THE STATE MINERAL LEASE FORM: A HISTORY AND DISCUSSION OF THE LATEST PROPOSED DRAFT

Jamie S. Manuel, Assistant Secretary
Office of Mineral Resources

Presented at
The 66th Mineral Law Institute Conference
March 15, 2019

TABLE OF CONTENTS

I. INTRODUCTION

In the spring of 2017 I had lunch with Tom Harris, the Secretary of the Department of Natural Resources, to discuss the newly vacant Assistant Secretary position over the Office of Mineral Resources. We couldn't have been more than ten minutes into our conversation before he brought up the state lease form revision process and the fact that he thought I would be well suited to bringing the process to a completion. While I definitely wouldn't consider myself a transactional attorney replete with years of experience in drafting oil and gas legal documents, I was intimately familiar with the inner-workings of an oil and gas lease and had tangled with many of the provisions common therein throughout my years of practice. I've always enjoyed the drafting process of a legal document, and so I viewed this opportunity to create a new mineral lease for the State of Louisiana with a lot of interest. At this point in my career, it seemed like a project I was comfortable and excited about taking on. As with other projects I have taken on in my career and in life, I usually jump first and only consider the consequences later—like when I agreed to first chair the trial of a twelve million dollar lawsuit a few months before the trial date—when I had never tried a case before. It wasn't until the trial date became imminent that the blinding fear and regret of making the decision to try the case began to become nearly overwhelming. But I went through with it and everything turned out fine, and it ended up being successful on appeal. Agreeing to take on the completion of the lease form revision process hasn't been much different.

Since starting my job as the Assistant Secretary of OMR in June of 2017, papers relating to the lease form revision have never NOT occupied space on my desk. Nor has the revision process ever left my meeting schedule, emails or thoughts for any longer than a few days at a time. While it has been a tedious and difficult project to complete, especially while trying to run and manage and to change many things in OMR, heading up the completion of the lease form revision process has been one of the most educational and rewarding experiences thus far in my professional career. Unlike when I agreed to try that case earlier in my career, I've generally felt equal to the challenge and fully equipped to lead this lease revision project. However, I did experience a great deal of fear when we published our proposed draft of the state lease form a few weeks ago (what I will refer to in this paper as the "2019 Version"). It's one thing to revise and draft a legal document and to send that document for comment to your client or to the other side of negotiations. It's another thing to publish your work product on the website for all the public to see and to hold monthly meetings inviting the public and board members to comment on and critique your work. But it's done now and I've accepted that what will be will be.

In going through the revision process in the last year and a half, not only have I been able to delve into the history and the meaning behind each particular mineral lease provision, I also have been able to gain a better understanding of how those individual provisions interact with each other and have gained a greater appreciation and understanding for the mineral lease as a whole. Inevitably, as a practicing attorney we are often only dealing with one or two provisions of a mineral lease or an agreement at any one particular time. We are also usually viewing those provisions in a vacuum and interpreting the meaning of those provisions in the most beneficial way to our client under a particular set of facts. Rarely are we given the opportunity to sit with an individual provision and ask the question: "What is the general purpose of this provision—presently and historically?" Not only did I have the time and space to go through these considerations, I was also able to (always with the help of OMR staff and legal team) research the history and evolution of mineral leases in general, but in particular the state lease form. All of this information helped inform my drafting decisions in preparation of our proposed draft and also gave me a depth of knowledge of the mineral lease in a general sense. The purpose of this paper is to put down in writing my observations, considerations and conclusions reached during this process. Some of them will be of value—and some won't. Some of them will be insightful, and even possibly correct—and some won't. This is not a law review article.

The first half of the paper will discuss the history of the state lease form and the evolution and changes that have happened over the last hundred years. I will then discuss the long and winding road that has been the present lease form revision process, which actually began in 2006 and is now finally (hopefully) reaching its conclusion this year. Finally, the last half of the paper will discuss particular considerations and thoughts that I made in drafting some of the more interesting and important provisions in our proposed lease form.

II. HISTORY OF THE STATE LEASE FORM

A. In The Beginning–Continuous Drilling Leases

Louisiana state government has a rich history of oil and gas leasing. State property was first leased for oil and gas exploration and development over one hundred years ago. Initially, state mineral leases were awarded by the Governor until Act 93 of the 1936 Regular Legislative Session was passed and the State Mineral Board (the "Board") was created. The power and responsibility for granting mineral leases was granted to the Board and in 1936 the lease form was amended to reflect that leases were to be awarded by the Board, rather than by the Governor. On March 29, 1938, the Board began awarding leases on this version of the lease form, and the first lease awarded by the Board was State Lease No. 358.

The first state mineral lease was executed by the Governor on April 1, 1915. This lease, containing approximately 6500 acres, was located in Caddo Parish and was awarded to J. W. McInerney. However, this was not the first state leased property to produce oil and gas. Previously, the Caddo Levee Board awarded a lease to Gulf Refining Company, on January 6, 1910. That lease included the water bottoms of Jeems Bayou in Caddo Lake (a/k/a Ferry Lake), which lands were later adjudicated to be owned by the State of Louisiana. Oil production was established on the property covered by this particular lease on October 13, 1911. State Lease No. 29, executed on June 13, 1917, was the first state lease issued on a standardized lease form. In preparing this paper, one of the most interesting things I discovered and learned was how mineral leasing has evolved since these first mineral leases were issued, not only with regard to state leases, but with regard to mineral leasing in general. This pattern of evolution consists of twists and turns that I had either forgotten or had never known existed—and I can't imagine that I am alone in this. So I hope the next few pages of this paper are as interesting to you as they were to me.

When I think about historical or "old" mineral leases, I think of mineral leases covering large portions of acreage that do not contain a Pugh clause and where the entirety of the mineral lease can be held by production from only a single well. For simplicity and ease of reference, I will refer to these type of mineral leases in this paper as HBP leases and sometimes as non-Pugh clause leases. I am sure the revelation that I am going to talk about here, to some of the more "experienced" readers, will be old news. However, to many of my contemporary peers and those younger, I would imagine that it will be interesting and something they might not have known. It really colors and informs my interpretation of even modern lease clauses that I review today, and it might do the same for you.

What I discovered as I went back into the history of the state lease form and the history of mineral leasing in general, is that the HBP non-Pugh clause type leases were not the original structure of the mineral lease, and in fact were only really prevalent for around twenty or so years. As you go back to the original mineral leases, you find that not only were they not HBP leases, but they were mineral leases that required continuous drilling obligations in order to develop the acreage covered by the lease—***even when there was a well producing minerals in paying quantities on the lease***. I will refer to these leases as continuous drilling leases, of which State Lease No. 1 was. So when one surveys the historical mineral leasing of the state, one does not just see a long and early period of HBP non-Pugh clause leases (which I presumed was the case), but you see that in the beginning the obligation to continuously drill and explore on the entirety of the leased premises was at the forefront of the lessee's obligations, even paramount to the obligation to obtain production in paying quantities. Even after obtaining production in paying quantities, these leases required the lessee to continuously drill and explore for minerals throughout the remainder of the leased premises. Once the lessee decided to cease its drilling activity, the lease would then terminate in its entirety…arguably even acreage surrounding wells producing in paying quantities. It wasn't until State Lease 224, executed in 1929, that the specific ability to retain acreage around producing wells made its appearance in the state lease form. These continuous drilling leases are of interest because they do not envision, at all, a situation where a large tract of land could be held by a mineral lease with only production from one well, without the lessee continuing to actively develop the remaining portions of the leased premises or to release portions on which it does not wish to conduct these drilling obligations. When reading these leases, the idea of a HBP non-Pugh clause lease seems very far away and foreign.

These continuous drilling leases, or some remnant thereof, were the predominant lease forms (with a few exceptions here and there) utilized by the state from the beginning with State Lease No. 1 through and until State Lease No. 1617 was issued on the 1948 lease form. The 1948 lease form, as will be discussed later, was the first HBP non-Pugh clause lease form. And, in order to give the reader the benefit of the big picture, this type of lease form was in place only until 1973 when the first Pugh clause was inserted into the state lease form. Accordingly, while I once thought that these HBP non-Pugh clause leases stretched back to the beginning of mineral leasing, that was incorrect and the opposite was actually true. An interesting point was made to me in one of our staff meetings with regard to these older continuous drilling leases. And that was the fact that most, if not all, of the exploration and production companies in the early part of the 1900s owned their own drilling rig or multiple rigs, and the event of drilling a well was much more matter of fact and of course far less of a large investment as it is today.

State Lease No. 1 required the lessee to drill a well on the leased premises within thirty days from the date of execution of the mineral lease. Following the drilling of the initial well within that thirty day period, the lessee was then required to continuously drill wells on the leased premises without a lapse of more than sixty days between the cessation or abandonment of work on one well and the beginning of work on another. If the lessee did not comply with this obligation he would lose the lease in its entirety. The most interesting provision in State Lease No. 1 is in Article No. II which requires the lessee, even after obtaining production in paying quantities,

> "… to begin within sixty days thereafter operation of drilling another well on said premises; and if such second well shall prove to be a producing oil well then he shall before the expiration of a like term begin operation of drilling a third well on the leased premises; it being the intention that as the wells so consecutively drilled shall prove to be producing oil or gas wells, such consecutive operations of drilling wells shall continue, until at least one well is drilled for every forty acres of the tract herein leased."

So you can see, with the aggressive drilling and development obligations of State Lease No. 1, there was not a need for a reasonable development obligation, as the obligations to drill and develop the leased premises were specifically set forth in the terms of the lease. What was amazing to me, is that Article V of State Lease No. 1 stated that the state could demand a surrender of the lease in its entirety if the lessee failed to fulfill its drilling obligations within sixty days of the lessor's notice to comply with such obligations. If the lessee failed to comply with the obligations within sixty days, then by its terms the entire lease would be terminated, even sections of the lease containing wells producing in paying quantities.

Additionally, Article V of State Lease No. 1 also required the lessee, at the end of the primary term, to declare to the lessor what portions of the leased premised were not developed at that time, and to identify which of those undeveloped portions were capable of development and which ones were not. Although not specifically set out, it is clearly implied that the areas identified as not capable of being developed at the end of the primary term by the lessee must be released or the lease is terminated as to those sections. As to the sections identified by the lessee as capable of development, the lessee was obligated to "proceed thereupon to locate a well on each forty acres of such undeveloped portion, if any, at intervals between the locations of such wells of not exceeding ninety days, under penalty that as to such undeveloped portion, this lease shall be cancelled." So it's clear from the overall terms of State Lease No. 1 that the lessee, regardless of whether it obtained production in paying quantities on a particular well, had a continuous obligation to drill one well per forty acres of this sixty five hundred acre lease with differing intervals between the cessation of operations and the beginning of a new one, depending on whether the operations were being conducted during the primary term or thereafter. If the lessee failed to comply with these obligations the lease would terminate in its entirety. Granted, these obligations seem draconian and onerous on the lessee in today's time and economy, but in the beginning of the oil and gas industry it seems that the drilling of wells across the entirety of the leased premises or losing the lease was the common flavor of mineral leases—with of course a few exceptions.

Over the next fifteen years or so, the state lease form maintained the effect and flavor of being a continuous drilling lease. Over this same time period however, the requirements for further drilling and development became less specific and began to move more to the more familiar standard of what we know today as "reasonable" development. The last of these true continuous drilling leases was State Lease No. 223 dated March 19, 1929. But even in State Lease No. 223, one can see how the continuous drilling obligation had been substantially softened and made less specific since State Lease No. 1 was executed in 1915. State Lease No. 223, as opposed to State Lease No. 1, allowed the lessee a full year to begin operations of drilling a well. Another difference between the two leases is State Lease No. 223 does not set out a specific pattern and time frame for the drilling of additional wells once a well is drilled that produces in paying quantities. Rather, State Lease No. 223 states that the "lessee binds himself thereafter he will proceed to further develop the said property with reasonable diligence and will so continue until such number of wells have been drilled upon the said property as to constitute a reasonable development thereof."[1]

Nonetheless, State Lease No. 223 maintains a strong requirement for continuous drilling operations by way of still allowing the lessor to make a demand on the lessee to surrender any portions of the lease that are undeveloped, and the surrender of the lease becomes automatically effective if the lessee fails to continue drilling operations within sixty days of receiving the notice.[2] The drilling obligations of the lessee are also strengthened by State Lease No. 223 retaining the requirement for the lessee at the end of the primary term to submit a report designating which portions of the lease it deems capable of development and which portions it doesn't.[3] As to those portions which are deemed not capable of development, the clear implication is that those portions will be released or surrendered by the lessee, and as to those portions deemed capable of development the "lessee shall proceed to develop further the property, locating a sufficient number of wells at such reasonably close intervals as consistent with the intent of both parties as to accomplish a reasonably profitable development of the entire tract as herein contemplated." Accordingly, even though the continuous drilling operations and development obligations of the lessee are somewhat softened by the lack of specificity that was contained in State Lease No. 1, one can still see that the intentions of the parties to State Lease No. 223 is that the entire tract will either be fully developed by continuous drilling operations or the lessee

[1] See Article II.
[2] See Article V.
[3] See Article V.

will release or surrender those portions it chooses not to develop. One additional note that will be of some interest in the later lease forms discussed, is the fact that the requirement for drilling one well for every forty acres of the leased premises does not appear in State Lease No. 223.

A new state lease form was adopted and became effective following the execution of State Lease No. 223. State Lease No. 224 was the initial lease executed on the new state lease form and was executed on June 25, 1929, only two months after State Lease No. 223 was executed. Again, while there are some aspects of State Lease No. 224 that soften the drilling and development obligations of the lessee, the overall flavor of the lease is still a continuous drilling lease. State Lease No. 224 retains the same provision contained in State Lease No. 223 which sets forth a general development obligation after minerals are discovered in paying quantities, i.e. that the lessee "binds itself to thereafter proceed to further develop the said premises with reasonable diligence, and to so continue until a reasonable development of the property has been accomplished."[4] Of great importance is the fact that State Lease No. 224 no longer contains a provision allowing the lessor to force the lessee into further development of the leased premises by placing the lessee on notice and requiring a surrender of any non-developed areas if the lessee chooses not to continue drilling activity within sixty days of that notice. Without this sixty day notice provision in State Lease No. 224, a lot of the weight and gravity was removed from the state's ability to enforce the lessee's development and drilling obligations on the entirety of the leased premises. With that said though, State Lease No. 224 still retains the end of the primary term report which must be made by the lessee in which the lessee designates areas which remain undeveloped and capable of development and requires the lessee to "proceed to develop the remainder of said property as contemplated herein."[5] As with previous similar provisions, the clear implication is that the Lessee must release or surrender those portions of the leased premises which remain undeveloped and which the lessee deems as not capable of development.

So again, while the drilling and further development obligation is somewhat softened by the removal of the sixty day period, State Lease No. 224 is still very far away from the HBP non-Pugh clause lease that will first make its appearance in 1948. An area where State Lease No. 224 actually implements a more onerous drilling and development obligation is in Article VI where it is stated that the "lessee shall not be required to drill more than one well for each forty acres held hereunder where the premises shall prove to be productive of gas only." Although stated in the negative, one can still see this provision retaining the idea that reasonable development of the leased premises should include at least one well per forty acres, a requirement that was stated specifically in the positive in State Lease No. 1 as discussed above.

B. Acreage Retention Clause—Where did that Come From?

Of additional interest with State Lease No. 224 is the appearance of the first acreage retention clause in the state lease form. Prior to this 1929 version, if the lessee failed to

[4] See Article II.
[5] See Article IV.

comply with its drilling obligations there remained the possibility that the lease could be cancelled or terminated in its entirety, thereby causing the lessee to lose access and the ability to produce already producing wells on the leased premises. In order to avoid this result, Article V in State Lease No. 244 provided that "should lessee, at any time after beginning to exploit the premises as understood herein, decide that it no longer cares to carry on drilling operations, then said Lessee is granted the right to cease such operations, and lessee shall if it so elects, retain its rights in and to ten (10) acres of the property for each and every well which lessee shall have drilled thereon in an effort to produce oil or gas therefrom." (oddly enough Article VI of this lease alters the provisions of Article V and allows the lessee to retain forty acres around producing gas wells). When this provision is read in conjunction with the remaining provisions of State Lease No. 224, and viewed in the historical context of the mineral leases we have already discussed, it is clear that the parties intended a situation where the lessee had to drill wells, find production in paying quantities, and continue to drill wells on the undeveloped acreage or to choose to "no longer carry on drilling operations" and to allow the lease to terminate; and upon termination, the lessee would be allowed to retain ten acres around producing oil wells and forty acres around producing gas wells.

As stated before, this type of required development is far from even the way that we view mineral leases today, and is much, much different from the HBP non-Pugh clause leases that will appear twenty years from the date of State Lease No. 224. Part of why a lessee would have been ok with such a development obligation and the resulting termination of the lease except for the acres retained around producing wells, is that this was a time prior to unitization really gaining a foothold in the state. Thus the idea of building lease blocks to fill out a lessee's interest in a particular well was non-existent. As long as the lessee still had access to the well bore following lease termination, and enough acreage surrounding it to keep that well in production, the lessee could produce the minerals therefrom and its interest in the well and the minerals produced was not lessened by the lack of acreage surrendered around that well as a result of the lease terminating. At this point in time of mineral production in the state, it appeared that access to the well bore was more important than assembling a lease block of acreage that would cover the boundaries of a unit. Accordingly, whether the lessee retained forty acres around a gas well or ten acres around an oil well, it could conceivably produce as much as it wanted from that particular well bore and its net revenue interest would not be lessened by not having a large lease block surrounding that well. In today's world of mineral leasing and exploration and production, where unitization is the default occurrence, assembling a lease block that will fill out and cover the acreage included in a unit is as important as actual access to producing the minerals in the well bore.

It was interesting to see historically how and why the acreage retention clause came about. A few months ago OMR had a situation where we put forth a claim against one of our lessees that it had not maintained its mineral lease because there was a lapse of more than ninety days between operations or production sufficient to maintain the lease. In addition to arguing the point that the operations were sufficient, the lessee put forth the interesting, but very wrong, argument that if the lease terminates as a result of insufficient operations or production then the acreage retention clause contained at Article 7 of the

2000 lease form would operate to somehow allow the lessee to retain the entirety of the lease because the entirety of the lease is included within a unit.[6] At first hearing of the lessee's legal argument with regard to the acreage retention clause, my gut reaction was to say that such a situation is inconceivable and that there is no way that the acreage retention clause could operate to maintain a lease after it is terminated by its own terms for failure to produce or continue operations required by the primary lease maintenance articles. Of course, after doing some legal research on the issue, I found some cases in Louisiana that also struggled with this same issue and the courts' decisions were in line with what my initial reaction was.

The main issue is what happens when the primary maintenance provisions in our mineral lease (presently Article 4) call for a lease to be terminated (in this case a lapse of greater than 90 days of operations and production sufficient to maintain), but the acreage retention clause (Article 7(b) in our lease) seemingly allows for the lease to be maintained. Because this exact acreage retention clause has appeared in most mineral leases almost from the very beginning, this conflict between these provisions has been thoroughly addressed by the courts. The Supreme Court in *Melancon v. Texas Co.*[7] addressed the fundamental problem and gave a guiding principle that courts thereafter have utilized, and one that works in the lessor's favor. The court stated that an outlying equitable provision such as the acreage retention clause cannot subvert the primary maintenance obligations. The court corralled the application of the acreage retention clause by stating that it only applied in situations where there was a "bona fide dispute as to which there is a real disagreement in good faith between the parties", and thus one that would likely require litigation. In any case, the court found that the acreage retention clause could not serve to stop the lease from terminating when the facts were clear upon which termination was based—such as no production or operations or the failure to pay a shut-in or a rental.

Melancon was followed in *Dawes v. Hale*[8] where the court found that the acreage retention clause could not preclude the assertion of a claim for cancellation based on the failure to reasonably develop the lease. The court in *Dawes* summarized the holding in *Melancon*… "***the essence of the opinion was the refusal of the court to allow the acreage retention clause to, in effect, nullify another clause embodying a primary obligation of the lease.***" The court in *Edmundson Bros. v. Montex Drilling Co.*[9] followed *Melancon* and also discussed *Dawes* in holding that the acreage retention clause was unenforceable because the court could not "construe the acreage retainage clause so as to abrogate the responsibility of Montex and the Moncriefs to maintain production in paying quantities on the Durham lease in order to maintain the lease beyond the 5-year primary term….To hold otherwise would lead to absurd consequences."

[6] Article 7(b) of the 2000 lease form states the following: "If any acreage covered by this lease shall have been included in a unit established by the Commissioner of Conservation, or by conventional agreement, or if any such acreage shall have been assigned to a producing or shut-in well under statewide allowable orders of the Commissioner and such acreage is actually being drained by the well or would be drained by it if the well were produced, Lessee may retain all the acreage included in such unit or units or so assigned for allowable purposes. Thereafter, each area so retained by Lessee shall be subject to the terms of this lease as regards future maintenance thereof."
[7] 89 So.2d 135 (La. 1956)
[8] 421 So.2d 1208 (La.App. 2 Cir. 1982)
[9] 672 So.2d 1061 (La.App. 3 Cir. 1996).

However, after resolving the issue to my satisfaction as to the legal interpretation of the issue, the fact that a lessee would be able to make such an argument struck an inquisitive nerve and made me go back and review the provisions of Article 7 of the 2000 form and ask the question: "Where did this provision come from and what is it trying to accomplish?" The answer to these questions can be found in the acreage retention clause contained in State Lease No. 224. That acreage retention clause only came into effect when the lessee decided that "it no longer cares to carry on drilling operations" as required by the drilling and development obligations contained therein. Because the failure to continue the drilling and development obligations would cause the lease to terminate in its entirety, the lessee was understandably allowed to retain ten acres around a producing oil well and forty acres around a producing gas well. So, if the lessee decided that it no longer cared to carry on its drilling and development obligations, it could release the mineral lease and be relieved of those drilling obligations, but it could also retain the small amount of acreage around any producing wells which would allow the lessee to produce the minerals as it wished. Once the state moved away from continuous drilling and development leases and no longer required the lessee to continually drill and develop in order to maintain the entirety of the lease, the acreage retention provision became unnecessary. However, in 1948 when the state moved to a HBP non-Pugh clause lease, and away from continuous drilling leases, the acreage retention clause was retained and has been retained almost unchanged even into the 2000 lease form. When one views the acreage retention clause in the modern lease form through the lens of knowing that such a clause was necessary only within the context of a continuous drilling lease, you begin to see the anomalies created by having an acreage retention clause still in the lease form today—and more importantly you begin to see that it is completely unnecessary.

If a lessee chooses to voluntarily release or surrender a portion of the leased premises as contemplated in Article 7(a) of the 2000 lease form, obviously the acreage retention clause is unnecessary in that instance. If the lessee is voluntarily releasing or surrendering a portion of the mineral lease, it can also retain whatever acreage it chooses to around any producing wells, thereby making an acreage retention clause completely unnecessary when the release or surrender is voluntarily done by the lessee. In the context of a continuous drilling lease, however, one can see the necessity of the acreage retention clause. In that case, the lessee isn't necessarily voluntarily deciding to release acreage or surrender acreage, it is deciding to forego its obligations to continuously drill and develop the remainder of undeveloped acreage, which would thereby trigger a termination of the entire lease. A much different situation than the one faced by a lessee voluntarily releasing acreage today. I believe that's why in Article 7(b), which is the actual acreage retention clause, that it necessitates a situation where there is a "cancellation or forfeiture of the lease", as opposed to a voluntary surrender of the lease by the lessee. The assumption in reading Article 7(b) is that the terms "cancellation or forfeiture" must refer to a situation where the lessor asserts a claim or brings an action for cancellation or forfeiture of the lease against the lessee. In none of these possible instances is an acreage retention clause appropriate. If the lessor brings an action for the lessee's failure to produce the lease in paying quantities, why should the lessee be allowed to retain acreage around a well that is not producing in paying quantities? If a lessor brings an action for failure to reasonably develop a portion of a mineral lease, an acreage retention clause would still be unnecessary because any areas of the mineral lease that have been developed, as is implied by the bringing of a failure to reasonably develop claim, then the lessee would already be allowed to retain an appropriate amount of acreage to produce from a developed area of the lease.

Finally, you get to a situation that we addressed with one of our lessees recently and discussed in the cases above—that there should be no right to retain acreage on a mineral lease that has been lost in its entirety as a result of the operation of a resolutory condition by failing to sufficiently operate or produce the lease in accordance with the lease maintenance obligations, or by failing to pay a rental or a shut-in payment. While I feel comfortable with the backing of the jurisprudence discussed above in relation to these issues, it was also painfully obvious that an acreage retention clause need no longer be included in the state lease form. As you can see in the 2019 Version, Article 17 dealing with termination and release of the mineral lease no longer contains an acreage retention clause. This is a clear instance where knowing the history of the various types of mineral leases executed in the past, and where and why certain provisions arose and were retained, really helped in identifying changes that needed to be made in the lease form today. So the answer to my question posed with regard to the acreage retention clause in year 2019, was answered by State Lease No. 224 executed in 1929. Interesting stuff.

While I have mentioned the substantial change that was made in the lease form in 1948, there was a new lease form issued and put into effect in 1942 and the first lease issued on the 1942 lease form was State Lease No. 516 dated May 7, 1942. This lease form contains many of the continuous drilling and development type provisions that were contained within the 1929 lease form, with just a few variations. Around this time unitization and pooling began to take shape, and the 1942 lease form reflects that. Article X of State Lease No. 516 allows the lessee, with consent and approval of the State Mineral Board, to pool the leased acreage into a unit. Additionally, the acreage retention clause contained in Article V of State Lease No. 516 allows the lessee to retain, not just the ten acres or forty acres around a particular well, but allows the lessee to retain "the size acreage unit for the field as established by a spacing or pooling order of the Department of Conservation." Another small variation between the 1929 and 1942 lease forms is that in Article IV of the 1942 lease form which, as in the 1929 lease form, requires the lessee to submit a report at the conclusion of the primary term in which it decides which portions of the lease are capable of development and which ones aren't. The change in the 1942 lease form from the 1929 lease form requires the lessee to "proceed immediately to develop the remainder of said property as contemplated herein, and lessee shall then release, by proper instrument, from the effect of this lease, any portion or portions of the premises not already under active development or included within the above described declaration as being capable of further development". So one can see that the continuous drilling and development intention is still permeating and actually increasing in the 1942 lease form. The 1929 lease form stated only that the lessee "shall proceed to develop the remainder of said property as contemplated herein" as opposed to the use of the term "immediately" in the 1942 form. Additionally, the implication was clear in the 1929 lease form that any portions designated by a lessee in this end of the primary term report as being not capable of development should be released, that obligation was not specifically spelled out therein. The 1942 lease form now specifically requires the lessee to release any portions that are not designated as capable of development in this end of the primary term development report.

C. 1948 Lease Form—Moving from *Required* Development to *Reasonable* Development

As has been noted throughout the paper so far, the lease form was substantially revised in 1948 and the first mineral lease granted on the 1948 form was State Lease No. 1617 dated October 6, 1948. The first obvious signal that the continuous drilling and development obligations are no longer in place is the fact that paragraph 2 of State Lease No. 1617 is the first to include the well-known habendum clause in which it is stated that the lease shall be for a certain number of years (the primary term) "and for as long thereafter as minerals are produced in paying quantities or any operation is conducted or payment made or condition exists which continues this lease in force, according to its terms". The previous leases that we have discussed all lead off with the requirement to drill and to continue to drill in order to develop the full extent of the leased premises, and that clear statement no longer exists in the beginning of the lease. The remainder of the 1948 lease form is very similar to what you see in BATH forms and also bears a resemblance to many of the provisions and structure of the modern state lease form that we are familiar with today. There is no longer the requirement to submit a development report at the end of the primary term and to release acreage that is not going to be developed and to immediately drill upon acreage that is designated as capable of development. The lease can be maintained merely by production in paying quantities from a single well and there is no longer a specific requirement of continuous drilling and development obligations after production in paying quantities are discovered, as had been previously spelled out in prior leases. The only continuous development/drilling obligations exist when there is no production in paying quantities in place, and that takes the form of what we all know as the ninety day cessation operations clause.

While there was no longer a specific required development obligation, by this time the Louisiana jurisprudence had created the implied obligation of reasonable development. It is possible that the drafters of the 1948 lease form may have made the decision to merely rely upon that jurisprudential authority. The implied obligation of further development was summarized by the Supreme Court of Louisiana, importantly in 1948, in *Carter v. Arkansas-Louisiana Gas Co*., 213 La. 1028, 1034, 36 So.2d 26, 28 (La. 1948) in which the court stated the following:

> The law of this state is well settled that the main consideration of a mineral lease is the development of the leased premises for minerals and that the lessee must develop with reasonable diligence or give up the contract; further that as to what constitutes development and reasonable diligence on the part of the lessee must conform to, and be governed by, what is expected of persons of ordinary prudence under similar circumstances and conditions, having due regard for the interest of both contracting parties.

Additionally, the court in *Carter* further defined the obligation for further development when it stated the following: "The principle, as we understand it, is that development of ***every part of the lease*** is an implied condition. Therefore, whether the undeveloped portion be a single tract remote from the rest, or a considerable portion of a very large tract… or the east one hundred acres of a tract of one sixty, ***it is an implied condition that the lessee will test every part***." With this type of jurisprudence in place, the drafters of the 1948 mineral lease form apparently felt comfortable relying on that rather than spelling out the development and drilling obligations in the lease form itself. The obligation for reasonable development and further development of the leased premises is now embodied in Mineral Code Article 122 which states the general principle that a lessee is to perform its obligations in good faith and operate the property leased as a reasonably prudent operator for the mutual benefit of himself and his lessor. The comments to Article 122 state that: "The jurisprudence since the Carter decision has recognized that the obligation of further exploration is embodied in our law." The reliance on the implied obligation of reasonable development and more generally, the obligation to act as a reasonably prudent operator, has been in place through the 2000 lease form and is utilized in the 2019 Version.

The introduction of the Pugh clause into mineral leasing has lessened the absolute reliance on the implied obligation of reasonable development. The state began using one in its lease form (actually in a rider attached to the lease form) in 1973, but it was, and is, called a deferred development clause. Nonetheless, there are a number of leases beginning in 1948 through 1973 that do not contain the deferred development clause and the state is left with utilizing the implied obligation of reasonable development and also the obligation to produce the lease in paying quantities in order to reduce and get back acreage that is not being either developed at all or that is being held by production not sufficient to constitute production in paying quantities. When I arrived at OMR in June of 2017, I noticed the staff in charge of the lease review process in our geology and engineering section would often times write letters to various lessees asserting positions that a lease had failed to be reasonably developed or that it was being held by production that was not sufficient to constitute paying quantities. However, those letters would usually stop before the actual claim for a release of the lease would be asserted. The problem voiced by the staff was that there was no one above them in management or legal who would take the next step that was many times necessary, but somewhat uncomfortable.

To the satisfaction of the staff, whenever they provided me with situations where the failure to reasonably develop or the failure to produce in paying quantities was obvious—we brought these matters to the Board and requested authority to demand a release of the lease or to file a lawsuit to enforce the claim. I, along with the lease review staff, have tried to shift away from the notion that the implied obligations of reasonable development and to produce a lease in paying quantities are "squishy" or difficult to define rights. These implied obligations on the lessee, and the corresponding rights in favor of the state, are in fact hard, real and enforceable obligations and rights—that are quite easy to define and enforce given a clear set of facts on which they are based. These implied obligations and rights are very valuable to large landowners who are still burdened with mineral leases which do not contain Pugh clauses and can theoretically be held in their entirety by production from a single well. The exercise of drafting this historical portion of the paper and seeing the weight and gravity that the original mineral leases gave to these drilling and development obligations gives further credence to the position we have taken since I arrived regarding these issues. This position is even further supported by the strength of the implied obligation discussed by the Supreme Court in *Carter*. The implied condition is the "development of every part of the lease', and if the lessee chooses not to do this, then those portions must be released. With these older non-Pugh clause leases, some lessees have developed the notion that they have the right to hold onto acreage that, while not considered capable of development at the time, might become so in the future. That isn't how the obligation of reasonable development works. Once a lessee is past the primary term, it must actively develop ***every part of the lease***, or that acreage must be released.

D. State Lease Form—1962 through the Present

Another new lease form became effective on April 11, 1962. This version of the lease form added the following provisions:

1) Lessee's rights to conduct geophysical and geological work on the leased premises,
2) Specifications regarding payments of royalty on processed gas,
3) Due dates for royalty payments,
4) Interest on late royalty payments, and
5) Lessee's obligation to provide copies of applications and plats for Commissioner's units.

The shut-in provision was revised to increase the payments for sulphur, other liquid or gaseous hydrocarbons, and gas in the second and third years. The shut-in payment for potash was reduced. The offset well provision was revised to require production in paying quantities for thirty consecutive days before the lessee was required to drill a well.

A substantially different version of the lease form was implemented in 1966. This version of the lease form was also revised several times in the early 1970's. Beginning on December 8, 1966, the definition for "reworking operations" was no longer in the lease form. Also, the following provisions were added to the lease form:

1) Force majeure,
2) Requirement for production to be in paying quantities for rental payment to be abated,
3) Geological and technical data to be furnished by the lessee upon request,
4) Royalty payments from the date of the lease if any portion of the lease was included in a producing unit on the date of the lease, and
5) A definition for "actual drilling operations".

Finally, the lease form was revised in 1975, 1981, and finally in the year 2000. While there are many differences in each of these revisions, for our purposes and the purposes of this paper, there are not a whole lot of revisions I feel necessary to note. Additionally, the 2000 lease form was revised at various times without putting out an entirely new lease form and those revisions were in 2005, 2006, and 2007. Additionally, the State Mineral Board authorized the staff to include the lease form rider, which had been in use since 1973 and which included the deferred development clause, into the body of the lease and beginning April 11, 2012 the leases were finally awarded without the rider.

E. This has been going on for how long?--Present Lease Revision

In meeting with the staff and reviewing their written contributions to me regarding the lease form revision process that occurred prior to my arrival in June 2017, it seems as if the 2000 lease form revision process began the moment that lease went into effect—and has continued since. In some written material provided to me in conjunction with this paper by OMR's very long standing engineer extraordinaire, Charles Bradbury, he gave the following disclaimer, making light of how long this has taken: "Many trees died in the preparation of the new lease form you see today. No animals, geologists, engineers, or accountants were physically harmed in the confection of this lease form. However, there were extended periods of aggravation and emotional distress." Amen Charles.

While, as previously noted, there have been amendments to the 2000 lease form actually implemented, the preparation for and drafting of a new lease form to take the place of the 2000 lease form, actually began in 2006. In early 2006, the OMR staff started collecting ideas for creating a new lease form that addressed many issues. This idea collection process included informally talking to large private mineral owners and researching other states for example copies of their lease forms. In March 2008, due to an audit settlement issue, staff recognized a need to revise and clarify the royalty provision in the lease form. Audit staff researched other state's royalty provisions and identified other needed revisions. Consequently, both the audit staff and the geology and engineering staff decided that the most prudent course of action was to review and revise the lease form in its entirety. In 2009, the staff was granted permission to begin reviewing and preparing ideas for a new lease form. Some of the issues that were identified as possible changes in the lease were to eliminate the rider (which was actually accomplished in 2012 as noted above), trying to simplify and shorten the lease form, consolidate portions of the lease form and have a more logical organization of the articles, attempting to do away with the ability of a lessee to operate over a rental date, bonding and plugging and abandonment issues, requiring a list of facilities and equipment with a release of the mineral release, the removal of the acreage retention clause and revisions to the royalty provision.

Ultimately, an initial lease form was created and circulated among staff in September of 2009. Staff met regularly in 2009 and 2010 and a summary of the draft lease form was presented to the public at the Sonris Seminar by Rick Heck. Thereafter the draft lease form was put out for public review and the staff received comments from various parties, including industry. The staff had an open meeting with the public in late 2010 and received more comments, primarily from industry representatives. After much research and discussion, a revised lease form was presented to the Mineral Board on August 11, 2010. The Board authorized the staff to post the proposed lease form on the office's website and solicit additional comments from the public. In February of 2011, the department management directed the staff to discontinue working on a revised lease form, and while there were concerns in January of 2012 with regard to the sufficiency of the environmental remediation language contained in the 2000 lease form, no further action was taken on the drafting of a new lease form until 2013. On June 12, 2013, the Board passed a resolution authorizing the staff of OMR to once again draft a revised oil and gas lease form. Over the next eleven months, OMR staff met and developed various issues it wished to address in the new lease form, many of which were consistent with the concerns and changes made in the form presented to the Board in 2010. The staff continued to hold industry meetings, and received and considered many of their comments, while also meeting with industry legal representatives to discuss particular language in the proposed lease form. The staff, in continuing through this process, reviewed the industry BATH form, other state's lease forms, and other large private mineral owners and landowner forms. Along this long and winding road, the staff actually reached an end point and restarted on three different occasions.

On May 14, 2014, staff presented information about each of the issues it wished to address in the new lease form, and the Board passed a resolution directing the staff to do the following:

1) Make a proposed lease form available to the public
2) Set a deadline of July 15, 2014 for the submission of public comments on the lease form
3) Schedule a public meeting within six weeks
4) Present a comparison of the current and proposed lease forms at the June 14th Board meeting
5) Present a summation of public comments at the July 2014 Board meeting
6) Present a revised draft form at the August 14th Board meeting

On June 11, 2014, the staff presented a draft lease form to the Board and made it available to the public on the office's website. On June 25, 2014, a public meeting of interested parties was held at the LaSalle building in Baton Rouge and following that meeting, the staff decided not to pursue the proposed changes to the bonus, rental and deferred development provisions because previous issues with those provisions were rare. On October 20th and 23rd, 2014, the staff and board members had two four hour work sessions on the proposed lease form. Over the next year the staff presented to the Board various provisions of the proposed lease form, after which the staff and Board began reviewing the lease form in its entirety to clarify any ambiguous language and to enhance the readability of the document. The staff presented an entirely revised oil and gas lease form to the Board at its December 9, 2015 meeting. At the January and February 2016 board meetings, action on the lease form was deferred, and the Board allowed the industry and public until April 11, 2016 to submit comments regarding certain issues. The lease form was scheduled for final approval of the Board on May 11, 2016. On May 10, 2016, a workshop was held for the board members and staff to discuss the proposed new lease form, and on the following day, the Board voted to defer consideration of the lease form until June 8, 2016 and at the June 8, 2016 board meeting the Board voted to defer any action on the proposed new lease form until August of 2016.

It was during this time that a new assistant secretary of OMR was appointed and began reviewing what is now referred to as the August 2016 lease form version that had been drafted and proposed for final adoption to the Board. The new assistant secretary David Boulet, at the December 2016 meeting and the January 2017 meeting, requested time from the Board to review and make revisions to the August 2016 version. Mr. Boulet's primary issue with the August 2016 version was how voluminous that lease form had become. After reviewing the August 2016 version on a consistent basis during this drafting process, I completely agree with Mr. Boulet's assessment. So for the next few months, Mr. Boulet worked with the staff and the legal team of OMR to cut down on unnecessary language and to add clarification to the lease in light of some of the practical considerations that the staff has to deal with on a daily basis. Primarily, the problem with the August 2016 version was that when there was a statute or regulation that dealt with the subject matter of the particular lease provision, that statute or regulation was then included in the body of the mineral lease. Additionally, there was excessive and unnecessary explanation of rights and obligations which, instead of clarifying and making it easier to read, further muddied the water as to what those rights and obligations were.

Eventually in the spring of 2017, a new version of the state lease form was completed and internally we referred to that version as the "2017 version", and I will refer to that version in this paper by that name also. In my review of the 2017 version, it looks as if Mr. Boulet and the OMR staff accomplished what they set out to do. The 2017 version is much shorter and concise and much more practically enforceable. It also struck a better balance (than the August 2016 version) between being aggressively in favor of the state and being reasonable enough to encourage industry leasing. Because of these facts, the 2017 version served as the primary basis of the 2019 version.

As you can see, this has been a much longer process than anybody ever wanted and it is oftentimes forgotten what a long and winding road it has taken to get here. I include the in depth history of the recent lease form revision process in this paper because such a history hasn't been yet assembled in one document. Doing so, I thought, could help guide the state and it's lessees in the future and help everyone involved realize that the lease form re-write needs to come to a conclusion and get a new form implemented. But it also has value in this paper as demonstrating to the public that the 2019 version has long been in the process since 2006, and that the different versions that have appeared throughout the past ten years have all built on one another, and have built on the comments from the pubic and industry and the endless hours spent by OMR staff and the attorneys in researching and drafting and comparing different versions from different states and different landowners. As I will discuss later in the paper, in the drafting process headed up by myself over the last year and a half, we made every effort to utilize all of the different versions at hand and utilize all of the historical information and comments and decisions that have been put forth by the public, industry, our staff, our attorneys, outside counsel, and the Board.

F. Process for the 2019 Version

When I first arrived in June of 2017, I attempted to work within the approval process that the staff and Board had in place relative to the 2017 version. However, since I was hired to put my stamp on the lease form by Secretary Harris, I felt like I needed more time in order to accomplish this. As I delved further and further in the next few months into where the staff and the Board was with regard to the different versions and issues being addressed, I felt like I needed a lot more time. So towards the end of the year in 2017 or the beginning of 2018, the Board gave me the leeway to do away with the approval process that was in place for the 2017 version and to conduct my own review process and drafting process in the next year.

Eventually I developed a process and a procedure that we used for the entirety of the lease. For each article I began the process by reviewing the article in the current lease form (the 2000 form), as the article was revised by the 2016 version and how the article was revised in the 2017 version. I research how the topic addressed by the particular article is dealt with in private landowner lease forms, lease forms of other states and the widely used Bath form. I also reviewed all comments that the public/industry had made with respect to the particular article—if that article had been publicly addressed. I would also conduct legal research and read cases and articles that had addressed and dealt with any issues with respect to the subject matter of the particular article. I utilized this information to help identify the overall rights and obligations that are being dealt with in the article—what areas of the state's interests need to be addressed—and also what concerns and issues does or will industry have with the revisions? At this point in time, I would then meet in an individual/one-on-one basis with whichever staff member had the most responsibility or knowledge regarding the particular article. I let them tell me the history behind the revisions that have taken place thus far and what practical issues those revisions were trying to alleviate. I then would meet with whichever attorney—either Blake Canfield, Jim Devitt or William Iturralde, or sometimes more than one of them—that had the most responsibility and knowledge regarding the particular article. We would discuss what legal issues were historically swirling around with respect to the article and what issues were the revisions meant to deal with. Sometimes I would ask one of these guys for additional research on a particular legal issue if I couldn't do it myself.

Finally, armed with what I felt like were most, if not all, of the issues to consider for a particular article, I set to revising the article. Where at all possible, I drew from language already in one of our forms—the 2000, the August 2016 version, the 2017 version—or I utilized language from other lease forms from private landowners or from other states. Once I had the article revised to my liking, I would then send it out to our lease form group, which is made up of the following individuals: Blake Canfield, Jim Devitt, William Iturralde, Ryan Seidemann, Christopher Lento, Stacey Talley, Rachel Newman, Emile Fontenot, Jason Talbot, Byron Miller, Charles Bradbury, and Suzanne Hyatt. After the group had a few days to review my draft of the article, we then met to discuss it. At that meeting the group made suggestions for changes to my draft and we also just generally discussed the issues behind and surrounding each article. After the meetings, I would go back and implement the revisions. Thereafter, I would oftentimes meet again with the attorneys, who were some of the primary drafters on the article. We would make sure that everything was in place and then we would move on to the next article. We plodded through this thing over the last year and a half. Once we completed all articles, we put some finishing touches on it, I asked a couple of the attorneys to go through it with a fine tooth comb to make sure that all references worked together. We all reviewed it again and met recently on it, some revisions were proposed, we made those revisions, and we were left with the 2019 version. It has been a group process and I appreciate the help of the lawyers and the staff, and all of the work that had been done by those that came before me.

III. DISCUSSION OF THE 2019 VERSION

A. Introduction—Drafting Principles

In speaking with individuals in industry and the public in general on various occasions, there is the sentiment out there that anytime state government decides to change something or issue something new, that the overriding intent is to inflict as much pain and burden on the public as possible. While that may be true for other areas of state government, OMR is substantially different. While OMR is obviously a part of the state government, OMR is much more of a business than it is a regulatory body. Our job at OMR is to encourage leasing on state owned property (to the extent we can), issue leases, and to make sure that the lease maintenance obligations and royalty obligations are complied with. OMR views industry primarily as a business partner as opposed to a sector of the public that OMR is regulating. If the oil & gas industry is our partner in this business of mineral leasing, and if part of our job is to make sure that we encourage that business activity while also ensuring that the state receives its just due for its minerals and the right to explore for those minerals on its lands, then it would cut against those purposes to issue a mineral lease that is entirely burdensome and unreasonably difficult economically and practically for industry to work with.

With these ideas and goals in mind, I eventually came to be guided by three overriding principles. The first, was to make sure that the state kept in place rights which it already had in place through prior lease forms, as long as those rights had not become outdated, unnecessary, or in an everyday practical sense—unworkable in their application by the staff of OMR. The provisions contained in the 2000 lease form presently being utilized by the state are similar in fashion and substance to most other large landowner lease forms and lease forms being utilized by other states. It is a fairly aggressive lease form that is weighted in favor of the lessor, as it should be because the state is the largest landowner in the state. Large landowner lease forms are always weighted in favor of the lessor, and the 2000 lease form is no different. Of course, with the state as my client in this drafting process, I wanted to ensure that the state did not lose any of its rights it already had in place for many years. Not only are those rights important in the state getting the value that it needs out of its minerals, but those rights, having been in place for many years, have obviously not dissuaded industry from participating as a leasing partner over these many years that the lease form has been in existence.

The next principle I was guided by was to attempt to achieve implementation of a couple of things that the state needs to have in its mineral lease, and provisions that have become common place since the last revisions to the 2000 lease form. As will be discussed in depth in the next section, this primarily resulted in the drafting of a deep rights release provision. It's a provision and a right that is contained in most large landowner lease forms and lease forms utilized by other states. Finally, the last principle that guided the majority of my general drafting procedures, was efforts to simplify, clarify and make the lease form more efficiently applicable in day to day utilization by our staff and our leasing partners. To summarize, the goals which I hoped to accomplish with the 2019 version were to implement a couple of necessary changes to the lease form, keep the rights and obligations of the parties essentially as they have been throughout the years, clarify, simplify and make the mineral lease more practically usable, and finally to do all these things with an eye of striking a balance between insuring the rights and value of the state for its minerals and also with the idea that we could not go too far in doing this without possibly discouraging oil and gas companies from spending their money in Louisiana. With that said, I cannot be sure if we accomplished that goal, but we did the best we could. I also say this knowing full well that people in industry and the public are going to complain no matter what we do and that some of those complaints have to be taken with a grain of salt, while other more substantive and reasonable complaints need to be listened to and addressed. The length of this paper does not allow me to fully discuss all the revisions that we made in the 2019 version. Instead, the remaining portions of this paper will discuss the revisions to the lease maintenance articles (focusing on the deep rights release provision), the royalty provision (with an in depth discussion of why we decided against a no-deductions royalty provision), and finally a fairly brief discussion of the articles dealing with environmental and remediation concerns.

B. Lease Maintenance Articles

1. Article 3—Core Lease Maintenance Issues

These set of articles in the beginning of the lease form were the first articles that I looked at when beginning this process. I can remember first when looking at this, I thought to myself everything looks fine to me here. As with most of the articles I drafted and revised, I began with the 2017 version as a baseline. It's interesting though, when looking at possible revisions for the lease maintenance articles, that being primarily Article 3, it was difficult to find a place to start. Unlike many of the other articles in a mineral lease which are more standalone articles, the lease maintenance articles in a mineral lease create a somewhat intricate structure in which almost every word and sentence are connected to each other. So that, if you change one word in one sentence, then it has a ripple effect throughout the remaining lease maintenance structure. Even though I felt like I had a good understanding of how the lease maintenance articles work together to create this structure, I realized quickly that I needed to sit with the articles and spend some time just mapping out in simple and practical terms what the article was attempting to accomplish. I began to see small variations on what type of operations were required during a primary term?; when and how much were the rentals to be paid to hold the lease during the primary term?; how could the lease be maintained in the last year of the primary term and at the end thereof?; what about when the acreage is included in a unit?; and finally how is the lease maintained following the end of the primary term?

The resulting revisions in the 2019 version really do not change very much of the substance of the lease maintenance articles in the 2000 lease form. As in the 2000 lease form, the 2019 version may be maintained during the primary term by conducting actual drilling operations, obtaining production in paying quantities or by the payment of a rental if neither of those are taking place on an anniversary date of the lease. At various times in the lease revision process since 2006 and thereafter, there have been certain individuals that have pushed for not allowing the lessee to avoid the payment of a rental if it is conducting actual drilling operations or obtaining production in paying quantities on an anniversary date—commonly referred to as "operating over a rental date'. The suggestion was to give the lessee credit for the dates and times in which it is conducting these operations or obtaining this production, and thereafter requires the lessee to pay a pro-rated rental in order to maintain the lease for the remainder of that year. However, this idea has never gained traction in the lease revision process, and I believe that is a good thing.

If our lessee is conducting actual drilling operations on an anniversary date, then the state as lessor has obtained exactly what it desired in this business transaction, i.e. that the lessee would explore for minerals on the state's property and attempt to obtain production therefrom and pay the state royalties on that production. The way the 2019 version defines actual drilling operations and the inclusion of a requirement of good faith and due diligence within that definition, the state insures that the actual drilling operations being conducted by its lessee are legitimate and not merely to avoid the paying of a rental. While I suppose it is conceivable that a lessee might have the poor intent of conducting operations in order to avoid paying rental, it is extremely unlikely given the amount of revenue expended in drilling a well compared to the payment of rental in most cases. If our lessee expends the capital to conduct an operation that complies with our definition of actual drilling operations and good faith, then that lessee has likely expended far more in favor of the state then it would in paying a rental, and therefore should be rewarded with earning another year of the lease without the payment of a rental. This is just good business for both the state and its lessees, and to require something otherwise, in my opinion, would be far too stringent and dissuade operations being conducted on state property. Although it is nice to receive the rentals pursuant to the terms of these leases, the real money that the state is hoping for comes through the exploration and the production and payment of royalties thereon.

An additional assurance that the operations and production which serve to hold the lease during the primary term are valuable to the state and can take the place of paying a rental, is the fact that the 2019 version, as well as the 2000 lease form, do not allow reworking operations to hold the lease during the primary term. The operations must be actual drilling operations and cannot merely be reworking operations. This changes for the anniversary date at the end of the last year of the primary term and thereafter, where "acceptable lease operations", which includes both actual drilling operations and actual reworking operations, can maintain the lease. Of course, the difference during this time period of the lease is that rentals can no longer can be paid to maintain the lease—the lease can only be maintained by continuous acceptable lease operations or production in paying quantities without a lapse of greater than ninety days.

2. Deep Rights Release Provision

Other than the issue of whether to include a no deductions royalty clause in the mineral lease, the inclusion of a deep rights release provision in the lease form is the most talked about and somewhat controversial aspect of the 2019 version. When I began the lease revision process in the summer of 2017, inclusion of a deep rights release was usually the first thing that Mineral Board members and staff would mention to me in general discussions of the lease form. The 2000 lease form does not have a deep rights release, but it is common place to find one in the lease forms of other states and in the forms used by other large landowners. Because of this, it is no surprise to the public and industry representatives to find out that we have included one in the 2019 version. However, even amongst the staff of OMR the deep rights release is not without its detractors.

A few years ago there was a push to amend the 2000 lease form to include a deep rights release provision and many of the staff here at OMR disagreed with its inclusion. The problem, the staff argued, was that the geology primarily in south Louisiana makes implementing such a provision difficult, and may in fact leave the state with a less valuable right than if the deep rights remain with the original lessee who owns the shallower rights above. The difference in south Louisiana is that the geology is so fractured and faulted in many areas that it is difficult to find a geologic boundary or depth at which both the original lessee's producing formations are protected and where the potential lessee of the released deep rights feels comfortable enough that the formations it drills to and produces are not interfering with the original lessees. The difficulty in creating a reliable "fence" between the two stratigraphically neighboring lessees creates a breeding ground of conflict and in some cases could make the severed deep rights worthless or at least much less valuable than if the rights to explore those depths had remained with the original lessee. No lessee will want to pay the upfront costs for leasing the deep rights or invest the money to drill a well into formations that it is not positive it has the right to do so.

While there is some of this extreme faulting and fracturing of geology in north Louisiana around salt domes and other similar structures, the changes in geology and formations for the most part are much more subtle and easier to identify and segregate with the application of a deep rights provision. So with all that said, I went into the analysis of whether the state should include a deep rights release in its lease form with an eye towards a general need for such a provision, but also with an eye towards drafting a provision that is both practically workable in its application and one that insures that the state would be left with something more valuable after the deep rights are severed from the original lease.

The solution to the problem came in the form of some language of a deep rights release provision provided to me by one of our Mineral Board members, and the solution to the seeming problem that the staff was voicing, which I believe is well founded, lies in the word "may". After the usual research, drafting, meetings and revisions were conducted, the following is the deep rights release provision that ended up being included in the 2019 version, and is located in Article 3E(1):

> No sooner than the second Anniversary Date beyond the end of the Primary Term, the Lessor may terminate this Lease as to all or a portion of the Leased Premises as to all depths one hundred feet (100') for vertical wells and three hundred feet (300') for horizontal wells below the deepest producing perforation in the well or wells located on the Leased Premises or on lands pooled or unitized therewith (***"Deep Rights Acreage"***). In applying this provision and arriving at a depth at which this Lease will terminate and the Deep Rights Acreage will begin (***"Termination Depth"***), the Termination Depth shall be measured in true vertical depth and shall be uniform, constant and unvarying throughout the entirety of the geographic confines of the Deep Rights Acreage

As one can see, the termination of the deep rights acreage is not automatic in that the "lessor ***may*** terminate this lease" as to the deep rights acreage. While this solution is not without its own problems, it was the consensus best option amongst those of us involved in drafting the mineral lease. Because it gives the staff and the Mineral Board the option to terminate the lease as to the deep rights acreage, the staff and the Board can consider whether the state of the geology at the point in which termination is to take place would allow for a feasible and workable separation of those rights.

The primary question for the state at the time this right is to be exercised, would be to ask whether the severance of the deep rights from the original lease would create a right that is more valuable than if it were to remain part of the original lease. If the geology is fractured to the point that a reliable border between the shallow and deeper severed depths could not be created, then the possibility of gaining a potential lessee of the deep rights acreage would be unlikely. If that is the case, the severed deep rights acreage would be substantially devalued if it is severed from the original lessee. Other considerations to be made in this determination are future development plans put forth by the original lessee prior to the state making its decision, the surface facilities available to the original lessee or those available to a possible potential lessee of the deep rights acreage, in addition to a myriad of other considerations that would only play out once the termination process takes shape. If the deep rights acreage automatically terminated at the point and time stated in the provision, then the state could very well be left with large amounts of deep rights acreage that may never be marketable, and may also prove to be either a nightmare or impossible for the staff (both lease review and audit) to track and ensure that lease provisions are being complied with.

However, as I mentioned before, even implementation of an *optional* deep rights release may prove to be difficult. Having to implement procedures to accept information from the original lessee, to verify that information, and to create their own set of parameters within which to make the decision, places a heavy burden on the lease review staff in our geology & engineering section. That said, these problems will hopefully be ameliorated by the percentage of leases that reach the seventh year in the term of the lease (three year primary term, possible two year extension and then the two years built into the release provision itself), should prove small enough to allow for a manageable situation for the staff and the Board to make a well-considered determination as to whether to apply the deep rights release provision.

After somewhat resolving the issue of making the deep rights provision an automatic termination or one that was optional, I turned to two other important aspects of the clause: 1) the time at which the termination is to take place; and 2) the defined depth at which the termination occurs. The timing of its application was fairly straightforward. There are some lease forms from other states and other large landowners that make the release of the deep rights applicable at the end of the primary term and there are some that make it applicable as late as ten years into the life of the lease. In one particular lease from the state of Alabama, immediately upon a portion of the lease being included in a unit the lease was not only divided geographically pursuant to the boundaries of the unit, but it was immediately severed into a separate lease based on the formation covered by the unit and the depths therein—very, very aggressively in favor of the lessor. The state of Colorado lease form allows for termination of undeveloped deep rights beginning with the tenth anniversary of the lease and the enforcement of the termination provision is optional. The Texas Gulf & Bays lease form utilizes a deep rights release provision that automatically applies two years following the end of the primary term of the lease. In deciding on the timing for the application of the deep rights release, we felt that two years following the primary term was a sufficient period of time for the lessee to exercise its exploration rights in the leased premises and to drill and prove up whatever exploration ideas it had sold to its investors. Taking into consideration the possible two year lease extension at the end of the primary term that can be granted under the 2019 version, this date would mostly likely occur at seven years into the life of the lease, plenty enough time for the lessee to fully exercise whatever rights it intends to prior to severance of the deep rights.

The most interesting aspect of drafting the deep rights release provision was determining how to define the depth at which the release was to occur. In performing my research, I found quite a few cases in which the parties were in conflict with regard to determining an accurate and agreed upon boundary at which termination will take place. The conflicts in these cases came about because the termination depth is tied to the base of a particular geological formation, reservoir or zone. The two primary disagreements the courts were trying to decide in these cases were determining where the formation occurs stratigraphically and once that depth is determined, whether the parties intended for that depth to vary with the different depths at which that formation occurs throughout the geographic confines of the leased premises—in areas away from where the well bore penetrates the formation, reservoir or zone.

The Court in *BRP LLC (Delaware) v. MC Louisiana Minerals LLC*[10], while not specifically interpreting a deep rights release provision, the Court does attempt to determine the boundary of a depth limited mineral transfer. The mineral rights being transferred were limited to the following depth:

[10] 196 So.3d 37 (La. App. 2d Cir. 5/18/16).

> below that depth which is a stratigraphic equivalent of the base of the Cotton Valley formation and the top of the Louark Group defined as correlative to a depth of 10,765' in the Winchester Samuels 23 #1 well (API #1703124064) located in Section 23-14N-13W, DeSoto Parish, LA, and correlative to a depth of 9,298' in the Tenneco Baker #1 well (API #1701320382) located in Section 12-16N-10W, Bienville Parish, LA

The disagreement between the parties was a differing interpretation as to what depths the described formations occurred at. One of the testifying experts identified the problem with utilizing formation depths and the stratigraphic equivalent of those depths, and she/he also voiced a solution: "**The location of formations in groups are subject to disagreement among geologists, and the general thought about their location can vary over time…, for this reason, stratigraphic markers, such as the well depths used in this case, are the more commonly used in the oil and gas industry**." In the case, BRP argued for defining the depth pursuant to the location of the formations—Chesapeake argued that the depth boundary of the minerals conveyed and retained should be defined by the specific well depth markers in the wells referenced in the description. Because of the inherent lack of clarity in the conveyance description, the trial court was forced to hear days of testimony from geological experts testifying as to their different interpretations of the intended depth. This case is an obvious demonstration that the use of references to the location of geological formations and their stratigraphic equivalents as the means of describing a stratigraphic depth boundary, brings great uncertainty. That amount of uncertainty would cost the state and its lessees a great amount of time and money. It would cost the state up front by making the severed deep rights less valuable to a potential lessee, and it would cost the state in litigation expenses to sort out the actual boundary through future litigation.

These issues surrounding the difficulty of determining the appropriate horizontal boundary for a deep rights release provision were also discussed by Aimee Williams Hebert in her paper titled "A Review of Selected Lease Clauses" given at the 2007 Mineral Law Institute.[11] The two cases Ms. Hebert discusses are *Sandefer Oil Gas, Incorporated v. Duhon*[12] and *EOG Resources, Incorporated v. Wagner and Brown, LTD*[13]. Each of these cases struggled with locating the depth at which a deep rights release provision was to be applied. Interesting though, each case also struggled with whether the chosen depth of the release was to be consistent throughout the entire geographic boundaries of the lease or whether the depth was to follow and change with the depth at which the particular identified zone or horizon would appear. The Court in *Sandefer* held that the boundary was one hundred feet below the base of the formation from which the well was producing, *at whatever depth the formation was found throughout the lease tract*. The boundary was therefore tied to the actual stratigraphy, rather than a particular true vertical depth. However, the court in *EOG* found the opposite. After determining that the boundary was to be fixed at a depth of 9,829 feet, the court held that that depth was to be consistent throughout the geographic confines of the lease, as opposed to a depth which follows where the formation actually occurs at varying points under the surface of the leased premises.

---

[11] See Pages 207-209.
[12] 961 F.2d 1207, 1209 (U.S. 5th Cir. 1992).
[13] 202 S.W.3d 338 (Tex. Ct. App. 2006).

Of course, when a drafter of a provision sees this type and level of confusion and conflict with regards to a very important boundary description related to the rights in a mineral lease, a primary concern is to avoid drafting something that will put your client in these type of cases. If the deep rights release provision contained in the 2019 version is not crystal clear as to both the depth at which the release is to occur and the fact that depth is to be consistent and unvarying throughout the entire lease boundary, then cases such as these in which parties fought long and hard over the boundaries, create much confusion for potential lessees and the specter of this type of litigation would devalue substantially the severed deep rights. Accordingly, we have attempted to avoid these issues by tying the depth at which the release is to occur to a definite identifiable point in the well bore, to measure that depth in true vertical depth and by making clear that that depth "shall be uniformed, constant and unvarying throughout the entirety of the geographic confines of the deep rights acreage." While we have chosen the particular point in the well bore at which the release is to occur as "one hundred feet for vertical wells and three hundred feet for horizontal wells *below the deepest producing perforation in the well or wells located on the leased premises or lands pooled or unitized therewith*", in discussions with representatives from industry and with board members, I am open to defining that depth to another definite and easily identifiable physical depth marker located in the well bore. Having recently begun discussions with industry, the public and board members with regard to this provision at the time of writing this paper, we are listening to different ideas and will continue to do so throughout the process.

Whether the defined depth utilizes a definition which creates a somewhat deeper boundary is really of much less concern to me, as long as that boundary is an easily identifiable physical point in the well bore that establishes a depth which cannot be open to interpretation by geologists, and also as long as that depth is uniform and unvarying throughout the geographical confines of the lease. Otherwise, any uncertainty over the boundary between the deep rights and the shallow rights (the original lease rights) will substantially devalue the severed deep rights. Just like with immovable property—folks like to know what they are getting—good fences make good neighbors. The only way to arrive at a "good fence" is tie the termination depth to a known physical point in the wellbore that is not open to geologic interpretation—and then to make that depth uniform throughout the lease.

C. Royalty Clause

1. Introduction

I don't believe we had gotten to the point of drafting the royalty provision until I was well into my first year on the job. By that time, I had developed many notions about the royalty provision currently in place in the 2000 lease form. I eventually learned these notions to be untrue. My only experiences with the royalty provision had been situations involving conflicts between our audit staff and the lessee regarding differing interpretations of the royalty provision. Because of this, there was a constant lamentation regarding the royalty provision in the 2000 lease form and how we desperately needed to improve it. This general lamenting of our royalty provision would also take place before, after and during the Mineral Board meetings and in meetings with public. So when I began the drafting process I thought that the royalty provision contained in our 2000 lease form had to be completely revamped or entirely replaced. As I went through my preparation and gathering of information at the beginning of the drafting process, I learned that was not true.

Due to the importance of the royalty provision and the wide range of issues addressed therein, I spent months preparing and becoming familiar with the various issues so that I could make well-informed decisions on what I felt the royalty provision should look like. The first place that I started was to meet with our audit staff to discuss what issues they had in applying the provisions of the royalty clause as it presently stands. We had various meetings and exchanged emails discussing what worked and what did not work. I learned very quickly that for the vast majority of audits conducted by our auditors, the staff had very little problems determining the propriety of the amount paid by our lessees and the deductions taken by our lessees from those amounts. Additionally, utilizing the royalty provision in the 2000 lease form and even the lease forms pre-dating that form, our staff had few problems enforcing those provisions and receiving payment when an auditor discovered that a lessee had improperly paid its royalty or improperly calculated or taken a deduction. In fact, our auditors have developed an entire handbook with guiding principles and issues discussed therein that assist and educate our auditors so that they can make decisions in the field without always consulting one of our legal staff. It became clear to me very quickly that the royalty provision as it stands today has done exactly what any type of contract is supposed to do, it has given our auditors and our lessees a clear set of parameters and rules that, for the most part, allow both sides to eventually reach an agreement and resolve the matter without having to consult our legal team or without having to spend large amounts of time and money in litigation trying to resolve these matters. The familiarity of the rules and language contained in the present royalty provision allow our auditors to efficiently conduct their day to day work—receiving royalty payments and insuring those payments comply with the terms of the lease.

So upon learning this, my first thought was that we should not change the already familiar and workable language of the royalty provision unless the state stood to substantially gain economically as a result of those changes. With further research, I came to see that the state's royalty provision and its valuation of production and rules for taking deductions, were typical of large landowner leases and many other state's lease forms—meaning the state's present royalty provision is good for the state economically. So, when I realized that the royalty provision was being successfully implemented by our staff and accepted by our lessees, and also that the valuation and allowed deductions were in line with other large landowner lease forms, my focus on drafting and revising the royalty provision began to shift.

I decided to utilize the 2000 lease form royalty provision as a beginning point for the drafting of the new provision. My focus was not on recreating an entirely new royalty provision as those involved in the drafting process had done in the 2016 version and the 2017 version, but my focus was on keeping the inherent usability and clarity of the provision that came with the familiar and oftentimes agreed upon language and dialogue those terms created between our audit staff and our lessees. However, I also tried to identify problem areas in the provision and to attempt to remedy and clarify those problems. When drafting a new provision, it is easy for one so situated as the state to want to draft an entirely new provision weighted even more favorably in its favor, and to utilize brand new language that those drafters believe will accomplish that. The problem with this, as any drafter of a legal document knows, is that utilizing new language that one side believes refers to something more favorable for themselves, can also result in language that the other side views as referring to a situation more favorable to them. When that happens, it is up to the court to decide what the new language means. Words are not the actual things they refer to, they are only an attempt to refer to those things. When new language is utilized in a contract, each party is going to interpret that language as referring to some thing or idea that favors their own position. That leaves a situation of conflict, a situation of unknown, a situation that costs money to resolve in the courts, and one that can be resolved entirely unfavorably to the parties originally drafting the language—usually to their utter surprise. Because of all of these reasons, I wanted to utilize and work from the historically familiar language in the 2000 form that has become customary for both our lessee and our audit staff, language that both sides can usually agree on as to what it references, and language that makes sure the state is getting a good value for the production obtained from its lands.

2. Revisions to the Royalty Provision

The three main issues in a royalty provision, in addition to setting the royalty percentage, are to clearly define what production is royalty bearing, how to value that production and what deductions can be taken by the lessee from the royalty owed on that production. Our lease form, as many others, is divided into three separate sections addressing these issues with respect to oil, gas and natural gas liquids ("NGLs"). With respect to the issue of what production is royalty bearing, Article 9(B), (C) and (D) of the 2019 version expands and clarifies that royalty is due to the state on all production that is "produced, saved, sold, utilized or severed from the leased premises." This defers from the 2000 lease form which requires royalty to be paid on all production "produced and saved or utilized". Our office has had multiple conflicts with operators and payors who interpret the 2000 lease form as allowing them to not pay royalties on oil that is lost, for whatever reason, and gas that is not utilized because it is flared. While in the context of these conflicts the state asserts that the language of the 2000 lease form should be interpreted differently, we wished to clarify these terms to include the hopefully undisputable term "severed"—meaning that any production that is taken out of the ground ("severed") must be royalty bearing. The only exception to this rule is given in Article 9(E)(5) which allows the lessee to recycle gas and liquid hydrocarbons produced from the leased premises for "injection into any oil or gas producing formation underlying the leased premises for stimulating the production of oil or for secondary recovery purposes and no royalties shall be payable on the gas or liquid hydrocarbons so recycled until such time as the same may thereafter be severed from, produced, saved, sold, or utilized by lessee in such manner as to entitle lessor to a royalty thereon under the royalty provisions of this lease." The addition of "severed" was the primary change to the royalty provision dealing with the issue of what production is royalty bearing, except for the additional provisions specifying this issue with regard to NGLs. Because processors of NGLs sometimes retain portions of the production as payment for processing, determining what NGLs produced by the lessee are royalty bearing is a bit more complicated. Because this issue has created some conflicts in our office with our lessees, we tried to clarify and be more specific with regard to what portion of the NGLs are royalty bearing and what portions are not. The entire part of paragraph D(1) of Article 9 deals with this issue and does so hopefully in a productive and efficient manner.

When reading commentary and articles discussing the issue of valuation of production and also in reading many different lease forms, there are really only three ways of going about it that insure some type of reliable and workable redundancy: 1) utilizing the price paid by the first purchaser pursuant to a prudently negotiated arms-length contract; 2) utilizing some identified pricing index; or 3) utilizing the average price being paid in the field or nearby fields. The consensus and most efficient and logical way of valuation seems to be to rely on the lessees own personal interest in obtaining the best price pursuant to a prudently negotiated arms-length contract. While utilizing a market index price seems more reliable and objective, the problem is that the index price is based on certain qualities of the oil or the gas, and the qualities being produced in the field on which the royalty is owed might be substantially different in value. This leads one into an area of unknown interpretation on both sides as to what the value of the quality of gas or oil actually being produced should be relative to the value of the stated quality for the index price. Additionally, market indexes come and go and agreeing on a substitute index can be a problem. Based on these issues, I felt that utilizing an index price was not the best way to go, at least as a first preference.

So with all three of the sections for oil, gas and NGLs, we heavily weighted the valuation on the front end to the price paid by a first purchaser pursuant to a prudently negotiated arms-length contract. It seems the best way to get the most consistent and highest value for the production—leaving the least amount of room for each side to interpret the price to their own position, thereby creating conflict which can be costly and time consuming. The lessee has a complete self interest in obtaining the best price and the price being paid is reflective of the quality of oil or gas that is being produced. For oil and gas, if there is no sale pursuant to a prudently negotiated arms-length contract, the second method of valuation is to use the average price paid in the field, or if there is no oil or gas being sold in the field, then the average price paid in the nearest three fields. In my discussions with the staff with regard to the workability of the present royalty provision, it was surprising that, for the most part, there are few issues with our lessees when using the average field price valuation provision. Because of this, I felt that average field price was the most reliable and efficient way of implementing a second choice of valuation. The average price paid in the field or the nearest three fields cannot be utilized with NGLs because that production is obtained and processed at a processing facility and there may not be another processing facility in the vicinity. Accordingly, the second level valuation if the NGLs are not sold pursuant to a prudently negotiated arms-length contract, is the value calculated "on the basis of oil, price information service (OPIS) at Mont Belvieu, Texas on the date sold."

With regard to the deductions allowed and disallowed—there are some important substantive changes. Many of these changes do not alter the general obligations of the lessee, but do clarify and specify what deductions are allowed and which ones are not. Many of these changes were gleamed from other lease forms utilized by other states. The first thing we did was expand the general disallowance of deductions for the costs of anything considered to be a producing function, to also be disallowed for any functions that are attributable to exploration, development, primary or enhanced recovery or abandonment. This change is more of a belt and suspenders type of provision. One issue that has caused some conflict between our auditors and payors is the issue of gathering. While we believe the 2000 lease form disallows gathering whether inside or outside the field, I wished to clarify this and make it absolutely clear that costs incurred for gathering are not allowed whether those costs are incurred inside or outside the field. As a side note, I thought when initially revising the royalty provision that we needed to go away from utilizing field boundaries as a physical parameter for when certain deductions are allowed or not allowed. However, in my discussions with the audit staff in preparing to draft the royalty provision, they made clear that while there are sometimes small disagreements over where the field boundaries lie, for the vast majority of cases the auditors are able to set field boundaries that our lessees can agree with. So I decided to keep that as an element in these provisions for the sole reason that they work.

For deductions with regard to oil and gas, the 2019 version makes more specific the costs that are not allowed as deductions because they fit into the general obligation that the lessee must place the production in a marketable condition. With regard to these deductions, we just attempted to clarify and specify those deductions that are allowed or not allowed. Our audit staff, in reviewing these changes, agreed that they would have a benefit in making the audits more efficient and also potentially increasing the value of the production in some small amount. Finally, with regard to the charges to be deducted in processing NGLs, there's often been difficulty in interpreting the 2000 lease form royalty provision. The primary issue arises in situations, which are common place, where the processor retains some portion of the NGLs in addition to charging a processing fee. While not necessarily changing the substance of the 2000 lease form, we attempted to draft around this problem by specifying and clarifying the provision related to this situation.

3. Deductions or No Deductions

The most controversial and interesting issue I was confronted with in drafting the royalty provision was whether to attempt to draft a no deduction royalty provision instead of one more in-line with the traditional provision that is in the 2000 lease form. After reviewing the history and legal landscape of this issue, I concluded that even if the state feels it is the better policy to go with a no deduction provision, it would be impossible to draft such a provision that could guarantee that it would actually be interpreted the way the state intends. A lessor can have the best intentions and seeming clarity in drafting a new provision utilizing new language—but because the language is new and untested, both its lessee, and more importantly a court, could have an entirely different idea about what that language was intended to accomplish. Below you will see how this struggle, both lengthy and costly, has played out in the Texas courts with regard to interpreting and enforcing language that was intended to be a no deduction royalty clause. The first question that needs to be answered, however, is whether a no deduction royalty clause in the state lease form is a good business decision for the state?

As discussed in earlier sections, we presently have a royalty provision that works in practice for our auditors and lessees, and it is also a royalty provision that gets about as much value as a lessor can get from its percentage of production. There is not a lot of extraneous value floating around in the economics of oil and gas exploration and production. Over the years large landowners like the state of Louisiana have done a good job of asserting the strength of their economic position and assembling royalty provisions that help insure receiving a fair share of value for the production obtained from their lands. Of course, the state will always be pushing for a higher royalty percentage where the market and area allows—which we have done since I have been here in the Austin Chalk and elsewhere, but as far as how that percentage of production is valued and what type of deductions can be taken, I believe we have reached a point where there is not much left to be added to the lessor's side of the economic equation.

The idea that the state, or any lessor, is going to draft a no deduction royalty provision and thereby acquire substantially more value for its production is incorrect. In fact, if a lessor was actually able to draft a no deductions royalty provision that is enforced by the courts, the lessees would react in two different ways in order to even out the economics. First, the lessees would use such a provision to justify lowering bonus and royalty amounts, substantially, probably. Second, the accountants for these oil and gas companies are intelligent folks—they will find ways (and I am not saying illegally) to keep the economics where they are. They will restructure sales points or create new labels for costs incurred and charged, but they will find a way to even out the economics…because there is no other option. Even if the state is able to draft an enforceable no deduction royalty clause (which, as discussed below, is unlikely and at the very least will be extremely costly and time consuming in the courts), such a clause will still not change the economics of the situation and because of the likelihood of receiving lessor amounts of bonus payments and royalty percentages, the state will end up getting less money than it is now. All this trouble, little or no reward—and to fix what? A royalty clause that already works?

Hopefully the way the 2019 version retains, but improves, the structure and language of the royalty provision in the 2000 lease form, creates a provision that utilizes language that is well known and workable between our lessees and our auditors. The familiar language and rules create a situation where our auditors can review what the lessees are paying and deducting, determine whether those amounts are correct and allowed under the terms of the lease and, for the vast majority of cases, the parties can reach an agreement which resolves the matter before it ever reaches the conflict stage, which is costly and time consuming. It allows our auditors to get the proper value for the state's production in a timely and efficient manner. The economic value that this means to the state far exceeds any type of additional value the state may receive as a result of a no deduction royalty clause. Creating an entirely new environment for our lessees to conduct their operations and within which to make their payments and deductions, also causes our auditors to create an entirely new process for dealing with this new environment. If a no deduction royalty clause is put in place, the lessees are going to restructure and relabel sales points, contracts and costs to the point that our auditors will spend the next few years just trying to understand and establish what it is the lessees are actually doing, and only at that point will they be able to truly understand whether or not the lessees are complying with the royalty provision. By saying this, I am not trying to disparage any of our lessees or future lessees, I am just describing a fact of doing business. Dealing with, understanding, and catching up with all of these unknowns will be a timely and a costly business for our audit staff. Which again, means less money for the state.

A final consideration, prior to moving on and discussing whether or not the state could actually draft an enforceable no deduction royalty provision, is to discuss the climate of the industry in the state of Louisiana right now. As everyone is aware, we are either on the heels of—or still in the midst of—quite an economic downturn in the industry. While there have been a lot of positive things happening in south and north Louisiana to indicate that the industry is on the rise again, there are still a lot of unknowns right now which make it economically difficult for investors to bring their money into the state to explore for oil and gas on state lands. Additionally, whether true or not, there is a real negative sentiment for doing business in the state of Louisiana amongst industry as a result of the coastal and legacy lawsuits that are prevalent throughout the state. I am not making a comment on whether those matters are good or bad for the state as a whole—I am only stating a fact that the negative sentiment in the industry does exist. While I did not draft the 2019 version to cater to and encourage industry to lease with the state, I would be a poor business manager for OMR if I did not at least consider the negative impact that certain more aggressive lessor friendly provisions in the lease form might have. There is always a balance with leading OMR—we must strike the most economically beneficial balance for the state, between encouraging our leasing partners (that being industry) to take leases with the state and getting the most value the state can for the production obtained from its lands. It is clear to me that a no deductions royalty provision would violate this most economically beneficial balance—resulting in less money for the state while at the same time furthering any negative sentiment that exists in the minds of industry. However, even disregarding these issues, if the Mineral Board ignored my point of view (which wouldn't be a first) and decided it wanted a no deduction royalty provision, the question still must be answered whether the state could draft an enforceable no deductions royalty provision?

Louisiana, like Texas and other historical oil and gas producing states, have a long history of interpreting royalty provisions in the manner in which the lessor is to bear its proportionate share of post-production costs.[14] The court in *Babin v. First Energy Corp.*[15] sums up the issue of royalty owners bearing post-production cost in the following manner:

> While the peculiarities of individual lease provisions may provide otherwise, the general rule is that a royalty owner is liable for a

[14] See Freeland v. Sun Oil Co., 277 F.2d 154, 159 (US 5 Cir 1960)
"It stands for the proposition that in determining market value costs which are essential to make a commodity worth anything or worth more must be borne proportionately by those who benefit. To put it another way: in the analytical process of reconstructing a market value where none otherwise exists with sufficient definiteness, all increase in the ultimate sales value attributable to the expenses incurred in *transporting and processing* the commodity must be deducted. The royalty owner shares only in what is left over, whether stated in terms of cash or an end product."
[15] 693 So.2d 813, 815 (La. App. 1 Cir. Mar.27, 1997).

> proportionate share of the cost incurred subsequent to production. Such 'subsequent to production' costs generally include those related to taxes, transportation, and *processing*.

The strength of this default jurisprudential rule has been evident in reviewing the fairly well developed jurisprudence in Texas in cases where the court is interpreting a royalty provision that is intended to be cost free and with no deduction. Louisiana has no reported cases that have addressed this issue—that I have found at least. The Texas Supreme Court originally addressed the issue in *Heritage Resources Inc v. Nations Bank*,[16] in which the lease provision at issue provided for royalties to be paid as a percentage of the market value at the well, provided, however, that there would be no deductions for post-production costs from the value of the lessor's royalty. In that case the court utilized the more familiar terms of "royalty" and "market value at the well" to determine that the royalty was to bear post-production costs and it found that the new no deduction for post-production costs language contained in the royalty provision was mere surplusage and was disregarded. The court agreed with the oil and gas company and found that the no deduction language did not sufficiently modify the general rule that royalty owners share in post-production costs. Thereafter, lessors in Texas attempted to avoid the application of the rule voiced by the court in *Heritage* by specifically referring that they were drafting around the decision and would specifically mention the case in the royalty provision—it has come to be known as the "Heritage disclaimer". Nonetheless, Texas courts have still struggled with this issue even as lessors began to react to the Heritage case and attempted to draft stronger no deduction clauses.

Most importantly is the recent case of *Commissioner of the General Land Office of Texas vs. Sandridge Energy, Inc*.[17] In *Sandridge* the court was interpreting a royalty provision in the Texas state lease form which, according to the State of Texas, was intended to be a no deduction "gross proceeds' provision. The court in *Sandridge* cited *Heritage* and found that the gross proceeds language was again surplus language and that the royalty clause would be treated as a market value at the well clause, thereby allowing post-production costs to be deducted from the royalty. Even more recently is the Texas Supreme Court case of *Chesapeake Exploration, LLC v. Hyder*[18]. In *Chesapeake* the court found that an overriding royalty (which the court distinguishes as different from a lessor's royalty, because it is in fact much different) can be allowed to be free of post-production costs pursuant to the language of the mineral lease. However, even in a case where the court was interpreting an overriding royalty instead of a normal lessor's royalty, there were still FOUR dissenting Justices calling for the override to bear post-production costs. Additionally, you have a similar result as was reached in *Sandridge* in two other cases appearing in the Texas jurisprudence in which no deduction language was interpreted as insufficient to overcome the presumption that a royalty bears post-production costs. [19]

[16] 939 S.W.2d 118 (Tex. 1996).
[17] 454 S.W.3d 603 (Tex. App.Ct. 8th Dist. 2014).
[18] 438 S.W.3d 870 (Tex. 2016).
[19] *Potts v. Chesapeake Exploration, L.L.C.*, 760 F.3d 470 (U.S. 5 Cir. 2014) and *L.B. Hailey Ltd. P'ship v. Encana Oil & Gas (USA) Inc*., 2018 WL 3150691 (U.S. W.Dist. Tex. 2018).

As one can see, it is very difficult for a lessor to draft a royalty provision that goes against the presumption that a royalty bears post-production costs—at least when trying to do so with a general blanket no deduction royalty. This well entrenched presumption is as strong in Louisiana as it is in Texas. Accordingly, I would predict that the Louisiana courts will have a similar difficulty in construing new language attempting to create a no deduction royalty provision. Therefore, not only for the reasons set forth above would a no deduction royalty provision be bad business for the state, if it *were* to implement one it will likely take years for a court to eventually make a final decision as to its effectiveness. This long and lengthy litigation process will not only be extremely costly, but for that time period it will create a huge amount of unknown variables with regard to the most important aspect of mineral production for the state, i.e. the proper payment of the royalty and proper deductions to be taken therefrom. At the end of the day, a court may still interpret the state's attempt at a no deductions royalty provision as creating a royalty which does in fact bear post-production costs. If that happens, the state would be left with no specific allowed or disallowed deductions spelled out in its lease form and therefore no specific parameters to manage those deductions. The state would be left to go back to the drawing board to either create either another attempt at a no deduction royalty provision or to do what it should do now—which is to continue using a royalty clause as used in the 2019 version that specifies deductions that are allowed and disallowed. The clause used in the 2019 version is open to very little interpretation by the parties, it continues a familiar and workable environment for our audit staff and lessees, and it insures the state receives the best value for the production obtained from its lands. Attempting to implement a no deduction royalty is a huge risk for the state, and one that would, in my opinion, not only fail to benefit the state economically but could have the opposite effect. However, ultimately it is not my decision.

D. Environmental Articles

Originally when I began reviewing these articles for possible revisions, I noticed that the obligations regarding the lessees operations on the surface of the leased premises and the future restoration and remediation of the leased premises, could be divided into four different areas:

1) Financial security for plugging and abandonment and associated surface restoration;
2) General applicability and compliance of laws and regulations; and
3) Standards and obligations covering lessee's exploration and production, operations on the leased premises; and
4) Plugging, abandonment and restoration obligations.

These issues were addressed in Articles 12 and 24 in our 2000 lease form, but with regard to both the 2016 version and the 2017 version, these obligations had become difficult to understand because they were scattered amongst a number of articles. The 2017 version addressed these different obligations in Articles 13, 14, 15 and 19.

So, when initially beginning the revision of these articles the overall purpose that I had was to organize and consolidate these matters into the least amount of articles as possible, as long as it didn't sacrifice clarity and effectiveness. The article, which appears as Article 14 in the 2019 version, dealing with financial security for plugging, abandonment and site restoration, was left in its own separate article. According to the staff and our legal team, many of the issues addressed in the financial security article had been discussed by the board, staff and members of the public already. Because I did not see any issues with the way that the 2017 version was drafted, I felt like that article should remain unchanged. The remaining three issues, which previously had been dealt with in three articles in the 2017 version, I consolidated into a single article, which is Article 13 in the 2019 version. That article is divided into two separate sections, the first section addresses the lessee's exploration and production activities on the leased premises and the second section addresses the lessee's restoration obligations once those operations have concluded or the lease has terminated. In Article 13(A)(1), one can see the general applicability of laws and regulations article. This article just states that the lessee will comply with all applicable state and federal laws and regulations in its exploration, production and restoration activities. The remainder of Section 13(A) sets forth the standards and obligations of the lessee in conducting its exploration and production activities on the leased premises.

While most of the standards and obligations covering the lessee's exploration and production activities on the leased premises remain substantially the same as they are in the 2000 form, I suppose the most notable inclusion is a general statement of the lessee's obligation to "conduct operations with the highest degree of care using standard industry practices and procedures and proper safeguards and take all reasonably necessary preparations and precautions to prevent pollution, fire, explosions, and environmental damage to the leased premises" and that the lessee "shall use all means at its disposal to recapture all escaped hydrocarbon minerals or other pollutants." Another change of interest is in Article 13(A)(3), which requires the following: "Within sixty (60) days following the completion of each operation under this Lease, Lessee shall remove all materials and equipment no longer necessary for exploration or production (including without limitation all submerged materials, equipment or debris) that were placed on the Leased Premises by or for the account of Lessee and may impede commercial fishing and trawling." This same obligation is required of the lessee in the 2000 lease form, but there was no time period given for the removal of equipment, which could lead one to conclude that the obligation must be complied with immediately, or it also allows room for the argument that it could be later. The addition of the sixty days is both reasonable and creates clarity with regard to this obligation that wasn't there before.

Article 13(B) addresses the lessee's plugging and abandonment and restoration obligations on the leased premises. The article attempts to consolidate all of these obligations into one single defined term, i.e. the "restoration obligations". These restoration obligations encompass the lessee's obligation to plug and abandon the wells on the leased premises, remove all structures and facilities placed on the leased premises and to restore the leased premises "as near as practicable, to the condition existing on the effective date of this lease." Both the 2000 lease form and the 2016 and 2017 versions failed to organize and to put these obligations into one place, which I hope was corrected by the 2019 version. These are not new obligations, only consolidated into one place and under one defined term. A change of interest to the public is that the 2000 lease form required the same obligation—that being to plug and abandon "all wells on the leased premises no longer necessary for operations or production", but it did not give a definite time frame in which to do so. Rather, the 2000 lease form required the lessee to perform these obligations "within a reasonable time". The 2019 version specifies that this obligation must be conducted within one year from the earliest of two occurrences—either the date "said wells, structures or facilities are no longer producing or no longer actually utilized for operations or production on the leased premises" or from "the date this lease has expired, terminated or been released."

IV. CONCLUSION

While you would think in a paper of this length I would have been able to address most, if not all, of the changes and issues that took place in the drafting process leading up to the publishing of the 2019 version. That, however, is not the case. In going through many legal pads that I have filled with notes and the correspondence between myself and our drafting team, there is a lot more that could have been put into the paper that I did not address. That doesn't mean that these issues are not important, it's just that they did not make the cut for inclusion into this paper. I am sure that something that I have not discussed in the paper will end up being the most controversial and hard to deal with issue in the entire approval process. What I have included in this paper are the issues that have heretofore been the most asked about and what I thought were the most interesting articles to discuss. If you have any issues with the 2019 version, or have an interest in the approval process for the lease form, please consult our website for the schedule of open meetings of the Mineral Board including the planned schedule for particular articles that will be discussed at those meetings for approval.