March 1, 2010

Via Electronic Mail: ra-epoilandgas@state.pa.us
Bureau of Oil and Gas
P. O. Box 8765
Harrisburg, PA 17105-8765

Re: Comments on Recommendations for Revisions of 25 Pa. Code Ch. 78 ("Chapter 78"), 40 Pa. Bull. 623 (Jan. 30, 2010)

Dear Bureau of Oil and Gas:

On behalf of the undersigned organizations, I want to thank the Pennsylvania Department of Environmental Protection ("DEP") for the opportunity to comment on the revisions to Chapter 78 that DEP proposes to recommend to the Pennsylvania Environmental Quality Board. 40 Pa. Bull. 623 (Jan. 30, 2010). Our comments are presented in a technical review of DEP's proposal (annexed as Exhibit A to this letter) prepared by Susan Harvey, a Petroleum and Environmental Engineer and a principal of Harvey Consulting, LLC. (Ms. Harvey's resume is annexed as Exhibit B to this letter.) On the basis of her 23 years of experience, Ms. Harvey has developed a set of recommendations designed to ensure that revised Chapter 78 regulations represent industry best practices, protect public health and the environment, and satisfy DEP's stated goals of: (1) minimizing public concerns associated with gas migration into public drinking water supplies.; (2) updating material specifications and performance testing requirements; and (3) revising design, construction, operations, monitoring, plugging, water supply replacement, and gas migration reporting requirements.

We look forward to working with you to develop a set of state-of-the-art regulations that will minimize contamination from oil and gas development in Pennsylvania. We also urge DEP to provide a more substantial public comment period, and to hold public hearings, on the proposed Chapter 78 regulations, when the formal rulemaking is noticed.

Sincerely,

Deborah Goldberg

Deborah Goldberg
Managing Attorney
Earthjustice, Northeast Office

Craig Segall
Environmental Law Fellow
Sierra Club Environmental Law Program

On behalf of:

David Gilpin
President
Chestnut Ridge Trout Unlimited

John K. Baillie
Senior Attorney
Citizens for Pennsylvania's Future

Myron Arnowitt
Pennsylvania State Director
Clean Water Action

B. Arrindell
Director
Damascus Citizens for Sustainability

Tracy Carluccio
Deputy Director
Delaware Riverkeeper Network

Joe Levine
Chair
NYH2O

R. Martin
Coordinator
Pennsylvania Forest Coalition

Mark Barbash
Co-Founder
Protecting Our Waters

Thomas Au
Conservation Chair
Sierra Club, Pennsylvania Chapter

Patrick Grenter
Legal Director
Three Rivers Waterkeeper (PA)

Exhibit A

Recommendations for Pennsylvania's Proposed Changes to Oil and Gas Well Construction Regulations

Report to:

Earthjustice and Sierra Club

Prepared by:

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

March 1, 2010

Email: sharvey@mtaonline.net

Phone: (907) 694-7994
Fax: (907) 694-7995

PO Box 771026
Eagle River, Alaska 99577

Contents

1. Introduction

This analysis responds to a request by Earthjustice and Sierra Club for a review of proposed revisions to the Pennsylvania's regulations governing construction of oil and gas wells [25 Pa.Cod Ch. 78 (Chapter 78)]. The purpose of this review is to examine whether the revisions proposed by the Pennsylvania Department of Environmental Protection (DEP or the Department) are: best practice, protective of human health and the environment, and consistent with DEP's stated goals of: (1) minimizing public concerns associated with gas migration into public drinking water supplies; (2) updating material specifications and performance testing requirements; and (3) revising design, construction, operations, monitoring, plugging, water supply replacement, and gas migration reporting requirements.

Analysis Approach

This analysis examined DEP's proposed changes to Chapter 78 and makes recommendations on whether those proposed changes are best practice and protective of human health and the environment. Additionally, this analysis examined sections of Chapter 78 that DEP did not propose to amend in order to identify further changes that would serve to achieve DEP's stated goals.

Recommendations made in this report are based on 23 years of experience as a Petroleum and Environmental Engineer and are highlighted in blue text boxes.

2. Subchapter A, General Provisions, Definitions § 78.1

Casing Seat. DEP has revised the definition to read:

> *"The depth to which the surface casing or coal protection casing or intermediate casing is set. In wells without surface casing, the casing seat shall be equal to the depth of casing which is typical for properly constructed wells in the area."*

The second sentence in this definition is not consistent with standard industry practice for construction of an oil and gas well. Surface casing, and in some cases an additional string of intermediate casing is used to protect ground water aquifers, provide the structure to support blowout prevention equipment, and provide a conduit for drilling fluids when drilling the subsequent section of the well. The second sentence of this definition should be deleted, or DEP should explain how an oil and gas well could be drilled safely, and protect ground water resources, without surface casing.

> **Recommendation No. 1**: Delete the second sentence of the proposed casing seat definition.

Surface Casing. DEP has revised the definition to read:

> *"Casing used to isolate the wellbore from fresh groundwater and to prevent the escape or migration of gas, oil and other fluids from the wellbore into fresh groundwater. The surface casing is also commonly referred to as the water string or water casing."*

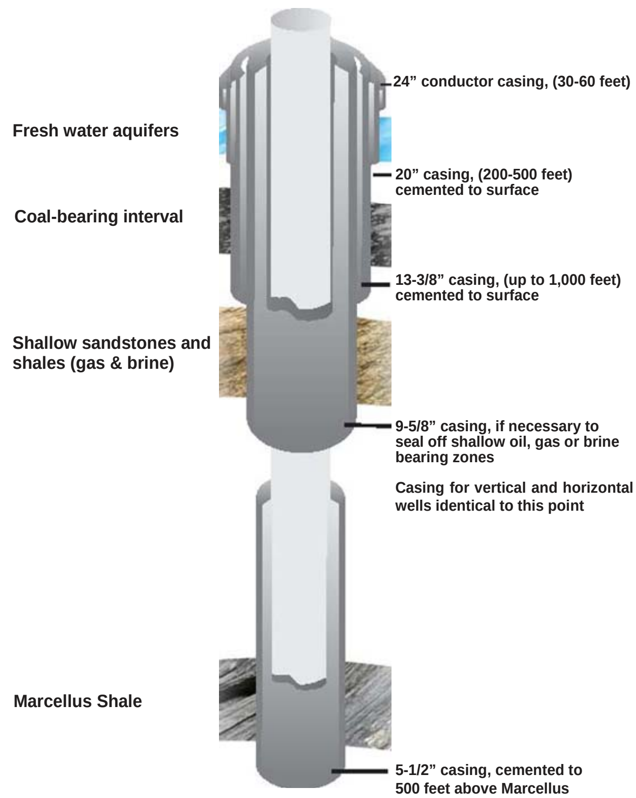
In addition to protecting ground water, surface casing also provides the very important structural support required to install blowout prevention equipment and provides a conduit for drilling fluids when drilling the subsequent section of the well.

Recommendation No. 2: The surface casing definition should clarify that the surface casing also provides the structural support required to install blowout prevention equipment and provides a conduit for drilling fluids when drilling the subsequent section of the well.

Intermediate Casing. DEP has added a new definition that reads:

"A string of casing other than production casing that is used in the wellbore to isolate, stabilize or provide well control to a greater depth than that provided by the surface casing or coal protection casing."

Generalized casing design for a Marcellus Shale gas well to protect the environment



Intermediate casing does play an important role in the structural stability of the wellbore, but it also provides a very important additional protective barrier of pipe and cement across shallow freshwater aquifer zones. In other words, it provides a second protective barrier, in addition to the surface casing and cement, when a well passes through a fresh water aquifer.

Intermediate casing may be set to provide a transition from the surface casing to the production casing for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may need to set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic "thief" zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure. Intermediate casing is typically set prior to drilling through the hydrocarbon-bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe if the intermediate casing depth is shallow enough.

Recommendation No. 3: The intermediate casing definition should clarify that intermediate casing also provides a very important additional protective barrier of pipe and cement across shallow freshwater aquifer zones, and provides a transition from the surface casing to the production casing for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards.

Casing Use Requirement. DEP's regulations at Chapter 78, and definitions at § 78.1, provide latitude in the amount and type of surface casing that can be run. Yet, industry trade groups operating in Pennsylvania recognize the importance of running both surface casing and intermediate casing in areas where freshwater resource protection is of critical importance, to provide a sound structural barrier that contains stimulation fluids when conducting large slickwater fracture treatments (e.g. Marcellus Shale).

For example, a typical wellbore diagram[1] of the casing program recommended by the oil and gas industry and industry trade groups operating in the Marcellus Shale in Pennsylvania[2] is shown on the previous page. Industry recommends three sets of casing (conductor, surface, and intermediate), all cemented to the surface, which puts freshwater behind three layers of casing and cement. Industry also recommends a fourth layer of production casing.

> **Recommendation No. 4**: Consistent with the recommendations of industry trade groups operating in Pennsylvania, DEP regulations should require the use of ***surface*** casing ***and intermediate*** casing in areas where freshwater resource protection is of critical importance. Casing and cement barriers also provide a sound structural barrier that contains stimulation fluids when conducting large slickwater fracture treatments.

Cement. DEP's current definition for cement reads:

> *"A mixture of materials for bonding or sealing that attains a 7-day maximum permeability of 0.01 millidaricies and a 24-hour compressive strength of at least 500 psi in accordance with applicable API standards and specifications."*

DEP's definition for cement sets a 24-hour compressive strength standard of at least 500 psi; however, other states, such as Texas, have found that standard insufficient to prevent vertical migration of fluids or gas behind pipe. Texas requires operators to have knowledge of the location and extent of all usable-quality water zones, and requires a higher cement quality to protect these zones. For example, Texas requires an **additional** 72-hour compressive strength standard of at least 1,200 psi across critical zones of cement. For example, Texas regulations define the critical zone as "all usable-quality water zones," and define the "critical zone of cement" as the bottom 20% of the casing string (at least 300', but no more than 1000').[3] This places a section of high strength cement at the bottom of the casing seat where the highest pressures and stresses are likely to be encountered.

Additionally, Texas requires the API free water separation to average no more than six milliliters per 250 milliliters of cement, tested in accordance with the current API RP 10B. The Texas commission[4] overseeing oil and gas development may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions (which must be provided by the permit applicant) indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

---

[1] http://www.pamarcellus.com/images/pdfs/casing_graphic-with_copy.pdf.
[2] http://www.pamarcellus.com/about.php. "Founded in 2008, the Marcellus Shale Committee is an organization committed to the responsible development of natural gas from the Marcellus Shale geological formation in Pennsylvania and the enhancement of the Commonwealth's economy that can be realized by this clean-burning energy source. The members of the committee bring the strength of the Pennsylvania Oil and Gas Association and the Independent Oil and Gas Association of Pennsylvania together to address concerns with regulators, government officials and the people of the Commonwealth about all aspects of drilling and extracting natural gas from the Marcellus Shale formation."
[3] 16 TAC Part 1.
[4] Texas Railroad Commission

Texas cement quality standards read:

"Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi. … In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B. The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.[5]

"Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure. (i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement. (ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.[6]*"*

Recommendation No. 5: Revise the cement definition to include a 72-hour compressive strength standard of 1,200 psi for cement mixtures in the zone of critical cement. Also, require conformance with the API free water separation standard of no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B. Provide a provision for the Department to set more stringent local standards if needed for pollution prevention, and establish quantitative temperature limits for water used in cement mixing. The cement definition should clarify that it applies to cement used for surface, intermediate, and production casing.

Cement Ticket. DEP's has added a new definition that reads:

"Cement ticket – A written record that documents the procedures and specifications of the cementing operation and the chemical composition of the cement for each cemented casing string. The record shall include the amount and composition of the cement slurry, the amount of cement returned to the surface, if any, the amount and type of additives to the cement slurry mixture. Slurry properties must include weight, yield, density, water requirements, compressive strength, fluid loss. Cementing operation information shall include a description of the stages and sequence of events during the cementing operation, calculations employed, and wellbore and casing information such as casing diameter and depth and hole size and depth and pump time."

[5] 16 TAC Part 1 §3.13(b)(2)(C)
[6] 16 TAC Part 1 §3.13(b)(2)(D)

DEP's recommendation to add a new definition for cement ticket is useful. However, it is recommended that the definition be expanded to include the recommendations listed below.

Recommendation No. 6: Expand the cement ticket definition to include: (a) a requirement for the operator to test the mixing water pH and temperature and note it on the cement ticket (this is standard industry practice and aids in determining cement quality); (b) a record of the Waiting on Cement [WOC] time, which is the time required to achieve the calculated compressive strength standard before the casing is disturbed in any way [described in the cement definition comments above]; and (c) a certification statement that requires the operator to certify, under penalty of law, that the cement job was completed in compliance with Pennsylvania regulatory requirements.

3. Subchapter C, Environmental Protection, Performance Standards, Protection of Water Supplies, § 78.51

DEP has proposed a number of important revisions to the regulations at § 78.51 to clarify what constitutes an adequately restored or replacement water supply. However, DEP did not recommend any revisions to the portion of § 78.51(c) that sets a timeframe for acting upon a complaint filed by a landowner, water purveyor, or affected person suffering pollution or diminution of a water supply as a result of drilling, altering, or operating an oil or gas well. DEP's regulations at § 78.51(c) currently allow a delay of up to 10 calendar days before an investigation must be completed.

If a violation of DEP standards is suspected, and that violation results in pollution or diminution of a water supply, or has the potential to threaten a water supply, immediate investigation by DEP is essential, not merely response within a 10-day time period. It is recommended that this regulation be revised to require an immediate investigation to commence within 24 hours of notification, and that if DEP's investigation team finds evidence to support the complaint, the noncompliant activity should be immediately shut down. Additionally, all potentially affected users of the water supply should be immediately notified and provided alternative water supplies until the DEP completes a final investigation and a final remedy is resolved with the non-compliant operator. Keep in mind that most wells take 14 - 30 days to drill, depending on depth; and depending on where the operator is within the drilling cycle when the problem begins, drilling rig operations could be completely packed up and moved off location before a DEP investigation team arrives on the site 10 days later. The same holds true for stimulation procedures such as fracture treatments that may take a few hours to a few days, depending on the number of stages and complexity.

It is unlikely that the operator or equipment will be on location, or any evidence can be examined or collected by an investigation team, 10 days after a report of a violation is made. Most importantly, if the agency is notified of a threat to a water supply, immediate action is necessary. A technical team should be sent out into the field without delay to examine the situation and determine whether action is needed to shut down operations. That same initial investigation team can collect the information, records, and evidence required to complete the formal written determination due in at least 45 days.

Recommendation No. 7: Revise § 78.51(c) to read: Within 24 hours of the receipt of the investigation request, the Department will send a technical team to the field site to examine the situation and determine whether immediate action is needed to shut down operations. The technical team will also collect the information, records, and evidence required to complete the investigation. If the technical team finds that there is any potential threat or impact to a water supply, the operator will be ordered to immediately cease operations, and the Department will immediately notify all potential affected users of the water supply and require the operator to provide alternative water supplies until the Department completes a final investigation and a final remedy is resolved with the non-compliant operator.

Within 45 days of receipt of the investigation request, the Department will issue a formal written determination. If the Department finds that pollution or diminution was caused by drilling, alteration, or operation activities, or if it presumes the well operator responsible for polluting the water supply of the landowner or water purveyor under section 208(c) of the act (58 P. S. § 601.208(c)), the Department will issue orders to the well operator necessary to assure compliance with this section.

DEP proposes to add a new requirement at § 78.51(i) that requires a well operator to notify DEP if a water supply contamination complaint has been received from a landowner, water purveyor, or affected person, within 10 calendar days. A 10-day notification period is too long. Notification should be made within 24 hours, followed by a written report via electronic communication or facsimile within a 24-hour period. This way the DEP is promptly notified and can send a technical team to the site to commence the investigation while the factors that may have contributed to the complaint are still present.

Recommendation No. 8: Revise the notification period in § 78.51(i) to 24 hours.

DEP proposes a new regulation § 78.51(e) that clarifies what constitutes an adequate restoration or replacement of a polluted water supply. This regulation is useful. However, the new language proposed for § 78.51(e)(2) appears to include redundant language, as well as language somewhat contradictory to the existing §78.51(d) regulation. It is recommended that these regulatory sections be combined and clarified.

The language proposed at § 78.51(e)(2) could allow an operator to construct a new, replacement water supply at a standard less than the Pennsylvania Safe Drinking Water Act if it were replacing a water source that originally did not meet the Pennsylvania Safe Drinking Water Act. All newly constructed water sources, especially those constructed to remedy a compliance violation, should meet the minimum water quality standards of the Pennsylvania Safe Drinking Water Act.

Recommendation No. 9: Revise § 78.51(e)(2) and § 78.51(d) to meet this stated intent: All ***restored*** water supplies must be at least equal to the quality of the water supply before it was affected by the operator. If the quality of the water supply, before it was affected by the operator, cannot be affirmatively established, the operator shall demonstrate that the concentrations of substances in the restored water supply meet the Pennsylvania Safe Drinking Water Act standards. Any new, ***replacement*** water supply must meet the Pennsylvania Safe Drinking Water Act standards.

4. Subchapter C, Environmental Protection, Performance Standards, Predrilling or Prealteration Survey, § 78.52

DEP regulations allow an operator to obtain water supply samples prior to drilling. The purpose of this "baseline" water quality assessment is to establish whether pollution already exists. The right to conduct the sampling is described in § 78.52(a). DEP's sampling instructions are found at § 78.52(c):

> *"(c) The survey shall be conducted by an independent certified laboratory. A person independent of the well owner or well operator, other than an employee of the certified laboratory, may collect the sample and document the condition of the water supply, if the certified laboratory affirms that the sampling and documentation is performed in accordance with the laboratory's approved sample collection, preservation and handling procedure and chain of custody."*

The sampling instructions at § 78.52(c) do not specify what type of tests must be completed, when the testing must be completed, or what testing procedures must be followed. A standard suite of water quality tests and procedures should be specified and required by DEP. Baseline testing should be completed over a full hydrologic cycle (multiple samples). Additionally, in areas where industrial activity has already occurred; testing should include examination of chemicals used by the oil and gas industry. See additional recommendations on this topic at § 78.122(b)(6).

DEP's reporting instructions are found at § 78.52(e):

> *" (e) The report describing the results of the survey must contain the following information:*
>
> *(1) The location of the water supply and the name of the surface landowner or water purveyor.*
>
> *(2) The date of the survey, and the name of the certified laboratory and the person who conducted the survey.*
>
> *(3) A description of where and how the sample was collected.*
>
> *(4) A description of the type and age, if known, of the water supply, and treatment, if any.*
>
> *(5) The name of the well operator, name and number of well to be drilled and permit number if known.*
>
> *(6) The results of the laboratory analysis."*

The reporting instructions at § 78.52(e)(6) are very generic. DEP only requests the "results of the laboratory analysis" to be provided with no clear instructions on what tests must be reported, at a minimum, or what test methods must be followed, along with evidence that quality control and quality assurance procedures were followed.

The report should include a summary, in layman's terms, verifying whether any contamination was found. If contamination was found, the report should clearly describe the amount of contamination found and by what factor it exceeds Pennsylvania's Safe Drinking Water Act.

This report should be made available to the public, and should be provided to all agencies responsible for ground water protection (e.g. county boards, commissions).

Additionally, DEP should require annual water quality testing (at a minimum) to verify the water supply condition while drilling, completion and production operations continue.

Recommendation No. 10: Revise the sampling instructions at § 78.52(c) to specify the type of tests and testing procedures that must be followed, and when samples must be obtained. A minimum standard suite of water quality tests and procedures should be required. Baseline testing should be completed over a full hydrologic cycle (multiple samples). In areas where industrial activity has already occurred, testing should include examination of chemicals used by the oil and gas industry. Revise the reporting instructions at § 78.52(e)(6) to ensure the report includes: test results; test methods; evidence that quality control and quality assurance procedures were followed; a summary, in layman's terms, verifying whether any contamination was found. If contamination was found, the report should clearly describe the amount of contamination found and by what factor it exceeds Pennsylvania's Safe Drinking Water Act. Require the test reports to be made available to the public, and to be provided to all agencies responsible for ground water protection (e.g. county boards, commissions). Require annual water quality testing (at a minimum) to verify the water supply condition while drilling, completion and production operations continue.

5. Subchapter C, Environmental Protection, Performance Standards, Control and Disposal Plan, § 78.55

DEP did not propose any changes to § 78.55; however, it is recommended that a revision be made to require operators to submit their control and disposal plans to DEP for review and approval. Currently, the plans are prepared by the operator, but there is no agency review for compliance with Pennsylvania Environmental Protection Standards.

Recommendation No. 11: Revise § 78.55 to require well operators to submit a copy of their control and disposal plan for DEP review and approval prior to commencing operations to ensure compliance with Pennsylvania Environmental Protection Standards.

6. Subchapter D, Well Drilling, Operation and Plugging, Use of Safety Devices, Well Casing, § 78.71

DEP proposes to revise § 78.71 (a) to read:

> *"(a) The operator shall equip the well with one or more strings of casing of sufficient cemented length and strength to prevent blowouts, explosions, fires and casing failures during installation, completion and operation."*

DEP's stated goal of revising the well casing requirements to enhance ground water protection and to minimize public concerns associated with gas migration into public drinking water supplies is not reflected in the regulations at § 78.71(a).

Recommendation No. 12: Amend § 78.71(a) to clearly state that sufficient casing and cement must be installed in the well to prevent contamination of ground water resources, in addition to the other purposes already listed.

7. Subchapter D, Well Drilling, Operation and Plugging, Use of Safety Devices, Blowout Equipment, § 78.72

A Blowout Preventer (BOP) cannot be installed until surface casing is set and cemented; therefore a gas flow diverter system should be installed to provide for personnel and public safety during the initial stages of well drilling and setting surface casing. Once surface casing is set, a BOP can be installed to control the well as it is drilled deeper into higher pressure zones. The proposed DEP regulations do not set standards for diverter systems, except later, at § 78.73, which states that excess gas encountered during drilling should be diverted away from the drilling rig in a manner that does not create a hazard to public health or safety. Yet, DEP provides no criteria or standards for what constitutes an acceptable design for a drilling diverter system. Shallow gas hazards are well known in the oil and gas industry to be the root cause of many well blowouts and explosions. Many of these situations could have been prevented by a more rigorous diverter system design. It is recommended that DEP improve the safety device regulations at § 78.72 to include diverter system specifications.

Recommendation No. 13: It is recommended that DEP improve the safety device regulations at § 78.72 to add the following diverter system specifications.

A diverter system should be at least as large as the diameter of the hole that will be drilled, and the system should include a remotely operated annular pack-off device, a full-opening vent line valve, and a diverter vent line with a diameter appropriately sized for geological conditions, rig layout, and surface facility constraints.

The diverter vent line outlet should be located below the annular pack-off device, either as an integral part of the annular pack-off device or as a vent-line outlet spool immediately below it. The actuating mechanism for the vent line valve should be integrated with the actuating mechanism for the annular pack-off device in a fail-safe manner so that the vent line valve automatically opens before full closure of the annular pack-off device. The diverter system vent line should extend at least 100 feet away from any potential sources of ignition and the drilling rig substructure, and should be secured. The diverter system area should be well marked as a "warning zone" at the vent line tip, prohibiting ignition sources, equipment, or personnel in this area.

DEP has revised the applicability standard of § 78.72 to specify the types of wells that are required to install a BOP when drilling. The proposed applicability standard includes four criteria:

1. Marcellus Shale gas wells;
2. wells where an operator anticipates pressures or flows that may result in a blowout;
3. wells drilled in areas where there is no previous pressure data; and
4. wells regulated by the Oil and Gas Conservation Law.

Criteria #1 & #3 are clear. BOPs are required on all Marcellus Shale gas wells and all wells drilled in areas where there is no previous pressure data.

Criterion #2 provides the operator with broad discretion to determine whether wellhead pressures or natural open flows that may occur during drilling operations could pose a threat of blowout. There are no safety or hazard criteria established to guide the operator as to when a BOP is required.

Criterion #4 is clear in that it requires BOPs on all wells regulated by the Oil and Gas Conservation Law, but that law excludes wells that do not penetrate the Onondaga horizon. The law also excludes wells that do not exceed a depth of 3,800 feet beneath the surface, including wells located in areas where the Onondaga horizon is nearer to the surface than 3,800 feet. Therefore, it is not clear if Criterion #4 conflicts with Criteria #1, #2 or #3.

Industry standard practice is to design, size, and install a BOP to handle wellhead pressures expected to be encountered while drilling (with a sufficient safety factor). Operators that propose to drill wells without BOPs should provide a technical and safety justification to DEP as part of their permit to drill application. This justification should be reviewed and approved by the Department. A BOP should be required on all wells, and BOP waivers should be the exception rather than the rule.

Blowouts are very serious human health, work safety, and environmental situations. Blowouts may result in human injury, fire, explosion, oil spills, gas venting, equipment damage, etc.

Recommendation No. 14: Revise § 78.72 to require all wells to be drilled with a BOP once surface casing is installed and cemented. Allow exceptions to that rule only if the operator submits a sufficient technical and safety justification to warrant drilling without a BOP.

The operator should be required to submit a copy of its blowout preventer (BOP), diverter, and related equipment plans, along with its proposed casing and cementing design plan, to DEP for review and approval, as part of permit to drill applications.

DEP regulations at § 78.72 do not specify the type of BOPs required. Typically for rotary drilling operations with a maximum potential surface pressure of 3,000 psi or less, the BOP must have at least three preventers, including: one equipped with pipe rams that fit the size of the drill pipe, tubing, or casing that is being used; one with blind rams; and one annular type. In rotary drilling rig operations with a maximum potential surface pressure of 3,000 psi or greater, the BOP typically has at least four preventers, including: two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing that is being used; one with blind rams; and one annular type.

Regulations typically specify that the rated working pressure of the BOP and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected. Interestingly, existing DEP regulations at § 78.72 (c) require operators to select the appropriate pressure rating for all pipe fittings, valves, and other connections to the BOPS, but DEP's regulations do not specify that the BOPs themselves must be capable of withstanding the maximum potential surface pressure to which it may be subjected. BOPs come in various sizes and pressure ratings. Larger, higher-pressure rated BOPs are more expensive to purchase and operate; therefore, it is important that this point be specified in regulation.

Recommendation No. 15: Revise § 78.72 to provide specific BOP type and pressure rating criteria.

DEP proposes a new requirement at § 78.72 (c) that reads:

> *"(c) The controls for the blow-out preventer shall be accessible to allow actuation of the equipment in the event of an emergency. Controls for a blow-out preventer with a pressure rating of greater than 3,000 psi should be located a safe distance from the drilling rig."*

This regulation requires BOP controls to be accessible during an emergency; this is logical. However, the second sentence of the proposed regulation, which instructs the operator to place the BOP controls at a safe distance away from the drilling rig, does not instruct the operator to have BOP controls on the rig itself. BOP controls need to be accessible **both** on the rig and at a location a safe distance away from the drilling rig.

> **Recommendation No. 16**: DEP regulations at § 78.72(c) should be revised to clarify that BOP controls are also needed on the rig.

DEP regulations at § 78.72(d) and (e) require BOPs to be tested; however, the regulations do not specify that a "pass" rate is required to continue drilling operations, although this is surely DEP's intent. It would be useful to clarify that drilling operations must cease if a BOP fails a test. The BOP must be repaired or replaced, and successfully retested, prior to resuming drilling.

> **Recommendation No. 17**: DEP regulations at § 78.72(d) and (e) should be revised to clearly state that drilling operations must cease if a BOP fails a test. The BOP must be repaired or replaced, and successfully retested, prior to resuming drilling.

8. Subchapter D, Well Drilling, Operation and Plugging, General Provisions for Well Construction and Operation, § 78.73

DEP proposes a more stringent casing pressure limitation in the new regulations at § 78.73(c), by adding an additional safety factor, and by expanding that safety factor to include protection at the intermediate casing seat, in addition to the surface casing seat. Both changes are safety and environmental improvements. DEP proposes § 78.73(c) to read:

> *"(c) After a well has been completed, recompleted, reconditioned or altered the operator shall prevent shut-in pressure and producing back pressure at the surface casing seat, coal protective casing seat or intermediate casing seat when the intermediate casing is used in conjunction with the surface casing to isolate fresh groundwater from exceeding 80 percent (80%) of the hydrostatic pressure of the surrounding fresh groundwater system in accordance with the following formula. The maximum allowable shut-in pressure and producing back pressure to be exerted at the casing seat may not exceed the pressure calculated as follows: Maximum pressure = (0.8 x 0.433 psi/foot) multiplied by (casing length in feet)."*

The proposed regulation applies to wells **after** they have been "completed, recompleted, reconditioned or altered." While it is understandable that this requirement does not apply while drilling, casing, and cementing are underway, it is important to clarify that this requirement will be in place during any testing, stimulation, or other well operations.

Most drilling is completed using overbalanced drilling fluid systems of sufficient density to counteract any potential hydrostatic pressures in the wellbore; therefore, it would not be possible to adhere to the proposed pressure limits during these operations. However, once the drilling is "completed" and the casing is set and cemented in place, the pressure limitation should apply to all subsequent operations to protect ground water resources.

The term "completion" is often more broadly defined by industry to include casing, cementing, and well stimulation operations. The regulation should be clear that the pressure limitation will apply to testing and stimulation treatments, and other well operations, because high pressure is exerted on the casing seat during these operations.

Recommendation No. 18: DEP regulations at § 78.73 (c) should be revised to make it clear that the pressure limit will apply to all well activities after the casing is cemented in place.

DEP's revised regulation at § 78.73(d) requires the operator to take action to prevent the migration of gas and other fluids from lower formations into fresh groundwater in the event that the hydrostatic pressure exceeds the newly proposed 80% safety factor, described in § 78.73(c). Requiring the operator to take action in the event that the hydrostatic pressure was exceeded is a good step; yet, the proposed regulations do not provide any instruction on what course of action is required to remedy mechanical defects in the wellbore construction, nor does it require the operator to notify the DEP of the problem, report the resolution, or notify anyone who may be potentially affected (e.g. by groundwater impacts).

Recommendation No. 19: DEP regulations at § 78.73(c) should be revised to require the operator to notify DEP of any pressure exceedance within 24 hours, followed by a written plan of action to be submitted to DEP for review and approval. The regulations should also include a requirement for the operator to work with DEP to notify any potentially affected parties.

DEP proposes a new regulation at § 78.73(e) that requires operators to ensure that excess gas encountered during drilling, completion, or stimulation be flared, captured, or diverted away from the drilling rig in a manner that does not create a public health or safety hazard. The proposed regulation does not mandate or encourage operators to select the most environmentally preferable, lowest impact methods available. While flaring and venting have been commonly used in the oil and gas industry to deal with unwanted, potentially explosive vapors, both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[7] Initially, the motive was to conserve hydrocarbon resources to maximize federal and state revenue and gas supply. More recently, focus on greenhouse gas (GHG) emission reduction has prompted additional innovation to further reduce flaring and venting. Reducing flaring and venting to the lowest level technically achievable is widely considered best practice.

Drilling & Completions: Flares may be used during well drilling, completion, and testing to safely combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not yet been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except equipment malfunction.

During the drilling and completion phase of the first well on a well pad, a gas pipeline may not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply is found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to route it to. However, subsequent wells drilled on that same pad would be in a position to implement Reduced Emission Completion (REC), also called "green completion," which involves routing gas to a pipeline. Green completions require equipment to be brought to the well site to process wet gas from the well (during well completion activities) to ensure the gas meets pipeline specifications.

Gas Production: High pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[8] and gaseous by-product streams[9]

[7] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

[8] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.

that are uneconomical to conserve.[10] Venting or flaring may also occur during manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and removal of hydrates from pipelines.[11]

Best practices for flaring and venting during gas production should limit flaring and venting to the smallest amount needed for safety. Gas should be collected for sale, used as fuel, or reinjected for pressure maintenance, unless it is proven to be technically and economically unfeasible.

DEP should adopt very clear regulations limiting flaring and venting during gas production operations. If gas collection, use, sale, or reinjection is not possible, DEP should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces hazardous air pollutants, volatile organic compound emissions, and GHG emissions.[12]

Several states (e.g. Alaska and California) require operators to keep accurate records of gas venting and flaring to ensure that the amount is limited to safety related needs. Some states and the federal government (in the Outer Continental Shelf) require operators to pay royalty and taxes on flared and vented gas not authorized for safety purposes. This encourages investment in gas collection and control devices to conserve natural gas.[13]

Best Practices for Flares: When flare use is necessary for safety, the following best practices should be instituted:

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

Best Practices for Venting and Fugitive Emissions: Best Practices for controlling venting and fugitive emissions include:

- Leak Detection and Repair (LDAR) programs, including acoustic detectors and infrared technology to detect odorless and colorless leaks;
- Use of low bleed pneumatic instruments,[14] and use of instrument air, electric or solar powered control devices;
- Use of dry centrifugal compressor seals;
- Use of smart automation plunger lifts for liquid unloading;
- Early installation of pipelines; and
- REC methods for gas well completions.

---

[9] For example: instrument vent gas; stabilizer overheads; and process flash gas.

[10] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[11] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[12] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[13] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

[14] Process controllers, chemical pumps, and glycol pumps often vent pressurized natural gas used for pneumatic actuation.

In most cases these best practices improve safety and collect marketable gas for sale. For example, green completions provide an immediate revenue stream by routing gas that would otherwise be vented to a sale line. Industry has demonstrated that green completions are both best environmental practice and profitable. Green completion equipment has a short economic payout. A green completion requires the operator to bring in gas processing equipment to the 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.[15] 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.[16] It is also possible for smaller operators to rent green completion equipment. A recent New York State study for the Marcellus Shale found that equipment payouts may be as short as three months, and more than $65 million in profits was made on a national level in 2005 by companies conducting green completions.[17] Natural Gas STAR also provided technical advice to New York State recommending green completions as a technically feasible economic method. The best practice of green completions should be codified in DEP regulation.

Recommendation No. 20: DEP should develop regulations to restrict flaring, venting, and fugitive emissions to the lowest level technically feasible, and require the use of Reduced Emission Completions ("green completions") whenever technically feasible.

DEP proposes a new requirement at § 78.73(f) that reads:

> *"(f) Casing which is attached to a blow-out preventer with a pressure rating of greater than 3,000 psi shall be pressure tested. A passing pressure test shall be holding 120 percent of the highest expected working pressure of the casing string being tested for 30 minutes with not more than a 10 percent change. Certification of the pressure test shall be confirmed by entry and signature of the person performing the test on the driller's log."*

This regulation requires casing to be pressure tested only when it is attached to a BOP of a pressure rating greater than 3,000 psi. Industry standard practice is to pressure test casing whenever a BOP is installed on casing, not just on BOPs with more than a 3,000 psi rating.

Typically the casing must be able to hold a surface pressure at least equal to 50% of the required working pressure of the BOP. Specifying a surface pressure of at least 50% of the working pressure of the BOP is an easily quantifiable, verifiable value.

Pressure testing the casing is a very important step in groundwater protection. A failed pressure test indicates an integrity problem that could potentially provide a conduit from the well to adjacent aquifers.

Recommendation No. 21: DEP regulations at § 78.73(f) should be revised to require pressure testing of all casing at a surface pressure of 50% of the required working pressure of the BOP.

---

[15] EPA, Green Completion, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, Fact Sheet No. 703, 2004.
[16] Reduced Emissions Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop, Casper Wyoming, August 30, 2005.
[17] DSGEIS, Appendix 25.

9. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Use of Conductor Pipe, § 78.82

DEP proposes to revise § 78.82 to read:

> *"If the operator installs conductor pipe in the well, the following provisions shall apply:*
> *(i) The operator may not remove the pipe.*
> *(ii) Conductor pipe shall be installed in a manner that prevents infiltration of surface water or fluids from the operation into groundwater.*
> *(iii) Conductor pipe shall be made of steel."*

The proposed changes are useful and provide additional instruction on conductor pipe, but should be expanded further. Regulations should provide specific instructions on how an operator should install conductor pipe to prevent infiltration of surface water or fluids from the operation into groundwater.

Most commonly the conductor casing is installed with a cement seal at the surface to prevent groundwater contamination. Cement is placed in the annulus (the space between the outside of the pipe and inside of the hole), to secure the pipe in the hole and ensure there is a continuous barrier. DEP should specify that conductor pipe be cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe.

Alternatively, if surface geology allows, conductor casing can be driven by mechanical percussion methods into unconsolidated strata. In this case, there is no annulus, and the casing is not cemented. And in this case, a mechanical or cement seal needs to be installed at the surface to prevent the downward migration of surface pollutants.

DEP should also provide instruction on what type of drilling fluids should be used when excavating the conductor casing hole, because this section of the well is being drilled through freshwater resources. Drilling fluids should be limited to air, fresh water, or water-based mud, and exclude oil based muds or use of other chemical lubricants.

Recommendation No. 22: DEP regulations at § 78.82 should include specific instructions on how an operator should install conductor pipe to prevent infiltration of surface water or fluids from the operation into groundwater. DEP should specify that conductor pipe be cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe. A mechanical or cement seal should be installed at the surface to prevent the downward migration of surface pollutants. Drilling fluids should be limited to air, fresh water, or water-based mud, and exclude oil based muds or use of other chemical lubricants.

10. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Surface and Coal Protective Casing and Cementing Procedures, § 78.83

DEP has proposed a number of important changes to the regulations at § 78.83. Revisions to this section of the regulations are most critical to DEP's stated goal of minimizing public concerns associated with gas migration into public drinking water supplies.

DEP proposes to revise § 78.83 to read:

> " *(a) For wells drilled, altered, reconditioned or recompleted after [effective date], surface casing or any casing functioning as a water protection casing shall not be utilized as production casing except if one of the following applies:*
>
> *(1) In oil wells where the operator does not produce any gas generated by the well and the annulus between the surface casing and the production pipe is left open.*
>
> *(2) The operator demonstrates that the pressure in the wellbore at the casing seat is no greater than the pressure permitted by § 78.73(c) and demonstrates that all gas and fluids will be contained within the well."*

The proposed rule at § 78.83(a) starts off clear and robust. Clearly stated, casing functioning as a water protection casing shall not be utilized as production casing. This approach is logical, and important to groundwater resource protection. Water protection casing should be an ***additional*** string of piping, cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe. By contrast with the clear initial prohibition, however, the two proposed exceptions to this rule at § 78.83(a)(1)-(2) do not make sense, and serve to compromise the protective barrier that surface casing is intended to create.

As drafted, § 78.83(a)(1) proposes to allow the surface casing to serve as production casing in an oil well where no gas is generated by the well and the annulus between the surface casing and the "production pipe" is left open. The term "production pipe" is not defined in DEP regulation at § 78.1, and it is not clear what piping string DEP is referencing. Is this DEP's term for production tubing? This proposed exemption is not clear or technically supported.

As drafted, § 78.83(a)(2) proposes to allow the surface casing to serve as production casing in all wells if an operator demonstrates that the casing seat pressure does not exceed § 78.73(c) (which the operator is required to do anyway so this is not an incremental requirement) and if the operator demonstrates that all gas and fluids will be contained within the well. Yet DEP sets no criteria or approval process for making this showing. The proposed exemption at § 78.83(a)(2) defeats the purpose of requiring § 78.83(a).

Recommendation No. 23: DEP regulations at § 78.83(a) should be revised to read: Surface casing or any casing functioning as a water protection casing shall not be utilized as production casing.

Exemptions proposed at § 78.83(a)(1)-(2) should be deleted or further technical justification should be provided by DEP to explain why these proposed requirements are more protective of human health and the environment.

DEP's proposed regulations at § 78.83(c) require an operator to set surface casing 50' below the deepest fresh ground water or into consolidated rock, whichever is deeper. The technical basis for selecting a 50' depth is not explained.

New York State has instituted more restrictive Fresh Water Aquifer Supplementary Permit Conditions on permits to drill for wells that pass through primary and principal aquifers, including setting surface casing at least 100' below the deepest fresh water zone and at least 100' into bedrock. Similar to DEP's proposal later at § 78.83(f), NYS allows for this setting depth to be adjusted to ensure the casing seat is set above any hydrocarbon interval. DEP should provide a technical basis to show how the 50’ depth criteria is sufficient to protect water resources, or DEP should increase it to the more protective standard of 100’.

Recommendation No. 24: DEP regulations at § 78.83(c) should be revised to increase the surface casing setting depth to 100’ below the deepest fresh water zone and at least 100' into bedrock. Correspondingly, DEP’s proposed regulation at § 78.83(f) needs to be adjusted to increase the 50’ criterion to 100’.

DEP’s proposed regulations at § 78.83(f) reads:

> *“The operator shall permanently cement the surface casing by placing the cement in the casing and displacing it into the annular space between the wall of the hole and the outside of the casing.”*

This language does not clearly require a continuous, equally thick layer of cement around the pipe. Nor does this language clarify that cement must be placed behind the casing from the bottom of the casing (casing seat) to the surface.

The most common methods of placing cement behind surface casing are the pump and plug or displacement methods that use sufficient cement to ensure a protective cement bond is achieved from the bottom of the casing to the top of the hole. To ensure that a continuous, equally thick layer of cement is achieved, with no void spaces, industry standard practice is to pump excess cement and verify its return at the surface. Pumping a minimum of 25% excess cement is common. If the excess cement does not return at the surface, a bond was not achieved behind the entire section of surface casing. In this case, steps must be taken to remedy the failed cement job. A common method is to install a cement basket and pump cement down the annulus from the surface. A cement bond log should be run to verify cement integrity prior to proceeding further in the wellbore.

Recommendation No. 25: The following language should be added to DEP regulations at § 78.83(f): Surface casing must be cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe. Cement must be placed behind surface casing by the pump and plug or displacement method and a sufficient amount of cement (at least 25% excess) must be used to ensure a protective cement bond is achieved from the bottom of the casing to the top of the hole. If the excess cement does not return at the surface, the operator must take steps to remedy the failed cement job, including pumping cement down the annulus from the surface to fill any void spaces. A cement bond log must be run to verify cement integrity prior to proceeding further in the wellbore. If the cement bond long does not verify placement of a continuous, solid layer of cement behind the surface casing from the bottom of the casing to the top of the hole, an additional string of casing must be set pursuant to § 78.83b(a)(1).

DEP’s regulations at § 78.83(g) reads:

> *“If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, the operator shall protect the additional fresh groundwater by installing and cementing a subsequent string of casing or other procedures approved by the Department to completely isolate and protect fresh groundwater. The string of casing may also penetrate zones bearing salty or brackish water with cement in the annular space being used to segregate the*

various zones. Sufficient cement shall be used to cement the casing at least 20 feet into the permanently cemented casing."

This regulation essentially says that if an operator sets surface casing too early,[18] and then continues to drill through freshwater, the operator must set another string of protective casing to "*completely isolate and protect the fresh groundwater*." The requirement to set a second set of casing is appropriate. This second set of casing is called "intermediate casing" and is a defined term in DEP regulations. The regulations should use this term for clarity.

The last line of this regulation requires the operator to place cement only 20' behind the intermediate casing, just above the casing shoe. This amount of cement is inadequate to "*completely isolate and protect the fresh groundwater*."

Depending on the intermediate casing seat depth, it may be possible to place cement behind the entire casing string. As explained above, industry trade groups operating in the Marcellus Shale in Pennsylvania[19] recommend 13-3/8" intermediate casing at depths up to 1,000' be cemented behind the entire section. Intermediate casing provides a second protective barrier across a freshwater aquifer. However, it is not usually possible to cement the entire intermediate casing string if it is more than a few thousand feet deep. In this case, intermediate casing strings are partially cemented in place to secure the lower section of the pipe. Most states specify a minimum number of feet of cement be placed behind intermediate casing (e.g. 500-600'). It is recommended that DEP apply similar standards.

Of note, § 78.83(g) conflicts with the new proposed regulation at § 78.83c for intermediate casing requiring cementing of at least 600' (which is more consistent with current regulatory practices in other states).

Recommendation No. 26: DEP regulation at § 78.83(g) should be revised to remove the last line and replace it with a requirement to install cement behind the entire section of the intermediate casing string, unless the operator can demonstrate it is not technically feasible to circulate cement all the way to the surface due to the depth of intermediate casing. In that case, a minimum of 600' of cement must be placed behind the casing, above the casing shoe. In all cases, the cement must be firmly affixed in the wellbore in a central location with a continuous, equally thick layer of cement around the pipe.

Inconsistencies between regulations at § 78.83(g) and § 78.83c should be remedied, because both seem to be addressing intermediate casing.

DEP's existing regulation at § 78.83(f) reads:

"Where potential oil or gas zones are anticipated to be found at depths within 50 feet below the deepest fresh groundwater, the operator shall set and permanently cement surface casing prior to drilling into a stratum known to contain, or likely containing, oil or gas."

As recommended above at § 78.83 (c) the 50' depth should be increased to 100', and the regulation should be clear that surface casing should stop above any significant pressure zone or hydrocarbon zone, to ensure the blowout preventer can be installed prior to drilling into a pressured zone or hydrocarbon

[18] Or in the in the case that freshwater intervals are separated by intervals of shallow gas requiring multiple casing strings to be set.
[19] *See* note 2, *supra.*

zone; and surface casing needs to be set to provide a protective barrier to prevent hydrocarbons from contaminating freshwater aquifers when the well is drilled deeper (below the surface casing).

Recommendation No. 27: Revise § 78.83(f) to read: Where potential oil or gas zones are anticipated at depths within 100 feet below the deepest fresh groundwater, the operator shall set and permanently cement surface casing prior to drilling into a stratum known to contain, or likely containing, oil or gas, to provide a protective barrier to prevent hydrocarbons from contaminating the fresh water aquifers when the well is drilled deeper. A blowout preventer must be installed prior to drilling into a pressured hydrocarbon zone.

DEP's existing regulation at § 78.83(c) and (h) require the use of centralizers. Centralizers are necessary to center the casing in the hole and ensure that a concentric cement ring is placed around the pipe, sealing the annular space between the wellbore and the casing. Once the casing is set, there is still drilling fluid inside the casing and in the annular space between the casing and the wellbore wall. Drilling mud is displaced out of the hole by pumping cement down the inside of the casing and up the back side of the annulus. Poorly centralized casing will allow the cement to bypass the drilling fluid, following the path of least resistance (usually down the wide side of the annulus), leaving drilling fluid behind the casing on the narrow side of the annulus; if this happens, a section of the annulus is not properly cemented/sealed. Centralizers serve many functions including: centering the casing; preventing drag while casing is run in the hole; minimizing differential sticking; aiding in mud displacement; and reducing mud channeling when cementing is underway. Centralizers need to be installed either on a casing collar or a mechanical stop collar. American Petroleum Institute Specification (API) 10D is the industry standard for proper selection, design, and placement of centralizers. It is recommended that this standard be referenced in the regulations, because the distance between centralizers is only one of the design criteria that should be considered when properly selecting, installing, and running casing centralizers.

Recommendation No. 28: Revise § 78.83(c) and (h) to include American Petroleum Institute Specification (API) 10D standard for centralizers.

DEP has proposed three new regulatory sections at § 78.83, and has labeled them § 78.83a, § 78.83b, and § 78.83c. Presumably these sections also apply to surface and coal protective casing and cementing procedures, although this is not clear and should be stated, or these requirements should just be added by expanding the existing standard at § 78.83 beginning at the letter (l) where the last regulation left off.

This numbering scheme has the potential to cause confusion with existing regulations at § 78.83(a), § 78.83(b) and § 78.83(c) and is not consistent with DEP's numbering scheme. As proposed, DEP's numbering scheme will include regulations labeled § 78.83(a) and § 78.83a(a).

Recommendation No. 29: Revise the § 78.83a, § 78.83b, and § 78.83c numbering scheme for consistency with existing DEP regulation format. DEP should clarify that these new standards apply to surface and coal protective casing and cementing procedures.

DEP has proposed a whole new regulatory section at § 78.83a that requires the operator to prepare and maintain a casing and cementing plan. DEP's proposed regulation at § 78.83a reads:

> *"§ 78.83a Casing and Cementing Plan*
> *(a) The operator shall prepare and maintain a casing and cementing plan showing how the well will be drilled and completed. The plan shall demonstrate compliance with this subchapter and include the following information:*

(1) The anticipated depth and thickness of any producing formation, expected pressures, and anticipated fresh groundwater zones.
(2) Diameter of the well bore,
(3) Casing type, depth, diameter, wall thickness and burst pressure rating.
(4) Cement type, additives and estimated amount.
(5) Estimated location of centralizers.
(6) Alternative methods or materials as required by the Department as a condition of the well permit.

(b) The plan shall be available at the well site for review by the Department.
(c) Upon request, the operator shall provide a copy of the well specific casing and cementing plan to the Department for review and approval.
(d) Any revisions to the plan made as a result of on-site modification must be documented by the operator and be available for review by the Department"

The proposed regulation is unclear. § 78.83a(a) requires the operator to prepare and maintain a casing and cementing plan, but does not require this plan to be submitted to DEP for review or approval.

Since the casing and cementing plan is not reviewed by DEP as part of the well permit (unless per § 78.83a(c) and DEP specifically requests it), how does DEP develop a list of "alternative methods or materials required" for the casing and cementing plan under § 78.83a(a)(6)? And how does DEP include that information in the well permit as described under § 78.83a(a)(6), if it doesn't normally review and approve casing and cementing plans?

Simply put, due to the importance of properly installing casing and cementing to protect groundwater, casing and cementing plans should be submitted to DEP as part of the well permit application, so that DEP can review, approve, and provide informed technical guidance to the operator in advance. Too often, regulators get involved in the tail end of the process, when the casing has been run, and the cement job has failed. Efficient and economic corrections are difficult to achieve at this stage. Advance review and approval is appropriate.

DEP proposes that the casing and cementing plan at § 78.83a(a)(1-6) include specific information. At § 78.83a(a)(3) DEP requests information on the casing burst pressure rating. Pipe strength information should be expanded beyond burst strength, to include collapse resistance and tensile strength, because to design a reliable casing string you must know the strength of the pipe under different load conditions.[20]

At § 78.83a(a)(3) DEP requests information on the casing type. This information should be expanded to include whether the casing is new or used casing, and if used, the date, condition, and location of prior use and prior service history should be recorded. As noted later in comments at §78.84, it is strongly recommended that no used casing be allowed for surface casing or intermediate casing, when its primary function is to protect groundwater. New casing should be used in these cases. However, in cases where used casing may be allowed by DEP (e.g. production casing), it is critical that DEP have a very thorough understanding of the service history and quality prior to allowing reuse.

The casing and cementing plan should include a quality control and quality assurance section that ensures the design specifications established by the engineering team, and approved by DEP, are followed in the field, and cement bond logs and pressure tests are run to verify integrity.

[20] Petroleum Engineering Handbook, Volume II, Drilling Engineering, Society of Petroleum Engineers, 2006.

Recommendation No. 30: Revise § 78.83a(a) to require the operator to prepare and submit a casing and cementing plan to DEP for review and approval as part of the well permit application.

DEP should review and approve a complete well drilling and completion plan application including a casing and cementing plan, as part of the well permitting process, so that appropriate permit stipulations may be placed in the permit.

Expand § 78.83a(a)(3) to include information on the casing's collapse resistance and tensile strength. Also require information on casing age, condition, location of prior use, and prior service history.

The casing and cementing plan should include a quality control and quality assurance section and should demonstrate conformance with the objectives of § 78.71, and procedures and standards of §§ 78.81-87.

The same recommendations regarding excess cement returns made at § 78.83(f) apply here at §78.83b(a).

Recommendation No. 31: Revise § 78.83b(a) to include the recommendations made at § 78.83(f) regarding a minimum 25% excess cement return.

The newly proposed regulations at § 78.83b(a)(1)-(2) and (b) are confusing, inconsistent with best practices for protecting groundwater, and conflict with the newly proposed intermediate casing regulations at § 78.83c(a)-(c).

The newly proposed regulations at § 78.83b(a)(1)-(2) read:

" (a) If cement used to permanently cement the surface or coal protective casing is not circulated to the surface, the operator shall do one of the following:

(1) Run an additional string of casing at least 50 feet deeper than the surface casing and cement the second string of casing back to the seat of the surface or coal protective casing and vent the annulus of the additional casing string to the atmosphere at all times unless closed for well testing or maintenance.

(2) if the additional string of casing is the production casing, the operator shall set the production casing on a packer and vent the annulus of the production casing to the atmosphere at all times unless closed for well testing or maintenance.

(a) If cement used to permanently cement the surface or coal protective casing is not circulated to the surface cement, the Department may require the operator to determine the amount of casing that was cemented by logging or other suitable method."

Under § 78.83b(a) when surface casing is set, if a cement job fails, and another set of casing (called intermediate casing) must be run, the operator would then go to the new section of the regulations at §78.83c(a)-(c) that provides instruction on how to install intermediate casing. This makes the new regulation at § 78.83b(a)(1) unnecessary. And as explained in the earlier recommendations at § 78.83, it may be possible to cement the entire section of intermediate casing, depending on depth. If possible, the entire length should be cemented in place.

§ 78.83b(a)(2), as proposed, does not make sense. It proposes to allow **<u>production casing</u>** to serve as a **<u>groundwater protection</u>** casing in the event surface casing is run, and the cement job fails. The reason this does not make sense is that an operator with a failed surface casing cement job would have to drill into a hydrocarbon bearing zone to set production casing, potentially exposing groundwater to hydrocarbon contamination.

Simply put, production casing cannot serve as groundwater protection casing. **<u>Groundwater protection casing must be set below the groundwater, but above the hydrocarbon zone</u>**, firmly anchored. If the first set of surface casing was not cemented in place properly, a second set (intermediate casing) must be run and cemented in place to ensure groundwater protection, prior to entering the hydrocarbon zone.

The production casing, by DEP's own definition at § 78.1, is: *"A string of pipe other than surface casing and coal protective casing which is run for the purpose of confining or conducting hydrocarbons and associated fluids from one or more producing horizons to the surface."* To set production casing, the operator would have to drill into the hydrocarbon-bearing zone; meanwhile, keep in mind that if the surface casing was not properly cemented, drilling into the production zone creates a potential pathway for hydrocarbons to reach groundwater behind improperly cemented casing.

§ 78.83b(b) is even more perplexing, because after reading § 78.83b(a), where the operator is clearly instructed to run another string of casing after a failed surface casing and cement job, § 78.83b(b) requests the operator to further examine the cement condition by logging or other methods. A more logical progression, and a more common progression, is the one explained above in the surface casing regulations. The surface casing cementing program should be designed with at least 25% excess cement. Excess cement should be observed at the surface. Cement bond logs should be run as a normal suite of quality control and assurance, to verify cement quality prior to proceeding. If necessary, additional cementing may be needed to fill voids (if any). If the cement job cannot be remedied, with routine cementing procedures, it may be necessary to run a string of intermediate casing and cement it in place.

> **Recommendation No. 32**: Revise § 78.83b to clearly state that if surface casing is not properly cemented in place with at least 25% excess cement returns at the surface, intermediate casing must be run and cemented in place following the recommendations made above at § 78.83. Cement bond logs should be run to verify cement quality. The proposal to allow an operator to continue drilling into a hydrocarbon bearing zone to set production casing, in the presence of a known failed surface casing cement job, is technically unsound and environmentally hazardous, and should be deleted.

11. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Casing Standards, § 78.84

DEP's casing standard requirement at § 78.84(a) should include a requirement to design and install casing to withstand the effects of corrosion and erosion, in addition to the other factors listed. This can included using coated piping, higher grade pipe, or thicker walled pipe with a higher corrosion allowance.

> **Recommendation No. 33**: Revise § 78.84(a) to include a requirement to design and install casing to withstand the effects of corrosion and erosion.

DEP has added a new regulation at § 78.84(b) that reads:

> *"(b) Surface casing shall be a string of new pipe with a pressure rating that is at least 20 percent greater than the anticipated maximum pressure. Used casing may be approved for use but must be pressure tested after cementing and before continuation of drilling. A passing pressure test is holding the anticipated maximum pressure for 30 minutes with not more than a 10 percent change in pressure."*

This standard allows the use of new or used surface casing. The quality of intermediate casing is not addressed.

Surface casing should not be constructed of used casing. Surface casing and intermediate casing should be made of new, high-quality piping. Keep in mind that surface casing and intermediate casing both play an important role in: preventing the contamination of freshwater; confining fluids to the wellbore; preventing migration of fluids and hydrocarbons from one stratum to another; ensuring control of well pressures encountered; and providing well control until the next casing is set. Oil and gas wells may be subject to elevated temperatures, pressures, erosion, corrosion, and other factors that reduce the operating life of the casing string, and its ability to protect groundwater supplies. Installation of new piping maximizes public and environmental protection, by extending the life cycle of the well.

Recommendation No. 34: DEP regulation at § 78.84(b) should be revised to read: (b) Surface and intermediate casing shall be a string of new casing with a pressure rating that is at least 20 percent greater than the anticipated maximum pressure.

Similarly, DEP should revise § 78.84(c) to require new welded piping for surface and intermediate casing strings.

The exemption for not obtaining API welder's certification at § 78.84(c)(3) appears to have a typo. Should it be "within **90 days** of the effective date," instead of "within **9** of the effective date"? The justification for the welding certification exemption is not clear. API welder's certifications were developed to improve the quality and consistency of casing and other types of piping welds. There are rigorous training and qualification requirements, and quality control and assurance procedures that must be followed. If a welder is not API certified, DEP should evaluate if there is an equivalent state welding certification training program in Pennsylvania that could be substituted. Alternatively, DEP should consider if a Pennsylvania certification program could be developed to test and certify those with existing experience, to validate their training, experience, and quality control and quality assurance procedures.

The technical basis for grandfathering in welders with 10 years or more experience is not clear. While these welders may have many years of welding experience, the concern is that they may not be familiar with the new quality control and quality assurance procedures that have been developed. Certification programs provide continuing education opportunities and information on new techniques as they are developed.

Recommendation No. 35: Revise § 78.84(c) to require new welded piping for surface and intermediate casing strings and API welder's certification. Alternatively, consider substitution of the API certification with an equivalent state welding certification training program. Allow a reasonable transition period to allow welders time to obtain this new certification.

12. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Cement Standards, § 78.85

DEP's revised cement standard at § 78.85 (a) reads:

> *"(a) The operator shall use cement that meets or exceeds the ASTM International C 150, type I, II or II standard. The cement shall also:*
> *(1) Secure the casing in the well bore,*
> *(2) Isolate the wellbore from fresh groundwater,*
> *(3) Contain any pressure from drilling, completion and production,*
> *(4) Protect the casing from corrosion, and*
> *(5) Resist degradation by the chemical and physical conditions in the well.*
> *(6) Prevent gas migration"*

The proposed language at § 78.85 (a) appears to have a few typos: type II is listed twice; in subsection (4), the word "and" should be deleted; in subsection (5), the period should be replaced with a comma, followed by the word "and"; and subsection (6) should close with a period.

In addition to preventing gas migration, as noted at § 78.85 (a)(6), cement should also prevent migration of fluids and hydrocarbons from one stratum to another.

Recommendation No. 36: Revise § 78.85(a) to correctly reference the ASTM International Standard for Portland Cement. Correct the typographical errors in Revise § 78.85 (a)(4)-(6). Revise § 78.85(a)(6) to read: Prevent migration of fluids and hydrocarbons, including gas, from one stratum to another.

DEP's existing regulation at § 78.85(b) includes a 350 psi compressive strength standard. As recommended, and described in detail in the comment on the definition of "cement" at § 78.81, DEP should consider a higher compressive strength standard to protect groundwater, especially in the critical zone of cement.

Recommendation No. 37: Revise § 78.85(b) to increase the compressive strength standard, consistent with the recommendations made at § 78.81.

13. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Mechanical Integrity of Operating Wells, § 78.88

DEP has proposed a new section of regulations for operating wells at § 78.88. The proposed regulations at § 78.88(a) require quarterly well inspections to verify the operating condition of the well, identify maintenance and repair needs, and take corrective action. Routine well integrity monitoring is best practice. Quarterly inspections, however, are too infrequent. Daily, or at least weekly, inspections are recommended.

Recommendation No. 38: Revise § 78.88(a) to increase the operating well inspection frequency to daily, or at least weekly.

DEP's proposed regulation at § 78.88(b)(3) requires the operator to determine if gas is escaping from the well, and the amount. DEP's proposed regulation at § 78.88(b)(4) requires the operator to determine if there is evidence of progressive corrosion, rusting, or other signs of equipment deterioration. Yet, DEP does not require the operator to take any action to stop the gas leak or remedy the corrosion, or equipment deterioration, except to take action to meet § 78.73(c) (to minimize pressure at the casing seat) or report the mechanical integrity problem at § 78.88(e).

Recommendation No. 39: Revise §7 8.88 to require wells with mechanical integrity problems to be repaired, shut in, or plugged and abandoned, as appropriate and safe to protect human health and the environment. The annual mechanical integrity report required at § 78.88(e) should summarize both the compliance status of each well and what action was taken to remedy non-compliant wells.

14. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Stray Gas Mitigation Response, § 78.89

DEP has proposed a new section of regulations for stray gas mitigation response at § 78.89. A stray gas mitigation response regulation is an excellent addition; however, the title should be expanded beyond "stray gas" to address the broad range of responses described and anticipated in § 78.89 (a), including "oil" and "other fluids" (presumably chemicals and well stimulation fluids).

Recommendation No. 40: Revise § 78.89 throughout, to address potential leaks and/or contamination from "stray gas," "oil," and/or "other fluids," including but not limited to chemicals and well stimulation fluids.

DEP's proposed regulation at §78.89(b) requires the operator to "immediately" notify DEP and conduct an investigation when the operator becomes aware of a "stray gas incident". Yet there is no timeframe designated for when the operator and DEP need to respond to the situation. The notification requirement and response action obligation should be extended to incidents including "oil" and "other fluids".

Recommendation No. 41: Revise the last sentence of § 78.89(b) to read: The operator, in conjunction with the Department and local emergency response agencies, shall **immediately** take measures to ensure public health, safety, and welfare. The requirements proposed at § 78.89(b) should be extended to oil and other chemicals.

15. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Plugging, § 78.91-98

Properly plugging and abandoning a well is critical to the protection of groundwater resources. In addition to DEP regulations at §§ 78.91-78.98, DEP should consider enhancing the regulations to require longer and additional cement barriers to ensure that hydrocarbons and freshwater are confined to their respective indigenous strata, and are prevented from migrating into other strata or to the surface. For example, while

DEP uses a 50' cement barrier, other states like Alaska require double the protection at 100'.[21] Texas requires an operator to submit a plugging procedure for agency review and approval.[22]

Recommendation No. 42: Revise the regulations at §§ 78.91-78.98 to include the following:

Plugging a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface.

All hydrocarbon-bearing strata should be permanently sealed off by installing a cement barrier at least 100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata.

Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe.

The operator is required to submit records to DEP to demonstrate that the well was plugged in compliance with DEP regulations.

16. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Well Record and Completion Report, § 78.122

DEP regulations at § 78.122(a)(6) should be expanded to include intermediate casing.

Recommendation No. 43: Revise the regulations at § 78.122(a)(6) to include intermediate casing.

DEP regulations at § 78.122(a)(7) should be expanded to include the requirement to submit an electronic copy of the cement bond log to verify cement integrity behind any casing used to protect groundwater resources, including surface and intermediate casing.

Recommendation No. 44: Revise the regulations at § 78.122(a)(7) to require submission of an electronic copy of the cement bond log.

DEP regulations at § 78.122(a) should be expanded to address waste.

Recommendation No. 45: Revise the regulations at § 78.122(a) to require a list of waste generated during drilling and workover operations, and a description of the waste handling and disposal methods and locations.

DEP revised the regulations at § 78.122(b)(6) to require additional information on stimulation procedures. It is recommended that the "composition" of stimulation fluids, including a list of all additives, identifying all chemical components, be reported.

[21] 20 AAC 25.
[22] 16 TAC Part 1§3.14

The lowest environmental impact methods should be considered. Possible methods for further DEP examination include:

1. Waste minimization (drilling mud recycle and reuse when possible);
2. Use of drilling mud additives with lower environmental impact;
3. Beneficial reuse of uncontaminated drilling wastes;
4. Use of closed loop tank systems to transport waste, versus use of reserve pits;
5. Burial (e.g. landfills, or reserve pits);
6. Commercial treatment and disposal facilities; and/or
7. Underground injection.

Recommendation No. 46: Revise the regulations at § 78.122(b)(6) to include information on the chemical additives, including all chemical components. Reported information should include biodegradability, bioaccumulation potential, toxicity, and any detrimental mutagenic or reproductive affects. Best practices would include a requirement to forbid chemicals that have low biodegradability, high bioaccumulation potential, high acute toxicity, or detrimental mutagenic or reproductive affects.

DEP regulations at § 78.122(b) should be expanded to provide a list of all waste generated during well completion operations, and a description of waste handling and disposal methods and locations. See waste management methods for consideration in Recommendation 45 above.

Recommendation No. 47: Revise the regulations at § 78.122(b) to require a list of waste generated during well completion operations, and a description of the waste handling and disposal methods and locations.

17. Copyrighted Standards

DEP should obtain a public access license to all copyrighted standards (e.g. API, ASTM) that are not available in the public domain. Regulations should be available for public review and comment, without having to purchase very expensive copies of copyrighted standards to understand the criteria and requirements that DEP is proposing. It is useful to reference technical standards and best practices when they serve to provide clear instruction; however, the public must be able to read and understand the regulations without an unreasonable financial burden. The cost to obtain a copy of these copyrighted standards can range up to several hundred dollars per standard.

Recommendation No. 48: Ensure that the public has access to all technical standards and criteria referenced in DEP's regulations. A public access version should be made available on the DEP website.

18. Inspection and Enforcement Program

Drafting new regulations to minimize contamination from oil and gas development in Pennsylvania is an important first step. New regulations must be accompanied by a rigorous inspection and enforcement program. It would be very useful for DEP to provide information on how it plans to expand and enhance its current inspection and enforcement program. DEP should provide more information on the following topics: budget, number of inspectors, inspector qualifications and expertise, frequency of inspections, type of inspections, and enforcement procedures and guidelines.

DEP should demonstrate that it has sufficient resources to oversee, inspect, and enforce the proposed enhanced regulations. This increases public confidence that a plan is not only required, but that DEP will ensure that it is followed.

Recommendation No. 49: DEP should provide information on how it plans to expand and enhance its current inspection and enforcement program to ensure regulatory compliance.

Exhibit B

Harvey Consulting, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Resume Summary

Susan L. Harvey, Owner
PO Box 771026
Eagle River, Alaska 99577

Education Summary:

Environmental Engineering	Petroleum Engineering
Masters of Science	**Bachelor of Science**
University of Alaska Anchorage	University of Alaska Fairbanks

Specific Areas of Expertise:

- Subsurface oil and gas reservoir engineering analysis
- Surface oil and gas system design and analysis
- Oil and gas leasing, right of way, royalty, tax and economic issues
- Oil and gas laws, regulations and permitting requirements
- Air quality environmental engineering and analysis
- Oil spill prevention and response planning
- Waste management and NPDES permitting for oil and gas projects
- Experience working in remote and rural areas and conditions

Employment Summary:

2002-Current	Harvey Consulting, LLC., Owner
2005-Current	Harvey Fishing, LLC., Owner
2002-2007	University of Alaska at Anchorage, Environmental Engineering Graduate Level, Adjunct Professor
1999-2002	State of Alaska, Department of Environmental Conservation, Environmental Supervisory Position
1996-1999	Arco Alaska Inc., Engineering and Supervisory Positions held
1989-1996	BP Exploration (Alaska), Inc., Environmental, Engineering, and Supervisory Positions held
1987-1989	Standard Oil Production Company *(purchased by BP in 1989)*, Engineering Position
1985-1996	Conoco, Engineering Internship and New Mexico Institute of Mining and Technology Petroleum Research & Recovery Center, Laboratory Research Assistant

Susan L. Harvey, Owner
PO Box 771026
Eagle River, Alaska 99577

Employment Detail:

2002-Current Harvey Consulting, LLC.
Owner of consulting business in Eagle River Alaska, providing oil and gas, environmental, regulatory compliance and training to clients in Alaska and the Lower 48 States.

2005-Current Harvey Fishing, LLC.
Owner of commercial salmon fishing business in Main Bay, Prince William Sound Alaska, providing healthy, high quality, sockeye salmon to markets in the US.

2002-2007 University of Alaska at Anchorage
Environmental Engineering Graduate Level Program, Adjunct Professor.
Air Quality Engineering (Master's Level)

1999-2002 State of Alaska, Department of Environmental Conservation
Environmental Supervisory Position
Industry Preparedness and Pipeline Program Manager, Alaska Department of Environmental Conservation, Division of Spill Prevention and Response. Managed 30 staff in four remote offices. Main responsibility was to ensure all regulated facilities and vessels across Alaska submitted high quality Oil Discharge Prevention and Contingency Plans to prevent and respond to oil spills. Staff included field and drill inspectors, engineers, and scientists. Managed all required compliance and enforcement actions.

1996-1999 Arco Alaska Inc.
Engineering and Supervisory Positions held
Prudhoe Bay Waterflood and Enhanced Oil Recovery Engineering Supervisor. Main responsibility was to set the direction for a team of engineers to design, optimize and manage the production over 120, 000 barrels of oil per day from approximately 400 wells and nine drill sites, from the largest oil field in North America.

Prudhoe Bay Satellite Development Engineering Supervisor for development of six new Satellites Oil Fields. Main responsibility was to set the direction for a multidisciplinary team of Engineers, Environmental Scientists, Facility Engineers, Business Analysts, Geoscientists, Land, Tax, Legal, and Accounting.

Lead Engineer for Arco Western Operating Area Development Coordination Team. Lead a multi-disciplinary team of engineers and geoscientists, working on the Prudhoe Bay oil field.

1989-1996 **BP Exploration (Alaska), Inc.**
Environmental, Engineering, and Supervisory Positions held

Senior Engineer Environmental & Regulatory Affairs Department. Main responsibilities included: air quality engineering and permitting support for Northstar, Badami, Milne Point Facilities and Exploration Projects.

Senior Engineer/Litigation Support Manager. Duties included managing a multidisciplinary litigation staff to support the ANS Gas Royalty Litigation, Quality Bank Litigation and Tax Litigation. Main function was to coordinate, plan and organize the flow of work amongst five contract attorneys, seven in-house attorneys, two technical consultants, eight expert witnesses, four in-house consultants and twenty-two staff members.

Senior Planning Engineer. Provided technical, economic, and negotiations support on Facility, Power, Water and Communication Sharing Agreements. Responsibilities also included providing technical assistance on recycled oil issues, ballast water disposal issues, chemical treatment options, and contamination issues.

Production Planning Engineer. Coordinated State approval of the Sag Delta North Participating Area and Oil Field. Resolved legal, tax, owner and facility sharing issues. Developed an LPG feasibility study for the Endicott facility.

Reservoir Engineer. Developed, analyzed and recommended options to maximize recoverable oil reserves for the Endicott Oil Field through 3D subsurface reservoir models, which predicted fluid movements and optimal well placement for the drilling program. Other duties included on-site wellbore fluid sampling and subsequent lab analysis.

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, rig completions, and well testing programs.

1987-1989 **Standard Oil Production Company, Production Engineer**

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, rig completions, and well testing programs. Engineering Internship, Barry Waterflood Oklahoma City OK.

1986 **Conoco, Production Engineer**

Production Engineer. Engineering Internship, Hobbs New Mexico.

1985-1986 **New Mexico Institute of Mining and Technology**
Petroleum Research & Recovery Center

Laboratory Research Assistant, Enhanced Oil Recovery, Surfactant Research.