NUMBER 13-19-00036-CV

COURT OF APPEALS

THIRTEENTH DISTRICT OF TEXAS

CORPUS CHRISTI – EDINBURG

DEVON ENERGY PRODUCTION COMPANY, L.P., F/K/A GEOSOUTHERN DEWITT PROPERTIES, LLC, BPX PROPERTIES (NA) LP, GEOSOUTHERN ENERGY CORPORATION, AND BPX PRODUCTION COMPANY, **Appellants,**

v.

MICHAEL A. SHEPPARD, ET AL., **Appellees.**

On appeal from the 24th District Court of DeWitt County, Texas.

MEMORANDUM OPINION

Before Chief Justice Contreras and Justices Benavides and Longoria
Memorandum Opinion by Chief Justice Contreras

We issued our memorandum opinion and judgment in this cause on June 25, 2020.

Appellants Devon Energy Production Company, L.P., f/k/a GeoSouthern DeWitt Properties, LLC, BPX Properties LP, GeoSouthern Energy Corporation, and BPX Production Company have filed a motion for rehearing. Pursuant to our request, appellees Michael A. Sheppard, et al. filed a response to the motion, and appellants filed a reply to the response. We deny the motion for rehearing but withdraw our earlier memorandum opinion and judgment and substitute the following memorandum opinion and its accompanying judgment in their place.

In this wide-ranging dispute concerning the valuation of oil and gas royalties, appellants argue that the trial court erred by granting summary judgment to appellees. Appellants also challenge the trial court's decision to exclude their experts' affidavits.

The case involves highly unique royalty provisions in some DeWitt County oil and gas leases. The parties jointly filed a stipulation with the trial court setting forth twenty-three issues, each asking whether appellants violated the leases by failing to add particular amounts to the total figure upon which appellees' royalty payments were based. Upon cross-motions for summary judgment, the trial court found in favor of appellees on all twenty-three disputed issues and rendered declaratory judgment.

We conclude that appellants are required to pay royalties on amounts attributable to post-production costs of the types specified in the leases, even when those costs are actually borne by a third-party downstream purchaser rather than by appellants. However, the leases do not require appellants to pay royalties on (1) amounts deducted from a sales price without a stated purpose, (2) volumes of gas which are used by appellants for their own operations and never sold, (3) volumes of gas which are deemed to be lost or unaccounted for by third parties, or (4) the excess value retained by processors as a result of applying predetermined factors to measure how much of each liquid hydrocarbon is recovered. We affirm in part and reverse and render in part.

I. Background

A. Royalty Terms

Beginning in 2007, appellees[1] leased mineral interests to appellants under agreements—the Sheppard Lease and the Crain Lease—which contain the following royalty provisions:

> 3. The royalties to be paid by Lessee are:
>
> (a) on oil, One-Fifth (1/5th)[[2]] of that produced and saved from said land, the same to be delivered, free of all costs and expenses to the Lessor into the pipeline, or other receptacle to which the Lessee may connect its wells or the market value thereof, at the option of the Lessor, such value to be determined by (1) the highest posted price, plus premium, if any, offered or paid for oil, condensate, distillate, or other liquid hydrocarbons, respectively of a like type and gravity for the field where produced and when run, or (2) the gross proceeds of the sale thereof, whichever is greater;
>
> (b) on gas, including casinghead gas or other gaseous substance, produced from said land, One-Fifth (1/5th) of the greater of (1) the market value at the wellhead of such gas, paid to Lessor free of all costs and expenses, or (2) the gross proceeds realized from the sale of such gas, free of all costs and expenses, to the first non-affiliated third party purchaser under a bona fide arms length sale or contract. "Gross proceeds" (for royalty payment purposes) shall mean the total monies and other consideration accruing to or paid the Lessee or received by Lessee for disposition or sale of all unprocessed gas proceeds, residue gas, gas plant products or other products. Gross proceeds shall include, but is not limited to advance payments, take-or-pay payments (whether paid pursuant to contract, in settlement or received by judgment) reimbursement for production or severance taxes and any and all other reimbursements or payments.

The parties agree that, with respect to all oil and gas produced from the leases, the royalty

[1] Appellees are Michael A. Sheppard, Constance S. Kirk, Jennifer S. Badger, Frank B. Sheppard, James K. Crain, Shirley R. Crain, Christopher M. Crain, James K. Crain III, and Patrick G. Crain.

[2] The Sheppard Lease calls for a 1/5 royalty whereas the Crain Lease prescribes a 1/4 royalty. The difference is immaterial for purposes of the issues considered here.

was paid as a percentage of appellants' gross proceeds from the sale of those minerals to downstream third-party purchasers. However, the leases' royalty terms continue with the following unique provision:

> (c) If any disposition, contract or sale of oil or gas shall include any reduction or charge for the expenses or costs of production, treatment, transportation, manufacturing, process or marketing of the oil or gas, then such deduction, expense or cost shall be added to the market value or gross proceeds so that Lessor's royalty shall never be chargeable directly or indirectly with any costs or expenses other than its pro rata share of severance or production taxes.

The leases also contained several addenda, including the following:

> L. ROYALTY FREE OF COSTS:
>
> Payments of royalty under the terms of this lease *shall never bear or be charged with, either directly or indirectly, any part of the costs or expenses of production, gathering, dehydration, compression, transportation, manufacturing, processing, treating, post-production expenses, marketing or otherwise making the oil or gas ready for sale or use*, nor any costs of construction, operation or depreciation of any plant or other facilities for processing or treating said oil or gas. Anything to the contrary herein notwithstanding, it is expressly provided that the terms of this paragraph shall be controlling over the provisions of Paragraph 3 of this lease to the contrary and this paragraph shall not be treated as surplusage despite the holding in the cases styled "Heritage Resources, Inc. v. NationsBank", 939 S.W.2d 118 (Tex. 1996) and "Judice v. Mewbourne Oil Co.", 939 S.W.2d 135–36 (Tex. 1996).

(Emphasis added.) This case concerns the construction and application of paragraph 3(c)[3] and Addendum L.

B. Procedural Background

On December 13, 2012, appellees filed suit alleging that appellants were selling the oil and gas produced from the leases under contracts which contain an $18-per-barrel

[3] There are two versions of the Sheppard Lease and three versions of the Crain Lease in the record. The "shall be added" language appears in all versions of both leases, but it is not always numbered as paragraph 3(c). We will refer to it as paragraph 3(c) for ease of reference.

"reduction" in the sales price attributable to "gathering and handling, including rail car transportation." Appellees alleged that appellants breached the leases by failing to add the $18-per-barrel "reduction" to the amount upon which the royalty is calculated (the royalty base) pursuant to the "shall be added" provision in paragraph 3(c) of the lease. Appellees sought damages for breach of contract as well as declaratory relief and an accounting. Appellees later filed two amended petitions, alleging several other instances in which they believed appellants breached paragraph 3(c).

In March of 2017, the parties entered into a "Joint Stipulation as to Disputed Issues for Adjudication" purporting to specify twenty-three issues for the trial court's consideration.[4] Each of the stipulated issues concerns a different marketing practice engaged in by appellants which appellees contend violates the leases. Many are similar to the claim concerning the $18-per-barrel charge in that they involve a reduction for post-production costs, though several are not. Most of the issues contain references to exemplar contracts between an appellant and a third-party purchaser. As to each of the stipulated issues, the question is whether appellants breached the "shall be added" clause of paragraph 3(c) of the leases by failing to add that particular amount to the royalty base. The entire list of issues, including the references to exemplar contracts but excluding record references, is attached as an appendix to this opinion.

C. Summary Judgment Motions

Both sides moved for summary judgment later in 2017. Appellees argued in their motion that the subject leases unambiguously "require that [appellants] add any 'reduction

[4] According to the stipulation, appellees' contract damages claim was severed into a separate lawsuit and abated pending resolution of the declaratory judgment action.

or charge' included in any 'disposition, contract or sale of oil or gas' back to the gross proceeds before calculating [appellees'] royalty." They argued that, whenever the appellants sold oil and gas for a published price minus a fixed dollar amount, the fixed dollar amount is a "reduction" which must be added to gross proceeds to calculate the royalty. They also argued that, when appellants sold natural gas liquids to processors and allowed the processors to keep a portion of the product, that reduces the volume sold, and this "volumetric reduction" is also subject to paragraph 3(c). Appellees further contended that, when appellants sold natural gas liquids to a processor for a percentage of a certain defined value, the reduction to the value must be added back to the royalty base. Finally, appellees argued that, when appellants or third parties use minerals produced from the leases as fuel for their own operations, or set a certain percentage of gas as "lost and unaccounted for," that also represents a "reduction" to which paragraph 3(c) applies. As evidence supporting their motion, appellees attached sealed deposition excerpts from Anice Johnston, Petrohawk's Royalty Compliance Supervisor,[5] and Kim Whyburn, Devon's Operations Accounting Supervisor. Appellants responded, and appellees filed a reply containing additional evidence, including an affidavit by Charles Graham, a petroleum engineer.

In their summary judgment motion, appellants agreed that the subject leases are unambiguous. But appellants argued that the lease bases the royalties on their "gross proceeds" received, meaning the amount each appellant actually receives "at the point of sale." Thus, according to appellants, paragraph 3(c) does not require them to add

[5] Following the filing of suit, Petrohawk was acquired by BHP Billiton Petroleum Properties N.A., LP, which later became appellant BPX Properties (NA) LP.

amounts to gross proceeds which were deducted for expenses which necessarily must take place *after* the point of sale. Appellants attached affidavits of oil and gas industry experts Kris Terry and Lesa Adair, as well as Lawrence Gregory, former Vice President of Marketing and Midstream at Devon's predecessor. They also attached sealed deposition excerpts from Johnston and Whyburn as well as attorneys Rodney Landes, Nelson Lee, and Diaco Aviki. Appellants filed a response accompanied by another affidavit by Graham, as well as an affidavit by appellee Christopher Crain.

The summary judgment evidence included two "Joint Appendi[ces] to Parties' Motions for Summary Judgment." One of the appendices was unsealed and contained copies of the leases at issue. The other appendix was filed under seal and contained all of the exemplar contracts identified in the stipulation.

D. Evidentiary Motions and Rulings

Appellants objected to twenty-five individual statements made in Graham's affidavits on various grounds, mainly arguing that Graham offered improper and unfounded legal opinions. Appellants also objected to Crain's affidavit on multiple grounds. Appellees objected to and moved to exclude the affidavits of Terry and Adair, specifying twenty-two different statements by Terry and thirty different statements by Adair which it contended were incompetent summary judgment evidence for various reasons.

After a hearing on October 12, 2017, the trial court: (1) granted appellees' motions to exclude the affidavits of Terry and Adair; (2) overruled appellants' objections to the affidavits of Graham and Crain; and (3) granted summary judgment in favor of appellees on all twenty-three issues specified in the stipulation. The trial court signed a "Declaratory

Judgment on the Parties' Cross-Motions for Summary Judgment" on December 28, 2017. Appellants attempted to perfect an appeal in 2018, but we held the December 28, 2017 judgment was not final because appellees' claim for attorney's fees remained pending. *See Devon Energy Prod. Co. v. Sheppard*, No. 13-18-00069-CV, 2018 WL 3062579, at *1–2 (Tex. App.—Corpus Christi–Edinburg June 21, 2018, no pet.) (mem. op.). After appellees non-suited their request for attorney's fees, the trial court signed an "Order Granting Nonsuit and Final Judgment" on December 13, 2018, and this appeal followed.

II. Evidentiary Rulings

We begin by addressing appellants' second issue, concerning the trial court's evidentiary rulings. Although the trial court serves as an evidentiary gatekeeper by screening out irrelevant and unreliable expert evidence, it has broad discretion to determine the admissibility of evidence. *Exxon Pipeline Co. v. Zwahr*, 88 S.W.3d 623, 629 (Tex. 2002). A trial court abuses its discretion when its ruling is arbitrary, unreasonable, or without reference to any guiding rules or legal principles. *E.I du Pont de Nemours & Co. v. Robinson*, 923 S.W.2d 549, 558 (Tex. 1995).

Appellants contend that the court erred by excluding Terry's and Adair's affidavits and by overruling their objections to Graham's and Crain's affidavits. They principally argue that Graham provided improper, conclusory opinions as to ultimate legal questions facing the court. They further argue that the trial court arbitrarily and unreasonably applied different standards to their expert affidavits. They contend that "[e]ither the experts are admissible, or they are not. . . . There is no principled reason to reject [appellants'] experts but accept [appellees']."

In order to obtain reversal based on an error in the admission or exclusion of evidence, an appellant must show that the ruling (1) probably caused the rendition of an improper judgment or (2) probably prevented the appellant from properly presenting the case on appeal. TEX. R. APP. P. 44.1(a). In their briefs on appeal, appellants do not allege or argue that the trial court's evidentiary rulings met this standard for reversible error. *See id.*; *see also* TEX. R. APP. P. 38.1(i). Instead, appellants are equivocal as to whether an analysis of the issue is necessary to the appeal's disposition. *See* TEX. R. APP. P. 47.1 ("The court of appeals must hand down a written opinion that is as brief as practicable but that addresses every issue raised and necessary to final disposition of the appeal."). For example, at the conclusion of the argument in their brief regarding their second issue, appellants ask us to find in their favor only "*[t]o the extent it is necessary* to consider the expert admissibility issues to decide this appeal . . ." (emphasis added). Elsewhere, appellants argue: "*If it is necessary to reach the expert testimony issues to decide this appeal*, the judgment cannot be upheld on the basis of the trial court's flawed and one-sided examination of expert testimony" (emphasis added).

The only statement in appellants' brief which could be construed as addressing harm resulting from the evidentiary rulings is as follows: "To the extent [the trial court] used these irrelevant opinions to alter the meaning of unambiguous text, the ruling was harmful." But appellants do not allege or establish that the trial court actually or probably *did* "use" Graham's or Crain's testimony in fashioning its ruling, and they do not provide any argument in this regard. Moreover, to the extent this cursory statement may be construed as addressing the reversibility standard, it pertains only to alleged harm resulting from the trial court's admission of appellees' expert affidavits; it provides no explanation for why the trial court's exclusion of *appellants'* expert affidavits would constitute reversible error.

We conclude that appellants have failed to establish that any error in the trial court's evidentiary rulings would be reversible. *See* TEX. R. APP. P. 38.1(i), 44.1(a). We therefore overrule their second issue.[6]

III. SUMMARY JUDGMENT

By their first issue, appellants contend the trial court erred in granting appellees' summary judgment motion and denying their motion. The parties agree that the royalty provisions at issue are unambiguous, and they agree that there are no Texas cases reviewing similar lease language. They simply disagree as to what the provisions unambiguously require.

A. Standard of Review

A movant for traditional summary judgment has the burden to establish that no genuine issue of a material fact exists and that it is entitled to judgment as a matter of law. TEX. R. CIV. P. 166a(c); *Amedisys, Inc. v. Kingwood Home Health Care, LLC*, 437 S.W.3d 507, 511 (Tex. 2014). We review summary judgments de novo. *Scripps NP Operating, LLC v. Carter*, 573 S.W.3d 781, 790 (Tex. 2019). When, as here, both parties move for summary judgment and the trial court grants one motion and denies the other, we review all the summary judgment evidence, determine all issues presented, and render the judgment the trial court should have rendered. *Merriman v. XTO Energy, Inc.*,

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[6] We note that, in this case, we are not asked to determine whether there is a genuine issue of material fact raised by the evidence. The parties agree that the leases are unambiguous and susceptible to interpretation by the court as a matter of law, and the factual background surrounding the formation of the leases and the transactions between producers and processors is largely undisputed. The question is how to apply the unique lease provisions to those facts. *See Jones Energy, Inc. v. Pima Oil & Gas, L.L.C.*, No. 07-17-00456-CV, 2020 WL 1869024, at *4 (Tex. App.—Amarillo Apr. 14, 2020, no pet. h.) (op. on reh'g) (noting that "the construction of an unambiguous instrument is a matter of law determination, upon which another's opinion would not be binding").

407 S.W.3d 244, 248 (Tex. 2013).

B. Applicable Law

As with any other unambiguous contract, we construe a mineral lease as a matter of law, seeking to enforce the intention of the parties as expressed therein. *Tittizer v. Union Gas Corp.*, 171 S.W.3d 857, 860 (Tex. 2005) (per curiam). We examine and consider the entire writing in an effort to harmonize and give effect to all its provisions so that none will be rendered meaningless. *J.M. Davidson, Inc. v. Webster*, 128 S.W.3d 223, 229 (Tex. 2003). No single provision taken alone will be given controlling effect; rather, all the provisions must be considered with reference to the whole instrument. *Id.*[7]

As a general rule, although royalty payments are not subject to the costs of production, they are usually subject to post-production costs, including taxes, treatment costs to render the minerals marketable, and transportation costs. *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996). But the parties to a lease may agree to modify this general rule. *Id.* Whether and to what extent a lease has effectively modified

[7] Courts have long held that, when an oil and gas lease is subject to two or more equally reasonable interpretations even after rules of construction are applied, the interpretation more favorable to the lessor will be adopted. *Zeppa v. Hous. Oil Co. of Tex.*, 113 S.W.2d 612, 615 (Tex. App.—Texarkana 1938, writ ref'd) ("[I]t appears to be the settled rule in this state that of two or more equally reasonable constructions of which the language of an oil and gas lease is susceptible the one more favorable to the lessor will be allowed to prevail."); *see Yturria v. Kerr-McGee Oil & Gas Onshore, LLC*, 291 Fed. App'x 626, 631 (5th Cir. 2008) (per curiam, not designated for publication); *Champlin Petroleum Co. v. Ingram*, 560 F.2d 994, 998 (10th Cir. 1977) (applying Texas law); *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 133 (Tex. 1996) (Gonzalez, J., dissenting); *Freeman v. Samedan Oil Corp.*, 78 S.W.3d 1, 7 (Tex. App.—Tyler 2001, judgm't vacated w.r.m.); *see also Sirtex Oil Indus., Inc. v. Erigan*, 403 S.W.2d 784, 788 & n.2 (Tex. 1966) (noting that, ordinarily, "a lease will be most strongly construed against the lessor," but "[t]his rule does not apply to oil and [ga]s leases"). But the preference for the lessor's interpretation is based at least in part on an assumption that the lease was drafted by the lessee. *See Freeman*, 78 S.W.3d at 7 (noting that "[i]n constructing an oil and gas lease, its language is generally regarded as that of the lessee" and "the language of an oil and gas lease is to be construed against the drafting party"). Here, the Crain Lease states: "This lease was prepared as the joint effort of the Lessor and Lessee. The rule of construction that ambiguities in a document will be construed against the party who drafted it will not be applied in interpreting the provisions of this lease." The Sheppard Lease does not contain this provision. Appellees do not argue on appeal that their interpretation of either lease should be favored merely because of their status as lessors.

this rule has been a recurring question for the courts. Every lease is different, and the result in one case does not control a case where the terms involved are different. *See Warren v. Chesapeake Expl., L.L.C.*, 759 F.3d 413, 416 (5th Cir. 2014) ("[I]f anything is clear from the many Texas decisions dealing with royalty provisions, it is that different royalty provisions have different meanings."). Still, a review of similar cases can assist in clarifying the jurisprudence in this area. Such cases include the two specifically cited in the Addendum L of the Sheppard and Crain Leases: *Heritage Resources, Inc. v. NationsBank* and *Judice v. Mewbourne Oil Co*.

In *Heritage*, the leases granted a royalty on gas equal to one-fourth or one-fifth of the "market value at the well," "provided, however, that there shall be no deductions from the value of the Lessor's royalty by reason of any required processing, cost of dehydration, compression, transportation or other matter to market such gas." 939 S.W.2d at 120. NationsBank, the royalty owner, sued Heritage, the lessee, claiming that Heritage improperly deducted certain transportation costs from their gas sale proceeds before calculating the royalty. *Id.* at 118. The trial court and court of appeals agreed with NationsBank that this was a violation of the no-deductions clause. *Id.*

On petition for review, Heritage argued that the leases "define the lessor's royalty as a fraction of the market value at the well" and therefore, "the clauses limiting deduction from the value of the lessor's royalty simply mean[] that Heritage cannot deduct an amount from the sales price that would make the royalty paid less than the required fraction of market value at the well." *Id.* at 121. The supreme court agreed, observing that "the Lessor's Royalty" is "clearly" defined in the leases as a fraction "of the market value at the well." *Id.* at 122. Therefore, the lease provision stating that "there shall be no deductions from the value of the Lessor's Royalty" for certain expenses merely means that "the lessee cannot pay the lessor less than his fractional value of the comparable sales price (market value)." *Id.* It does *not* mean that the lessee is prohibited from deducting post-production costs, such as expenses for transporting gas from well to market, from the total amount the lessee realizes from a downstream sale. *See id.*

The lessee was permitted to deduct those costs from its gross proceeds because the royalty was defined as a percentage of the "market value at the well." The *Heritage* Court explained that "market value at the well" has a "commonly accepted meaning in the oil and gas industry" and may be calculated by taking the market value at the point of sale and then subtracting reasonable post-production marketing costs. *Id.* at 122. "Post-production marketing costs include transporting the gas to the market and processing the gas to make it marketable." *Id.* In light of these definitions, the Court rejected NationsBank's argument, which had been adopted by the court of appeals, that the no-deductions clause evinced an intent to prohibit the deduction of post-production transportation costs when determining "market value at the well." *See id.* The Court "did not disagree" with the court of appeals' view that, because royalty interests are normally subject to post-production costs anyway, Heritage's interpretation renders the no-deductions clause meaningless. *Id.* at 121. Nevertheless, the Court found that the clause "merely restate[s] existing law"—i.e., that a royalty based on the "market value at the well" does not bear *production* expenses—and constitutes "surplusage as a matter of law." *Id.*

The Texas Supreme Court handed down *Judice* on the same day as *Heritage*. There, the royalty owners argued that "Mewbourne had improperly paid royalties on gas by deducting the Judices' pro rata share of post-production compression costs from the proceeds from the sale of the gas." 939 S.W.2d 133, 135 (Tex. 1996). The royalties in that case were due under two leases and three division orders. *Id.* at 135–36. The leases defined the Judices' gas royalty as a fraction of the "market value of the well"—therefore, under the leases, Mewbourne was entitled to deduct a "proportionate share of the reasonable cost of post-production compression" from the royalty base. *Id.* at 135. On the other hand, two of the division orders stated that the Judices' royalty on gas sold is "based on the gross proceeds realized at the well." *Id.* at 136. The Court held this was ambiguous because, while "gross proceeds" means that the royalty is to be based on the "gross price received by Mewbourne," the term "at the well" "indicates just the opposite"—i.e., that the royalty is to be based on its value "before it has been compressed and before other value is added in preparing and transporting the gas to market." *Id.* Finally, the third division order stated that the Judices' interest is "based on the net proceeds realized at the well by [the Judices]." *Id.* The Court concluded that, due to its use of the word "net," the third order unambiguously permitted Mewbourne to "deduct[] post-production compression costs from the proceeds received for the sale of the gas." *Id.* (observing that the term "net proceeds" "expressly contemplates deductions," and "at the well" means "before value is added by preparing the gas for market").

Twenty years later, in *Chesapeake Exploration v. Hyder*, the supreme court considered a similar question in the context of an overriding royalty interest (ORRI). *See* 483 S.W.3d 870, 872 (Tex. 2016) (defining an ORRI as a "given percentage of the gross production carved from the working interest but, by agreement, not chargeable with any of the expenses of operation"). The lease at issue there contained three royalty provisions: the first entitled the Hyders to 25% of "the market value at the well of all oil and other liquid hydrocarbons" produced from the leases; the second entitled them to 25% of "the price actually received by [Chesapeake]" for all gas produced from the leases, expressly "free and clear of all production and post-production costs and expenses"; and the third royalty provision entitled the Hyders to "a perpetual, cost-free (except only its portion of production taxes) overriding royalty of five percent (5.0%) of gross production obtained" from directional wells drilled on the lease but bottomed on nearby land. *Id*. at 871–72.

In that case, Chesapeake sold all of the gas produced from the lease at issue to its marketing affiliate, which in turn sold the gas to third-party purchasers in distant markets. *Id*. at 872. The marketing affiliate paid Chesapeake a "gas purchase price" which was calculated based on a weighted average of the third-party sales prices received by the marketing affiliate (the "gas sales price") minus post-production costs. *Id*. For the Hyders' ORRI in the gas produced from seven directional wells bottomed on adjacent land, Chesapeake paid 5% of the "gas purchase price," but the Hyders sued, claiming that they were instead entitled to 5% of the "gas sales price." *Id*.

The trial court, the court of appeals, and a 5–4 majority of the Texas Supreme Court agreed with the Hyders. The Court's majority noted that the first two royalty provisions in the lease were clear as to post-production costs. *Id*. at 873. First, the 25% oil royalty bears post-production costs because it is paid on the "market value of the oil at the well," which "should equal the commercial market value less the processing and transporting expenses that must be paid before the gas reaches the commercial market." *Id*. (citing *Heritage*, 939 S.W.2d at 122). Second, the 25% gas royalty does *not* bear post-production costs because it is "based on the price Chesapeake actually received from its marketing affiliate," without deductions for Chesapeake's post-production costs. *Id.*[8]

The ORRI provision, on the other hand, was not as clear. *Id*. The Hyders argued that "cost-free" must refer to post-production costs, since a royalty by its nature is already free of production costs; but Chesapeake argued that "cost-free" is "merely a synonym for overriding royalty" and simply emphasizes that the ORRI is free of production costs. *Id*. at 873–74. Chesapeake further contended that the term "gross production" refers to "production at the wellhead," meaning the royalty at issue would be equivalent to one based on the "market value of production at the wellhead," which bears post-production costs. *Id*. at 874.

The *Hyder* majority noted that the ORRI's exception for production taxes, which are generally considered post-production costs, cuts against Chesapeake's argument because "[i]t would make no sense to state that the royalty is free of production costs, except for post[-]production taxes (no dogs allowed, except for cats)." *Id*. (citing *Heritage Res*., 939 S.W.2d at 122 (characterizing taxes as post-production costs)); *but see id.* at 878 (Brown, J., dissenting) (opining that the parties intended "production taxes" to be a production cost). Nevertheless, the Texas Supreme Court observed that "drafters frequently specify that an overriding royalty does not bear production costs even though an overriding royalty is already free of production costs simply because it is a royalty

[8] The 25% gas royalty provision also stated that it is "free and clear of all production and post-production costs and expenses." *Chesapeake Expl., LLC v. Hyder*, 483 S.W.3d 870, 873 (Tex. 2016). But the majority in *Hyder* noted that "[t]his addition has no effect on the meaning of the provision" and may be regarded as surplusage. *Id*. (holding that "the price-received basis for payment in the lease is sufficient in itself to excuse the [Hyders] from bearing post[-]production costs").

interest.” *Id*. at 874 (observing that this suggests that “lease drafters are not always driven by logic”).

As to the “gross production” language, the Court noted that the other two royalties mentioned in the lease are also based on “full production” at the wellhead, and yet one bears post-production costs and one does not. *Id*. at 874–75. It held that “[s]pecifying that the volume on which a royalty is due must be determined at the wellhead says nothing about whether the overriding royalty must bear post[-]production costs.” *Id*. at 874.

The *Hyder* majority concluded:

> Chesapeake argues that the [25%] gas royalty provision shows that when the parties wanted a post[-]production-cost-free royalty, they were much more specific. But as we have already said, the additional detail in the gas royalty provision serves only, if anything, to emphasize its cost-free nature. The simple “cost-free” requirement of the overriding royalty achieves the same end.
>
> The overriding royalty provision reads as though the royalty is in kind, but Chesapeake does not argue that it must be, and in fact the royalty has always been paid in cash. Were the Hyders to take their overriding royalty in kind, as they are entitled to do, they might use the gas on the property, transport it themselves to a buyer, or pay a third party to transport the gas to market as they might negotiate. In any event, the Hyders might or might not incur post[-]production costs equal to those charged by [its marketing affiliate]. The lease gives them that choice. The same would be true of the gas royalty, which is to be paid in cash but can be taken in kind. The fact that the Hyders might or might not be subject to post[-]production costs by taking the gas in kind does not suggest that they must be subject to those costs when the royalty is paid in cash. The choice of how to take their royalty, and the consequences, are left to the Hyders. Accordingly, we conclude that “cost-free” in the overriding royalty provision includes post[-]production costs.

Id. at 875.

Burlington Resources Oil & Gas Co. v. Texas Crude Energy also addressed whether an ORRI was subject to post-production costs. The instrument at issue in that case, an assignment, stated that the ORRI “shall be delivered to ASSIGNEE into the pipelines, tanks or other receptacles with which the wells may be connected, free and clear of all development, operating, production and other costs." 573 S.W.3d 198, 201 (Tex. 2019). The assignment further provided that, should the assignee opt to take its royalty in cash, the royalty would be based on the "value of the oil, gas or other minerals, as applicable, produced and saved under the leases"—and "value" was defined as "the amount realized from such sale of such production and any products thereof." *Id.* at 201–202. The assignee sued when it discovered that Burlington, the lessor, was deducting post-production costs from its "amount realized" before calculating the royalty. *Id.* at 202; *see Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 699 (Tex. 2008) ("'Proceeds' or 'amount realized' clauses require measurement of the royalty based on the amount the lessee in fact receives under its sales contract for the gas."); *Occidental Permian Ltd. v. Helen Jones Found.*, 333 S.W.3d 392, 399 (Tex. App.—Amarillo 2011, pet. denied) ("'Amount realized' means the proceeds received from the sale of gas or oil."). The Texas Supreme Court held that, because the assignment twice stated that the royalty "shall be delivered . . . into the pipeline," that meant the parties unambiguously specified a valuation point "at the well"—i.e., before any additional value is added via post-production expenses. *Burlington*, 573 S.W.3d at 209–11. Thus, notwithstanding the "amount realized" language, the assignees were required to pay their share of post-production costs. *See id.* at 205 ("We have never construed a contractual 'amount realized' valuation method to trump a contractual 'at the well' valuation point. To the contrary, prior decisions suggest that when the parties specify an 'at the well' valuation point, the royalty holder must share in post-production costs regardless of how the royalty is calculated."); *id.* at 207 ("A royalty on production valued at the well does not include the value added by post-production costs. When a royalty payment is based on a downstream sales price, the value added by post-production costs must be subtracted from the sales price or otherwise accounted for in order to approximate the 'at the well' value of the products."); *cf. Hyder*, 483 S.W.3d at 874 ("Specifying that the volume on which a royalty is due must be determined at the wellhead says nothing about whether the overriding royalty must bear postproduction costs.").

C. Summary Judgment Evidence

Appellees' expert, Graham, explained in his affidavit that when raw natural gas is produced from underground reservoirs, it is initially unsuitable for commercial use and unsuitable for transportation in intrastate or interstate pipelines. To generate a marketable product, the raw "wet" or "rich" natural gas must be processed to separate the liquid hydrocarbons from the "dry" methane gas. The natural gas liquids (NGLs) then undergo fractionation, a process under which the various NGL components—including ethane, propane, butane, and isobutane—are separated from each other by boiling the mixture at different temperatures.

After the methane gas is extracted, the liquid hydrocarbon mixture is known as "y-grade." Graham stated that the major fractionation center for producers in the Eagle Ford Shale is located at Mont Belvieu, thirty miles east of Houston. According to Graham, though daily market prices are published for the various components listed above, as well as for "pipeline quality natural gas," "[t]here have never been price postings or indices for unfractionated y-grade at Mont Belvieu or at any other receipt points along a pipeline system." Accordingly, it is "common practice for purchasers of y-grade liquids at processing plants to offer prices for y-grade based on postings for fractionated products, . . . less the costs associated with transporting, fractionating, and marketing." Therefore, Graham stated, "the aggregate unit price for each gallon of a respective batch of y-grade (demethanized mix of unfractionated [NGLs]) has embedded deductions for transportation, fractionation and marketing." The "residue gas" which remains after the NGLs have been removed must then be processed to meet quality standards in order to be transported via pipelines. Graham stated: "There are costs related to the production of marketable products and the transportation of those marketable products to the commercial market place. Furthermore, commercial markets for residue gas (pipeline quality gas), located downstream of the gas processing plants utilized by [appellants], are in the Houston Ship Channel area."

In his affidavit, Crain averred that royalty clauses at issue in this case were included in the leases "for the purpose of assuring that the intention that the Lessor not be burdened with Lessees' transportation and marketing decisions, costs and expenses is clearly articulated." He stated that, in his experience, oil and gas lessees such as appellants "generally insist on having flexibility in their operations for marketing, processing, transporting, fractionating, and otherwise enhancing the value of the hydrocarbons produced from a lessor's leased land." Thus, a "lessor who does not want to bear any part of the costs or expenses associated with a lessee's marketing decisions typically must find other ways to ensure that the reductions, expenses, charges, and costs that may result from those decisions do not directly or indirectly reduce the lessor's royalty." One way to do this, according to Crain, is to "bargain for and negotiate for a favorable method of calculating and paying royalties, at the initial lease drafting and negotiating phase." Crain further opined that "lessors generally strive to ensure" that lease agreements are "flexible to ever-changing industry factors," including the development of new technology and regulatory changes. He stated:

> 10. . . . The need for flexibility was particularly prevalent in the early days of the Eagle Ford shale development around 2010. The landscape was evolving as to whether the production would primarily yield oil or gas, how the regulatory landscape might adjust to horizontal drilling and hydraulic fracturing, how the industry infrastructure in the area might evolve, how the midstream sector would adapt, and other critical commercial factors that were out of a lessor's control. These factors placed additional limitations on a lessor's ability to bargain for provisions that would influence a lessee's marketing decisions.
>
> 11. The provisions affecting the payment of royalty that are present in the leases in this lawsuit result from these competing lessor/lessee interests. While lessors typically have no control over a lessee's marketing decisions, these unique provisions ensure that a lessor will avoid any costs or expenses associated with a lessee's marketing decisions. . . . There are no exclusions in the provisions affecting the payment of royalties for "bargained" reductions or pricing formulas. Also, there is no reference to any point of sale, downstream or upstream, transfer of title, transfer of possession, benefit, reasonableness, custom, or any . . . other limitation in the royalty provisions. Rather than guess at describing the various contracts and expenses associated with marketing, transporting, and processing hydrocarbons produced from a lessor's leased lands, the royalty provisions are flexible by broadly requiring a lessee to add to the gross proceeds or market value the amount of any reduction or charge included in any disposition, contract or sale.

D. Analysis

Paragraph 3(c) of the leases is the starting point for all of the issues in dispute. Appellants refer to this as an "add-back" clause and appellees refer to it as an "add-to-proceeds" clause—a difference that echoes their respective summary judgment positions.

Appellants argue "[t]his case involves an ordinary gross proceeds clause"—that is, they claim the leases call for royalties "based on the gross proceeds [appellants] actually receive at the point of sale, with no deductions." They argue that whether or not an adjustment to the royalty base for post-production expenses may be made is therefore dependent on when and where those expenses are incurred relative to the "point of sale" for each transaction. Thus, appellants agree that when they sell oil and gas downstream from the well, the royalty base is equal to the gross proceeds received by the appellants from that sale, without any downward adjustments for any post-production costs it incurred or expended prior to the point of sale. However, according to appellants, if post-production costs are expended *after* the point of sale, then downward adjustments to the sale price to account for such anticipated costs are permissible under the leases. In such a situation, appellants argue, the adjustments are not subject to paragraph 3(c) because appellants never "directly or indirectly" incurred the costs at issue—instead, the downstream purchaser incurred or anticipated incurring those costs. Appellants claim that paragraph 3(c) "was negotiated for an economically rational purpose: to bargain around the 'at the well point of valuation' rule established in *Heritage* and *Judice* regarding post-production costs."

On the other hand, appellees generally contend that the leases do not limit the base to the gross proceeds received by appellants. Instead, they note that paragraph 3(c) contemplates the *addition* of certain amounts to appellants' gross proceeds before calculating the royalty, and this necessarily means that the royalty base may end up being larger than the proceeds received. And they emphasize that there is nothing in the leases stating that an appellant must "incur" an expense in order for an adjustment related to that expense to be subject to the "shall be added" clause. Appellees argue that appellants' sales contracts "plainly include reductions or charges for expenses or costs" specified under paragraph 3(c), and therefore, appellants were required to add all of those "reductions or charges" to the royalty base. They contend that the leases were "intended to strike an appropriate balance" in light of the "unknown and unique characteristics that existed in the Eagle Ford in 2007." According to appellees, the leases "allow [appellants] wide latitude in determining whether to sell the products at the well, in the field, or take them all the way to the target market center"; and "[a]s a tradeoff, the royalty provisions entitled [appellees] to receive royalties that are insulated from the costs of [appellants'] decisions."

Under Texas law, "gross proceeds" means the amount the producer actually receives in the sale of the minerals at issue. *See Bowden*, 247 S.W.3d at 699; *Occidental Permian Ltd.*, 333 S.W.3d at 399. This is generally consistent with paragraph 3(b) of the leases, which defines "gross proceeds" as "total monies and other consideration accruing to or paid the Lessee or received by Lessee for disposition or sale of all unprocessed gas proceeds [sic], residue gas, gas plant products or other products."

Appellants made royalty payments based on their "gross proceeds," without deductions for post-production expenses incurred by appellants prior to the point of sale, but without any additions pursuant to paragraph 3(c). Appellants argue that this was proper in part because the parties merely intended to prohibit deductions from "Lessor's royalty," which they claim is defined as a percentage of gross proceeds—no more, no less. But, when the royalty provisions are read together, they do not restrict "Lessor's royalty" in this manner. Though paragraphs 3(a) and 3(b) initially define the royalty at least in part based on appellant's gross proceeds, paragraph 3(c) expressly contemplates the *addition* of certain sums to gross proceeds in order to arrive at the proper royalty base. If the parties wished merely to prohibit *deductions* from gross proceeds, there would be no reason to include paragraph 3(c). Appellants offer no other explanation for why paragraph 3(c) would be included in the leases if not to allow the royalty base to exceed gross proceeds. We will not construe the leases in such a manner as to render that unique provision superfluous or meaningless. *See J.M. Davidson, Inc.*, 128 S.W.3d at 229.[9]

Under appellants' interpretation, paragraph 3(c) would merely prohibit any deductions from appellees' royalty for costs incurred prior to the point of sale. But the language in paragraph 3(c) is exceptionally broad, and there is nothing in the leases suggesting that paragraph 3(c) is limited to pre-point-of-sale expenses. Further, if the point of sale were the deciding factor in determining whether paragraph 3(c) applies, appellants could choose to sell all of their production *at the wellhead* and thereby unilaterally transform the royalty into a "market value at the well" royalty, which appellants acknowledge would be contrary to the parties' intent. In any event, the result of appellants' proposed construction of paragraph 3(c)—freeing appellees of post-production, pre-point-of-sale costs—is already achieved by paragraphs 3(a) and 3(b) of the leases, which specify that the royalty is to be initially based on appellants' gross proceeds (before paragraph 3(c) is applied). *See Bowden*, 247 S.W.3d at 699 (stating that gross proceeds

[9] We observe that, under the Sheppard and Crain Leases, the oil royalty is not the same as the gas royalty. In particular, the oil royalty is defined as a percentage of the produced oil itself, with the lessor having the option to take the "market value thereof" in cash, whereas the gas royalty is defined exclusively in terms of its cash value—either "the market value at the wellhead" or gross proceeds, whichever is greater. Therefore, at least in theory, the oil royalty may be taken in kind, but the gas royalty must be taken in cash. Relatedly, the oil royalty, whether it is taken in kind or in cash, is to be "delivered . . . into the pipeline," which arguably means the valuation point for the oil royalty is necessarily "at the well" and all post-production expenses are chargeable to the royalty owner, notwithstanding other contractual clauses hinting otherwise. *See Burlington Res. Oil & Gas Co. v. Tex. Crude Energy*, 573 S.W.3d 198, 205 (Tex. 2019); *Judice v. Mewbourne Oil Co*., 939 S.W.2d 133, 135 (Tex. 1996); *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996). On the other hand, as noted, the gas royalty is a percentage of either "the market value at the wellhead" or gross proceeds, whichever is greater (though gross proceeds, as defined by the case law, will always be greater than the market value at the well). Despite these differences, the parties do not argue that the oil royalty should be treated any differently than the gas royalty for purposes of the twenty-three stipulated issues. In any event, though the "into the pipeline" language controlled over the "amount realized" provision in *Burlington*, the lease in that case did not involve any terms similar to paragraph 3(c) of the Sheppard and Crain Leases.

means the amount the lessee actually receives, free of post-production costs). Again, if we were to adopt appellants' construction, paragraph 3(c) would be meaningless.

Importantly, the language of paragraph 3(c) differs significantly from the no-deductions clause considered in *Heritage*. The *Heritage* lease defined the royalty as a fraction of the "market value at the well" and stated that "there shall be no deductions from the value of the Lessor's royalty," clearly indicating the parties' intent to free the lessor from any responsibility for post-production costs. 939 S.W.2d at 120. That clause, though, gave no hint of an intent to require the *addition* of any sums to the market value at the well in order to calculate the royalty. Moreover, unlike the *Heritage* clause, paragraph 3(c) of the Sheppard and Crain Leases does not concern deductions made *to the royalty* for post-production expenses; rather, it applies whenever a "reduction or charge" for such expenses is "include[d]" *in dispositions or sales contracts*, and it imposes an affirmative duty on appellants to add any such "reduction[s] or charge[s]" to the royalty base.

It is true, as appellants argue, that the "Royalty Free of Costs" provision clearly indicates the parties intended to prohibit deductions for post-production costs incurred by appellants. The citations to *Heritage* and *Judice* in Addendum L underscore this. The clause at issue in *Heritage*—which stated that there shall be no deductions from the royalty for post-production expenses—was considered "surplusage" because it merely restated the rule that royalties are generally not subject to production expenses. *See* 939 S.W.2d at 121. By citing *Heritage* and *Judice*, and by stating that the "Royalty Free of Costs" provision is not mere surplusage, the parties exhibited their intent to allow the royalty base to include value added by post-production costs and thereby exceed "at the well" market value. But, crucially, this mere fact has no bearing on whether the base may *also* exceed appellants' gross proceeds. There is nothing about Addendum L that modifies or contradicts paragraph 3(c), either explicitly or implicitly, nor is there anything about it that prohibits the addition of sums to the royalty base so that the base exceeds appellants' gross proceeds.

Appellants emphasize the final clause of paragraph 3(c), which implies that the purpose of the "shall be added" requirement is to ensure that "Lessor's royalty" is "never . . . chargeable" with post-production expenses. They argue that this language suggests the parties merely intended to prohibit deductions from a previously-defined royalty, as in *Heritage*. That may be persuasive, if the clause were viewed alone. But we may not view these words alone. *See J.M. Davidson, Inc.*, 128 S.W.3d at 229. Rather, we must view them in light of the entire agreement, including the immediately preceding "shall be added" clause, which unambiguously requires additions of certain amounts to the royalty base, without limitation to gross proceeds or any other prescribed maximum. The "never . . . chargeable" language in the final clause of paragraph 3(c), like the "Royalty Free of Costs" addendum, does not modify or contradict the "shall be added" clause. If the parties intended to limit additions so that the total royalty base could never exceed gross proceeds, they could have easily said so in certain terms, but they did not.

Indeed, the words immediately following "never . . . chargeable" in paragraph 3(c) suggest a contrary intent. They state the royalty is not to be chargeable either "directly *or indirectly*" with post-production costs or expenses (emphasis added). Addendum L also contains this language. A "direct" charge against the royalty would simply be a pro rata deduction from the producer's gross proceeds to account for the producer's post-production costs. But what is an "indirect" charge against the royalty? Appellants suggest that an "indirect" deduction of an expense occurs whenever a producer "net[s] out any of their post-production costs from a sales price." This interpretation is not sensible considering the context. Paragraph 3(c) applies whenever a "disposition, contract or sale . . . include[s] any reduction or charge" for post-production expenses. A "disposition, contract or sale" contemplates the conveyance of minerals from a producer to a downstream purchaser in exchange for compensation; thus, if such a transaction "include[s]" a "reduction or charge" for post-production expenses, that "reduction or charge" could conceivably be either (1) an increase in the sales price to account for expenses already incurred by the producer, or (2) a decrease in the sales price to account for expenses incurred (or anticipated to be incurred) by the purchaser. But if "reduction or charge" referred to an *increase* in the sales price, then appellants' gross proceeds in that situation would increase as well, and there would be no reason to add any such amounts to gross proceeds in order to ensure the royalty is cost-free. Such a construction would lead to a windfall for the lessor, who would be entitled to a royalty on the same expenses twice. A logical solution to this conundrum is that appellants' interpretation of "indirect" is misguided and does not reflect the parties' intent—an "indirect" charge to the royalty has nothing to do with expenses incurred by the producer. Instead, an "indirect" charge to the royalty must have been intended to refer to the situation when a downstream sales price is *reduced* to account for costs incurred or anticipated by the *purchaser*. On appeal, appellants suggest no other explanation for why this "direct or indirect" language would have been included twice in the lease's royalty provisions, other than to show the parties' intent to base the royalty on more than mere gross proceeds.

Appellants contend that this interpretation would not make economic sense. *See Frost Nat'l Bank v. L & F Distribs., Ltd.*, 165 S.W.3d 310, 312 (Tex. 2005) (per curiam) (noting that courts construe contracts "from a utilitarian standpoint bearing in mind the particular business activity sought to be served" and "will avoid when possible and proper a construction which is unreasonable, inequitable, and oppressive"). We disagree. The royalty is paid as a fraction of the value of the oil and gas produced from the leases, but that value increases as the minerals are processed, fractionated, and transported to the market center, where they are finally put on the open market and prices are standardized. It is not unreasonable to construe the leases as ensuring the lessors' royalty is based on the standardized value of the gas at the market center, and that is effectively what the Sheppard and Crain Leases accomplish. The value of the minerals at the market center will likely be more than the gross proceeds received by the producer—how much more depends on the terms of the contracts between the producers and the downstream purchasers. But as appellees argue, the purpose of the provisions at issue in this case is to insulate appellees from the effects of appellants' decisions regarding when, where, and for what price the oil and gas is sold between the time it is produced and the time it is marketable. The unique provisions of the Sheppard and Crain Leases make economic sense for both parties because they effectively allow appellees to collect a royalty based on standardized market prices while appellants remain able to freely make those decisions.

Appellees point to *Yturria v. Kerr-McGee Oil & Gas Onshore, LLC*, 291 Fed. App'x 626 (5th Cir. 2008) (per curiam, not designated for publication), as an example of a case where the parties bargained for a royalty valuation point downstream of the producer's point of sale. There, four leases required Kerr-McGee to pay a royalty on "all plant products, or revenue derived therefrom, attributable to gas produced by [Kerr-McGee] from the leased premises." *Id.* at 628. Two of the leases at issue stated that the lessors' royalty on NGLs "shall never bear, either directly or indirectly, any part of the costs or expenses of production, gathering, dehydration, compression, transportation (except transportation by truck), manufacture, processing, treatment or marketing of the oil or gas from the leased premises . . . ." *Id.* Enterprise, a third-party purchaser, contracted with Kerr-McGee to process and fractionate gas from the leases, with title transferring after the gas was processed but before it was transported to Enterprise's plant for fractionation. *Id.* The price for the gas was set at "80% of Enterprise's 'Net Proceeds,' which consist of the total value of the fractionated [NGLs] (based on price averages) minus product marketing, transporting, and fractionating costs." *Id.* The lessors sued Kerr-McGee when it discovered that it was calculating royalties based on the revenue it actually received from Enterprise, which "includes deductions for Enterprise's transportation and fractionation costs," rather than on the total revenue generated by the NGLs, exclusive of costs. *Id.* at 629. The Fifth Circuit agreed with the lessors' interpretation of the lease and concluded that such deductions were impermissible. *Id.* at 633–35.

The *Yturria* court noted that the royalty provision at issue—which based the royalty on "all . . . revenue derived" from NGLs "attributable to gas produced" on the leases—resulted from an amendment to the lease which was negotiated following a previous lawsuit between the parties. *Id.* at 633. The amended provision replaced language stating that the royalty was based on "revenue . . . received by [Kerr-McGee]." *Id.* The old language "allowed Kerr–McGee, through its affiliate processor, to receive the full benefit of the [NGLs] while at the same time decreasing the amount it owed Lessors as a royalty," and "[t]he amendments were designed to address this problem." *Id.* at 634. Although the specific circumstances regarding the formation of the lease in *Yturria* are not present here, the terms are broadly similar to those contained in the Sheppard and Crain Leases in that they do not restrict the royalty base to amounts actually received by the producer. *Yturria* demonstrates that there is nothing unreasonable, inequitable, or oppressive about an oil and gas producer agreeing to base royalty payments on more than just the gross proceeds it receives in a sale.

With the above considerations in mind, we conclude that the Sheppard and Crain Leases provide generally for a "proceeds-plus" royalty, which in most circumstances is based on an approximation of the value of production at the market center after the individual hydrocarbons have been separated and are ready to be sold for standardized index prices on the open market.

That said, we must still review the individual issues set forth in the stipulation to determine whether paragraph 3(c) applies. This requires an examination of the sales contracts which the parties have stipulated exemplify those issues.[10] The twenty-three issues each concern a different aspect of an oil and gas sale—most of which are enshrined in a written contract—which appellees allege represents a "reduction or charge" that was required to be added to gross proceeds under paragraph 3(c). The

[10] In contesting summary judgment, appellants enumerate only one issue with two sub-issues. And at the summary judgment hearing, appellees' counsel impressed upon the trial court that the case is "really quite simple" because "[e]ach issue presents the same exact thing, does the lease require that the reduction or charge contained in these exemplar contracts . . . be added back to the defendants' gross proceeds. . . . So it's not really 23 distinct issues, it's just 23 issues asking the Court the same question." Unfortunately, as any reader of this opinion will attest, the case is by no means simple. The Sheppard and Crain Leases differ slightly but significantly in their terms. The parties make varying arguments for each of the twenty-three issues, and so each must be analyzed separately to determine whether paragraph 3(c) applies.

issues may be categorized as follows: (1) price adjustments of a fixed amount with a stated purpose; (2) price adjustments of a fixed amount without a stated purpose; (3) price adjustments based on the actual costs incurred by a third-party purchaser; (4) adjustments for volumes of gas used by the producer for its own operations and never sold to a third party; (5) adjustments for volumes of production deemed to be lost or unaccounted-for by third parties; and (6) value retained by the producer as a result of the application of contractually fixed recovery factors.

1. Adjustment of Fixed Amount With Stated Purpose

Stipulated Issues 2, 7, 8, 10, 11, and 13 concern sales contracts under which the price for oil and gas is calculated in part by deducting a fixed sum from a published price, and the contract states what that fixed sum is intended to account for.

One of the exemplar contracts for Issue 2 is a 2011 agreement between GeoSouthern and Enterprise for the sale of crude oil and/or condensate. The price per barrel is set as a weighted average of published index prices “minus $18.00 gathering and handling, including rail car transportation” per barrel. This is the issue which was raised in appellees’ original petition.

Issues 7 and 13 are exemplified by a 2010 “Gas Processing Agreement” under which ETC Texas Pipeline, Ltd. (ETC) agreed to process gas produced by Petrohawk and to purchase 100% of the resulting NGLs and 50% of any drip condensate “attributable to [Petrohawk]’s gas.” The price for both was set as a published index price “less [ETC’s] actual transportation and fractionation (T&F) cost, less retention gallons (if any) required to secure T&F services, and less a marketing fee of one quarter cent ($0.0025) per gallon.” Issue 7 concerns the marketing fee as it relates to the sale of NGLs; Issue 13 concerns the marketing fee as it relates to the sale of condensate.

For Issue 8, the exemplar contract is a 2012 "Gas Services Agreement" under which Copano agreed to gather and process gas produced by GeoSouthern, to purchase the resulting NGLs, and to return the remaining residue gas. The price for the NGLs was set at a published index price "less" a "T&F fee" of "$0.104 per gallon."

Stipulated Issue 10 concerns the sale of NGLs from GeoSouthern to Martin Gas Sales under various sales orders. The orders set the price as an average of published index prices "less" a "fixed fee" determined by a formula. The contract states: "Fixed fee includes pipeline fee, fixed frac fee, truck transportation, terminalling fee and margins."

In Issue 11, the exemplar contract is a 2012 "Gas Processing Agreement" between Enterprise and Petrohawk. The contract provides that Enterprise shall pay Petrohawk on a monthly basis "ninety-two percent (92%) of the Producer Plant Products Value," which is defined as the (1) the volume of the plant products attributable to Petrohawk, times (2) a published index price "minus the T&F Fee" applicable for that month.

There is no dispute that these constitute "disposition[s], contract[s] or sale[s] of oil or gas" under paragraph 3(c) of the leases. We agree with appellees that the fixed deductions are properly considered "reduction[s] or charge[s]" "include[d]" in such "contract[s] or sale[s]" because they reduce the amount that would otherwise be payable to appellants. And the contracts expressly provide that the fixed amounts specified in these contracts are "for the expenses or costs" of transportation, processing, and marketing. Appellants argue that these amounts do not represent *appellant's expenses* for such post-production activities, but as noted, the leases do not specify that the expenses or costs must necessarily be incurred or expended by appellants in order for paragraph 3(c) clause to apply. Thus, we conclude appellants were required to add these amounts to their gross proceeds in order to calculate appellees' royalties. The trial court did not err in granting summary judgment to appellees on these issues.

2. Adjustment of Fixed Amount Without Stated Purpose

Issues 1, 3, 6, 15, 16, 17, 18, and 19 in the stipulation concern sales contracts under which the price for oil and gas is calculated in part by deducting a fixed sum from a published price, but without stating what that fixed sum is intended to represent or account for.

One of the exemplar contracts for Issue 1 is a 2013 agreement between Petrohawk and ExxonMobil for the sale of gas condensate and crude oil. As to price, the agreement stated that "[a] differential of -7.1500 US dollars . . . will be applied to" a formula based on published index prices. Delivery of oil was specified to take place in Houston at the purchaser's designated facility, but as to condensate, the purchaser also had the option to take delivery at Point Comfort, Texas, and if that option is taken, the differential is increased to "-7.500 US dollars" per barrel.

The exemplar contract for Issue 3 is a 2012 agreement for the sale of crude oil and condensate from appellant GeoSouthern to Enterprise Crude Oil LLC (Enterprise). An exhibit to the contract indicates that the applicable price is a published index price "plus amount shown per barrel." The "amount shown," which appellees contend is a deduction which must be added to gross proceeds, is -$9.15 or -$8.15 for the leases at issue here.

Issue 6 concerns the sale of NGLs under a similar pricing scheme. The exemplar contract is a 2012 "Gas Gathering and Processing Agreement" under which Copano Processing, L.P. (Copano) agreed to gather and process gas produced by Petrohawk, to purchase the liquefiable hydrocarbons resulting from processing, and to return residue gas to Petrohawk. The purchase price for the NGLs was set at a published index price "less $0.15 per gallon" for normal butane and natural gasoline and "less $0.12 per gallon" for isobutane.

Stipulated Issue 15 concerns an arrangement under which ETC agreed to gather and sell drip condensate delivered by Petrohawk. The exemplar contract, a 2012 "Individual Transaction Confirmation," states that ETC will pay Petrohawk its "net cash proceeds" from the sale of the condensate, "less any and all costs associated with handling and transporting the Condensate to market," including but not limited to "trucking, stabilization, and any other transportation and fractionation fees, less a $0.03 per gallon fee." Appellees argued that both the actual costs and the fixed fee constitute charges to which paragraph 3(c) of the leases applies.

Issues 16 and 17 concern appellants' sale of residue gas or "dry gas"—i.e., methane gas returned to the producer after all liquids have been condensed and impurities removed by the processor. As to price, the exemplar contract provides that Houston Pipe Line Company shall pay "ninety-eight percent (98%)" of a published index price "LESS $0.105" per MMBtu (millions of British Thermal Units). Issue 16 is whether the "$0.105" per MMBtu is a deduction which must be added to gross proceeds; Issue 17 is whether the two percent reduction to the index price must be added.

Issues 18 and 19 refer to a 2010 "Gas Purchase and Sale Agreement" between Copano and GeoSouthern. The agreement contains a complicated pricing scheme which is initially based on "ninety-eight percent (98%) of [a published index price] minus forty-five cents ($0.45) for each MMBtu." Issue 18 is whether the forty-five-cent deduction must be added to the royalty base under paragraph 3(c) of the leases; Issue 19 is whether the two percent reduction to the index price must be added.

With the exception of the actual-cost deduction discussed in Issue 15, there is no dispute that all of the fixed-dollar-amount and percentage deductions from published index prices constitute “reduction[s] or charge[s]” “include[d]” in a “disposition, contract or sale of oil and gas.” However, unlike the contracts discussed in the previous category of issues, these contracts do not specify the *purpose* for the reductions. Paragraph 3(c) applies only if the specific charge is “for the expenses or costs of production, treatment, transportation, manufacturing, process[ing] or marketing of the oil or gas.” Appellees have not pointed to any evidence establishing that the purpose for these reductions is one of those specifically identified in paragraph 3(c). Accordingly, appellants were not required to add these amounts to their gross proceeds before calculating the royalty. The trial court erred in granting summary judgment to appellants on Stipulated Issues 1, 3, 6, 16, 17, 18, and 19. It also erred in granting summary judgment as to the three-cent-per-gallon fee discussed in Issue 15.

3. Adjustment Based on Processor’s Actual Costs

Issues 4, 9, 12, and 15 concern sales agreements under which the purchaser’s actual costs for post-production expenses are deducted from a published index price in order to determine the applicable sales price.

The exemplar contract for Issue 4 is for the 2013 sale of crude oil from GeoSouthern to Petrohawk, to be delivered into a specific pipeline, for a price based on a weighted average of sales “less transport, terminal and marketing costs.”

For Issues 9 and 12, the exemplar contract is the same 2010 “Gas Processing

Agreement" between ETC and Petrohawk considered in Issues 7 and 13. These issues concern the deduction made to the sales price for ETC's "actual transportation and fractionation (T&F) cost." Issue 9 relates to the sale of NGLs and Issue 12 relates to the sale of drip condensate.

As noted, Issue 15 involves a contract where the processor's actual costs for "handling and transporting," including "trucking, stabilization, and any other transportation and fractionation fees," are deducted from the sales price.

These adjustments are all deductions from the downstream sales price which are intended to reflect the actual transportation, processing, and marketing costs of the third-party purchaser. Thus, these costs are required to be added to gross proceeds under paragraph 3(c) of the Sheppard and Crain Leases. Appellants contend that addition of these sums was not required because: (1) appellants did not "directly or indirectly" incur the costs at issue, and (2) the deduction was not made "from [appellees'] royalty." We reject these arguments for the reasons previously elucidated. The leases do not require that appellants directly incur an expense in order for the "shall be added" clause to apply. They do not merely prohibit deductions "from [appellee's] royalty" for such costs, but also mandate *additions* to the royalty base for post-production costs incurred or anticipated by the third-party purchaser. The trial court did not err in granting summary judgment to appellees on these issues.

4. Adjustments For Unit Fuel/Lease Fuel

The remaining stipulated issues are qualitatively different from those already considered in that they do not involve the deduction of post-production costs (either incurred by appellants or by third-party purchasers) from the royalty base.

Issues 20 and 21 concern whether appellees are entitled to royalties "on actual volumes of gas used by [appellants] for unit fuel" or "lease fuel"—i.e, gas used by appellants to fuel their own operations, either on the leases themselves or on other leases within a pooled unit, and never sold to a third party. Appellees argue that the use of gas for appellants' own operations constitutes a "disposition" which "result[s] in a reduction or charge" in appellants' gross proceeds because the practice "reduce[s] the volume of hydrocarbons that are paid for." Appellees argue that this "reduction" is therefore subject to the "shall be added" clause in paragraph 3(c) of the leases.[11]

On the other hand, appellants note that the leases do not provide any mechanism for valuing the gas used as unit fuel or lease fuel, and they argue this indicates the parties did not intend to have any such values added to gross proceeds. Appellants further argue that the leases specifically allow them to deduct volumes used for operations before calculating the royalty. They note that paragraph 4 of the subject leases permits the lessee to "pool or combine the acreage covered by the lease" with other land, and it states:

> For the purpose of computing the royalties to which owners . . . shall be entitled on production of oil and gas, or either of them, from the pooled unit, there shall be allocated to the land covered by this lease and included in

[11] Appellants argue that appellees abandoned these issues. They note that appellees provided the trial court with a proposed judgment that included rulings in favor of appellees on all other issues but did not include any rulings on Stipulated Issues 20 or 21. (The trial court eventually signed appellees' proposed judgment, but only after adding handwritten rulings in appellees' favor on Issues 20 and 21.) Appellees' proposed judgment was accompanied by a letter from their counsel stating: "In the interests of simplifying the issues and limiting complications in the severed damages phase of this case, Plaintiffs are withdrawing their requests for relief on issues 20 and 21 in the [Stipulation]." Appellants neglect to mention that their counsel replied with his own letter to the court in which he objected to appellees' "attempt to unilaterally withdraw these two issues from consideration" as "procedurally improper and in conflict with the parties' joint submission of disputed issues in this case." Appellants' counsel requested that the court "keep all twenty-four [sic] Disputed Issues under consideration." Appellants cannot now complain that the trial court granted that request. *See Tittizer v. Union Gas Corp.*, 171 S.W.3d 857, 862 (Tex. 2005) (per curiam) ("[A] party cannot complain on appeal that the trial court took a specific action that the complaining party requested."). We conclude the issues were not abandoned.

> said unit (or to each separate tract within the unit if this lease covers separate tracts within the unit) a pro rata portion of the oil and gas, or either of them, produced from the pooled unit *after deducting that used for operations on the pooled unit*.

(Emphasis added.) The Sheppard Lease also explicitly states, in paragraph 3(d), the following: "Lessee shall have free use of oil, gas, and water from said land, except water from Lessor's wells, tanks, creeks, and watering places for all operations hereunder, and the royalty on oil and gas shall be computed after deducting any so used."

We cannot conclude that appellants' retention of gas for use in their own operations constitutes a "reduction or charge" that is "include[d]" in a "disposition" so as to implicate paragraph 3(c). The fact that "disposition" appears in paragraph 3(c) in a list with "contract" and "sales" signifies that "disposition" was meant to refer to a transfer to a third party, not a unilateral disposal or use by the producer. "Disposition" is the act of disposing; to "dispose" of something means to get rid of it or to transfer it to the control of another. MERRIAM-WEBSTER ONLINE DICTIONARY, https://www.merriam-webster.com/dictionary/disposition (last visited June 19, 2020); *id.*, https://www.merriam-webster.com/dictionary/dispose (last visited June 19, 2020). In light of this common definition as well as the lease language cited by appellants, which indicates an intent to exclude gas used for appellants' operations from the royalty base, it would be unreasonable to construe the word "disposition" as including the use of gas for fueling appellants' operations on the subject leases or on the pooled unit which includes those leases.

We conclude that paragraph 3(c) does not require the addition to gross proceeds of any amounts attributable to appellants' use of gas for unit fuel or lease fuel. Therefore, the trial court erred in granting summary judgment to appellees on Stipulated Issues 20 and 21.

5. Adjustment for Production Retained or Lost by Third Parties

Stipulated Issues 14, 22, and 23 concern whether royalty is owed on gas which is produced on the leases and sold by appellants to third parties, but then retained or lost by the third-party purchaser.

The exemplar contracts for Issue 14 include the 2010 "Gas Processing Agreement" between ETC and Petrohawk. Section 7.7 of that agreement states that the "quantity" of a particular plant product is determined in part by multiplying the deemed volume of gas attributable to that product by a "Component Recovery Factor," ranging from 0.75 to 0.98 depending on the specific product. Essentially, the agreement provides that ETC is only required to pay Petrohawk for a certain percentage of the products which are attributable to Petrohawk's gas. Appellees argue that this "volumetric reduction" constitutes a "reduction or charge" subject to paragraph 3(c) of the leases.

Issues 22 and 23 concern lost and unaccounted-for gas. The exemplar contracts include a 2012 "Gas Processing Agreement" under which Petrohawk agreed to sell to Enterprise, among other things, "the right to consume" gas as "FL&U" ("flared, vented, and/or lost and unaccounted for"). Under the agreement, title to plant products passes to Enterprise "when the same are removed from the Gas stream and/or become identifiable Plant Products," whereas title to lost and unaccounted-for gas passes as soon as it is delivered to Enterprise.

Appellees contend that, whenever a third-party processor such as Enterprise loses gas or uses gas for its own operations in this way, that constitutes a "disposition" which "results in a reduction or charge related to the costs and expenses of the services those third-parties perform" because it reduces the volume of gas upon which the producer is entitled to payment. Issue 22 argues that such a reduction is subject to paragraph 3(c) of the Sheppard Lease and Issue 23 argues that it is subject to the equivalent provision in the Crain Lease.

We disagree. Unlike Issues 20 and 21, these issues involve specific contractual provisions which operate, ultimately, to reduce the gross proceeds to which appellants would otherwise be entitled. And the volumetric reduction is arguably a "reduction or charge" that is "include[d]" in a "disposition, contract or sale" under paragraph 3(c). However, appellees' summary judgment motion pointed to no evidence indicating that this type of volumetric reduction is "for the expenses or costs of production, treatment, transportation, manufacturing, process[ing] or marketing of the oil or gas" as required by paragraph 3(c). Therefore, these volumetric reductions are not charges which must be added to the royalty base. The trial court erred in granting summary judgment to appellees on Stipulated Issues 14, 22, and 23.

6. Excess Value Resulting From Application of Contractually Fixed Recovery Factors

Issue 5 as listed in the stipulation concerns a complex arrangement under which appellants are compensated by downstream purchasers based on the gas's heating value rather than its volume in certain situations.

Under the exemplar 2012 "Gas Services Agreement" between GeoSouthern and Copano, there is a provision conclusively deeming each different liquid plant product, such as ethane or propane, to have been "recovered" by the processor at certain percentages. According to appellants, these "contractual fixed recovery factors" are agreed to in advance "for ease of accounting, and to provide certainty" to the parties. Appellees claimed in their summary judgment motion that the value of the "excess liquids”—i.e., the amount by which the volume of each hydrocarbon liquid actually recovered by the processor exceeds the deemed recovery percentage—serves as a form of “compensation to the processor for its processing services and constitutes an in-kind payment” which should be added to the royalty base under paragraph 3(c) of the leases.

Appellants note that, according to deposition testimony from Whyburn, Devon’s accountant, appellants are compensated by Copano and other processors for the “excess liquids” by the processor’s increasing the amount of residue gas appellants are entitled to receive back after the liquids have been extracted. However, the extra gas is measured in BTUs rather than cubic feet, and the relative market price for gas fluctuates depending on whether it is measured in heating value (BTUs) or volume (cubic feet).[12] Appellees argue that the difference between the two measures represents additional compensation flowing from processor to producer and must be added to gross proceeds under lease paragraph 3(c).

We cannot conclude that paragraph 3(c) is applicable in this situation. In their summary judgment motion, appellees did not contend that the difference between the heating-value-based price and volume-based price is intended to represent or account for expenses of the type listed in paragraph 3(c). Thus, even assuming that the excess value retained by appellants as a result of applying the contractually fixed recovery factors is a “reduction or charge,” we cannot conclude that such a “reduction or charge” is “for the expenses or costs of production, treatment, transportation, manufacturing, process[ing] or marketing of the oil or gas” as required by paragraph 3(c). The trial court

[12] At the summary judgment hearing, appellees’ counsel also argued that BTUs in gas form are worth less than BTUs in NGL form.

therefore erred by granting summary judgment to appellees on Stipulated Issue 5.

IV. CONCLUSION

The Texas Supreme Court has lamented the "considerable time, money, and heartache" which is expended due to the use of "cryptic language" in oil and gas leases. *Burlington*, 573 S.W.3d at 210 n.10. This case epitomizes the problem. Appellants urge that the inclusion of "gross proceeds" language in the Sheppard and Crain Leases necessarily controls over all others and mandates a result similar to that which obtained in *Hyder*, but paragraph 3(c) of the leases is highly unique and sets this case apart. It shows that the parties intended to allow the royalty base not only to exceed the market value at the well, but also to exceed appellants' gross proceeds. That said, it is difficult to fathom that the parties, when executing the leases, shared a mutual common conception of what was to be covered by paragraph 3(c). We can only speculate as to how many dollars and hours would have been saved had the parties drafted the leases, in Justice Blacklock's words, "to say exactly what [they] intend[ed], without resort to industry jargon, outdated legalese, or tenuous assumptions about how judges will interpret industry jargon or outdated legalese." *Id.*

For the reasons set forth herein, we reverse the trial court's judgment on Stipulated Issues 1, 3, 5, 6, 14, 16, 17, 18, 19, 20, 21, 22, and 23. We also reverse the trial court's judgment on Stipulated Issue 15 insofar as it concerns the fixed fee of three cents per gallon on the sale of drip condensate. We render judgment in favor of appellants on these issues. The remainder of the trial court's judgment is affirmed.

DORI CONTRERAS
Chief Justice

Delivered and filed the
22nd day of October, 2020.

APPENDIX

1. Where dispositions, contracts, or sales of oil provide for payment to Lessee based upon a Published Price[[13]] per barrel minus a fixed dollar amount, whether such fixed dollar amount constitutes a Contractual Charge.[[14]]

> Example Contracts: Petrohawk/ExxonMobil oil sales contract; Petrohawk/Exxon amendment; GeoSouthern/Flint Hills oil purchase agreement; GeoSouthern/Genesis Crude Oil agreement; Petrohawk/Shell oil purchase contract; Petrohawk/Shell oil purchase contract.

2. **Plaintiffs' version:** Where dispositions, contracts, or sales of oil provide for payment to Lessee based upon a Published Price per barrel minus a fixed dollar amount for the cost of production, treatment, processing, transportation, manufacturing, marketing, or terminalling, whether such fixed dollar amount constitutes a Contractual Charge.

Defendants' version: Where dispositions, contracts, or sales of oil provide for payment to Lessee based upon a Published Price per barrel minus a fixed dollar amount for the cost of production, treatment, processing, transportation, manufacturing, marketing, or terminalling **downstream of the Lessee's point of sale,** whether such fixed dollar amount constitutes a Contractual Charge.

> Example Contracts: GeoSouthern/Enterprise oil sales contract; GeoSouthern/Enterprise oil sales contract and amendments; Petrohawk/Shell oil sales agreement.

3. Under the following contracts, which provide for payment to Lessee based upon a Published Price per barrel minus a dollar amount, whether such dollar amount constitutes a Contractual Charge.

> Example Contracts: GeoSouthern/Enterprise oil amended sales contract; Enterprise contract amendments.

4. **Plaintiffs' version:** Where dispositions, contracts, or sales of oil provide for payment to Lessee based upon a weighted average sales price per barrel minus the actual cost of production, treatment, processing, transportation, terminalling, or marketing, whether such fixed dollar amount

[13] The stipulation defined "Published Price" as "prices generally published by commercial market services providers relative to sales of hydrocarbons at identified industry or market centers (i.e., OPIS Mont Belvieu. Platts' Inside FERC's Gas Market Report, Houston Ship Channel, etc.)."

[14] A "Contractual Charge" is defined in the stipulation as one that appellants were required to add to gross proceeds in order to calculate the royalty under paragraph 3(c) of the leases.

constitutes a Contractual Charge.

Defendants' version: Where dispositions, contracts, or sales of oil provide for payment to Lessee based upon a Published Price per barrel minus a fixed dollar amount for the cost of production, treatment, processing, transportation, manufacturing, marketing, or terminalling **downstream of the Lessee's point of sale,** whether such fixed dollar amount constitutes a Contractual Charge.

> Example Contract: GeoSouthern/Petrohawk oil sales contract.

5. Where a Lessee sells natural gas liquids to a processor and the volume of each natural gas liquid component on which Lessee is paid is calculated using contractually fixed plant recovery factors, whether the value of the Excess Liquids[[15]] constitutes a Contractual Charge.

> Example Contract: Copano 2012 Gas Services Agreement.

6. Where dispositions, contracts, or sales of natural gas liquids to a processor provide for payment to Lessee based upon a Published Price per gallon minus a fixed dollar amount, whether such fixed dollar amount constitutes a Contractual Charge.

> Example Contract: Petrohawk/Copano Gas Gathering & Processing Agreement.

7. **Plaintiffs' version:** Where dispositions, contracts, or sales of natural gas liquids to a processor provide for payment to Lessee based upon a Published Price per gallon minus a fixed dollar amount for marketing, whether such fixed dollar amount constitutes a Contractual Charge.

Defendants' version: Where dispositions, contracts, or sales of natural gas liquids to a processor provide for payment to Lessee based upon a Published Price per gallon minus a fixed dollar amount for marketing **downstream of the Lessee's point of sale**, whether such fixed dollar amount constitutes a Contractual Charge.

> Example Contract: Petrohawk/ETC Gas Processing Agreement.

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[15] "Excess liquids" is defined in the stipulation as:

> the difference between (a) the natural gas liquids actually recovered by a processor from the gas delivered to the plant by Lessee, and (b) the sum of the contractually fixed component recoveries of natural gas liquids attributed to the gas delivered to the plant by Lessee and the MMBtus of residue gas credited to Lessee in place of the natural gas liquids recovered by the processor in excess of the fixed recovery factors.

8. **Plaintiffs' version:** Where dispositions, contracts, or sales of natural gas liquids to a processor provide for payment to Lessee based upon a Published Price per gallon minus a fixed dollar amount for transportation and fractionation ("T&F"), whether such fixed dollar amount constitutes a Contractual Charge.

Defendants' version: Where dispositions, contracts, or sales of natural gas liquids to a processor provide for payment to Lessee based upon a Published Price per gallon minus a fixed dollar amount for transportation and fractionation ("T&F") **downstream of the Lessee's point of sale**, whether such fixed dollar amount constitutes a Contractual Charge.

> Example Contracts: GeoSouthern/Copano Gas Gathering & Processing Agreement; GeoSouthern/Enterprise Gas Processing Agreement.

9. **Plaintiffs' version:** Where dispositions, contracts, or sales of natural gas liquids to a processor provide for payment to Lessee based upon a Published Price per gallon minus the actual cost of transportation and fractionation ("T&F"), whether such fixed dollar amount constitutes a Contractual Charge.

Defendants' version: Where dispositions, contracts, or sales of natural gas liquids to a processor provide for payment to Lessee based upon a Published Price per gallon minus the actual cost of transportation and fractionation ("T&F") **downstream of the Lessee's point of sale**, whether such fixed dollar amount constitutes a Contractual Charge.

> Example Contract: Petrohawk/ETC Gas Processing Agreement.

10. **Plaintiffs' version:** Where dispositions, contracts, or sales of natural gas liquid hydrocarbons at central delivery points provide for payment to Lessee based upon a Published Price per gallon minus a fixed dollar amount identified as being for the cost of production, treatment, processing, transportation, manufacturing, marketing, or terminalling, whether such fixed dollar amount constitutes a Contractual Charge.

Defendants' version: Where dispositions, contracts, or sales of natural gas liquid hydrocarbons at central delivery points provide for payment to Lessee based upon a Published Price per gallon minus a fixed dollar amount identified as being for the cost of production, treatment, processing, transportation, manufacturing, marketing, or terminalling **downstream of the Lessee's point of sale**, whether such fixed dollar amount constitutes a Contractual Charge.

> Example Contracts: GeoSouthern/Martin contract; GeoSouthern/Texon Purchase Agreement

11. **Plaintiffs' version:** Where a Lessee sells natural gas liquids to a processor who pays Lessee less than 100% of the calculated natural gas liquids' value, whether the value retained by the processor constitutes a Contractual Charge.

Defendants' version: Where a Lessee sells natural gas liquids at the point specified in the contract to a processor who pays Lessee a price based upon less than 100% of a calculated natural gas liquids' value (i.e., 92% of such calculated natural gas liquids value), whether the percentage retained by the processor (i.e., 8%) constitutes a Contractual Charge.

> Example Contract: GeoSouthern/Enterprise Gas Processing Agreement.

12. **Plaintiffs' version:** Where a Lessee sells drip condensate to a processor based upon a weighted average sales price minus a dollar amount for the actual cost of transportation and fractionation ("T&F"), whether such dollar amount constitutes a Contractual Charge.

Defendants' version: Where a Lessee sells drip condensate to a processor based upon a weighted average sales price minus a dollar amount for the processor's actual cost of transportation and fractionation ("T&F") **downstream of the Lessee's point of sale**, whether such dollar amount constitutes a Contractual Charge.

> Example Contracts: Petrohawk/ETC 2010 Gas Processing Agreement, §7.7; Petrohawk/ETC 2010 Gathering & Natural Gas Services Agreement and ITC.

13. **Plaintiffs' version:** Where a Lessee sells drip condensate to a processor based upon a weighted average sales price minus a fixed dollar amount for marketing, whether such dollar amount constitutes a Contractual Charge.

Defendants' version: Where a Lessee sells drip condensate to a processor based upon a weighted average sales price minus a dollar amount for the actual cost of transportation and fractionation ("T&F") **downstream of the Lessee's point of sale**, whether such dollar amount constitutes a Contractual Charge.

> Example Contracts: Petrohawk/ETC 2010 Gas Processing Agreement, §7.7; Petrohawk/ETC 2010 Gathering & Natural Gas Services Agreement and ITC.

14. Where a natural gas transportation or processing agreement allows a transporter or processor to retain some or all drip condensate without purchasing it from the Lessee, whether the volume of drip condensate retained by the transporter or processor constitutes a Contractual Charge.

Example Contracts: ETC 2010 Gas Processing Agreement, §7.7; Petrohawk/ETC 2010 Gathering & Natural Gas Services Agreement and ITC; Geo/ETC Gath. & Proc. Agmt.; Geo/ETC Gath. & Proc. Agmt. ITC.

15. **Plaintiffs' version:** Where a Gatherer pays Lessee the cash proceeds received from the sale of Lessee's drip condensate minus a dollar amount for the actual costs associated with handling and transporting the condensate to market and a fixed fee per gallon, whether such dollar amount and fixed fee constitute a Contractual Charge.

Defendants' version: Where a Lessee sells drip condensate to a gatherer and receives the cash proceeds from the gatherer's downstream sale of the condensate minus a dollar amount for the gatherer's actual costs associated with handling and transporting the condensate and a fixed fee per gallon, whether such dollar amount and fixed fee constitute a Contractual Charge.

Example Contracts: 2012 Individual Transaction Confirmation to Petrohawk-ETC 2010 Gas Gathering Agreement 9116-102, Condensate, "Net Cash Proceeds".

16. Where residue gas is sold by a Lessee for a stated percentage that is less than 100% of a Published Price minus a fixed dollar amount (i.e., 98% of HSC Gas Daily Midpoint Price less $0.105 per MMBtu), whether that fixed dollar amount constitutes a Contractual Charge.

Example Contract: Houston Pipeline/Petrohawk Energy Corp. Contract

17. Where residue gas is sold by a Lessee for a stated percentage that is less than 100% of a Published Price minus a fixed dollar amount (i.e., 98% of HSC Gas Daily Midpoint Price less $0.105 per MMBtu), whether the percentage adjustment to the Published Price constitutes a Contractual Charge.

Example Contract: Houston Pipeline/Petrohawk Energy Corp. Contract

18. Under the 2010 Copano Gas Purchase And Sale Agreement, where gas is sold by the Lessee at specified Point(s) of Delivery (i.e., at the tailgate of the Central Delivery Point) for a calculated value for the constituent natural gas liquids plus less than 100% of a Published Price minus a fixed dollar amount (i.e., 98% IF HSC Index minus $0.45 per MMBtu) for the anticipated residue gas, whether such fixed dollar amount constitutes a Contractual Charge.

Example Contract: 2010 Copano Gas Purchase and Sale

Agreement

19. Under the 2010 Copano Gas Purchase And Sale Agreement, where gas is sold by the Lessee at specified Point(s) of Delivery (i.e., at the tailgate of the Central Delivery Point) for a calculated value for the constituent natural gas liquids plus less than 100% of a Published Price minus a fixed dollar amount (i.e., 98% IF HSC Index minus $0.45 per MMBtu) for the anticipated residue gas, whether the percentage adjustment to the Published Price constitutes a Contractual Charge.

Example Contract: 2010 Copano Gas Purchase and Sale Agreement

20. Whether Lessors are owed royalties on actual volumes of gas used by Lessee for unit fuel under the Lessors' Leases.

Example Contract: None needed.

21. Whether Lessors are owed royalties on actual volumes of gas used by Lessee for Lease Fuel:

i. Under the Sheppard Lease;

ii. Under the Crain Lease

Example Contract: None needed.

22. Whether the following volumes of actual and/or contractually fixed percentages of gas used/retained as fuel or deemed to be lost and unaccounted for gas by third-party processing plants, gatherers, or transporters constitute a Contractual Charge under the Sheppard Lease:

i. Actual gas used by a third-party processor, gatherer, or transporter for fuel in providing services to Lessee;

Example Contracts: Hawk Field Services Firm Gas Gathering Agreement. Ex. C; Petrohawk/Enterprise Gas Processing Agreement.

ii. Contractually fixed percentages of gas retained by a third-party processor, gatherer, or transporter for fuel in providing services to Lessee; and

Example Contracts: Individual Transaction Confirmation to Gathering and Natural Gas Services Agreement, ETC and Petrohawk. No. 9116-103; Petrohawk/Oasis Intrastate Transp. Agmt; Petrohawk/Oasis ITC; GeoSouthern/Copano 2012 Gas Services Agreement; 2012 ITC to Petrohawk-ETC

2010 Gas Gathering Agreement, 9116-102.

iii. Contractually fixed percentages of gas deemed to be lost and unaccounted for gas in a processing, gathering, or transportation agreement.

Example Contracts: Individual Transaction Confirmation to Gathering and Natural Gas Services Agreement. ETC and Petrohawk. No. 9116-103; 2012 ITC to Petrohawk-ETC 2010 Gas Gathering Agreement. 9116-102

23. Whether the following volumes of actual and/or contractually fixed percentages of gas used/retained as fuel or deemed to be lost and unaccounted for gas by third-party processing plants, gatherers, or transporters constitute a Contractual Charge under the Crain Lease:

i. Actual gas used by a third-party processor. gatherer, or transporter for fuel in providing services to Lessee;

Example Contract: same as 22.i

ii. Contractually fixed percentages of gas retained by a third-party processor, gatherer, or transporter for fuel in providing services to Lessee; and

Example Contract: same as 22.ii

iii. Contractually fixed percentages of gas deemed to be lost and unaccounted for gas in a processing, gathering, or transportation agreement.

Example Contract: same as 22.iii