STATE OF ALABAMA DEPARTMENT OF REVENUE,	§	STATE OF ALABAMA DEPARTMENT OF REVENUE
	§	ADMINISTRATIVE LAW DIVISION
v.	§	DOCKET NO. MISC. 86-228
PETRO-LEWIS CORPORATION Petro-Lewis Tower	§	
717 17th Street Denver, CO 80201,	§	
Taxpayer.	§	

ORDER

This matter involves a disputed preliminary assessment of oil and gas production and/or privilege tax entered by the Revenue Department ("Department") against Petro-Lewis Corporation ("Taxpayer") concerning the period February, 1982 through May, 1984. A hearing was conducted in the matter on February 17, 1987. The Taxpayer was represented by the Hon. Edward A. Dean and the Hon. G. Thomas Smith. Assistant counsel John J. Breckenridge was present and represented the Department. Based on the evidence introduced at said hearing, and in consideration of briefs filed by both parties, the following findings of fact and conclusions of law are hereby made and entered.

FINDINGS OF FACT

The assessment in issue concerns the Taxpayer's interest in various producing natural gas wells located in the Womack Hill and Big Escambia Creek fields in Alabama. In dispute is the method by which the taxable measure of the gas should be computed for purposes of the Alabama oil and gas production and/or privilege tax found at Code of Alabama 1975, §40-20-1, et seq.

WOMACK HILL

In the early 1970's, Placid Oil, the predecessor-in-interest of the Taxpayer, and five other well owners in the Womack Hill area agreed to jointly build an on-site gas gathering and processing facility ("Womack Hill plant", or "plant"). Placid Oil and the other plant owners also had an ownership interest in various producing wells in the area.

Prior to construction of the Womack Hill plant, the gas produced in the area was vented and burned because the remoteness of the wells made gathering and processing uneconomical. However, the plant was constructed at the insistence of the Alabama Oil and Gas Board so as to provide a more environmentally sound method of disposing of the gas.

The Womack Hill field produces "sour gas", so called because it contains noxious hydrogen sulfide. The gas is also "wet" in that it contains various liquid hydrocarbons ("NGLs") such as ethane, butane, propane and gasoline.

After extraction, the gas is separated from the oil and measured at the wellhead meter. Thereafter, it is commingled with gas from other wells and routed along the gathering system to the plant. At the plant, the gas is compressed, cleaned, and the hydrogen sulfide is removed. The NGL's are then separated from the residue gas, and both are subsequently sold to various customers at the plant tailgate.

Prior to investment in the plant, the plant owners negotiated and subsequently entered into agreements ("casinghead gas contracts") to purchase gas from most of the well owners in the area. Under those contracts, title to the gas passed at the wellhead, and the seller was paid a price equal to 60% of the sales price of the residue gas, and 50% of the sales price of the processed NGLs. The above formula was also followed in purchasing gas from most of the well owners that did not enter into a casinghead gas contract.

The Taxpayer and the other plant owners, i.e., "associated" well owners, also entered into an agreement under which they were obligated to sell their gas to the plant under the same terms and for the same sales price as set out in the casinghead gas contracts entered into by the "non-associated" well owners.

The Department concedes that the price as established by the casinghead gas contracts is the proper wellhead value as concerns the non-associated well owners. However, concerning the associated owners, including the Taxpayer, the Department rejects said contract as not having been at arms-length. Rather, the Department argues that the "workback" method should be employed, under which the value of the gas is computed by taking the price received for the refined products at the tailgate and then subtracting actual processing costs.

Consequently, relative to the Taxpayer, the Department taxed 100% of the residue gas sales price and 79% of the NGL sales price. The 21% processing fee deduction allowed on the NGLs was based on a prior audit agreement between the Department and an unrelated oil company. The Department has no regulations relating to the workback method, or otherwise as to how the value of oil and gas should be computed under §40-20-1(3).

The Department agrees that the 21% allowance may not be an accurate account of the Taxpayer's actual processing costs at the Womack Hill plant, but argues that the Taxpayer has repeatedly failed to provide the Department with sufficient evidence as to actual processing expenses, and that in the absence of such records the 21% allowed on a previous audit is the best estimate available. The evidence indicates that at no time has the Taxpayer produced records from which the processing costs at the Womack Hill plant could be determined.

The Taxpayer argues that the taxable value of the gas produced at the Womack Hill field should be the sales price as established by the casinghead gas contracts for both the associated and non-associated well owners.

BIG ESCAMBIA CREEK

The Taxpayer owns an interest in various gas wells in the Big Escambia Creek field. All well owners in the field are also part owners in the processing plant, which is operated by Exxon.

There is no sale of the gas at the wellhead in the Big Escambia Creek field. Rather, the gas is gathered and processed in substantially the same manner as at the Womack Hill field, and the residue gas and NGLs are then sold at the plant tailgate. The sales proceeds, less plant operating costs, are then filtered back proportionately to the various well owners.

During the period in dispute, the Taxpayer reported its gas for severance tax purposes pursuant to the terms of a processing agreement ("Brooker contract") under which gas from the adjacent Little Escambia Creek field was once processes at the Brooker plant in Florida. The gas in the Little Escambia Creek field is similar in BTU content and quality to the gas in the Big Escambia Creek field. Under the Brooker contract, the Brooker plant purchased gas from the well owners and paid said well owners 50% of the NGL sales proceeds and 100% of the residue gas sales proceeds. Thus, during the period in dispute the Taxpayer reported tot he Department 100% of the residue gas sales and 50% of the NGL sales.

The Department rejected the Taxpayer's computations and assessed the tax based on the same 100% residue gas/79% NGL formula that was applied relative to the Womack Hill field.

<u>CONCLUSIONS OF LAW</u>

Code of Alabama 1975, §40-20-2 levies a tax on the severance of oil and gas in Alabama as follows:

> (a) There is hereby levied, to be collected hereafter, as herein provided, annual privilege taxes upon every person engaging or continuing to engage within the State of Alabama in the business or producing or severing oil or gas, as defined herein, from the soil or the waters or from beneath the soil or the waters, of the state for sale, transport, storage, profit or for use. <u>The amount of such tax shall be measured at the rate of 8% of the</u>

> gross value of said oil or gas at the point of production except as provided herein . . .
>
> (b) The tax is hereby levied upon the basis of the entire production in this state, including what is known as the royalty interest, on which production the amount of such tax shall be a lien, regardless of the place of sale or to whom sold, or by whom used, or the fact that the delivery may be made to points outside the state; and the tax shall accrue at the time such oil or gas is severed from the soil or the waters or from beneath the soil or the waters, and in its natural, unrefined or unmanufactured condition . . . (emphasis added)

The "value", or taxable measure to be applied, is set out in Code of Alabama 1975, §40-20-1(3) as follows:

> (3) VALUE. The sale price or market value at the mouth of the well. If the oil or gas is exchanged for something other than cash, if there is no sale at the time of severance or if the relation between the buyer and the seller is such that the consideration paid, if any, is not indicative of the true value or market price, then the Department shall determine the value of the oil or gas subject tot he tax hereinafter provided for, considering the sale price for cash of oil or gas of like quality.

It is clear that the above privilege tax accrues at the point of production, i.e. the wellhead, and is measured by the sales price or market value of the unrefined product at that point.

Concerning the Womack Hill field, gas is purchased by the plant from the non-associated well owners under various casinghead contracts. Those standard contracts provide that title to the gas (unrefined) is transferred to the plant at the wellhead. The sales price is set at 50% of the eventual sales price of the refined NGLs and 60% of the sales price of the residue gas. The Taxpayer and the other associated owners are also obligated by agreement to sell their gas production to the plant under the same terms and for the same sales price as set out in the standard casinghead contracts.

The Department does not dispute that the sales price as fixed by the casinghead gas contracts is the proper value to be applied for tax purposes to that gas sold by the non-associated owners. However, as to the associated owners (Taxpayer), the Department argues in effect that they cannot sell their gas to themselves and consequently, that the sales price paid under such circumstances is not the result of an arms-length transaction, and thus is not indicative of the true market value of their gas.[1]

To begin, the Department's contention that the associated well owners are not selling their gas at arms-length to the plant is incorrect. The associated owners operate in two separate capacities, each independent of the other. As well owners, they sell their production to the plant as required by an arm's-length agreement under the same terms and for the same prevailing market price as the non-associated owners. They profit accordingly. On the other hand, as plant owners, they gather and process the gas and sell the refined products at the plant tailgate. Fifty percent

[1]The Department's brief, at page 7, states as follows:

> On the other hand, the "associated" well owners, (those well owners who are also owners of the plant), cannot sell the gas they severed from beneath the earth to themselves. The relationship between the buyer and the seller is not an "arms-length transaction" and the consideration paid is not indicative of the residue gas and NGLs. Clearly it does not cost the plant owners the same amount to process their own gas as the service charge they are

of the NGL sales proceeds and 60% of the residue gas proceeds are then paid to the well owners, both associated and non-associated alike, per the casinghead gas contracts. The remainder is retained by the plant to cover processing and other operating expenses, with any excess over expenses, if any, divided among the plant owners as profit. There is no collusion between the associated owners in their capacity as well owners and their separate capacity as plant owners, as evidenced by the fact that the amounts received by the associated owners for their gas is tied to that sales prices as established for all well owners under the casinghead contracts.

Further, the Department's contention that it does not cost the associated owners (plant) the same to process their own gas as the "service charge" collected from the non-associated owners is both incorrect and irrelevant. First, characterization of the amount retained by the plant as a service charge for processing is incorrect. It is simply the difference between what the plant pays for the raw gas and what it receives for the processed products, and is unrelated to the plant's processing expenses. Second, all of the gas is commingled in the gathering system and processed together. Thus, there can be no distinction or difference in the

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collecting from the other well owners.

cost of processing the gas of an associated owner versus the gas purchased from a non-associated owner. Finally, the point is irrelevant because the plant's processing expenses are not related to the sales price paid under the casinghead contracts, and thus even if processing costs could be broken down concerning associated and non-associated gas, that fact would not support the Department's conclusion drawn therefrom that the consideration paid to the associated owners is not a fair market price.

However, even if the sales price as contracted by the associated owners is disregarded as not being at arms-length, §40-20-1(3) provides that in such circumstances where the relationship between the seller and the buyer is such that the sales price does not reflect the true market value, then the value should be determined "considering the sale price for cash of oil or gas of like quality."

The evidence is clear in the present case that the gas sold by the non-associated owners is identical in average BTU content and quality of the gas extracted and sold by the associated owners. The gas from all wells in the area is in fact commingled in the gathering system and routed of the plant for processing. Thus, clearly the sales price received by the non-associated owners, which is accepted as the taxable value of such gas by the Department, would constitute the sales price of gas of like quality and therefore would constitute the proper value under §40-20-1(3) fo the gas sold by the associated owners.

The Department is attempting through the use of the workback method to tie the wellhead value to the sales price of the refined products less actual processing costs. However, the sales price or amount received by the well owners in the Womack Hill field is unrelated to the plant's operating expenses, and thus such expenses would certainly have no impact on the sales price (value) of the unrefined gas at the wellhead. Accordingly, the workback method is not an accurate gauge of wellhead value in the Womack Hill field, is also contrary to the valuation method authorized by §40-20-1(3), and its use would as a practical matter cause the taxable value of the gas to fluctuate randomly depending on the cost efficiency of the plant operator.

Further, the workback method was specifically rejected as an economically viable method for determining the value of an unprocessed product in Northern Natural Gas Co. v. Grounds, 393 F.Supp. 949, as follows:

> Determinations of the value of "raw materials" is not determined upon a "proceeds less expense" theory in the American economy. The price that a farmer receives for wheat or the price that he receives for feed grains is not determined by "working back" from the retail price of bread or meat. This was illustrated in the testimony of Dr. Morton, an economist, in the following terms: ". . . One does not find the value of, say, wheat in Kansas, by taking the price of bread, deducting from the price of bread the grocer's profit, and then the drayman's profit who hauls it to the grocer, then the baker's profit, the miller's profit, plus his cost, and the railroad's profit

> in hauling it to the mill, plus its cost, in order to find the price of wheat."

The Department incorrectly argues in brief, beginning at page 14, that the Taxpayer is also using the workback method to arrive at taxable value. The Taxpayer's argument is that the actual sales price as established by the casinghead gas contracts should be determinative. The plant's operating expenses are in no way used in the sales price calculation, as should be the case. Tying the sales price to be paid the well owners to a set percentage of the ultimate sales price of the refined products is clearly distinct from the workback procedure of tailgate price less operating costs.

Concerning the Big Escambia Creek field, there are no cash sales at the wellhead. This is because all of the well owners in the field share proportionately in ownership of the processing plant. Thus, the gas is gathered, processed and sold as at the Womack Hill field, and the gross proceeds derived from the refined products, less plant operating and maintenance expenses, are remitted proportionately to the well owners in accordance with their percentage of ownership.

As stated, §40-20-1(3) provides that where there is no sale at the wellhead, the Department shall determine the value considering the sales price for gas of like quality. Because there are no wellhead sales in the Big Escambia Creek field, there obviously are no comparable sales of like quality gas within the field itself, as were the non-associated owner sales in the Womack Hill field.

However, owners in the adjacent Little Escambia Creek field once sold their gas under contract to the Brooker plant in return for 100% of the residue gas proceeds and 50% of the processed NGL proceeds. Evidence taken at the administrative hearing indicates that he raw, unrefined gas in the Little Escambia Creek field is of like quality of the gas in the Big Escambia Creek field. Thus, the sales price paid to the well owners for like quality gas in the Little Escambia Creek field should, as directed by §40-20-1(3), be used in determining the taxable value of the unrefined gas in the Big Escambia Creek field.

The above determination is made based on the specific mandate of §40-20-1(3) that the value shall be determined based on the sale price of like quality gas. The Brooker contract provides such a comparable sales price computation. Thus, even if the workback method would provide an approximate fair market value for the unrefined gas in the Big Escambia Creek field, §40-20-1(3) would require application of comparable sales in determining taxable value.[2]

[2]The workback method would provide a more accurate value of the unrefined Big Escambia Creek gas because the plant there does not make a profit, but rather, is simply a tool through which the owners process and market their products. Thus, unlike the situation at Womack Hill, the plant's operating expenses would have a direct effect on the ultimate sales price or value received by the well owners. Accordingly, assuming that the refined products are sold at fair market value and that an average processing cost can be calculated, it would be accurate to say that the processed products sales price less processing cost would equal the worth or fair market value of the unrefined gas at the

wellhead. For example, if the NGLs and residue gas from a given volume of gas can be sold for $1,000.00, and the cost of processing can be calculated at $500.00, then the fair market value at the wellhead would be $500.00. If the processing cost was $750.00, then the value received by the well owner, i.e. sales price, would be $250.00.

The above considered, the preliminary assessment should be reduced and made final showing no additional tax due.

Done this 22nd day of July, 1987.

BILL THOMPSON
Chief Administrative Law Judge