STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

APPLICATION OF THE JOINT INDUSTRY TECHNICAL COMMITTEE TO AMEND COMMISSION ORDER R-111-P, LEA AND EDDY COUNTIES, NEW MEXICO.

CASE NO.__________

APPLICATION

The Joint Industry Technical Committee ("JITC"), through undersigned counsel, files this application with the New Mexico Oil Conservation Commission ("Commission") pursuant to NMSA 1978, Section 70-2-6, NMSA 1978 Section 70-2-12(B)(17), and the continuing jurisdiction of the Commission under paragraph (2) on page 13 of Commission Order R-111-P, to amend Order R-111-P to add anti-collision measures, to modify the well casing and cementing requirements, to provide additional notification requirements to potash operators, to provide for subsidence monitoring, and to adopt other proposed changes. In support of this application the JITC states:

1. The JITC is an association recognized and defined by the Department of the Interior Secretarial Order No. 3324 and subject to the management and control of representatives of the potash mining and oil and gas industry. *See* § 4(j) Department of the Interior, Secretarial Order No. 3324, dated December 3, 2012. The purpose of the JITC "is to study how concurrent development of potash and oil and gas can be safely performed in proximity to each other." *Id.*

2. The JITC members are engaged in the drilling and production of oil and gas, or the mining and refining of potash, within acreage in Eddy and Lea Counties. Each of the JITC members are therefore directly affected by Commission Order No. R-111-P, which was adopted in April of 1988 under Case No. 9316.

3. The stated purpose of Commission Order R-111-P was to address advances in drilling technology and practices, to address concerns regarding potash mining and oil and gas

drilling in areas where the leasehold interests overlap, and to eliminate confusion between the boundaries of the Known Potash Lease Area ("KPLA") and the area covered by Commission Order R-111-A, as amended by Orders R-111-B through O. *See* Order R-111-P at ¶¶(1)-(3).

4. With the enactment of Commission Order R-111-P in 1988, the KPLA and the area governed by Order R-111-P have been "coterminous" and subject to the drilling, casing, cementing, and other provisions contained therein. *See* Order No. R-111-P at ¶ B(1).

5. A working group of the JITC, comprised of experts from the oil and gas and potash industries, met periodically between 2018 and 2022 to review potential negative interactions between oil and gas operations and potash mining operations within the KPLA. Following these meetings, the JITC working group agreed upon a set of improved practices for the safe and responsible concurrent development of oil and gas and potash within the KPLA.

6. The JITC working group incorporated these mutually acceptable improved practices into amendments and additions to paragraphs A through J of Order No. R-111-P. These proposed amendments are shown in redline/strikeout format on **JITC Exhibit 1** filed with this application. The proposed additions are underlined and highlighted in yellow, while the proposed deletions are shown with strikeout red font.

7. A clean copy of the proposed amended rule is filed with this application as **JITC Exhibit 2.** This second exhibit includes the current Exhibit A to R-111-P defining the KPLA, which remains unchanged, and four Wellbore Diagrams identified as Figures A, B, C and D referenced in Paragraphs D(4) and D(5) of the proposed amended rule.

8. Adopting the proposed amendments to Order No. R-111-P will promote the safe and responsible concurrent development of oil and gas and potash within the KPLA, prevent the undue waste of potash and oil and gas resources, and protect correlative rights.

WHEREFORE, the JITC respectfully requests the Commission set this matter on the August 10, 2023, Commission docket, and that after notice and hearing as required by law, the Commission enter an order adopting the proposed amendments to Order No. R-111-P.

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ATTORNEYS FOR THE JOINT INDUSTRY TECHNICAL COMMITTEE

CASE ____: **Application of the Joint Industry Technical Committee to Amend Order No. R-111-P, Lea and Eddy Counties, New Mexico.** Applicant in the above-styled cause seeks to amend Commission Order R-111-P, adopted in 1988 under Case 9316, to add anti-collision measures, to modify the well casing and cementing requirements, to provide additional notification requirements to potash operators, to provide for subsidence monitoring, and to adopt other proposed changes for oil and gas development in the Known Potash Leasing Area located in Eddy and Lea Counties, New Mexico. This area presently consists of all or parts of:

Township 18 South, Range 30 East
Township 19 South, Ranges 29 through 34 East
Township 20 South, Ranges 29 through 34 East
Township 21 South, Ranges 29 through 34 East
Township 22 South, Ranges 28 through 34 East
Township 23 South, Ranges 28 through 31 East
Township 24 South, Ranges 29 through 31 East
Township 25 South, Range 31 East

Said area extends approximately 50 miles east of Carlsbad, New Mexico and approximately 50 miles south of Maljamar, New Mexico. The affected area is more particularly described in Exhibit A to Commission Order R-111-P, which can be found on the Oil Conservation Commission website at: https://ocdimage.emnrd.nm.gov/imaging/.

IT IS THEREFORE ORDERED THAT:

This order shall be known as The Rules and Regulations Governing the Exploration and Development of Oil and Gas in Certain Areas Herein Defined, Which Are Known To Contain Potash Reserves.

A. OBJECTIVE

The objective of these Rules and Regulations is to prevent waste, protect correlative rights, assure maximum conservation of the oil, gas and potash resources of New Mexico, and permit the economic recovery of oil, gas and potash minerals in the area hereinafter defined.

B. THE POTASH AREA

(1) The Potash Area, as described in Exhibit A attached hereto and made a part hereof, represents the area in various parts of which potash mining operations are now in progress, or in which core tests indicate commercial potash reserves. Such area is coterminous with the Known Potash Leasing Area (KPLA) as determined by the U.S. Bureau of Land Management (BLM).

(2) The Potash Area, as described in Exhibit "A" may be revised by the Division after due notice and hearing at the regular pool nomenclature hearings, to reflect changes made by BLM in its KPLA.

C. DRILLING IN THE POTASH AREA

(1) All drilling of oil and gas wells in the Potash Area shall be subject to these Rules and Regulations.

(2) No wells shall be drilled oil or gas at a location which, in the opinion of the Division or its duly authorized representative, would result in undue waste of potash deposits or constitute a hazard to or interfere unduly with mining of potash deposits.

(3) No mining operations shall be conducted in the Potash Area, that would, in the opinion of the Division or its duly authorized representative, constitute a hazard to oil or gas production, or that would unreasonably interfere with the orderly development and production from any oil or gas pool.

~~(3)~~(4) Upon discovery of oil or gas in the Potash Area the Oil Conservation Division may promulgate pool rules for the affected area after due notice and hearing in order to address conditions not fully covered by these rules and the general rules.

~~(4)~~(5) The Division's District Supervisor may waive the requirements of Sections D and H ~~F~~ which are more rigorous than the general rules upon satisfactory showing that a location is outside of the Life of Mine Reserves (LMR) and surrounding buffer zone as defined hereinbelow and that no commercial potash resources will be unduly diminished.

~~(5)~~ (6) ~~All e~~Encounters during drilling operations with flammable gas, including hydrogen sulfide, ~~during drilling operations~~ other than normal drill gas from known gas bearing intervals shall be reported immediately to the appropriate ~~OCD~~Division's District office followed by a written report of the same. Drill gas is the gas released from the pore space in the volume of rock drilled.

D. DRILLING AND CASING PROGRAM

(1) For the purpose of the regulations and the drilling of wells for oil and gas, shallow and deep zones are defined as follows:

EXHIBIT
1

(a) The shallow zone shall include all formations above the base of the Delaware Mountain Group or, above a depth of 5,000 feet, whichever is lesser.

(b) The deep zone shall include all formations below the base of the Delaware Mountain Group or, below a depth of 5,000 feet, whichever is lesser.

(c) For the purpose of identification, the base of the Delaware Mountain Group is hereby identified as the geophysical log marker found at a depth of 7485 feet in the Richardson and Bass No. 1 Rodke well in Section 27, Township 20 South, Range 31 East, NMPM, Eddy County, New Mexico.

(2) **Anti-collision Measures:**

(a) While drilling, the operator will monitor separation distance to offset. Operators will maintain a Separation factor ("SF") greater than 1.0 for any active (capable of natural free flowing or on active gas lift) or inactive wells through the potash interval. For blind or inclination only offset wells, maintaining greater than 300' center-to-center separation is acceptable.

(b) If the SF for any well projected to the next survey point is equal to or less than 1.0 while drilling through the potash interval, the operator shall perform all of the following mitigation measures if applicable:

(i) The applicable offset active well(s) will be shut-in (if well is on active gas lift, the well shall be shut in and the gas lift pressure shall be bled off from casing). Monitor the applicable annulus continuously in the event that corrections cannot be made.

(ii) Drilling must cease and efforts made to correct or alter the well path so the SF becomes greater than 1.0. Setting a plug in the offset active well below the estimated intercept depth should be considered.

(iii) Monitoring magnetic interference and ranging away from the offset well shall be considered an acceptable well path correction.

(iv) If offset wells are owned by another operator, reasonable efforts shall be made to contact the offset operator and raise awareness prior to commencing drilling.

(v) Prior to requesting another operator to shut in a well, the drilling operator shall make reasonable effort to reduce the drilling well Ellipse of Uncertainty ("EOU") through the use of Measurement While Drilling ("MWD") corrections (SAG, IFR, one Gyro run, etc.).

(c) In the case where laterals are stacked and the True Vertical Depth ("TVD") separating the lateral wellbores is less than or equal to 50 feet, corrections should be made if SF fall below 1.0 in the lateral according to directional plan. All laterals must be geo-steered to control lateral placement in the vertical plane.

(d) The drilling operator will implement a survey tool QA/QC program consistent with applicable API and ISCWSA industry standards. All wells shall include directional surveys with both inclination and azimuth and a maximum separation of 200' between survey points.

(e) The drilling operator will monitor for and document within a daily drilling summary or equivalent the following: erratic torque, standpipe pressure changes and other signs of collision.

~~(2)~~(3) **Surface Casing String:**

(a) A surface casing string of new ~~or used~~ oil field casing in good condition that meets API specifications and rated for the loads expected over the lifecycle of the well shall be set in the "Red Bed" section of the basal Rustler formation immediately above the salt section, or in the anhydrite at the top of the salt section, as determined necessary by the regulatory representative approving the drilling operations, and the cement shall be circulated to the surface.

(b) The surface casing string shall have at least the following centralization program:

(i) 1 centralizer per joint across the shoe track

(ii) 1 centralizer per 2 joints from casing shoe to the top of useable fresh water

(iii) Not less than one centralizer every 3 joints for surface casing.

~~(b)~~(c) Cement shall be allowed to cure an adequate amount of time to allow ~~to stand a minimum of twelve (12) hours under pressure~~ for both the lead and ~~a total of twenty-four (24) hours~~the tail cement to reach 500 psi compressive strength before drilling ~~the plug~~ or initiating pressure tests. Cement slurry lab test shall be performed at expected bottom hole temperature.

~~(c)~~ (d) ~~Casing and water-shut-off tests~~A casing pressure test shall be made ~~both~~ before ~~and after~~ drilling ~~the plug and~~ below the casing seat ~~as follows:~~

~~(i) If rotary tools are used, the mud shall be displaced with water and a hydraulic pressure of six hundred (600) pounds per square inch shall be applied.~~ or at the time of plug bump. The casing shall be tested to 0.22 psi per foot of casing string length or 1500 psi whichever is greater, but not to exceed 70% of casing burst. ~~, i~~ If a drop of ~~one hundred (100) pounds per square inch~~10% or more should occur within thirty (30) minutes, corrective measures shall be applied.

~~(ii) If cable tools are used, the mud shall be bailed from the hole, and if the hole does not remain dry for a period of one hour, corrective measures shall be applied.~~

(e) Verify shoe integrity via a formation integrity test ("FIT"). Surface applied pressure during the FIT should take into account the maximum anticipated equivalent mud weight that will be required to drill the next hole section.

~~(d)~~ (f) The above requirements for the surface casing string shall be applicable to wells targeting both the shallow and deep ~~zones.~~zone wells

~~(3)~~(4) **1st Intermediate / Salt Protection Casing String:**

(a) ~~A~~ The 1st intermediate casing string, also known as the salt protection string, shall consist of new ~~or used~~ oil field casing in good condition that meets API specifications and rated for the loads expected over the lifecycle of the well.

(b) The casing shall be set not less than one hundred (100) feet ~~nor more than six hundred (600) feet~~ below the base of the salt section~~; provided that such string~~. The casing shall ~~not~~ be set ~~below~~above the top of the highest known oil or gas zone.

(c) ~~With prior approval of the OCD District Supervisor the~~The wellbore may be deviated from the vertical after completely penetrating USGS Marker Bed No. 126 ~~(USGS) but that section of the casing set in the deviated portion of the wellbore shall be centralize d at each joint.~~

(d) The 1st intermediate casing string shall have at least the following centralization program:

(i) 1 centralizer per joint across the shoe track and not less than 1 centralizer every 3 joints to the surface.

(ii) The operator shall confirm the effectiveness of centralization program with cement placement simulations.

(iii) The Division district supervisor, or its duly authorized representative, may require the use of additional centralizers on the salt protection string when in its judgement the use of such centralizers would offer further protection to the salt section.

(e) The 1st intermediate casing string cement slurry shall have the following characteristics:

(i) Cement should be a high sulfate resistance ("HSR") slurry.

(ii) Include a minimum of 10% (by weight of water) salt.

(iii) Include an expansion additive (1 – 3% by weight of magnesium oxide or equivalent thereof).

(iv) Have free water separation of no more than two millimeters per 250 millimeters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements (or any update thereto).

(v) The zone of critical cement shall be the bottom 20% of the casing string, or 300 vertical feet above the casing shoe, whichever is less. The zone of critical cement shall have a 72 hour compressive strength of at least 1200 psi. Lab testing criteria shall be performed at bottom hole static temperature of the anticipated casing seat.

(vi) Cement with volume extenders (filler cement) may be used above the zone of critical cement but in no case shall the cement have a compressive strength less than 500 psi the time of drill out. For the filler cement, the test temperature shall be the temperature found 100' below the ground level, or 80 degrees Fahrenheit, whichever is greater.

~~(b)~~ (f) The ~~salt protection string~~ 1st intermediate casing string shall be cemented~~,~~ as follows:

~~(i) For wells drilled to the shallow zone, the string may be cemented with a nominal volume of cement for testing purposes only. If the exploratory test well is completed as a productive well, the string shall be re-cemented with sufficient cement to fill the annular space back of the pipe from the top of the first cementing to the surface or to the bottom of the cellar or may be cut and pulled if the production string is cemented to the surface as provided in sub-section D (5)(a)(i) below.~~

(i) Cement shall be pumped with a top plug. To minimize cement contamination, either a bottom plug shall be used or minimum 50% excess applied to the annulus cement volume.

(ii) Include a viscosified saltwater spacer of higher density than the drilling fluid followed by enough cement to circulate to surface. Use enough spacer to cover a minimum 500-ft of annular length, check its compatibility with the mud and cement, and use surfactant spacer when displacing OBM (Oil Based Mud).

(iii) Consider use of lightweight cement, diverter tools, external casing packers ("ECP") or other mitigation if losses are a concern during cementing.

~~(ii)~~ (g) ~~For wells drilled to the deep zone, the~~The 1st intermediate casing string must be cemented with sufficient cement to fill the annular space ~~back of~~behind the pipe from the casing seat to the surface or to the bottom of the cellar.

~~(c)~~ If the cement fails to reach the surface or the bottom of the cellar, ~~where required,~~ the top of the cement shall be located by a temperature, ~~gamma ray~~cement bond log, or other survey and additional cementing shall be done until the cement is brought to the point required.

~~(d) The fluid used to mix with the cement shall be saturated with the salts common to the zones penetrated and with suitable proportions but not less than 1% of calcium chloride by weight of cement.~~

~~(e)~~ (h) Cement shall be allowed to cure an adequate amount of time to allow ~~to stand a minimum of twelve (12) hours under pressure and a total of twenty-four (24) hours~~both the lead and the tail cement to reach 500 psi compressive strength based on cement slurry lab testing before drilling ~~the plug~~ or initiating pressure tests.

~~(f)~~ (i) ~~Casing tests~~A casing test shall be made ~~both~~ before ~~and after~~ drilling ~~the plug and~~ below the casing seat~~, as follows:~~

~~(i) If rotary tools are used, the mud shall be displaced with water and a hydraulic pressure of one thousand (1000) pounds per square inch shall be applied. If a drop of one hundred (100) pounds per square inch~~ or at plug bump. The casing shall be tested to 0.22 psi per foot of casing string length or 1500 psi whichever is greater, but not to exceed 70% of casing burst. If a drop of 10% or more should occur within thirty (30) minutes, corrective measures shall be applied.

~~(i) If cable tools are used, the mud shall be bailed from the hole and if the hole does not remain dry for period of one hour, corrective measures shall be applied.~~

~~(g) The Division, or its duly authorized representative may require the use of centralizers on the salt protection string when in their judgment the use of such centralizers would offer further protection to the salt section.~~

~~(h) Before drilling the plug a drilling spool installed below the bottom blowout preventer or the wellhead casing outlet shall be equipped with a rupture disc or other automatic pressure-relief device set at 80% of the API-rated burst pressure of new casing or 60% of the API-rated burst pressure of used casing. The disc or relief device should be connected to the rig choke manifold system so that any flow can be controlled away from the rig. The disc or relief device shall remain installed as long as drilling activities continue in the well until the intermediate or production casing is run and cemented~~.

~~(i) The above requirements for the salt protection string shall be applicable to both the shallow and deep zones except for sub-section D (3) (b) (i) and (ii) above.~~

(j) Verify shoe integrity via a FIT. Surface applied pressure during the FIT should take into account the maximum anticipated equivalent mud weight that will be required to drill the next hole section.

(k) For all wells within the KPLA where a 2nd intermediate string will not be utilized resulting in a 3-string wellbore design (surface, salt protection, production strings), the following safeguard shall apply to safely divert flow of wellbore fluids away from the salt interval in the event of a sudden production casing failure:

(i) The surface equipment utilized during stimulation operations shall be designed to relieve pressure from the intermediate x production casing annulus below the failure threshold of the casing string components.

(ii) A monitored open annulus will be incorporated during completion by leaving the intermediate x production casing annulus un-cemented and monitored inside the intermediate string. Reference wellbore diagram Figure A.

(iii) The top of cement in the intermediate x production casing annulus shall stand un-cemented at least 500' below the intermediate casing shoe. Zero percent excess shall be pumped on the production cementing slurry to ensure no tie-back into the intermediate casing shoe.

(iv) Not less than 2 weeks prior to commencing hydraulic fracturing operations on wells of this design, operator shall provide notice to operators of offset wells actively producing from the Delaware Mountain Group located within 1 mile of subject well's surface hole location. During hydraulic fracturing operations, the pump pressure and intermediate x production casing annulus shall be continuously monitored for signs of production casing failure.

(v) After stimulation operations have been concluded and no longer than 180 days after the well is brought online, the operator will be responsible for Bradenheading cement to ensure at least a 500' tie back has been established inside the intermediate (Salt) string but not higher than USGS Marker Bed No. 126.

(vi) The top of cement may be estimated through pumped displacement volumes or with the use of a fluid shot tool prior to filling backside with fluid.

~~(4)~~(5) **2nd Intermediate Casing String (if applicable):**

(a) In drilling wells to the deep zone for oil or gas, the operator shall have the option of running an intermediate string of pipe, unless the Division requires an intermediate string be run.

(b) The 2nd intermediate string shall consist of new oil field casing in good condition that meets API specifications and rated for the loads expected over the lifecycle of the well. ~~Cementing procedures and casing tests for the be the same as provided under sub-sections D (3) (c), (e) and (f) for the salt protection string.~~

(c) For all wells within the KPLA where a 2nd intermediate string will be utilized resulting in a 4-string wellbore design (surface, 1st intermediate, 2nd intermediate, production), one of the following three methods shall apply to safely divert flow of wellbore fluids away from the salt Interval in the event of a sudden production casing failure. For all methods described, the surface equipment utilized during stimulation operations shall be designed to relieve pressure from the 2nd intermediate x production casing annulus below the failure threshold of the casing string components.

(i) A monitored open annulus may be incorporated by leaving the 1st intermediate (salt string) x 2nd intermediate annulus un-cemented and monitored inside of the 1st intermediate casing string. Reference wellbore diagram Figure B. This design is appropriate if the 2nd intermediate casing is set below the Delaware Mountain Group / Brushy Canyon formation.

(1) The top of cement in the 1st intermediate (salt string) x 2nd intermediate casing annulus shall stand un-cemented at least 500' below the 1st intermediate casing shoe. Zero percent excess shall be pumped on the

2nd intermediate cementing slurry to ensure no tie-back into the 1st intermediate casing shoe.

(2) After stimulation operations have been concluded and no longer than 180 days after the well is brought online, the operator will be responsible for bradenheading cement to ensure at least a 500' tie back has been established inside the 1st intermediate string but not higher than USGS Marker Bed No. 126.

(3) The top of cement may be estimated through pumped displacement volumes or with the use of a fluid shot tool prior to filling backside with fluid.

(ii) A monitored open annulus may be incorporated by leaving the 2nd intermediate x production annulus un-cemented and monitored inside of the 2nd intermediate string. Reference wellbore diagram Figure C. This design is appropriate if the 2nd intermediate string is set above the Delaware Mountain Group / Brushy Canyon formation.

(1) The top of cement in the 2nd intermediate x production casing annulus shall stand un-cemented at least 500' below the 2nd intermediate casing point. Zero percent excess shall be pumped on the production cementing slurry to ensure no tie-back into the 2nd intermediate casing shoe.

(2) After stimulation operations have been concluded and no longer than 180 days after the well is brought online, the operator will be responsible for bradenheading cement to ensure at least a 500' tie back has been established inside the 2nd intermediate casing but not higher than USGS Marker Bed No. 126.

(3) The top of cement may be estimated through pumped displacement volumes or with the use of a fluid shot tool prior to filling backside with fluid.

(iii) An engineered weak point may be included in the 2nd intermediate casing string below the salt interval in the form of a lower strength casing or rupture disc to divert fluid into a suitable relief zone below the salt formation. Reference wellbore diagram Figure D.

(1) The 2nd intermediate casing string engineered weak point must be placed no less than 100' below the salt.

(2) The top of production casing cement must tie back at least 500' inside the 2nd intermediate casing but not above the engineered weak point.

(3) The 2nd intermediate x production casing annulus will remain open to surface and monitored

(4) The engineered weak point shall be designed to meet the minimum casing design criteria for the well but remain weaker than the rest of the casing string to ensure that the fluid is directed into the appropriate relief zone. For example: 7-5/8" 29.7# L-80 from shoe to Cherry Canyon crossed over to 7-5/8" 29.7# P-110 to surface. The L-80 grade meets the design requirements but is weaker than the P-110.

(d) A casing integrity test shall be performed before drilling below the casing seat or at plug bump. The casing shall be tested to 0.22 psi per foot of casing string length or 1500 psi whichever is greater, but not to exceed 70% of casing burst. If a drop of 10% or more should occur within thirty (30) minutes, corrective measures shall be applied.

(e) Cement shall be allowed to cure an adequate amount of time to allow tail cement to reach 500 psi compressive strength before drilling or initiating pressure tests. Lab testing criteria shall be performed at bottom hole static temperatures of the anticipated casing seat.

(f) Operator shall verify shoe integrity via a FIT. Surface applied pressure during the FIT should take into account the maximum anticipated equivalent mud weight that will be required to drill the next hole section.

(g) If sustained annular pressure build-up in the 1st intermediate x 2nd intermediate annulus occurs in excess of 500 psi while the well is being drilled, the operator will bleed off this pressure safely and establish a plan to safely manage the annular pressure. Maximum Allowable Wellhead Operating Pressure (MAWOP) = the lesser of:

(i) 50% of the Minimum Internal Yield Pressure (MIYP) of pipe body of intermediate casing string being evaluated

(ii) 80% of the MIYP of pipe body of the next outer casing string

(iii) 75% of the minimum collapse pressure of the production casing.

~~**(5) Production String:**~~

~~(a) A production string shall be set on top or through the oil or gas pay zone and shall be cemented as follows:~~

~~(i) For wells drilled to the shallow zone the production string shall be cemented to the surface if the salt protection string was cemented only with a nominal volume for testing purposes, which case the salt protection string can be cut and pulled before the production string is cemented; provided that if the salt protection string was cemented to the surface, the production string shall be cemented with a volume adequate to protect the pay zone and the casing above such zone~~.

~~(ii) For wells drilled to the deep zone, the production string shall be cemented with a volume adequate to protect the pay zone and the casing above such zone; provided, that if no intermediate string sha I I have been run and cemented to the surface, the production string shall be cemented to the surface.~~

~~(b) Cementing procedures and casing tests for the production string shall be the same as provided under sub-section D (3) (c), (e) and (f) for the salt protection string; however if high pressure oil or gas production is discovered in an area, the Division may promulgate the necessary rules to prevent the charging of the salt section.~~

(6) **Production Casing String:**

(a) The production string shall consist of new oil field casing in good condition that meets API specifications. Production casing shall have the following design considerations:

(i) Ensure production casing and connections are properly designed to handle all completion and production loads. Combined Von Mises Equivalent stress loading as well as cyclical fatigue should also be considered.

(ii) Production casing string shall be selected to perform as designed in all the anticipated environments that may be encountered during the life of the well.

(b) Production casing string make-up shall be monitored, recorded, and documented.

(c) The top of cement will consist of at least a 500' tie back inside the last Intermediate casing string but not higher than USGS Marker Bed No. 126 or an engineered weak point if present as described in Section D.5.c. If an un-cemented shoe is utilized, reference Section D.4.k or D.5.c for top of cement requirements before and after stimulation.

(i) Maximum FL 150 cc/30min zero FW @ 45 degree angle.

(ii) If the production section is drilled with Non-Aqueous Fluid (NAF), utilize a viscous weighted spacer with surfactants that are effective at water wetting the wellbore.

(d) Production casing string shall be pressure tested to operating pressures for a minimum of 30 minutes that are anticipated during fracture stimulation as well as during the production lifecycle of the well.

(e) The production x intermediate casing string annulus shall be monitored for pressure during stimulation operations. During stimulation operations, a pressure relief valve or appropriate venting system must be installed to relieve pressure in the event of a production casing failure.

(f) Emergency pump shutoff system shall be used to prevent system overpressure during completion operations and shall be set not more than 85% of the pipe body and/or connection internal yield pressure.

E. DRILLING FLUID FOR ~~SALT~~1ST INTERMEDIATE HOLE SECTION

The fluid used while drilling the salt section shall consist of water, to which has been added sufficient salts of a character common to the zone penetrated to completely saturate the mixture~~.~~ or non-aqueous drill fluid. Other additives ~~mixtures~~ may be added to the fluid by the operator in overcoming any specific problem. This requirement is specifically intended to prevent enlarged drill holes.

F. NOTIFICATION REQUIREMENTS TO POTASH OPERATOR

Any oil and gas well operator within the KPLA must notify both potash operators as soon as possible if any of the following conditions are encountered during oil and gas operations:

(1) Indication of any well collision event,

(2) Suspected well fluid flow (oil, gas, or produced water) outside of casing,

(3) Sustained annulus pressure between the 1st intermediate and next innermost casing string in excess of 500 psi above the baseline pressure of the well, or above 1500 psi total,

(4) Increasing pressure buildup rates (psi/day) across multiple successive bleed-off cycles on the annulus between the 1st intermediate and next innermost casing during well production, or

(5) Sustained losses in excess of 50% through the salt interval during drilling.

G. SUBSIDENCE MONITORING

For a well or group of wells drilled with surface locations within 1 mile of an existing mine or planned mine activity as defined in 3 year development plans, subsidence should be monitored to provide an early warning of conditions that may threaten the integrity of active wells. Devices or methods providing subsidence measurement at the surface, casing deformation measurements along the wellbore, or equivalent technology should be utilized.

~~F.~~H. PLUGGING AND ABANDONMENT OF WELLS

~~(1)~~ All wells heretofore and hereafter drilled within the Potash Area shall be plugged in a manner and in accordance with the general rules or field rules established by the Division that will provide a solid cement plug through the salt section and any water-bearing horizon and prevent liquids or gases from entering the hole above or below the salt section.

~~(2) The fluid used to mix the cement shall be saturated with the salts common to the salt section penetrated and with suitable proportions but not more than three (3) percent of calcium chloride by weight of cement being considered the desired mixture whenever possible.~~

~~G.~~I. DESIGNATION OF DRILLABLE LOCATION FOR WELLS

(1) ~~(a)~~ Within ninety (90) days following effective date of this Order and annually thereafter by January 31 if revised, each potash lessee, without regard to whether the lease covers State or Federal lands, shall file with the District Manager, BLM, and the State Land Office (SLO), a designation of the potash deposits considered by the potash lessee to be its life-of-mine reserves ("LMR"). For purposes of this Agreement, "life of mine reserves" means those potash deposits within the Potash Area reasonably believed by the potash lessee to contain potash ore in sufficient thickness and grade to be mineable using current day mining methods, equipment and technology. Information used by the potash lessee in identifying its LMR shall be filed with the BLM and SLO but will be considered privileged and confidential "trade secrets and commercial ~~. . . .~~information~~.~~" within the meaning of 43 C.F.R. §2.13(c)(4) (1986), Section 19-1-2.1 NMSA 1978, and not subject to public disclosure.

(2) ~~(b)~~ Authorized officers of the BLM and SLO shall review the information submitted by each potash lessee in support of its LMR designation on their respective lands and verify upon request, that the data used by the potash lessee in establishing the boundaries of its LMR is consistent with available to the BLM and SLO. Any disputes between the BLM and potash lessee concerning the boundary of a designated LMR shall be resolved in accordance with the Department of Interior's Hearings and Appeals Procedures, 43 C.F.R. Part 4 (1986).

(3) ~~(c)~~ A potash lessee may amend its designated LMR by filing a revised designation with the BLM and SLO accompanied by the information referred to in Section ~~A~~ (1) above. Such amendments must be filed by January 31 next following the date the additional data becomes available.

(4) ~~(d)~~ Authorized officers of the BLM and SLO shall commit the designated LMR of each potash lessee to a map(s) of suitable scale and thereafter revise the map(s) as necessary to reflect the latest amendments to any designated LMR(s). These maps shall be considered privileged and confidential and exempt from disclosure under 43 C.F.R. Part 2 and §19-1-2.1 NMSA 1978 and will be used only for the purposes set forth in this Order.

(5) ~~(e)~~ The foregoing procedure can be modified by policy changes within the BLM and State Land Office.

(6) ~~(2)~~ Before commencing drilling operations for oil or gas on any lands within the Potash Area, the well operator shall prepare a map or plat showing the location of the proposed well, and said map or plat ~~to~~shall accompany each copy of the Notice of Intention to Drill. In addition to the number of copies required by the Division, the well operator shall send one copy by registered mail to each potash operator holding potash leases within a radius of one mile of the proposed well, as reflected by the plats submitted under ~~paragraph I (2).~~Section K(2) The well operator shall furnish proof of the fact that said potash operators

were notified by registered mail of ~~h~~its intent by attaching return receipt to the copies of the Notice of Intention to Drill and plats furnished to the Division.

(7) ~~(3)~~ Drilling applications on federal lands will be processed for approval by BLM. Applications on state or patented lands will be processed by the Division and, in the case of state lands, in collaboration with the SLO. The Division will first ascertain from the BLM or SLO ~~that~~whether the location is ~~not~~ within the LMR area. Active mine workings and mined-out areas shall also be treated as LMR. Any application to drill in the LMR area, including buffer zones, may be approved only by mutual agreement of lessor and lessees of both potash and oil and gas interests. Applications to drill outside the LMR will be approved as indicated below; provided there is no protest from potash lessee within 20 days of ~~h~~its receipt of a copy of the notice:

(a) a shallow well shall be drilled no closer to the LMR than one-fourth (1/4) mile or 110% of the depth of the ore, whichever is greater.

(b) A deep well shall be drilled no closer than one-half (1/2) mile from the LMR.

~~H.~~J. INSPECTION OF DRILLING AND MINING OPERATIONS

A representative of any potash lessee within a radius of one mile from the oil or gas well location may be present during drilling, cementing, casing, and plugging of any oil or gas wells to observe conformance with these regulations. Likewise, a representative of the oil and gas lessee may inspect mine workings on ~~h~~its lease to observe conformance with these regulations.

~~I.~~K. FILING OF WELL SURVEYS, MINE SURVEYS, AND POTASH DEVELOPMENT PLANS

(1) **Directional Surveys:**

The Division may require an oil and gas operator to file a certified directional survey from the surface to a point below the lowest known potash-bearing horizon on any well drilled within the Potash Area.

(2) **Mine Surveys:**

Within 30 days after the adoption of this order and thereafter on or before January 31st of each year, each potash operator shall furnish the Division two copies of a plat of a survey of the location of ~~his~~ its leaseholdings and all of ~~h~~its open mine workings, which plat shall be available for public inspection and on a scale acceptable to the Division.

~~J.~~L. APPLICABILITY OF STATEWIDE RULES AND REGULATIONS

All general statewide rules and regulations of the Oil Conservation Division governing the development, operation, and production of oil and gas in the State of New Mexico not inconsistent or in conflict herewith, are hereby adopted and made applicable to the areas described herein.

IT IS THEREFORE ORDERED THAT:

This order shall be known as The Rules and Regulations Governing the Exploration and Development of Oil and Gas in Certain Areas Herein Defined, Which Are Known To Contain Potash Reserves.

A. OBJECTIVE

The objective of these Rules and Regulations is to prevent waste, protect correlative rights, assure maximum conservation of the oil, gas, and potash resources of New Mexico, and permit the economic recovery of oil, gas and potash minerals in the area hereinafter defined.

B. THE POTASH AREA

(1) The Potash Area, as described in Exhibit A attached hereto and made a part hereof, represents the area in various parts of which potash mining operations are now in progress, or in which core tests indicate commercial potash reserves. Such area is coterminous with the Known Potash Leasing Area (KPLA) as determined by the U.S. Bureau of Land Management (BLM).

(2) The Potash Area, as described in Exhibit "A" may be revised by the Division after due notice and hearing at the regular pool nomenclature hearings, to reflect changes made by BLM in its KPLA.

C. DRILLING IN THE POTASH AREA

(1) All drilling of oil and gas wells in the Potash Area shall be subject to these Rules and Regulations.

(2) No wells shall be drilled oil or gas at a location which, in the opinion of the Division or its duly authorized representative, would result in undue waste of potash deposits or constitute a hazard to or interfere unduly with mining of potash deposits.

(3) No mining operations shall be conducted in the Potash Area, that would, in the opinion of the Division or its duly authorized representative, constitute a hazard to oil or gas production, or that would unreasonably interfere with the orderly development and production from any oil or gas pool.

(4) Upon discovery of oil or gas in the Potash Area the Oil Conservation Division may promulgate pool rules for the affected area after due notice and hearing in order to address conditions not fully covered by these rules and the general rules.

(5) The Division's District Supervisor may waive the requirements of Sections D and H which are more rigorous than the general rules upon satisfactory showing that a location is outside of the Life of Mine Reserves (LMR) and surrounding buffer zone as defined hereinbelow and that no commercial potash resources will be unduly diminished.

(6) Encounters during drilling operations with flammable gas, including hydrogen sulfide, other than normal drill gas from known gas bearing intervals shall be reported immediately to the appropriate Division's District office followed by a written report of the same. Drill gas is the gas released from the pore space in the volume of rock drilled.

D. DRILLING AND CASING PROGRAM

(1) For the purpose of the regulations and the drilling of wells for oil and gas, shallow and deep zones are defined as follows:

EXHIBIT
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(a) The shallow zone shall include all formations above the base of the Delaware Mountain Group or, above a depth of 5,000 feet, whichever is lesser.

(b) The deep zone shall include all formations below the base of the Delaware Mountain Group or, below a depth of 5,000 feet, whichever is lesser.

(c) For the purpose of identification, the base of the Delaware Mountain Group is hereby identified as the geophysical log marker found at a depth of 7485 feet in the Richardson and Bass No. 1 Rodke well in Section 27, Township 20 South, Range 31 East, NMPM, Eddy County, New Mexico.

(2) **Anti-collision Measures:**

(a) While drilling, the operator will monitor separation distance to offset. Operators will maintain a Separation factor ("SF") greater than 1.0 for any active (capable of natural free flowing or on active gas lift) or inactive wells through the potash interval. For blind or inclination only offset wells, maintaining greater than 300' center-to-center separation is acceptable.

(b) If the SF for any well projected to the next survey point is equal to or less than 1.0 while drilling through the potash interval, the operator shall perform all of the following mitigation measures if applicable:

(i) The applicable offset active well(s) will be shut-in (if well is on active gas lift, the well shall be shut in and the gas lift pressure shall be bled off from casing). Monitor the applicable annulus continuously in the event that corrections cannot be made.

(ii) Drilling must cease and efforts made to correct or alter the well path, so the SF becomes greater than 1.0. Setting a plug in the offset active well below the estimated intercept depth should be considered.

(iii) Monitoring magnetic interference and ranging away from the offset well shall be considered an acceptable well path correction.

(iv) If offset wells are owned by another operator, reasonable efforts shall be made to contact the offset operator and raise awareness prior to commencing drilling.

(v) Prior to requesting another operator to shut in a well, the drilling operator shall make reasonable effort to reduce the drilling well Ellipse of Uncertainty ("EOU") through the use of Measurement While Drilling ("MWD") corrections (SAG, IFR, one Gyro run, etc.).

(c) In the case where laterals are stacked and the True Vertical Depth ("TVD") separating the lateral wellbores is less than or equal to 50 feet, corrections should be made if SF fall below 1.0 in the lateral according to directional plan. All laterals must be geo-steered to control lateral placement in the vertical plane.

(d) The drilling operator will implement a survey tool QA/QC program consistent with applicable API and ISCWSA industry standards. All wells shall include directional surveys with both inclination and azimuth and a maximum separation of 200' between survey points.

(e) The drilling operator will monitor for and document within a daily drilling summary or equivalent the following: erratic torque, standpipe pressure changes and other signs of collision.

(3) **Surface Casing String**:

(a) A surface casing string of new oil field casing in good condition that meets API specifications and rated for the loads expected over the lifecycle of the well shall be set in the “Red Bed” section of the basal Rustler formation immediately above the salt section, or in the anhydrite at the top of the salt section, as determined necessary by the regulatory representative approving the drilling operations, and the cement shall be circulated to the surface.

(b) The surface casing string shall have at least the following centralization program:

(i) 1 centralizer per joint across the shoe track

(ii) 1 centralizer per 2 joints from casing shoe to the top of useable fresh water

(iii) Not less than one centralizer every 3 joints for surface casing.

(c) Cement shall be allowed to cure an adequate amount of time to allow for both the lead and the tail cement to reach 500 psi compressive strength before drilling or initiating pressure tests. Cement slurry lab test shall be performed at expected bottom hole temperature.

(d) A casing pressure test shall be made before drilling below the casing seat or at the time of plug bump. The casing shall be tested to 0.22 psi per foot of casing string length or 1500 psi whichever is greater, but not to exceed 70% of casing burst. If a drop of 10% or more should occur within thirty (30) minutes, corrective measures shall be applied.

(e) Verify shoe integrity via a formation integrity test (“FIT”). Surface applied pressure during the FIT should take into account the maximum anticipated equivalent mud weight that will be required to drill the next hole section.

(f) The above requirements for the surface casing string shall be applicable to wells targeting both the shallow and deep zone wells

(4) **1st Intermediate / Salt Protection Casing String**:

(a) The 1st intermediate casing string, also known as the salt protection string, shall consist of new oil field casing in good condition that meets API specifications and rated for the loads expected over the lifecycle of the well.

(b) The casing shall be set not less than one hundred (100) feet below the base of the salt section. The casing shall be set above the top of the highest known oil or gas zone.

(c) The wellbore may be deviated from the vertical after completely penetrating USGS Marker Bed No. 126

(d) The 1st intermediate casing string shall have at least the following centralization program:

(i) 1 centralizer per joint across the shoe track and not less than 1 centralizer every 3 joints to the surface.

(ii) The operator shall confirm the effectiveness of centralization program with cement placement simulations.

(iii) The Division district supervisor, or its duly authorized representative, may require the use of additional centralizers on the salt protection string when in its judgement the use of such centralizers would offer further protection to the salt section.

(e) The 1st intermediate casing string cement slurry shall have the following characteristics:

(i) Cement should be a high sulfate resistance ("HSR") slurry.

(ii) Include a minimum of 10% (by weight of water) salt.

(iii) Include an expansion additive (1 – 3% by weight of magnesium oxide or equivalent thereof).

(iv) Have free water separation of no more than two millimeters per 250 millimeters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements (or any update thereto).

(v) The zone of critical cement shall be the bottom 20% of the casing string, or 300 vertical feet above the casing shoe, whichever is less. The zone of critical cement shall have a 72-hour compressive strength of at least 1200 psi. Lab testing criteria shall be performed at bottom hole static temperature of the anticipated casing seat.

(vi) Cement with volume extenders (filler cement) may be used above the zone of critical cement but in no case shall the cement have a compressive strength less than 500 psi the time of drill out. For the filler cement, the test temperature shall be the temperature found 100' below the ground level, or 80 degrees Fahrenheit, whichever is greater.

(f) The 1st intermediate casing string shall be cemented as follows:

(i) Cement shall be pumped with a top plug. To minimize cement contamination, either a bottom plug shall be used or minimum 50% excess applied to the annulus cement volume.

(ii) Include a viscosified saltwater spacer of higher density than the drilling fluid followed by enough cement to circulate to surface. Use enough spacer to cover a minimum 500-ft of annular length, check its compatibility with the mud and cement, and use surfactant spacer when displacing OBM (Oil Based Mud).

(iii) Consider use of lightweight cement, diverter tools, external casing packers ("ECP") or other mitigation if losses are a concern during cementing.

(g) The 1st intermediate casing string must be cemented with sufficient cement to fill the annular space behind the pipe from the casing seat to the surface or to the bottom of the cellar. If the cement fails to reach the surface or the bottom of the cellar, the top of the cement shall be located by a temperature, cement bond log, or other survey and additional cementing shall be done until the cement is brought to the point required.

(h) Cement shall be allowed to cure an adequate amount of time to allow both the lead and the tail cement to reach 500 psi compressive strength based on cement slurry lab testing before drilling or initiating pressure tests.

(i) A casing test shall be made before drilling below the casing seat or at plug bump. The casing shall be tested to 0.22 psi per foot of casing string length or 1500 psi whichever is greater, but not to exceed 70% of casing burst. If a drop of 10% or more should occur within thirty (30) minutes, corrective measures shall be applied.

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(j) Verify shoe integrity via a FIT. Surface applied pressure during the FIT should take into account the maximum anticipated equivalent mud weight that will be required to drill the next hole section.

(k) For all wells within the KPLA where a 2nd intermediate string will not be utilized resulting in a 3-string wellbore design (surface, salt protection, production strings), the following safeguard shall apply to safely divert flow of wellbore fluids away from the salt interval in the event of a sudden production casing failure:

(i) The surface equipment utilized during stimulation operations shall be designed to relieve pressure from the intermediate x production casing annulus below the failure threshold of the casing string components.

(ii) A monitored open annulus will be incorporated during completion by leaving the intermediate x production casing annulus un-cemented and monitored inside the intermediate string. Reference wellbore diagram Figure A.

(iii) The top of cement in the intermediate x production casing annulus shall stand un-cemented at least 500' below the intermediate casing shoe. Zero percent excess shall be pumped on the production cementing slurry to ensure no tie-back into the intermediate casing shoe.

(iv) Not less than 2 weeks prior to commencing hydraulic fracturing operations on wells of this design, operator shall provide notice to operators of offset wells actively producing from the Delaware Mountain Group located within 1 mile of subject well's surface hole location. During hydraulic fracturing operations, the pump pressure and intermediate x production casing annulus shall be continuously monitored for signs of production casing failure.

(v) After stimulation operations have been concluded and no longer than 180 days after the well is brought online, the operator will be responsible for Bradenheading cement to ensure at least a 500' tie back has been established inside the intermediate (Salt) string but not higher than USGS Marker Bed No. 126.

(vi) The top of cement may be estimated through pumped displacement volumes or with the use of a fluid shot tool prior to filling backside with fluid.

(5) **2nd Intermediate Casing String (if applicable):**

(a) In drilling wells to the deep zone for oil or gas, the operator shall have the option of running an intermediate string of pipe, unless the Division requires an intermediate string be run.

(b) The 2nd intermediate string shall consist of new oil field casing in good condition that meets API specifications and rated for the loads expected over the lifecycle of the well. (c) For all wells within the KPLA where a 2nd intermediate string will be utilized resulting in a 4-string wellbore design (surface, 1st intermediate, 2nd intermediate, production), one of the following three methods shall apply to safely divert flow of wellbore fluids away from the salt Interval in the event of a sudden production casing failure. For all methods described, the surface equipment utilized during stimulation operations shall be designed to relieve pressure from the 2nd intermediate x production casing annulus below the failure threshold of the casing string components.

(i) A monitored open annulus may be incorporated by leaving the 1st intermediate (salt string) x 2nd intermediate annulus un-cemented and monitored inside of the 1st intermediate casing string. Reference wellbore diagram Figure B. This design is appropriate if the 2nd intermediate casing is set below the Delaware Mountain Group / Brushy Canyon formation.

(1) The top of cement in the 1st intermediate (salt string) x 2nd intermediate casing annulus shall stand un-cemented at least 500' below the 1st intermediate casing shoe. Zero percent excess shall be pumped on the 2nd intermediate cementing slurry to ensure no tie-back into the 1st intermediate casing shoe.

(2) After stimulation operations have been concluded and no longer than 180 days after the well is brought online, the operator will be responsible for bradenheading cement to ensure at least a 500' tie back has been established inside the 1st intermediate string but not higher than USGS Marker Bed No. 126.

(3) The top of cement may be estimated through pumped displacement volumes or with the use of a fluid shot tool prior to filling backside with fluid.

(ii) A monitored open annulus may be incorporated by leaving the 2nd intermediate x production annulus un-cemented and monitored inside of the 2nd intermediate string. Reference wellbore diagram Figure C. This design is appropriate if the 2nd intermediate string is set above the Delaware Mountain Group / Brushy Canyon formation.

(1) The top of cement in the 2nd intermediate x production casing annulus shall stand un-cemented at least 500' below the 2nd intermediate casing point. Zero percent excess shall be pumped on the production cementing slurry to ensure no tie-back into the 2nd intermediate casing shoe.

(2) After stimulation operations have been concluded and no longer than 180 days after the well is brought online, the operator will be responsible for bradenheading cement to ensure at least a 500' tie back has been established inside the 2nd intermediate casing but not higher than USGS Marker Bed No. 126.

(3) The top of cement may be estimated through pumped displacement volumes or with the use of a fluid shot tool prior to filling backside with fluid.

(iii) An engineered weak point may be included in the 2nd intermediate casing string below the salt interval in the form of a lower strength casing or rupture disc to divert fluid into a suitable relief zone below the salt formation. Reference wellbore diagram Figure D.

(1) The 2nd intermediate casing string engineered weak point must be placed no less than 100' below the salt.

(2) The top of production casing cement must tie back at least 500' inside the 2nd intermediate casing but not above the engineered weak point.

(3) The 2nd intermediate x production casing annulus will remain open to surface and monitored

(4) The engineered weak point shall be designed to meet the minimum casing design criteria for the well but remain weaker than the rest of the casing string to ensure that the fluid is directed into the appropriate relief zone. For example: 7-5/8" 29.7# L-80 from shoe to Cherry Canyon crossed over to 7-5/8" 29.7# P-110 to surface. The L-80 grade meets the design requirements but is weaker than the P-110.

(d) A casing integrity test shall be performed before drilling below the casing seat or at plug bump. The casing shall be tested to 0.22 psi per foot of casing string length or 1500 psi whichever is greater, but not to exceed 70% of casing burst. If a drop of 10% or more should occur within thirty (30) minutes, corrective measures shall be applied.

(e) Cement shall be allowed to cure an adequate amount of time to allow tail cement to reach 500 psi compressive strength before drilling or initiating pressure tests. Lab testing criteria shall be performed at bottom hole static temperatures of the anticipated casing seat.

(f) Operator shall verify shoe integrity via a FIT. Surface applied pressure during the FIT should take into account the maximum anticipated equivalent mud weight that will be required to drill the next hole section.

(g) If sustained annular pressure build-up in the 1st intermediate x 2nd intermediate annulus occurs in excess of 500 psi while the well is being drilled, the operator will bleed off this pressure safely and establish a plan to safely manage the annular pressure. Maximum Allowable Wellhead Operating Pressure (MAWOP) = the lesser of:

(i) 50% of the Minimum Internal Yield Pressure (MIYP) of pipe body of intermediate casing string being evaluated

(ii) 80% of the MIYP of pipe body of the next outer casing string

(iii) 75% of the minimum collapse pressure of the production casing.

(6) **Production Casing String:**

(a) The production string shall consist of new oil field casing in good condition that meets API specifications. Production casing shall have the following design considerations:

(i) Ensure production casing and connections are properly designed to handle all completion and production loads. Combined Von Mises Equivalent stress loading as well as cyclical fatigue should also be considered.

(ii) Production casing string shall be selected to perform as designed in all the anticipated environments that may be encountered during the life of the well.

(b) Production casing string make-up shall be monitored, recorded, and documented.

(c) The top of cement will consist of at least a 500' tie back inside the last Intermediate casing string but not higher than USGS Marker Bed No. 126 or an engineered weak point if present as described in Section D.5.c. If an un-cemented shoe is utilized, reference Section D.4.k or D.5.c for top of cement requirements before and after stimulation.

(i) Maximum FL 150 cc/30min zero FW @ 45-degree angle.

(ii) If the production section is drilled with Non-Aqueous Fluid (NAF), utilize a viscous weighted spacer with surfactants that are effective at water wetting the wellbore.

(d) Production casing string shall be pressure tested to operating pressures for a minimum of 30 minutes that are anticipated during fracture stimulation as well as during the production lifecycle of the well.

(e) The production x intermediate casing string annulus shall be monitored for pressure during stimulation operations. During stimulation operations, a pressure relief valve or appropriate venting system must be installed to relieve pressure in the event of a production casing failure.

(f) Emergency pump shutoff system shall be used to prevent system overpressure during completion operations and shall be set not more than 85% of the pipe body and/or connection internal yield pressure.

E. DRILLING FLUID FOR 1ST INTERMEDIATE HOLE SECTION

The fluid used while drilling the salt section shall consist of water, to which has been added sufficient salts of a character common to the zone penetrated to completely saturate the mixture or non-aqueous drill fluid. Other additives may be added to the fluid by the operator in overcoming any specific problem. This requirement is specifically intended to prevent enlarged drill holes.

F. NOTIFICATION REQUIREMENTS TO POTASH OPERATOR

Any oil and gas well operator within the KPLA must notify both potash operators as soon as possible if any of the following conditions are encountered during oil and gas operations:

(1) Indication of any well collision event,

(2) Suspected well fluid flow (oil, gas, or produced water) outside of casing,

(3) Sustained annulus pressure between the 1st intermediate and next innermost casing string in excess of 500 psi above the baseline pressure of the well, or above 1500 psi total,

(4) Increasing pressure buildup rates (psi/day) across multiple successive bleed-off cycles on the annulus between the 1st intermediate and next innermost casing during well production, or

(5) Sustained losses in excess of 50% through the salt interval during drilling.

G. SUBSIDENCE MONITORING

For a well or group of wells drilled with surface locations within 1 mile of an existing mine or planned mine activity as defined in 3-year development plans, subsidence should be monitored to provide an early warning of conditions that may threaten the integrity of active wells. Devices or methods providing subsidence measurement at the surface, casing deformation measurements along the wellbore, or equivalent technology should be utilized.

H. PLUGGING AND ABANDONMENT OF WELLS

All wells heretofore and hereafter drilled within the Potash Area shall be plugged in a manner and in accordance with the general rules or field rules established by the Division that will provide a solid cement plug through the salt section and any water-bearing horizon and prevent liquids or gases from entering the hole above or below the salt section.

I. DESIGNATION OF DRILLABLE LOCATION FOR WELLS

(1) Within ninety (90) days following effective date of this Order and annually thereafter by January 31 if revised, each potash lessee, without regard to whether the lease covers State or Federal lands, shall file with the District Manager, BLM, and the State Land Office (SLO), a designation of the potash deposits considered by the potash lessee to be its life-of-mine reserves ("LMR"). For purposes of this Agreement, "life of mine reserves" means those potash deposits within the Potash Area reasonably believed by the potash lessee to contain potash ore in sufficient thickness and grade to be mineable using current day mining methods, equipment, and technology. Information used by the potash lessee in identifying its LMR shall be filed with the BLM and SLO but will be considered privileged and confidential "trade secrets and commercial information" within the meaning of 43 C.F.R. §2.13(c)(4) (1986), Section 19-1-2.1 NMSA 1978, and not subject to public disclosure.

(2) Authorized officers of the BLM and SLO shall review the information submitted by each potash lessee in support of its LMR designation on their respective lands and verify upon request, that the data used by the potash lessee in establishing the boundaries of its LMR is consistent with available to the BLM

and SLO. Any disputes between the BLM and potash lessee concerning the boundary of a designated LMR shall be resolved in accordance with the Department of Interior's Hearings and Appeals Procedures, 43 C.F.R. Part 4 (1986).

(3) A potash lessee may amend its designated LMR by filing a revised designation with the BLM and SLO accompanied by the information referred to in Section (1) above. Such amendments must be filed by January 31 next following the date the additional data becomes available.

(4) Authorized officers of the BLM and SLO shall commit the designated LMR of each potash lessee to a map(s) of suitable scale and thereafter revise the map(s) as necessary to reflect the latest amendments to any designated LMR(s). These maps shall be considered privileged and confidential and exempt from disclosure under 43 C.F.R. Part 2 and §19-1-2.1 NMSA 1978 and will be used only for the purposes set forth in this Order.

(5) The foregoing procedure can be modified by policy changes within the BLM and State Land Office.

(6) Before commencing drilling operations for oil or gas on any lands within the Potash Area, the well operator shall prepare a map or plat showing the location of the proposed well, and said map or plat shall accompany each copy of the Notice of Intention to Drill. In addition to the number of copies required by the Division, the well operator shall send one copy by registered mail to each potash operator holding potash leases within a radius of one mile of the proposed well, as reflected by the plats submitted under Section K(2). The well operator shall furnish proof of the fact that said potash operators were notified by registered mail of its intent by attaching return receipt to the copies of the Notice of Intention to Drill and plats furnished to the Division.

(7) Drilling applications on federal lands will be processed for approval by BLM. Applications on state or patented lands will be processed by the Division and, in the case of state lands, in collaboration with the SLO. The Division will first ascertain from the BLM or SLO whether the location is within the LMR area. Active mine workings and mined-out areas shall also be treated as LMR. Any application to drill in the LMR area, including buffer zones, may be approved only by mutual agreement of lessor and lessees of both potash and oil and gas interests. Applications to drill outside the LMR will be approved as indicated below; provided there is no protest from potash lessee within 20 days of its receipt of a copy of the notice:

(a) a shallow well shall be drilled no closer to the LMR than one-fourth (1/4) mile or 110% of the depth of the ore, whichever is greater.

(b) A deep well shall be drilled no closer than one-half (1/2) mile from the LMR.

<u>J. INSPECTION OF DRILLING AND MINING OPERATIONS</u>

A representative of any potash lessee within a radius of one mile from the oil or gas well location may be present during drilling, cementing, casing, and plugging of any oil or gas wells to observe conformance with these regulations. Likewise, a representative of the oil and gas lessee may inspect mine workings on its lease to observe conformance with these regulations.

<u>K. FILING OF WELL SURVEYS, MINE SURVEYS, AND POTASH DEVELOPMENT PLANS</u>

(1) <u>Directional Surveys</u>:

The Division may require an oil and gas operator to file a certified directional survey from the surface to a point below the lowest known potash-bearing horizon on any well drilled within the Potash Area.

(2) <u>Mine Surveys</u>:

Within 30 days after the adoption of this order and thereafter on or before January 31st of each year, each potash operator shall furnish the Division two copies of a plat of a survey of the location of its leaseholdings and all of its open mine workings, which plat shall be available for public inspection and on a scale acceptable to the Division.

L. APPLICABILITY OF STATEWIDE RULES AND REGULATIONS

All general statewide rules and regulations of the Oil Conservation Division governing the development, operation, and production of oil and gas in the State of New Mexico not inconsistent or in conflict herewith, are hereby adopted and made applicable to the areas described herein.

EXHIBIT "A"
CASE 9316
ORDER **R-111-P**

CONSOLIDATED LAND **DESCRIPTION** OF THE KNOWN POTASH
LEASING AREA, AS OF FEBRUARY **3, 1988**

EDDY **COUNTY,** NEW MEXICO

TOWNSHIP **18** SOUTH, RANGE 30 EAST, **NMPM**

Section **10:**	**SE/4** SE/4
Section 11:	S/2 SW/4
Section 13:	W/2 SW/4 and SE/4 SW/4
Section 14:	W/2 NE/4, NW/4 and S/2
Section 15:	E/2 NE/4, SE/4 SW/4 and SE/4
Section 22:	N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 23:	**A**ll
Section 24:	N/2 **NW/4,** SW/4 NW/4 and NW/4 SW/4
Section **26**:	NE/4, N/2 NW/4 and SE/4 NW/4
Section 27:	N/2 NE/4 and NE/4 NW/4

TOWNSHIP 19 SOUTH, RANGE 29 EAST, NMPM

Section 11:	SE/4 SE/4
Sect**ion** 12:	SE/4 NE/4 and S/2
Section 13:	All
Section 14:	NE/4, SE/4 NW/4 and S/2
Section 15:	SE/4 SE/4
Section 22:	NE/4, E/2 W/2 and SE/4
Section 23:	All
Section 24:	All
Section 25:	NW/4 NW/4
Section 26:	N/2 NE/4 AND NW/4
Section 27:	NE/4 AND E/2 NW/4

TOWNSHIP 19 SOUTH, RANGE 30 **EAST**, NMPM

Section **2:** SW/4
Section 3: W/2 SW/4, SE/4 SW/4, S/2 SE/4 and NE/4 SE/4
Section 4: Lots 3 and 4. SW/4 NE/4, S/2 NW/4 and S/2
Section 5: Lots 1, 2. and 3, S/2 NE/4, S/2 NW/4 and S/2
Section 6: S/2 SE/4 and NE/4 SE/4
Sections 7 to 10 **inclusive**

Section 11:	S/2 NE/4, NW/4 NW/4 and S/2
Section 12:	NE/4, S/2 NW/4 and S/2
Section 13:	NE/4, W/2, N/2 SE/4 and SW/4 SE/4

Sections 14 to 18 inclusive
Section 19: Lots 1, 2, and 3, NE/4, E/2 NW/4, NE/4 SW/4, E/2 SE/4 and NW/4 SE/4
Sections 20 to 23 inclusive
Section 24: NW/4. NW/4 SW/4 and S/2 SW/4

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EXHIBIT "A" con'd

Section 25:	NW/4 NW/4
Section 26:	NE/4 NE/4, W/2 NE/4, W/2, W/2 SE/4 and SE/4 SE/4
Section **27:**	Al**1**
Section **28:**	Al**1**
Section 29:	E/2, E/2 NW/4 and **NW/4** NW/4
Sect ion 32:	E/2 and SE/4 SW/4
Section 33 to 35 **incl**usive	
Section 36:	NW/4 NW/4, S/2 NW/4 and S/2

<u>**TOWNSHIP 19 SOUTH**, RANGE **31** EAST, NMPM</u>

Section 7:	Lots 1, 2, and **3** and E/2 NW/4
Section 18:	Lots **1, 2,** and 3 and SW/4 NE/4, E/2 NW/4 and NE/4 SW/4
Section **31**:	Lot 4
Section 34:	SE/4 SE/4
Section 35:	S/2 SW/4 and SW/4 SE/4
Section 36:	S/2 SE/4

LEA COUNTY, NEW **MEXICO**

<u>**TOWNSHIP 19 SOUTH,** RANGE **32** EAST, NMPM</u>

Section **31**:	Lot 4
Section 33:	Lots 1 to 4 inclusive and N/2 S/2
Section 34:	Lots 1 to 4 inclusive and N/2 S/2
Section 35:	Lots 1 to 4 inclusive and N/2 S/2
Section **36**:	Lots 1 to 4 inclusive, SE/4 NE/4, NW/4 SW/4 and NE/4 SE/4

<u>**TOWNSHIP 19** SOUTH, RANGE 33 EAST, NMPM</u>

Section 22:	SE/4 NE/4, E/2 SW/4 and SE/4
Section 23:	S/2 NW/4, SW/4. W/2 SE/4 and SE/4 SE/4
Section 25:	SW/4 NW/4, W/2 SW/4 and SE/4 SW/4
Section 26:	All
Section 27:	All
Section 28:	S/2 SE/4 and NE/4 SE/4
Section 30:	Lots 2 to 4 inclusive, S/2 NE/4, SE/4 **NW/4.** E/2 SW/4 and SE/4
Section 31:	All
Section 32:	NE/4, S/2 NW/4 and S/2
Sections 33 to 35 **i**nc**l**us**ive**	
Section 36:	W/2 NE/4, SE/4 NE/4, NW/4 and S/2

<u>TOWNSHIP **19 SOUTH,** RANGE 34 EAST, NMPM</u>

Section 31	**Lots 3 and 4**

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EXHIBIT “A” con’d

EDDY COUNTY, NEW **MEXICO**

TOWNSHIP 20 SOUTH, **RANGE** 29 **EAST**, NMPM
Section **1**: SE/4 NE/4 and E/2 SE/4
Section 13: SW/4 **NW/4,** W/2 SW/4 AND SE/4 SW/4
Section 14: NW/4 NE/4, S/2 NE/4, NW/4 and S/2
Section15: E/2 E/2, SE/4 SW/4 and W/2 SE/4
Section 22: E/2 and E/2 NW/4
Section 23: All
Section 24: SW/4 NE/4, W/2, W/2 SE/4 and SE/4 SE/4
Section 25: N/2, SW/4, W/2 SE/4 and NE/4 SE/4
Section 26: All
Section 27: E/2
Section 34: NE/4
Section 35: N/2
Section 36: W/2 NE/4 AND NW/4

TOWNSHIP 20 SOUTH, **RANGE** 30 **EAST**, NMPM
Sections 1 to 4 inclusive
Section 5: Lots 1 to 3 inclusive, S/2 N/2 and S/2
Section 6 Lots 5, 6, and 7, S/2 NE/4, E/2 SW/4 and SE/4
Section 7 Lots 1 and 2. E/2 and E/2 NW/4
Sections 8 to 17 inclusive
Section 18 E/2
Section 19 E/2 and SE/4 SW/4
Sections 20 to 29 inclusive
Section 30: Lots 1 to 3 inclusive , E/2 and E/2 W/2
Section 31 E/4 and E/2 SE/4
Sections 32 to 35 inclusive

TOWNSHIP 20 SOUTH, RANGE **31** EAST, NMPM
Section 1 Lots 1 to3 inclusive, S/2 N/2 and S/2
Section **2**: All
Section 3: Lots 1 and 2, S/2 NE/4 and SE/4
Section **6**: Lots 4 to 7 inclusive , SE/4 NW/4, E/2 SW/4, W/2 SE/4 and SE/4 SE/4
Section 7: All
Section 8: S/2 N/2 and S/2
Section 9: S/2 NW/4, SW/4, W/2 SE/4 and SE/4 SE/4
Section 10: E/2 and SW/4
Section **11** to 36 i**nclusive**

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EXHIBIT "A" **con'd**

LEA **COUNTY**, NEW **MEXICO**

TOWNSHIP 20 SOUTH, RANGE 32 EAST, NMPM
Sections 1 to 4 inclusive
Section 5: S/2 SE/4
Section 6: Lots 4 to 7 inclusive, SE/4 NW/4,
E/2 SW/4 and SW/4 SE/4
Sections 7 to 36 inclusive

TOWNSHIP 20 **SOUTH**, RANGE 33 EAST, NMPM
Sections 1 to 36 inclusive

TOWNSHIP 20 **SOUTH, RANGE** 34 **EAST,** NMPM
Section 6: Lots 3 to 7 **inclusive**, SE/4 NEW/4,
E/2SW/4, W/2 SE/4 AND
SE/4 SE/4
Section 7: **All**
Section 8: SW/4, S/2 NW/4, W/2 SE/4 and
SE/4 SE/4
Section 16: W/2 NW/4, SE/4 NW/4, SW/4 and
S/2 SE/4
Sections 17 to 21 inclusive
Section 22: N/2 **NW/4,** SW/4 **NW/4,** W/2 **SE/4**,
and SE/4 SE/4
Section 26: SW/4, W/2 SE/4 and SE/4 SE/4
Sections 27 to 35 inclusive
Section 36: SW/4 NW/4 and W/2 SW/4

EDDY COUNTY, NEW **MEXICO**

TOWNSHIP 21 **SOUTH, RANGE 29 EAST, NMPM**
Sections 1 to 3 in**cl**usive
Section 4: Lots 1 through 16, NE/4 SW/4 and
SE/4
Section 5: Lot 1
Section **10**: N/2 NE/4, SE/4 NE/4 and SE/4 SE/4
Sections 1**1** to **14 inclu**sive
Section 15: E/2 NE/4 and NE/4 SE/4
Section 23: N/2 NE/4
Section 24: E/2, N/2NW/4 and SE/4NW/4
Section 25: NE/4 NE/4 and S/2 SE/4
Section 35: Lots 2 to 4 inclusive, S/2 NE/4,
NE/4 SW/4 and N/2 SE/4
Section 36: Lots 1 to 4 inclusive, NE/4,
E/2 NW/4 AND N/2 S/2

TOWNSHIP 21 SOUTH, **RANGE** 30 EAST, NMPM
Sections 1 to 36 inclusive

TOWNSHIP 21 SOUTH, RANGE 31 EAST, NMPM
Sections 1 to 36 inclusive

LEA **COUNTY**, NEW **MEXICO**

TOWNSHIP 21 SOUTH, **RANGE** 32 EAST, NMPM
Sections 1 to 27 inclusive
Section 28: N/2 and N/2 S/2
Sections 29 to 31 inclusive
Section 32: NW/4 NE/4, NW/4 and **NW/4** SW/4
Section 34: N/2 NE/4
Section 35: N/2 N/2
Section 36: E/2, N/2 NW/4, SE/4 **NW/4** and
NE/4 SW/4

TOWNSHIP **21 SOUTH, RANGE** 33 EAST, NMPM
Section 1: Lots 2 to 7 **inclusive**, Lots 10
to 14 inclusive, N/2 SW/4 and
SW/4 SW/4
Sections 2 to 11 inclusive
Section 12: NW/4 NW/4 and SW/4 SW/4
Section 13: N/2 NW/4, S/2 N/2 and S/2
Sections 14 to 24 inclusive
Section 25: N/2. SW/4 and W/2 SE/4
Sections 26 to 30 inclusive
Section **31**: Lots 1 to 4 inclusive, NE/4,
E/2 W/2, N/2 SE/4 and
SW/4 SE/4
Section 32: N/2 and NW/4 SW/4
Section 33: N/2
Section 34: NE/4, N/2 NW/4 and E/2 SE/4
Section 35: **All**
Section 36: W/2 NE/4, NW/4 and S/2

TOWNSHIP 21 SOUTH, RANGE 34 EAST, NMPM
Section 17: **W/2**
Section 18: All
Section 19: Lots 1 to 4 inclusive, NE/4,
E/2 W/2, N/2 SE/4 and
SW/4 SE/4
Section 20: NW/4 NW/4
Section **30:** Lots 1 and 2 and NE/4 NW/4
Section 31: Lots 3 and 4

EDDY COUNTY, NEW **MEXICO**

TOWNSHIP 22 **SOUTH, RANGE** 28 EAST, NMPM
Section 36: E/2 E/2

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EXHIBIT "A" **con'd**

TOWNSHIP 21 SOUTH, RANGE 29 EAST, NMPM
Sections 1 and 2 inclusive
Section 3 SE/4 SW/4 and SE/4
Section 9 S/2 NE/4 and S/2
Sections **10** to 16 inclusive
Section 17 S/2 SE/4
Section 19 SE/4 NE/4 and E/2 SE/4
Sections 20 to 28 inclusive
Section 29 N/2 N/2, S/2 NE/4 and SE/4
Section 30 NE/4 NE/4
Section 31 Lots 1 to 4 inclusive, S/2 NE/4,
E/2 W/2 and SE/4
Sections 32 to 36 inclusive

TOWNSHIP 22 **SOUTH, RANGE** 30 EAST, NMPM
Sections 1 to 36 inclusive

TOWNSHIP 22 SOUTH, RANGE 31 EAST, NMPM
Sections 1 to 11 inclusive
Section 12: NW/4 **NE/4**, NW/4 and NW/4 **SW/4**
Section 13: S/2 NW/4 and **SW/4**
Sections **14** through 23 **inclusive**
Section 24: W/2
Section 25: NW/4
Section 26: NE/4 AND N/2 NW/4
Sections 27 to 34 **inclusive**

LEA COUNTY, NEW **MEXICO**

TOWNSHIP 22 SOUTH, RANGE **32 EAST,** NMPM
Section 1: Lot 1
Section 6: Lots 2 to 7 inclusive and SE/4 NW/4

TOWNSHIP 22 SOUTH, RANGE **33** EAST NMPM
Section 1: Lots 1 to 4 inclusive, S/2 N/2 and
N/2 S/2
Section 2: All
Section 3: Lot **1**, SE/4 NE/4 and SE/4
Section 6: Lot 4
Section 10: NE/4
Section 11: NW/4 NE/4 AND NW/4

TOWNSHIP 22 **SOUTH**, RANGE 34 EAST NMPM
Section 6: Lots 4 to 6 inclusive

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EXHIBIT "A" **con'd**

EDDY COUNTY, NEW **MEXICO**

TOWNSHIP 23 SOUTH, RANGE **28 EAST**, NMPM
Section 1: Lot 1

TOWNSHIP 23 SOUTH, **RANGE** 29 EAST, NMPM
Sections 1 to 5 **incl**usive
Section 6: Lots 1 to 6 inclusive, S/2 NE/4,
SE/4 NW/4, E/2 SW/4 and SE/4
Section 7:NE/4 and NE/4 NW/4
Section 8: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Sections 9 to **16** i**ncl**usive
Section 17: NE/4 and E/2 SE/4
Sections 21 to 23 i**ncl**usive
Section 24: **N/2**, SW/4 and N/2 SE/4
Section 25: W/2 NW/4 and NW/4 SW/4
Section 26: All
Section 27: **Al**l
Section 28: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 33: N/2 NE/4 and NE/4 NW/4
Section 34: NE/4, E/2 NW/4, NW/4 **NW/4**,
NE/4 SW/4 and SE/4
Section 35: All
Section 36: W/2 NE/4, NW/4 and N/2 SW/4

TOWNSHIP 23 **SOUTH, RANGE 30 EAST**, NMPM
Sections 1 to 18 inclusive
Section 19 N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 20 **All**
Section 21 All
Section 22 N/2, S/2 SW/4, N/2 S/2 and SE/4 SE/4
Sections 23 to 25 inclusive
Section 26 E/2, SE/4 NW/4 and **SW/4**
Section 27 N/2 NW/4, SW/4 NW/4, SE/4 SW/4,
S/2 SE/4 and NE/4 SE/4
Section 28 N/2 and SW/4 Sect ion 29 N/2 and SE/4
Section 30 N/2 NE/4
Section 32 N/2 NE/4
Section 33 SE/4 NE/4, N/2 NW/4, NE/4 SE/4
and S/2 SE/4
Sections 34 to 36 inclusive

TOWNSHIP 23 SOUTH, RANGE 31 EAST, NMPM
Section 2: Lot 4, SW/4 **NW/4** and W/2 SE/4
Sections 3 to 7 i**ncl**us**ive**
Section 8:NE/4 NE/4, W/2 NE/4 and W/2
Section 9: N/2 N/2
Section 10: NW/4 NW/4 and SE/4 SE/4
Section **11**: S/2 NE/4, S/2 SW/4 and SE/4

Section 12: SW/4 NW/4 and SW/4
Section 13: SW/4 **NE/4**, W/2 and W/2 SE/4
Section 14: All
Section 15: E/2, SE/4 NW/4 and **SW/4**
Section 16: SW/4 and S/2 SE/4
Section 17: NW/4 and S/2
Sections 18 to 23 inclusive
Section 24: W/2 NE/4 and W/2
Section **25**: W/2 NE/4, NW/4, N/2 SW/4 and NW/4 SE/4
Section 26 to 34 inclusive
Section 35: N/2 NW/4 and SW/4 NW/4

TOWNSHIP 24 SOUTH, **RANGE** 29 **EAST**, NMPM
Section 2:Lots 2 to 4 inclusive
Section 3:Lot 1

TOWNSHIP 24 **SOUTH, RANGE 30** EAST, NMPM
Section 1: Lots 1 to 4 inclusive, S/2 N/2, SW/4 and NW/4 SE/4
Sect**ion** 2: All
Section 3: All
Section 4:Lots 1 and 2, S/2 NE/4, SE/4 NW/4, SW/4 SW/4. E/2 SW/4 and SE/4
Section 9: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 10: All
Section 11: Al**l**
Section 12: W/2 NW/4 and NW/4 SW/4
Section 1**4**: W/2 NE/4 and **NW/4**
Section 15: NE/4 and N/2 NW/4

TOWNSHIP 24 SOUTH, **RANGE 31 EAST,** NMPM
Sect**ion** 3: Lots 2 to 4 inclusive, SW/4 NE/4, S/2 NW/4, SW/4 and W/2 SE/4
Section 4:All
Section 5: Lots 1 to 4 inclusive, S/2 N/2, N/2 S/2 and SE/4 SE/4
Section 6: Lots 1 to 6 inclusive, S/2 NE/4, SE/4 NW/4, NE/4 SW/4 and N/2 SE/4
Section 9: E/2 and NW/4
Section 10: W/2 NE/4 and W/2
Section **35**: Lots 1 to 4 inclusive, S/2 N/2 and N/2 S/2
Section **36**: Lots 1 and 2, SW/4 NW/4 and N/2 SW/4

TOWNSHIP 25 SOUTH, **RANGE 31 EAST,** NMPM
Section **1**: Lots 3 and 4 and S/2 NW/4
Section 2: Lots 1 to 4 inclusive and S/2 N/2

Wellbore Diagrams

3-String Design – Open Production Casing Annulus

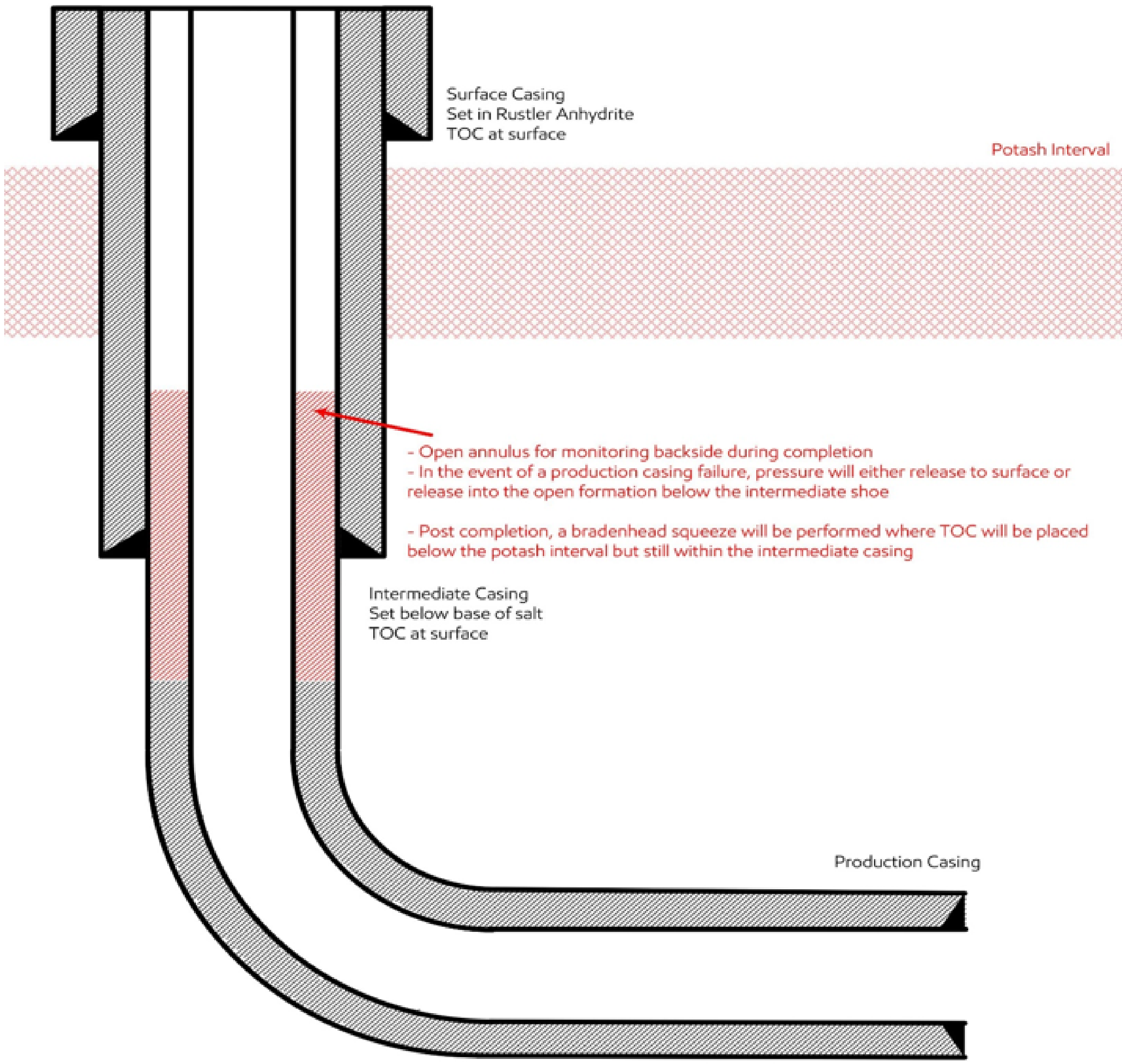

Figure A: 3 – String Uncemented Annulus

4-String Design – Open Int 1 x Int 2 Annulus (ICP 2 below relief zone)

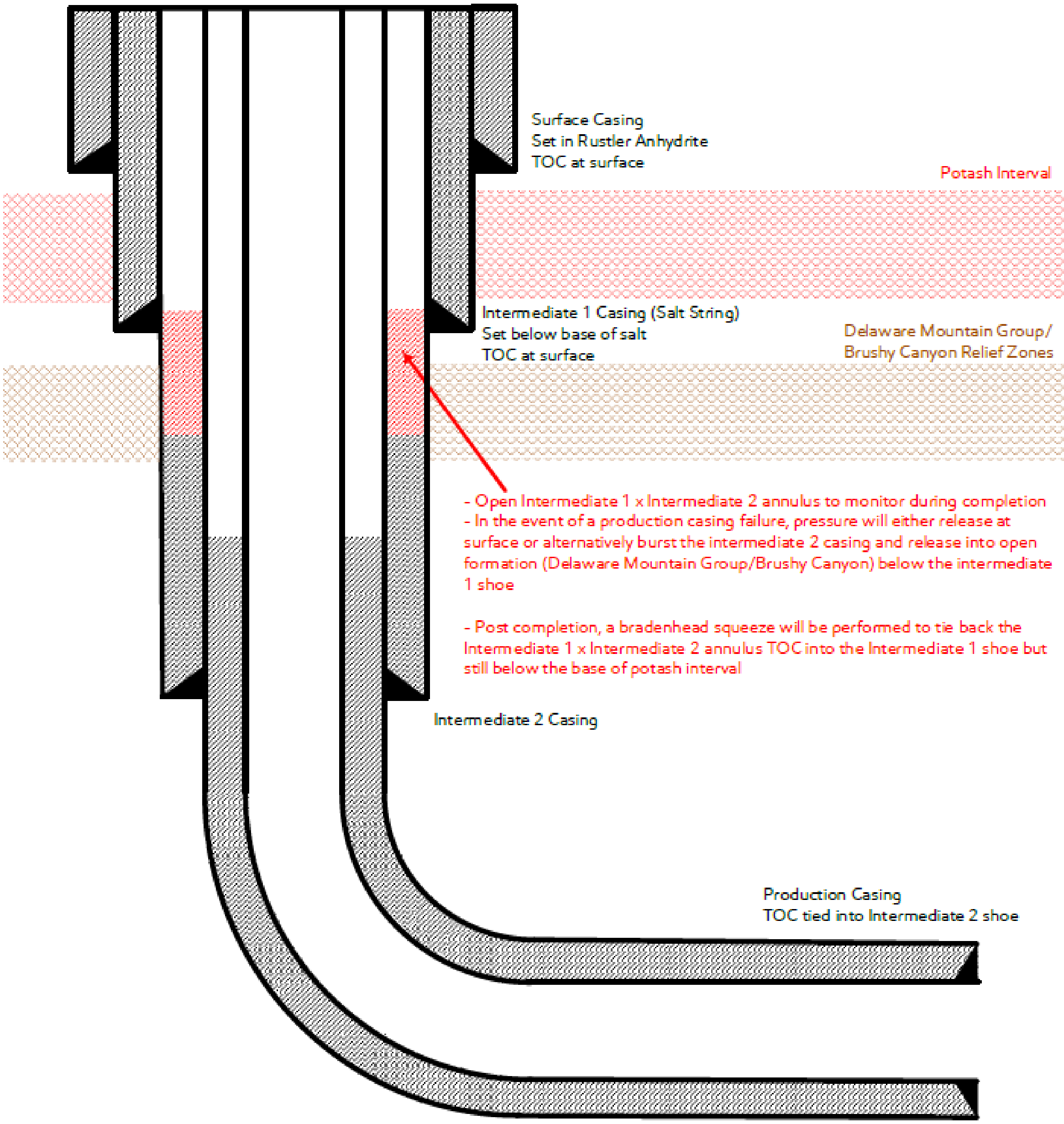

Figure B: 4 – String Uncemented Int 1 x Int 2 Annulus

4-String Design - Open Int 2 x Production Casing Annulus (ICP 2 above relief zone)

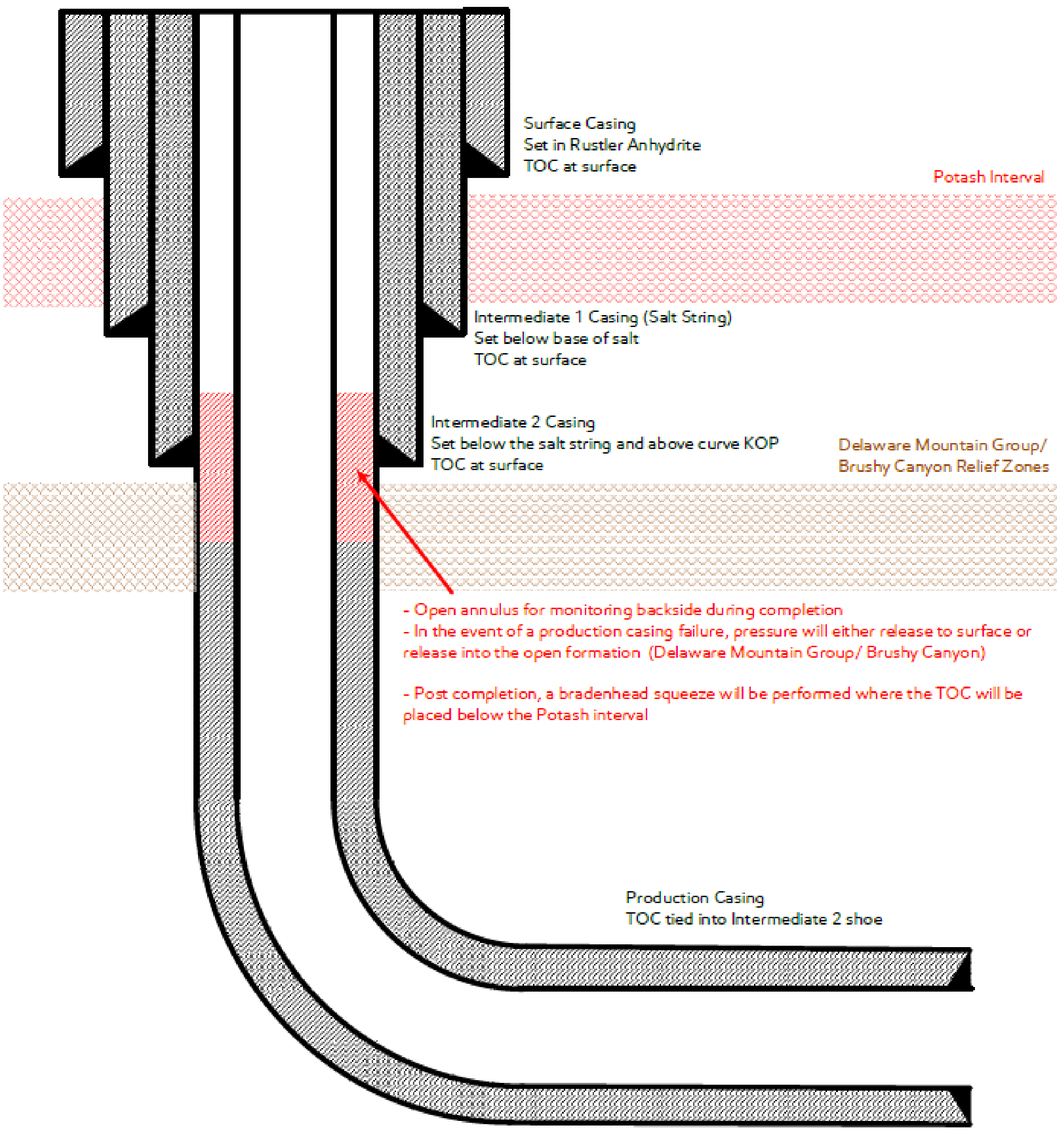

Figure C: 4 String – Uncemented Int 2 x Production Annulus

4-String Design – Engineered Weak Point

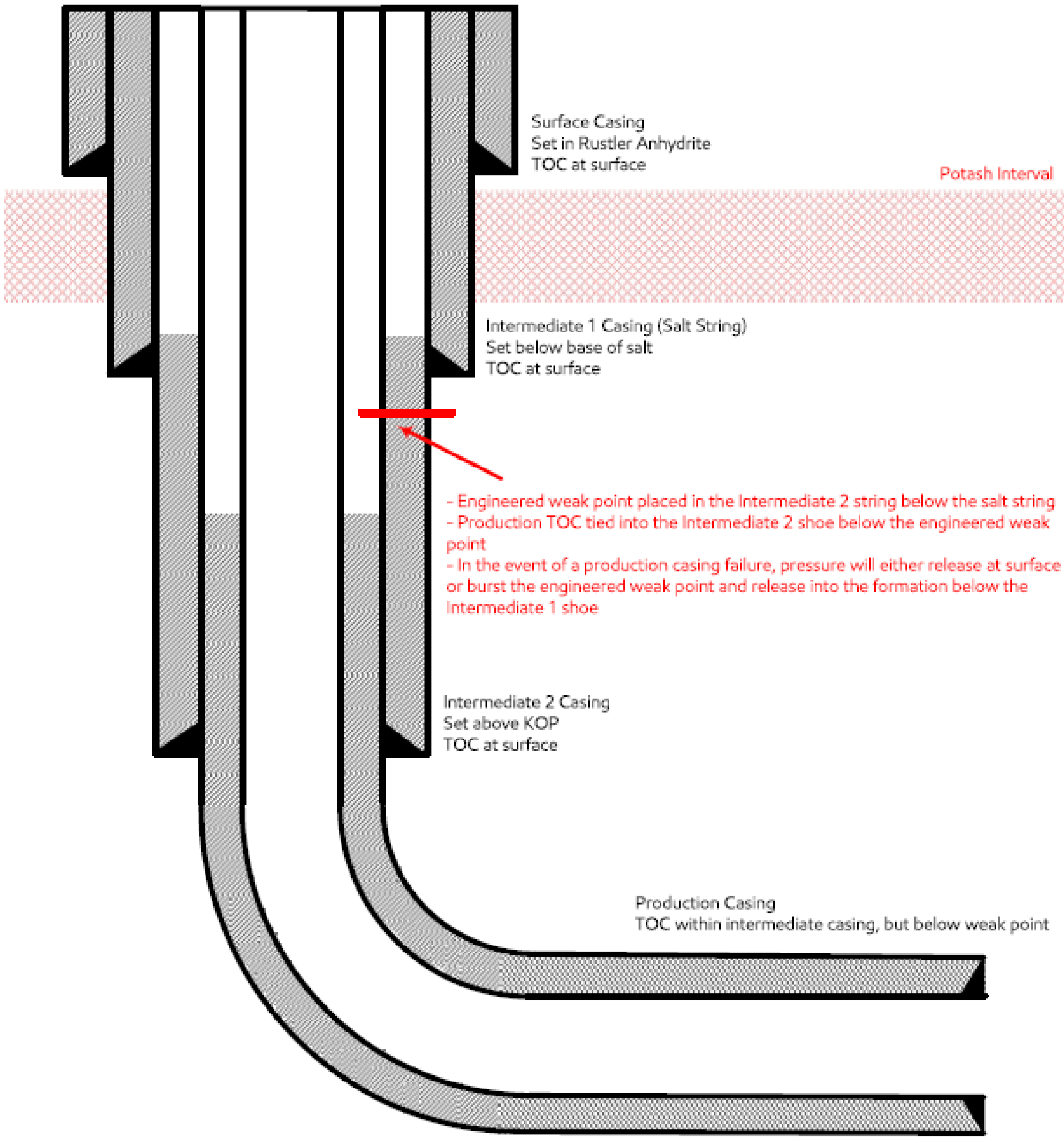

Figure D: 4 String – 2nd Intermediate casing engineered weak point

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