mcf/hr)
G = Gas from pipeline routed to casing to lift fluids (Mcf/well), typically used on low energy reservoirs
$C_s$ = Transportation and set-up cost ($/well)
$C_e$ = Equipment and labor cost ($/day)
$P_g$ = Sales line gas price ($/Mcf)

W = 25 wells/yr
D = 8000 ft
$P_s$ = 100 psig
$T_s$ = 1 day/well
$T_c$ = 9 days/well
O = 24 hr/well
F = 10 Mcf/hr
G = 500 Mcf/well (See Exhibit 5)
$C_s$ = $600/well
$C_e$ = $2,000/day
$P_g$ = $7/Mcf

**Calculate Total Transportation and Set-up Cost, $C_{TS}$**

$C_{TS} = W * C_s$

$C_{TS}$ = 25 wells/yr * $600/well
$C_{TS}$ = $15,000/yr

**Calculate Total Equipment Rental and Labor Cost, $C_{EL}$**

$C_{EL} = W * (T_s + T_c) * C_e$

$C_{EL}$ = 25 wells/yr * (1 day/well + 9 days/well) * $2,000/day
$C_{EL}$ = $500,000/yr

**Calculate Other Costs, $C_O$**

$C_O = W * [(O * F) + G] * P_g$

$C_O$ = 25 wells/yr * [( 24 hr/well * 10 Mcf/hr) + 500 Mcf/well] * $7/Mcf
$C_O$ = $129,500/yr

**Total Annual REC Program Cost, $C_T$**

$C_T = C_{TS} + C_{EL} + C_O$
$C_T$ = $15,000/yr + $500,000/yr + $129,500/yr
$C_T$ = $644,500/yr

***Step 3: Estimate Savings from RECs.***

Gas recovered from RECs can vary widely because the amount of gas recovered depends on a number of variables such as reservoir pressure, production rate, amount of fluids lifted, and total completion time. Exhibit 7 shows the range of recovered gas and condensate reported by Natural Gas STAR partners. Partners also have reported that not all the gas that is produced during well completions may be captured for sales. Fluids from high pressure wells are often routed directly to the frac tank in the initial stages of completion as the fluids are often being produced at a rate that is too high for the REC equipment. Where inert gas is used to energize the frac, the initial gas production may have to be flared until the gas meets pipeline specifications. Alternatively, a portable acid gas membrane separator may be used to recover methane rich gas from $CO_2$. As the flow rate of fluids drops and gas is encountered, backflow is then switched over to the REC equipment so that the gas may be captured. Gas compressed from the sales line to lift fluids (by artificial gas lift) will also be recovered in addition to the gas produced from the reservoir. The volume of gas needed to lift fluids can be estimated based on the well depth and sales line pressure. Gas saved during RECs can be translated directly into methane emissions reductions based on the methane content of the produced gas.

In addition to gas savings, valuable condensate may also be recovered from the REC three-phase separator. The amount of condensate that can be recovered during a REC is dependent on the reservoir conditions and fluid compositions. Condensate may also be lost if fluids are produced directly to the frac tank before switching to the REC equipment.

**Exhibit 7: Ranges of Gas and Condensate Savings**

| Produced Gas Savings (Mcf/day/well) | Gas-Lift Savings (Mcf/well) | Condensate Savings (bbl/day/well) |
|---|---|---|
| 500 to 2,000 | See Exhibit 5 | Zero to several hundred |

Exhibit 8 shows typical values of gas and condensate savings during the REC process.

***Step 4: Evaluate REC economics.***

The example application of an REC program to 25 wells within a producing field can yield a total theoretical revenue of $2,152,500 based on the assumptions listed above from the sale of natural gas and condensate. Equipment rental, labor, and other costs associated with implementing this program are estimated to be $644,500 (see Exhibit 6) resulting in an annual theoretical profit of $1,508,000. To maintain a profitable REC program, it is important to move efficiently from well to well within a producing field so that there is little down time when paying for equipment rental and labor. Other factors that affect the profitability of an REC program include the amount of condensate recovery and sales price, the need for additional compressors, the amount of gas recovered, and gas sales price.

Exhibit 9 shows a five year cash flow projection for carrying out a 25 well per year REC program. In this example, the equipment necessary to perform RECs has been purchased by the operator rather than using a third party contractor to perform the service. The capital cost of a simple REC set-up without a portable compressor has been reported by British Petroleum (BP) to be $500,000.

Producers with high levels of localized drilling and workover activity may benefit from constructing and operating their own REC equipment. As illustrated above, even though large capital outlay is required to construct a REC skid, a high rate of return can be achieved if the equipment is in continuous use. If the operator is unable to keep the equipment busy on their own wells, they may

**Nelson Price Indexes**

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

**Exhibit 8: Savings of a 25 Well Annual REC Program**

**Given**

W = Number of completions per year
D = Well depth in feet (ft)
$P_s$ = Sales line pressure in pounds per square inch gage (psig)
$S_p$ = Produced gas savings (Mcf/day)
$T_c$ = Time recovered gas flows to sales line in days (days/well)
$S_c$ = Condensate savings (bbl/well)
G = Gas used to lift fluids (Mcf/well), typically used on low energy reservoirs
$P_g$ = Sales line gas price ($/Mcf)
$P_l$ = Natural gas liquids price ($/bbl)

W = 25 wells/yr
D = 8000 ft
$P_s$ = 100 psig
$S_p$ = 1,200 Mcf/day
$T_c$ = 9 days/well
$S_c$ = 100 bbl/well
G = 500 Mcf/well (See Exhibit 5)
$P_g$ = $7/Mcf
$P_l$ = $70/bbl

**Calculate Produced Gas Savings**

$S_{PG} = W * (S_p * T_c) * P_g$

$S_{PG}$ = 25 wells/yr * (1,200 Mcf/day * 9 days/well) * $7/Mcf
$S_{PG}$ = $1,890,000/yr

**Calculate Other Savings**

$S_O = W * [(G * P_g) + (S_c * P_l)]$

$S_O$ = 25 wells/yr * [(500 Mcf/well * $7/Mcf) + (100 bbl/well * $70/bbl)]
$S_O$ = $262,500/yr

**Total Savings, $S_T$**

$S_T = S_{PG} + S_O$
$S_T$ = $1,890,000/yr + $262,500/yr
$S_T$ = $2,152,500/yr

contract it out to other operators to maximize usage of the equipment.

When assessing REC economics, the gas price may influence the decision making process; therefore, it is important to examine the economics of undertaking a REC program as natural gas prices change. Exhibit 10 shows an economic analysis of performing the 25 well per year REC program in Exhibit 8 at different gas prices.

**Exhibit 9: Economics for Hypothetical 25 Well Annual REC Program with Purchased Equipment**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| **Volume of Natural Gas Savings (Mcf/yr)[a]** | | 270,000 | 270,000 | 270,000 | 270,000 | 270,000 |
| **Value of Natural Gas Savings ($/year)[a]** | | 1,890,000 | 1,890,000 | 1,890,000 | 1,890,000 | 1,890,000 |
| **Additional Savings ($/yr)[a]** | | 175,000 | 175,000 | 175,000 | 175,000 | 175,000 |
| **Set-up Costs ($/yr)[b]** | | (15,000) | (15,000) | (15,000) | (15,000) | (15,000) |
| **Equipment Costs ($)[b]** | (500,000) | | | | | |
| **Labor Costs ($/yr)[c]** | | (106,250) | (106,250) | (106,250) | (106,250) | (106,250) |
| **Net Annual Cash Flow ($)** | **(500,000)** | **1,943,750** | **1,943,750** | **1,943,750** | **1,943,750** | **1,943,750** |

**Internal Rate of Return = 389%**
**NPV (Net Present Value)[d] = $6,243,947**
**Payback Period = 3 months**

[a] See Exhibit 8.
[b] See Exhibit 6.
[c] Labor costs for purchased REC equipment estimated as 50% of Equipment Rental and Labor costs in Exhibit 3.
[d] Net present value based on 10% discount rate over five years.

**Exhibit 10: Gas Price Impact on Economic Analysis of Hypothetical 25 Well Annual REC Program with Purchased Equipment**

| | Gas Price | | | | |
|---|---|---|---|---|---|
| | **$3/Mcf** | **$5/Mcf** | **$7/Mcf** | **$8/Mcf** | **$10/Mcf** |
| **Total Savings** | $985,000 | $1,525,000 | $2,065,000 | $2,335,000 | $2,875,000 |
| **Payback (months)** | 7 | 5 | 4 | 3 | 3 |
| **IRR** | 172% | 280% | 389% | 443% | 551% |
| **NPV (i = 10%)** | $2,522,084 | $4,383,015 | $6,243,947 | $7,174,413 | $9,035,345 |

### Partner Experience

This section highlights specific experiences reported by Natural Gas STAR partners.

#### BP Experience in Green River Basin

- ★ Implemented RECs in the Green River Basin of Wyoming
- ★ RECs performed on 106 wells, which consisted of high and low pressure wells
- ★ Average 3,300 Mcf of natural gas sold versus vented per well
  - – Well pressure will vary from reservoir to reservoir
  - – Reductions will vary for each particular region
  - – Conservative net value of gas saved is $20,000 per well
- ★ Natural gas emission reductions of 350,000 Mcf in 2002
- ★ Total of 6,700 barrels of condensate recovered per year total for 106 wells
- ★ Through the end of 2005, this partner reports a total of 4.17 Bcf of gas and more than 53,000 barrels of condensate recovered and sold rather than flared. This is a combination of activities in the Wamsutter and Jonah/Pinedale fields.

#### Noble Experience in Ellis County, Oklahoma

- ★ Implemented RECs on 10 wells using energized fracturing.
- ★ Employed membrane separation in which the permeate was a $CO_2$ rich stream that was vented and the residue was primarily hydrocarbons which were recovered.
- ★ Total cost of $325,000.
- ★ Total gas savings of approximately 175 MMcf.
- ★ Estimated net profits to be $340,000
- ★ For more information, see the Partner Profile Article in the Spring 2011 Natural Gas STAR Partner Update available at: http://epa.gov/gasstar/newsroom/partnerupdatespring2011.html

#### Partner Company A

- ★ Implemented RECs in the Fort Worth Basin of Texas
- ★ RECs performed on 30 wells, with an incremental cost of $8,700 per well
- ★ Average 11,900 Mcf of natural gas sold versus vented per well
  - – Natural gas flow and sales occur 9 days out of 2 to 3 weeks of well completion
  - – Low pressure gas sent to gas plant
  - – Conservative net value of gas saved is $50,000 per well
- ★ Expects total emission reduction of 1.5 to 2 Bcf in 2005 for 30 wells

## Lessons Learned

- ★ Incremental costs of recovering natural gas and condensate during well completions following hydraulic fracturing result from the use of additional equipment such as sand traps, separators, portable compressors, membrane acid gas removal units and desiccant dehydrators that are designed for high rate flowback.
- ★ During the hydraulic fracture completion process, sands, liquids, and gases produced from the well are separated and collected individually. Natural gas and gas liquids captured during the completion may be sold for additional revenue.
- ★ Implementing a REC program will reduce flaring which may be a particular advantage where open flaring is undesirable (populated areas) or unsafe (risk of fire).
- ★ Wells that do not require hydraulic fracturing are not good candidates for reduced emissions completions. Methane emissions reductions achieved through performing RECs may be reported to the Natural Gas STAR Program unless RECs are required by law (as in the Jonah-Pinedale area in WY).

## References


Alberts, Jerry. Williams Company. Personal contact.

American Petroleum Institute. Basic Petroleum Data Book, Volume XXV, Number 1. February 2005.

Bylin, Carey. U.S. EPA. Gas STAR Program Manager

Department of Energy. GASIS, Gas Information System. Release 2 – June 1999.

Fernandez, Roger. U.S. EPA. Gas STAR Program Manager

McAllister, E.W., Pipeline Rules of Thumb Handbook, 4th Edition, 1998.

Middleman, Stanley. An Introduction to Fluid Dynamics, Principles of Analysis and Design. 1998.

Perry, Robert H., Don W. Green. Perry's Chemical Engineers Handbook, 7th Edition. 1997.

Pontiff, Mike. Newfield Exploration Company. Personal contact.

Process Associates of America. "Reciprocating Compressor Sizing." Available on the web at: http://www.processassociates.com/process/rotating/recip_s.htm.

Smith, Reid. BP PLC. Personal contact.

Smuin, Bobby. BRECO, Incorporated. Personal contact.

U.S. EPA. "The Natural Gas STAR Partner Update – Spring 2004." Available on the web at: http://www.epa.gov/gasstar/pdf/partnerupdate.pdf

Wadas, Janelle. Noble Energy Inc. 2010 Annual Implementation Workshop Presentation titled "Reducing Vented Flowback Emissions from CO2 Fractured Gas Wells Using Membrane Technology". Available on the web at: http://epa.gov/gasstar/documents/workshops/2010-annual-conf/01wadas.pdf

Waltzer, Suzanne. U.S. EPA. Gas STAR Program Manager

**United States**
**Environmental Protection Agency**
**Air and Radiation (6202J)**
**1200 Pennsylvania Ave., NW**
**Washington, DC 20460**

**2011**

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.