IN THE SUPREME COURT OF TEXAS

No. 17-0266

BURLINGTON RESOURCES OIL & GAS COMPANY LP, PETITIONER,

v.

TEXAS CRUDE ENERGY, LLC AND AMBER HARVEST, LLC, RESPONDENTS

ON PETITION FOR REVIEW FROM THE
COURT OF APPEALS FOR THE THIRTEENTH DISTRICT OF TEXAS

Argued October 9, 2018

JUSTICE BLACKLOCK delivered the opinion of the Court.

Amber Harvest, an affiliate of Texas Crude Energy, owns overriding royalty interests in oil and gas leases operated by Burlington Resources. For several years, Burlington made royalty payments only after charging the royalty holder its proportionate share of the post-production costs expended to bring the products from the wells to the point of sale. Texas Crude later sued Burlington, alleging that the parties' contracts prohibit Burlington from charging post-production costs to the royalty holder. Burlington contends that the contracts require the royalty holder to bear its share of post-production costs. All parties agree that the relevant contracts are unambiguous and therefore amenable to judicial interpretation.

The question before the Court resembles the question presented in *Chesapeake Exploration, L.L.C. v. Hyder*, 483 S.W.3d 870 (Tex. 2016), another case in which the question was whether a royalty interest bears its share of post-production costs. In *Hyder*, as in prior decisions, this Court has emphasized that "the effect of a lease is governed by a fair reading of its text." *Id.* at 876 (discussing *Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996)). We interpreted the contract language at issue in *Hyder* to create a royalty interest free from post-production costs. *Id*. *Hyder* and other decisions interpreting royalty agreements serve as informative guides for today's decision, but the decisive factor in each case is the language chosen by the parties to express their agreement. *See Heritage Res.*, 939 S.W.2d at 124 (Owen, J., concurring) ("Our task is to determine how those costs were allocated under *these* particular leases.").[1]

The contractual language at issue in this case differs from the language at issue in *Hyder*. The outcome also happens to be different. Construing the overlapping contractual provisions based on the language the parties chose, we conclude that Burlington may deduct post-production costs when calculating royalty payments. We therefore reverse the judgment of the court of appeals and remand the case to the trial court for further proceedings.

I. Factual and Procedural Background

Petitioner is Burlington Resources Oil & Gas Co. LP (Burlington). Respondents are Texas Crude Energy, LLC (Texas Crude) and its affiliate, Amber Harvest, LLC (Amber Harvest). In 2005, Burlington and Texas Crude executed a Prospect Development Agreement (PDA) and a Joint Operating Agreement (JOA). The agreements applied to leases in an Area of Mutual Interest (AMI) in the "Sugarloaf Prospect" located in parts of Live Oak, Karnes, and Bee Counties. Under

[1] Justice Owen's concurring opinion in *Heritage Resources* became the plurality opinion of the Court on rehearing. *See Hyder*, 483 S.W.3d at 875 & n.25.

the PDA, Burlington would operate the entire field, and each party would receive a percentage of the other's working interests in leases either party had previously acquired in the AMI. Burlington got 87.5% of the working interests, and Texas Crude got 12.5%. Each party agreed to offer the other these same percentages if it acquired future leases in the AMI. Under the PDA and JOA, Texas Crude received an overriding royalty interest, ranging from 0% to 6.25%, on leases within the AMI. Texas Crude retained an overriding royalty interest on leases it originated, and it assigned these interests to its affiliate, Amber Harvest.[2] On leases Burlington originated, Burlington assigned an overriding royalty interest to Texas Crude, and Texas Crude later assigned the interest to Amber Harvest. The overriding royalty interest assignments, whether from Burlington to Texas Crude or from Texas Crude to Amber Harvest, contained substantially identical language. Each assignment includes a clause the parties call the Granting Clause and a clause the parties call the Valuation Clause. These clauses describe the disputed royalty interests.

The Granting Clause provides:

> [Assignor] does hereby ASSIGN, TRANSFER AND CONVEY unto [Assignee], its successors and assigns, those certain overriding royalty interests, as set out below, in the quantity described below in all oil, gas, condensate, drip gasoline and other hydrocarbons that may be produced and saved from those lands covered by those certain oil, gas and mineral leases described in Exhibit "A" attached hereto and made a part hereof for all purposes, and pursuant to the terms and conditions of the said oil, gas and mineral leases. Said overriding royalty interests shall be delivered to ASSIGNEE <u>into the pipelines</u>, tanks or other receptacles with which the wells may be connected, free and clear of all development, operating, production and other costs. However, ASSIGNEE shall in every case bear and pay all windfall profits, production and severance taxes assessed against such overriding royalty interest.

[2] For simplicity we refer to the Respondents generally as Texas Crude when the difference between the two entities is immaterial.

(emphasis added).

The Valuation Clause provides that the assignment "shall be subject to the following terms and conditions":

> The overriding royalty interest share of production shall be delivered to ASSIGNEE or to its credit <u>into the pipeline</u>, tank or other receptacle to which any well or wells on such lands may be connected, free and clear of all royalties and all other burdens and all costs and expenses except the taxes thereon or attributable thereto, <u>or</u> ASSIGNOR, <u>at ASSIGNEE's election</u>, shall pay to ASSIGNEE, for ASSIGNEE's overriding royalty oil, gas or other minerals, the applicable percentage of the <u>value</u> of the oil, gas or other minerals, as applicable, produced and saved under the leases. "<u>Value</u>", as used in this Assignment, shall refer to <u>(i) in the event of an arm's length sale on the leases, the amount realized from such sale of such production and any products thereof, (ii) in the event of an arm's length sale off of the leases, the amount realized for the sale of such production and any products thereof</u>, and (iii) in all other cases, the market value at the wells.

(emphasis added).

The parties agree on two points that simplify the analysis: (1) the sales were arms-length, and (2) Amber Harvest took its royalty payments in cash, not in kind.[3]

For nine years, Amber Harvest and Texas Crude accepted royalty payments reflecting a deduction for the royalty holder's share of post-production costs. Disagreements later arose regarding calculation of royalty payments and other matters. Citing the Valuation Clause's definition of "Value," Texas Crude demanded a percentage of the sales price derived from arms-length sales with no deduction for post-production costs. Under this theory, Texas Crude sought

[3] Texas Crude contends that all the sales were off the leases, while Burlington contends the sales were both on and off the leases. Because the relevant agreements establishing the royalty interest apply identical rules to arms-length sales whether they occur on the lease or off the lease, this distinction does not affect our inquiry into whether Burlington may deduct post-production costs when calculating royalty payments for arms-length transactions. The location of the sales may, however, affect the amount of post-production costs expended. Off-lease sales would presumably involve greater post-production costs than on-lease sales near the well. The record before the Court does not establish the location of each sale. We reach no conclusions on the amount of post-production costs associated with any given sale or on the amount Burlington must pay the royalty holder.

recovery of previously underpaid royalties. Burlington claimed the parties' agreements—including the Granting Clause, the Valuation Clause, the PDA, and the JOA—when read together entitle it to deduct Texas Crude's share of post-production costs from the royalty payments. On cross-motions for partial summary judgment on this contract-interpretation question, the trial court ruled for Texas Crude, concluding that the agreements do not permit Burlington to deduct post-production costs. The trial court order decided only "the liability question of whether post-production costs are deductible by Burlington when calculating overriding royalty payments to Amber Harvest." The trial court did not address other claims and did not address the amount of damages owed to Texas Crude. Recognizing the existence of "substantial grounds for difference of opinion regarding whether post-production costs are deductible by Burlington when calculating overriding royalty payments to Amber Harvest," the trial court authorized an interlocutory appeal under TEX. CIV. PRAC. & REM. CODE § 51.014(d).

The court of appeals accepted the appeal, *see id.* § 51.014(f); TEX. R. APP. P. 28.3, and affirmed the trial court's judgment, *Burlington Res. Oil & Gas Co. LP v. Texas Crude Energy, LLC*, 516 S.W.3d 638, 649 (Tex. App.—Corpus Christi 2017).

II. Analysis

The standard rules of contract construction apply to the overriding royalty interest assignments[4] at issue. The Court's task is to "ascertain the true intentions of the parties as expressed in the writing itself." *Italian Cowboy Partners, Ltd. v. Prudential Ins. Co. of Am.*, 341

[4] The parties executed assignments of overriding royalty interests as well as assignments of working interests and perhaps other interests. Unless otherwise indicated, all references herein to "assignments" are references to overriding royalty interest assignments from Burlington to Texas Crude or from Texas Crude to Amber Harvest.

S.W.3d 323, 333 (Tex. 2011). This analysis begins with the contract's express language. *Id.* We "examine and consider the entire writing in an effort to harmonize and give effect to all the provisions of the contract so that none will be rendered meaningless." *Seagull Energy E & P, Inc. v. Eland Energy, Inc.*, 207 S.W.3d 342, 345 (Tex. 2006) (quoting *Coker v. Coker*, 650 S.W.2d 391, 393 (Tex. 1983)) (emphasis omitted). We "give terms their plain, ordinary, and generally accepted meaning unless the instrument shows that the parties used them in a technical or different sense." *Heritage Res.*, 939 S.W.2d at 121. These guidelines apply to oil and gas agreements just as they would to any other contract. *See, e.g.*, *id.* (articulating rules of contract construction applicable to a royalty agreement).

A. "Post-Production Costs"

In general, oil and gas royalty interests are free of production expenses but "usually subject to post-production costs, including taxes . . . and transportation costs." *Hyder*, 483 S.W.3d at 872 (quoting *Heritage Res.*, 939 S.W.2d at 122). As in most situations, "the parties may modify this general rule by agreement." *Id.*; *accord French v. Occidental Permian Ltd.*, 440 S.W.3d 1, 3 (Tex. 2014). Before examining the parties' arguments, we address briefly what it means for a royalty interest to be "subject to post-production costs."

Although parties to an agreement may define post-production costs any way they choose, the term generally applies to processing, compression, transportation, and other costs expended to prepare raw oil or gas for sale at a downstream location. *Hyder*, 483 S.W.3d at 875–76. Products on which post-production costs have been expended are generally more valuable than products straight out of the well. *See, e.g.*, *French*, 440 S.W.3d at 3 ("[P]ostproduction processing that makes the gas marketable enhances its value after it leaves the well."). It follows that a royalty on products at their downstream point of sale is more valuable than a royalty on the same products at the well. *See id.* The crux of the parties' dispute is whether Texas Crude holds royalties on products at the well (Burlington's position) or on treated and transported products at their downstream point of sale (Texas Crude's position).

The question of how to allocate post-production costs can arise when the sale used to calculate the royalty payment is downstream from the point at which the royalty interest is valued. If the royalty is valued at the well but the sale takes place after the product has been processed and transported, the product sold is generally of greater value than the product in which the royalty holder has an interest. *See id.* In this situation, the sales price must be adjusted to properly calculate the royalty payment. *See Heritage Res.*, 939 S.W.2d at 122–23. Courts have recognized that one way to make this adjustment is to subtract the costs of bringing the product to the market (the post-production costs) from the sale price obtained at the market. *E.g.*, *id.* at 122 (explaining that one method of calculating value at the well "involves subtracting reasonable post-production marketing costs from the market value at the point of sale"); *French*, 440 S.W.3d at 3 ("The market price of the processed gas reflects the value of the unprocessed gas at the well only if reasonable postproduction processing costs are deducted.").[5]

Of course, the parties are free to contract for a royalty calculated based not on the value of the oil and gas at the well but on its value at the point of sale. *Heritage Res.*, 939 S.W.2d at 131 (Owen, J., concurring) ("If [the parties] had intended that the royalty owners would receive royalty

[5] If the sale giving rise to the royalty payment took place at an upstream point before the expenditure of post-production costs, then the sales price would already reflect the lower value of the product at that stage of development, and there would be no costs to deduct. The sales price would already reflect the raw product's lower value. *See French*, 440 S.W.3d at 3; *Heritage Res.*, 939 S.W.2d at 130 (Owen, J., concurring).

based on the market value at the point of *delivery or sale*, they could have said so.") This is how Texas Crude interprets its royalty interest. The holder of such a royalty would generally not be responsible for post-production costs since those costs would have already been expended prior to the sale. *See, e.g.*, *Hyder*, 483 S.W.3d at 873.

Burlington emphasizes the oft-repeated statement that royalty interests usually bear post-production costs. *Hyder*, 483 S.W.3d at 872; *Heritage Res.*, 939 S.W.2d at 122. Texas Crude does not quibble with this general proposition. Instead, it contends the parties contracted otherwise by specifying that the royalty would be paid after sale of the product based on the "amount realized from such sale," not based on the product's value at the well. This Court and other courts have recognized that an agreement to value a royalty interest based on the "amount realized," or similar language, can grant the royalty holder the right to a percentage of the sale proceeds with no adjustment for post-production costs. The majority opinion in *Hyder* stated that a royalty provision giving lessors 25% of "the price actually received by Lessee" disallowed deduction of post-production expenses because "it is based on the price [lessee] actually received for the gas through its affiliate, Marketing, after postproduction costs have been paid" and because "the price-received basis for payment in the lease is sufficient in itself to excuse the lessors from bearing postproduction costs." 483 S.W.3d at 871, 873. The *Hyder* dissent agreed with the majority that this royalty of "25% of the price actually received . . . does not bear post-production costs." *Id.* at 877 (Brown, J., dissenting). *See also 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."); *Warren v. Chesapeake Exploration, L.L.C.*, 759 F.3d 413, 417 (5th Cir. 2014) (Owen, J.) (explaining that, under Texas law, "[h]ad the lease provided only that the [Lessors] are to receive 22.5% of the amount realized by Lessee, there would be little question that the [Lessors] would be entitled to 22.5% of the sales contract price that the lessee received, with no deduction of post-production costs.").

According to Texas Crude, the "amount realized" language in the Valuation Clause creates the kind of cost-free royalty mentioned in *Hyder* and *Warren*. First, it gives Texas Crude the option to take its royalty in cash, which the parties agree Texas Crude has done. Next, it requires Burlington to "pay to [Amber Harvest] . . . the **<u>value</u>** of the oil, gas or other minerals, as applicable, produced and saved under the leases" (emphasis added). Finally, it defines "Value" as:

> <u>(i) in the event of an arm's length sale on the leases, the amount realized from such sale of such production and any products thereof, (ii) in the event of an arm's length sale off of the leases, the amount realized for the sale of such production and any products thereof</u>, and (iii) in all other cases, the market value at the wells.

(emphasis added). The parties agree the relevant sales were arms-length, so either (i) or (ii) applies. Both (i) and (ii) define "value" as the "amount realized" for the sale. These subparts of the definition make no mention of an upstream valuation point or responsibility for post-production costs. Further, as Texas Crude argues, subparts (i) and (ii) reference "any products thereof," and subpart (ii) also references sales "off the leases." As Texas Crude reads these provisions, they necessarily refer to downstream sales since products from production at the well occur downstream from the well, as do sales off the lease. Texas Crude is correct that for the arms-length cash sales at issue, the provision boils down to an agreement that Burlington "shall pay to ASSIGNEE . . . the applicable percentage of . . . the amount realized for the sale." The court of appeals concluded that this language creates a royalty free of post-production costs. 516 S.W.3d at 647. Viewed in isolation, the Valuation Clause's definition of "Value" provides considerable support for this position. *See, e.g.*, *Warren*, 759 F.3d at 417 (stating that an "amount realized" clause, standing alone, would create a royalty interest free of post-production costs).

But we must examine the entire Valuation Clause in its context and in conjunction with other clauses to which the parties agreed, including the immediately preceding Granting Clause. *Seagull Energy*, 207 S.W.3d at 345; *Heritage Res.*, 939 S.W.2d at 121 ("[W]e examine the entire document and consider each part with every other part so that the effect and meaning of one part on any other part may be determined."). We have never held that an "amount realized" valuation method frees a royalty holder from its usual obligation to share post-production costs even when the parties have agreed to value the royalty interest at the well. The court of appeals incorrectly suggested otherwise. It stated, "Even assuming that, under the granting clause, the [royalty] is generally to be delivered 'at the well,' the parties are still free to allocate post-production costs as they see fit." 516 S.W.3d at 647 (citing *Hyder*, 483 S.W.3d at 874). This statement by the court of appeals misunderstands our decision in *Hyder*. 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. *E.g.*, *Heritage Res.*, 939 S.W.2d at 123; *id.* at 129 (Owen, J., concurring); *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 136 (Tex. 1996); *Warren*, 759 F.3d at 417–18. This is generally the case even when the agreement calls for payments based on the "amount realized" or "proceeds." *Id.* Allowing the holder of an "at the well" royalty to escape his responsibility for post-production costs would improperly convert the royalty interest from a royalty on raw products at the well to a royalty on refined, downstream products. *Id.*

B. The Parties' Agreements

With these observations in mind, the dispositive question in this case is whether the parties agreed to an "at the well" valuation point or its equivalent. If they did, Burlington is right that it may deduct post-production costs when calculating royalty payments based on downstream sales of treated and transported products.[6] If they did not, Texas Crude is entitled to a percentage of the downstream sales price, without deductions, under the plain language of the Valuation Clause. This question must be answered based on the language used in the agreements binding these parties. *See Warren*, 759 F.3d at 416 ("[I]f anything is clear from the many Texas decisions dealing with royalty provisions, it is that different royalty provisions have different meanings."). Both parties make plausible arguments. Ultimately, we are persuaded that Burlington's position is more faithful to all of the contractual language chosen by the parties and more aligned with the parties' intent as expressed in writing.[7]

As a preliminary matter, Burlington emphasizes the course of the parties' performance of the agreements. It alleges that Texas Crude accepted Burlington's practice of deducting post-production costs for years before raising an objection. But both parties moved for partial summary judgment under the theory that the agreements are unambiguous. We agree. Where contracts are

[6] For royalty payments based on sales at the well, there would presumably be little or no post-production costs to deduct since none have been incurred.

[7] Burlington suggests that it should not be bound by language in assignments between Texas Crude and its affiliate Amber Harvest, assignments to which Burlington was not a party. As discussed above, under the various agreements Burlington would either obtain a lease in the AMI and assign an overriding royalty interest to Amber Harvest, or Texas Crude would originate the lease, retain a royalty interest, and assign that interest to Amber Harvest. Burlington was not a party to assignments from Texas Crude to Amber Harvest. Texas Crude argues that the critical language of all the assignments is identical and that Burlington drafted the language. Because we are ultimately persuaded by Burlington's understanding of its obligations under either set of assignments, we need not consider whether Texas Crude's interpretation of the assignments would bind Burlington even in assignments to which Burlington is not a party.

unambiguous, we decline to consider the parties' course of performance to determine its meaning. *Frost Nat'l Bank v. L & F Distribs., Ltd.*, 165 S.W.3d 310, 313 n.3 (Tex. 2005); *E. Montgomery Cty. Mun. Util. Dist. No. 1 v. Roman Forest Consol. Mun. Util. Dist.*, 620 S.W.2d 110, 112 (Tex. 1981) (per curiam). Burlington would need to contend the agreements are ambiguous before it could rely on extrinsic course-of-performance evidence. It has not done so.

Burlington makes other, more persuasive arguments for its construction. Burlington points to the Granting Clause's provision that "overriding royalty interests shall be delivered to ASSIGNEE into the pipelines, tanks or other receptacles with which the wells may be connected." Burlington argues that requiring delivery of the interest "into the pipelines, tanks, or other receptacles" has the effect of requiring valuation of the interest "at the well." Courts have often interpreted the phrase "at the well" or "at the wellhead" to establish a wellhead valuation point, which generally requires the royalty holder to bear post-production costs. *See Heritage Res.*, 939 S.W.2d at 126–30 (Owen, J., concurring) (discussing Texas and out-of-state decisions). Texas Crude counters that because the assignments make the Granting Clause "subject to" the Valuation Clause, the Valuation Clause controls. According to Texas Crude, the Valuation Clause entitles it to a percentage of the "amount realized" from the sale without deduction of post-production costs.

But even if we consider only the Valuation Clause, it too contains an "into the pipeline" provision nearly identical to that found in the Granting Clause. The Valuation Clause provides: "The overriding royalty interest share of production shall be delivered to ASSIGNEE or to its credit into the pipeline, tank or other receptacle to which any well or wells on such lands may be connected . . . ." Burlington urges that "into the pipeline, tank or other receptacle" identifies the valuation point for the royalty. This valuation point, according to Burlington, is essentially the same as the "at the well" valuation point addressed in our previous decisions. *See Hyder*, 483 S.W.3d at 873 ("The oil royalty bears postproduction costs because it is paid on the market value of the oil at the well."); *Heritage Res.*, 939 S.W.2d at 122–23; *id.* at 129 (Owen, J., concurring); *Judice*, 939 S.W.2d at 135–36; *Warren*, 759 F.3d at 417.

The court of appeals declined to address the meaning of "into the pipeline, tank, or other receptacle." It reasoned that the "amount realized" calculation method forecloses deduction of post-production costs "[e]ven assuming that, under the Granting Clause, the [royalty interest] is generally to be delivered 'at the well.'" 516 S.W.3d at 647. As explained above, this reasoning misinterpreted our prior decisions involving "at the well" valuation points. *See Heritage Res.*, 939 S.W.2d at 130 (Owen, J., concurring). A royalty on production valued at the well does not include the value added by post-production costs. *Id.* 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. *Id.* If Burlington is correct that the Granting Clause and the Valuation Clause establish the equivalent of an "at the well" valuation point, then Burlington is also correct that it may subtract post-production costs from downstream sales prices when calculating royalty payments.

The outcome of this case therefore turns on whether Burlington correctly interprets the "into the pipeline" provisions. Textually, Burlington's view is defensible. The agreements twice provide that the royalty interest "shall be delivered . . . into the pipelines, tanks, or other receptacles." A sensible reading of this rather abstruse provision is that the "pipelines, tanks, or other receptacles" are the physical spot at which Texas Crude's interest in the products arises. Moreover, several authors familiar with industry practices seem to agree with Burlington that a provision for delivery "into the pipeline" contemplates valuation at the well and therefore authorizes deduction of post-production costs.[8] One treatise states that under an agreement "providing for delivery 'free of cost *in the pipe line* to which Operator may connect his wells,' the expense of transportation or of treating oil or gas or of compressing gas to make it deliverable must be shared by the owner of the nonoperating interest." This language "suggests that the parties assumed that a pipe line connection at the well would be available," and the lessor's duties "will not include the burden of bearing the expense of treating, compressing or transporting [the nonoperator's] share of production." 3 HOWARD R. WILLIAMS & CHARLES J. MYERS, OIL AND GAS LAW § 646.2 (Patrick H. Martin & Bruce M. Kramer, eds., 2018) (footnote omitted). Another treatise noted, as a general matter, "[i]f the royalty clause provides for delivery of royalty gas to the lessor's credit free of cost in the pipeline to which the well is connected, the parties contemplate a delivery of royalty gas at the well." 3 EUGENE KUNTZ, TREATISE ON THE LAW OF OIL AND GAS § 40.5(a) (1989). Another commentator similarly recognized an equivalence between "in the pipe line" and "at the wells" clauses, noting that "some leases provide that the royalty oil may be delivered in the pipe line to which the wells may be connected, 'or at the wells,' or 'into storage tanks.' It would seem, under this clause, that the lessee's obligations are at an end when he has made a delivery at the place designated, and that the expense of storage and transportation thenceforth must be borne by the lessor." A. W. Walker, Jr., *Nature of the Property Interests Created by an Oil and Gas Lease in Texas*, 10 TEX. L. REV. 291, 313 (1932). While the parties

[8] In interpreting unambiguous mineral-interest deeds and contracts, we sometimes refer to treatises and other scholarly sources that provide views on the meaning of technical terms or terms commonly used by the industry. *E.g.*, *Wenski v. Ealy*, 521 S.W.3d 791, 796 (Tex. 2017); *Tittizer v. Union Gas Corp.*, 171 S.W.3d 857, 861 (Tex. 2005) (per curiam); *Temple-Inland Forest Prods. Corp. v. Henderson Family P'ship, Ltd.*, 958 S.W.2d 183, 186 (Tex. 1997); *Heritage Res.*, 939 S.W.2d at 121–22.

point to no judicial decision interpreting an "into the pipeline" clause like the one at issue here, these commentaries lend further credence to Burlington's textually defensible understanding of this contractual term.

Burlington finds further support for its position in the JOA, which the parties executed at the outset of their venture. Burlington contends that the following provision in the JOA is consistent with its interpretations of the Granting Clause and Valuation Clause:

> Each party shall have the right but not the obligation to take in kind or separately dispose of its proportionate share of the oil and gas produced from the Contract Area . . . . In the event any party shall fail to make the arrangements necessary to take in kind or separately dispose of its proportionate share of the oil and/or gas produced from the Contract Area, Operator shall have the right, subject to the revocation at will by the party owning it, but not the obligation, to purchase such oil and/or gas or sell it to others at any time and from time to time, and shall account to such party for the <u>actual net proceeds</u> received for such production if sold to a non-affiliated third party in an arm's length transaction, or the current market price if purchased by Operator or an affiliate of Operator.

(emphasis added). Burlington argues that "actual net proceeds" from a sale means net of post-production costs. We agree that this language provides additional support to Burlington's view that the royalty payments should be made net of post-production costs. Burlington does not argue that the JOA would control over contrary language in the assignments. Instead, it argues that our interpretation of the assignments should take the JOA into account and attempt to harmonize its provisions with the assignments. This is correct. "Under generally accepted principles of contract interpretation, all writings that pertain to the same transaction will be considered together, even if they were executed at different times and do not expressly refer to one another." *DeWitt Cty. Elec. Coop., Inc. v. Parks*, 1 S.W.3d 96, 102 (Tex. 1999); *accord Fort Worth Indep. Sch. Dist. v. City of Fort Worth*, 22 S.W.3d 831, 840 (Tex. 2000). In addition to this general principle in favor of harmonizing related agreements, here some of the assignments are expressly made "pursuant to the terms and conditions of" the JOA or the PDA. The PDA is "subject to the terms of" the JOA. And the JOA provides that subsequent transfers and assignments of any party's interests shall be subject to the JOA. All this express language indicates that the parties intended their agreements to be construed together. We should therefore consider the JOA when construing the assignments. The JOA contemplates that each party will account to the other for the "actual net proceeds received from such production." We have previously interpreted a "net proceeds" royalty provision to authorize deduction of post-production costs. *Judice*, 939 S.W.2d at 137. Thus, the JOA appears to contemplate, albeit obliquely, that later-assigned royalty interests would be calculated net of post-production costs. This lends additional support to Burlington's view that the assignments should be interpreted to create a royalty that bears post-production costs.

The court of appeals reasoned that the later executed assignments of royalty interests override the JOA under the "merger doctrine." *Burlington Res.*, 516 S.W.3d at 646–47. The merger doctrine provides that "[w]hen a deed is delivered and accepted as performance of a contract to convey, the contract is merged in the deed." *Alvarado v. Bolton*, 749 S.W.2d 47, 48 (Tex. 1988). Whether the parties intended the relatively brief assignment agreements to render the JOA—and its scores of highly detailed provisions—a nullity is questionable. *See Fish v. Tandy Corp.*, 948 S.W.2d 886, 898 (Tex. App.—Fort Worth 1997, pet. denied) (stating that application of merger doctrine is "largely a matter of intention of the parties"). And even if the merger doctrine *could* apply to these agreements, we need not consider it here. The doctrine operates when earlier contracts "are contradicted in the deed." *Alvarado*, 749 S.W.2d at 48. Because the JOA is consistent with our interpretation of the assignments, the merger doctrine is inapplicable.

Texas Crude argues that the "net proceeds" language from the JOA only applies to working interests, not overriding royalty interests. But we see no such express limitation in the JOA. To the contrary, the JOA provides for overriding royalty interests to Texas Crude[9] and applies to "[e]very sale, encumbrance, transfer or other disposition made by any party." Further, the assignments of overriding royalty interests state that they are "made pursuant to the terms and conditions" of the JOA or the PDA. And the PDA states that "[a]ll interests acquired in the AMI shall be subject to the terms of [the] JOA."

Texas Crude understands the "into the pipeline" provisions in the Valuation and Granting Clauses to apply only to in-kind transfers. Under this reading, the first portion of the Valuation Clause applies only to in-kind transfers, while the rest of the clause applies only to cash royalties. This reading is not absurd, but for several reasons it is less convincing than the alternative. First, while oil and gas agreements are not known for their clarity and simplicity, the parties surely could have used the words "in kind" or similar words if they intended to create one set of rules for in-kind royalties and another for in-cash royalties. The JOA explicitly references in-kind transfers, as noted above, showing that the parties were capable of using that term when needed. Second, Texas Crude's construction renders the second sentence of the Granting Clause—which contains the "into the pipeline" provision—ineffective except in the unusual circumstance that the royalty holder chooses to take delivery of the interest in kind. Texas Crude never took its overriding royalty in kind, yet it understands the second sentence of the Granting Clause to apply only to hypothetical in-kind transactions. But nothing in the Granting Clause's second sentence suggests

[9] For example, Article III(D) of the JOA governs the effect of creation of subsequent or undisclosed interests—including overriding royalty interests—on the parties. Article XV(K)(4) gives Texas Crude the right to retain or be assigned overriding royalty interests or all leasehold interests within the AMI.

it was intended to apply only to a small subset of transactions. To the contrary, the Granting Clause is the opening provision of the assignment and reads like a general statement of the nature of the royalty interest conveyed. It makes no distinction between in-kind and in-cash royalties, and it provides that the "overriding royalty interests shall be delivered to ASSIGNEE into the pipelines, tanks or other receptacles with which the wells may be connected." On its face, this provision applies to "the overriding royalty interests," not to a subset or category of them. Texas Crude's proposed limitation of the provision to in-kind transfers would relegate its broadly applicable language to irrelevant surplusage in most instances. On the other hand, Burlington's view that the "into the pipeline" provision creates an "at the well" valuation point gives the provision the broad effect it seems intended to have and allows the provision to be applied to the actual transactions that occurred among these parties.[10]

Another problem with Texas Crude's interpretation is that it makes responsibility for post-production costs—and therefore the value of the royalty—dependent on whether Burlington conducts arms-length sales or sells to an affiliate. If Burlington makes a non-arms-length sale to an affiliate, then under the Valuation Clause Texas Crude would only receive the "market value at the wells." But in the case of an arms-length sale, according to Texas Crude, Burlington cannot deduct post-production costs and Texas Crude receives a share of the proceeds regardless of how

[10] Of course, neither party advocates the most literal reading of the "into the pipeline" provision, which mandates an absurdity. How can the royalty interest—not the oil itself but the royalty *interest*, an incorporeal concept—be "delivered . . . into the pipelines, tanks, or other receptacles"? We conclude that the rules of contract construction favor Burlington's interpretation of this recondite clause. But the parties could have saved considerable time, money, and heartache if their cryptic language had truly been "delivered . . . into the . . . receptacle[]." It could then have been re-written to say exactly what the parties intend, without resort to industry jargon, outdated legalese, or tenuous assumptions about how judges will interpret industry jargon or outdated legalese. If you can't understand what your contract means without asking the lawyer who wrote it, you should not be surprised later if judges—who can't just take your lawyer's word for it—also have trouble understanding what it means.

much has been expended to increase the value of the product. Texas Crude's construction would encourage the operator, Burlington, not to make arms-length sales, an odd result that Texas Crude as royalty holder would not likely have bargained for *ex ante*.

Further, under Texas Crude's construction, if Burlington made a sale to a third party "on the lease," pricing the sale at the wellhead price and leaving the third party to make post-production enhancements, the royalty payment would be based on the wellhead price because the "amount realized" would be based on that price. But if Burlington conducted its own post-production enhancements, it would not be allowed to deduct the costs of these enhancements, and Texas Crude would receive a higher royalty. We can see no reason why the parties would reward the operator for leaving post-production efforts to a third party and penalize the operator for doing these enhancements itself. And we can see no reason why parties would make the nature of the royalty holder's interest dependent on decisions by the operator over which the royalty holder has no influence.

Yet another strange result would follow from Texas Crude's construction. If, as Texas Crude contends, the references in the Granting and Valuation Clauses to delivery "into the pipelines, tanks or other receptacles" only cover in-kind transfers, then an in-kind distribution would give Texas Crude its royalty percentage of production at the well. But an arms-length sale off the lease would give Texas Crude a higher royalty based on the downstream price after post-production enhancements. Under this construction, Burlington would be penalized for marketing Texas Crude's share of production, finding a third-party buyer, transporting the product, and performing other post-production enhancements. It is difficult to fathom why either party would have intended such a result.

Of course, the parties were free to contract for these odd results, and we have recognized "that lease drafters are not always driven by logic." *Hyder*, 483 S.W.3d at 874. But these parties did not do that. Our best reading of the contractual text supports Burlington's position. The implausible results that flow from Texas Crude's position merely reinforce this result.

If, as Burlington contends, the assignments require valuation at the well in all cases, one might question why the Valuation Clause has three subparts—two specifying valuation based on the "amount realized" and the last based on "market value at the wells." Burlington plausibly argues that all subparts place the valuation point at the well, but for *arms-length* sales the amount realized from actual sales must be used to calculate the value at the well. On the other hand, for sales to an affiliate—which the royalty holder might worry do not reflect full market value—the valuation of the royalty is not based on the actual sales price but instead requires an objective calculation of market value. *See Heritage Res.*, 939 S.W.2d at 122 (describing comparable sales as the most desirable method of calculating market value at the well); *id.* at 130 (Owen, J., concurring).

Finally, Burlington's construction mirrors the result reached by the Fifth Circuit in *Warren*, a factually similar case. There, as here, the agreement provided that the royalty holder would receive a percentage of the "amount realized" by the lessee. But this language was modified with language that the amount realized shall be "computed at the mouth of the well," leading the court to conclude that "the royalty is based on net proceeds, and the physical point to be used as the basis for calculating net proceeds is the mouth of the well." 759 F.3d at 417. Therefore, the lessee could "deduct from sales proceeds the reasonable cost of post-production costs incurred in delivering marketable gas from the mouth of the well to the actual point of sale." *Id.* at 418. If, as we conclude, these parties intended their "into the pipeline" clauses to place the royalty valuation point at or near the well, *Warren* is consistent with Burlington's interpretation of the assignments.

To sum up, the Valuation Clause specifies that the royalty payment shall be calculated based on the "amount realized" from the sale, but the agreements also provide that the royalty interest shall be delivered "into the pipelines, tanks, or other receptacles with which the wells may be connected." In the context of these agreements, this latter term fixes the royalty's valuation point at the physical spot where the interest must be delivered—at the wellhead or nearby. This gives Burlington the right to subtract post-production costs from the "amount realized" in downstream sales prices in order to calculate the product's value as it flows "into the pipelines, tanks or other receptacles with which the wells may be connected." *See Hyder*, 483 S.W.3d at 873; *French*, 440 S.W.3d at 3; *Heritage Res.*, 939 S.W.2d at 122–23.

III. Conclusion

We find ourselves once again tasked to construe an opaquely worded oil and gas agreement. While both sides present well-reasoned arguments, we conclude that Burlington's construction of the royalty assignments is correct. The assignments permit Burlington to charge Texas Crude its proportionate share of post-production expenses when calculating royalty payments. The judgment of the court of appeals is reversed and the case is remanded to the trial court for further proceedings consistent with this opinion.

James D. Blacklock
Justice

OPINION DELIVERED: March 1, 2019