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Ms. Veronica Larson
Texas Railroad Commission
1701 N. Congress Ave.
Austin, Texas 78701

RE: Informal Comment on Revised Version of Proposed Rule 13 (16 TAC §3.13, relating to Casing, Cementing, Drilling, and Completion Requirements)

Dear Ms. Larson:

In association with the Texas Land and Mineral Owners Association (TLMA), Treybig Enterprises, Inc. is submitting this letter for the purpose of presenting suggested changes to the wording in those parts of Rule 13, 16 TAC §3.13 that are related to the placement of cement slurries around casing strings and the associated purpose of preventing fluids migration in the annulus and/or sustained casing pressure. The current language in those parts of the rule, if allowed to stand as proposed, will permit the creation of conditions in the casing annuli which are favorable for inter-zonal fluid flow and vertical migration of liquids and gases to the surface. These two conditions are the principal sources of sustained casing pressure on wellheads at the surface. Sustained casing pressure is a serious problem as it can present substantial risks to the safety of personnel, damage to property, and contamination of groundwater. It is our understanding that there are a large number of wells in the state that now have sustained casing pressure on the wellheads. The proposed wording in this rule will certainly not reduce the number of those wells; rather, it will establish a lower standard of care and will increase the number of wells with sustained casing pressure and/or uncontrollable subsurface flows between zones.

In the Railroad Commission's most recent revisions of 3.13, the intent for the proposed rule is that "...casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and *all productive zones, potential flow zones, and zones with corrosive formation fluids be isolated and sealed off to prevent vertical migration of fluids and gases behind the casing*. When the section does not detail specific methods to achieve these objectives, the responsible party shall *make every effort to follow the intent of this section, using good engineering practices and the best available technology*."

In order to satisfactorily satisfy the intent of this rule, the content of the rule must provide a clear and relevant set of operating practices that are in agreement with the intent, and are based upon established

engineering principles and the best available technology within the industry. The recognized industry standard for documenting the latest technology and practices for the prevention of annular flow in wells is API Standard 65 - Part 2, "Isolating Potential Flow Zones During Well Construction", Second Edition, December 2010.

Recognized Industry Standard

The scope and intent of API Standard 65 - Part 2 are stated as follows:

- "This standard contains practices for isolating flow zones, an integral element in maintaining well integrity. The focus of this standard is the prevention of flow through or past barriers that are installed during well construction. Barriers that seal wellbore and formation pressures or flows may include mechanical barriers such as seals, cement, or hydrostatic head..." [Section 1.1,Overview]
- "The objectives of this guideline are two-fold. The first is to help prevent and/or control flows just prior to, during, and after primary cementing operations... The second objective is to help prevent sustained casing pressure (SCP)..." [Section 1.2, Objectives]
- "The process of barrier element selection and installation (including cement) is governed by the anticipated presence or absence of potential flow zones that require isolation for well integrity or regulatory purposes.... The guidance from this document covers recommendations for pressure-containment barrier (cement, packer, etc.) design and well construction practices that affect the zonal isolation process to prevent or mitigate annular fluid flow or pressure. These practices may also help prevent loss of well control incidents and minimize the occurrence of sustained casing pressure during construction and production." [Section 1.4, Conditions of Applicability]

API Standard 65 - Part 2 has been used by the Bureau of Safety and Environmental Enforcement (BSEE), U.S. Department of the Interior as the basis for amending their regulations regarding well casing and cementing. On October 14, 2010, as a result of the BP Macondo blowout in the Gulf of Mexico, the Bureau of Offshore Energy Management, Regulation, and Enforcement (BOEMRE) published their Interim Final Rule (75 FR 63346), "Increased Safety Measures for Energy Development on the Outer Continental Shelf." In August 2012, the Bureau of Safety and Environmental Enforcement (BSEE), U.S. Department of the Interior amended the interim 2010 rule. One principal reason for updating the interim rule was the publication of API Standard 65, Part 2 in December 2010. The following wording was included in the Final Rule issued by the BSEE. "This Final Rule ... updates the incorporation by reference to the second edition of API Standard 65 - Part 2, which was issued December 2010. This standard outlines the process for isolating potential flow zones during well construction. The new Standard 65 - Part 2 enhances the description and classification of well-control barriers, and defines testing requirements for cement to be considered a barrier." Since the Federal Government relied on the information contained in API 65 - Part 2 to improve the existing regulations regarding the isolation of potential flow zones in the wells under their jurisdiction (waters of the outer continental shelf), the Texas Railroad Commission should have no problem with using that document for the basis for revising their rules regarding isolation of potential flow zones in the State of Texas. The conditions that could allow migration of formation gases and liquids in the annulus of a deep-water well located on the outer continental shelf of the Gulf of Mexico are the same conditions that could allow formation gases and liquids to migrate in an annulus of a shallow well in north Texas. Although there will undoubtedly be differences in the resulting pressure conditions in those two wells, the potential for subsurface pollution and loss of well control are the same.

API Standard 65 - Part 2 has also been used by Det Norske Veritas (DNV), an independent, international, risk management foundation, in preparing a set of recommended practices that cover the entire life cycle of shale gas wells. The specific areas of that recommended practice where API 65-2 was used were as guidance on well barriers and on cementing procedures. One of DNV's intended applications of their recommended practices was its use as a reference for development of shale gas specific regulations.

It is therefore clear that the contents of API Standard 65 - Part 2 are indeed intended to be used by the industry as a standard for developing procedures to prevent annular flow, or migration, of fluids in wellbores. Therefore in amending rule 3.13, it is most appropriate that the recommended practices contained in API Standard 65-Part 2 be used.

API Standard 65 - Part 2, Isolating Potential Flow Zones During Well Construction

The following excerpts from API Standard 65 - Part 2 are relevant to the rules that are addressed in this letter.

- Section 1.7 - Summary of Considerations
  - Certain cementing process elements… may be individually critical to isolating a potential flow zone or may be of minor consequence until made critical by a separate (sometimes unrelated) event or past well engineering decision.
  - Conversely, certain elements may not be dominant factors in the success in one cementing operation, yet vitally important in another.
- Section 3.1 - Definitions
  - Annular flow – *The flow of formation fluids (liquids and/or gases) from the formation into a space or pathway in an annulus within a well. The annular flow may follow various flow paths inside the annulus to other points including those at shallower or deeper depths.*
  - Barrier (barrier element) – *A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed.*
  - Formation fluids – *Fluids present within the pores, fractures, faults, vugs, caverns, or any other spaces of formations are called formation fluids whether or not they were naturally formed or injected therein. The physical state of formation fluids may be liquids or gases and include various types such as hydrocarbons, fresh or saline water, carbon dioxide, hydrogen sulfide, etc.*
  - Loss of well control – *A loss of well control incident is an uncontrolled flow of subterranean formation fluids such as gas, oil, water, etc. and/or well fluids into the environment or into a separate underground formation, in which case it is called an underground blowout.*
  - Physical barrier element – *Physical barrier elements can be classified as hydrostatic, mechanical, or solid chemical materials (usually cement).*
  - Pore pressure – *Pore pressure is the pressure of the fluid inside the pore spaces of a formation.*
  - **Potential flow zone** – *Any zone in a well where flow is possible when wellbore pressure is less than pore pressure.*
  - Sustained casing pressure (SCP) – *Pressure in an annulus of casing strings that is measurable at the wellhead that rebuilds to at least the same pressure level after pressure has been bled down. SCP is not due solely to temperature induced fluid expansion or a pressure that has been imposed by the operator.*
  - Well integrity – *A quality or condition of a well in being structurally sound with competent pressure seals by application of technical, or operational and organizational solutions that reduce the risk of uncontrolled release of formation fluids throughout the well life cycle.*

- Section 5.6.2 - Zonal Coverage Determination
  - (Potential flow zones) should be covered with cement slurries designed to prevent flow after cementing, and the cement placement mechanics should be designed to maximize drilling fluid removal.
  - Zones left uncemented may not flow in the short term if pore pressure is balanced by drilling fluid hydrostatic pressure. However, the phenomena such as barite sag and drilling fluid dehydration may lead to SCP.
- Section 5.7.1 - The primary goal of cementing is to maintain the required hydraulic isolation for the life of the well.
- Section 7.3 – Cement Evaluation
  - Caution should be exercised when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier. The interpretations of cement evaluation logs are opinions based on inferences from downhole measurements. As such, the interpretation of cement evaluation logs can be highly subjective.
- Annex B, Section B.2.7 - Barrier Design
  - The operational goal of *any* well design is to provide sufficient barriers between formations and between those formations and the surface. A well's barrier plan should include maintaining well control via hydrostatic pressure from fluids, selection of well control equipment, and the placement of cement or other mechanical barriers in the well.
  - The well design… should consider including a minimum of two barriers available during any operation to prevent uncontrolled flow from the well to the environment.
- Annex D – Critical Well Design Parameters
  - The planned top of cement *shall* cover the shallowest potential flow zone.
  - [**NOTE**] As stated in the Foreword of Standard 65 - Part 2, "As used in this standard, *shall* denotes a minimum requirement in order to conform to the recommended practice."

Current Revised Rule 3.13

The parts of rule 3.13 that are the subject of this letter are (a)(4)(C), (a)(4)(D), (b)(2)(A), (b)(3)(B), and (c)(1)(C). These parts are specifically concerned with the placement of cement slurries around casing strings. In order to properly amend these parts of the rule, it is first necessary to redefine several of the terms that are currently used in those parts. Those terms are, "productive zones", potential flow zones", and "zones with corrosive formation fluids". In all but (a)(4)(C) of the above parts of the rule, these three terms are used to define the extent of the cement coverage required by the rule. Based on the many comments made to the RRC during the previous comment periods, there is a high level of confusion and misunderstanding regarding these terms. The three terms are now defined in (a)(2) of the proposed rule as:

- (D) Productive zone – Any stratum known to contain oil, gas, or geothermal resources in commercial quantities in the area.
- (N) Potential flow zone – A zone designated by the director or identified by the operator using available data that needs to be isolated to prevent sustained pressurization of the surface casing/intermediate casing or production casing annulus sufficient to cause damage to casing and/or cement in a well such that it presents a threat to subsurface water or other subsurface resources, or sufficient to cause the fluids in the annulus to maintain a static fluid level at or less than 250 vertical feet below the protection depth.

- (O) Zone with corrosive formation fluids – Any zone containing formation fluids that are capable of negatively impacting the integrity of casing and/or cement or have a demonstrated trend of failure for similar casing and cement design in the field.

The given definition of "Productive zone" describes a zone that is a candidate for a completion attempt in that wellbore. Although there is no requirement that it have the capability to flow fluids into the wellbore, that condition could be made possible by stimulation treatments during the completion of the well. Since it is possible that a "productive zone" will allow fluid flow during the life of the well, it is necessary that it be covered with cement and properly sealed so that all of the formation fluids are transmitted directly from the zone into the production casing. It is important that all "productive zones" in the wellbore be cemented accordingly, whether or not they are included in the original completion.

Parts of the proposed definition of "Potential flow zone" are ambiguous and difficult to follow. The first condition that is used in the proposed definition is that it will create sufficient sustained pressurization of the annulus to cause damage to the casing or cement. Damage to the casing or cement does not have to occur for annular pressurization to be a problem. Annular flow can create enough additional pressure in the annulus to fracture formations below the last casing shoe. Once a formation has been fractured, and the *potential flow zone* has sufficient flow capacity, fluids from the *potential flow zone* will flow through the annulus and be injected into the fractured formation, i.e. an uncontrolled subsurface flow, or underground blowout. The second criteria used in this definition is that it will create sufficient sustained pressurization of the annulus to cause the fluids in the annulus to maintain a static fluid level at or less than 250 feet vertical depth below the protection depth. The protection depth is, by definition, the depth to which usable quality water must be protected. Also, under the provisions of (b)(1)(B) of this rule, surface casing must be set and cemented to protect all usable quality water strata. Therefore, surface casing must be set below the protection depth. The above definition states that the pressure in the potential flow zone will only sustain a column of fluid which extends no higher than the protection depth. Since the fluid level does not extend to the surface, the pressure gradient in the potential flow zone is less than a normal gradient. Therefore, when the fluid level in the wellbore (annulus) is at any depth above the protection depth, the fluids in the potential flow zone will not flow into the wellbore. Under that condition, where the fluid level is above the static fluid level depth, this zone could be a zone of lost circulation and would not be a source of either annular flow or sustained casing pressure. However, when by some means the pressure in the wellbore at the zone depth decreases to less than that in the potential flow zone, the fluids in the flow zone will flow into the wellbore (annulus). Under those conditions, the zone becomes a flow zone that requires cement coverage. In order to remove any misunderstandings or uncertainties regarding what zones are to be covered with cement, the description of "potential zone" should be as simple as possible. A much less confusing and ambiguous definition of "potential flow zone" is given in API Standard 65 – Part 2. That definition is, "*Any zone in a well where flow is possible when wellbore pressure is less than pore pressure*". It is suggested that the RRC delete the present definition and adopt a definition consistent with the API's definition. (The proposed definition is given in "Proposed Revised Wording for Rule 3.13", below.)

Included in the zones that require cement coverage in the revised rule are "zones with corrosive formation fluids". The proposed definition is, "*Any zone containing formation fluids that are capable of negatively impacting the integrity of the casing and/or cement or have a demonstrated trend of failure for similar casing and cement design in the field.*" This definition only describes what types of fluids are contained in the zone. It says nothing about the zone having the capacity or capability to permit those fluids to flow into the annulus. Unless the fluids flow into the annulus, they will not have access to the casing or the

cement. Only if the zone has sufficient permeability to allow the fluids to flow into the annulus would there be a need to seal that zone to protect the casing and cement. If the zone is capable of producing flow into the annulus, it would be a potential flow zone and would be covered by that definition. Therefore, the proposed definition of, and all references to, "zones with corrosive formation fluids" should be removed from rule 3.13. In doing this, the RRC would eliminate the basis for a number of comments regarding the requirement to cover many tight or impermeable zones containing salt water.

In the currently proposed wording of the rule, the description of how the intermediate and production casing strings shall be cemented is stated differently in the various parts of the rule covering this subject. Under the heading "(a) General", there are two distinctly different well types covered. In (a)(4)(C), cementing requirements for injection wells are that casing shall be cemented across and above all formations permitted for injection. The requirements for all other wells are given in (a)(4)(D) where it states that casing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids. Under the heading "(b)(2) Intermediate casing requirements for land wells and bay wells", it states that intermediate casing strings shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe; and, if any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe to some specified point above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids. Under the heading "(b)(3) Production casing requirements for land wells and bay wells", it states that production casing strings shall be cemented with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe; and if any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such zones by one of the methods specified for intermediate casing. Under the heading "(c) Casing, cementing, drilling, and completion requirements for offshore wells", it states that in cementing the production casing, sufficient cement shall be used to fill the calculated annular space above the shoe to isolate any productive zone, potential flow zone, or zone with corrosive formation fluids and to a depth that isolates abnormal pressure from normal pressure (0.465 psi per vertical foot of gradient). It should be noted that the part of the rule covering cementing for offshore wells is unique to the others in two ways. First, there is no requirement for how intermediate casing strings are to be cemented in offshore wells. Second, the description of how production casing strings in offshore wells are to be cemented does not have a cement top requirement, as do the casing strings on onshore wells. Attempting to determine how various strings of casing are to be cemented to meet the requirements of this rule is apparently difficult for a lot of operating companies, as was evidenced by the large numbers of comments received on this subject during the recent comment periods. With the exception of the injection wells covered in (a)(4)(C), the wording in the above mentioned parts of the rule need to be changed. The requirements for cement coverage should be as simple as possible and should be consistent throughout the rule.

The amount of cement coverage required in API Standard 65 – Part 2, to prevent and/or control annular flow and sustained casing pressure, is simply stated in Annex D of that document. "*The planned top of cement shall cover the shallowest potential flow zone.*" This requirement, along with the revised definition of potential flow zone ("*Any zone in a well where flow is possible when wellbore pressure is less than pore pressure*") will provide a simple, concise, and effective means of determining what cement coverage will be required on all intermediate and production casing strings.

The current rule requires 600 ft. of cement above the top of the shallowest productive zone in the annulus. The Railroad Commission's proposed changes to the rule would allow operators, if they

measured the top of cement with a cement evaluation log, to have as little as 100 ft. of cement above the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids. As far as I have been able to determine, there is no scientific or technical basis to support this reduced compliance criteria on cement coverage above and across troublesome zones.

For Rule 3.13 to be effective, the component parts of the rule should be in agreement with, and be designed to accomplish, the stated intent of the rule. As previously stated above, the intent [(a)(1)] for Rule 3.13 contains the following wording, *"It is the intent of this section that ... all productive zones, potential flow zones, and zones with corrosive formation fluids be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing."* Webster's Collegiate Dictionary defines "isolate" as "*to set apart from others*". "Seal" is defined as "*to close completely, especially so as to make air tight*". The only sealing element that is routinely placed behind the casing is the cement sheath. Therefore, in the context of this rule, the cement sheath must accomplish the requirements stated in the intent. That is, to isolate the named zones and seal against vertical migration of fluids or gases behind the casing. Section 5.7.1 of API Standard 65 – Part 2, Second Edition, December 2010 states that "*The primary goal of cementing is to maintain the required hydraulic isolation for the life of the well*". The following statement is made on page 5 of API Guidance Document HF1, First Edition, October 2009, "*The purpose of cementing the casing is to provide zonal isolation between different formations, ...*" In that same API document on page 7 in section 5.3, Zone Isolation, it is stated that, "*Placement of the cement completely around the casing and at the proper height above the bottom of the drilled hole (cement top) is one of the primary factors in achieving successful zonal isolation and integrity. Good isolation requires complete annular filling and tight interfaces with the formation and casing. Complete displacement of drilling fluid by cement and good bonding of the cement interfaces between the drilled hole and the casing immediately above the hydrocarbon formation are key parts of well integrity and seal integrity. The absence of voids and good bonding of cement at these interfaces prevent migration paths and establish zone isolation.*" API Guidance Document HF1 has been referenced in The Department of The Interior, Bureau of Land Management document 43 CFR Part 3160 "Oil and Gas Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands". This document sets out the BLM's proposal for revising the current regulations covering hydraulic fracture treatments. The included reference on HF1 states, "The BLM's proposed rule is consistent with the American Petroleum Institute's (API) guidelines for well construction and well integrity (see API Guidance Document HF 1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, First Edition, October 2009). Based on what is contained in the above API documents that are designed to provide guidelines on isolating flow zones and on well construction and integrity, the following requirements are necessary to assure the isolation of certain formations and to establish an annular seal to prevent migration of fluids and gases behind the casing [i.e. satisfy the intent of the rule].

- The cement must completely displace the drilling fluid in the annulus
- The cement must completely fill the annulus behind the casing
- The cement must be completely around the casing at the proper depth
- The cement must form tight interfaces with both the formation and the casing
- There must be good bonding at the cement/casing and cement/formation interfaces
- There must be no voids in the cement sheath

In the latest revision of Rule 3.13, the proposed wording for the required cementing coverage for onshore wells uses the top of cement in the annulus as the standard for assessing the quality of the cement job; and, implies that if the cement actually extends at least 100 feet above the top of a zone of interest, there

will be an effective seal in that 100 feet to prevent vertical migration of fluids or gases from that zone through the annular space between the casing and the borehole wall. In an extensive review of industry material [SPE papers, industry magazine articles, technical reports, API standards and API recommended practices] that covers recommended practices for cementing operations, a number of factors were reported that affect the isolating and sealing qualities of the cement sheath. Some of the most quoted were: pipe movement, pipe centralization, differences in fluid density, interface drag forces, pump rates, slurry flow regime, spacer design, condition of casing outer wall, contact time, condition and shape of the borehole, and slurry properties that affect gas migration (API 65-2). In that review, it was found that there is no reported direct correlation between a measured top of cement and the existence of an effective annular seal within the cement sheath. Therefore, since no basis has been found to support the assumption that achieving a given top of cement will produce the necessary annular seals, the condition in the annulus that is necessary to accomplish the stated intent of this rule cannot be defined solely by the arbitrary location of the cement top in the casing annulus.

Creating effective seals between formations in the annulus with cement is a complicated operation that involves many factors. To simplify and reduce the description of all those factors into something that is suitable for use in an official RRC rule is not practical. For any rule to be effective there must be some means available to verify its application. In this case, the RRC has adopted the location of the cement top in the annulus as the means to quantify the effectiveness of the cementing operations covered by Rule 3.13. In order for the top of cement to be a valid means of verification it must, in some way, also be a measure of at least one of the recognized practices which influence the establishment of effective annular seals. Of all the reported practices that relate to the sealing quality of the annular cement sheath the one that correlates the most to the top of cement is the contact time. Contact time is defined as the length of time the cement slurry remains in contact with a particular point in the annulus while that slurry is being pumped in turbulent flow. That time period is controlled by two factors, the pumping rate and the volume of the slurry that passes by the specified point. In the above mentioned review of industry documents, the recommended minimum contact time necessary to create effective annular seals ranged from four (4) minutes to more than ten (10) minutes.

For any given combination of annular configuration (hole and casing size) and slurry properties there will be a specific pumping rate that will be required for the slurry to be in turbulent flow. As a result, for any given cementing operation where contact time is an issue there will be a defined minimum pumping rate. Since the contact time is a function of only pumping rate (defined) and slurry volume, there will be a minimum volume of slurry for that particular cementing operation that will be necessary to result in a given contact time. [*The cement volume controls the contact time.*] Also, for that same combination of hole and casing size (annular configuration), the top of the cement column will be controlled by the volume of the cement slurry pumped into the annulus. [*The cement volume controls the top of cement.*] Therefore requiring a minimum depth for the cement top will also define the minimum contact time. The higher the cement top the longer the contact time, and the better chance there will be for the cement to produce the desired annular seals. To evaluate the relative suitability of the cement tops proposed by the RRC, contact times were calculated for a number of casing and hole sizes using the density and rheology of an assumed cement slurry. (The assumed slurry used in the calculations was one found in API RP 10B, Recommended Practice for Testing Oil Well Cements). The above mentioned contact time calculations showed that for the proposed case where the top of cement was 100 feet above the zone of interest the contact times were only about 30 seconds. For the case where the top of cement was 250 feet above the zone of interest the contact times averaged about 1.5 minutes. When the top of cement was

increased to 600 feet above the zone of interest the contact times were between three (3) and four (4) minutes.

Since the minimum recommended contact time given in the industry literature is four (4) minutes, the top of cement used in sections (a)(4)(C), (a)(4)(D), (b)(2)(A), and (b)(3)(B) should be **no less than 600 feet**; and, consideration should be given to increasing the required top of cement to 1,000 feet above the zones of interest to achieve a six (6) minute contact time. In using the cement top as the means of compliance with this rule it is essential that the proper contact time occur. Since contact time is only that time when the slurry is in turbulent flow it is also essential that, if at all possible, the slurries be designed for and be pumped at rates to achieve turbulent flow across all zones of interest. An additional condition of compliance for these parts of Rule 3.13 should be that the cement tops on all casing strings be verified through the performance of either a temperature survey or a cement evaluation log as soon as is practical after completion of the cement job.

In section (c), Casing, cementing, drilling, and completion requirements for offshore wells, the current cementing requirement for production casing in offshore wells is significantly different than that used for cementing production casing in land and bay wells. In order to have continuity throughout this rule, it is suggested that the current wording in (c)(1)(C)(iii) be deleted and replaced with wording similar to that used in (b)(3)(B) for land and bay wells. Also in section (c), there are no requirements given in the current revised rule for intermediate casing and cement in offshore wells. It is suggested that wording similar to that used for intermediate casing strings in land and bay wells be included in the section covering offshore wells.

Proposed Revised Wording for Rule 3.13

(a)(2)(N)
Potential flow zone - Any zone in a well where flow is possible when the wellbore pressure across the zone is less than the zone's pore pressure

(a)(2)(O)
Zone with corrosive formation fluids - **Delete**

(a)(4)(C)
Casing shall be cemented across and above all formations permitted for injection under §3.9 of this title (relating to Disposal Wells), or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs), within one-quarter mile of the proposed well location, in the following manner:

- *(i) across and extending at least 600 [1,000] feet (measured depth) above the permitted formations; or*
- *(ii) across and extending at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or*
- *(iii) as otherwise approved by the district director.*
- *(iv) If conditions permit, the cement slurry shall be pumped at a rate that will place the slurry in turbulent flow while it is being placed across and above the permitted formation.*
- *(v) All cement tops shall be verified through the performance of either a temperature survey or a cement evaluation log.*

(a)(4)(D)

Intermediate and production casing strings shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe. If any productive zone or potential flow zone is open to the wellbore, the casing shall be cemented in the following manner:

- *(i) across and extending at least 600 [1,000] feet (measured depth) above the shallowest productive zone or potential flow zone, in such a manner as to isolate and seal off all productive and/or potential flow zones; or*
- *(ii) across and extending at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or*
- *(iii) as otherwise approved by the district director.*
- *(iv) If conditions permit, the cement slurry shall be pumped at a rate that will place the slurry in turbulent flow while it is being placed across and above the permitted formation.*
- *(v) All cement tops shall be verified through the performance of either a temperature survey or a cement evaluation log.*

(a)(4)(E)

Where productive zones, and/or potential flow zones are present in the planned cemented interval of any borehole, the cement slurry, used to satisfy the provisions in (a)(4)(C) and (a)(4)(D) above, shall be designed to control annular gas migration consistent with the standards in Section 5.7, Slurry Design and Testing, of API Standard 65 – Part 2, Isolating Potential Flow Zones During Well Construction.

(b)(2)(A)

Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 [1,000] feet (measured depth) above the shoe. If any productive zone or potential flow zone is open to the wellbore above the casing shoe, the casing shall be cemented:

- *(i) from the shoe to a point at least 600 feet [1,000] (measured depth) above the top of the shallowest productive zone, or potential flow zone, in such a manner as to isolate and seal off all productive and/or potential flow zones; or*
- *(ii) to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or*
- *(iii) as otherwise approved by the district director.*
- *(iv) If conditions permit, the cement slurry shall be pumped at a rate that will place the slurry in turbulent flow while it is being placed across and above the zone(s).*
- *(v) All cement tops shall be verified through the performance of either a temperature survey or a cement evaluation log.*

(b)(3)(B)

Cementing method. The production string of casing shall be cemented by the pump and plug method, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 [1,000] feet (<u>vertical</u> depth) above the shoe. If any productive zone or potential flow zone is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such zones by one of the methods specified for intermediate casing in paragraph (2) of this subsection. If conditions permit, the cement slurry shall be pumped at a rate that will place the slurry in turbulent flow while it is being placed across and above the

zone(s). All cement tops shall be verified through the performance of either a temperature survey or a cement evaluation log.

(c)(1)(C)(iii)
Cementing method. The production string of casing shall be cemented by the pump and plug method, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 [1,000] feet (vertical depth) above the shoe. If any zone having a pressure gradient greater than 0.465 psi per vertical foot, or any productive zone or any potential flow zone is open to the wellbore above the casing shoe, the casing shall be cemented:

- *(i) from the shoe to a point at least 600 feet [1,000] (measured depth) above the top of any zone having a pressure gradient greater than 0.465 psi per vertical foot or, the shallowest productive zone, or potential flow zone, in such a manner as to isolate and seal off all overpressured, productive and/or potential flow zones; or*
- *(ii) to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or*
- *(iii) as otherwise approved by the district director.*
- *(iv) If conditions permit, the cement slurry shall be pumped at a rate that will place the slurry in turbulent flow while it is being placed across and above the zone(s).*
- *(v) All cement tops shall be verified through the performance of either a temperature survey or a cement evaluation log.*

Both Treybig Enterprises and TLMA would like to thank the Commission for the opportunity to offer our comments on the proposed revisions to Rule 3.13. We hope the Commission finds these comments to be helpful in developing the final content of this rule. I am available at any time should you like any additional information or clarification on any of the subjects included in this letter.

We commend the Commission for their commitment to maintaining high and up to date standards for well construction and wellbore integrity. These standards are essential to the protection of the environment and the State's subsurface resources. Should the Commission ever initiate any further efforts to enhance the required practices for well construction and the protection of subsurface resources, I would look forward to the opportunity of working with the Commission on those efforts.

Again, thank you for allowing us to submit these comments.

Sincerely,

Jerry K. Treybig
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cc: Ms. Leslie Savage