Supreme Court of Texas

No. 20-0904

Devon Energy Production Company, L.P., f/k/a GeoSouthern DeWitt Properties, LLC, BPX Properties (NA) LP, GeoSouthern Energy Corporation, and BPX Production Company,

Petitioners,

v.

Michael A. Sheppard, et al.,

Respondents

On Petition for Review from the
Court of Appeals for the Thirteenth District of Texas

Argued October 5, 2022

JUSTICE DEVINE delivered the opinion of the Court, in which Chief Justice Hecht, Justice Lehrmann, Justice Boyd, Justice Busby, Justice Bland, and Justice Huddle joined.

JUSTICE BLACKLOCK filed a dissenting opinion.

Justice Young did not participate in the decision.

This oil-and-gas dispute presents a new wrinkle to a perennial problem: how to calculate the landowners' royalty under the terms of a mineral lease. The landowners and producers are characteristically at odds over the allocation of postproduction costs. But unlike the typical case, the parties agree that (1) the landowners' royalty is free of costs between the wellhead and the point of sale; and (2) the producers cannot—and do not—directly or indirectly charge the royalty holders with a proportionate share of those expenses. At issue here is whether a bespoke lease provision also makes the landowners' royalty free of *post-sale* postproduction costs that add value after the point of sale but are not part of the producers' "gross proceeds."

The subject leases expressly mandate that in determining the royalties to be paid by the producers, if "*any reduction or charge* for [postproduction] expenses or costs" has been "include[d]" in "any disposition, contract or sale" of production, those amounts "shall be *added to the . . . gross proceeds* so that [the landowners'] royalty *shall never be chargeable directly or indirectly with any costs or expenses* other than its pro rata share of severance or production taxes."[1] In a declaratory-judgment action, the lower courts held that, based on this language, the landowners' royalty is payable not only on gross proceeds but also on an unaffiliated buyer's post-sale postproduction costs if the producers' sales contracts state that the sales price has been derived by deducting such costs from published index prices downstream from the point of sale. We agree and therefore affirm summary judgment for the landowners as to those types of marketing arrangements. This broad lease language unambiguously contemplates a royalty base that may

[1] Emphases added.

exceed gross proceeds and plainly requires the producers to pay royalties on the gross proceeds of the sale *plus* sums identified in the producers' sales contracts as accounting for actual or anticipated postproduction costs, even if such expenses are incurred only by the buyer after or downstream from the point of sale.

I. Background

Although mineral leases operate against a backdrop of oil-and-gas jurisprudence that states the "usual" rules, we have consistently recognized that parties are free to make their own bargains.[2] Usually, the landowners' royalty is free of the expenses incurred to bring minerals to the surface (production costs) but not expenses incurred thereafter to make production marketable (postproduction costs).[3] After production, costs are incurred to remove impurities, to transport production from the wellhead, and to otherwise

[2] *E.g.*, *Nettye Engler Energy, LP v. BlueStone Nat. Res. II, LLC*, 639 S.W.3d 682, 696 (Tex. 2022).

[3] *BlueStone Nat. Res. II, LLC v. Randle*, 620 S.W.3d 380, 387 (Tex. 2021); *see French v. Occidental Permian Ltd.*, 440 S.W.3d 1, 3 (Tex. 2014) ("Generally speaking, a royalty is free of the expenses of production [but] subject to postproduction costs . . . to render [production] marketable, but the parties may modify this general rule by agreement." (alterations in original) (internal quotations omitted)).

ready it for sale to a downstream market or the public.[4] These investments generally make production more valuable.[5]

Landowners and producers can "agree on what royalty is due, the basis on which it is to be calculated, and how expenses are to be allocated."[6] A landowner's royalty free of postproduction costs is more valuable to the royalty holder—and more costly to the producer—because it means the landowner will share in the enhanced value of production but not the expenses incurred to make it so. For this reason, litigation over the construction of mineral leases and the allocation of postproduction costs is common. We have grappled with these issues many times, but the variation presented in this appeal is one of first impression.

The mineral leases at issue convey interests in the Eagle Ford Shale.[7] The Sheppard leases were executed in 2007, before the shale's viability was established with the first successfully drilled well, and the

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[4] Byron C. Keeling, *In the New Era of Oil & Gas Royalty Accounting: Drafting a Royalty Clause That Actually Says What the Parties Intend It to Mean*, 69 BAYLOR L. REV. 516, 524-25 (2017).

[5] *Id.* at 525 ("Oil and gas production is less valuable at the wellhead because any arm's length purchaser will assume that it will have to incur the cost to remove impurities from the production, to transport it from the wellhead, or otherwise to get it ready for sale to a downstream market or the general public.").

[6] *French*, 440 S.W.3d at 8; *see Burlington Res. Oil & Gas Co. v. Tex. Crude Energy, LLC*, 573 S.W.3d 198, 203 (Tex. 2019) (the contracting parties may "define post-production costs any way they choose").

[7] Only five mineral leases are involved in this case, but the parties have described the litigation as a bellwether for as many as 200 other leases employing the same language.

Crain leases were executed in 2010 and 2011 amid the rising boom.[8] The producers are original and successor lessees.[9]

The following royalty provisions are relatively standard fare in the industry:[10]

> 3. The royalties to be paid by Lessee are:
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> (a) on oil, [1/5th of production for the Sheppard or 1/4th of production for the Crain leases] 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 . . . *the gross proceeds of the sale* thereof . . . ;
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> (b) on gas . . . [1/5th for the Sheppard or 1/4th for the Crain leases of] . . . *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

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[8] *See Petty Bus. Enters. v. Chesapeake Expl., L.L.C.* (*In re Chesapeake Energy Corp.)*, Nos. 20-33233, 20-3433, 2021 WL 4190266, at *1 (Bankr. S.D. Tex. Sept. 14, 2021) (noting the first successful horizontal well in the Eagle Ford Shale was completed in 2008); Bret Wells, *Please Give Us One More Oil Boom—I Promise Not to Screw It Up This Time: The Broken Promise of Casinghead Gas Flaring in the Eagle Ford Shale*, 9 TEX. J. OIL GAS & ENERGY L. 319, 348 (2013–2014) ("The Eagle Ford shale was not even shown to be viable until 2008[.]").

[9] The producers/lessees are petitioners Devon Energy Production Co., L.P., f/k/a GeoSouthern DeWitt Properties, LLC; BPX Properties (NA) LP; GeoSouthern Energy Corp.; and BPX Production Co.

[10] Paragraph numbering differs slightly between the Sheppard and Crain leases, but for consistency with the parties' briefing and the court of appeals' opinion, we follow the numbering scheme in the Sheppard leases.

> 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.[11]

The conflict here centers on more unconventional language found in Paragraph 3(c) and Addendum L, which provide:

> (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[ing] or marketing of the oil or gas, *then such deduction, expense or cost shall be added to . . . 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.
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> . . . .
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> L. ROYALTY FREE OF COSTS:
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> 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[[12]] of this

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[11] Emphases added.

[12] The Crain leases make Addendum L controlling over the corollaries to Paragraphs 3(a) and 3(b) but do not reference the corollary to Paragraph 3(c).

> 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 [133,] 135-36 (Tex. 1996).[13]

The interpretive question is whether this unusual lease language manifests contractual intent to include in the royalty base post-sale postproduction costs that are not part of the producers' gross sales proceeds.

As authorized by the Sheppard and Crain leases, the producers sell oil-and-gas production to unaffiliated third parties at various points downstream from the wellhead and pay royalty to the landowners on the gross proceeds "paid to" or "received by" the producers for those sales.[14] Consistent with both the contractual definition of "gross proceeds" and the ordinary meaning of that term,[15] the producers do not deduct—directly or indirectly—any expenses they incur to ready production for sale. Along these lines, when unaffiliated third-party processors have purchased production at the tailgate of the processing plant, and they have paid a lower price as a cost adjustment for having transported and

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[13] Emphases added. Underlining in original.

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

[15] *Chesapeake Expl., L.L.C. v. Hyder*, 483 S.W.3d 870, 873-74 (Tex. 2016) (observing that "gross" means without deductions and that, when a lease provides for royalty to be paid on the producer's sales proceeds, "the price-received basis for payment . . . is sufficient in itself to excuse the lessors from bearing postproduction costs"); *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 136 (Tex. 1996) ("The term 'gross proceeds' means that the royalty is to be based on the gross price received by [the lessee].").

processed gas on the producers' behalf, the producers have added the pre-sale transportation and processing expenses to the stated sales price before computing the landowners' royalty payment. Both sides agree this addition (or "add back") to the price the producers actually received is required and proper under the lease terms because those transportation and processing expenses are consideration accruing to the producers' benefit and, therefore, part of the producers' "gross proceeds."

The producers do not, however, include in the royalty calculation any post-sale costs to be incurred by unaffiliated third-party buyers after the point of sale. Although everyone agrees those costs are not part of the producers' gross proceeds, the exclusion of such costs from the royalty base is at the heart of the landowners' allegation that the producers have been underpaying royalties.

The royalty dispute arose when the landowners discovered that the producers sold oil under contracts setting the sales price—and thus the gross sales proceeds—by using published index prices[16] at market centers downstream from the point of sale and then subtracting $18 per barrel for the buyer's anticipated post-sale costs for "gathering and handling, including rail car transportation." The producers did not add the $18 adjustment to the royalty base and, instead, paid royalty only on their gross sales proceeds. As the landowners later learned, the

[16] Neither the producers nor the buyers set the index price. Rather, "[i]ndex prices are published by major industry publications and are based on actual, arms-length transactions in the geographic locations covered by the particular indices." *Union Pac. Res. Grp., Inc. v. Neinast*, 67 S.W.3d 275, 279 (Tex. App.—Houston [1st Dist.] 2001, no pet.).

producers also engaged in other transactions with complicated pricing formulas that similarly employed market-center index prices that were adjusted downward by flat, percentage, or volume amounts that the sales contracts sometimes—but not always—identified as accounting for the buyer's actual or anticipated post-sale postproduction costs.[17] The producers have never included any of those cost adjustments in the royalty calculation because they read the leases as requiring payment of royalties only on their gross sales proceeds.[18]

The landowners have no quarrel with how the producers have calculated gross proceeds, but they read the leases as requiring royalty to be paid on additional sums that are not gross proceeds and that do not inure to the producers' benefit: the buyer's actual or anticipated costs to enhance the value of production after the point of sale. In alleging royalties have been underpaid, the landowners cite the specially written language in Paragraph 3(c) and Addendum L as obligating the producers to pay royalty on those expenses by adding the deducted amounts to the producers' gross sales proceeds before calculating the royalty payment.

The landowners' sued for a declaration to that effect and sought damages for breach of contract. In teeing up the interpretive divide, the

[17] *See* 643 S.W.3d 186, 205-08 (Tex. App.—Corpus Christi–Edinburg 2020) (discussing and quoting the terms of various sales agreements the parties offered as exemplars of disputed issues).

[18] The leases provide two valuation options for oil-and-gas production, with gross proceeds as the required option for both if it produces a higher royalty payment. The parties agree that royalty has been properly paid on gross proceeds rather than on the leases' alternative valuation options.

landowners described Paragraph 3(c) as an "add-to-proceeds" clause that expressly contemplates royalty payments on sums exceeding gross proceeds while the producers dubbed it an "add back" clause that applies only to pre-sale expenses that have been deducted, directly or indirectly, from gross proceeds. Both sides interpreted Addendum L as supporting their conflicting constructions of Paragraph 3(c).

The landowners argued that the downward adjustments in the producers' sales contracts—whether labeled as accounting for post-sale postproduction costs or not—are, in the words of Paragraph 3(c), "reduction[s] or charge[s]" the producers are required to "add[] to" "gross proceeds" so that the landowners' royalty is "never" burdened by postproduction costs even "indirectly." According to the landowners, Paragraph 3(c)'s specially written language unburdens the royalty interest from postproduction costs irrespective of the producers' unilateral choices about where and in what condition to sell production and, in that way, affords the producers latitude in structuring their sales transactions without impacting the royalties payable to the landowners. As they explained it, if the producers had incurred those same costs to take production to market, there would be no dispute that the landowners' royalty would be calculated on the downstream value without reduction for those expenditures. In their estimation, Paragraph 3(c) makes the royalty calculation consistent no matter where the producers choose to sell production. This construction, they said, was supported by Addendum L's repetition of the mandate that royalty payments "shall never bear or be charged with" postproduction expenses "either directly or indirectly."

Seeing things quite differently, the producers characterized Paragraph 3(c) as mere surplusage that emphasizes the cost-free nature of a "gross proceeds" royalty by requiring them to "add back" only pre-sale postproduction costs that may have diminished the sales price. Although the producers have never disputed that parties to a mineral lease are free to allocate expenses in any way they see fit, they urged that the landowners' construction of Paragraph 3(c) is untenably contrary to the industry's expectation that a royalty free of postproduction costs means only those costs incurred up to the point of sale. In their view, nothing in the leases contemplates payment of a royalty on expenses to enhance the value of production after the point of sale to the first unaffiliated buyer. To the contrary, because Addendum L cites this Court's opinions in *Heritage Resources, Inc. v. NationsBank*[19] and *Judice v. Mewbourne Oil Co.*,[20] the producers understand that provision as emphasizing that the landowners' royalty is free of postproduction costs only between the well and the point of sale because both cases involved disputes about postproduction costs of that nature.

At the parties' request, the trial court severed and abated the breach-of-contract action. Then, in the declaratory-judgment action, the parties filed cross-motions for summary judgment on 23 "Stipulated Disputed Issues" involving, among other things, post-sale costs under a variety of pricing and marketing formulas set forth in the producers'

[19] 939 S.W.2d 118 (Tex. 1996).

[20] 939 S.W.2d 133 (Tex. 1996).

contracts with third-party buyers. For most issues, the parties submitted exemplar transactions for which the landowners claim additional royalties are owed. Some disputed issues involved agreements stating the purpose for a downward adjustment, while others did not. Some disputed issues involved adjustments based on the buyer's actual post-sale expenditures, while other adjustments were based on anticipated post-sale expenditures. The trial court ruled in the landowners' favor across the board.

The court of appeals affirmed in part and reversed and rendered in part.[21] Before considering the individual issues, the appellate court determined that the "highly unique" lease terms provide for a "proceeds-plus" royalty that "expressly [and unambiguously] contemplates the *addition* of certain sums to gross proceeds in order to arrive at the proper royalty base."[22] The court explained that Paragraph 3(c)'s "exceptionally broad" language—which is not limited to pre-sale costs or only those expenses incurred by the producers—could be enforced as written without rendering it surplusage.[23] To that end, the court concluded that the royalties payable by the producers under the Sheppard and Crain leases are, "in most circumstances," "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."[24]

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[21] 643 S.W.3d at 211.

[22] *Id.* at 189, 201, 205, & 211.

[23] *Id.* at 201-02.

[24] *Id.* at 205.

With the leases so construed, the court turned to the disputed issues, which it grouped into six broad categories: (1) price adjustments of a fixed amount with a stated purpose corresponding to "production, treatment, transportation, manufacturing, process[ing] or marketing" expenses; (2) price adjustments of a fixed amount without a stated purpose; (3) price adjustments based on the actual costs incurred by third-party purchasers for "production, treatment, transportation, manufacturing, process[ing] or marketing" expenses; (4) adjustments for volumes of gas used by the producers for their own operations and never sold to third parties; (5) adjustments for volumes of production deemed to be lost or unaccounted-for by third parties; and (6) value retained by the producers as a result of the application of contractually fixed recovery factors.[25] All of the disputed issues are set out individually in an appendix to the court of appeals' opinion.[26]

The court reversed and rendered summary judgment in the producers' favor on the 13 disputed issues comprising categories (2), (4), (5), and (6).[27] Because the landowners have not appealed the adverse judgment on those issues, we express no opinion as to their disposition. The only matters before this Court are the 10 disputed issues encompassed by categories (1) and (3)—price adjustments for a stated purpose—as to which the court of appeals affirmed summary judgment

[25] *Id.* at 205-10.

[26] *Id.* at 211-16 (omitting only the record citations).

[27] *Id.* at 206-11.

for the landowners.[28] The parties have agreed that all of the arrangements at issue involved costs incurred or to be incurred after the point of sale to an unaffiliated buyer.

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[28] *Id.* at 205-08. Exemplar contracts the parties cited in relation to the disputed issues comprising those categories include:

- Disputed Issue 2: A 2011 agreement for the sale of crude oil and condensate with the price per barrel set as a weighted average of published index prices "minus $18.00 gathering and handling, including rail car transportation" per barrel.
- Disputed Issue 4: A 2013 sale of crude oil from one producer to an unaffiliated producer, to be delivered into a specific pipeline, for a price based on a weighted average of sales "less transport, terminal and marketing costs."
- Disputed Issues 7 and 13: A 2010 "Gas Processing Agreement" under which a third-party processor agreed to process gas and to purchase 100% of the resulting natural gas liquids and 50% of any drip condensate "attributable to [the producer]'s gas." The price for both was set as a published index price "less [the processor'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."
- Disputed Issue 8: A 2012 "Gas Services Agreement" under which a third party agreed to gather and process gas production, purchase the resulting natural gas liquids, and return the remaining residue gas to the producer. The price for the natural gas liquids was set at a published index price "less" a "T&F fee" of "$0.104 per gallon."
- Disputed Issues 9 and 12: A 2010 "Gas Processing Agreement" between a third-party processor and a producer that includes reductions based on the processor's actual T&F cost.
- Disputed Issue 10: Various sales orders for natural gas liquids that set the purchase price as an average of published index prices "less" a "fixed fee" determined by a formula that

In affirming summary judgment as to these types of transactions, the court of appeals concluded that, unlike the category (2) issues in which contractual reductions had not been attributed to any of the types of costs specifically enumerated in Paragraph 3(c), the category (1) and (3) sales contracts involved downward adjustments specifically labeled as accounting for "production, treatment, transportation, manufacturing, process[ing] or marketing" expenses. The court concluded that summary judgment for the landowners was proper on the category (1) and (3) issues because the specified deductions fall

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"includes pipeline fee, fixed frac fee, truck transportation, terminalling fee and margins."

- Disputed Issue 11: A 2012 "Gas Processing Agreement" under which the buyer agreed to pay the producer on a monthly basis "ninety-two percent (92%) of the Producer Plant Products Value," which the contract defined as the volume of the plant products attributable to the producer times a published index price "minus the [T&F] Fee" applicable for that month.
- Disputed Issue 15: An arrangement under which a third-party processor agreed to gather and sell drip condensate delivered by the producer under a 2012 "Individual Transaction Confirmation" stating the processor would pay the producer 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 the processor's actual costs for "trucking, stabilization, and any other [T&F] fees."

The transaction referenced in Disputed Issue 15 also included a deduction for a flat-rate fee of $0.03 per gallon, and the court of appeals reversed the summary judgment as to that portion of the transaction because the agreement did not state that the fee corresponded to any category of postproduction costs, as contemplated by Paragraph 3(c). *See id.* at 207.

squarely within Paragraph 3(c)'s "added to . . . gross proceeds" requirement.[29]

In their petition for review, the producers contend they are entitled to judgment as a matter of law because the Sheppard and Crain leases are gross-proceeds leases that do not "plainly and in a formal way express a clear intent to create an exception to the basic principle [of oil-and-gas law] that royalties are not paid on post-sale expenses that may be incurred to resell production at market centers *after* oil and gas is sold by the lessee to generate the 'gross proceeds' from which royalties are paid."[30] In an alternative issue not presented to the court of appeals, the producers assert that, even if the appellate court's construction of the leases is otherwise correct, the court improperly held that Paragraph 3(c) requires them to include expenses for a specific type of processing—"transportation and fractionation"—in the royalty base.

II. Discussion

On cross-motions for summary judgment, each party bears the burden of proving its entitlement to judgment as a matter of law.[31] When the trial court grants one motion and denies the other, as in this case, we "determine all questions presented" and render the judgment

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[29] *Id.* at 205-08.

[30] On this issue, SM Energy Company and Texas Oil & Gas Association have submitted amicus briefs supporting the producers, and Texas Land and Mineral Owners Association has submitted an amicus brief supporting the landowners.

[31] *City of Garland v. Dall. Morning News*, 22 S.W.3d 351, 356 (Tex. 2000).

the trial court should have rendered.[32] Whether any party is entitled to summary judgment here turns on the proper construction of the mineral leases.[33] Interpretation of a mineral lease involves questions of law we consider de novo.[34]

As with any other contract, our fundamental objective is to ascertain the parties' intent as expressed in the leases.[35] In doing so, we construe the instruments as a whole, giving the language its plain, ordinary, and generally accepted meaning unless the context indicates the parties used terms in a technical or different sense.[36] To the extent possible, we strive to harmonize and give effect to all the lease provisions so that none will be rendered meaningless.[37] In doing so, we are cognizant that contracts should be construed "from a utilitarian standpoint" that is mindful of "the particular business activity sought to be served."[38]

When, as here, a contract can be given a definite and certain meaning, it is not ambiguous even though the parties advance

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[32] *Id.*

[33] *See BlueStone Nat. Res. II, LLC v. Randle*, 620 S.W.3d 380, 387 (Tex. 2021).

[34] *Id.*

[35] *Murphy Expl. & Prod. Co.–USA v. Adams*, 560 S.W.3d 105, 108 (Tex. 2018).

[36] *Id.*

[37] *Id.*

[38] *Kachina Pipeline Co. v. Lillis*, 471 S.W.3d 445, 450 (Tex. 2015) (quoting *Lenape Res. Corp. v. Tenn. Gas Pipeline Co.,* 925 S.W.2d 565, 574 (Tex. 1996)).

competing constructions.[39] Unambiguous contracts must be enforced as written without considering extrinsic evidence bearing on the parties' subjective intent.[40] In keeping with our commitment to freedom of contract, we will not rewrite the leases to "add to or subtract from [their] language" or to "interpolate constraints" not found in the unambiguous language.[41]

Applying these well-settled principles to the Sheppard and Crain leases, we agree with the lower courts that when the producers' dispositions of production include price adjustments with a stated purpose corresponding to "production, treatment, transportation, manufacturing, process[ing] or marketing" expenses, those amounts must be "added to" "gross proceeds" before calculating the landowners' royalty payments.

A.

The Sheppard and Crain leases are, to an extent, "gross proceeds" leases, so everyone agrees that the leases have departed from the usual rules by freeing the landowners' royalty from at least some postproduction costs. Concordant with the common understanding of the term, the Sheppard and Crain leases define "[g]ross proceeds (for royalty purposes)" as "the total monies and other consideration accruing to or paid the Lessee or received by Lessee for disposition or sale[.]" As

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[39] *URI, Inc. v. Kleberg County*, 543 S.W.3d 755, 764-65 (Tex. 2018).

[40] *Id.*

[41] *Id.* at 758, 769-70; *see Tenneco Inc. v. Enter. Prods. Co.*, 925 S.W.2d 640, 646 (Tex. 1996) ("We have long held that courts will not rewrite agreements to insert provisions parties could have included or to imply restraints for which they have not bargained.").

we have explained, "royalties computed on gross amounts received means royalties are paid based on point-of-sale proceeds without deduction of postproduction costs."[42] And when a lease provides for royalty to be paid on the producer's gross sales proceeds, "the price-received basis for payment . . . is sufficient in itself to excuse the lessors from bearing postproduction costs."[43] There is no dispute in this case that the producers have properly calculated their gross proceeds, including by increasing the amount received under a sales contract by "other consideration accruing to" the producers, such as pre-sale processing and transportation costs incurred by buyers on the producers' behalf.

But the leases also plainly require certain sums to be "added to" gross proceeds. The question is not whether an unaffiliated buyer's postproduction costs are gross proceeds under the leases or under the law. Of course, they are not. The question is whether the leases nonetheless require the producers to pay royalty on those costs.

The landowners cite no precedent requiring producers to pay royalty on postproduction costs incurred downstream from the point of sale. But the parties to a mineral lease could unquestionably make that agreement.[44] Indeed, absent an agreement to the contrary, a minority

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[42] *BlueStone Nat. Res. II, LLC v. Randle*, 620 S.W.3d 380, 391 (Tex. 2021).

[43] *Chesapeake Expl., L.L.C. v. Hyder*, 483 S.W.3d 870, 873-74 (Tex. 2016); *see BlueStone*, 620 S.W.3d at 389-91 (explaining the difference between gross-proceeds leases and net-proceeds leases).

[44] *See, e.g.*, *Yturria v. Kerr-McGee Oil & Gas Onshore, LLC*, 291 F. App'x 626, 627, 633-34 (5th Cir. 2008) (holding, in a dispute about whether the

of jurisdictions charge producers with paying royalties on a "marketable product"—meaning one that is both in a commercially useable condition and sold in a commercial marketplace—regardless of where and in what condition the product is actually sold.[45] Considering the obvious economic advantage such an arrangement provides to the royalty holder, it would not be unreasonable for Texas landowners to negotiate lease terms that provide for something similar.[46] Nor would it be

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lessor's royalty was burdened by post-sale postproduction costs, that the parties had agreed to base royalty not only on the lessee's revenue from gas production but on "all" revenue under "uniquely worded natural gas liquid royalty provisions" that had been modified as part of a settlement to delete language limiting the calculation of royalties to only the lessee's revenue).

[45] *See, e.g.*, *Wellman v. Energy Res., Inc.*, 557 S.E.2d 254, 264 (W. Va. 2001) ("[T]he duty to market embraces the responsibility to get the oil or gas in marketable condition and actually transport it to market."); *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 906 (Colo. 2001) (under the marketable product rule "the expense of getting the product to a marketable condition and location are borne by the lessee"); *accord* 30 C.F.R. §§ 1206.20, .55 (requiring lessees on federal or Native American lands to place oil-and-gas production in marketable form, defined as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a [typical] sales contract"); *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 725 (D.C. Cir. 2005) (noting that the federal Mineral Leasing Act and the rules adopted pursuant to the Act obligate lessees to put gas production in marketable condition at no cost to the federal lessor, so "[i]f a lessee sells 'unmarketable' gas at lower cost, the gross proceeds for purposes of royalty calculation must be increased to the extent that gross proceeds have been reduced because the purchaser, or any other person, is providing certain services to place the gas in marketable condition" (internal quotations omitted)).

[46] *See Petty Bus. Enters. v. Chesapeake Expl., L.L.C.* (*In re Chesapeake Energy Corp.)*, Nos. 20-33233, 20-3433, 2021 WL 4190266, at *6 (Bankr. S.D. Tex. Sept. 14, 2021) (construing an Eagle Ford Shale lease specifically requiring the lessee to add to the royalty base "any adjustment or reduction" for postproduction expenses that are "deducted by . . . the purchaser *for purposes of arriving at a price or value for Minerals*" (emphasis added)).

unreasonable for landowners to bargain for a fraction of the value at market rather than at the wellhead to avoid disputes about whether shared postproduction costs are reasonable. As in any contract dispute, our task is to determine how postproduction costs were allocated under these particular leases.[47]

The inescapably broad language in Paragraph 3(c) is clear in that regard. It requires "any reduction or charge" for postproduction costs that have been included in the producer's disposition of production to be "added to" gross proceeds so that the landowners' royalty "never" bears those costs even "indirectly." Paragraph 3(c) is not textually constrained to the expenses incurred by the seller or prior to the point of sale.[48] Rather, those costs are encompassed by Paragraphs 3(a) and 3(b), which require royalty to be paid on the producers' gross proceeds. A plain and natural reading of Paragraph 3(c) unambiguously contemplates royalty payable on an amount that may exceed the consideration accruing to the

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[47] *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 124 (Tex. 1996) ("[W]e are construing specific language in specific oil and gas leases. Parties to a lease may allocate costs, including post-production or marketing costs, as they choose. Our task is to determine how those costs were allocated under *these* particular leases." (internal citation omitted)).

[48] *Compare with* 6 WEST'S TEX. FORMS, *Minerals, Oil & Gas* § 3:26 (4th ed.) ("[L]essor's royalty share of oil and gas shall not bear any portion of the costs of producing, treating, processing, compressing, gathering, transporting or marketing lessor's share of production *incurred prior to the point of sale thereof*. Regardless of whether [the lease] calls for lessor's royalty to be calculated on the basis of the market price, the amount realized by lessee or the market value, or otherwise, and whether calculated at the well, at the point of sale or elsewhere, if such value would otherwise have any of such costs *incurred by lessee* deducted before such calculation is made, the amount of any such deduction shall be added to and included in such value before calculation of lessor's royalty share thereof." (emphases added)).

producers. Furthermore, because Paragraphs 3(a) and 3(b) alone suffice to free the royalty from all pre-sale costs, Paragraph 3(c) serves no purpose at all if not to allow the amount on which the royalty payment is calculated to exceed gross proceeds. As the court of appeals explained, Paragraph 3(c)'s prohibition on "indirectly" charging the royalty with postproduction costs could only refer to the buyer's post-sale expenditures because all other pre-sale expenditures—whether incurred directly or indirectly by the producers—are already included in gross proceeds.[49] An obvious and reasonable purpose for a provision like Paragraph 3(c) is to provide the producer with the flexibility to sell production at any point downstream of the well while discharging the landowners from the usual burden to share the costs of rendering production marketable—whether through direct expenditures or indirectly through a lower valuation at the producer's chosen point of sale.

Unable to avoid the breadth of the negotiated lease language, the producers argue that we must construe Paragraph 3(c) as mere surplusage because (1) payment of royalty on non-proceeds is so at odds with the usual expectations that it cannot be required when the leases do not state such an intent "plainly and in a formal way";[50] (2) the leases

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[49] 643 S.W.3d 186, 203 (Tex. App.—Corpus Christi–Edinburg 2020).

[50] *Wenske v. Ealy*, 521 S.W.3d 791, 797 (Tex. 2017) ("Parties are free to contract for whatever division of the interests suits them. Their intent, as expressed in the deed, controls. [But i]f they want their agreement to operate differently from this basic principle of mineral conveyance, . . . they should 'plainly and in a formal way express that intention.'" (quoting *Benge v. Scharbauer*, 259 S.W.2d 166, 169 (Tex. 1953))).

are replete with surplusage emphasizing that "gross" really means "gross," so the rule against avoiding surplusage holds no purchase; and (3) Addendum L, by citing the *Heritage Resources, Inc. v. NationsBank*[51] and *Judice v. Mewbourne Oil Co.*[52] opinions, demonstrates that the parties were concerned only with prohibiting deductions for the producer's postproduction costs, not the buyer's. These contentions do not withstand examination.

To assure "continuity and predictability" in oil-and-gas law,[53] it is incumbent on the courts to construe commonly used terms in a uniform and predictable way.[54] Lease agreements often "contain provisions that are standard throughout the oil and gas industry [that] have been judicially interpreted many times over many years."[55] "Careful adherence to those interpretations, and consistent application of them, is important to industry stability."[56] But there is nothing common, usual, or standard about the language in Paragraph 3(c), which is quite clear in expressing the intent to deviate from the usual

[51] 939 S.W.2d 118 (Tex. 1996).

[52] 939 S.W.2d 133 (Tex. 1996).

[53] *See Wenske*, 521 S.W.3d at 798 ("Yet we are acutely aware that parties who draft agreements rely on the principles and definitions pronounced by this Court. They rightly depend on us for continuity and predictability in the law, especially in the oil-and-gas field.").

[54] *See Heritage Res. Inc. v. NationsBank*, 939 S.W.2d 118, 129 (Tex. 1996) (Owen, J.) (plurality op.) ("In construing language commonly used in oil and gas leases, we must keep in mind that there is a need for predictability and uniformity as to what the language used means.").

[55] *French v. Occidental Permian Ltd.*, 440 S.W.3d 1, 8 (Tex. 2014).

[56] *Id.*

expectations regarding the allocation of postproduction costs. The parties "plainly and in a formal way" expressed their intent for the agreement to "operate differently" in two ways: first by requiring that royalties be paid on gross proceeds and then by requiring an *addition* to gross proceeds for the stated purpose of freeing the landowners' royalty from "any costs or expenses other than its pro rata share of severance or production taxes."[57] Contrary to the uniform and predictable understanding of these terms, the producers would have us construe "added to . . . gross proceeds" as the equivalent of "gross proceeds." A reasonable person would not read those words in the way the producers suggest.

As for avoiding surplusage, our construction of the leases does not rely on that construction canon and, instead, is only confirmed by it. We are enforcing the leases exactly as they are written, according to their plain language, which also happens to avoid giving rise to a redundancy. As we have said time and again, courts should avoid rendering contract language meaningless if possible, and it is possible and reasonable to construe the Sheppard and Crain leases without rendering

[57] *See Wenske*, 521 S.W.3d at 798 (observing that parties who want their agreement to "operate differently" from basic principles of mineral conveyances should "plainly and in a formal way" express the intent to make a different agreement). In a post-submission letter, the producers contend that this Court's opinions have applied an "industry-accepted meaning" of "costs and expenses" that refers only to the lessees' postproduction costs. While it is true that our precedent has involved disputes about allocation of the lessee/seller's postproduction costs, the producers cite no authority limiting the term in that way, and in any event, the meaning of these terms ultimately depends on how the parties used them in these leases. *See Burlington Res. Oil & Gas Co. v. Tex. Crude Energy, LLC*, 573 S.W.3d 198, 203 (Tex. 2019) (the contracting parties "may define post-production costs any way they choose").

Paragraph 3(c) nugatory. Parties may, of course, repeat themselves for emphasis or out of an abundance of caution, and the leases' lengthy definition of "gross proceeds" is a good example. But Paragraph 3(c) goes far beyond mere emphasis or repetition. It serves the distinct purpose of defining not what gross proceeds are but what must be added to that already defined term.

Finally, by citing and disclaiming the holdings in *Heritage Resources* and *Judice*, Addendum L—which the parties made controlling in the event of a conflict with Paragraph 3—does indeed manifest an intent to prohibit deductions for postproduction costs incurred by the producers, but it conveys no intent to override the "added to" language in Paragraph 3(c). Those contemporaneously issued opinions involved disputes about costs incurred between the well and the point of sale under leases or division orders providing for a royalty to be calculated on the value of production "at the well."[58]

In *Heritage Resources*, a plurality of the Court concluded that lease language purporting to prohibit "deductions" from royalties based on production valued "at the well" was ineffective to relieve the royalty interest of its usual obligation to share postproduction costs for the simple—and mathematical—reason that there aren't any

[58] *See Heritage Res.*, 939 S.W.2d at 121-23 (considering a clause prohibiting deductions of postproduction costs on a royalty based on "market value at the well"); *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 135-36 (Tex. 1996) (construing a lease with an unambiguous "market value at the well" royalty clause and a division order with contradictory language requiring "[s]ettlement for gas sold" to be based on "the gross proceeds realized at the well").

postproduction costs to "deduct" when value is determined at the well.[59] The *Heritage Resources* lease required royalty to be valued at the well, and by merely prohibiting deduction of postproduction costs, the provision under consideration there had done nothing to change the valuation point.

While neither *Heritage Resources* nor *Judice* involved a dispute about costs or expenses incurred by buyers after or downstream from the point of sale, that circumstance does not produce any inconsistency with Paragraph 3(c) and, thus, does not preclude enforcing that subsection as allowing the royalty base to exceed the producers' gross proceeds—exactly as it is written.[60] Notably, Justice Owen's concurring opinion in *Heritage Resources* (which became the plurality opinion on rehearing) explained that, to make a royalty free of postproduction costs, a lease could change the point at which it was valued or specify that something would be added to the royalty base.[61] The Sheppard and Crain leases do both.

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[59] *Heritage Res.*, 939 S.W.2d at 121-23 (Baker, J.); *id.* at 130-31 (Owen, J.) (plurality op.) (observing that "logic and economics tell us there are no marketing costs to 'deduct' from value at the wellhead" and "[a]ll costs would already be borne by the lessee"); *see BlueStone Nat. Res. II, LLC v. Randle*, 620 S.W.3d 380, 388 n.29 (Tex. 2021) (explaining how Justice Owen's concurring opinion became the plurality opinion on rehearing); *see also Judice*, 939 S.W.2d at 136.

[60] *See* 643 S.W.3d 186, 202 (Tex. App.—Corpus Christi–Edinburg 2020).

[61] *Heritage Res.*, 939 S.W.2d at 131 (Owen, J.) (plurality op.) ("There are any number of ways the parties could have provided that the lessee was to bear all costs of marketing the gas. If they had intended that the royalty owners would receive royalty based on the market value at the point of *delivery or sale,* they could have said so. If they had intended that *in addition to* the payment

We thus agree with the landowners that the Sheppard and Crain leases are "proceeds plus" leases that employ a two-prong calculation of the royalty base. First, the producers must properly determine their gross proceeds from selling the production, which by definition must be free of postproduction costs. Second, when the producers' contracts, sales, or dispositions state that enumerated postproduction costs or expenses have been deducted in setting the sales prices, those costs and expenses "shall be added to the . . . gross proceeds." The words chosen by the parties in these unique provisions demonstrate an intent and expectation that some amount may be added to the producers' gross proceeds when calculating royalties. This does not mean that any "reduction or charge" for postproduction costs in the *buyers'* subsequent dispositions must be included in the royalty base *ad infinitum*. To the contrary, Paragraphs 3(a), (b), and (c) contractually tether the royalty obligation to the time and place where gross proceeds are realized.

In so holding, we once again caution that, "[i]f anything is clear from the many Texas decisions dealing with royalty provisions, it is that different royalty provisions have different meanings,"[62] and the construction of an oil-and-gas lease must ultimately be based predominantly on the particular clause at issue construed within the

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of market value at the well, the lessee would pay all post-production costs, they could have said so. They did not. There is no direct statement in the leases that the royalty owners are to receive anything *in addition* to the value of their royalty, which is based on value at the well.").

[62] *Burlington Res.*, 573 S.W.3d at 206 (quoting *Warren v. Chesapeake Expl., L.L.C.*, 759 F.3d 413, 416 (5th Cir. 2014)).

context of the lease as a whole.[63] Today, we address only the specific language of the provisions before us as applied to the disputed issues on appeal.

B.

In their final issue, the producers contend that even if some post-sale postproduction costs must be included in determining the royalties payable to the landowners, the court of appeals improperly held that expenses for "transportation and fractionation" (T&F) are among them. The appellate court did not address this issue because the producers never argued that T&F costs should be treated differently than other post-sale postproduction costs. Issues not briefed in the appellate court are waived.[64]

Even if the issue were properly before us, it would fail on the merits. As the producers concede and their filings and summary-judgment evidence confirm, T&F is a "term of art" that refers to transporting raw gas products to a downstream location for fractionation, which is a type of processing to separate raw gas into purer natural gas liquids like ethane, butane, propane, isobutane, and natural gasoline.[65] Expenditures to "process" production are among the

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[63] *Endeavor Energy Res., L.P. v. Energen Res. Corp.*, 615 S.W.3d 144, 155 (Tex. 2020).

[64] *See Nall v. Plunkett*, 404 S.W.3d 552, 556 (Tex. 2013).

[65] *See* Patrick H. Martin & Bruce M. Kramer, WILLIAMS & MEYERS, MANUAL OF OIL AND GAS TERMS § 410.3 (Matthew Bender 2021) (defining "[f]ractionation" as "[a] process of separating various hydrocarbons from natural gas or oil as produced from the ground"); *see also Petty Bus. Enters., L.P. v. Chesapeake Expl., L.L.C. (In re Chesapeake Energy Corp.)*, Nos. 20-33233, 20-3433, 2021 WL 4190266, at *7 (Bankr. S.D. Tex. Sept. 14, 2021)

expressly enumerated postproduction costs that must be "added to" "gross proceeds" under Paragraph 3(c). Even so, the producers maintain that the failure to separately enumerate T&F as an expenditure encompassed by Paragraph 3(c) evinces the contracting parties' intent to exempt it from the obligation to add those costs to gross proceeds because other unique processes, like "treatment" and "manufacturing," are separately and expressly enumerated. This argument is fatally flawed because Paragraph 3(c) is exhaustive and unmistakably clear that the landowners' royalty is to be free of "any costs or expenses" in the producers' sales contracts, with the only exception being the landowners' "pro rata share of severance or production taxes." Because T&F charges are processing costs and not severance or production taxes, they are not excluded from Paragraph 3(c)'s ambit.

III. Conclusion

The Sheppard and Crain leases employ atypical lease language to unburden the landowners' royalty from "any costs or expenses" by requiring the producers to "add[] to . . . gross proceeds" all reductions or charges for the "expenses or costs of production, treatment, transportation, manufacturing, process[ing] or marketing" included in the producers' sales and marketing arrangements. The lease language is broad and without limitation to only those costs incurred up to the point of sale or by the producers. Because we must give effect to the language the parties chose, we affirm summary judgment for the

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(holding it "indisputable" that "the T&F Fee is a 'reduction for any cost or expense, including the cost or expense of producing, gathering, dehydrating, compressing, transporting, manufacturing, processing, treating or marketing'").

landowners on the disputed issues brought forward on appeal to this Court.

John P. Devine
Justice

OPINION DELIVERED: March 10, 2023