CLEAN AIR ADVOCATES' EXHIBIT 9

Don Schreiber

Gobernador, NM | 505-320-0032 | vivarioarriba@gmail.com |

SUMMARY

Provide information to New Mexico Environmental Improvement Board regarding proposed 20.2.50 NMAC

EXPERIENCE

December 1998–Current

Owner, Operator Devil's Spring Ranch, Gobernador, NM

- Member Lujan Grisham Energy Transition Team
- Member EMNRD/NMED Methane Advisory Panel
- Member State Land Office Oil Advisory Council
- Board Member Western Leaders Network
- Witness Subcommittee on Energy and Mineral Resources, Natural Resources Committee, US House of Representatives field hearing on methane waste and pollution
- Witness EPA DC on methane pollution
- Declarant federal courts on methane waste and pollution
  * Wyoming v. Department of Interior (D.Wyo.)
  *California v. BLM (N.D. Cal.)
  *California v. BLM (N.D. Cal.)
  *California v. Bernhardt (N.D. Cal.)
  *Clean Air Council v. Pruitt (D.C. Cir.)
  *California v. Wheeler (D.C. Cir.)
  *New York v. Wheeler (D.D.C.)
- Testimony Office of Management and Budget on methane waste and pollution
- Testimony Royalty Policy Committee, Interior Department on methane waste and pollution
- Evidence presentations New Mexico Oil Conservation Commission hearings on methane waste and pollution
- Developer Open Space Pilot Project (OSPP) w/Bureau of Land Management, ConocoPhllips and Holistic Management International for new drilling land conservation in San Juan Basin
- Developer Green Completion Initiative w/Burlington and ConocoPhillips OSPP drilling program
- Interface w/oil producers/contractors/regulators re: impacts of oil andgas drilling and production
- 122 active gas wells w/i OSPP/ranch and grazing permit
- Holistic management contract w/BLM for remediation of oil and gas surface damage using animal impact
- Cow/calf, feeder operation using sustainable agriculture practice.

February 1976 – December 1998

Owner, Schreiber Insurance Agency, Inc., Farmington, NM

- Risk management services for oil and gas geologists, drillers, producers, transport, service contractors
- Claims investigation and adjustment for oil and gas industry San Juan Basin
- Rig inspection for drilling, completion and workover equipment San Juan Basin
- Member national faculty for Oil and Gas, Certified Insurance Counselors

REFERENCES

https://nmpoliticalreport.com/2018/12/05/lujan-grisham-names-transition-team-for-environment-energy-and-water-issues-en/

https://www.env.nm.gov/new-mexico-methane-strategy/methane-advisory-panel/

https://www.congress.gov/116/meeting/house/109319/documents/CHRG-116hhrg36076.pdf

https://holisticmanagement.org/images/stories/Services/ospp_brochure_51.pdf

https://www.westernleaders.org/staff-and-board

EDUCATION

1971

University of New Mexico
Bachelor of Science

1982

University of Texas
Petroleum Production Technology
Certified

CLEAN AIR ADVOCATES' EXHIBIT 10

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF DON SCHREIBER

Q: Please state your name.

A: Don Schreiber.

Q: What is your educational background?

A: I have a Bachelor's of Science from the University of New Mexico.

Q: Can you describe your work experience?

A: For 22 years, from 1976 to 1998, I was the owner of Schreiber Insurance Agency in Farmington, New Mexico, where we provided risk management services for the oil and gas industry, including oil and gas producers, service contractors, drillers, and geologists. We investigated, evaluated, and adjusted claims throughout the San Juan Basin, including inspecting rigs for drilling, completion, and workovers, and processing claims arising from accidents associated with the drilling and production of natural gas. In the course of my work, I would be called to the scene of a rig fire or blowout while it was still in progress. Over my career, I witnessed tremendous property damage -- including entire drilling and completion rigs, workover rigs, and associated equipment burned to the ground – and, worse, terrible injuries and even death to field workers.

Q: Do you have any certificates or educational experience related to the oil and gas industry?

A: Yes, in an effort to improve safety in drilling and production operations, I attended the University of Texas Permian Basin in Odessa, Texas and received an Elementary Drilling

Certificate that included instruction in well completions.

Q: Were you involved in any industry associations?

A: I was a member of the national faculty for Certified Insurance Counselors teaching oil and gas risk management. Certified Insurance Counselors is a national program that certifies insurance agents and brokers based on their expertise and commitment to the industry. At the time, it was the largest insurance education organization in the U.S., serving 65,000 agents.

Q: What activities have you been engaged in since 1998?

A: I retired from my insurance business that year and, since then, my wife and I have owned and operated Devil's Spring Ranch, a 3000+ acre ranch in Gobernador, New Mexico, an old ranching community in northwest Rio Arriba County. Our objective was to create a scalable model for sustainable agriculture using non-traditional ranching methods. We wanted to help address decades' long degradation from overgrazing and surface impacts from oil and gas drilling and production, and find a path to re-establish the once vibrant economy of the area that was based on agriculture. Today we lease our deeded land and federal grazing allotment for cattle operations when range conditions permit.

Q: Is Clean Air Advocates'[1] Exhibit 9 an accurate copy of your resume?

A: Yes.

Q: Mr. Schreiber, are there oil and gas wells in and around your ranch?

A: Yes, currently there are about 122 gas wells on or around our ranch, including 33 wells within one mile of our home.

[1] Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, 350 New Mexico, and 350 Santa Fe.

Q: After you purchased the ranch, what did you begin to learn about the oil and gas operations there?

A: In the early 2000's, drilling pressures in the area were on the increase. ConocoPhillips Petroleum Co. ("ConocoPhillips") leased the subsurface rights to our land, and wanted to drill 44 new wells on and around our ranch. We were concerned about impacts to our land and health, including emissions from well completions, surface disturbances, and spills.

Well completions and recompletions were a particular concern. Well completions – which is the process of taking a drilled well to a producing one – were still being done in essentially the same as they had been for over 50 years in the San Juan Basin. This process includes casing the hole, cementing the well, and perforating the casing and cement so the gas enters the well bore. Before production, flowback gases, water, and debris are pushed to the surface. Solid wastes are discharged into an earthen pit and gases are vented or burned via a line from the wellhead called a blewie line. Clean Air Advocates' Exhibit 11 is a picture of a blewie line in operation in 1958 in the San Juan Basin. Clean Air Advocates' Exhibit 12 has pictures of blewie line completions near our ranch around 2005 or 2006.

Q: What impacts did you see from well completions on and around your land?

A: The environmental impacts of blewie line completions were obvious to us -- given all the audio, visual and olfactory evidence before us -- as we lived and worked around our ranch. These impacts came into especially sharp focus when one time as the flared gasses cooled, black "snowflakes" were created and drifted onto our home from a blewie line completion about 1 1/4 mile northeast of our ranch.

Q: What actions did you take?

A: Moving away from blewie line technology and avoiding the harmful and toxic waste from completions became a priority as we began discussing the 44 well drilling program with ConocoPhillips, in 2008. Our concerns led us to the discovery that "reduced emissions completions" or "RECs" or "green completions" could help prevent the harmful emissions we worried about and were already being done in the San Juan Basin.

Q: What are reduced emissions completions?

A: According to the U.S. Environmental Protection Agency ("EPA"), reduced emissions completions "is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing." *See* Lessons Learned from Natural Gas STAR Partners: Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, EPA (2011) [Clean Air Advocates' Ex. 13]. Reduced emissions completions means capturing emissions during completion or recompletion or combusting emissions instead of venting. These emissions include volatile organic compounds, including methane, and toxic air pollutants such as benzene.

Q: How did you learn about reduced emissions completions?

A: Actually, personnel from an oil and gas company, Devon Energy Corporation ("Devon"), introduced me to reduced emission completion equipment at their Navajo Dam yard, which is about 30 miles from our ranch. Devon had REC equipment onsite that was owned by Williams Companies, a pipeline service company. The Williams REC equipment at Devon was brought to our ranch, as was other REC equipment by ConocoPhillips, and used in the completion of wells in and around our ranch, beginning in 2008 and continuing until 2012. Before that, we didn't know about REC technology, but came to learn it was widely used in the industry.

As a matter of fact, the New Mexico Oil and Gas Association ("NMOGA") and EPA had

put on a workshop for producers in Farmington in early 2006 on reduced emissions completions. During that workshop, presenters explained that REC equipment could process gas for sale and reduce venting and flaring, and that hundreds of millions of dollars could be recovered every year from the billions of cubic feet of gas that would otherwise be lost to the atmosphere. *See* Reduced Emissions Completions and Smart Automation, Producers and Processors Technology Workshop, NMOGA and EPA Natural Gas STAR Program (Feb. 21, 2006) [Clean Air Advocates' Ex. 14]. Similarly, the New Mexico Environment Department ("NMED") partnered with EPA, NMOGA, and ConocoPhillips in a 2010 workshop in Farmington promoting reduced emissions completions. Reducing Methane Emissions from Production Wells: Reduced Emissions Completions, Producers Technology Transfer Workshop, ConocoPhillips, NMED, and NMOGA (May 11, 2020) [Clean Air Advocates' Ex. 15].

An example from that workshop is instructive. Weatherford International successfully completed three wells in the Fruitland coal formation in the San Juan Basin in Durango, Colorado, not far from our ranch. In just those three wells, Weatherford captured and sold two million cubic feet of gas. *See id.* The Williams Companies identify average household use of natural gas at 196 cubic feet per day. Williams Northeast Supply Enhancement, Natural Gas: The Facts [Clean Air Advocates' Ex. 16. Therefore, those three REC well completions alone would provide year-round gas for 27.9, almost 28, households.[2]

Q: You said you learned of RECs from Devon. Were RECs a common practice of Devon's?

Yes. Devon was using REC equipment, as were many others including ExxonMobil, ConocoPhillips, and British Petroleum, to name a few. In fact, Devon described its use of RECs

[2] 2,000,000 cu ft ÷ (196 cu ft x 356 days / yr) = 27.9 households / yr.

as "standard practice."

> Green completions have been Devon's **standard practice** in the Barnett Shale since 2004. The company uses the same process to complete wells in **New Mexico**, Wyoming, Oklahoma and south Texas. Using this process, Devon has reduced methane emissions by more than 15 billion cubic feet in the Barnett Shale area of north Texas. Not long ago, green completions were so uncommon that Devon had to look as far as Wyoming to rent the necessary filtering equipment. Now, more than 2,000 green completions later, that rental equipment is available readily and locally.

"Natural Gas and Green Completions in a Nutshell," Energy in Depth (Nov. 26, 2012) (emphasis added) [Clean Air Advocates Ex. 17].

Q: You stated that REC equipment was used at your ranch between 2008 and 2012. How did that come about?

A: We worked with ConocoPhillips and the U.S. Bureau of Land Management ("BLM") to develop a program for drilling the 44 wells that would reduce impacts to the land, water, and air. In September 2008, we reached agreement with ConocoPhillips and BLM on the use of REC equipment, closed loop systems, well spacing, road construction, reclamation of surface damage, and other considerations that allowed the 44 well drilling program to begin in late 2008.

Between 2008 and 2012, 22 of the 44 wells in the program were completed or recompleted. We visited each of the 22 drilling sites multiple times to make sure the agreement was being followed, which it was, and we observed REC equipment in use. There were no reported accidents or incidents from blowouts or uncontrolled methane emissions on any of the wells completed or recompleted during the entire period of the agreed drilling and completion/recompletion program. In 2012, natural gas prices declined and the drilling program stopped.

Q: What happened after ConocoPhillips suspended the drilling program in 2012?

A: In August of 2017, Hilcorp Energy Company ("Hilcorp") acquired the assets of

ConocoPhillips in the San Juan Basin, including all of the wells on and around our ranch. Hilcorp first contacted us about new drilling through a notice we received on February 7, 2018 to recomplete a well -- San Juan 28-6 Unit 127 ("Unit 127") – on our federal grazing permit land. Hilcorp set the onsite meeting for February 20. Onsite meetings were routine for my wife and me, having attended over 100 since coming to the ranch. However, we were shocked when the Hilcorp representative stated that he wasn't sure that Hilcorp would use reduced emissions completion equipment for the well, telling us that Hilcorp didn't have REC equipment, that it had no trained crews, and that formation pressures might be too low.

However, my wife and I knew that REC equipment was available and that highly skilled oil field labor was readily available. Also, we had evidence that formation pressures in the area were sufficient or, if not, gas pressure could be boosted.

Q: What was your reaction to this news?

A: We believed that Hilcorp should honor the agreement we had with ConocoPhillips to conduct RECs. And, since 2012, emissions from hydraulically fractured natural gas wells during completion/recompletion had been regulated by EPA under its OOOO rule, which was later expanded with EPA's OOOOa rule.

Q: What happened then?

A: Hilcorp removed Unit 127 from the recompletion schedule, but proceeded with recompletion of another wellsite, San Juan 28-6 Unit 143 ("Unit 143"), approximately 1.4 miles from our home without even giving us the benefit of an onsite meeting. We learned that the well was to be fracked on March 7, 2018. We arrived that day, only to find out that the fracking operation was concluding and preparations for recompletion were in place -- with flowback gasses to be vented directly to the atmosphere, into the space where we lived and worked. Clean Air

Advocates' Exhibit 18 has photographs of the Hilcorp Unit143 set up for flowback with no REC equipment in place, and the gases to be vented to the atmosphere. Hilcorp has continued to complete and recomplete wells without using REC equipment since that time.

Q: What happened next?

A: It was clear that Hilcorp was not going to comply with the intent of the 2012 EPA REC regulations or honor the agreement we had with ConocoPhillips. We looked more closely into EPA green completion language in its 2012 regulations. EPA's reduced emissions completions rules were intended to stop venting and limit flaring during completion/recompletion operations. However, industry had exploited the regulatory language giving an out to industry if capture was "technically infeasible" to evade the requirements. In 2020, EPA amended its regulations, but the "technically infeasible" language remains.

Q: What's happened more recently?

A: Hilcorp divides the San Juan Basin into five operating areas. In February 2020, we were notified that Hilcorp intended to recomplete 22 wells in our area alone. Applying the Weatherford gas capture ratio, using REC equipment for those recompletions would translate to the same amount of gas used in over 200 households for an entire year.[3]

Q: Mr. Schreiber, you were appointed to Governor Michelle Lujan Grisham's Energy Transition Team in 2018, correct?

A: Yes, I was. I also served on the Methane Advisory Panel sponsored by NMED and the Energy, Minerals and Natural Resources Department. And I was proud to be present in January 2019 when the one of the Governor's first executive orders, Executive Order 2019-003, targeted climate change. That order acknowledged both the potency of methane as a greenhouse gas and

[3] (22 wells ÷ 3 wells) x 27.9 households / yr = 204.6 households / yr.

that the oil and gas industry is the largest industrial source of methane emissions.

The Governor has committed to passing the strongest methane rules in the nation. To keep that commitment, the Environmental Improvement Board ("EIB") rules must require control of emissions during completions and recompletions. New Mexico's rules should be at least as strong as Colorado's.

Q: What do you mean by that?

A: Last fall, the Colorado Air Quality Control Commission – Colorado's analog to the EIB -- passed regulations on completions and recompletions that closed the loopholes in EPA's regulations on reduced emissions completions, and generally require emissions during completions and recompletions to be captured, with some exceptions. *See* 5 CCR § 1001-9:D.VI.D and Statement of Basis [Clean Air Advocates' Ex. 19]. The Colorado Oil and Gas Conservation Commission – Colorado's equivalent to New Mexico's Oil Conservation Commission -- adopted those same requirements this year, incorporating the air quality control regulation by reference. *See* 2 CCR § 404-1:903.c and Statement of Basis for 2 CCR § 404-1:903.c [Clean Advocates' Exhibits 20 and 21, respectively].

I strongly support New Mexico adopting Colorado's approach, which would close the loopholes in EPA's regulations and place New Mexico at the forefront of emissions control during completions and recompletions. This proposal to reduce emissions during completions and recompletions is set forth in the Joint Proposed Amendments from Clean Air Advocates, the Environmental Defense Fund ("EDF"), and the Center for Civic Policy and NAVA Education Fund, and is Clean Air Advocates' Exhibit 1. This proposal will be supported with technical testimony by EDF expert Tom Alexander.

There is now a gaping hole in New Mexico regulations that creates a serious issue that

has plagued my family and other families who live, work, and go to school close to where oil and gas wells exist or may be drilled in the future.

Standing on my ranch, I can see Colorado, less than 25 miles away. To know that the same operators that are allowed to vent ozone precursors, methane, and toxic pollutants from completions and recompletions in New Mexico are prohibited from doing so in Colorado is deeply troubling. These operators drill into the same formation. They vent pollutants into the same air shed. And they threaten communities in the same region of the country.

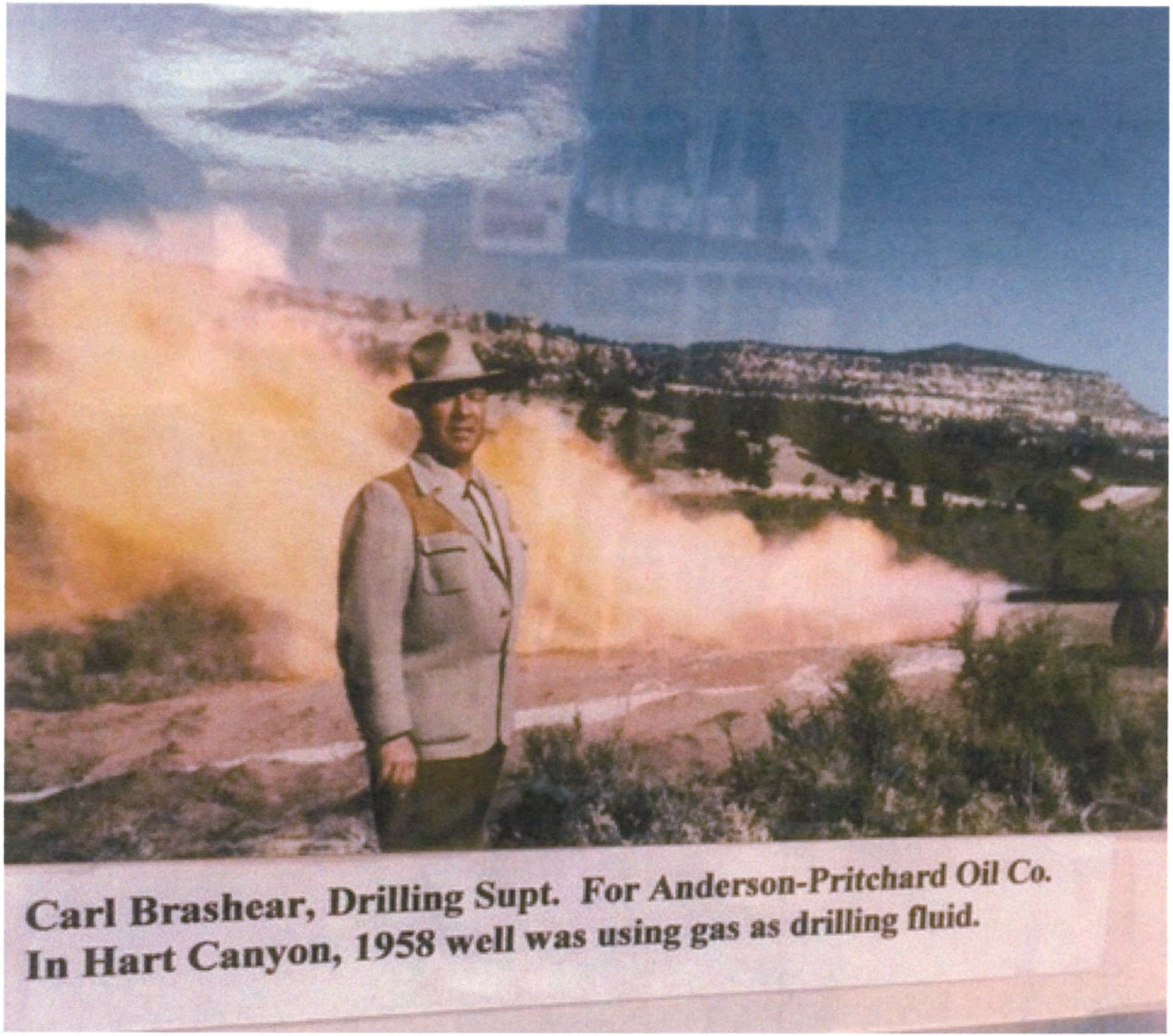
If, unlike Colorado, New Mexico fails to adopt reduced emissions completion/recompletion requirements – requirements that are technically feasible, reduce waste, and protect our public health and environment – our state will have ignored, denied and discounted years of successful capture of emissions, verified by industry and its experts. We will failed to prevent the unnecessary waste of our natural resource and to maximize royalty and tax revenues to the State. Most importantly, the State will have missed an opportunity to reduce emission of ozone precursors – the primary purpose of this hearing; failed to prevent the unnecessary emission of harmful air pollutants that threaten public health; and failed to do all it can to take on the existential threat of our time -- climate change. And rural New Mexico families like mine will continue to suffer the harmful effects of unnecessary venting and flaring of toxic pollutants where we live and work and where our children and grandchildren play. I urge the EIB to close the loophole for completions and recompletions, and to require oil and gas producers to prevent unnecessary and harmful emissions during completions and recompletions.

This ends my testimony, which is accurate to the best of my knowledge.

/s/ Don Schreiber July 26, 2021

Don Schreiber Date

CLEAN AIR ADVOCATES' EXHIBIT 11



Carl Brashear, Drilling Supt. For Anderson-Pritchard Oil Co.
In Hart Canyon, 1958 well was using gas as drilling fluid.

CAA Ex. 11

Blewie line completions were typical in San Juan Basin for about 75 years

CLEAN AIR ADVOCATES' EXHIBIT 12

CAA Ex. 12

Slide **5**

Blewie line completions near ranch ~ 2005-2006

CLEAN AIR ADVOCATES' EXHIBIT 13

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	Immediate	Immediate	Immediate

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.

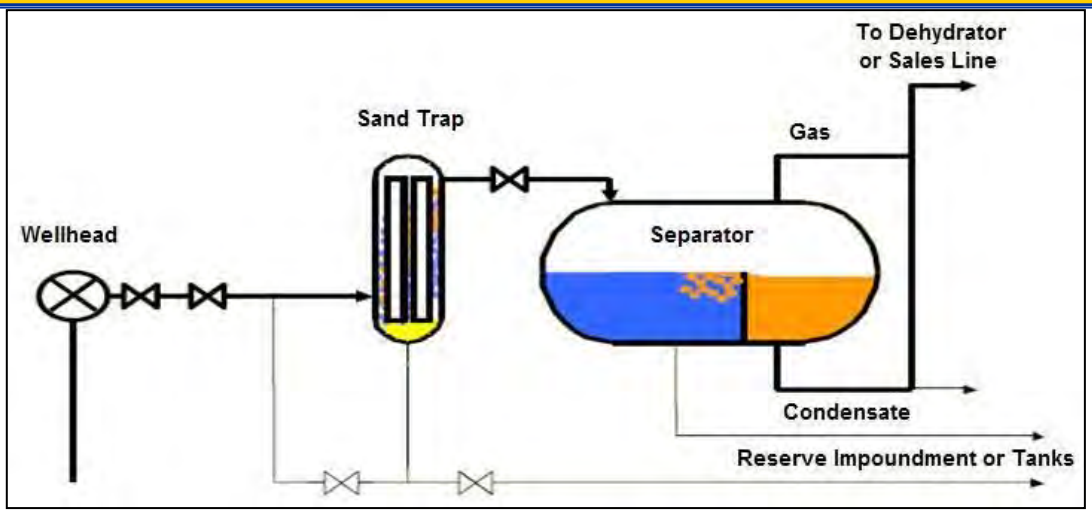
These new and "workover" wells are completed by producing the fluids at a high rate to lift the excess sand to the surface and clear the well bore and formation to increase gas flow. Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and 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.

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.

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 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

Reduced Emissions Completions
(Cont'd)

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

Reduced Emissions Completions
(Cont'd)

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.

CLEAN AIR ADVOCATES' EXHIBIT 14

Reduced Emissions Completions and Smart Automation

Lessons Learned from Natural Gas STAR

Producers and Processors Technology Transfer Workshop

New Mexico Oil and Gas Association and EPA's Natural Gas STAR Program
Farmington, NM
February 21, 2006

1

Agenda

- Reduced Emissions Completions
  - Methane Losses
  - Methane Recovery
  - Is Recovery Profitable?
  - Industry Experience
  - Discussion Questions
- Smart Automation Well Venting
  - Methane Losses
  - Methane Recovery
  - Is Recovery Profitable?
  - Industry Experience
  - Discussion Questions

2

Methane Losses During Well Completions

- It is necessary to clean out the well bore and formation surrounding perforations
  - After new well completion
  - After well workovers
- Operators produce the well to an open pit or tankage to collect sand, cuttings and reservoir fluids for disposal
- Vent or flare the natural gas produced
  - Venting may lead to dangerous gas buildup
  - Flaring is preferred where there is no fire hazard or nuisance

3

Methane Losses: Well Completions and Workovers

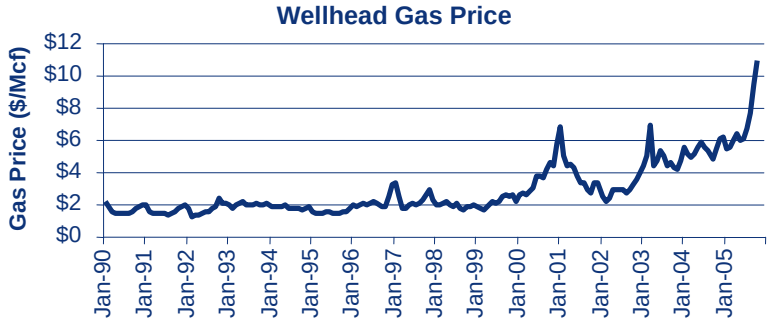
- An estimated 44.5 Bcf of natural gas lost annually due to well completions and workovers[1]
  - 44,000 MMcf in losses from high pressure wells
  - 319 MMcf in losses from low pressure wells
  - 48 MMcf in losses from workovers
- An estimated total of 480,000 Bbl condensate lost annually due to venting and flaring
- This amounts to over $455 million[2] lost due to well completions and workovers

1 - Percentage that is flared and vented unknown
2 - Value of natural gas at $10/Mcf, Value of condensate at $22/bbl

4

Wellhead Gas Prices

- Gas prices have increased sharply in recent years to over $10/Mcf



Source: EIA "US Natural Gas Wellhead Price" 1990 – 2005 available at http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3m.htm

5

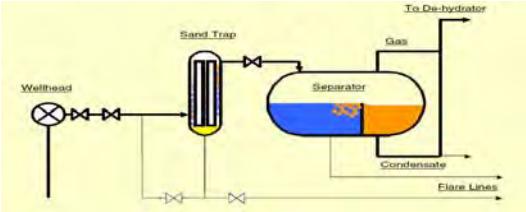
Reduced Emissions Completions (REC)

- REC or green completions recover natural gas and condensate produced during well completions or workovers
- Use portable equipment to process gas and condensate suitable for sales
- Send recovered gas through permanent dehydrator and meter to sales line, reducing venting and flaring
- An estimated 25.2 Bcf or $250 million of natural gas can be recovered annually using Green Completions
  - 25,000 MMcf from high pressure wells
  - 181 MMcf from low pressure wells
  - 27 MMcf from workovers

6

Green Completions: Equipment

- Truck or trailer mounted equipment to capture produced gas during cleanup
  - Sand trap
  - Three-phase separator
- Use portable desiccant dehydrator for workovers requiring glycol dehydrator maintenance



Temporary, Mobile Surface Facilities
Source: BP

7

Green Completions: Preconditions

- Must have permanent equipment on site before cleanup
  - Piping from well-head to sales line
  - Dehydrator
  - Lease meter
  - Stock tank
- Sales line gas can be used for fuel and/ or gas lift in low pressure wells

8

Green Completions: Low Pressure Wells

- Can use portable compressors to start-up the well when reservoir pressure is low
  - Artificial gas lift to clear fluids
  - Boost gas to sales line
- Higher cost to amortize investment in portable equipment

Portable Compressors, Separator and Other Equipment on a trailer

Source: Herald

9

Is Recovery Profitable?

- Partners report recovering an average of 53% of total gas produced during well completions and workovers
- Estimate an average of 3,000 Mcf[1] of natural gas can be recovered from each cleanup
- Estimate 1- 580 Bbl of condensate can be recovered from each cleanup

1 - Values for high pressure wells

10

Green Completions: Benefits

- Reduced methane emissions during completions and workovers
- Sales revenue from recovered gas and condensate
- Improved relations with state agencies and public neighbors
- Improved safety
- Reduced disposal costs

11

BP Experience

- Capital investment ~ $1.4 million on portable three-phase separators, sand traps and tanks
- Used Green Completions on 106 wells
- Total natural gas recovered ~ 350 MMcf/year
- Total condensate recovered ~ 6,700 Bbl/year

12

BP Experience

- Total value of natural gas and condensate recovered ~ $840,000 per year
- Investment recovered in 2+ years

Three Phase Separator, Source: BP

Note:

- Value of natural gas at $1.99/Mcf
- Value of condensate at $22/bbl

13

Weatherford Durango Experience

- Successfully completed pilot project in the Fruitland coal formations in Durango, Colorado
  - Well depth: 2,700 to 3,200 feet
  - Pore pressure: estimated at 80 pounds per square inch gauge (psig)
  - Well type: coal bed methane
  - Hole size: 5 ½ inches
  - No. of wells: 3 well pilots
- Captured 2 MMcf of gas and sold by client

14

Weatherford Portable Equipment

15

Weatherford Green Completions

- Use pipeline gas with proprietary foaming agent as compressible fluid to initiate cleanout
- System includes
  - Wet screw compressor when well pressure is less than 80 psig
  - Booster compressor, three phase separator and sand trap
- Estimate cleanup pressure of 300 to 400 psig at a well depth of 8000 feet
- Suggest use in all kinds of completion and workover cleanup operations

16

Discussion Questions

- To what extent are you implementing this opportunity?
- Can you suggest other approaches for reducing well completion venting?
- How could this opportunity be improved upon or altered for use in your operation?
- What are the barriers (technological, economic, lack of information, regulatory, focus, manpower, etc.) that are preventing you from implementing this practice?

17

Smart Automation Well Venting

- Automation can enhance the performance of plunger lifts by monitoring wellhead parameters such as:
  - Tubing and casing pressure
  - Flow rate
  - Plunger travel time
- Using this information, the system is able to optimize plunger operations
  - To minimize well venting to atmosphere
  - Recover more gas
  - Further reduce methane emissions

18

Methane Losses

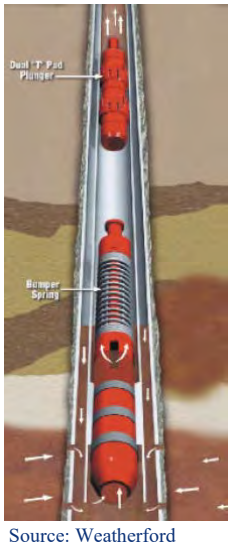
- There are 360,000 natural gas and condensate wells (on and offshore) in the US[1]
- Accumulation of liquid hydrocarbons or water in the well bores reduces, and can halt, production
- Common “blow down” practices to temporarily restore production can vent 80 to 1600 Mcf/yr[2] to the atmosphere per well
- Estimate 7 Bcf/yr methane emissions from U.S. onshore well venting[1]

1 - Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 - 2003
2 – Mobil Big Piney Case Study 1997

19

What is the Problem?

- Conventional plunger lift systems use gas pressure buildups to repeatedly lift columns of fluid out of well
- Fixed timer cycles may not match reservoir performance
  - Cycle too frequently (high plunger velocity)
    - Plunger not fully loaded
  - Cycle too late (low plunger velocity)
    - Shut-in pressure can’t lift fluid to top
    - May have to vent to atmosphere to lift plunger



Source: Weatherford

20

Conventional Plunger Lift Operations

- Manual, on-site adjustments tune plunger cycle time to well's parameters
  - Not performed regularly
  - Do not account for gathering line pressure fluctuations, declining well performance, plunger wear
- Results in manual venting to atmosphere when plunger lift is overloaded

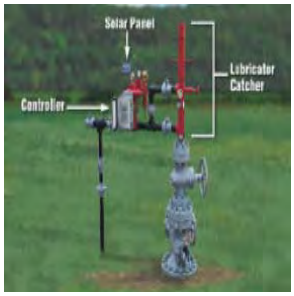
21

Methane Recovery: How Smart Automation Reduces Methane Emissions

- Smart automation continuously varies plunger cycles to match key reservoir performance indicators
  - Well flow rate
    - Measuring pressure
  - Successful plunger cycle
    - Measuring plunger travel time
- Plunger lift automation allows producer to vent well to atmosphere less frequently

22

Automated Controllers



Source: Weatherford

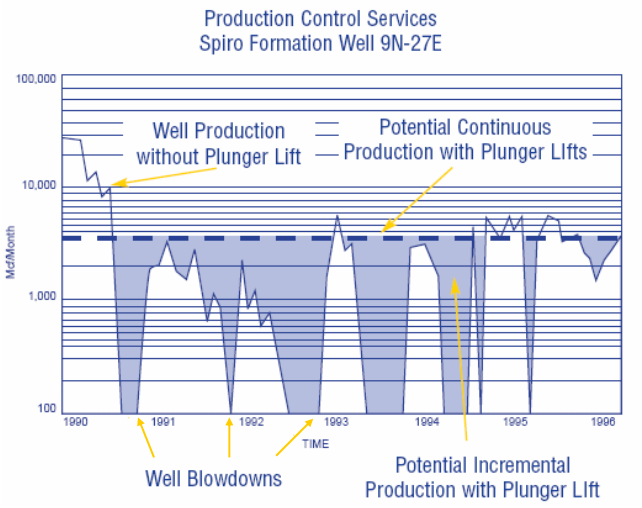
- Low-voltage; solar recharged battery power
- Monitor well parameters
- Adjust plunger cycling

Source: Weatherford

- Remote well management
  - Continuous data logging
  - Remote data transmission
  - Receive remote instructions
  - Monitor other equipment

23

Plunger Lift Cycle



24

Methane Savings

- Methane emissions savings a secondary benefit
  - Optimized plunger cycling to remove liquids increases well production by 10 to 20%[1]
  - Additional 10%[1] production increase from avoided venting
- 500 Mcf/yr methane emissions savings for average U.S. well

1 – Reported by Weatherford

25

Other Benefits

- Reduced manpower cost per well
- Continuously optimized production conditions
- Remotely identify potential unsafe operating conditions
- Monitor and log other well site equipment
  - Glycol dehydrator
  - Compressor
  - Stock Tank
  - VRU

26

Is Recovery Profitable?

- Smart automation controller installed cost: ~$11,000
  - Conventional plunger lift timer: ~$5,000
- Personnel savings: double productivity
- Production increases: 10% to 20% increased production

- Savings =

  (Mcf/yr) x (10% increased production) x (gas price)
  + (Mcf/yr) x (1% emissions savings) x (gas price)
  + (personnel hours/yr) x (0.5) x (labor rate)

  $ savings per year

27

Economic Analysis

- Non-discounted savings for average U.S. Well =

(50,000 Mcf/yr) x (10% increased production) x ($10/Mcf)
+ (50,000 Mcf/yr) x (1% emissions savings) x ($10/Mcf)
+ (500 personnel hours/yr) x (0.5) x ($30/hr)
- ($11,000) cost

$51,500 savings in first year

3 month simple payback

28

Industry Experience

- BP reported installing plunger lifts with automated control systems on ~2,200 wells
  - 900 Mcf reported annual savings per well
  - $12 million costs including equipment and labor
  - $6 million total annual savings
- Another company shut in mountaintop wells inaccessible during winter
  - Installed automated controls allowed continuous production throughout the year[1]

1 - Morrow, Stan and Stan Lusk, Ferguson Beauregard, Inc. Plunger-Lift: Automated Control Via Telemetry. 2000.

29

Discussion Questions

- To what extent are you implementing this opportunity?
- Can you suggest other approaches for reducing well venting?
- How could this opportunity be improved upon or altered for use in your operation?
- What are the barriers (technological, economic, lack of information, regulatory, focus, manpower, etc.) that are preventing you from implementing this practice?

30

CLEAN AIR ADVOCATES' EXHIBIT 15

Reducing Methane Emissions from Production Wells: Reduced Emission Completions

Lessons Learned from the
Natural Gas STAR Program

Producers Technology Transfer Workshop

ConocoPhillips Petroleum Company,
New Mexico Environment Department,
New Mexico Oil & Gas Association

Farmington, New Mexico
May 11, 2010

epa.gov/gasstar

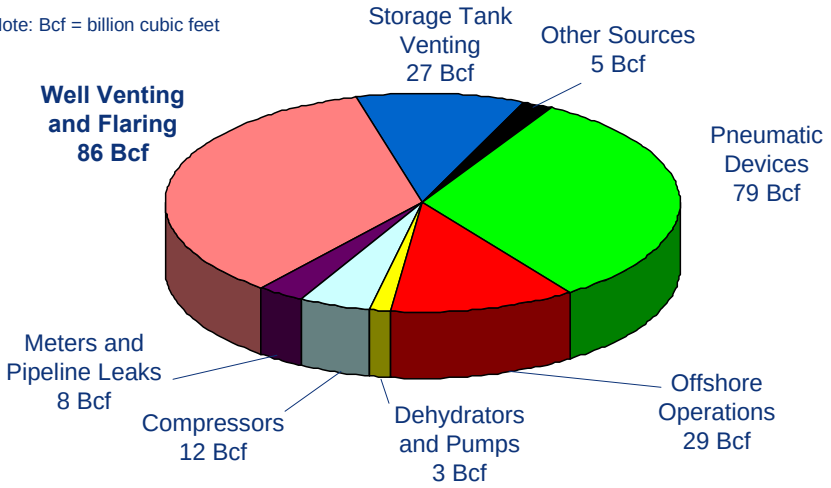
Agenda

- **Reduced Emissions Completions**
  - Methane Losses
  - Methane Recovery
  - Is Recovery Profitable?
  - Partner Experience
- **Discussion**

1

U.S. Production Sector Methane Emissions (2007)

Note: Bcf = billion cubic feet



EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2007.* April, 2009. Available on the web at: epa.gov/climatechange/emissions/usinventoryreport.html. Updated with revised emissions estimates for glycol dehydrators, well venting, pneumatic devices, and storage tanks.

2

Methane Losses During Gas Well Completions

- Gas wells in tight formations and coal beds require hydraulic fracture
- It is necessary to clean out the well bore and formation
  - After new completion
  - After well refracturing workovers
- Operators produce to an open pit or tank to collect sand, cuttings, and fluids for disposal
- Vent or flare the natural gas produced
- 54 Bcf[1] of methane is vented or flared from completions and workovers in the U.S., 27 Bcf of methane is emitted

Williams E&P, Glenwood Springs, CO

1 – EPA estimate – well completions and workovers only.
Bcf = billion cubic feet

3

Methane Recovery by Reduced Emission Completions

- Recover natural gas and condensate produced during flow-back following hydraulic fracture
- Portable equipment separates sand and water, processes gas and condensate for sales
- Route recovered gas through dehydrator and meter to sales line, reducing venting and flaring

Portable REC Equipment

Source: Weatherford

4

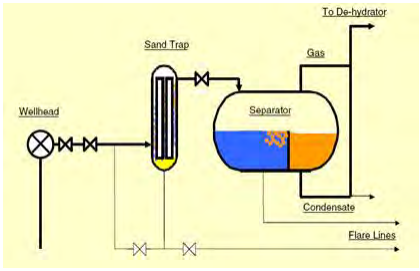
Reduced Emission Completions: Preconditions

- Permanent equipment required on site before cleanup
  - Piping from well head to sales line
  - Dehydrator
  - Lease meter
  - Stock tanks for wells producing significant amounts of condensate
- Sales line gas can be used for compressor fuel and/ or gas lift in low pressure wells

5

Reduced Emission Completions: Equipment

- Skid or trailer mounted portable equipment to capture produced gas during cleanup
  - Sand trap
  - Three-phase separator
- Use portable desiccant dehydrator for workovers requiring glycol dehydrator maintenance



Temporary, Mobile Surface Facilities, Source: BP

Source: Williams

6

Reduced Emission Completions: Low Pressure Wells

- Partners and vendors are perfecting the use of portable compressors when pressure in reservoir is too low to enter sales line
  - Artificial gas lift to clear fluids
  - Boost gas to sales line
  - Manage slug flow
  - Adds cost to project

Source: Herald

7

Reduced Emission Completions: Benefits

- Reduced methane emissions during completions and workovers
- Sales revenue from recovered gas and condensate
- Improved relations with government agencies and public neighbors
- Reduced environmental impact
- Improved safety
- Reduced disposal costs

8

Is Recovery Profitable?

- Partners report recovering 2% - 89% (average of 53%) of total gas produced during well completions and workovers
- Estimate 7,000 – 12,500 thousand cubic feet (Mcf) of natural gas can be recovered from each cleanup
  - $50,000 to $85,000 savings at $7/Mcf
- Estimate 1 – 580 barrels (bbls) of condensate can be recovered from each cleanup
  - Up to $30,000 additional revenue at $50/barrel
- Incremental contracted cost of typical REC is $700 to $6,500/day for 3 to 10 days of well cleanup
- Purchase of REC equipment costs $500,000
  - Payback in 3 to 5 months for 25 well/year drilling program
  - Assuming gas prices of $7 and $3/Mcf, respectively

9

REC Partner Experience: BP

- Capital investment of about $500,000 per skid on portable three-phase separators, sand traps, and tanks in the Rocky Mountain Region
- Used Green Completions on 106 wells
- Total natural gas recovered about 350 million cubic feet per year (MMcf/year)
  - 3.3 MMcf per well average
    - Conservative net value of gas saved is $20,000 per well[1]
- 6,700 barrels/year condensate recovered
- 1.5 year payback based on British Petroleum's prices for natural gas and condensate

[1] Natural gas valued by company to be $7/Mcf

10

REC Partner Experience: BP

- Through the end of 2005 British Petroleum reports:
  - 4.1 Bcf of gas and
  - 53,000 barrels of condensate recovered[1]

Portable Three Phase Separator, Source: BP

[1] Combination of activities in Montana and Wyoming, U.S.

11

REC Partner Experience: Williams

- Williams Fork Formation (Piceance Basin) – low permeability, tight, lenticular sandstone (10% porosity, permeability range of 1 to 10 microdarcies.
- Wells drilled to depths of 6,500 ft to 9,000 ft
- Flow pressures range from 1,500 to 2,500 psi
- Fracture stimulation needed to make wells economical
- Frac about 5 to 6 stages per well
- BRECO flowback skids used to separate sand, water and gas during initial flowback
- BRECO flowback skid resides on typical 4 well pad for 32 days

[1] Natural gas valued by company to be $7/Mcf

12

REC Partner Experience: Williams

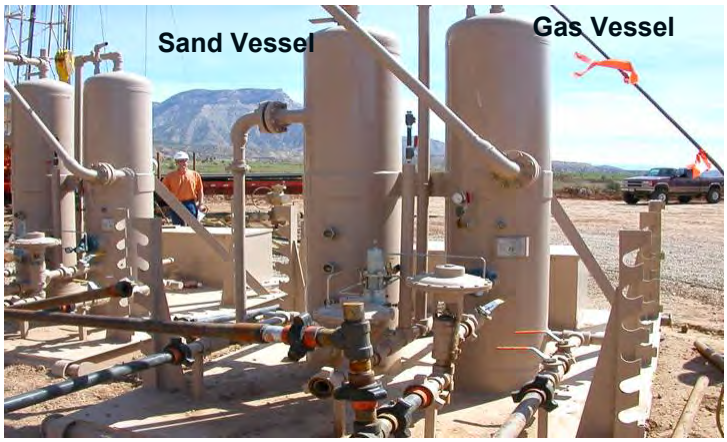
Piceance Well Completions

- Well Completion Type = Mechanical Isolation
- Perforate casing prior to Stage 1 – makes fracture stimulation possible
- Frac Stage 1
- Flow back well, first 12 hours is water, afterwards routed to BRECO skid
- Set plug to isolate frac stage
- REPEAT for each stage (avg. 5 to 6 stages/well)
- Plugs drilled out by workover rig
- Producing to flowback skid after frac'ing and before plugs drilled out

13

REC Partner Experience: Williams

BRECO Flowback Skid



14

REC Partner Experience: Williams

How BRECO Works?

- Sand vessel separates sand from backflow fluids
- Gas vessel separates gas from water used for hydraulic fracturing
  - Gas routed to sales line
- Sand is dumped to reserve pit manually
- Water dumps to holding tanks automatically
  - Water is filtered and reused for future frac jobs
- Flowback skid operates at 20 to 40 psi greater than gas gathering line pressure which is about 260 to 320 psi in Piceance Basin

15

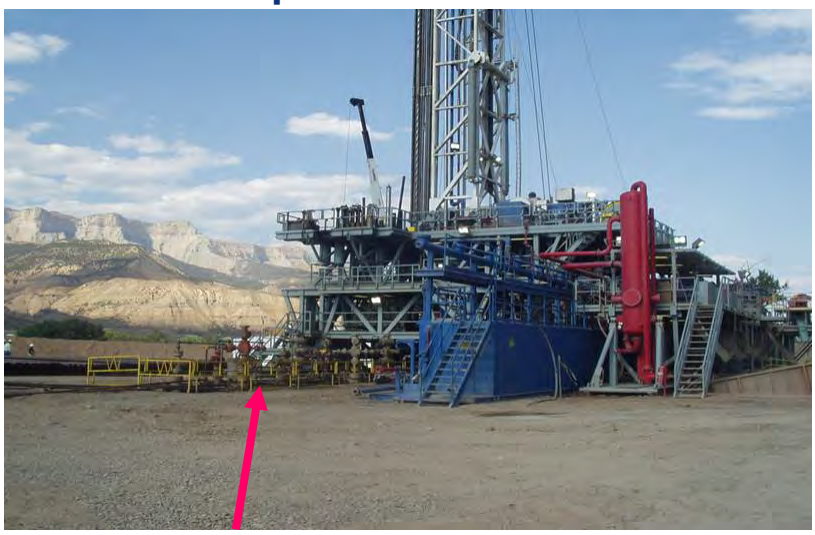
REC Partner Experience: Williams

Flowback Skid – When Is It Used?

- Used after each zone is fracture stimulated (frac'd)
- Used when all zones are fractured and waiting for workover rig to drill out plugs for final completion (Up to 10 days)
- Production well must be located near gathering system
- Wildcat and step-out wells are not completed with Green Completion Technology
- One Month = time wells at typical 4-well pad are routed to flowback skid

16

REC Partner Experience: Williams



Source: Williams

Two rows of four wells closely spaced.

17

Green Completion Economics

AVERAGE PER WELL FLOWBACK STATISTICS	
Average Number of Days of Flowback =	32
Average MMcf Gas Recovered During Flowback =	23
Average MMcf Gas Flowback Recovered/Day =	0.71
Average Revenue Per Flowback ($) =	$139,941
Average Cost Drill/Complete Well ($) =	$1.3 to $1.5 MM
Average Cost Per Flowback ($) =	$11,855
Average Net Saving Per Flowback ($) =	$129,510
CH_4 recovered in 2005 = Estimated Mean Methane Concentration Gas: 89.043 vol. %	5982 MMscf or 16 MMscf/day

18

Conclusions

- Reduces methane emissions, a potent greenhouse gas (GHG)
- Well completion type determines viability of green completion technologies
- Produced water and stimulation fluids from green completions are recycled
- Eliminates emissions, noise and citizen complaints associated with flaring
- Increases economic value added

19

Discussion Questions

- What industry experiences do you have applying these technologies and practices?
- What are your limitations on applying these technologies and practices?
- Actual costs and benefits

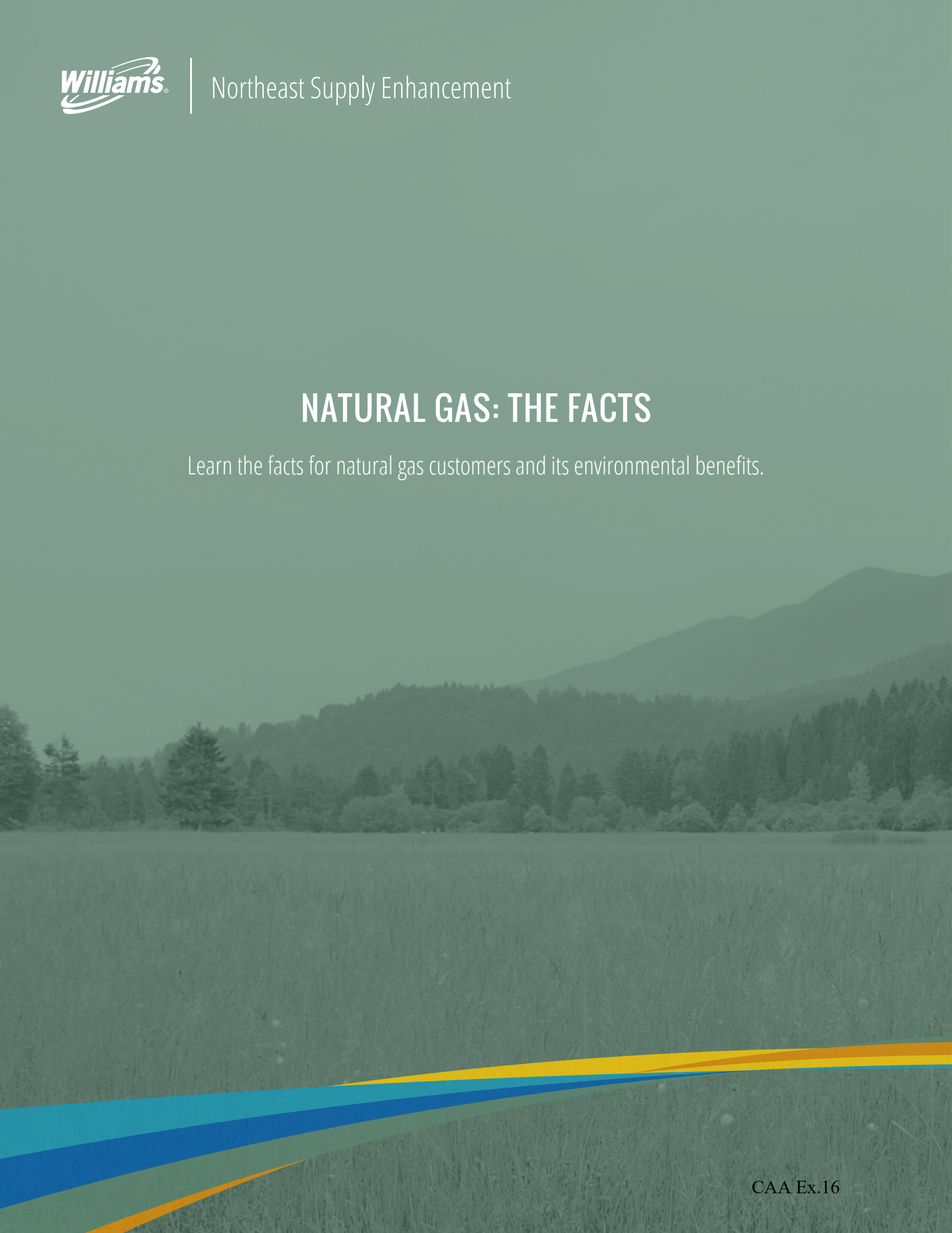
20

CLEAN AIR ADVOCATES' EXHIBIT 16

Williams | Northeast Supply Enhancement

NATURAL GAS: THE FACTS

Learn the facts for natural gas customers and its environmental benefits.



CAA Ex.16

2016

Natural Gas: The Facts

Natural Gas Customers

- Natural gas serves nearly 66.7 million homes; 5.4 million businesses like hotels, restaurants, hospitals, schools and supermarkets; 192,000 factories; and 1,900 electric generating units. On a daily basis, the average U.S. home uses 196 cubic feet of natural gas.
- Natural gas comprises almost one-fourth of all primary energy used in the U.S. and is directly linked to jobs and economic health. The natural gas industry supports the employment of nearly 3 million Americans in all 50 states.
- Residential space heating and water heating cost analyses show that natural gas costs less to use than other major home energy sources. Households that use natural gas appliances for heating, water heating, cooking and clothes drying spend an average of $840 less per year than homes using electric appliances.
- Fertilizer used to grow crops is composed almost entirely of natural gas components, so U.S. agricultural producers rely on an affordable, stable supply of natural gas.
- Natural gas utilities do not earn a profit on the natural gas they deliver. They earn their revenues from the service and delivery fees they charge customers to transport the natural gas to them. This fee is directly linked to the volume of natural gas consumed, rather than the price of natural gas being delivered.

Environmental Benefits

- Washington State University conducted a nationwide field study in 2015 that found that as little as 0.1 percent of the natural gas delivered nationwide is emitted from local distribution systems.
- Due to the higher efficiency of natural gas combined cycle generation compared with coal-fired boilers, natural gas emits 52 to 56 percent less GHG than coal for the same amount of electricity.
- Natural gas is the cleanest fossil fuel on the market today because it produces much lower emissions than those of other fossil fuels like coal or oil. It is also extraordinarily efficient.

72 MILLION

There are more than 72 million natural gas customers in the United States.

"Natural gas comprises almost one-fourth of all primary energy used in the U.S. and supports the employment of nearly 3 million Americans in all 50 states."

2016

Natural Gas: The Facts

Efficiency

- The direct use of natural gas in America's homes and businesses achieves 92 percent energy efficiency.
- The average American home consumes 40 percent less natural gas than it did 40 years ago.
- By funding natural gas efficiency programs, natural gas utilities helped customers save 175 trillion Btu of energy and offset 9.1 million metric tons of carbon dioxide emissions in 2014.

Domestically Abundant

- Domestic gas production accounts for nearly 93 percent of all natural gas consumed in the United States and shale gas production now accounts for about 50 percent of gas produced.
- According to the Energy Information Administration and the Potential Gas Committee, the U.S. estimated future supply of natural gas stood at 2,884 trillion cubic feet (Tcf) at year end 2014 – enough to meet America's energy needs for more than 100 years.

Safe and Reliable

- According to the U.S. Department of Transportation, pipelines are the safest form of energy transportation. Safety is the number one priority for America's natural gas utilities.
- There are more than 2.5 million miles of pipeline that transport natural gas to more than 177 million Americans throughout the U.S.
- Natural gas utilities spend more than $22 billion annually to help enhance the safety of natural gas distribution and transmission systems.
- The dedicated efforts of natural gas utilities over the past decade have led to an approximately 40 percent decline in serious pipeline incidents throughout the natural gas distribution system.
- There are nearly 1.3 million miles of plastic pipe – the leading edge of advanced utility pipeline materials. In the past decade, natural gas utilities have installed updated plastic lines at a rate of 30,000 miles per year.

To Learn More Visit www.aga.org

or connect with us on Twitter @AGA_naturalgas and facebook.com/naturalgas

"The U.S. estimated future supply of natural gas stood at 2,884 Tcf at year end 2014 – enough to meet America's energy needs for more than 100 years."

There are more than 2.5 million miles of pipeline that transport natural gas to more than 177 million Americans.

2.5 MILLION

CLEAN AIR ADVOCATES' EXHIBIT 17

APPALACHIAN BASIN

NATURAL GAS AND GREEN COMPLETION IN A NUT SHELL

BY RACHAEL BUNZEY NOV. 26, 2012 31

Green completion may be a foreign term for some people but it's real and is one more demonstration of how technology is always one step ahead of the natural gas opposition.

Green completions are now becoming standard in the natural gas industry, eliminating one of the latest objections of natural gas opponents who like to say the industry is venting too much methane into the air and contributing to global warming (when it's actually doing the exact opposite by lowering carbon emissions). When a natural gas well is developed, there is an excess of natural gas which, in the past, was released into the air or flared (burned off) but now companies are moving toward capturing the natural gas at the well head instead of releasing it.

Let's take a closer look at green completions and how the process is regulated because a new report suggests this technique is already having a major impact in reducing greenhouse gas emissions.

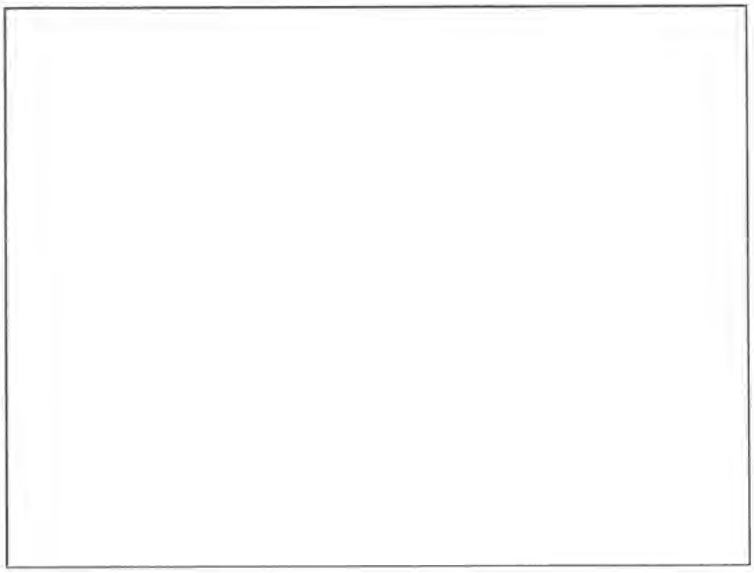
WHAT IS A GREEN COMPLETION?

The Clean Air Act authorized the Environmental Protection Agency to regulate certain aspects of natural gas development. It adopted a rule in April of this year that, by it's own description, "generally requires owners/operators to use reduced emissions completions, also known as "RECs" or "green completions," to reduce VOC emissions from well completions. To achieve these VOC reductions, owners and/or operators may use RECs or completion combustion devices, such as flaring, until January 1, 2015; as of January 1, 2015, owners and/or operators must use RECs and a completion combustion device."

Green completion essentially requires natural gas companies to capture the gas at the well head immediately after well completion instead of releasing it into the atmosphere or flaring it off. Here's how Environmentally Friendly Drilling Systems (EFD), a service company to the industry, describes them:

> Green completions are systems to reduce methane losses during well completions. After a new well completion or workover, the well bore and formation must be cleaned of debris and fracture fluid. Conventional methods for doing this include producing the well into an open pit or tank to collect sand, cuttings and reservoir fluids for disposal. Typically, the natural gas that is produced is vented or flared. The large volume of natural gas that is lost may not only affect regional air quality, it might also affect the profitability of drilling operations.
>
> Green completion systems present a significant opportunity for cost savings. By using portable equipment to process gas and condensate, the recovered gas can be directed to a pipeline and sold. These truck or trailer mounted systems can typically recover more than half of the total gas produced and industry results have shown that investment in portable three phase separators, sand traps and tanks can be recovered in 2 years or less.

space



Example of Green Completion Equipment (FracmasterUSA)

space

Combined with the shift to closed-loop systems that eliminate the need for open pits, this development means both air emissions and flowback water are being recaptured and reused with both economic and environmental benefits; the classic "win-win." Here's a concise technical definition:

> In green completions, gas and hydrocarbon liquids are physically separated from other fluids and delivered directly into equipment that holds or transports the hydrocarbons for productive use. There is no venting or flaring. This practice then links upstream activities with mid and downstream efforts.

Flaring of course, is a process of burning excess natural gas instead of just releasing it to the environment. Not commonly understood is the fact flaring of natural gas actually puts more water into the hydrologic cycle than not burning it, because one of the two byproducts of methane is water. Nonetheless, gas companies are in the business of selling the product, so capturing it for sale makes even more sense.

WHAT ARE THE EXPECTED IMPACTS OF GREEN COMPLETIONS?

The EPA has, as noted above, established the standards for green completions, and here is their expectation, as reported by the *The State Journal* (West Virginia):

> The EPA's New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants will improve air quality and reduce health risks.
>
> "The action taken today is expected to yield nearly a 95 percent reduction in smog-forming volatile organic compounds emitted from more than 13,000 hydraulically fractured gas wells each year," said EPA Office of Air and Radiation Assistant Administrator Gina McCarthy.
>
> Under the rule, operations are required to use "reduced emissions" or "green well completion" equipment to capture gas and condensate that comes up with hydraulic fracturing flowback, preventing their release into the air and making the valuable hydrocarbons available to the producer for sale.

And, this is what EPA says:

> To ensure that smog-forming volatile organic compounds (VOCs) are controlled without slowing natural gas production, EPA's final NSPS for VOCs establishes two phases for reducing VOCs during well completion. This approach will provide industry time to order and manufacture enough equipment to capture natural gas using a process called green completions, also known as "reduced emissions completions."

They go on to describe the other stages as well.

> **Phase 1:** In the first phase (before Jan. 1, 2015), industry must reduce VOC emissions either by flaring using completion combustion device or by capturing the gas using green completions with a completion combustion device (unless combustion is a safety hazard or is prohibited by state or local regulations).
>
> A completion combustion device burns off the gas that would otherwise escape during the well-completion period (combustion generally would occur through pit flaring). Industry may use completion combustion devices to reduce VOC emissions until Jan. 1, 2015, unless state or local requirements prohibit the practice or require more stringent controls. EPA encourages industry to begin using green completions during this time.
>
> **Phase 2:** Beginning Jan. 1, 2015, operators must capture the gas and make it available for use or sale, which they can do through the use of green completions.
>
> - EPA estimates that use of green completions for the three- to 10-day flowback period reduces VOC emissions from completions and recompletions of hydraulically fractured wells by 95 percent at each well.
>
> - Both combustion and green completions will reduce the VOCs that currently escape into the air during well completion. However, capturing the gas through a green completion prevents a valuable resource from going to waste and does not generate NOx, which is a byproduct of combustion.

Interestingly, a study has just been released by MIT that indicates "The use of flaring and **reduced emission completions reduce the levels of actual fugitive emissions from shale well completion operations to about 216 Gg CH_4, or 50 Mg CH_4 per well**, a release substantially lower than several widely quoted estimates." It looks like the Howarth study just took yet another hit.

ARE GREEN COMPLETIONS SOMETHING NEW? NOT EXACTLY.

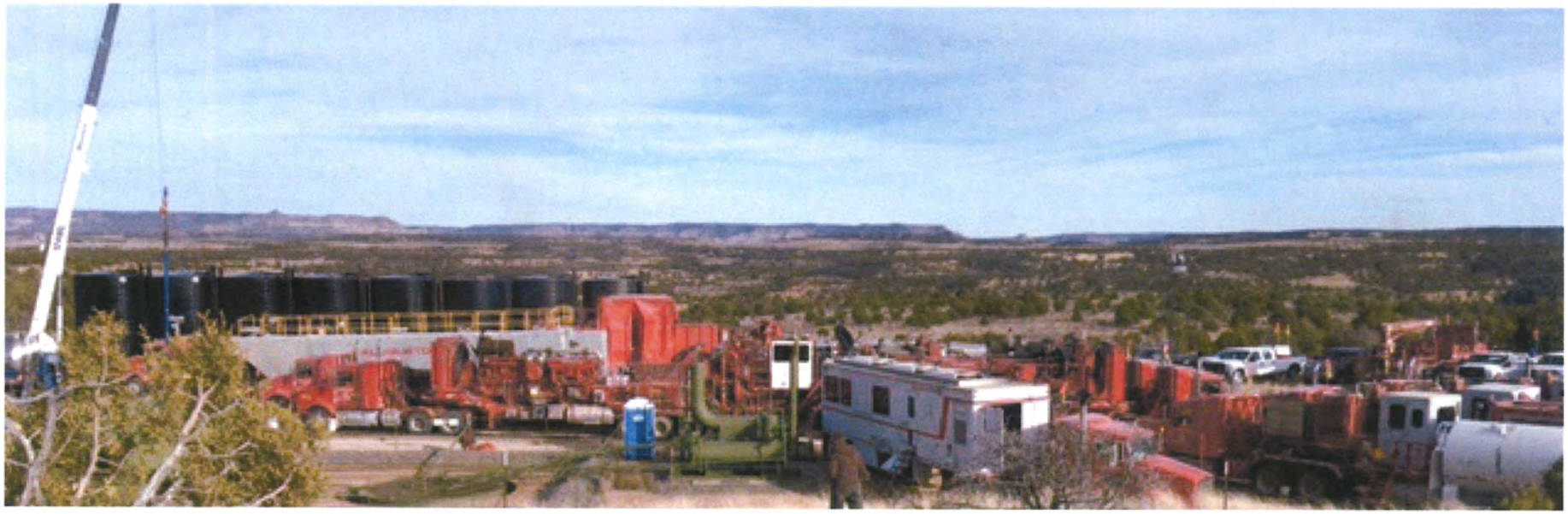
Some companies have been doing green completions for almost a decade. One example is Devon Energy Corporation and [here's what they have to say](#):

> Green completions have been Devon's standard practice in the Barnett Shale since 2004. The company uses the same process to complete wells in New Mexico, Wyoming, Oklahoma and south Texas. Using this process, Devon has reduced methane emissions by more than 15 billion cubic feet in the Barnett Shale area of north Texas. Not long ago, green completions were so uncommon that Devon had to look as far as Wyoming to rent the necessary filtering equipment. Now, more than 2,000 green completions later, that rental equipment is available readily and locally.
>
> Devon's green completions practice stems from their voluntary participation in the EPA's Natural Gas STAR Program. The procedure generally is not required in the Barnett Shale except in the city of Fort Worth and at Dallas Fort Worth International Airport. The vast majority of Devon's Barnett Shale wells are outside those locales.

EFD reports, based on input from Devon, that "the rental cost for the equipment is roughly $1,000 per day and can save an average of 11,900 Mcf of natural gas per well from being vented into the atmosphere. In their case, the conservative net value of gas saved was $50,000 per well."

Green completions are yet another demonstration of technology advancing faster than natural gas opponents, who are always debating yesterday's issues. They're still talking flaring and open pits, while the industry has moved well beyond both. It just keeps getting better, while our friends on the other side only see doom and gloom because they're focused on the past and refuse to see the future.

CLEAN AIR ADVOCATES' EXHIBIT 18



CAA Ex. 18

Slide 9

Hilcorp Recompletion of #143 venting to atmosphere 3/8/18

CAA Ex. 18

Slide 12

Setup for initial flowback with no REC in place as frac finishes.
Well will vent to atmosphere through open flowback container.

CLEAN AIR ADVOCATES' EXHIBIT 19

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS
(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

Outline of Regulation

Pursuant to Colorado Revised Statutes Section 24-4-103 (12.5), materials incorporated by reference are available for public inspection during normal business hours, or copies may be obtained at a reasonable cost from the Air Quality Control Commission (the Commission), 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.govinfo.gov. Materials incorporated by reference are those editions in existence as of the date indicated and do not include any later amendments.

V.C.2.ff. Wellhead bradenhead.

VI. (State Only) Oil and Natural Gas Pre-Production and Early Production Operations

VI.A. Definitions

VI.A.1. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

VI.A.2. "Drill-out" means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore clean-up.

VI.A.3. "Drilling" or "drilled" means the process to bore a hole to create a well for oil and/or natural gas production.

VI.A.4. "Flowback" means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

VI.A.5. "Flowback vessel" means a vessel that contains flowback.

VI.A.6. "Hydraulic fracturing" means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

VI.A.7. "Hydraulic refracturing" means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

VI.A.8. "Pre-production operations" means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

VI.A.9. "Tank measurement system" means equipment and methods used to determine the quantity of the liquids inside a flowback vessel without requiring direct access through the flowback vessel thief hatch or other opening.

VI.A.10. "Well" means a hole drilled for the purpose of producing oil and/or natural gas.

VI.A.11. "Well completion" means the process that allows for the flow of petroleum and/or natural gas from newly drilled wells, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic fracturing, drill-out, flowback).

VI.A.12. "Well re-completion" means the process that allows for the flow of petroleum and/or natural gas from an existing well from any geological interval not currently producing in the existing well, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic re-fracturing, drill-out, flowback).

VI.C.2.b.(v) A summary of monitored air quality results, including time series plots as hourly or higher time resolution and a statistical summary including number of observations, maximum concentrations or levels, periodic averages, and date distributions including 5th, 25th, median, 75th and 95 percentile values.

VI.C.2.b.(vi) A description of responsive action(s) taken as a result of monitoring results, including the date; concentration or level measured; correlations with specific events, activities, and/or monitoring thresholds; and any additional steps taken as a result of the responsive action.

VI.C.2.b.(vii) The results of any speciated or other samples of chemical constituents identified by the Division and collected when site-specific concentrations indicate such samples are necessary.

VI.C.2.b.(viii) A summary of meteorological data, including in the time intervals identified for concentration readings in the air quality monitoring plan during the time period of responsive action(s). If meteorological data is collected on-site, the meteorological data assessed in as close to the sampling and/or measurement intervals as possible.

VI.C.2.b.(ix) A description of how data will be processed, if available from the manufacturer, and summarized for purposes of fulfilling monthly reporting requirements, including whether and how data will be corrected, and how missing data and values that are below detection limits will be treated in statistical summaries.

VI.C.2.b.(x) In the last monthly report, a certification by the company representative that supervised the development and submission of the monitoring reports that, based on information and belief formed after reasonable inquiry, the statements and information in the monthly reports are true, accurate, and complete.

VI.C.3. Owners or operators must notify the Division and the local government with jurisdiction over the location of the operations, using the contact provided in Section VI.C.1.b.(iv), within forty-eight (48) hours of responsive action(s) taken as a result of recorded values in excess of the response level.

VI.D. Emission reduction from pre-production flowback vessels

VI.D.1. Control

VI.D.1.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of at least 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

VI.D.1.a.(i) Owners or operators must use enclosed, vapor-tight flowback vessels.

VI.D.1.a.(ii) Flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.

VI.D.3.a.(i) The API number of the well and the associated facility location, including latitude and longitude coordinates.

VI.D.3.a.(ii) The date and time of the onset of flowback.

VI.D.3.a.(iii) The date and time the flowback vessels were permanently disconnected, if applicable.

VI.D.3.a.(iii) The date and duration of any period where the air pollution control equipment is not operating.

VI.D.3.a.(iv) Records of the inspections required in Section VI.D.2. including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

VI.D.3.a.(v) Where a combustion device is used, the date and result of any EPA Method 22 test or investigation pursuant to Section VI.D.2.a.(v).

VI.D.1.a.(iii) Owners or operators must use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section VI.D.1.a.(ii)(A).

VI.D.1.a.(iv) Combustion devices used during pre-production operations must be enclosed, have no visible emissions during normal operation, and be designed so that an observer, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

VI.D.1.a.(iv)(A) Combustion devices must be equipped with an operational auto-igniter upon installation of the combustion device.

VI.D.2. Monitoring

VI.D.2.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must conduct daily visual inspections of the flowback vessel and any associated equipment.

VI.D.2.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

VI.D.2.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating.

VI.D.2.a.(iii) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the flowback vessel to the air pollution control equipment are open.

VI.D.2.a.(iv) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

VI.D.2.a.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

VI.D.3. Recordkeeping

VI.D.3.a. The owner or operator of each flowback vessel subject to Section VI.D.1. must maintain records for a period of two (2) years and make them available to the Division upon request, including

PART F Statements of Basis, Specific Statutory Authority and Purpose

A. December 21, 1995 (Section II.B.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted consolidate the list of NRVOCs into the Common Provisions, assuring that the same list of NRVOCs apply to all the Colorado regulations. This provides more consistency in those chemicals regulated as VOCs.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to Organic solvents and photochemical substances. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulations Numbers 3, 7, and the Common Provision are intended to clarify substances that are negligibly reactive VOCs, which are reflected in the EPA list of non-photochemically reactive VOCs. By consolidating the list (which consists of the EPA list of non-photochemically VOCs), and adopting the EPA definition by reference, a single list of negligibly reactive VOCs will apply uniformly to all Colorado Air Quality Control Commission regulations.

This revision will also include EPA's recent addition of acetone to the negligibly reactive VOC list. The addition of acetone to the list of negligibly reactive VOC's provides additional flexibility to sources looking for an alternative to more photochemically reactive VOCs. Because the EPA has added acetone to their list of non-photochemically reactive VOCs many industries, which make and supply products to Colorado industries, are planning to substitute acetone for more reactive VOCs. This change in the content of products purchased by industry for use in Colorado would adversely affect industries in Colorado if acetone remains a regulated VOC in Colorado. By adopting acetone as a negligibly-reactive VOC, industry's will be able to take advantage of and benefit from this possible shift in product contents.

B. March 21, 1996 (Sections I.A.1. through I.A.4.; II.D.; II.E.)

The changes to Regulation Number 7 were adopted as part of the Commission's decision to redesignate the Denver metro area as an attainment and maintenance area for ozone, together with the relevant amendments to the Ambient Air Quality Standards regulation and Regulation Number 3. The Ozone Maintenance Plan, also adopted by the Commission on March 21, 1996 as part of the redesignation, based part of its demonstration of maintenance on the continued existence of rules regulating VOC emissions. Such rules include the application of the permit requirements of Regulation Number 3 to gasoline stations, and the continued application of Regulation Number 7 for the control of VOC in nonattainment areas. The VOC controls in Regulation Number 7 were adopted into the SIP in May 1995, after Denver attained the ozone standard. The maintenance demonstration was based on future inventories that assumed the continuance of existing VOC controls in the Denver Metro area.

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

Hundreds of people from across the state submitted written comments on the proposed changes to Regulations 3 and 7. Most of these written comments called for additional regulation of oil and gas operations, to fulfill the directives of SB 19-181, protect public health, and reduce greenhouse gas emissions. Prior to the rulemaking hearing, the Commission held public comment sessions in Rifle, Durango, and Loveland, on December 10, 11 and 16, respectively. Dozens of members of the public spoke at each of these sessions. Many commenters expressed support for the proposed changes to Regulations 3 and 7, citing concerns about risks to health and to the climate from oil and gas emissions. Many commenters at the Rifle and Durango meetings emphasized the need for rules to be applied statewide. Commenters also called on the Commission to develop requirements for continuous monitoring of oil and gas emissions. Some speakers at each comment session expressed concern that the industry was being overregulated, with some on the Western Slope emphasizing that their part of the state was in attainment with ozone standards and expressing concerns with the impact more stringent rules might have on the industry.

T. September 17-18 & 23, 2020 (Part D, Sections II., IV., V., VI. and Part E, Section I.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act § 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

Basis

The Commission revised Part E, Section I. to reduce emissions from natural gas fired reciprocating internal combustion engines (RICE) greater than or equal to 1,000 horsepower (hp) on a state-wide basis. The revisions are in response to four distinct directives to secure reductions: Senate Bill 19-181 (SB 19-181); the second implementation period of the Regional Haze Rule pursuant to Clean Air Act Section 169A; progress towards the 2008 ozone National Ambient Air Quality Standard (NAAQS) of 75 ppb and 2015 ozone NAAQS of 70 pp; and to address nitrogen deposition at Rocky Mountain National Park (RMNP).

For example, concentrations at 2000-4000 feet away from the operations are likely to be low and, therefore, would require high-sensitivity instruments; monitors placed in close distance to the operations may need to be placed at variable heights to detect emissions from equipment of different heights; or monitors may need to be placed in both upwind and downwind locations, depending on the monitoring technology. In addition, the Commission expects the Division to work with operators in approving air quality monitoring plans to make sure that local jurisdiction air quality monitoring requirements and COGCC site preparation requirements are considered. The Commission expects the Division to consult with relevant local governments in reviewing monitoring plans, to obtain their input on local circumstances or concerns that may guide the Division's determinations on plan adequacy.

Owners or operators will also submit monthly reports of air quality monitoring to the Division. These monthly reports will include descriptions of activities that occurred during the monitoring period such that monitoring data can be understood in relation to activity onsite (e.g., accounting for engine emissions). The Commission recognizes that monitoring data often requires additional analysis to interpret the resulting data. Therefore, for this first oil and gas air quality monitoring program, the Commission expects that operators will make the raw data (e.g., monitor/sensor and meteorological readings prior to analysis or processing) available to the Division upon request (and expects the Division to make the raw data available to the relevant local government entities upon request) but submit the analyzed data results in the monthly reports. The Commission believes these reports will provide valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make the reports publicly available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. This flexible monitoring program is intended as an initial step to help inform future oil and gas monitoring efforts.

Recognizing that this pre-production emissions monitoring program represents a first step in understanding both pre-production emissions and the rapidly evolving technologies that may be used to monitor them, the Commission directs the Division to report back to the Commission no later than March 31, 2022 with an initial summary of activities to implement the rule since September, 2020; learnings and insights on monitoring technologies, including technologies for continuous methane monitoring; appropriate data summaries on observed emissions based on the monthly reports received; initial feedback on the adequate length of monitoring time during and possible identification of exemptions from monitoring for certain types of facilities.

Flowback vessels

The Commission also adopted in the new Section VI. a requirement for owners of operators of pre-production operations to control emissions from flowback vessels. After hydraulic fracturing, operators bring the frac fluids and entrained solids to the surface. EPA's NSPS OOOOa Section 60.5375a requires operators to route flowback during the initial flowback stage into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. During the separation flowback stage, NSPS OOOOa requires operators to route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into a well, or route the liquids to a collection system. NSPS OOOOa allows operators to use open vessels to contain flowback fluids and solids and does not consider a well completion vessel a storage vessel, which means operators are not required to control well completion vessel emissions. Therefore, to build on the NSPS reduced emission completion requirements and further reduce pre-production tank emissions, owners or operators of pre-production operations must use enclosed flowback vessels after the drill-out phase, which the Commission recognizes has a high ratio of solids to liquids, and route emissions from flowback vessels to air pollution control equipment.

CLEAN AIR ADVOCATES' EXHIBIT 20

DEPARTMENT OF NATURAL RESOURCES

Oil and Gas Conservation Commission

PRACTICE AND PROCEDURE

2 CCR 404-1

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

---

100 SERIES DEFINITIONS

ACT shall mean the Oil and Gas Conservation Act of the State of Colorado.

AFFECTED PERSON means any person who satisfies the requirements of Rule 507.a.

ANNULAR OVER-PRESSURIZATION means a wellbore condition that occurs when fluids in the annulus between the surface casing and the intermediate or production casings are pressurized to a degree that may cause migration of confined fluids or gases out of the annular space.

ANNULUS means the space between the borehole and a casing string or between two casing strings in a well.

APPLICANT shall mean the person who institutes a proceeding before the Commission which it has standing to institute under these rules.

AQUIFER shall mean a geologic formation, group of formations or part of a formation that can both store and transmit ground water. It includes both the saturated and unsaturated zone but does not include the confining layer which separates two (2) adjacent aquifers.

AUTHORIZED DEPUTY shall mean a representative of the Director as authorized by the Commission.

AVAILABLE WATER SOURCE shall mean a water source for which the water well owner, owner of a spring, or a land owner, as applicable, has given consent for sampling and testing and has consented to having the sample data obtained made available to the public, including without limitation, being posted on the COGCC website.

AVOID ADVERSE IMPACTS means to differentially select alternative locations, practices, or methods for Oil and Gas Operations based on site-specific circumstances, so that those operations will not cause quantifiable direct, indirect, or cumulative adverse impacts to the potentially affected resource(s). Avoidance may include a no action alternative.

BARREL shall mean 42 (U.S.) gallons at 60° F. at atmospheric pressure.

BASE FLUID shall mean the continuous phase fluid type, such as water, used in a hydraulic fracturing treatment.

BATTERY shall mean the point of collection (tanks) and disbursement (tank, meter, LACT unit) of oil or gas from producing well(s).

BEST MANAGEMENT PRACTICES (BMPs) are practices that are designed to prevent or reduce impacts caused by oil and gas operations to air, water, soil, or biological resources, and to minimize adverse impacts to public health, safety and welfare, including the environment and wildlife resources.

b. Operators will prevent adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

c. Operators will prevent the unauthorized discharge or disposal of oil, condensate, gas, E&P Waste, Chemical substances, trash, discarded equipment, and other oil field waste.

d. No Operator, in the conduct of any Oil or Gas Operation, may violate numeric or narrative water quality standards or classifications established by the WQCC for Waters of the State, or any Point of Compliance established by the Director pursuant to Rule 914. The Director may require the Operator to establish one or more Points of Compliance for any event of Pollution, which will be complied with by all parties determined to be a Responsible Party for such Pollution.

e. No Operator, in the conduct of any Oil or Gas Operation, may violate any applicable air quality law, regulation, or permit as administered by the Air Quality Control Commission or any other local or federal agency with authority for regulating air quality associated with such activities.

f. No person may accept water produced from Oil and Gas Operations, or other oil field waste for disposal in a commercial disposal facility, without first obtaining a certificate of designation from the county in which such facility is located, in accordance with the regulations pertaining to Solid Waste Disposal sites and facilities as promulgated by CDPHE.

903. VENTING OR FLARING NATURAL GAS

Venting and Flaring of natural gas represent waste of an important energy resource and pose safety and environmental risks. Venting and Flaring, except as specifically allowed in this Rule 903, are prohibited.

a. **Notice to Local Governments and Emergency Responders.**

(1) **Prior Notice.** As soon as practicable prior to, but no later than two hours before, any planned Flaring of natural gas allowed pursuant to this Rule 903, Operators will provide verbal, written, or electronic notice to the Relevant and Proximate Local Governments and to the local emergency response authorities.

(2) **Subsequent Notice.** In the event of Flaring due to an Upset Condition, Operators will provide verbal, or electronic notice as soon as possible, but no later than 12 hours, to the Relevant and Proximate Local Governments and to the local emergency response authorities.

(3) **Waiver.** Relevant and Proximate Local Governments and local emergency response authorities may waive their right to notice under this Rule 903.a at any time, pursuant to Rule 302.f.(1).A.

(4) **Recordkeeping.** Operators will maintain records of notice provided pursuant to this Rule 903.a, and provide the records to the Director upon request.

b. **Emissions During Drilling Operations.**

(1) Operators will capture or combust gas downstream of the mud-gas separator using best drilling practices while maintaining safe operating conditions.

(2) If capturing or combusting gas would pose safety risks to onsite personnel, Operators may Vent and will provide verbal notification to the Director within 12 hours and submit a Form 4, Sundry Notice within 7 days. The Operator need not seek a formal variance pursuant to Rule 502. A Form 23, Well Control Report may also be required if the criteria in Rule 428.c are met. If Venting pursuant to this Rule 903.b.(2) exceeds 24 hours, the Operator will seek the Director's approval to continue Venting.

(3) Combustors will be located a minimum of 100 feet from the nearest surface hole location and enclosed.

c. Emissions During Completion Operations.

(1) **Reduced Emission Completions Practices.** Operators will adhere to reduced emission completion practices as specified in 40 C.F.R. § 60.5375a, as incorporated by reference in Rule 901.b, on all newly Completed and re-completed oil and gas Wells regardless of whether the Well is hydraulically fractured, unless otherwise specified in this Rule 903.c.

(2) **Flowback Vessels.** Operators will enclose all Flowback vessels and adhere to the AQCC Regulation No. 7 standards for emission reduction from pre-production Flowback vessels as specified in 5 C.C.R. § 1001-9:D.VI.D, as incorporated by reference in Rule 901.b.

(3) Operators may Flare gas during completion operations with specific written approval from the Director under any of the following circumstances:

A. The Operator obtains the Director's approval to Flare through an approved gas capture plan pursuant to Rule 903.e;

B. The Operator submits, and the Director approves, a Form 4 allowing the Operator to Flare gas that would otherwise not be permitted pursuant to Rule 903.c.

i. On the Form 4 the Operator will explain why Flaring is necessary to Complete the Well, and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

ii. On the Form 4 the Operator will estimate anticipated Flaring volume and duration.

iii. On the Form 4 the Operator will explain its plan to connect the facility to a Gathering Line or otherwise utilize the gas in the future.

iv. The Director may approve a Form 4 requesting permission to Flare during completion if the Director determines that the Flaring is necessary to Complete the Well and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources; or

C. The Operator may direct gas to an emission control device and combust the gas if necessary to ensure safety or during an Upset Condition for a period not to exceed 24 cumulative hours. If Flaring pursuant to this Rule 903.c.(3).C exceeds 24 hours, the Operator will seek the Director's approval to continue Flaring. Within 7 days of the Flaring event, the Operator will submit a Form 4 reporting the Upset Condition or safety issues that resulted in the Flaring event and include the estimated volume of gas Flared.

CLEAN AIR ADVOCATES' EXHIBIT 21

APPENDIX B

Statement of Basis, Specific Statutory Authority, and Purpose
New Rules and Amendments to Current Rules of the
Colorado Oil and Gas Conservation Commission, 2 C.C.R. § 404-1

Cause No. 1R Docket No. 200600155
800/900/1200 Mission Change, Cumulative Impacts,
and Alternative Location Analysis Rulemaking

This statement sets forth the basis, specific statutory authority, and purpose for amendments ("800/900/1200 Mission Change Rulemaking") to the Colorado Oil and Gas Conservation Commission ("Commission" or "COGCC") Rules of Practice and Procedure, 2 C.C.R. § 404-1 ("Rules").

Unless otherwise specified, the new rules and amendments become effective on January 15, 2021.

In adopting amendments to the Rules, the Commission relied upon the entire administrative record for this rulemaking proceeding, which formally began on June 19, 2020, when the Commission submitted its Notice of Rulemaking to the Colorado Secretary of State for revisions to its 800, 900, and 1200 Series Rules and related 100 Series definitions. This record includes public comments, written prehearing statements, written prehearing testimony, and oral testimony and comments provided during public hearings and Commission deliberations.

Background

In the 800/900/1200 Mission Change Rulemaking, the Commission revised its Rules to align with the statutory amendments adopted in Senate Bill 19-181. The 800/900/1200 Mission Change Rulemaking fulfills the Commission's statutory obligation to undertake three specific rulemakings: one to implement changes to the agency's mission, one to evaluate and address potential cumulative impacts, and one to adopt an alternative location analysis process. Because each of these topics are fundamentally interrelated, the Commission chose to address all three topics in the same rulemaking process. The 800/900/1200 Mission Change Rulemaking occurred simultaneously with a separate but closely related Mission Change Rulemaking, in which the Commission revised its 200 through 600 Series Rules and related 100 Series definitions.

Additionally, in the 800/900/1200 Mission Change Rulemaking the Commission revised its Rules to comply with several other statutory changes made by Senate Bill 19-181, including provisions relating to the role of local governments, the transition to a full-time Commission, and revisions to several statutory definitions.

Finally, the Commission improved the clarity of its Rules by grouping related Rules

lighting standards, none of which are considerations in the AQCC's rules. Accordingly, the Commission determined that it was appropriate for its definition to focus on whether a well is capable of producing separable gas or salable liquid hydrocarbons that flow consistently to a sales line, gathering line, or tank, rather than on the presence of permanent production equipment at a location, which is the standard used in the AQCC definition.

Production frequently commences prior to the end of flowback, and production can and does commence prior to permanent equipment being in place and temporary equipment being removed. The Commission does not intend for the presence of some temporary equipment at a location to mean that production operations have not yet commenced if separable gas or salable liquid hydrocarbons are already being produced and consistently flowing to a sales line, gathering line, or tank. The Commission tailored its definition to provide additional clarity on a frequent question that has arisen in the past as a result of operator confusion about when to designate the date of first production on Form 5A, Completed Interval Reports. The Commission's new definition clarifies when the date of first production occurs and will resolve that question on Form 5As going forward. The Commission recognizes that there are situations where a well may be drilled and completed, but temporarily shut in and not actually producing. The Commission understands that *production* may not yet be occurring at such a well, but because the well is capable of *production operations*, the Commission intends for it to fall within the definition of Commencement of Production Operations. The Commission believes that it has appropriately tailored the use of this defined term to avoid imposing unnecessary or irrelevant burdens on such wells.

Completed Well

Consistent with the new definition of Commencement of Production Operations, the Commission revised its definition of "Completion" to instead define a "Completed Well." The revised definition is simpler and clarifies that a well will be considered completed when oil or gas is produced through the wellhead from the producing interval, and after the production string has been installed. Some stakeholders suggested changing the term "production string" to "tubing." The Commission did not adopt this suggestion because not all operators utilize tubing strings.

Flowback

Also consistent with the new definition of Commencement of Production Operations and the revised definition of Completed Well, the Commission adopted a new definition of Flowback. This definition codifies and clarifies the EPA definitions of initial Flowback stage and separation Flowback stage that the Commission has used for several years in its March 18, 2016 Notice to Operators ("NTO") re: Rule 912.

The Commission chose not to specify when the flowback period begins and ends in the 100 Series Definition of Flowback, because such specification was not necessary given the limited uses of the term in the Commission's 400 Series Rules and Rule 903.c.(2). However, the Commission intends for operators to control separable gas as soon as possible. The Commission recognizes that Flowback is a term that is commonly used in the oil and gas industry, and that the defined term "Flowback" in the Commission's Rules does not necessarily match that definition. The Commission also recognizes that its definition is similar to, but somewhat different from, the AQCC's definition. This is the reason the Commission has provided a definition of the term—because it is a term used in specific contexts in the Commission's Rules, governing only a limited subset of operations, and accordingly the Commission narrowly tailored the definition to match those specific uses in the Commission's Rules.

Upset Condition

Finally, the Commission adopted a new definition of Upset Condition. The Commission also adopted this definition based on close consultation with the APCD's staff. As used in Rule 903, the term Upset Condition refers to sudden and unavoidable circumstances, beyond an operator's control, that result in abnormal operations and require correction. The Commission recognizes that unique standards for venting and flaring may need to apply in such circumstances in order to protect public safety and public health. The Commission intends for its definition of Upset Condition to include sudden unplanned lack of pipeline capacity, which is why the definition includes the term "event."

Some stakeholders asked the Commission to define conditions that do not constitute an Upset Condition. The Commission did not adopt this suggestion, because the Commission did not want to inadvertently omit any categories of activities that would not be considered an Upset Condition from this list, thereby implying that they are, in fact, an Upset Condition. However, the Commission does not consider an operator's negligence, failure to install appropriate equipment, or failure to perform scheduled maintenance to be Upset Conditions.

Productivity Test & Production Evaluation

Consistent with adopting Rule 903.d.(1).C, the Commission also adopted definitions of Productivity Test and Production Evaluation in its 100 Series Rules, which were previously undefined terms. Each term has a distinct meaning, but both refer to tests and evaluations used to determine whether a wildcat or exploratory well is viable and capable of producing economic quantities of oil or gas.

that is vented at later stages pursuant to Rules 903.c.(3).B and 903.d.(3), the Commission does not believe that it is possible for operators to provide a natural gas analysis for natural gas vented at the drilling stage, because the emergency nature of such venting would likely make it impossible to capture a sufficient quantity of natural gas to analyze the sample

Rule 903.b.(3)

In Rule 903.b.(3), consistent with prior Rules 317.p, 606A, 606B, and 912.d, the Commission required that all combustors used during drilling operations be located at least 100 feet from the nearest surface hole location and enclosed. Providing a single standard specifying an objective safe distance for combustors to be located during drilling operations will provide better clarity to operators about where combustors may be safely located.

Some stakeholders suggested removing the requirement that combustors be enclosed. The Commission did not adopt these stakeholders' suggestion, because it determined that enclosing combustors is an important safety standard to minimize the risk of accidental fires, which can be spread from unenclosed combustion devices during windy periods. Enclosing combustors may also in many cases limit the visibility of flame, which may reduce calls to local emergency response agencies.

The Commission did not specify an efficiency standard for combustion devices used during drilling operations, understanding that the unique characteristics of natural gas escaping from a well during drilling operations may increase the likelihood of incomplete combustion. However, the Commission intends for operators to capture as much natural gas as possible in the event of incomplete combustion, and determined that requiring combustion devices to be enclosed facilitates this intent.

Rule 903.c

The Commission combined prior Rules 604.c.(2).C and 805.c into a single Rule 903.c.

Rule 903.c.(1)

Prior Rule 805.c provided detailed technical standards for green completion practices, which the Commission adopted in 2008 primarily as an effort to reduce odors during completion operations. Prior Rule 604.c.(2).C provided specific requirements for completion operations in designated setback locations. The Commission has successfully implemented Rules 805.c and 604.c.(2).C to reduce odors, emissions, and waste during completion operations for several years. However, after Rule 805.c was adopted, in 2012 the EPA adopted, and in 2016 revised, federal standards for reduced emission completions, which are similar to the Commission's Rule 805.c, but distinct in several ways. Since 2016, all new and modified oil and gas facilities constructed

or modified have been required to comply with EPA's reduced emission completion standards, which are colloquially referred to as "OOOOa" or "Quad-O A," based on their location in subpart OOOOa of Part 60 of the Code of Federal Regulations. *See* 40 C.F.R. § 60.5375a (2019). Consistent with its obligations as an agency with delegated authority under the federal Clean Air Act, the AQCC has incorporated EPA's 2012 reduced emission completion standards by reference. *See* 5 C.C.R. § 1001-8:A.

Accordingly, to eliminate confusion that might arise from differences between the Commission's green completion standards from prior Rule 805.c and EPA's and the AQCC's reduced emission completion standards, the Commission chose to largely align its completion emissions standards with EPA and the AQCC in Rule 903.c.(1).

In July 2020, EPA revised its OOOOa new source performance standards, including 40 C.F.R. § 60.5375a. Among other changes, EPA expanded exceptions for low-pressure wells. Additionally, EPA's reduced emission completion standards (both the 2016 and 2020 versions) apply only to hydraulically fractured wells. Accordingly, the Commission did not fully incorporate EPA's 2020 reduced emission completion standards for three reasons. First, the Commission intends for its reduced emission completion standards to apply to all wells, regardless of whether they are hydraulically fractured. Second, the Commission determined that the exceptions for low-pressure wells are unnecessary given the unique circumstances of well completions in Colorado, and that they were not fully consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority, C.R.S. § 34-60-106(2.5)(a), and ongoing statutory obligation to prevent waste. Finally, at the time of the Commission's 800/900/1200 Mission Change Rulemaking hearing, the status of EPA's 2020 revisions to its OOOOa new source performance standards was uncertain, because the revisions were subject to active litigation. Therefore, the Commission incorporated the 2016 version of 40 C.F.R. § 60.5375a by reference in Rule 901.b.(3).G, and in Rule 903.c.(1) clarified that the reduced emission completion standards apply to all wells, regardless of whether the well is hydraulically fractured.

Although this means there will continue to be direct overlap between the Commission's Rules and the AQCC's regulations, the Commission determined that this overlap is appropriate in consultation with APCD Staff, because the Commission has historically been the primary enforcement agency for completion-stage emissions standards. The Commission will continue to closely coordinate closely with APCD staff about facilitating compliance, enforcement priorities, and avoiding duplication. Overall, the Commission determined that better aligning its completion standards with EPA and the AQCC will provide improved clarity and efficiency for operators while still fulfilling the Commission's statutory obligations to protect and minimize adverse impacts to public health and the environment and prevent waste. The Commission determined that protecting public health is particularly paramount during completion operations, because evidence in the administrative record

demonstrates that health risks associated with oil and gas operations are likely greatest during completion operations such as flowback.

Some stakeholders questioned why Rule 903.c.(1) did not explicitly prohibit venting during completion operations. The Commission determined that expressly prohibiting venting during the completion stage is unnecessary, but did not intend to permit venting during the completion stage. First, based on the definition of "Commencement of Production Operations," wells would produce very little or no natural gas to vent prior to the commencement of production operations. Thus the prohibition on venting in Rule 903.d.(1) obviates the need for a distinct prohibition on venting in Rule 903.c. Second, Rule 903.c.(1)'s reduced emission completion standards require capture or combustion of natural gas in nearly all circumstances. *See* 40 C.F.R. § 60.5375a(a)(4) (2016). That leaves only flaring, rather than venting, as an alternative with the Director's prior approval pursuant to Rule 903.c.(3).

Other stakeholders raised questions about the meaning of the term "re-completed" in Rule 903.c.(1).A. The Commission intends for the term "re-completion" to refer to a completion that is not an initial completion that targets a formation that was not initially permitted for a well. Re-completions require operators to submit a Form 2, Application for Permit to Drill to obtain the Commission's approval. By contrast, re-stimulating an already completed formation does not require operators to submit a Form 2. Re-completing a well may require an operator to submit a gas capture plan pursuant to Rule 903.e even if the operator did not initially submit a gas capture plan as an attachment to their Form 2A, Oil and Gas Location Assessment. The Commission's Staff have issued guidance about form submittals related to various recompletion situations, which is available on the Commission's website, under the instructions for the Form 2.

Rule 903.c.(2)

In Rule 903.c.(2), the Commission adopted a new requirement for operators to enclose all flowback vessels and to adhere to AQCC regulations governing reducing emissions from flowback vessels. The AQCC adopted its regulations for flowback vessel emissions in 2020. The Commission accordingly determined it was appropriate to include a standard to remind operators of their obligation to enclose flowback vessels in its own Rules, to streamline compliance with both agencies' obligations. Moreover, the Commission determined that enclosure of flowback vessels will reduce emissions that may adversely impact public health and the environment, and is therefore consistent with Senate Bill 19-181's changes to the Commission's mission and statutory authority. *See* C.R.S. § 34-60-106(2.5)(a). As with the reduced emission completion standards in Rule 903.c.(1), the Commission's Staff will continue to closely coordinate with APCD staff about facilitating compliance, prioritizing enforcement efforts, and avoiding duplication.

Rule 903.c.(3)

In Rule 903.c.(3), the Commission provided standards for operators to obtain the Director's approval to flare natural gas during completion operations. Operators may either obtain the Director's prior approval when submitting a gas capture plan as an attachment to their Form 2A pursuant to Rule 903.e, or by subsequently submitting a Form 4. The Form 4 must include similar information to a gas capture plan, including why the flaring is necessary to complete the well, estimating a volume and duration of flaring, and explaining why the operator is unable to connect its facility to a gathering line. This is consistent with the Commission's March 18, 2016 NTO re: Rule 912.

In Rule 903.c.(3).C, the Commission adopted standards for combusting natural gas in order to protect safety of onsite personnel and during upset conditions. Among the reasons that flaring may be permissible to protect safety pursuant to Rule 903.c.(3).C are to purge oxygen from the line. For this type of unplanned flaring event during completion, operators may obtain the Director's subsequent approval by submitting a Form 4 within 7 days. However, the Commission limited the upset conditions and safety emergencies that will authorize flaring without prior Director approval pursuant to Rule 903.c.(3).C to periods not to exceed 24 cumulative hours. If flaring pursuant to an upset condition exceeds 24 hours, then operators must obtain the Director's approval to continue flaring. The Commission determined that this appropriately balanced the need for operators to react quickly to upset conditions and safety emergencies with ensuring that unnecessary and excessive venting and flaring does not occur.

Some stakeholders raised questions about the use of the term "emission control device" in Rule 903.c.(3).C. Because sending separable gas from a well or a separator to an emissions control device would meet the 100 Series definition of "Flaring," the Commission adopted standards to regulate such activities in Rule 903.c.(3).C.

Rule 903.d

The Commission combined portions of prior Rules 805.b, 912.a, 912.b, 912.c, and 912.d into a single Rule 903.d, providing a clearer standard for venting and flaring during production operations.

Consistent with these changes, the Commission eliminated prior Rules 805.b.(2).A, B, and D, which addressed emissions from tanks, glycol dehydrators, and pneumatic devices, respectively. Because AQCC regulations set emissions standards for these types of equipment, the Commission determined that it was unnecessarily duplicative to continue setting its own distinct standards for those categories of equipment.