EXXON MOBIL CORPORATION §
P.O. BOX 2443
HOUSTON, TX 77210-2443, §

Taxpayer, §

v. §

STATE OF ALABAMA §
DEPARTMENT OF REVENUE.

STATE OF ALABAMA
DEPARTMENT OF REVENUE
ADMINISTRATIVE LAW DIVISION

DOCKET NOS. MISC. 03-141
MISC. 03-281

OPINION AND PRELIMINARY ORDER
(STAGE TWO)

These consolidated appeals involve two denied petitions for refund of oil and gas privilege and production ("severance") tax filed by Exxon Mobil Corporation ("Exxon") for the periods January 1992 through December 1996 and March 1997 through December 2000; and a final assessment of severance tax entered by the Revenue Department against Exxon for the period January 1992 through December 1996. The dispute involves the taxable wellhead value of gas produced by Exxon during the subject periods at three offshore fields in Mobile Bay, and also at two onshore wells in Escambia County, Alabama.

The parties agreed that because of the complexity of the facts and issues involved, the case should be bifurcated and heard in two parts. Accordingly, a Stage One hearing was conducted over a seven day period in June 2004 for the purpose of determining (1) the point of production at which the taxable value of the gas in issue must be calculated, and (2) what post-production costs or expenses incurred by Exxon can be deducted under the workback method.

The Administrative Law Division entered an Opinion and Preliminary Order (Stage One) on February 8, 2006 which identified the point of production, the various deductions that must be allowed under the workback method, and how those deductions should be computed. The Order did not finally decide two issues, i.e., the royal allocation issue and the take-in-kind issue, which are addressed later in this Order.

A Stage Two hearing was conducted from October 30 through November 1, 2006. Conrad Armbrecht and Duane Graham again represented Exxon. Chief Counsel Henry Chappell and Assistant Counsel John Breckenridge again represented the Department. The purpose of the Stage Two hearing was for the parties to present evidence from which the amount of any refund due or additional tax owed by Exxon for the periods could be calculated. Additional evidence was submitted at the hearing concerning the royalty allocation and the take-in-kind issues. The parties also submitted a joint stipulation, with attached exhibits, by which they agreed that the dollar amounts, volumes, and other numbers shown on the exhibits were the correct amounts, volumes, and other numbers to be used in making the final tax computations. The stipulation further specified that neither party was barred from challenging the legal arguments of the other party, nor was the Department barred from challenging the Administrative Law Division's findings and conclusions in the Stage One Order concerning the point of production and the workback method deductions.

The royalty allocation and the take-in-kind issues will be addressed first.

(1). The Royalty Allocation Issue.

Alabama's severance taxes are levied "upon the producers of such oil or gas in proportion to their ownership at the time of severance. . . ." Code of Ala. 1975, §40-20-3(a). "Producer" is defined to include any party that receives money as a royalty for oil or gas. Code of Ala. 1975, §40-20-1(8). The State was thus a producer of the gas in issue because it received cash royalties based on a percentage of the gross proceeds from the sale of the refined gas. The parties also agree that the State's ownership interest in the gas is tax exempt. The problem is how to allocate or determine the State's proportionate interest in the value of the unrefined gas at the time of severance.

This issue is difficult because the State did not own or have a right to a percentage portion of the raw gas at the wellhead. Rather, it only had an intangible royalty interest at the time of severance that gave it a right to a percentage of the gross proceeds from the subsequent sale of the processed, and higher valued, gas at the processing plant tailgate (or at some other downstream location).

The Department claims that the State's exempt portion of the raw gas at the time of severance was the percentage royalty interest the State had in the proceeds from the sale of the refined product. For example, if the value of the unrefined gas at the wellhead per the workback method was $1,000, and the State's royalty interest in the sale proceeds was 28 percent, the Department's position is that 28 percent of the wellhead value of $1,000, or $280, was the State's exempt interest. Exxon's taxable share would thus be 72 percent.

Exxon argues that the State's proportionate share must be computed based on the actual dollar royalties received by the State. Consequently, if the refined gas in the above example sold for $1,200 at the plant tailgate, the State would receive a royalty of 28 percent of that amount, or $336. Exxon asserts that the State's ownership interest in the unrefined gas at the time of severance must be based on the percentage that the dollar royalty amount ($336) bears to the value of the gas at the time of severance ($1,000). Exxon thus contends that in the above example, the State's exempt interest would be $336/$1,000, or 33.6 percent. Exxon's taxable share would be the remaining 66.4 percent.

As discussed, the State had no direct ownership interest in the unrefined gas at the time of severance. It only had a right to a percentage of the cash proceeds from the subsequent sale of the refined gas. The State's royalty percentage interest in the sale proceeds did not represent the State's percentage interest in the unrefined gas at the wellhead because the royalty percentage related to the higher valued refined gas at the plant tailgate. That is, Exxon's right to a percentage (28 percent, for example) of the sale proceeds of the refined gas was more valuable than a 28 percent ownership interest in the less valuable unrefined gas at the wellhead. Consequently, the royalty percentages in the leases cannot be used to determine the State's percentage interest in the gas at the time of severance.

The State's interest in the gas at the wellhead must be determined by comparing the dollar value of the State's royalty interest at the time of severance with the dollar value of the unrefined gas at the time of severance. Consequently, in the above example, the State's exempt share would be 33.6 percent because that represents the percentage share of the dollar value of the unrefined gas at the wellhead to which the State was entitled. The fact that the State's exempt interest could only be determined after the gas was processed and sold is irrelevant because the gas must be processed and sold in any case before the severance tax due can be computed using the workback method.

This is an issue of first impression in Alabama. The issue has, however, been addressed in Texas. See, *Hearing No. 11,661*, Texas Comptroller of Public Accounts

(6/23/82), 1982 WL 12800; *Hearing No. 10,468* (7/28/82, 1982 WL 12853; *Hearing No. 12,001* (6/24/82), 1982 WL 12827; *Hearing No. 11,660* (6/23/82), 1982 WL 12798; and *Hearing No. 10,936* (6/23/82), 1982 WL 12857. Those administrative decisions are quoted and analyzed at length in Exxon's Stage Two Brief at 6 – 8, and also in Exxon's Stage Two Reply Brief at 2 – 10. There is no need to repeat the analysis here. The Texas decisions are not easy reading, but suffice it to say that they support the above finding. They conclude that a royalty interest owner's percentage liability for severance tax must be determined using the actual dollar royalty amounts received, not the royalty percentage to which the royalty owner was entitled.[1]

As noted in one of the Texas decisions, a royalty owner that has a percentage interest in the proceeds from the sale of the refined product has a larger percentage interest in the unrefined gas at the wellhead because it is not required to bear the cost of processing the raw product. "Thus, the difference in the two fractions, (the royalty owner's share based on the royalty percentage versus the royalty actually paid) is attributable to the fact that the royalty interest pays none of the costs prior to the downstream sale." Hearing No. 12,001 at 1. The same applies in this case. The State's percentage interest in the value of the gas at the wellhead was larger than the royalty percentages stated in the lease agreements because the State was not required to pay any of the post-production processing costs.

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[1] The Department does not disagree with or otherwise discuss the Texas cases in its Stage Two Brief. It also states in its Stage Two Brief at 7, that "[i]t must be emphasized that the State's revenue received for its share is exempt from taxation." That statement is consistent with the above finding (and Exxon's position) that the actual dollar royalty amounts received by the State, i.e., "the State's revenue received," represents the State's exempt portion of the gas.

(2). The Take-In-Kind Issue.

The Stage One Order at 33, 34, found that "Exxon, as the entity in charge of production operations at the BEC wells, is ultimately liable for the tax due on the take-in-kind product distributed to the owners." The Order also concluded, however, that Exxon was not liable for take-in-kind volumes produced at the wells it did not operate. Evidence submitted in the Stage Two proceeding established that Exxon did not operate the Godwin well during the periods in issue. It thus cannot be held liable for tax on the take-in-kind volumes from that well. The evidence also established that certain in-kind takers had paid tax on the in-kind product, i.e., the Wynn-Crosby and Murphy volumes. Exxon also is not liable for tax on those volumes.

The Department acknowledged in the Stage One proceeding that if Exxon had identified the take-in-kind producers and the amounts or quantities taken, Exxon would have been relieved of liability on those volumes. However, because Exxon failed to identify the in-kind takers and the volumes taken, the Department argued that Exxon remained liable for the tax due.

The Stage One Order directed Exxon to explain why it failed to identify the "BEC interest owners that took their product in-kind, and the volume taken." Stage One Order at 34. Exxon responded in the Stage Two proceeding that it did not report the take-in-kind data on the NGL returns because those returns did not request that data. It conceded that it did not provide the information on its returns for the gas, but that the Department did not notify it that the information was required until 1997, at which time it began providing the information. Importantly, Exxon also submitted the take-in-kind information concerning 1992 – 1996 into evidence at the Stage Two hearing. See, Exxon Ex. 803.

The Department addressed the take-in-kind issue in its Stage Two Brief at 10 – 12. The Department again conceded that Exxon would have been relieved of liability for tax on the take-in-kind product if it had identified the take-in-kind producers and the amounts taken. "An operator is only relieved of its responsibility to pay all taxes for its products when it has properly reported the identity of a take-in-kind producer, and has reported the correct amount/quantities received by each take-in-kind recipient." Department's Stage Two Brief at 11, 12. The Department continued to argue, however, that because Exxon did not identify the take-in-kind producers and the amounts taken during the audit, Exxon should remain liable for tax on all of the take-in-kind product.

Exxon maintained information in its database that showed the in-kind producers and the in-kind volumes taken at the Big Escambia Creek Field from 1992 – 1996. T. 324. Exxon provided the Department with access to at least a portion of the information during the audit. A Department severance tax manager conducted a lengthy analysis of the information for two sample months, April 1995 and October 1996, in an attempt to identify the in-kind volumes on which tax had not been paid. The analysis found that for April 1995, tax had not been paid on 18,263 mcf of in-kind product.[2] The Department subsequently projected that amount to each month in the audit period to determine or estimate Exxon's liability for the in-kind product.

The parties agree that to analyze Exxon's in-kind information for each month of the audit period would be extremely time-consuming and a practical impossibility.

[2] The amount of take-in-kind product on which tax was not paid for the test month of October 1996 is not in evidence (or at least it cannot be located in the voluminous exhibits submitted in the case).

Exxon argues that because it provided all of the in-kind information in the Stage Two hearing, it should be relieved of liability. As indicated, however, it would be practically impossible, and thus unreasonable, to require the Department to analyze the data on a month-to-month basis. Rather, Exxon's liability in the two sample months analyzed by the Department to estimate Exxon's in-kind liability should be projected over the entire period; provided, the Godwin well should not be considered because it was not operated by Exxon, and the in-kind Wynn-Crosby and Murphy volumes on which tax has already been paid also should not be considered.

The Computation of Exxon's Liability.

The parties submitted a joint stipulation, with exhibits, by which they agreed that the dollar amounts, volumes, and other numbers shown on the exhibits were correct for purposes of determining Exxon's total liability for the period, and the resulting refund or tax due, as the case may be. Exxon also submitted additional exhibits and explanatory testimony at the Stage Two hearing concerning the dollar amounts, volumes, and other numbers relevant to Exxon's total liability for the period. Exxon has computed its liability, and the resulting refunds due, based on the stipulation and evidence, and in accordance with the findings in the Stage One Opinion and Preliminary Order.

The Department does not object in its Stage Two Brief to the method, mechanics, or numbers used by Exxon in calculating the net refunds due. Rather, the Department contends that the calculations are "not acceptable because they are based on false premises and faulty logic." Department's Stage Two Brief at 2. Specifically, the Department argues that the calculations are flawed because the Stage One Order incorrectly identified the point of production and the various costs that are allowable under the workback method. I disagree.

As discussed at length in the Stage One Order at 10 – 17, the point of production under Alabama law for severance tax purposes is "at the top of the well structure at or near the wellhead apparatus where the gas is severed from the soil or waters of Alabama." Stage One Order at 17. The Department contends that the above conclusion is contrary to the "point of production" as specified in its workback regulation, Reg. 810-8-6-.01. "The ALD erred when it concluded that its own definition of the 'point of production' should supersede that promulgated by the Department in its rule." Department's Stage Two Brief at 13. I again disagree. The Stage One Order reads in pertinent part, as follows:

> Paragraph (2)(g) of the regulation defines "point of production" as "[t]he mouth of the well as defined in (2)(h)." Paragraph (2)(h) defines "mouth of the well" as "[t]he point of production where the well production is severed from the soil or the waters, or from beneath the soil or the waters" of Alabama. The regulation thus identifies the point of production as the mouth of the well where the gas is physically extracted or severed from beneath the soil or waters of Alabama. To reiterate, this occurs at some point in the well bore at or immediately before the gas flows through the wellhead apparatus at the top of the well structure.

Stage One Order at 14.

The Department regulation clearly and unambiguously confirms the holding in the Stage One Order that the point of production is at or near the wellhead where the product is severed from the soil or waters of Alabama, not at some downstream location. Consequently, I do not understand the Department's claim that the point of production as identified in the Stage One Order is contrary to the regulation. Just the opposite is true. The regulation plainly identifies the point of production as the mouth of the well where the oil or gas is severed from the soil or waters of Alabama.

The Department also contends that the Stage One Order incorrectly held that the workback deductions should include all direct and indirect costs necessarily incurred by Exxon between the wellhead, i.e., the point of production, and the point of sale of the refined product. It asserts that the above finding is contrary to the Alabama Supreme Court's holding in *Ex parte State of Alabama (In re State of Alabama v. Phillips Petroleum Co.)*, 638 So.2d 886 (Ala. 1992). The Department's position is again incorrect.

Alabama's severance tax statutes do not define or even refer to the workback method. The Department nonetheless began using the workback method in the mid-1980's. The Alabama Supreme Court approved the use of the workback method in *Phillips Petroleum* in 1992. The sole issue in *Phillips Petroleum* was whether the Department could use the workback method to determine wellhead value. The Court did not address the issue of what costs or expenses should be allowed under the method. Rather, in generally discussing the method, it quoted from a textbook that "[u]nder this method costs of transportation, processing and treatment are deducted. . . ." *Phillips Petroleum*, 638 So.2d at 888, quoting Howard R. Williams and Charles J. Meyers, Oil and Gas Terms 977-78 (6th ed. 1984). That broad statement gives little guidance as to what specific costs incurred in transporting, processing, and treating oil or gas should be allowed.

The Stage One Order held that all direct and indirect costs necessarily incurred in transporting, processing, and otherwise treating the gas can be deducted because those costs affect or have an impact on the wellhead value of the product. The Stage One Order reads in pertinent part, as follows:

The goal of the workback method is to arrive at "an amount approximating market value" at the wellhead. *Phillips Petroleum*, 638 So.2d at 889. Wellhead value is what a willing buyer would pay a willing seller for the unrefined product at the wellhead. A Department expert, John Bower, testified in substance that a prospective buyer, in deciding what to pay for unrefined gas at the wellhead, must consider all costs that would be incurred in bringing the refined product to market. (R. 1630 – 1635) Bower gave essentially the same testimony in *BP America*. Relying in part on that testimony, the Administrative Law Division held in *BP America* as follows:

> The workback method should "result in an amount *approximating* market value." *Phillips Petroleum*, 638 So.2d at 889. Market value is determined by what a willing buyer would pay a willing seller. A Department expert testified that if a prospective buyer was determining what to pay for raw gas at the wellhead, the buyer would consider all costs necessarily incurred in bringing the processed gas to the point of sale. (R. 995 – 999) It thus follows that for workback purposes, all costs necessarily incurred from the wellhead to the point of sale should be allowed. Those costs would include all direct processing costs, and also all "indirect" costs such as water gathering and disposal that a producer necessarily incurs and must pay as a direct result of processing the gas.

BP America, at 40.

A post-production expense or cost must be allowed if it affects the value of the unrefined oil or gas at the wellhead. As discussed, any costs necessarily incurred in bringing the product from the wellhead to the market must be considered by a prospective buyer, and thus affects the wellhead value of the product. Those costs include not only the "direct" costs of physically transporting, treating, and processing the product, but also the various "indirect" costs that are necessarily incurred or result from those activities. (footnote omitted) Department expert Bower testified that anyone buying unrefined Mobile Bay gas at the wellhead would have to consider the cost of the janitors, cooks, and technicians on the platforms, among other costs. (R. 1632 – 1634) Those and other indirect costs must be allowed as workback deductions, because, according to Bower, "[a]ll of those functions are required." (R. 1634)

The Department's official position, at least in prior cases and presumably in this case, is that only those direct costs incurred in physically treating and transporting the product should be allowed. I disagree because, as discussed, numerous costs not directly related to the physical processing

> and transporting of oil or gas are unquestionably allowed as workback deductions. Ad valorem taxes, insurance, and administrative overhead are not direct processing-related costs, but are allowed costs in the Department's workback regulation, see Reg. 810-8-6-.01(6)(b)6., 7., and 8., respectively. Depreciation and return on investment are two more "indirect" costs that are allowed at Reg. 810-8-6-.01(6)(b)1. and (b)2., respectively. (footnote omitted)
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> To summarize, in computing the taxable value of Exxon's gas at the wellhead, all post-production costs incurred by Exxon in transporting, processing, and treating its gas downstream from the wellhead, and all other direct and indirect costs necessarily incurred or resulting from those activities, should be allowed.

Stage One Order at 20 – 22.

The above holding is consistent with the general statement in *Phillips Petroleum* that all costs associated with transporting, processing, and treating the product should be allowed. It is also consistent with the theoretical underpinning of the workback method; that is, all costs or expenses necessarily incurred and that affect the wellhead value of the raw product must be considered or allowed in determining that value.

Exxon is directed to modify its spreadsheet calculations in accordance with this Order. It should notify the Administrative Law Division of the amounts of the recalculated refunds. A Final Order will then be entered.

The parties also submitted the following agreed statement concerning the one percent Baldwin County tax.

A one percent Baldwin County privilege tax was levied pursuant to Act No. 1971-2120, as amended by Act No. 1987-629, and by Act No. 1989-959, Acts of Alabama, to be collected and administered in the same manner as the state oil and gas production tax. Under these Acts, the tax was to remain in effect only until a total sum of $15,000,000 in net severance tax revenues was collected. The amount of payments and collections reached a total net sum of $15,000,000 in 2005, after which the Department notified the affected taxpayers to stop making payments under these Acts, and any affected taxpayers were allowed a three-month period for making any prior period adjustments, after which the excess amounts collected were refunded to taxpayers in accordance with Section 40-20-50, Code of Ala. 1975.

Exxon provided calculations at the hearing showing what it claimed to be the amount of one percent Baldwin County tax refund it was due. In addition, the Department's assessments included what it claimed were additional amounts due with respect to this Baldwin County one percent tax portion. However, because the $15,000,000 amount has been reached, because a period of time has been provided for adjustments, and because excess amounts collected have been refunded; the Department has agreed not to collect any additional amounts with respect to the 1% Baldwin County privilege tax. Furthermore, Exxon has agreed to withdraw any claim for refund of the one percent Baldwin County privilege tax. Accordingly, no refund and no assessment is allowed with respect to the one percent Baldwin County privilege tax. This paragraph does not address in any way any assessment or refund claim with respect to any oil and gas privilege, production, or severance taxes other than the one percent Baldwin County privilege tax.

This Opinion and Preliminary Order is not an appealable Order. The Final Order, when entered, may be appealed to circuit court within 30 days pursuant to Code of Ala. 1975, §40-2A-9(g).[3]

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[3] Exxon has several other severance tax appeals pending before the Administrative Law Division (as do other taxpayers). The holding in these consolidated cases is directly applicable to those appeals. It is anticipated, however, that these consolidated cases

(continued)

Entered August 2, 2007.

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BILL THOMPSON
Chief Administrative Law Judge

bt:dr
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will be appealed to circuit court and beyond. The Administrative Law Division will thus continue to hold the pending severance tax appeals in abeyance until these cases are finally decided.