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NORTHERN ALASKA ENVIRONMENTAL CENTER ◆ SIERRA CLUB
THE WILDERNESS SOCIETY

August 5, 2013

Alaska Oil and Gas Conservation Commission
333 West 7th Avenue, Anchorage, Alaska 99501
Submitted via hand delivery and online at: www.doa.alaska.gov/ogc/

Re: Proposed regulations on hydraulic fracturing and workover operations: 20 AAC §§ 25.280, 25.283, and 25.990 (Revised June 2013)

To Whom This Concerns:

Thank you for the opportunity to comment on the Alaska Oil and Gas Conservation Commission's June 2013 revisions to its proposed regulations concerning workover operations and hydraulic fracturing. We are pleased that many of the revisions are consistent with our recommendations on the previous draft regulations.

Below, we offer comments on the June 2013 proposal. First, however, we want to reiterate the issues raised in our April 1, 2013, comments (attached as Appendix A). Those comments identified significant issues in the original proposed regulations, the majority of which are not resolved by the June 2013 revision. In particular, the Commission must address flaring and venting of gas. More generally, the majority of our April 1, 2013, comment continues to apply to the Commission's June 2013 proposal. We believe that the recommendations provided in those comments, together with the additional comments provided here, will provide for improved rulemaking.

I. Chemical Disclosure

The Commission has retained its proposed chemical disclosure provisions and improved on them in several ways. We appreciate the pre-fracturing disclosure provisions and the absence of exemptions for trade secrets. It is widely accepted that the public and those working with fracturing chemicals have a right to know what these chemicals are.[1]

A. Pre-fracturing Disclosure

Commendably, the Commission's revisions bring into line several of the pre-fracturing disclosure requirements with the more comprehensive post-fracturing disclosure requirements.

We appreciate the clarification in revised section 25.283(a)(14) that the proposed hydraulic fracturing program provided by operators must include pumping procedures by stage where applicable, with chemical disclosure based on the total amounts and volumes per well. This provides for more specific disclosure of which chemicals are being used at each stage in each well.

We are satisfied with the use of the term "base fluid" (as opposed to "principle fluid") in section 25.283(a)(14)(B-C) and the pre-fracturing reporting requirements associated with base fluids and additives. We also appreciate the new requirement to report the actual or maximum concentration of each chemical ingredient in the hydraulic fracturing fluid in percent by mass; without this information, disclosure would be incomplete and insufficient to allow the Commission and the public to take appropriate precautions to avoid harm to human health or the environment.

It is unclear why the Commission removed the proposed requirement to provide pre-fracturing disclosure on "freeze-protect fluids pumped before and/or after hydraulic fracturing." The previously proposed disclosure requirement should be reinstated. Any chemical pumped into the ground presents a potential threat to human health and the environment. For example, ethylene glycol (anti-freeze) is a common chemical used in hydraulic fracturing operations. This toxic, carcinogenic chemical and others like it should not be shielded from disclosure in the event that it is not pumped contemporaneously with the base fluid and additives. Disclosure of all pumped chemicals is essential to determine the source of any subsequent contamination of groundwater, surface water, or soil, and to provide emergency responders, medical professionals and the public with information needed to fully assess the risks associated with fracturing. Disclosure also promotes operator responsibility, while calling attention to practices that could jeopardize the environment and public health. Transparency will help increase public confidence to the extent it demonstrates that hydraulic fracturing is done safely and with non-toxic chemicals. And public disclosure serves an even more important function in instances where potentially dangerous

[1] *See* Det Norske Veritas, DNV-RP-U301, Risk Management of Shale Gas Developments and Operations (Jan. 2013), p. 29 [hereafter "DNV Recommended Practice"] (setting forth recommended regulations, none of which suggest trade secret exemptions, and stating, "Data should be openly disclosed to relevant stakeholders. Updates should be issued regularly[.]") (excerpts attached as Appendix B).

hydraulic fracturing chemicals are being used—including freeze-protect fluids—by allowing the Commission and the public to take appropriate precautions to avoid health and environmental harms.

B. Post-Fracturing Reporting

We appreciate the revision of the term “materials” in the post-fracturing reporting requirements of section 25.283(h) to “base fluid(s) and additives,” along with the requirement that operators provide information on base fluids and additives including the trade name, supplier and a brief description of the purpose of the chemical. The previous version of the regulations did not clearly provide for reporting on the composition of base fluids.

We are pleased with the new requirement to indicate the actual or maximum concentration for each chemical ingredient in each base fluid and additive in terms of percent by mass, as well as the requirement to report the maximum concentration of each chemical ingredient used in the hydraulic fracturing fluid in percent by mass. As noted above with respect to pre-fracturing disclosure, without this information, disclosure would be incomplete and insufficient to allow the Commission and the public to exercise appropriate precautions.

The previous draft regulations limited reporting to chemicals subject to material safety data sheet (MSDS) requirements under 29 CFR 1910.1200. We appreciate the removal of this limitation, since there may be harmful chemicals for which MSDSs are not available.

As with the pre-fracturing disclosure requirements, it is unclear why the Commission removed the proposed post-fracturing disclosure requirement concerning “freeze-protect fluids pumped before and/or after hydraulic fracturing.” Again, there is no basis for this exemption: any chemical pumped into the ground presents a potential threat to human health and the environment, necessitating full disclosure for the numerous reasons outlined above and in our April 1, 2013, comments.

C. Use of FracFocus

We recognize that FracFocus, the reporting website operated by the Interstate Oil and Gas Compact Commission/Groundwater Protection Council hydraulic fracturing website, has been revised since our April 1, 2013, comments. Namely, the standardized disclosure form has been updated to allow for more information to be reported. But FracFocus still does not facilitate—and indeed prohibits—aggregation of data by the public, and there is no system for the pre-fracturing disclosure required by the proposed regulations. We continue to recommend that the Commission upload the reports submitted by operators on the Commission’s website and to create a database which is searchable by the public by geographic area, chemical, Chemical

Abstract Service number (CAS), time period, and operator. Such a database would enable the local public, researchers, municipal officials, etc. to get a clear picture of all the fracturing operations occurring in an area or a region, and to perform trend analyses over time. There is no reason that information should be made difficult to retrieve except the lack of desire by some operators to make such information available.

Finally, in addition to the difficulties surrounding FracFocus we identified previously, we note that FracFocus's status as an independent project raises several troubling issues. For example, it is unclear to what extent FracFocus is subject to state administrative and public records laws, and thus, how the public would challenge any conduct relating to FracFocus. FracFocus also does not provide any standards for data retention, verification, or quality control—all issues that should be addressed in a repository of public records.

II. Notifying Stakeholders

We appreciate the proposed revision to Section 25.283(a) requiring notification to landowners, surface owners, and operators within one-half mile (rather than one-fourth mile) of the wellbore trajectory, because issues at a well may affect local residents at a distance beyond one-quarter mile. We are concerned, however, that operators need only provide notice of operations, so the burden is on potentially affected parties to request complete copies of the applications for permits to drill from operators. Additionally, the regulations lack any requirement that a request for a complete copy of the application be provided by the operator in a timely manner or at the expense of the operator. If an operator were to delay its response to a request for a complete application or insist that an affected (and potentially economically disadvantaged) party pay for the copy, the goals of transparency and public participation could be easily subverted. We therefore suggest that the Commission retain the language requiring that a copy of the entire application be provided or that there be a web-based link to all applications.

III. Protecting Water

We appreciate the proposed revision to Section 25.283(a)(5) to clarify timelines for the water testing as follows (additions underlined): "Water sampling consists of collection of baseline water data pre-fracture (<u>but not more than 90 days prior</u>) and follow-up water sampling collected at the same location no sooner than 90 days and no later than 120 days after the conclusion of any hydraulic fracturing operations." When an accident or contamination occurs or is alleged, such specific timelines facilitate identification of the responsible party.

IV. Well Integrity

A. Pressure Monitoring

Section 25.283(f-g) pertains to pressure monitoring during hydraulic fracturing to prevent casing and cement damage and to identify pressures that may damage wellbore integrity. We appreciate the revision to section 25.283(f) pertaining to surface casing, whereby surface casing pressures must be monitored with a gauge and a pressure relief device when hydraulic fracturing operations are in progress. This should help the operator monitor and report pressure changes during fracturing. As we indicated in our previous comments, the maximum set pressure on the relief device should be a pressure change that is 20% of the calculated pressure increase due to thermal expansion.

B. Parameters for Fracturing

Revised section 25.283(a)(14)(F) would require the operator to report the designed height and length of the proposed fracture(s), including reporting of the calculated measured depth and true vertical depth of the top of the fracture(s). We support the proposed revision to require the operator to submit a description of the methods and assumptions used to determine designed fracture height and length, although we believe that a requirement to use a three-dimensional model would result in better estimates. To the extent possible, an applicant should be required to develop estimates using the best scientific data and technology available. Additionally, we support requiring operators to collect observable fracture propagation data, and to refine their modeling calculations using those data.[2]

We also support the proposal to add measured and true vertical thickness for the fracturing and confining zones under section 25.283(a)(10). This should help the Commission get a better picture of the parameters for the fracturing and confining zones.

V. Permit to Drill

The proposed revision would remove all references to section 25.005 (permit to drill). It is not clear whether this means that operators would no longer have to disclose their intent to use a well for hydraulic fracturing on an application for a permit to drill. In the interest of full and meaningful transparency, we oppose any removal of the requirement for operators to disclose

[2] *See* Appendix B, DNV Recommended Practice, p. 31 ("it is essential that the actual fracture creation and propagation is monitored in real time using BAT micro-seismic arrays and methods that allow direct location of and indirect observation of subsequent induced fracture surfaces. The resulting observed induced fracture geometry, direction and extent should then be compared to values predicted for these. If there is considerable deviation between predictions and observations, any necessary model revisions, corrections and updates should be performed in time to improve the design, planning and execution of future fracturing operations.").

their intent to use a well for hydraulic fracturing on an application for a permit to drill, and we conversely urge the Commission to require such disclosure.

VI. Variance

The proposed new section 25.283(j) would allow the Commission to modify the regulations on a case-by-case basis as follows:

a. change a deadline upon a showing of good cause
b. approve a variance from any other requirement if the variance provides at least an equally effective means of complying with the requirement
c. approve a waiver of a requirement of this section if the waiver will not promote waste, is based on sound engineering and geoscience principles, will not jeopardize the ultimate recovery of hydrocarbons, will not jeopardize correlative rights, and will not result in an increased risk to health, safety, or the environment, including freshwater.

We appreciate the need to provide flexibility in the regulatory process, and we understand that <u>under certain limited circumstances</u>, an alternative design may meet the intent of the Commission's regulations even if it does not strictly adhere to the language of the regulations. That said, the broad scope of the proposed variance provision threatens to undermine all of the other regulations proposed and is therefore unacceptable.

First, we do not support the proposal to change deadlines merely "upon a showing of good cause." This language is vague and subject to inconsistent application by the Commission. To the extent a variance provision for deadlines is adopted, it should specify that a deadline may not be modified "except in the case of an emergency, defined as an unplanned event that, in the absence of immediate remedial action, can cause death or significant harm to human health, safety or welfare, wildlife or wildlife habitat." In no event should a deadline be waived.

Second, under no circumstances should the Commission be allowed to vary or waive any requirements relating to public disclosure. The disclosure requirements are necessary and serve compelling needs, including public confidence in the Commission's regulatory decision-making, the need for informed emergency response to contamination, promotion of operator responsibility, and protection of human health and the environment. The regulations should indicate that variances (or waivers) must not pertain to any of the public disclosure requirements.

Third, to the extent a variance for non-deadline and non-disclosure provisions is retained, we suggest that the Commission add some more specific criteria for variances, including that the proposed activity:

1. complies with all other applicable laws;
2. will not negatively interfere with the use or enjoyment of adjacent property;

3. achieves the intent of the section(s) containing the standards applicable to the activity or development to an equal or better degree; and
4. will not set a precedent.

We note that the Commission must have adequate staff and resources to effectively review and analyze variance requests.

Finally, the proposed waiver component of the variance provision should be eliminated. While a variance may be justified in certain limited circumstances, under no circumstance should regulatory requirements for hydraulic fracturing be waived. The very purpose of this rulemaking is to determine what is necessary to avoid waste, to comply with sound engineering and geoscience principles, to protect disclosure rights, and to reduce any risk to health, safety, or the environment, including freshwater. A potential case-by-case waiver subverts the current public rulemaking process and the substantial efforts for effective regulatory oversight by the Commission, invites unfair and otherwise arbitrary decision-making—as well as litigation over such decision-making—and could be an enormous drain on staff resources. For these reasons, no waiver of the regulatory requirements should be allowed.

IX. Definitions

We appreciate the Commission's effort to clarify terms by adding new definitions to Section 25.990, but we are concerned that the definition for "chemical ingredient" may be too limited. Section 25.990(14) defines a chemical ingredient as "a discrete chemical constituent with its own specific name or identity, such as a CAS registry number, <u>that is contained in an additive</u>" (emphasis added). This might imply that base fluid chemicals not meeting the definition of "additives"[3] are not chemical ingredients, such that they need not be reported under Sections 25.283(a)(14)(C) and (h)(3).

We suggest that the definition for chemical ingredient be revised to add the underlined language as follows: "(14) 'Chemical Ingredient' means a discrete chemical constituent with its own specific name or identity, such as a Chemical Abstract Service registry number, that is contained in an additive <u>or a base fluid</u>."

[3] Section 25.990(3) defines additive as "any chemical substance or combination of substances, including a proppant, contained in a hydraulic fracturing fluid that is intentionally added to a base fluid for a specific purpose whether or not the purpose of any such substance or combination of substances is to create fractures in a formation."

Thank you very much for your consideration of these comments. We appreciate the Commission's recognition of the need for clear regulations on issues that matter deeply to the public. If you have any questions, please contact Lois Epstein, P.E., Arctic Program Director at The Wilderness Society (lois_epstein@tws.org or 907-272-9453, x107) or Barrett Ristroph, Esq., Arctic Program Representative at The Wilderness Society (ristroph@tws.org or 907-272-9453 x102).

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April 1, 2013

Alaska Oil and Gas Conservation Commission
333 West 7th Avenue, Anchorage, Alaska 99501

Submitted via hand delivery and online at: www.doa.alaska.gov/ogc/

Re: Proposed regulations on hydraulic fracturing and workover operations:
20 AAC §§ 25.280, 25.283, and 25.990

To Whom This Concerns:

Thank you for the opportunity for the undersigned organizations to submit comments on Alaska Oil and Gas Conservation Commission's proposed changes to its regulations concerning workover operations, hydraulic fracturing, and definitions for hydraulic fracturing applications, operations, and reporting. We appreciate your efforts to promote safe and responsible oil and gas development statewide, in both permafrost and non-permafrost areas. The proposed regulations support this goal and go a long way toward providing the public with critical information regarding fracturing.

Low-volume hydraulic fracturing of conventional oil and gas wells has been taking place in Alaska for some time, allowing operators to maximize the withdrawal of oil and gas in highly permeable geologic strata. High-volume hydraulic fracturing to obtain shale oil and shale gas in less permeable geologic strata (which represent a form of unconventional oil and gas production) is just beginning in Alaska, with projects such as those proposed by Great Bear Petroleum, LLC on the North Slope. Unconventional oil and gas production using fracturing requires significantly more wells and infrastructure than conventional production and some different operations that raise the risks of negative impacts. Thus, the time is right for the Alaska Oil and Gas Conservation Commission (the "Commission") and other Alaska agencies to develop regulations and requirements that can avoid or mitigate these impacts.

This letter outlines our suggestions to strengthen the Commission's regulations in order to ensure protection of the Alaska public and the environment.[1] The following chart summarizes the topics where we think the proposed regulations should be modified and where additional regulations should be developed.

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[1] In support of these comments, we are submitting twenty-nine (29) additional documents that are cited herein. One hardcopy set of the supporting documents, as well as an electronic set on CD, will be provided to the Commission on April 1, 2013, by hand delivery to the above address. A list of the supporting documents appears as Appendix 2 at the end of these comments. Each of these documents, in its entirety, should be included in the administrative record and carefully considered by the Commission.

Table: Summary of Key Suggested Changes

	Topic	Proposed or Existing Regulations	Changes Needed
I	Chemical Disclosure	20 AAC § 25.283(a) and (h)	Ensure that the components of fracturing chemicals and base/principle fluids are disclosed to the public prior to fracturing operations. Avoid the exclusive use of FracFocus.com to provide disclosure.
II	Notifying Stakeholders	20 AAC § 25.283(a)	Expand notification to owners and residents within one-half mile of the wellbore trajectory, and any local governments, including tribal governments, within 20 miles of a regulated well.
III	Protecting Water	20 AAC §§ 25.283(a)(5) (timeline for water testing); 25.990 (27) (freshwater definition); 25.440 (freshwater exemption); 25.283(a)(11) (freshwater depth); 25.030(c)(3) (surface casing); 25.030(c)(4) (intermediate casing); 25.033 (drilling fluids)	Clarify the timing of pre- and post-fracturing testing and ensure that there is enough time before fracturing operations for interested parties to do their own testing. Ensure that test results are provided to interested parties. Ensure that freshwater needed for drinking water as well as other purposes will be protected, and that the depth of freshwater will be properly determined. Where freshwater depth is unknown, require operators to verify depth. Ensure that surface casing and intermediate casing are deep enough to protect aquifers. Prevent the use of toxic drilling fluids.
IV	Well Integrity	20 AAC §§ 25.030 (casing); 25.200 - 25.290 (production practices); 25.283 (b-c, f-g) (pressure testing and monitoring); 25.283(a)(14)(F) (modeling); 25.283(h) (post-fracture reporting)	Ensure that casing and cement are properly installed and applied by incorporating best practices, and protected from corrosion and erosion. Ensure that pre-testing of a shale formation occurs and that a well's ability to withstand fracturing pressures is established prior to fracturing. Set standards for calculating measured depth and true vertical depth, including a requirement for 3D reservoir modeling. Require reporting on the actual vertical and/or horizontal fracture lengths. Provide more specific instruction on pressure monitoring during hydraulic fracturing, and ensure that wells are sufficiently monitored after fracturing.
V	Flaring	20 AAC § 25.235	Limit flaring and venting to the smallest amount needed for safety. Require operators to implement technically feasible and cost effective gas control practices during hydraulic fracturing operations. When flaring is necessary for safety, require best practices to be followed.
VI	Buffers	20 AAC § 25.283(e)	Avoid out-of-zone fracturing by requiring an additional margin of safety (vertical buffers).
VII	Storage, Handling, and Disposal	Authority under AS 31.05.030(e) and (j)	Ensure that fracturing chemicals are properly stored. Prohibit the storage of wastes in surface impoundments and require the use of tanks instead. Require injection of fracturing-related wastes wherever feasible.
VIII	Definitions	20 AAC § 25.990	Define "wellbore trajectory" and "principal fluid."
IX	Earthquake Risk	20 AAC § 25.252(c)	Require disposal or storage operations not to increase seismic events above background levels.
X	Misc.		Consider requiring applicants to provide compliance records; allow for a 30-day public comment opportunity for high-volume fracturing operations; and increase the bonding for these operations. Ensure there is sufficient staffing to maintain roughly the current staff-to-well oversight ratio.

I. Chemical Disclosure

We are pleased to see that the Commission's proposed regulations include substantial disclosure provisions. A growing number of states—at least fourteen as of June 2012—have implemented hydraulic fracturing disclosure rules.[2] Transparency will help increase public confidence to the extent it demonstrates that hydraulic fracturing is done safely and with non-toxic chemicals. Public disclosure serves an even more important function in instances where potentially dangerous hydraulic fracturing chemicals are being used, by allowing the Commission and the public to take appropriate precautions to avoid harm to human health or the environment. In the event of an accident or harm to human health or the environment, disclosure is critical for emergency response as well as the longer-term care of affected community members and resources.

A. Full Disclosure of Fracturing Chemicals Prior to Commencement of Fracturing

The proposed regulations contain two sections related to the disclosure of hydraulic fracturing chemicals. Section 25.283(a)(14) requires the operator to include information in the application regarding the name of the principal[3] fluids to be used and the estimated volumes to be used. This information would be provided to nearby landowners pursuant to Section 25.283(a)(1). A different section, 25.283(h)(2), requires the operator to report information about fracturing chemicals to the Commission within 30 days of completing fracturing. The information required by this section—which includes the amount and types of materials used at each stage, the additive type of each fluid used, the chemical ingredient name and the Chemical Abstracts Service (CAS) Registry number of each additive—is not necessarily reported to the nearby landowners.

We appreciate that Section 25.283(h)(2) would require disclosure of each fracturing chemical along with its CAS Registry number to the Commission. Disclosure of these chemicals is essential to determine the source of any subsequent groundwater or surface water or soil contamination, and to provide emergency responders, medical professionals, and the public with information needed to fully assess the risks associated with fracturing. Disclosure promotes operator responsibility, while calling attention to practices that could jeopardize the environment and public health.

The disclosure requirements for the post-fracturing report to the Commission under Section 25.283(h)(2), however, are not the same as the pre-fracturing disclosure requirements to the

[2] *See* Matthew McFeeley, *NRDC Issue Brief 12-06-A, State Hydraulic Fracturing Disclosure Rules and Enforcement: A Comparison* 7 (July 2012).

[3] The term "principle" in 25.283(a)(14) should probably be written as "principal."

public under Section 25.283(a)(14). In its current form, Section 25.283(a) would not require full chemical disclosure to affected members of the public prior to hydraulic fracturing.

Adequate *pre*-fracturing disclosure is important to allow owners and users of nearby water sources to conduct independent baseline water quality testing to determine if water resources are uncontaminated or if they contain any of the chemicals planned to be injected during hydraulic fracturing. If specific chemical data are not provided until after hydraulic fracturing, a concerned person would be unable to test for all potential chemicals that may be used. Without the ability to conduct effective baseline testing, it will be difficult if not impossible to establish causal responsibility when chemicals are discovered where they do not belong. Baseline testing avoids the defense that "the contamination was there before we arrived." If fracturing chemicals are safe, and leaks are unlikely, then there should be no resistance to pre-fracturing disclosure requirements.

Rather than requiring the information identified under Section 25.283(h) to be reported to the Commission only within 30 days after fracturing,[4] we suggest that this information be provided in the permit application and made available to the nearby landowners and the public under Section 25.283(a). Upon approval, a final copy of the permit should be provided to the nearby landowners and the public with sufficient time for them to conduct independent baseline testing, if they elect to exercise that option.

Additionally, Section 25.283(a) should state that the operator is limited to using the fracturing products identified in the approved well permit. If the operator is not limited to the chemicals listed in the approved well permit, there will be uncertainty as to whether sufficient baseline testing was achieved. If, after the initial permit is approved, the operator desires to use different or additional chemicals, the operator should submit a new notice and permit application, to give nearby water users the opportunity to respond to the new disclosures.

B. *Complete Disclosure of Fracturing Chemicals and Base Fluid Constituents*

While Section 25.283(h)(2) would require disclosure of the concentration of each additive, it does not solicit the concentration of each chemical constituent that makes up each additive. For example, an operator would have to indicate that a fluid contains 1% of Additive X, and that Additive X contains benzene, but would not have to indicate how much benzene is in Additive

[4] We assume that the 30-day timeframe is based on AS 31.05.030(d)(2)(A), which requires reports to be filed within 30 days after the completion, abandonment, or suspension of the well. Requiring reports to be filed in advance of well drilling would not violate this timeline, as it is *more* rather than *less* stringent, and would ensure that the Commission meets its duties under AS 31.05.030(j) to regulate hydraulic fracturing in nonconventional wells in order to protect drinking water quality.

X. We suggest that Sections 25.283(h)(2)(C) and 25.283(a)(14) be revised to require reporting of the concentration of each chemical constituent prior to fracturing.[5]

In other states, industry representatives have expressed unwarranted concerns that disclosing the concentration of chemical constituents, if linked to additive products, might allow competitors to reverse-engineer proprietary additive products. This risk is easily avoided by: (a) requiring the operator to report the concentrations of all chemicals (identified by CAS Registry number) used in a hydraulic fracturing treatment, but (b) not requiring that the chemicals be organized according to the additive of which they are a part. Such an approach would ease any proprietary concerns but nonetheless facilitate the necessary disclosure of both the individual chemical constituents used and their quantities.

Section 25.283(h)(2) would require reporting of each additive, but does not clearly require reporting of the base fluid.[6] We recommend requiring disclosure of the type and chemical composition of the base fluid (i.e., freshwater, seawater, recycled water, produced water, or other non-listed fluid) in addition to that of the additives. This ensures public awareness of any toxic or other chemicals that might be found in recycled water or other base fluids.[7] It also reveals the extent to which the operator is recycling wastewater or using produced water, for example, rather than relying on Alaska's freshwater resources. We also recommend that the operator be required to report the source of water (e.g., the GPS coordinates of the fresh or groundwater body from which it was extracted) or any other base fluid used so that the public can better understand the effect of an operation on local water resources.

C. Use of FracFocus

Section 25.283(i) would provide for information to be reported to the Interstate Oil and Gas Compact Commission/Groundwater Protection Council hydraulic fracturing web site (http://www.fracfocus.org), a website used by a number of states to provide disclosure. While FracFocus provides a user-friendly interface with a mapping function, it has a number of shortcomings (as described below). We do not recommend the use of FracFocus unless the

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[5] For each chemical, the operator should be required to provide the CAS Registry number as well as the percentage by mass of each chemical component. The percent mass values should be for the entire fracturing operation, not for the individual stages. *See* Wyo. Adm. Regs., Ch. 3, § 45(d); Ark. Rule B-19(m)(3).

[6] Section 25.283(a)(14) requires reporting of the "principle fluids," but it is not clear whether principle fluids are equivalent to base fluids.

[7] If produced water is used as a base fluid, naturally-occurring petroleum compounds or other impurities may be present. Wyoming's hydraulic fracturing regulations expressly recognize this concern, stating that: "[i]t is accepted practice to use produced water that may contain small amounts of naturally occurring petroleum distillates as well stimulation fluid in hydrocarbon bearing zones." Wyo. Adm. Regs., Ch. 3, § 45(g). While this may be an "accepted practice," any petroleum distillates and other impurities found in the base fluid should be fully disclosed.

Commission is able to work with the Interstate Oil and Gas Compact Commission/Groundwater Protection Council to resolve these problems.

First, the standardized disclosure form on FracFocus contains only a few fields of information. This means that not all the information required by the regulations would be submitted or displayed.

Second, it is not possible to easily search and aggregate data in FracFocus. The Natural Gas Subcommittee of the Secretary of Energy Advisory Board, which was directed by President Obama to make recommendations about improving the safety and environmental performance of hydraulic fracturing, recommended that disclosures be "posted on a publicly available website that includes tools for searching and aggregating data by chemical, well, by company, and by geography."[8] The Subcommittee found that one "limitation of FracFocus.org is that … there are no tools for aggregating data."[9]

Access to the database of information mandated for public disclosure and aggregation of search result data is important because it provides information such as how many wells are hydraulically fractured in a given area, or the total quantity of a given chemical used in that area, so that the environmental and health impacts of fracturing can be better understood. Providing access to aggregate data allows researchers, the public, and decision-makers to look beyond conditions at individual wells and make broader policy assessments about the relative risks presented by fracturing in a particular area, or with a particular chemical.

In addition to these technical limitations, FracFocus's terms of use purport to limit republication of the data provided on the site.[10] This restriction may limit the public's ability to share, discuss, study, and use information about what chemicals are being used and the risks posed.

Finally, FracFocus does not allow for disclosure prior to fracturing operations.

We recommend that the Commission upload the reports submitted by operators on the Commission's website and create a database that is searchable by geographic area, chemical, Chemical Abstract Service number, time period, and operator. For each well, the database should contain links to the permit application, permit, and other files so that all of the information related to the well may be accessed by the public. This database should be downloadable and permit and facilitate aggregation, reorganization, analysis, and redistribution of data.

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[8] Natural Gas Subcommittee of the Secretary of Energy Advisory Board, Interim Report, 24 (Aug. 18, 2011), *available at* http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.

[9] *Id.*

[10] http://fracfocus.org/terms-of-use, § 7.

Alternatively, the Commission should work with the Interstate Oil and Gas Compact Commission/Groundwater Protection Council to resolve the problems discussed above.

D. Right to Know

We are pleased to see that the proposed disclosure requirements do not suggest that any of the required chemical information may be withheld from the Commission or the public under the guise of protecting a trade secret. The public and those working with fracturing chemicals have a right to know what these chemicals are. To ensure that this right is protected, we suggest that the Commission declare that it will require public disclosure regardless of whether an operator considers the information to be a trade secret under the Alaska Uniform Trade Secrets Act.[11] AS § 31.05.035(a) gives the Commission broad authority to request subsurface information on a permitted well. AS § 31.05.090(b), which requires permit applications for wells to "include all information required by the commission," does not limit what information the Commission may require. To the extent any of that information may be proprietary, it is addressed by AS § 31.05.035(c), which specifies that required information may only be kept confidential from public disclosure if it "relate[s] to an exploratory or stratigraphic test well" *and* "the commission determines [it] contains proprietary engineering or geotechnical information."

Complete disclosure of all chemicals and techniques used in well stimulation is required to adequately protect the environment and public health. No trade secret exemptions should be allowed where doing so would be at the expense of public and workers' health. For instance, if the identities of certain chemicals are withheld, physicians may be unaware of certain chemicals to which a patient may have been exposed. This may make it difficult or impossible to accurately diagnose and treat the patient, or to understand the interactive effects that chemicals can have on a patient's health. Because complete information is necessary to "ensure that acute exposures are handled appropriately and to ensure that surveillance programs are optimized," the Pediatric Environmental Health Specialty Units, a network of experts in children's environmental health, have recommended full disclosure of all chemical information.[12] Chemical information is also needed by government regulators and industry to create safer products and by parents and

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[11] *See* Alaska Uniform Trade Secrets Act, AS §§ 45.50.910 - 45.50.945. Even when information may be considered proprietary, disclosure to the public has been upheld when authorized by law. *See, e.g., U.S. v. Geophysical Corp. of Alaska*, 732 F.2d 693, 702 (9th Cir. 1984). One example of a regulation that provides for disclosure of trade secrets is the Alaska Department of Environmental Conservation's (ADEC's) 18 AAC 31.015 (Confidentiality of trade secrets). Under this regulation, ADEC considers whether the public interest that would be served by disclosure is outweighed by the privacy interest in preserving the secret. ADEC has the authority to release information in an emergency. In the context of the public health and environmental risks posed by hydraulic fracturing, we believe that the balance of interests should always tilt in favor of full disclosure.

[12] Pediatric Environmental Health Specialty Units, *PEHSU Information on Natural Gas Extraction and Hydraulic Fracturing for Health Professionals* 3 (Aug. 2011) *available at*: aoec.org/pehsu/documents/hydraulic_fracturing_and_children_2011_health_prof.pdf.

community leaders to protect families from unnecessary toxic exposures. Trade secret exemptions undermine these purposes and put public health at risk.

To the extent the Commission may consider adopting a trade secret provision (though it should not), in no event should operators be excused from disclosure to the Commission itself. The Alaska Oil and Gas Conservation Act explicitly authorizes the Commission to require any and all "subsurface information on a well for which a permit to drill has been issued"[13] and the State Supreme Court likewise has recognized "AOGCC's authority to require well data and to use the data to prevent waste and protect health and safety."[14]

If the Commission develops a provision allowing operators to claim trade secret protection for reported information, the Commission should adopt companion requirements to ensure that any protected information actually constitutes a trade secret. Trade secret claims should be supported with specific factual justifications demonstrating entitlement to the exemption, similar to what is required under the Emergency Planning and Community Right-to-Know Act (EPCRA) regulations.[15] There also should be a clear process for evaluating each claim whereby the public can challenge decisions to preclude access to information.[16] These requirements would discourage questionable trade secret claims, helping to ensure that any trade secret protections are not exploited to avoid disclosure. Such requirements are also necessary under AS § 31.05.035(c), which specifies that the Commission itself must make a finding that information is proprietary before it can be withheld from presumptive public disclosure.

If any trade secret provision is adopted to limit disclosure, the Commission should also indicate the circumstances in which information deemed a trade secret can be revealed to the public. Information deemed a trade secret should remain on file with the Commission and should be immediately available to emergency responders and medical professionals.[17] This information would be critical to enable medical professionals and emergency responders to make an accurate diagnosis and provide proper treatment.

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[13] AS § 31.05.035.

[14] *State Dep't of Natural Res. v. Arctic Slope Reg. Corp*., 834 P.2d 134, 140, 143 (Alaska 1991).

[15] *See* 40 C.F.R. § 350.7 (substantiating claims of trade secrecy); Ark. Rule B-19(l)(8) (adopting trade secret criteria in EPCRA, 42 U.S.C. § 11042). Wyoming regulations also require applicants to justify and document the nature and extent of the proprietary information in connection with fracturing chemicals. *See* Wyo. Adm. Regs., Ch. 3, § 45(d) (reporting requirements) and § 45(f) (referring to confidentiality protection afforded under the Wyoming Public Records Act, Wyo. Stat. § 16-4-203(d)(v)).

[16] *See, e.g.*, 40 C.F.R. § 350.15 (public petitions requesting disclosure of chemical identity claimed as trade secret).

[17] *See, e.g.*, 16 Texas Admin. Code § 3.29(c)(4) (allowing access to hydraulic fracturing trade secret information by health professionals and emergency responders). Even when information may be considered proprietary, disclosure to the public has been upheld when authorized by law. *See, e.g.*, *Geophysical Corp. of Alaska*, 732 F.2d at 702.

Even in a non-emergency, at a minimum, the chemical family of each substance considered a trade secret should be disclosed to the public.[18] This would provide basic information to the public about the chemicals.

II. Notifying Stakeholders

In the event of a blowout[19] and/or water contamination, effects are likely to be felt beyond a quarter-mile from the well by all the people who make use of the land—not just owners. The parameters in proposed Section 25.283(a) should be expanded so owners and residents within one-half mile of the wellbore trajectory, along with any local governments (including tribal governments) within 20 miles of a regulated well would receive advance notification of fracturing operations. Notification also should be posted on the Commission's website. The notification should include the chemical disclosures discussed above in Part I of these comments and information on water quality and the timing of pre-testing and fracturing operations.

III. Protecting Water

A. Sampling and Monitoring

We support the Commission's proposal under Section 25.283(a)(5) to require the operator to conduct water sampling of nearby water wells prior to hydraulic fracturing in order to collect baseline data, and after hydraulic fracturing to verify that freshwater contamination did not occur.

We suggest that the language of Section 25.283(a)(5) be revised to provide clear timelines for the water testing. The Commission should require baseline testing of nearby water wells prior to fracturing but not more than 90 days prior, and should require post-fracturing water well testing to occur within 90 days. Thereafter, testing should continue quarterly for a period of five years and then annually through year 20.

Further, Section 25.283(a)(5) should be revised to include radium and barium. These naturally-occurring radioactive materials have been found in produced water from fracturing operations in

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[18] *See, e.g.*, Colo. Oil and Gas Conservation Comm'n Rule 205A.b.2.B (requiring disclosure of the chemical family where the chemical identity of a hydraulic fracturing additive is withheld).

[19] A blowout on a well using fracturing chemicals could lead to the contamination of nearby lands and waters with toxic chemicals. Such a scenario is not just hypothetical. On April 19, 2011, in Bradford County, Pennsylvania, one of Chesapeake Energy Corporation's many fracturing wells had a catastrophic blowout, leading to contamination of nearby land and waterways with thousands of gallons of chemically-laden water. *See* Gas Well Spews Polluted Water, N.Y. TIMES, Apri121, 2011, at Al4. Since more wells will be used for shale fracturing than for conventional oil and gas, the risk of blowout may be higher for equivalent production.

Pennsylvania.[20] If these materials are present in produced water, additional precautions would need to be taken in connection with disposal.

Section 25.283(a)(5) also should indicate which wells need to be tested. We suggest that all wells within one-quarter mile radius from the wellbore trajectory be tested.

We recommend that the report results be made available on a publicly accessible website and provided directly to well owners and well users, along with a report summarizing the sample findings. We also recommend an immediate reporting obligation to notify the Commission, the Departments of Environmental Conservation and Natural Resources, well owners, and well users of any significant deviation from a baseline concentration.

In areas where water wells do not exist, but groundwater resources may serve as a drinking water supply or for agricultural use, operators should be required to propose and install a groundwater monitoring system.

In addition to monitoring water quality, operators are required under the current 20 AAC 25.230 to report produced oil, gas, and water monthly to the Commission. We recommend that operators also report the annular, tubing, and casing pressure of each well[21] to the Commission (see also Part III of these comments).

For the sake of clarity, we suggest that water monitoring requirements be placed in a new subsection (i.e., 25.283(j)), rather than being grouped with the list of items in Section 25.283(a) that must be submitted in the application.

B. Definition of Freshwater

Hydraulic fracturing operations pose a risk of contaminating subsurface water resources in Alaska that may serve as a current or future source of drinking water or be used for agriculture or fish and wildlife habitat. The Commission's current regulations generally define freshwater to include drinking water, but not water used for purposes such as agriculture.[22] Likewise, the

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[20] *See* Pennsylvania Department of Environmental Protection, DEP Announces Comprehensive Oil and Gas Development Radiation Study (Jan. 24, 2013), http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=19827&typeid=1; Analysis of Marcellus flowback finds high levels of ancient brines, Penn State News (Dec.17, 2012) http://news.psu.edu/story/143694/2012/12/17/analysis-marcellus-flowback-finds-high-levels-ancient-brines.

[21] These monitoring requirements are modeled after those in Section 1787 of the Pre-Rulemaking Discussion Draft released by the California Department of Conservation, Division of Oil, Gas and Geothermal Resources on December 18, 2012, *available at* http://www.conservation.ca.gov/dog/general_information/Documents/121712DiscussionDraftofHFRegs.pdf .

[22] *See* 20 AAC § 25.990 (27) (defining "freshwater" as waters with a total dissolved solids concentration of less than 10,000 mg/l and water that occurs in a stratum not exempted under the Freshwater Aquifer Exemption (20 AAC §

Commission requires surface casing to be: “set below the base of all strata known or reasonably expected to serve as a source of drinking water for human consumption …” 20 AAC § 25.030(c)(3). This means that water sources for purposes other than drinking water (namely agriculture and fish and wildlife habitat) are not protected from fracturing.

We recommend that the regulations at 20 AAC § 25.990(27), 20 AAC § 25.030(c)(3), and 20 AAC § 25.440 be amended to clarify that Alaska’s protected freshwater sources include all waters that may serve as a current or future source of drinking water, as well as waters used for agriculture, fish and wildlife, and other purposes requiring freshwater. This change is particularly important to protect freshwater sources in Alaska’s agricultural and farming areas, such as the Matanuska Valley, where hydraulic fracturing may occur. Due to rapid warming of permafrost in Alaska, changes that affect hydrological systems and potential effects on freshwater systems are taking place. Accordingly, clarifying the breadth of Alaska’s protected freshwater sources is especially warranted to give attention in areas of discontinuous permafrost where increased conduits through an already complex hydrological system could dramatically increase as a result of hydraulic fracturing

C. Locating Freshwater

Accurately determining the depth of aquifers containing freshwater is important to ensure that surface casing is set deep enough to protect the water from contamination. Section 25.283(a)(11) requires an applicant to indicate the depth to the bottom of all freshwater aquifers, but does not require the applicant to demonstrate the basis for determining this depth. We recommend that applicants be required to submit scientific and technical data showing the method and information used to establish the depth.

Where adequate scientific and technical data exist to define the protected freshwater interval in an operating field or a region, it may be efficient for an applicant to provide a single scientific and technical assessment that can be reviewed and approved by the Commission, and referenced in subsequent well applications. In the absence of these data, the Commission should require the operator to verify the freshwater depth by using a resistivity log or by sampling during drilling operations.

D. Well Construction – Surface Casing Setting Depth

Surface casing plays an important role in protecting freshwater aquifers by providing the structure to support blowout prevention equipment and a conduit for drilling fluids while drilling

25.440), or occurs in a stratum that serves as a source of drinking water for human consumption). The Freshwater Aquifer Exemption at 20 AAC § 25.440 allows the Commission to exempt certain freshwater zones from protection from during fracturing operations if the water source does not currently provide drinking water or be expected to in the future, or if the water is contaminated or contains commercially producible hydrocarbons.

the next section of a well. Surface casing should stop above any significant pressure or hydrocarbon zone, ensuring that the blowout preventer can be installed and the surface casing can be cemented into place prior to drilling into a pressure or hydrocarbon zone. Surface casing should provide a protective barrier to prevent hydrocarbons from contaminating aquifers when the well is drilled below the surface casing into a hydrocarbon-bearing zone.

Section 25.030(c)(3) requires surface casing to be: "set below the base of all strata known or reasonably expected to serve as a source of drinking water for human consumption and at a depth to provide a competent anchor for [blowout prevention equipment]." This means that surface casing must be installed below the base of freshwater, but there is no requirement for an additional length of surface casing and cement to provide a margin of safety. We recommend that the Commission revise the regulation by requiring surface casing to be installed and cemented at least 100 feet below the base of freshwater so as to provide an additional safety margin for drinking water as well as freshwater used for other purposes such as agriculture.

E. Well Construction – Intermediate Casing Setting Depth

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards.

Intermediate casing also may be needed to isolate freshwater resources if surface casing alone is not sufficient. For example, if surface casing must be set above the base of freshwater to install the blowout preventer for safety reasons, or if surface casing was set prematurely and continued drilling below the surface casing finds additional freshwater intervals, intermediate casing must be set across any exposed freshwater interval and cemented in place to protect that zone.

Section 25.030(c)(4) requires intermediate casing to be "set if required for protection of oil or gas or for protection against abnormally geo-pressured strata and lost circulation zones, or if otherwise required by well conditions." Intermediate casing currently is not specifically required to be set in the event that surface casing was set at a depth above the base of the protected freshwater interval. We recommend that the Commission revise its regulations by requiring intermediate casing to be installed and cemented at least 100 feet below the base of freshwater in cases where freshwater protection was not achieved by surface casing.

F. Drilling Fluid Use

The Commission has drilling fluid system standards at Section 25.033, but these standards do not currently include a requirement to use non-toxic drilling fluids. While we recognize that the Commission has set limits on drilling fluid system types in some permits to drill with the goal of freshwater protection, we recommend that this requirement be included in a statewide standard applicable to all permits to drill.

Section 25.033 should be revised to clarify that drilling fluids must be Water-Based Muds (WBM) containing only non-toxic additives[23] or air drilling (where technically feasible and safe), and that Oil-Based Muds (OBM) and Synthetic-Based Muds (SBM) are prohibited.

OBM contain diesel or other hydrocarbons. SBM use synthetic oil. SBM are less harmful than OBM, but still contain toxic materials that bio-accumulate and do not biodegrade.

IV. Well Integrity

A. Casing and Cementing

The Commission currently regulates the casing and cementing of wells under Section 25.030. Casing and cementing provide a protective seal and conduit for hydraulic fracturing fluids to be injected into targeted hydrocarbon formations and to be isolated from fresh water. Wells that will be subjected to the additional risk of hydraulic fracturing injection pressures should have a robust casing and cementing design, and the Commission should pay particular attention to well integrity for existing, older wells where hydraulic fracturing will occur.

We recommend that the Commission incorporate the following best practice measures into Section 25.030 for hydraulic fracturing wells and, ideally, for conventional wells:

a. *New Conductor, Surface and Intermediate Casing*: To maximize casing life and corrosion allowance, all conductor, surface and intermediate casing should be new.
b. *Excess Cement Requirements*: A minimum of 25% excess cement should be used to ensure the annulus is completely filled with cement with no void spaces, unless a caliper log is run to more accurately assess hole shape and required cement volume.
c. *Cement Sheath Width*: A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. Casing should be centralized (American Petroleum Institute RP 10D-2).
d. *Cement Type*: The cement should conform to API Specification 10A, Specifications for Cement and Material for Well Cementing, and contain a gas-block additive. It should include additives in areas where carbon dioxide (CO_2) and hydrogen sulfide (H_2S), and other lithological and physical conditions exist around the wellbore to protect the casing from corrosion and the cement from subsequent deterioration, and to resist degradation by chemical and physical conditions anticipated in the well.
e. *Cement Mix Water Temperature and pH Monitoring*: Free water separation should average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B, and pH and water chemistry should be monitored to ensure cement is mixed to manufacturers' recommendations.

[23] Any additives required for safe drilling through the groundwater interval with WBM should be limited to non-toxic additives that are biodegradable and do not bio-accumulate.

f. *Spacer Fluids and Wellbore Conditioning*: Spacer fluids should be used to separate mud and cement, to avoid mud contamination of the cement. The wellbore should be conditioned before cementing. Drilling fluids should be circulated and conditioned for a minimum of two wellbore volumes; adjusting drilling fluid rheology to optimize conditions for displacement of the drilling fluid and ensuring that the wellbore is static and that all gas flows are killed.

g. *Cement Installation and Pump Rate*: Cement should be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus. Float valves must be used and verified to be capable of preventing cement backflow in the drill string. Casing should be rotated and reciprocated during cementing.

h. *Cement Setting Time*: Surface casing strings should stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.

i. *State Inspectors*: A state inspector should be on site during cementing operations to verify surface casing cement is correctly installed and to oversee remedial cementing operations when required.

j. *Cement Quality Control*: A cement evaluation tool and a temperature survey should be run to verify cement placement.[24]

B. Wellbore Integrity Monitoring for Corrosion and Erosion

We recommend that the Commission consider revising Article 3, Production Practices (20 AAC §25.200 - 25.290) to supplement its well casing program with a corrosion and erosion control program.

Well casing, once installed and cemented into place, will remain in the well for its entire life and is often abandoned in place. It is in an operator's economic interest to ensure that its casing investment is protected from corrosion and erosion. Delayed attention to corrosion and erosion can result in increased safety, environmental, and human health risks. Failures of equipment handling or producing natural gas occur in the absence of an adequate corrosion control program. For example:

- Casing corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings,

[24] Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only quality assurance check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids in the cement column. Circulating cement to the surface also may not identify poor cement-to-casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and a temperature survey.

and valves. Corroded well casings can provide a pathway for gas and well fluids to leak into protected aquifers.

- Corrosive fluids are known to degrade the quality of a cement barrier. They can reduce cement strength and make it more permeable, providing a potential pathway for hydrocarbons to migrate from zones of higher pressure to lower pressure freshwater zones.
- The bond between the casing and cement can be compromised over a well's life, creating a "micro-annulus" (a space between the outer pipe wall and cement sheath) that allows vertical migration of hydrocarbons along the outside of a pipe wall. Micro-annuli can be formed during initial cementing, or later in a well's life due to pipe wall thinning, cement deterioration, the shock of additional well workover activities (perforations, stimulation, drilling), pressure and temperature changes in the well, or by seismic vibrations.

It is important to install a robust casing system and ensure that the integrity of the system is maintained throughout the life of a well. Chemicals, metallurgy, monitoring, and repair techniques are available to an operator to manage corrosion and erosion downhole (i.e., in the well) and at its surface facilities (e.g. corrosion inhibitors, cathodic protection systems, and coatings). Corrosion and erosion programs that are instituted early can prolong the life of equipment and well casings, and reduce environmental risks. A successful program includes: (1) anticipation of corrosion in design factors for all equipment, (2) detection of corrosion within the system and measurement of its severity for future reference, (3) use of mitigation measures, and (4) continual follow-up and adjustment of control techniques.

We recommend that the Commission require equipment to be designed to prevent corrosion and erosion. Monitoring programs should be required to identify corrosion and erosion over the well and equipment operating lifetime. Finally, operators should be required to repair and replace damaged wells and equipment.

C. Timing of Pressure Testing

We support the proposal in Section 25.283(b) and (c) to ensure a well casing's ability to withstand the maximum fracture treatment, plus a 10% safety factor, but a time frame for this testing was not included. We recommend that the proposed regulation specify that this pressure testing be successfully completed *prior* to hydraulic fracturing.

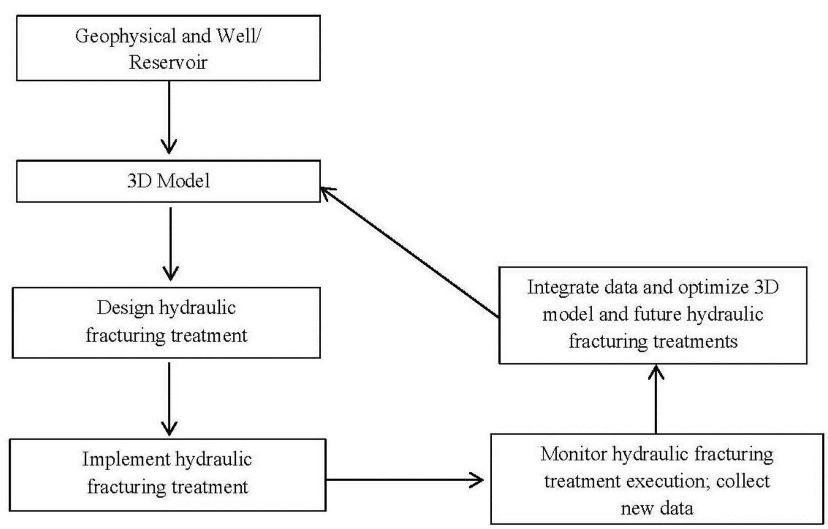
D. Fracturing Models and Fracture Performance Monitoring and Verification

Section 25.283(a)(14)(F) would require an operator to indicate the designed height and length of the proposed fracture(s), including the calculated measured depth (MD) and true vertical depth (TVD) of the top of the fracture(s). We support the proposed requirement to provide these data, however we recommend that the Commission set a technical standard for computing these estimates using a high-quality, three-dimensional reservoir model. This will prevent rough estimates and "back-of-the-envelope" calculations from being submitted and require an applicant to develop estimates using the best scientific data and technology available.

More specifically, we recommend that an applicant be required to

1. Collect geophysical and reservoir data to support a reservoir simulation model;
2. Use those data to develop a high-quality 3D[25] reservoir model(s) to safely design fracture treatments;
3. Maintain and run hydraulic fracturing models prior to each fracture treatment to ensure that fractures are contained in the targeted zone;
4. Design the hydraulic fracturing to mitigate vertical propagation out-of-zone and prevent fractures from intersecting with existing, improperly constructed and improperly abandoned wells and transmissive faults and fractures, which can provide pollutants a direct pathway to groundwater resources;
5. Ensure there is a sufficiently large vertical buffer between the base of the deepest freshwater interval in the area and the top of the maximum estimated vertical fracture and an intervening confining layer to prevent fresh water contamination by collecting and evaluating new data and rerunning the 3D reservoir model if necessary; and
6. Estimate the maximum vertical and horizontal fracture propagation length for each well, and submit technical information (e.g., model outputs) with an application to support the computations.

The modeling process is shown in the following flowchart:



We also recommend that an operator be required to do the following in connection with the post-hydraulic fracturing reporting requirements under proposed Section 25.283(h):

[25] Ideally, the models would be "4D," with time as the fourth dimension.

1. Collect and carefully analyze data from hydraulic fracturing to calibrate the 3D model and optimize future treatments;
2. Explain whether the predicted vertical and horizontal fracture propagation lengths were accurate, or note discrepancies;
3. Certify that the actual hydraulic fracturing was implemented safely, and fracture propagations did not intersect protected aquifers or nearby wells; and
4. Immediately notify the Commission if the actual vertical and/or horizontal fracture length exceeds the job design since a risk may be present to the environment.

E. Pressure Limit

Section 25.283(f-g) would require pressure monitoring during hydraulic fracturing to prevent casing and cementing damage and to identify pressures that may damage wellbore integrity. We recommend that this regulation provide more specific instruction to an operator on how to monitor well pressure, when to shut down fracturing, and how to take remedial action when a problem arises.

The operator should be required to monitor all wellbore annuli during hydraulic fracturing and report any surface casing pressure change that is 20% greater than the calculated pressure increase due to thermal expansion, or a pressure that exceeds 80% of the American Petroleum Institute-rated minimum internal yield on any casing string in communication with the hydraulic fracturing treatment.

If the fracturing treatment design does not allow the surface casing annulus to be open to atmospheric pressure, then the surface casing pressures should be monitored with a gauge and a pressure relief device. The maximum set pressure on a relief device should be a pressure change that is 20% of the calculated pressure increase due to thermal expansion.

The fracturing treatment should be terminated if pressures are observed in the surface casing annulus that exceed expected increased pressure due to thermal expansion or if pressures on any casing string exceed 80% of the API-rated minimum internal yield pressure for such a casing string throughout the treatment.

If, during a fracturing treatment, the operator has reason to suspect any potential failure of the production casing, the production casing cement, or the isolation of any sources of freshwater due to excessive fracture height growth or the intersection of a hydraulically-induced fracture with a transmissive fault or offset wellbore that causes an increase in annular pressure in such offset wellbore, then the operator should be required to immediately discontinue the treatment, notify the Commission, and perform diagnostic testing on the well as needed to determine whether such a failure has actually occurred. The diagnostic testing should be required to take place as soon as reasonably practical after the operator has reasonable cause to suspect any such failure. If the testing reveals that a failure has occurred, then the operator should be required to shut in the well, isolate the perforated interval, and notify the Commission as soon as reasonably practical.

F. Well Monitoring Post-Hydraulic Fracturing

We recommend that the Commission consider adding the following post-hydraulic fracturing monitoring requirements to Section 25.283:

1. Each well should be carefully monitored on a daily basis for the first 30 days and monthly thereafter, to identify any potential problems with the well's operation or integrity that could endanger water sources or pose a health, safety or environmental risk. Immediate action should be taken to remedy the problem and notify the Commission.
2. All surface wellhead control system equipment should be maintained and tested at least quarterly to ensure pressure control is maintained throughout the life of the well.
3. Tubing and casing pressure should be monitored at each well at least quarterly and reported to the Commission within 7 days. If annular overpressure is observed, immediate action should be taken to remedy the overpressure situation, notify the Commission, and institute a daily monitoring program until the Commission specifies otherwise.
4. Each well should be monitored at least weekly for surface equipment corrosion, equipment deterioration, hydrocarbon releases or changes in well characteristics that could potentially indicate a deficiency in the wellhead, tree and related surface control equipment, production casing, intermediate casing, surface casing, tubing, cement, packers, or any other aspect of well integrity necessary to ensure isolation of any underground sources of water and prevent any other health, safety or environmental concern. Immediate action should be taken to remedy any deficiencies found and notify the Commission.
5. A casing inspection log, temperature log, and mechanical integrity test should be run in each well at least once every 5 years and reported to the Commission within 7 days. Immediate action should be taken to remedy any deficiencies found and notify the Commission.

V. Flaring

The Commission currently regulates gas disposition under Section 25.235. This section requires reporting as to whether gas is flared or vented, including the volume flared or vented and efforts to minimize the volume of gas vented, burned, or otherwise permitted to escape into the air. Flaring or venting is considered waste, unless it does not exceed one hour and is authorized for safety purposes. But Section 25.235 does not actually require flaring to be minimized or emissions to be reduced—operators simply have to track their waste and justify why it occurred.

Flaring wastes natural gas resources wherever it occurs, even while the central parts of Alaska are in great need of cleaner sources. Flaring also produces air pollutants that are detrimental to air quality and climate. The carbon dioxide (CO_2) emissions from flares are well-quantified and a significant contributor to global climate pollution.[26] Other pollutants from flares are not well-quantified, but flares can produce large amounts of carbon monoxide (CO), volatile organic compounds (VOC), unburned methane, nitrogen oxides (NO_x), black carbon (BC), and other particulate matter, at least under some conditions. BC, the sooty particulate produced by incomplete combustion, is a climate pollutant of particular concern. BC is possibly the second most important climate pollutant, behind only carbon dioxide.[27] BC is particularly damaging to the climate when it is emitted in cold areas with significant snow cover such as Alaska. BC settles out of the atmosphere onto snow and ice, where the dark BC absorbs sunlight that would otherwise be reflected from the surface, warming it and accelerating the melting of snow and ice.[28]

When natural gas is produced at oil wells with no pipeline to carry the gas to a market, the gas is often flared off as a waste product. In some U.S. locations, gas associated with oil wells is flared from wells for months, or even over a year.[29] Such flaring may be prevalent at oil wells in shale formations for two reasons. First, re-injecting natural gas back into these formations may not be feasible. Second, geological formations which produce oil after hydraulic fracturing also typically produce significant amounts of natural gas.[30] Flaring of associated gas from shale formations is a common practice in North Dakota's Williston Basin, where oil well development has outpaced the building of pipelines to accept associated natural gas from those wells. Currently, about 30% of the natural gas produced in North Dakota—over six billion cubic feet *per month*—is flared off, producing significant air pollution.[31]

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[26] World Bank, Global Gas Flaring Reduction, http://go.worldbank.org/016TLXI7N0 (last visited Mar. 27, 2013).

[27] T.C. Bond *et al.*, "Bounding the role of black carbon in the climate system: A scientific assessment." Journal *of Geophysical Research-Atmospheres*, (2013) DOI: 10.1002/jgrd.50171, *available at:* http://onlinelibrary.wiley.com/doi/10.1002/jgrd.50171/abstract.

[28] P.K. Quinn *et al.*, *The Impact of Black Carbon on Arctic Climate* (2011). Arctic Monitoring and Assessment Programme (AMAP), Oslo. 72 pp, *available at*: http://amap.no/documents/index.cfm?action=getfile&dirsub=&filename=89439%5Fimpact%20of%20black%20carbon%5FLO%5FFFINAL.pdf&sort=default.

[29] Energy Information Administration, "Over one-third of natural gas produced in North Dakota is flared or otherwise not marketed." *Today In Energy*, (Nov. 23, 2011), *available at*: http://www.eia.gov/todayinenergy/detail.cfm?id=4030#.

[30] We are not aware of any shale oil formation that does not produce significant gas. EPA noted in the recent Federal Implementation Plan for the Fort Berthold Indian Reservations that producing lighter crude oil from tight formations such as the Bakken "has greater potential to produce natural gas in addition to oil," relative to conventional wells. *See* EPA, Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations) ND, 77 Fed. Reg. 48,878, 48,883.

[31] Calculation by Clean Air Task Force based on North Dakota Industrial Commission data for 2012 (available at: https://www.dmr.nd.gov/oilgas/stats/Gas1990ToPresent.pdf) adjusted with figures from US Energy Information Administration for removal of non-hydrocarbon gases (available at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_snd_a.htm).

The Commission should limit flaring and venting to the smallest amount needed for safety, and require operators to implement technically feasible and cost-effective gas control practices during hydraulic fracturing operations and during production from hydraulically fractured oil wells. Given the isolation of some shale oil formations in Alaska and the significant distance between those formations and markets for natural gas, the Commission needs to ensure that venting and flaring of associated gas during future oil production from fractured wells does not occur. Natural gas must not be wastefully vented or flared in Alaska.

A number of approaches and technologies exist to utilize natural gas on or near gas wells to avoid venting and flaring. Pipelines connecting wells to consumers of natural gas are the most straightforward approach to utilize gas, and some jurisdictions prohibit using the lack of a pipeline as justification to flare.[32] If pipelines are very costly, the Commission should investigate whether injection of gas into geological formations, including, but not limited to the producing formation, is feasible. Additionally, gas should be utilized at or near wells for electrical generation or for engines used in drilling, fracturing, trucking, or pipelines. Liquefying or compressing gas for transport to parts of the state where it is needed also should be investigated. Finally, the volume of "stranded" gas can be reduced by separating condensable liquids from associated gas for sale or injection into oil, with equipment powered by the residual dry gas. The Commission should require approaches such as these to avoid flaring.

We further suggest that operators be required to implement Reduced Emission Completions (RECs), also called "green completions," wherever technically feasible.[33] The Environmental Protection Agency's (EPA's) Natural Gas Star Program identifies green completions as a proven technology to mitigate air pollution caused by the flaring and venting of waste gas during hydraulic fracturing flowback operations.[34] EPA's recent New Source Performance Standards for Oil and Natural Gas (40 CFR Part 60, Subpart OOOO)[35] require REC use on most hydraulically fractured natural gas wells[36] beginning on January 1, 2015.

[32] Wyoming's application for a well completion permit states, "Unacceptable reasons for flaring or venting hydrocarbon fluids associated with completions and re-completion activities [include] lack of a pipeline connection due to reasons other than wildcat, exploratory or step-out well classification." *See*: State of Wyoming, Dept. of Environmental Quality – Air Quality Division, *Well Completions / Re-completions Permit Application* (Form AQD-OG11) (August 2010) at 2. *Available at*: http://deq.state.wy.us/aqd/Oil%20and%20Gas/AQD-OG11_Green%20Completion%20Application.pdf.

[33] A green completion requires the operator to bring in gas processing equipment to a well pad to clean up wet gas, improving it to gas pipeline quality. Typically, portable gas dehydration units, gas-liquid-sand separator traps, and additional tanks are required. Most companies report a one-to-two-year payout for investment in their own green completion equipment, and substantial profit thereafter, depending on the gas flow rate. *See* Susan Harvey, *et al.*, Leaking Profits, The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste (2012), *at* http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

[34] http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf.

[35] EPA, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

[36] Low-pressure wells, exploratory wells, and delineation wells are exempted from the REC requirement that comes into effect in 2015.

We recommend the following specific measures to strictly limit flaring of natural gas:

- Require drilling and well completion operations to be coordinated with gas transmission pipeline installation if applicable, facilitating green completions for all wells drilled subsequent to an initial exploration well;
- Set limits on the maximum amount of gas that can be flared per well;
- Specifically define other "operational requirements" justifying gas flaring, and limit flaring to the amount required for emergency or safety purposes only (that which cannot otherwise be eliminated by prudent operational planning);
- Limit planned[37] flaring during gas production to the smallest amount possible and allow even that amount only for purposes of safety. A minimum flare efficiency of 98% should be achieved;
- Require any gas not collected for sale, used as fuel by producers for oil or gas operations, or re-injected be made available to local residents as an affordable fuel supply; and
- In the event that flaring is allowed, require economic study of all options for productive use of gas and transport of gas to appropriate locations for re-injection before allowing any routine flaring of natural gas, especially flaring of associated gas during oil production.

Where RECs or other use of gas is not possible, we recommend that the Commission require carefully controlled gas flaring as an environmentally preferable alternative over venting, because flaring can reduce hazardous air pollutants, volatile organic compound emissions, and greenhouse gas emissions.

More specifically, we recommend the following to strictly limit venting of natural gas:

- Prohibit intentional, planned gas venting from wells, unless it occurs during an unavoidable emergency well control event;
- Require green completion equipment to capture gas and liquids coming out of wells as they are being drilled, repaired, or stimulated during hydraulic fracturing;
- If green completions are not technically feasible, require that all gas released during the allowed 48- and 24-hour periods for completion, stimulation, or workover be routed through a flare;
- Set limits on the maximum amount of gas that can be vented per well; and
- Specifically define other "operational requirements" justifying gas venting, and limit gas venting to the amount required for emergency or safety purposes only (that which cannot otherwise be eliminated by prudent operational planning).

[37] There is a difference between planned flaring and emergency flaring. Emergency flaring is conducted to safely route combustible and potentially toxic gas (e.g. hydrogen sulfide gas) and in most cases cannot be avoided. Planned flaring can be avoided in most cases.

When flaring is necessary for safety, operators should be required to undertake the following best practices:

1. Minimize the risk of flare pilot blowout by installing a reliable flare system;
2. Ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams;
3. Ensure use of a reliable ignition system;
4. Minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and
5. Maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates.

The reports on flaring and venting required under Section 25.235 (Gas Disposition) should be made available to the public through the Commission's website, so that the quantity of natural resources wasted in this manner is available to the public.

VI. Vertical Buffers

Vertical fractures that extend above or below a hydrocarbon zone will decrease recovery rates by allowing vertical migration into nearby strata, or by allowing water influx from aquifers above or below the shale. Section 25.283(e) aims to avoid such out-of-zone fractures by requiring all fracturing fluids to be confined to the approved formations. To further avoid out-of-zone fracturing, we suggest that the regulations provide an additional margin of safety. We recommend that Section 25.283(e) limit the maximum vertical fracture to be less than the total vertical height of the hydrocarbon zone, leaving an un-fractured "vertical buffer"—at the top of the hydrocarbon zone and at the base of the hydrocarbon zone. This will provide a margin of safety at the top of the zone and the base of the zone to ensure fractures are confined to the approved formation to be hydraulically fractured. Buffer size should increase with geologic and technical uncertainty.

VII. Storage, Handling, and Disposal

The proposed regulations contain limited details on the requirements for storage, handling, and disposal of fracturing fluids. While much of the storage, handling, and disposal of waste associated with drilling is regulated by other agencies (see the Appendix), Alaska statutes do give the Commission a role in waste regulation.[38]

[38] *See* AS 31.05.030(e) (including in the powers and duties of the Commission "the disposal of salt water, nonpotable water, and oil field wastes," "the contamination or waste of underground water," and "the disposal of drilling mud, cuttings, and nonhazardous drilling operation wastes in the annular space of a well for which a permit to drill has been issued by the commission"); AS 31.05.030(j) "For exploration and development operations involving nonconventional gas, the commission (2) shall (A) regulate hydraulic fracturing in nonconventional gas wells to ensure protection of drinking water quality; (B) regulate the disposal of wastes produced from the

We recommend that the Commission's proposed regulations be revised to address storage, handling, and disposal of fracturing fluids. Where the Commission finds it more efficient or appropriate to include these requirements under the authority of another state agency, we recommend that the Commission identify the regulatory gap and work with that state agency to enhance its regulations.

A. Chemical Storage

All hydraulic fracturing chemicals should be stored in secondary containment, or in double-wall tanks. Chemicals, especially corrosive chemicals, can result in storage container leaks and spills to the environment. The best practice for chemical storage is to install secondary containment under the storage container, and ensure the containers are not in contact with soil or standing water.[39]

B. Surface Impoundments

The use of temporary surface impoundments results in surface disturbances and provides an opportunity for wildlife to become contaminated and injured. Surface impoundments also have the potential for leakage to occur through or around the liner, or for overflow to occur during periods of heavy precipitation, impacting surface waters and the subsurface and creating substantial amounts of hazardous air pollution.

The best practice for hydraulic fracturing chemical use and waste storage is to bring the hydraulic fracturing chemicals to the well site in tanks, combine the chemicals with water onsite in closed-loop tank and piping systems, inject the mixture into the well during fracturing, and capture fracturing fluid waste at the surface in closed-loop tank and piping systems for transportation to a waste injection well, certified waste treatment and disposal facility, or to another well for reuse. The use of surface impoundments should be eliminated altogether.[40]

Where impoundments continue to exist, regulations should require the use of impermeable, chemical resistant liner material as well as fencing and netting to prevent wildlife access.

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operations unless the disposal is otherwise subject to regulation by the Department of Environmental Conservation or the United States Environmental Protection Agency …").

The Commission has acted on these powers and duties to implement 20 AAC 25.252 (Underground disposal of oil field wastes and underground storage of hydrocarbons), 20 AAC 25.235 (Gas disposition), and 20 AAC 25.528 (Open pit storage of oil).

[39] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.

[40] The Bureau of Land Management recommends the use of closed loop tank systems whenever possible. *Id.*

C. Waste Injection

All hydraulic fracturing chemical waste and flowback waters that are not recycled should be collected and injected into an EPA-approved subsurface disposal well. If disposal well injection is not technically feasible or unsafe to freshwater resources, the hydraulic fracturing fluid waste should be collected and transported via closed-loop tank and piping systems to a waste handling and treatment facility that is certified, trained, equipped, and qualified to treat and dispose of this waste.[41]

VIII. Risk of Induced Earthquakes

Wastewater injection activities—many associated with hydraulic fracturing—in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas have induced seismicity at levels that are noticeable to the public.[42] Induced earthquakes are a concern in Alaska, where many areas are already earthquake-prone. We suggest that the Commission consider the risk of induced seismic events in formulating regulations.

We suggest that the Commission amend Section 25.252(c) (Underground disposal of oil field wastes and underground storage of hydrocarbons) by adding a subsection that requires disposal or storage operations not increase seismic events above background levels. The National Research Council report cited above provides suggestions on developing appropriate regulations to address induced earthquakes, regulations which are now under consideration in Illinois.[43]

IX. Definitions

Some of the terms in the proposed regulations would benefit from additional clarification. We suggest that the following terms be defined in Section 25.990:

- "wellbore trajectory" in proposed Section 25.283(a)(1) and (2); and
- "principle fluid" in proposed Section 25.283(a)(14).

[41] This would ensure that the Commission meets its duties under AS 31.05.030(j)(2)(B) to regulate the disposal of wastes produced from nonconventional gas operations (unless the disposal is otherwise subject to regulation by ADEC or EPA).

[42] National Research Council, *Induced Seismicity Potential in Energy Technologies*, Advance Copy (June 15, 2012), *available at* http://i2.cdn.turner.com/cnn/2012/images/06/15/induced.seismicity.prepublication.pdf.

[43] *See id; see also* Mike Soraghan, Earthquakes: States deciding not to look at seismic risks of drilling, E&E (Mar. 25, 2013), at http://www.eenews.net/public/energywire/2013/03/25/1 (noting that a 2012 National Academy of Sciences panel recommended that oil and gas regulators take steps to prevent man-made earthquakes).

X. Miscellaneous Comments

Our organizations request that the Commission consider the following issues in its future work:

1) *Using compliance records from Alaska, other states, and other countries to evaluate potential "bad actors."* The Commission could require in its application process that operators provide all compliance records as a condition of permitting. Operators with poor records then could be denied well permits.
2) *Provide a 30-day public comment opportunity for all high-volume hydraulic fracturing applications and all variance/waiver requests.*
3) *Increase the blanket bond required for high-volume hydraulic fracturing operations.* Currently, 20 AAC 25.025(b)(1) requires a blanket bond of $200,000 for all of an operator's wells in the state. Since hydraulic fracturing operations require many more wells for equivalent production than conventional oil and gas wells, the blanket bond should be increased substantially. Alternatively, the Commission could require a much higher blanket bond for all operators in the state.

Finally, we note that the introduction of oil and, potentially, gas fracturing operations in Alaska may mean that the Commission has to increase its technical staff significantly to maintain roughly the same staff-to-well oversight ratio. These comments assume that the Commission will ask for, and receive, sufficient funds from the legislature to ensure oversight at current levels.

Thank you for your consideration of these comments. We appreciate the Commission's recognition of the need for clear regulations on issues that matter deeply to the public. If you have any questions, please contact Lois Epstein, P.E., Arctic Program Director at The Wilderness Society (lois_epstein@tws.org or 907-272-9453, x107) or Barrett Ristroph, Arctic Program Representative at The Wilderness Society (ristroph@tws.org or 907-272-9453 x102).

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Appendix 1
Oversight Considerations by Other Alaska Agencies

State agencies other than the Alaska Oil and Gas Conservation Commission necessarily will be involved in overseeing hydraulic fracturing, either because of a statutory mandate or existing expertise. To ensure adequate oversight of fracturing, the state agencies listed below should consider developing regulations or best management practice guidance, as appropriate, to ensure adequate oversight of the following activities:

Alaska Department of Environment Conservation (ADEC)

ADEC oversees pollution-related industrial activities including storage and spill prevention for oil and hazardous substances, air and water discharges, and solid waste management. Activities ADEC might issue approvals or permits for include:

- Storing used or unused fracturing fluids
- Maximizing recycling and reuse of fracturing fluids
- Utilizing waste impoundments
- Monitoring air pollution, including baseline monitoring, and ensuring air quality standards are met
- If it is not possible to inject wastewater and drilling wastes, ensuring that water quality and waste management standards, respectively, are met
- Waste tracking and record-keeping
- Solid waste management related to fracturing personnel

Alaska Department of Natural Resources (ADNR)

Through the stipulations included in its leases, ADNR can require that operators meet important environmental protection requirements. These include:

- Limiting fracturing leases to areas that are less environmentally sensitive
- Establishing distances for well pads from surface water bodies, drinking water sources, homes, and other human infrastructure, etc.
  - A hazard identification analysis could be used to assess the safe distance from human and sensitive environmental receptors. The analysis should estimate the blowout radius, likely spill trajectories, explosion hazards, other industrial hazards, fire code compliance, human health, agricultural health, and quality-of-life factors.
  - Minimum well setbacks should be at least 1,320 feet (¼ mile) from homes, public buildings, and schools; 4,000 feet from private and public wells, primary aquifers, and other sensitive water resources; and 660 feet (1/8 mile) from other water resources.
- Minimizing the wildlife habitat footprint and habitat fragmentation from fracturing's roads, pipelines, well pads, seismic tests etc.

- Promoting efficient development for multiple nearby operators[44]
- Establishing noise standards for fracturing operations
- Ensuring tundra protection through the use of low-ground-pressure vehicles, ice roads, and other measures
- Protecting freshwater uses by preventing damaging levels of water use, including limiting fish-bearing water body withdrawals
- Developing tracking requirements for water use, recycling, waste injection, waste disposal, etc.
- Requiring that gravel for pads and roads be obtained from particular sources or types of sources
- Requiring that operators use natural gas, rather than diesel, to power equipment
- Prohibiting roads alongside transmission pipelines, which are not needed for leak detection or spill response
- Prohibiting wastewater discharges to surface water
- Ensuring appropriate well abandonment

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[44] Stipulations in the 2013 National Petroleum Reserve-Alaska Record of Decision provide an example of permit stipulations addressing footprint. *See* K-11 Lease Stipulation – Lease Tracts A-G (setting maximum acreage for development), NPR-A IAP Record of Decision, p. 88, https://www.blm.gov/epl-front-office/projects/nepa/5251/42462/45213/NPR-A_FINAL_ROD_2-21-13.pdf.

Appendix 2
Sources Submitted in Support of Comments

1. 40 C.F.R. § 350.7, Substantiating claims of trade secrecy.

2. 40 C.F.R. § 350.15, Public petitions requesting disclosure of chemical identity claimed as trade secret.

3. 42 U.S.C. § 11042, Trade secrets.

4. T.C. Bond *et al*., "Bounding the role of black carbon in the climate system: A scientific assessment." Journal *of Geophysical Research-Atmospheres,* (2013) DOI: 10.1002/jgrd.50171.

5. Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book (2007).

6. California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Pre-Rulemaking Discussion Draft, Article 4 – Hydraulic Fracturing (Dec. 18, 2012).

7. Energy Information Administration, "Over one-third of natural gas produced in North Dakota is flared or otherwise not marketed." *Today In Energy*, (Nov. 23, 2011).

8. Environmental Protection Agency, Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), ND, Final Rule, 77 Fed. Reg. 48,878 (Aug. 15, 2012).

9. Environmental Protection Agency, Lessons Learned from Natural Gas STAR Partners: Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells (2011).

10. Environmental Protection Agency, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

11. Harvey, Susan, *et al*., Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste (Mar. 2012).

12. McFeeley, Matthew, NRDC Issue Brief 12-06-A, State Hydraulic Fracturing Disclosure Rules and Enforcement: A Comparison (July 2012).

13. National Research Council, Induced Seismicity Potential in Energy Technologies (2012).

14. New York Times, "Gas Well Spews Polluted Water" (Apr. 20, 2011).

15. North Dakota Monthly Gas Production and Sales.

16. P.K. Quinn, *et al.*, *The Impact of Black Carbon on Arctic Climate* (2011). Arctic Monitoring and Assessment Programme (AMAP), Oslo.

17. Pediatric Environmental Health Specialty Units, PEHSU Information on Natural Gas Extraction and Hydraulic Fracturing for Health Professionals (Aug. 2011).

18. Pennsylvania Department of Environmental Protection, *DEP Announces Comprehensive Oil and Gas Development Radiation Study* (Jan. 24, 2013).

19. Pennsylvania State University, *Analysis of Marcellus flowback finds high levels of ancient brines* (Dec. 17, 2012).

20. Railroad Commission of Texas, *Eagle Ford Shale Task Force Report*, (Mar. 2013).

21. Shale Gas Production Subcommittee of the Secretary of Energy Advisory Board, 90-Day Report (Aug. 18, 2011).

22. Soraghan, Mike, "States deciding not to look at seismic risks of drilling," *EnergyWire* (Mar. 25, 2013).

23. Jeff Tollefson, "Oil boom raises burning issues," *Nature,* (Mar. 19, 2013).

24. World Bank, Global Gas Flaring Reduction.

25. State of Wyoming, Department of Environmental Quality – Air Quality Division, *Well Completions / Re-completions Permit Application* (Form AQD-OG11) (Aug. 2010).

26. Arkansas Rule B-19, excerpted.

27. Wyoming Administrative Regulations, Ch. 3, § 45, excerpted.

28. Colorado Oil and Gas Conservation Commission General Rules, excerpted.

29. Texas Administrative Code, Title 16, § 3.29, excerpted.

RECOMMENDED PRACTICE

DNV-RP-U301

Risk Management of Shale Gas Developments and Operations

JANUARY 2013

The electronic pdf version of this document found through http://www.dnv.com is the officially binding version

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FOREWORD

DNV is a global provider of knowledge for managing risk. Today, safe and responsible business conduct is both a license to operate and a competitive advantage. Our core competence is to identify, assess, and advise on risk management. From our leading position in certification, classification, verification, and training, we develop and apply standards and best practices. This helps our customers safely and responsibly improve their business performance. DNV is an independent organisation with dedicated risk professionals in more than 100 countries, with the purpose of safeguarding life, property and the environment.

DNV service documents consist of among others the following types of documents:

— *Service Specifications.* Procedural requirements.
— *Standards.* Technical requirements.
— *Recommended Practices.* Guidance.

The Standards and Recommended Practices are offered within the following areas:

A) Qualification, Quality and Safety Methodology
B) Materials Technology
C) Structures
D) Systems
E) Special Facilities
F) Pipelines and Risers
G) Asset Operation
H) Marine Operations
J) Cleaner Energy
O) Subsea Systems
U) Unconventional Oil & Gas

Any comments may be sent by e-mail to *rules@dnv.com*

All results shall be documented and used as part of the EMS.

6.5.3 Reporting

Reporting the emissions to air, water and ground, as well as the use of raw material should be carried out during all phases of the shale gas activities. This allows tracking the environmental performance as required by the EMS, and allows populating relevant databases for further use.

The following emissions and use of raw materials should be reported, at a minimum:

- water volumes and origin
- chemicals - nature and volumes
- sand volumes and type
- energy use by type of energy source
- estimated GHG emissions (vented, combustion, and fugitive)
- drilling mud volumes and treatment
- flowback water surface return rate
- produced water (incl. flowback and brine) volumes and treatment solution
- brine volumes
- spills volume, nature, location, and clean-up.

Data should be openly disclosed to relevant stakeholders. Updates should be issued regularly, e.g., monthly, quarterly or annually, as appropriate for the data being presented.

6.5.4 Post operations survey

A post operations survey (POS) shall document the characteristics of the surrounding environment at the shale gas activity location after the operations. When compared to the results from the EBS (see 6.5.1), the POS will allow assessing environmental impacts from the operations.

The POS shall be carried out after the site is reclaimed.

Topics for the survey include but are not limited to:

- groundwater quality, including drinking water wells
- surface water quality
- air quality
- soil quality
- fauna and flora diversity
- presence of invasive species
- presence of methane seepages.

Water shall, at a minimum, be analysed for pollutants that have been involved in the operations, such as chemicals used in the hydraulic fracturing process, heavy metals (from flowback water), methane (biogenic/thermogenic), and NORM.

The POS should be carried out by an independent third party, and analyses shall be undertaken by certified laboratories.

Depending on the results of the POS, the implementation of additional remediation measures may be required.

7 Well Risk Management

7.1 Introduction

This section provides recommended practices for the management of specific shale gas well risks. The complete well risk scenario is made up by these risks and the risks common for shale gas activities and conventional gas activities.

Typical specific shale gas risks are related to the following:

- a large number of wells, and a high density of wells, within the field
- risks to groundwater from well operations and wells
- hydraulic fracturing may introduce seismic events and adversely influence well integrity.

The operator shall have a systematic risk management system in place that covers the processes of planning and execution of drilling and well completion operations, hydraulic fracturing, well maintenance, production operation and plugging and abandonment (see Sec.4).

Traceability in the planning and execution of the operations shall be ensured in order to enable verification that the defined safety level and well integrity are maintained in all phases.

The following standards provide guidance:

— API guidance document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines
— API guidance document HF2, Water Management Associated with Hydraulic Fracturing
— API guidance document HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing

7.2 Well barriers

There shall be clearly defined barriers in place to prevent:

— uncontrolled flow of natural gas to the environment
— cross flow between adjacent formation layers
— contamination of groundwater during drilling and cementing operations, during the subsequent production phase, until a well is abandoned.

Well barriers are envelopes of one or several dependent well barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to the surface.

Generally, the configuration of well barriers will vary for the different operational phases; however, it shall be clearly defined for each phase. The functional requirements for each barrier and its controls should also be defined for each operational step.

Geological formations may also be part of the well barrier envelope. The different geological formations overlying and underlying the target zone, also referred to as formation boundaries, should be located and characterized. Preventive measures shall be implemented to avoid fractures from breaching these formation boundaries. It is important that the formations enclosing the fractures do not allow cross flow between adjacent formations. Cross flow towards surface or towards the well via adjacent formation layers is a concern; especially when groundwater entities are located nearby or along the well trajectory. The effectiveness of the well barriers should be monitored throughout the life-cycle of the well. Frequency, extent and method of monitoring of the barrier elements should be determined on the basis of assessments of the importance of the barriers in mitigating risks. Particular attention should be paid to the condition of the well barriers during and after the hydraulic fracturing process.

The following standard provides guidance on well barriers:

— API standard 65 - Part 2, Isolating Potential Flow Zones During Well Construction.

7.3 Geological risks

The main geological risks associated with shale gas operations involve groundwater contamination and micro-seismicity events.

The geological risks involving groundwater contamination primarily relate to shallow producing zones or to pre-existing faults in the producing zone connected to the surface or groundwater zones.

Isotropic and homogeneous rocks seldom occur in nature. Most rock masses present a degree of anisotropy and heterogeneity. This implies that the physical, dynamic, thermal, mechanical, etc. properties of rocks vary in direction. Geological stresses, rock geomechanical properties and hydraulic fracturing process design are the most significant constraints on fracture growth but due to stress anisotropy it is often complicated to determine the direction and extent of fracture propagation. Furthermore, the production of gas from the reservoir will reduce the pore pressure and thereby change the original state of stress.

The direction, shape and extent of induced fractures can be anticipated using recognized geomechanical and engineering methods but uncertainties in quantitative predictions can be significant due to the limited data that can be practicably collected from the relevant underground formations and fundamental limits to the resolution of predictive models. The natural properties of the target formation for fracturing determine the final shape and direction of the induced fractures. Careful design, planning, monitoring and execution of the fracturing process can provide high confidence that the final realized fractures do not introduce unacceptable environmental consequences. In addition, induced fractures may intersect pre-existing fractures which can then dilate and propagate fracturing fluids in ways not planned for and that should be avoided. The most relevant example of this is the case of fugitive fractures. Induced fractures may extend upward beyond the target gas producing zone despite careful design and planning. The main cause would likely be existence of undetected pre-existing fault/ fracture surfaces that can intersect the production well itself at a shallower depth, and which is intersected by an induced fracture. Such a fugitive fracture may continue to propagate along the wellbore by creating a micro-annulus between the cement and rock formation and potentially reach the groundwater. Alternatively, in the case of shallow producing zones, it may reach the groundwater through direct fracture propagation (i.e., not along the wellbore) depending on vertical distance separation between the groundwater and the producing zone.

The operator should therefore characterize the in situ stresses within the target formation as part of the planning and design process in advance of drilling and fracturing operations. Special emphasis should be made to understand and map possible stress field anisotropies at the specific site for shale gas production in order to reliably predict the direction and extent to which fractures will tend to propagate. It is expected that the key data source for this will be well breakouts observed in exploration wells in the area in addition to well breakout data from production wells (collected before completion and the fracturing process).

As part of understanding the geomechanical stress state of the target formation and improving predictions of induced fracture growth, it is essential that the actual fracture creation and propagation is monitored in real time using BAT micro-seismic arrays and methods that allow direct location of and indirect observation of subsequent induced fracture surfaces. The resulting observed induced fracture geometry, direction and extent should then be compared to values predicted for these. If there is considerable deviation between predictions and observations, any necessary model revisions, corrections and updates should be performed in time to improve the design, planning and execution of future fracturing operations. This micro-seismic data may also have value in the resolution of potential claims of groundwater contamination.

In order to avoid possible groundwater contamination from induced fractures, the operator should estimate:

— the minimum required vertical separation between the deepest groundwater formation boundary and the shallowest edge of induced fractures
— the minimum required distance between the wellbore above the target shale gas formation and the nearest edge of an induced fracture
— the minimum required distance between the outermost edge of an induced fracture and any nearby wellbores
— the minimum required distance between any identified pre-existing faults or fractures to the nearest edge of an induced fracture.

Computerized simulation of fracture creation and growth should be used to design and plan the hydraulic fracturing process to satisfy these minimum distance requirements. The computer simulations should also contribute to establish a high degree of confidence that these minimum distances are achievable during actual fracturing operations. Site specific data acquired during exploration should be used to develop the simulation model.

The operator should carefully monitor fracture evolution during the hydraulic fracturing operations to ensure that induced fractures are created in a manner that satisfies the minimum distance requirements above.

Micro-seismic events are a routine feature of hydraulic fracturing and are due to the propagation of induced fractures. Larger seismic events are generally rare but can be triggered by hydraulic fracturing in the presence of a pre-stressed fault. In order to mitigate unacceptable induced seismicity the operator should carry out site specific surveys to identify directions of local stresses and locations of pre-existing faults. Once identified, these should be characterised and compared with historical records to assess the risks of larger induced seismic events, particularly ground accelerations near engineered structures.

Micro-seismicity should be monitored by the operator using appropriate monitoring tools and layouts before, during and after hydraulic fracturing in order to locate and mitigate any risks associated with induced seismicity.

7.4 Well planning

There is the potential risk of contamination of groundwater by drilling fluids, fracturing fluids, cement or natural gas. The overall risk of groundwater contamination shall be considered during well planning. Therefore the following should be assessed:

— The use of additives in the drilling fluid and hydraulic fracturing fluid which may pose toxic hazards or potentially degrade groundwater. The specific toxicological profile and planned volumes of such additives should be documented. In cases where it can be reasonably expected that significant drilling losses can occur in the groundwater, the drilling plan should include enhanced drilling design and procedures to minimize contamination of the groundwater to acceptable levels. A probabilistic estimate should be made of the overall contamination load from the drilling and fracturing processes on all contacted groundwater formations.
— The visualization of the actual hydraulic fractures, their location, shape and extent, as witnessed in real time during their creation in the fracturing operation, should be planned for. This will allow for direct judgement as to the vertical extent of the created fractures and if required minimum distances are satisfied. Real-time monitoring of induced fracture creation will also allow the fracturing operator to stop pumping before the minimum distance criteria cannot be complied with. The best available technology (BAT) for this may be installing an array of passive micros-seismic sensors in the near vicinity, and possibly within the wellbore. Use of highly sensitive tilt meters installed in near-surface environment may also be considered, but these are not expected to provide data that directly indicates geometric detail of the created fractures.
— Sufficient knowledge of the pre-existing water quality of all groundwater formations and the depths of the main formation boundaries of those to be drilled through, should be collected as part of a baseline survey of site conditions before drilling, fracturing and production. This data should be provided by or verified by an independent third party.