THE TEXAS RAILROAD COMMISSION:
AN INTRODUCTION FOR THE OIL AND GAS TITLE EXAMINER

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CHAPTER 15

BACKGROUND

Chrysta Castañeda is a go-to lawyer for high-stakes litigation in the energy industry and beyond. She is an engineer with a deep understanding of energy operations, finance and markets, as well as a sought-after speaker and author on energy issues and litigation matters. With nearly 30 years' experience, she has built a solid reputation for adeptly handling technical litigation, often serving as lead trial counsel in high-profile disputes of media interest.

Her win for T. Boone Pickens' Mesa Petroleum Partners was recognized as the 12th largest verdict in 2016 in the nation by *The National Law Journal* and earned her a spot as one of the *NLJ*'s Elite Trial Lawyers of 2018, as well as induction into *Texas Lawyer*'s Texas Verdicts Hall of Fame. Following this series of high-profile recognitions, Chrysta was inducted as a fellow of the Texas Bar Foundation in the beginning of 2020. She was also named a "Trailblazer" by *The National Law Journal*.

She is also the co-author of *The Last Trial of T. Boone Pickens*, which recounts the events leading up to, and the trial of, the Mesa lawsuit.

Chrysta not only has more than two decades of experience litigating energy and oil and gas matters, but also holds a degree in engineering. Her technical training, in combination with her experience in crisis communications, frequently proves invaluable to clients, enabling her to effectively explain complex scientific concepts to judges and juries.

Outside of the oil and gas and energy industries, Chrysta has extensive experience in commercial litigation, trade secrets, products liability, pharmaceutical, medical device, and toxic tort litigation. In 2020, she was the Democratic nominee for the Texas Railroad Commission.

Background

Scott Petry is a transactional oil and gas attorney and former Hearings Examiner (Administrative Law Judge) with the Railroad Commission of Texas. Over the last 20+ years, he has advised his clients in all areas of oil and gas law, with special attention given to navigating the interaction of regulatory issues with the complexities of contracts and title examination.

Mr. Petry is a south Louisiana native with extensive experience in oil and gas. His work as a field engineer providing real-time, downhole monitoring in electromagnetic wave resistivity, gamma radiation, radioactive source and position monitoring tools in the offshore oilfield environment, contributes to his deep understanding of the drilling environment. His experience as an ALJ with the Railroad Commission included adjudicating lease line spacing and density exceptions, rulings on violations of environmental rules, hearings for injection wells and saltwater disposal permits and field rules hearings. He is a former research assistant to Professor Ernest Smith, Rex G. Baker Centennial Chair in Natural Resources Law and has prior CLE articles quoted by the courts in both *ConocoPhillips Co. v. Vaquillas Unproven Minerals, Ltd.* and *Endeavor Energy Resources LP v. Discovery Operating*. His work as a title examiner has included prospects in east Texas, Barnett Shale, Eagle Ford, and Permian, and many others in between. Of recent note, he has examined title to one of the few remaining Wintergardens in South Texas covering 1,386 separate and distinct tracts.

Outside of the legal profession, he has been homebrewing since 1992 and donates beer and food for their annual charity fundraiser, “Skotoberfest”. The proceeds go to various charities, but always include the Cystic Fibrosis Foundation in honor of the son of a good friend and RRC co-worker.

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Someone once said that details create the big picture. As title examiners, we are required to know many, many facets of the law. In addition to oil and gas, title examiners must understand the legal intricacies from bankruptcy to martial interests, from parties in possession to the rule against perpetuities, and everything in between.

But what about the Railroad Commission of Texas? There are some practitioners that view the Railroad Commission as a world unto itself. "It's regulatory, not real property", or so the thinking goes. A seasoned title examiner, however, knows that this is not the case, and that the regulatory world does in fact affect the status of title.

The purpose of this paper is to share some key points about the Railroad Commission and its effects on your title examination. Specifically, this paper outlines (i) an overview of the Texas Railroad Commission; (ii) some key aspects of regulatory authority at the Railroad Commission; and (iii) some regulatory issues to consider when examining title.

I. OVERVIEW OF THE TEXAS RAILROAD COMMISSION.

The Railroad Commission of Texas (RRC) was established in 1891 under a constitutional and legislative mandate to prevent discrimination in railroad charges and establish reasonable tariffs. It is the oldest regulatory agency in the State and one of the oldest of its kind in the nation. The Railroad Commission of Texas no longer has any jurisdiction or authority over railroads in Texas, a duty which was transferred to other agencies, with the last of the rail functions transferred to the Texas Department of Transportation in 2005.

The RRC has primary regulatory jurisdiction over the oil and natural gas industry, intrastate pipelines, natural gas utilities, the LP-gas industry, and coal and uranium surface mining operations. The RRC exists under provisions of the Texas Constitution and exercises its statutory responsibilities under state and federal laws for regulation and enforcement of the state's energy industries, including the delegation of some EPA responsibilities. The Commission also has regulatory and enforcement responsibilities under federal law including the Surface Coal Mining Control and Reclamation Act, Safe Drinking Water Act, Pipeline Safety Acts, Resource Conservation Recovery Act, and Clean Water Act.[1]

The RRC's name has been the frequent target of political candidates and groups advocating for governmental transparency. In fact, the misunderstanding of the RRC's mission is so common that the RRC has a page devoted to the issue, directing readers to resources on railroad regulations.[2]

1. Fundamentals of Oil & Gas Regulation.

"The production, storage or transportation of oil or gas in a manner, in an amount, or under conditions that constitute waste is unlawful and is prohibited." TEX. NAT. RES. CODE §85.045; *see id.* §86.011. The RRC regulates the manner in which oil and gas is produced in the state, which includes regulations that may limit production, prohibit flaring, control the escape of natural gas, and prevent drilling that would reduce the overall recovery from a reservoir. *Id.* §85.046.

Some of the RRC's major regulatory powers include:

- Oversight of operator permits, including drilling, recompleting and flaring exceptions;
- Regulations relating to hydrocarbon measurement;
- Regulations relating to the reporting of production to the RRC;
- Assignment of allowable production & proration;
- Regulation of marginally producing and abandoned wells; and
- Environmental oversight of oil and gas operations.

While the RRC's regulatory powers can greatly impact title and ownership of production, it is important to note that the RRC has no oversight of royalties or non-operating stakeholders generally and does not offer services to royalty owners.[3]

2. Core Responsibilities of the RRC's Oil & Gas Division.

The Railroad Commission's responsibilities are extensive, and a complete analysis of those responsibilities are beyond the limited scope of this

[1] https://www.rrc.texas.gov/about-us/
[2] https://www.rrc.texas.gov/about-us/faqs/railroads/
[3] "Areas over which the Railroad Commission has no authority include lease and royalty matters (including leasing, payment of royalties and the right to receive royalties), the financing of or investment in oil and gas activities, and bankruptcy."https://www.rrc.texas.gov/about-us/faqs/royalties-faq/

paper. However, we note that some of the core responsibilities include the following.

A. Administrative Compliance.

- Issue organization reports (P5 forms) and accept operator financial assurance. These are the first steps required for anyone doing business under RRC's jurisdiction.
- Review applications and issue drilling permits for oil and gas wells and waste haulers.
- Collect and maintain production and well completion reports, well maps and other RRC required forms.

B. Field Operations.

- Maintain nine District Offices across Texas – Kilgore, Wichita Falls, Pampa, Abilene, San Angelo, Midland, Houston, Corpus Christi and San Antonio – to perform routine inspections, enforce RRC rules, respond to emergencies 24/7, respond to citizen complaints, witness well plugging and installation of groundwater protection surface casing in wells.
- Oversee State Managed Cleanup Program, Voluntary Cleanup Program and Grant Cleanup Programs-Brownfields Response, Nonpoint Source and Texas Coastal Impact Assistance.
- Direct actions for site remediation, spill containment and clean-up.
- Manage State well-plugging program.

C. Technical Permitting.

- Set requirements for Groundwater Advisory Unit and surface casing to protect usable quality groundwater.
- Review permit applications for disposal wells, injection wells used in enhancing oil and gas production, underground hydrocarbon storage wells, and brine mining wells.
- Review environmental permit applications for surface management of oil and gas waste, reclamation, recycling and waste separation.

D. Public Data Provided to the Public.

- RRC Online Inspection Lookup (RRC OIL): 24/7 online query of inspection and violation data for oil and gas wells.
- Oil and Gas Production data.
- Drilling permits and well completion data.
- GIS Public Map Viewer to assist in viewing well, pipeline and other data.[4]

3. Contested Case Hearings.[5]

The RRC conducts its own contested case hearings. The Hearings Division has its own clerk's office (Docket Services), judiciary (Administrative Law Judges), and staff experts (Technical Examiners). After a hearing, at which the parties present evidence as one would in a bench trial, the ALJ and Technical Examiner assigned to a case issue a written Proposal for Decision and Recommended Final Order ("PFD"), to which the parties may take exception, and which is then presented to the three elected Railroad Commissioners for ultimate decision at a duly noticed Open Meeting, which at the Railroad Commission is called Conference.

The RRC's hearings section provides recommendations to the elected Commissioners on a wide range of issues, from commingling permits to lease line spacing exceptions. Certain hearings which have captured the public's attention recently include saltwater disposal well permits and flaring permits.

A. Saltwater Disposal Wells (SWDs).

Oil and gas operations produce associated water that requires disposition or disposal. Saltwater Disposal Wells ("SWDs") are wells that inject produced water into formations of sufficient porosity and permeability to take the water. SWD hearings have received renewed interest and scrutiny due to concerns over induced seismicity and water availability and quality, as well as operational concerns if a SWD is located too close to producing intervals.

SWD Wells are governed by the Texas Water Code. Specifically, Chapter 27 of the Texas Water Code requires the Commission to promulgate SWD permitting rules.[6] The RRC has adopted two rules governing SWD permitting: injection into nonproductive formations (16 Texas Administrative Code ("T.A.C.") §3.9), and injection into productive formations (16 T.A.C. §3.46). The basic permitting requirements are summarized in Section 27.051(b) of the Water Code. The RRC may issue the permit if it finds: (1) that the use or installation of the injection well is in the public interest; (2) that the use or installation of the injection well will not endanger or injure any oil, gas, or other mineral formation; (3) that, with proper

[4] ttps://www.rrc.texas.gov/media/ysxbny5k/oilgaspagev8.pdf
[5] The authors wish to give recognition to Rob Hargrove for his "Railroad Commission Update" submitted to the Advanced Oil, Gas and Energy Resources Law conference held on September 24-25, 2020. Many of Mr. Hargrove's points and analysis served as the basis for the discussion that follows.
[6] TEX. WATER CODE §27.034.

safeguards, fresh water can be adequately protected from pollution; and (4) that the applicant has made a satisfactory showing of financial responsibility required by Section 27.073 (TEX. WATER CODE §27.051).

B. Flaring.

The flaring of natural gas is presumptively illegal ten days after a well is completed, because it constitutes waste of natural resources. The Commission's Statewide Rule 32 (16 T.A.C.§3.32) states that all gas from any oil well, gas well, gas gathering system, gas plant or other gas handling equipment shall be utilized for purposes and uses authorized by law. Statewide Rule 32 allows an operator to flare gas while drilling a well and for up to 10 days after a well's completion to conduct well potential testing. It also allows an operator to request an exception to flare gas in certain circumstances. The majority of exceptions authorizing flaring received by the Commission are for flaring casinghead gas from oil wells. Exceptions to flare from gas wells are not typically issued as natural gas is the main product of a gas well.

According to the RRC, flaring of casinghead gas for extended periods of time may be necessary if the well is drilled in areas that are new to exploration and lacking infrastructure. In such areas, pipeline connections are not typically constructed until after a well is completed and a determination is made about the well's productive capability. Other reasons for flaring include gas plant shutdowns; repairing a compressor or gas line or well; or other maintenance. In existing production areas, flaring also may be necessary because existing pipelines may have reached capacity. Commission staff issue flare exceptions administratively for 45 days at a time, for a maximum limit of 180 days. Extensions beyond 180 days must be granted through a Commission Final Order.[7]

In the past decade, more than 45,000 flaring permits have been authorized. It has been estimated that enough natural gas from oil wells has been flared to power every home in Texas over the past several years. In a response to public criticism, the RRC approved a new data sheet that must be submitted for permit applications that theoretically will impose a higher burden on the operator.[8]

II. KEY ASPECTS OF REGULATORY AUTHORITY AT THE RAILROAD COMMISSION.

Drilling down further, so to speak, there are additional key aspects of regulatory authority to consider when examining RRC matters.

1. Proration & Allowables.

The RRC has statutory authority to limit the production of both oil and gas wells. Proration, or limiting oil production, was originally put in place to prevent the premature pressure depletion of conventional reservoirs. During the last century the RRC has occasionally limited oil production for market-based reasons as well. In fact, the RRC was the "first OPEC," according to historians.

In the Spring of 2020, the COVID-19 outbreak spurred a collapse in the demand for oil, which was coupled with an inability amongst members of OPEC+ to agree to voluntary production cuts, causing an historic collapse in the price of oil. Major oil purchasers sent notice to producers that interruptible contracts were being cancelled and oil might not be picked up in May. On March 30, 2020, Pioneer Natural Resources USA, Inc. and Parsley Energy Inc. filed a joint Motion Requesting a Market Demand Hearing pursuant to Section 85.049 of the Natural Resources Code. They asked the RRC to impose market demand proration, something that had not happened since the 1970s. The statutory basis for market demand proration is old, but it is still on the books. The Natural Resources Code states: "The production, storage, or transportation of oil or gas in a manner, in an amount, or under conditions that constitute waste is unlawful and is prohibited." TEX. NAT. RES. CODE §85.045. A lengthy definition of waste is provided, which includes: "production of oil in excess if transportation or market facilities or reasonable market demand, and the commission may determine when excess production exists or is imminent and ascertain the reasonable market demand." TEX. NAT. RES. CODE §85.046(10).

The RRC did not impose market-based proration but did pass a number of other measures in response to the price collapse. Certain regulatory fees were waived through the end of 2020, in order to incentivize the construction of additional oil storage. Additional storage options were authorized so that more oil could be stored.

2. Statewide Rule 40.

The RRC establishes "field rules" for oil and gas formations for the purposes of regulating spacing and other well parameters in order to maximize the production of the reservoir. These field rules prescribe a number of matters (well spacing, well density, acreage assignments, allowable production, etc.) that can be

[7] https://www.rrc.texas.gov/about-us/faqs/oil-gas-faqs/flaring-regulation/

[8] https://www.rrc.texas.gov/announcements/110420-rrc-approves-revisions-to-form-r-32/

very important to title issues. This is particularly true when a lease is alleged to have terminated for want of production, in whole or in part, or the leasehold becomes severed by depth.

On February 11, 2020, the Commission voted to approve amendments to Statewide Rule 40 relating to the double assignment of acreage. Statewide Rule 40 provides, among other things, that an operator cannot assign acreage to a well for proration/allowable purposes if that acreage has already been assigned to another well in the field.[9] Field rules for "unconventional fracture treated fields" or UFTs - reservoirs that have been developed through unconventional hydraulic fracturing - typically provide operators significant flexibility in assigning allowables to horizontal wells. Most UFT field rules would allow a single well to be assigned an entire section's worth of acreage, and most have designated intervals that encompass multiple potentially productive horizons. Most modern leases, including the General Land Office (GLO) form lease, provide for some manner of depth severance at the end of the primary term or continuous development. The GLO enforced these depth severances, and then re-leased the deeper depths. Problems occur when the new lessee cannot drill a well because the surface has already been assigned to another producing wellbore.

The amendments to Statewide Rule 40 allow for double assignment of acreage in a UFT Field when mineral ownership is severed at different depths. The RRC had recently granted this relief on a case-by-case basis but has now codified this handling via Rule.

3. Commingling.

The Form P-17 is used when oil and gas operators want to "mix" or commingle the production from more than one lease or horizon (or production with disparate ownership) into the same tank or holding facility. The operator must file a form P-17 to obtain permission to commingle. Commingling is an exception to the RRC's measurement and reporting requirements, which normally require custody-transfer level measurement prior to mixing the property of disparate owners. There are situations where the Commission will administratively approve of the form P-17 and there are situations where a hearing is required.

Statewide Rule 26 distinguishes the circumstances when an operator is allowed to commingle without a commingling permit, such as when the operator measures the production stream from each tract and reservoir separately before combining or the tracts and reservoir have identical working interest and royalty interest ownership percentages.[10] However, even if the commingling is allowed under Statewide Rule 26, the operator still must file the Form P-17A, Application for Commingle Permit Pursuant to Rules 26 and/or 27.

In situations where an operator is *not* allowed to commingle without a commingling permit, the RRC may administratively approve the application if, after proper notice has been provided, no protest has been made and the applicant has shown that its proposed method of allocating production will protect correlative rights and that all working and royalty interest owners have been notified by certified mail or that same have waived their notice requirement. A commingling permit may be necessary for production from the same wellbore that is produced at different depths (such as when leases are segregated by depth) or when production is processed at a central facility before accurate measurement.

For situations where a commingling exception is required, but there has been a protest, the applicant must show at hearing that the commingling is necessary to prevent waste, to promote conservation, or to protect correlative rights. Again, the applicant must show that its allocation methodology attributes to each interest its fair share of aggregated production.[11]

Failure to obtain and comply with commingling permit specifications may result in the operator, lessee or purchaser of production being legally liable to the party entitled to be paid on production for the entirety of the commingled production. *See* TEX. NAT. RES. CODE §88.052 (commingling); §91.401 (definition of payor); and §91.402 (payment of proceeds) for additional information.

III. SOME REGULATORY ISSUES TO CONSIDER IN TITLE EXAMINATION.

As title examiners, we typically operate under a very defined set of materials examined. Practically every title opinion will have a disclaimer as to what is covered and what is not covered. However, there will inevitably be situations where you just do not have all of the pieces of the puzzle.

1. Production Information.

Consider an example where your title materials include multiple leases from the same party. Maybe even a situation where your client has the original lease, but a third party stranger lessee has a "new lease". Such a situation is certainly worthy of a requirement, but

[9] See 16 T.A.C.§40(d).
[10] 16 T.A.C.§3.26. Found at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=26
[11] Id.

often times it may behoove an examiner to contact his client as soon as possible if there are other pieces of the puzzle that need to be included in the opinion. Prior to doing that, consider looking at the RRC's vast amount of publicly available data, including production statistics.[12] A quick search of the RRC's Production Data Query may provide some insight as to whether there were extended periods of non-production. If your search of the Production Data Query shows four months of zero production, but your continuous operations lease provisions have ninety days to reestablish production, it may inform your subsequent conversation with your client.

Please note that we are NOT suggesting that you rely upon the RRC's online records as part of your title examination, as the RRC includes disclaimers that the online information may not always be correct.[13] Also, please note that production records are usually at least ninety days out and therefore will not be accurate to the day that you are reviewing them. Rather, this information is useful in client discussions as to whether you have all the materials necessary to opine upon the title.

2. Allocation Wells, Part One.

Ms. Jessica Mendoza of McElroy Sullivan Miller & Weber has provided a presentation on Allocation Wells, and we refer you to her materials for a detailed analysis of this matter. However, Allocation Wells are brought up again here for title examination concerns.

Consider an example where your title materials include information reflecting that your Division Order Title Opinion will be for an Allocation Well. Do your materials include production allocation agreements? What if the client has not obtained production allocation agreements?

For this situation, some background is in order. First, Allocation Wells are basically wells where a contractual agreement in two (or more) pooled units or leases allows a horizontal well to be drilled with part of its productive drainhole under each unit or lease. However, if an Allocation Well does not have an agreement with the interest owners, "[t]he absence of an agreed upon formula creates room for disputes over the operator's allocation method."[14]

Second, consider that in an Allocation Well, the hydrocarbons are commingled, and all production comes up the same wellbore. Again, some questions:

- If you are preparing a Division Order Title Opinion for an Allocation Well, how has your client requested production be set forth?
- What information has been provided to show with "reasonable probability" what production comes from which unit or tract?
- Is the formation homogenous enough that payment according to productive lateral is reasonably prudent? What if there is a geological fault, such that production from Blackacre is more condensate rich than the production from Whiteacre?
- If it all comes up the same wellbore, how does one attribute what production came from what tract? Doesn't this violate 16. T.A.C.§3.26(a)(2), which holds that "[a]ll oil and any other liquid hydrocarbons as and when produced shall be adequately measured …before the same leaves the lease from which they are produced…" as noted in Section II (3) of this paper?

A Production Allocation Agreement alleviates many of these concerns. Arguments have been made that the "standard oil and gas lease gives the lessee all of the authority needed to drill a horizontal well that crosses lease lines" and Allocation Wells are perfectly valid under the authority in the underlying leases.[15] But an argument could be made that Production Allocation Agreements head off most of the thorny issues before they arise. Indeed, "the lessee can address the question of production allocation by reaching agreement with affected royalty owners as to how production will be allocated among the various tracts…. When a lessee drills a horizontal well pursuant to a PSA, the PSA is normally executed before the lessee drills the horizontal well. Thus, by the time the lessee obtains production from the horizontal well, the lessee already knows how

[12] https://www.rrc.texas.gov/resource-center/research/research-queries/

[13] The RRC's disclaimer: "The data sets provided by the Online Research Query System are continually being updated and are provided as a public service for informational purposes only. They are NOT intended to be used as an authoritative public record and have no legal force or effect. Users are responsible for checking the accuracy, completeness, currency, and/or suitability of these data sets themselves….The Commission specifically disclaims any and all warranties, representations, or endorsements, express or implied, with regard to these data sets, including, but not limited to, the warranties of merchant-ability, fitness for a particular purpose, or non-infringement of privately owned rights."

[14] *Clifton A. Squibb*, The Age of Allocation: The End of Pooling As We Know It?, 45 Tex. Tech L. Rev. 929, 930 (2013).

[15] *Ernest E. Smith*, Applying Familiar Concepts to New Technology: Under the Traditional Oil and Gas Lease, a Lessee Does Not Need Pooling Authority to Drill a Horizontal Well That Crosses Lease Lines, 3 Oil & Gas, Nat. Resources & Energy J. 553, 569 (2017).

that production will be allocated."[16]

Please remember that the RRC does not have authority to adjudicate contract, but as part of its rules it must determine whether an operator has a good faith claim sufficient to warrant the issuance of a drilling permit.[17] In *Magnolia Petroleum Co. v. Railroad Commission*, the Texas Supreme Court noted that " [i]f the applicant makes a reasonably satisfactory showing of a good faith claim of ownership in the property, the mere fact that another in good faith disputes his title is not alone sufficient to defeat his right to the permit; neither is it ground for suspending the permit or abating the statutory appeal pending settlement of the title controversy.[18] Statutorily, 16 T.A.C.§3.15(a)(5) holds that a "good faith claim" is a "factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate."

Additionally, please note that in *Opiela v. Railroad Commission of Texas*, Cause No. D-1-GN-20-000099, 53rd Judicial District Court, Travis County, with respect to an allocation well, the court held that: (i) the RRC failed to comply with the requirements of the Administrative Procedure Act, Tex. Gov't Code §2001.001 et seq.; (ii) the RRC erred in concluding that it had no authority to review whether an applicant seeking a well permit has authority under a lease or other relevant title documents to drill the well; (iii) the RRC erred in failing to consider the pooling clause of the lease when analyzing the good faith claim; and (iv) the RRC erred in finding that the operator had a good faith claim to drill the subject well. The case was reversed and remanded to the RRC for further proceedings. Please note that as of the writing of this paper, the appeal for this matter is still pending, and this information is subject to change.

Given the issues that exist with respect to Allocation Wells, a title examiner should request support for the proposed allocation, usually vis-a-vis Production Allocation Agreements, or at the very least provide information and disclaimers in his or her opinion that the court has not fully adjudicated this issue.

3. Allocation Wells, Part Two.

Consider again the above example where your title materials include information reflecting that your Division Order Title Opinion will be for an Allocation Well. However, in this scenario, it is not your standard Allocation Well from one unit or lease traversing perpendicular to another unit or lease. Rather, in this situation, you have been informed that the Allocation Wells will be drilled ON THE LEASE LINE. Again, do your materials include production allocation agreements? What if the client has not obtained production allocation agreements?

Under a Lease Line Allocation Well, an operator places the wellbore directly on the lease or unit line. Whereas many, if not most, of the prior Allocation Wells were wells perpendicular to unit lines, these are *on the unit or lease line* and bring with them some distinct issues. A Lease Line Allocation Well looks clean on a permit map. It is a straight line. However, with Lease Line Allocation Wells there will inevitably be wellbore drift such that the well will rarely, if ever, be located on the actual lease line.

What if the directional driller was having a perfectly awful, no good, very bad day and approximately 80% of the wellbore is on the Whiteacre side of the unit boundary line? If there are no Production Allocation Agreements, an operator may find itself subject to claims by the Whiteacre royalty owners to royalty on 80% of the production. The Blackacre royalty owners are demanding to be paid on 50% of the production. Where does "reasonable probability" for allocation fall when a party can prove that the wellbore is 80% on its side of the unit line? Wellbore drift supports the need for Production Allocation Agreements.

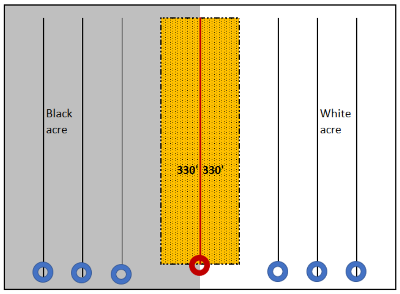
If the operator has drilled the well without a Production Allocation Agreement, the essential question is, "How do you allocate the production?" There appear to be two methodologies that are gaining traction, but, again, both should be done *with* Production Allocation Agreements.

The first method is what some refer to as the "fifty fifty". Simply enough, the production from the wellbore is shared 50% to the Whiteacre participants and 50% to the Blackacre participants. For many Lease Line Allocation Wells, the back and forth of a directionally drilled well would approximate 50% to either side. Usually, this methodology simplifies payment to royalty owners. The second method is what some refer to as the "box rule". Under the box rule, a box is typically drawn 330' on each side of the proposed well and 100' perpendicular to the first and last take points. The "box" may look something like this:

[16] Id, at 567.

[17] 16 TEX. ADMIN. CODE §3.15(a)(5) holds that a "good faith claim" is a "factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate."

[18] Magnolia Petroleum Co. v. Railroad Commission 170 S.W.2d 189, 191 (Tex. 1943).



We say "typically" because some operators use different sized "boxes". It is recommended that the box comport with the applicable field rules. In any event, production is allocated according to the surface acreage amounts in said box, regardless of the well's ultimate location. Under the box rule, "threading the needle" down the lease line is less of a concern and accounts for wellbore drift. However, to repeat and repeat, both methodologies should be done with Production Allocation Agreements.

Again, a title examiner should request support for the proposed allocation methodology from the client. If not, a disclaimer should be provided in the opinion that courts have not fully adjudicated this issue.

4. Retained Acreage Provisions That Incorporate Governmental Authority.

Consider an example where you are updating title that has an oil and gas lease many years past its primary term and said lease was not pooled. Further, consider that the lease has a retained acreage provision that incorporates governmental authority provisions akin to the following:

> If larger units than any of those herein permitted…are required under any governmental rule or order, for the drilling or operation of a well at a regular location, or for obtaining maximum allowable from any well to be drilled… any such unit may be established or enlarged to conform to the size required by such governmental order or rule.

How does the RRC's rules and regulations affect your title? What is actually retained?

Simply put, you cannot answer this question without understanding the RRC's rules and regulations. To obtain the "maximum allowable", you have to know the field rules and the components used when the RRC created the allowable formula. Consider looking at the RRC's vast amount of publicly available data, including the field rules inquiry.[19] The reason that this is necessary for your review is that the RRC has multiple factors it can use in determining a field's allowable. It may use productive acreage as a factor, but it may also use net-acre feet, initial potential, deliverability, or pressure or any combination thereof. You have to have the actual field rules available to you to consider these factors. Additionally, consider that the *type* of field rules will affect your determination. While many practitioners are aware that each field has differing factors, remember the difference between Special Field Rules and Statewide Field Rules. Under Statewide Rules, the density for both oil *and* gas wells is 40 acres.

Finally, please be aware that "maximum allowable" should be viewed in tandem with the actual facts on the ground. If the technical evidence clearly shows that the well is draining "x" acreage, but the client is claiming "4x" acres under the maximum allowable, that client may open itself up to claims that it did not act in good faith in retaining the full amount of acreage. These are factors that will impact your analysis. This information, if not provided in your materials examined, could lead to an incorrect opinion as to what is actually retained.

5. Changes in Gas-Oil Classification.

Consider yet another example where you are updating title that has an oil and gas lease that was perpetuated many years past its primary term. Further, consider that the lease has a retained acreage provision that differentiates between the retained acreage for an oil well versus retained acreage for a gas well. Your materials reflect that the well started off as a gas well. Do your materials reflect the current status of the well? Do your materials reflect that it was ALWAYS a gas well?

As noted above, consider looking at the RRC's vast amount of publicly available data, including production statistics.[20] If your review of the subject well reflects that it was classified as a gas well but was subsequently changed to an oil well, or vice-versa, you may have a problem. The RRC defines what is an "oil well" and what is a "gas well" by the Gas to Oil Ratio, or the "GOR". Specifically, the GOR is defined as the ratio of "2,000 cubic feet of gas per barrel of oil produced".[21] If a well, originally classified as a gas well, ends up producing less than 2000 cubic feet of gas per barrel of oil produced, then the Commission may change its classification to an oil well.

Under many leases, the retained acreage would be reduced to the acreage allowed for oil under the field

[19] https://www.rrc.texas.gov/resource-center/research/research-queries/

[20] https://www.rrc.texas.gov/resource-center/research/research-queries/

[21] 16 T.A.C.§3.49.

rules, i.e., 40 acres. The reverse may be that the client operator has an oil well and retained 40 acres, but then the gas ratio goes up in the production and it is classified by the RRC as a gas well. But that acreage has already been released. Everybody loses in that situation.

The court in *Hunt Oil Company v. H.E. Dishman*[22] addressed a situation such as this where a gas well experienced a change in the GOR. The court opined that, without adherence to the rework provisions of the lease, the change in GOR triggered the dissolution of the gas unit, and the parties were entitled to retain only the 40 acres allocated to an oil well. In other words, changing classification from a gas well to an oil well resulted in lost acreage. Specifically, the court held that the:

> …agreement made no express provision controlling a well that would change from oil to gas or from gas to oil production. In this situation we think the problem should be considered as though two different locations were producing-one as a gas well of 320 acres and the other an oil well of 40 acres. If the gas well in this example should cease production and no effort was made to renew its life, the 320 acres would revert to the lessor. Likewise, if such an oil well ceased production and no effort was made to renew it, the 40 acres would likewise revert. That the wells occupied the same location should not require a different solution under the facts before us…. Consequently, we hold that after the end of gas production in Dishman-Lucas No. 4 and failure to attempt reworking operations looking to further gas production, Hunt lost its determinable fee in the 320 mineral acres, except the 40 acre area for the well as an oil well…. Hunt argues that if a well originally holding 320 acres may later be cut to 40 acres under the settlement agreement, then a well holding 40 acres should likewise upon later production of gas, cover 320 acres. We are not persuaded by this argument.[23]

So, generally, a change in GOR will result in an acreage change.

However, for a unique twist, consider the RRC's handling of a GOR situation in a Mineral Interest Pooling Unit case. While the court's handling in the *Dishman* case is relatively straightforward, at least one RRC docket suggests that the handling is different if it involves the Mineral Interest Pooling Act. In Oil & Gas Docket No. 03-0223275, styled the *Application of Tri-Union Development Corporation to Consider the Status of the E.J. Force Unit (118949), Alvin North (8550) Field, Brazoria County, Texas and, if Dissolved, to Consider an Application Pursuant To Statewide Rule 38(D)(3),* a Mineral Interest Pooling Action Unit was created for a 244-acre gas unit. The corresponding Designation of Pooled Unit filed in the official public records was likewise for a gas unit. Approximately seven years after the MIPA Unit was formed, the well's classification changed from gas to oil.

Notwithstanding the court's handling in *Dishman*, the RRC ruled that the MIPA Unit remained in effect even if the well was subsequently classified as an oil well. Interestingly, the MIPA does not allow oil units in excess of 160 acres.

The rationale for the RRC's handling was statutorily based. Citing the Texas Natural Resources Code, §102.081 and §102.082, the Administrative Law Judge noted that the MIPA act clearly states that "[a] unit established by order of the commission under this chapter may not be modified or dissolved subsequently without the consent of all mineral owners affected…" and that the provisions for automatic dissolution had not been met. Given that the affected mineral owners did not consent to the dissolution of the unit, the RRC held that the underlying MIPA Unit remained in force and effect.

Based on the above, a title examiner would be well advised to determine whether MIPA is involved and whether the materials examined are sufficient to confirm that the GOR has not changed.

6. Continuing Good Faith Claim.

As referenced above, the RRC does not have authority to adjudicate contract, but as part of its rules it must determine whether an operator has a good faith claim sufficient to warrant the issuance of a drilling permit. The RRC considers a "good faith claim" to be a "factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate."[24] The concept of a good faith claim may have a direct impact on the Form P-12 versus unit designation for the property you are examining.

For background, please consider that the term "Unit" has different meanings in the regulatory versus contract world context. The regulatory context may use "drilling unit", "proration unit", "Form P12 Certificate of Pooling Authority" or "MIPA Unit", which are all

[22] Hunt Oil Company v. H.E. Dishman, 352 S.W.2d 760 (Tex.App.-Beaumont 1961).

[23] Hunt Oil Company v. H.E. Dishman, 352 S.W.2d 760, 765 (Tex.App.-Beaumont 1961).

[24] 16 T.A.C.§3.15.

distinct. A "drilling unit" is "the acreage assigned to a well for drilling purposes" and is the acreage submitted with the RRC Form W-1 drilling permit to show sufficient acreage for density requirements.[25] A "proration unit", on the other hand, is "the acreage assigned to a well for the purpose of assigning allowables and allocating allowable production to the well."[26] The actual configuration of a proration unit depends on situations where, as discussed above, acreage is used as part of the allowable calculation. Not all allowables use acreage as a factor. As referenced above, a MIPA Unit is a "forced pooled" unit under Chapter 102 of the Texas Natural Resources Code, or the Mineral Interest Pooling Act ("MIPA").

Please remember that that a designation of pooled unit ("DPU") filed at the courthouse as a Unit Declaration is NOT the same thing as the Railroad Commission Form P-12, Certificate of Pooling Authority (the "P-12"). They could, in fact, cover the same acreage and unit, but filing a Form P-12 is part of the regulatory universe. A DPU filed at the courthouse is part of the real property universe. Consider this interaction when looking at your regulatory materials compared to your official public records. Also, please consider that a DPU filed in the official public records does not have to cover the acreage reported on the Form P-12, but it is advisable to make sure that they match. The reason for this recommendation is that while the Commission's rules do not specifically mandate that the P-12 and DPU be identical, it requires that an operator have at least a "good faith claim to the right to produce the minerals in the tracts that will be penetrated by the well bore."[27]

By way of example, a prior client operator enlarged the size of its DPU in compliance with the underlying leases and *Expando Production Co. v. Marshall,* 407 S.W.2d 254 (Tex.Civ.App., 1966), but did not file a duplicate of that unit acreage on an amended Form P-12 at the RRC. A non-operating working interest owner was able to file a complaint at the RRC. In its complaint correspondence, the RRC required evidence of the continuing good faith claim of the client to operate the properties listed on the Form P-12. Fortunately for the client, the good faith claim was satisfied by language in the pooling provision of its leases that held that:

> *... Production, drilling or reworking operations anywhere on an oil and/or gas unit which includes all or part of the leased premises shall be treated as if it were production, drilling or reworking operations on the leased premises*, except that the production on which Lessor's royalty is calculated shall be that proportion of the total oil or gas unit production which all or part of the acreage covered by this lease is included in the oil or gas unit bears to the total gross acreage in the unit (emphasis added).

In other words, the pooling provision provided the good faith claim even though, technically speaking, portions of the P-12 Unit were not actually included in the DPU and vice-versa. The client would have had difficulty with the RRC if the pooling provisions had more stringent language.

IV. CONCLUSION.

Erno Rubik, the Hungarian inventor whose name came to epitomize the greatest puzzle of the 1980's, once said, "[a] good puzzle, it's a fair thing. Nobody is lying. It's very clear, and the problem depends just on you."

Title examiners are, if nothing else, great at solving puzzles. However, as title examiners know, you can only complete the puzzle if you have all of the pieces. It is our hope that this overview of the Railroad Commission has helped you in identifying some of those key puzzle pieces and where to find them.

[25] 16 T.A.C.§3.38.
[26] 16 T.A.C.§3.38.
[27] Quoting correspondence from Colin Lineberry, then Director of the Hearings Section, Railroad Commission of Texas.