THIS DECISION HAS BEEN APPEALED TO A COURT FOR JUDICIAL REVIEW
01-0033, 04-1283,04-1284
TAX TYPE: SEVERANCE TAX/ CONSERVATION FEE
DATE SIGNED: 4-15-2014
COMISSIONERS: B. JOHNSON, D. DIXON, M. CRAGUN, R. PERO
GUIDING DECISION

BEFORE THE UTAH STATE TAX COMMISSION

TAXPAYER, Petitioner, v. AUDITING DIVISION OF THE UTAH STATE TAX COMMISSION, Respondent.	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND FINAL DECISION** Appeal No. 01-0033 Tax Type: Severance Tax Audit Period: 1994, 1995, 1996 & 1997 Appeal No. 04-1283 Tax Type: Conservation Fee Audit Period: 1998 & 1999 Appeal No. 04-1284 Tax Type: Severance Tax Audit Period: 1998 & 1999 Judge: Chapman

STATEMENT OF THE CASE

These matters pertain to a consolidated appeal of three separate Statutory Notices issued to TAXPAYER ("TAXPAYER" or "taxpayer") by the Auditing Division of the Utah State Tax Commission (the "Division"), specifically: 1) Appeal No. 01-0033 (Severance Tax); 2) Appeal No. 04-1283 (Conservation Fee); and 3) Appeal No. 04-1284 (Severance Tax) (collectively referred to as the "Consolidated Appeals"). In March 2007, the Utah State Tax Commission ("Commission") conducted a Formal Hearing for the Consolidated Appeals (the "Formal Hearing"). On December 24, 2007, the Commission issued its Findings of Fact, Conclusions of Law, and Final Decision (the "2007 Decision").

In the 2007 Decision, the Commission upheld the Division's severance tax valuations for oil and residue gas by applying the pre-*ExxonMobil*[1] interpretation of value "at the well" for purposes of Utah Code Ann. §59-5-102(1)(a) (1999). In the 2007 Decision, the Commission did not apply the Court's *Exxonmobil* interpretation of "at the well," in part, because it determined that the prospective limitation of *ExxonMobil* was triggered. TAXPAYER's Appeal No. 01-0033 was pending when the Court issued its *ExxonMobil* decision in 2003.

TAXPAYER appealed the Commission's interpretation of the "selectively prospective application" of *ExxonMobil* and the Commission's decision not to apply the *ExxonMobil* rule when determining the value of its oil and gas. In *Union Oil Company of California v. Utah State Tax Comm'n*, 2009 UT 78, 22 P.3d 1158 (Utah 2009) ("*TAXPAYER*"), the Utah Supreme Court determined that the prospective limitation, as set forth in *ExxonMobil*, would have applied to Appeal No. 01-0033, but not to Appeal Nos. 04-1283 and 04-1284. The Court, however, decided to refine its prospective limitation so that its *ExxonMobil* ruling would apply to all three of TAXPAYER's appeals. After doing so, the Court remanded these matters back to the Commission to apply its *ExxonMobil* ruling in valuing TAXPAYER's oil and residue gas.

After the matter was remanded back to the Tax Commission, the parties engaged in some additional discovery until TAXPAYER filed a Motion to Quash the Division's Request for Production of Documents. The Commission heard oral arguments on the motion on June 29, 2011. On July 6, 2011,

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1 *ExxonMobil Corp. v. Utah State Tax Comm'n*, 2003 UT 53, 86 P.3d 706 (Utah 2003). In *ExxonMobil*, the Utah Supreme Court determined that the Commission had improperly accepted Auditing Division's interpretation of the statutory term "at the well" to be "at the point of actual sale." The Court ruled that "the statute contemplates calculation within the immediate vicinity of the point of removal from the earth, but it also compels calculation at some point where sales are not a distinct rarity." However, the Court gave its ruling "selectively prospective application," stating that "[a]lthough ExxonMobil is entitled to further adjudication of its claim for a refund, as to other parties who may have refund requests, deficiency proceedings, or similar matters pending before the Tax Commission, our holding is to apply prospectively only."

the Commission issued its Order Granting Petitioner's Motion to Quash the Division's Request for Production of Documents and Order Concerning Remand (the "2011 Order"). In the 2011 Order, the Commission denied the Auditing Division's request for additional discovery, stating that it was:

> . . . not inclined to allow additional discovery in this case at this time. The legal and factual issues in this case were already presented at a Formal Hearing. The Division was aware of TAXPAYER's legal position concerning the applicability of the *ExxonMobil* rule prior to the Formal Hearing. It was also aware that both legal and factual matters were going to be argued at that hearing. It is telling that most of the additional discovery involves backup for the original returns or for the claims for refund. The Division had the returns and refund claims months if not years before the hearing and had full opportunity to request any backup they thought necessary. The Division has already had an opportunity to conduct discovery and make its arguments to contest TAXPAYER's position in case TAXPAYER's legal position succeeded. Based on the information received at the Formal Hearing, the Commission made Findings of Fact that were not contested and which the Commission is reluctant to disturb. For these reasons, the Commission has decided to grant TAXPAYER's Motion.

As part of the 2011 Order, the Commission ordered the parties to submit proposed Findings of Fact and Conclusions of Law. The Commission also gave each party an opportunity to respond and object to the other party's proposed Findings of Fact and Conclusions of Law. In the 2011 Order, the Commission stated that "it is incumbent on TAXPAYER to show that the evidence and testimony already in the record is sufficient for the Commission to make a decision concerning the remanded valuation issue."

TAXPAYER submitted the Petitioner's Proposed Finding of Fact and Conclusions of Law on August 22, 2011. The Division submitted its proposed Findings of Fact, Conclusions of Law and Final Decision on September 26, 2011. Also on September 26, 2011, the Division submitted its Objection to Petitioner's Proposed Findings of Fact and Conclusions of Law. On October 17, 2011, TAXPAYER submitted TAXPAYER's Response to the Division's Objections and TAXPAYER's Objections to the Division's Proposed Findings of Fact and Conclusions of Law.

The Commission makes the following:

FINDINGS OF FACT

The Commission incorporates the Findings of Fact that it established on pages 2 through 18 of its 2007 Decision, which are identified as Findings of Fact 1 through 92. Because the Commission did not apply the *ExxonMobil* ruling to TAXPAYER's oil and residue gas in the 2007 Decision, the Commission did not include in the 2007 Decision all of the findings of fact necessary to now address these issues. Accordingly, the Commission makes additional findings of fact, as follows:

93. In the 2007 Decision, the Commission found as follow:[2]

a. The Commission found that it has jurisdiction to hear all three appeals (the Division had argued that the Commission does not have jurisdiction to hear Appeal Nos. 04-1293 and 04-1284);

b. The Commission upheld the Division's valuation of oil and residue gas, which was based on the value of these products after they processed at the PLANT-1. The Commission reached this conclusion after determining that the prospective relief limitation prescribed in *ExxonMobil* required it to apply the pre-*ExxonMobil* rule to the Consolidated Appeals;[3]

c. The Commission found that the limitations found in the federal regulations are applicable when determining value under the net-back method for Utah severance tax purposes. As a result, the Commission rejected TAXPAYER's net-back calculations in regards to the natural gas liquids ("NGLs") it produced for all tax years at issue. The Commission sustained the Division's net-back valuation of TAXPAYER's NGLs for 1994 and 1995, but amended the NGL valuations for 1996, 1997, 1998, and 1999 to reflect a 99% processing allowance approved by

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2 2007 Decision, pp. 44-45.

3 Commissioner Dixon concurred in part and dissented in part with the majority in the Commission's 2007 Decision for these appeals. Commissioner Dixon disagreed with the majority's conclusion concerning the prospective relief limitation found in *ExxonMobil* and how it applied to these appeals. She found that the *ExxonMobil* ruling should apply to all years at issue in these appeals.

Minerals Management Services ("MMS") for these years;

d. The Commission rejected TAXPAYER's claims regarding the annual exemption;

e. The Commission granted TAXPAYER's request to waive or abate the 10% penalty for failure to file a severance tax return for the 1999 tax year.

94. TAXPAYER appealed the Commission's 2007 Decision to the Utah Supreme Court. The issues raised by TAXPAYER concerned the point of valuation for the oil and residue gas; the refusal to expand the processing allowance applicable to the NGLs through the net-back approach for 1994 and 1995; the refusal to permit an adjustment to the taxable value of the NGLs for transportation costs; and the Commission's conclusions regarding the calculation of the annual exemption.

95. The Utah Supreme Court affirmed the Commission's ruling in regards to the valuation of TAXPAYER's NGLs, as well as its ruling on the annual exemption. However, the Court reversed the Commission's finding that the *ExxonMobil* rule did not apply to the Consolidated Appeals and "remand[ed] only the question arising from the point at which the oil and gas are to be valued for consideration of the appropriate valuation as set forth in ExxonMobil."[4]

96. The Utah Supreme Court affirmed that portion of the 2007 Decision in which the Commission sustained the Division's net-back approach to value TAXPAYER's NGLs for 1994 and 1995 and in which it found that the Division's net-back approach for 1996, 1997, 1998, and 1999 needed adjustment to allow a processing allowance of 99%. 2007 Decision, pp. 44 – 45. Accordingly, the method with which TAXPAYER's NGLs should be valued is no longer at issue.[5]

97. The issues now before the Commission on remand are the values of the oil and residue gas produced from the UNIT-1, the oil and residue gas produced from the UNIT-2, and conservations

4 *TAXPAYER*, ¶¶ 21-26.

5 Still at issue, however, is TAXPAYER exact liability for NGLs, once this portion of the 2007 Decision is applied. That issue will be discussed later in the "Discussion" section of the instant decision.

fees.

98. During the 1st Audit Period, the Division did not assess residue gas or NGLs produced from the UNIT-1. Otherwise, the Division assessed the oil, residue gas, and NGLs from both the UNIT-2 and the UNIT-1 for all years of the Consolidated Audit Period. Petitioner's Exhibit 13 ("Exhibit P-13") and Exhibit P-14. The following chart indicates with a "Yes" if the Division assessed taxable value to a particular product for a particular year for purposes of the severance tax and with a "No" if the Division did not assess taxable value to that product for that year, as follows:

Year	UNIT-2 Gas	UNIT-2NGLs	UNIT-2 Oil	UNIT-1 Gas	UNIT-1 NGLs	UNIT-1 Oil
1st Audit Period						
1994	Yes	Yes	Yes	No	No	Yes
1995	Yes	Yes	Yes	No	No	Yes
1996	Yes	Yes	Yes	No	No	Yes*
1997	Yes	Yes	Yes	No	No	Yes*
2nd Audit Period						
1998	Yes	Yes	Yes	Yes	Yes	Yes
1999	Yes	Yes	Yes	Yes	Yes	Yes

* For 1996 and 1997, the Division combined the UNIT-1 oil volumes and values into the UNIT-2 oil production on its Statutory Notice for the 1st Audit Period. Exhibit P-13, Sch. 5, p. 1 of 1. Otherwise, each product from each unit was separately assessed.

99. At the Formal Hearing, TAXPAYER conceded some severance tax liability for oil and gas produced from the UNIT-1 during the years at issue, based on the fact that some of the UNIT-1 oil was sold at the well and that the UNIT-1 gas was either transported out of the field for storage or sold at the PLANT-1 tailgate with the plant taking a 30% processing fee out of the price. It also conceded some liability for UNIT-2 gas for the 1998 and 1999 tax years, based on the net-back approach.

<u>UNIT-1 Oil Liability</u>

100. TAXPAYER sometimes sold the UNIT-1 sweet oil at the tanks located near the UNIT-1 wellheads at which the oil was stored. As a result, TAXPAYER conceded that it owes severance tax for oil produced from the UNIT-1 during the Consolidated Audit Period.

101. TAXPAYER calculated the amount of severance tax that it claims to owe on the UNIT-1 oil for each of the years under audit, as shown on Exhibit P-17.[6] TAXPAYER indicated that the amounts it calculated for the 1st Audit Period (1994 through 1997) were derived with the same methodology that the Division used when it imposed its assessment on UNIT-1 oil for the 1st Audit Period. Transcript of 2007 Formal Hearing ("Tr."), p. 149. Furthermore, TAXPAYER calculated the severance tax using just one annual exemption of $$$$$, which comports with the Utah Supreme Court's 2009 ruling in *TAXPAYER*. With this methodology, TAXPAYER proposes an amount of tax liability for UNIT-1 oil for 1994 and 1995 that appears to be identical when compared to the amounts assessed by the Division.[7] This comparison was possible for 1994 and 1995 because the Division separated its assessments of UNIT-1 oil and UNIT-2 oil for these two years in its Statutory Notice for the 1st Audit Period. Exhibit P-13. For these reasons, TAXPAYER's severance tax liability for UNIT-1 oil is $$$$$ for 1994 and $$$$$ for 1995.

102. For 1996 and 1997, the Division did not show its assessment of UNIT-1 oil separately from its assessment of UNIT-2 oil in its Statutory Notice for the 1st Audit Period. Exhibit P-13. TAXPAYER claims to have calculated its proposed severance tax for UNIT-1 oil for 1996 and 1997 using the same methodology with which it calculated its liability for 1994 and 1995. The Division has not shown that TAXPAYER's calculations for 1996 and 1997 were prepared any differently than the way

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6 As shown on both the original version of Exhibit P-17 that TAXPAYER submitted at the Formal Hearing and the revised version that it submitted with its most recent Proposed Findings of Fact and Conclusions of Law.

7 Based on the taxable values for UNIT-1 oil, as shown in the Division's Statutory Notice for the 1st Audit Period (Exhibit P-13, Schedule 2, p. 2 of 2).

in which TAXPAYER prepared them for 1994 and 1995. Nor has the Division shown that TAXPAYER's proposed tax calculations for 1996 and 1997 are incorrect or that the tax amounts proposed for these two years are too low. Accordingly, TAXPAYER's severance tax liability for UNIT-1 oil is $$$$$ for 1996 and $$$$$ for 1997.

103. For the 2nd Audit Period (1998 and 1999), the Division assessed value to the UNIT-1 oil using spot prices for sweet oil produced from the AREA-1, which is a different methodology than the Division used to determine the value of the UNIT-1 oil for the 1st Audit Period. TAXPAYER claims to have calculated the tax it proposes to be due on UNIT-1 oil for 1998 and 1999 using the same methodology it used to calculate its proposed tax for the 1994 through 1997 tax years (except that it did not apply the annual exemption of $$$$$, which is a detriment to TAXPAYER). With this methodology, TAXPAYER calculated taxes for UNIT-1 oil for 1998 and 1999 that appears to be slightly higher than the amounts assessed by the Division for these years.[8] Again, however, the Division has not shown that the tax amounts that TAXPAYER calculated and proposes for UNIT-1 oil for 1998 and 1999 are too low. Accordingly, TAXPAYER's tax liability on UNIT-1 oil is $$$$$ for 1998 and $$$$$ for 1999.

104. TAXPAYER's tax liability for UNIT-1 oil for 1994 through 1999, as found in the three preceding paragraphs, totals $$$$$ (which is the total amount TAXPAYER proposed on Exhibit P-17).

<u>UNIT-1 Gas Liability</u>

105. NAME-1 testified that the UNIT-1 gas production was of sufficient quality so that it could be sold into a pipeline. Tr., pp. 522 - 523. Neither party provided an analysis of the composition of

[8] Based on the taxable values for UNIT-1 oil, as shown in the Division's Statutory Notice for the 2nd Audit Period (Exhibit P-14, Schedule 1, p. 1 of 1).

gas produced from an individual UNIT-1 well during the audit period. However, TAXPAYER showed the composition of UNIT-1 Well No. ##### to be 95.3495% methane in February 2007.[9] Exhibit P-33.

106. The Division does not appear to have assessed any value or tax to UNIT-1 gas or UNIT-1 NGLs during the 1st Audit Period (1994 through 1997). The Division, however, did assess value and tax to UNIT-1 gas and UNIT-1 NGLs for the 2nd Audit Period (1998 and 1999), based on contract prices of sales that occurred after the products were processed at the PLANT-1.

107. TAXPAYER claims that it entered into a contract to sell the UNIT-1 gas (both residue gas and NGLs) at the PLANT-1 tailgate price minus a 30% processing allowance. Tr., pp. 154 – 156; Exhibit P-21, contract C-1. Although TAXPAYER has calculated a proposed tax liability for UNIT-1 "residue gas" on Exhibit P-17, it appears that TAXPAYER's proposed tax liability is for the entire gas stream (which, after processing, would include both UNIT-1 residue gas and UNIT-1 NGLs). First, TAXPAYER did not include a separate column for UNIT-1 NGLs on Exhibit P-17. Second, TAXPAYER indicated that it applied the contract price (adjusted downward by 30%) to "wellhead volume," which would have included both residue gas and NGLs prior to their being separated for processing at the PLANT-1. Tr., pp. 194 – 195. With this "concession," TAXPAYER claims that its tax liability calculation would approximate how the UNIT-1 gas would have been originally reported and assessed. Tr., pp. 196 - 197.

108. For 1998, TAXPAYER calculated a tax liability of $$$$$ for UNIT-1 "residue gas." Exhibit P-17. On the Division's Statutory Notice for the 2nd Audit Period, the Division valued the separate residue gas component and the separate NGLs component after the gas steam was separated and

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9 The Division claimed that the same UNIT-1 well produced gas with a composition that was only 58.4756% methane in June 2001. Respondent's Exhibit 57 ("Exhibit R-57"). TAXPAYER, however, claimed that during 2001, this UNIT-1 well had been "recompleted" and was producing gas from the UNIT-2 Unit. The Division's evidence was insufficient to show that the UNIT-1 gas that TAXPAYER produced during the Audit Period was contaminated to the extent that it could not be sold onto a pipeline.

processed into these separate components at the PLANT-1. It appears that the Division assessed a tax liability of $$$$$ for the UNIT-1 residue gas and $$$$$ for the UNIT-1 NGLs for 1998, which total $$$$$.[10] Accordingly, TAXPAYER has supported its claim that its proposed tax calculations for the UNIT-1 gas stream (prior to separation into residue gas and NGLs) approximate how the UNIT-1 gas would have been originally reported and assessed (as separate residue gas and separate NGLs). In addition, TAXPAYER's proposed tax liability for UNIT-1 gas and NGLs for 1998 is in excess of the Division's assessed taxes for these products for this year.

109. Furthermore, in the 2007 Decision, the Commission previously found that the Division's assessment for NGLs is too high for 1996 through 1999. Once the Division's 1998 assessment of UNIT-1 NGLs is reduced to reflect the 2007 Decision, the revised assessment of tax liability for UNIT-1 NGLs would drop from $$$$$ to around $$$$$. The revised UNIT-1 NGLs assessment of approximately $$$$$, when combined with the Division's assessment of $$$$$ for UNIT-1 residue gas, would total approximately $$$$$ for 1998, which is much less than the $$$$$ amount that TAXPAYER proposes for this year. The Division has not shown that the tax amount that TAXPAYER calculated and proposes for UNIT-1 combined residue gas and NGLs for 1998 is too low. Accordingly, TAXPAYER's tax liability for UNIT-1 gas (both residue gas and NGLs) for 1998 is $$$$$.

110. For 1999, TAXPAYER calculated a tax liability of $$$$$ for UNIT-1 "residue gas." Exhibit P-17. On the Division's Statutory Notice for the 2nd Audit Period, it appears that the Division assessed a tax liability of $$$$$ for the UNIT-1 residue gas and a separate liability of $$$$$ for the

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10 Based on the taxable values for UNIT-1 gas and UNIT-1 NGLs, as shown in the Division's Statutory Notice for the 2nd Audit Period (Exhibit P-14, Schedule 1, p. 1 of 1).

UNIT-1 NGLs for 1999, which total $$$$$.[11] TAXPAYER's proposed tax liability for UNIT-1 gas and NGLs for 1999 is lower than the Division's original assessment of these products for 1999.

111. However, in the 2007 Decision as previously discussed, the Commission found that the Division's assessment for NGLs is too high for 1996 through 1999. Once the Division's 1999 assessment of UNIT-1 NGLs is reduced to reflect the 2007 Decision, the revised assessment of tax liability for UNIT-1 NGLs would drop from $$$$$ to around $$$$$. The revised UNIT-1 NGLs assessment of approximately $$$$$, when combined with the Division's assessment of $$$$$ for UNIT-1 residue gas, would total approximately $$$$$ for 1999, which is significantly less than the $$$$$ amount that TAXPAYER proposes. The Division has not shown that the tax amount that TAXPAYER calculated and proposes for UNIT-1 combined residue gas and NGLs for 1999 is too low. Accordingly, TAXPAYER's tax liability for UNIT-1 gas (both residue gas and NGLs) for 1999 is $$$$$.

112. The Division did not assess any value or tax to UNIT-1 residue gas or UNIT-1 NGLs for the 1st Audit Period (1994 through 1997) because TAXPAYER did not report this production on its original returns for these years. Through July 1997 of the 1st Audit Period, the gas TAXPAYER produced from the UNIT-1 was transported from the UNIT-1 and "reinjected" into the nearby UNIT- 3 (which is located four or five miles off of the FIELD-1), where it was eventually lost in the formation and could no longer be recovered.[12] From August 1997 through the remainder of the Consolidated Audit Period, the UNIT-1 gas was transported from the FIELD-1 to the PLANT-1, where it was processed and sold at the tailgate of the plant.

113. Although the Division did not assess UNIT-1 residue gas or NGLs for the 1st Audit Period (1994 though 1997), TAXPAYER concedes that it owes liability on these products for these years.

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[11] Again, based on the taxable values for UNIT-1 gas and UNIT-1 NGLs, as shown in the Division's Statutory Notice for the 2nd Audit Period (Exhibit P-14, Schedule 1, p. 1 of 1).

[12] NAME-1 testified that the UNIT-1 gas was stored because there was not room for the gas in the PLANT-1. Tr., pp. 785 - 786.

TAXPAYER calculated its proposed tax liability for UNIT-1 “residue gas” for 1st Audit Period, as shown on Exhibit P-17. As explained earlier, this amount appears to be TAXPAYER’s proposed liability for both residue gas and NGLs. The Division has not shown that any of these proposed tax amounts is too low. Accordingly, TAXPAYER’s tax liability on UNIT-1 gas (both residue gas and NGLs) is $$$$$ for 1994, $$$$$ for 1995, $$$$$ for 1996, and $$$$$ for 1997.

114. TAXPAYER’s tax liability for UNIT-1 gas (both residue gas and NGLs) for 1994 through 1999, as found in the five preceding paragraphs, totals $$$$$ (which is within one cent of the total amount TAXPAYER proposed on Exhibit P-17).

<u>TAXPAYER’s Net-Back Approach for UNIT-2 Oil and Residue Gas</u>

115. TAXPAYER used the net-back approach to determine the severance tax value of its UNIT-2 oil and gas. CORPORATION-1 (“CORPORATION-1”) prepared the net-back approach originally to compare the total revenues received from oil, gas, and NGLs to total costs for return on investment (“ROI”), depreciation, and operating expenses for both field gathering and plant treating and processing. Exhibits P-8 and P-35. Because these costs also included the costs to produce helium, TAXPAYER indicates that the Tax Commission asked CORPORATION-1 to remove the costs associated with helium. Tr., pp. 125 - 126.

116. NAME-2, who works for CORPORATION-1, testified that he derived the net-back calculations by starting with prices at the tailgate of the PLANT-1 and working back to the meters located at the well by deducting costs. Tr., p. 544. He determined that 92% of these costs occurred in the PLANT-1 and that the remaining 8% of the costs were on the “field gathering system.” Exhibit P-34, p. 3; Tr., pp. 546 - 547.

117. NAME-2 then produced a net-back value for each component (i.e., oil, gas, and NGLs) by allocating the total costs between the various components, as follows; 1) 54.97% for NGLs; 2)

24.92% for residue gas; 3) 9.69% for oil; 4) 10.15% for helium; and 5) 0.27 for "gas lift" (gas used in the production process). Exhibit P-34, p. 4. NAME-2 stated that he determined these percentages based on an analysis agreed on between him and the state, specifically allocating the costs on the basis of the *revenue* received for a product. Tr., p. 570.[13]

118. NAME-2 did not allocate costs to each product on the basis of the actual costs incurred for each product. Neither party discussed whether TAXPAYER kept track of the separate, actual costs incurred for each product. There is some question as to whether the costs allocated to those products subject to severance tax (oil, residue gas, and NGLs) are too high because NAME-2 underestimated the costs associated with products not subject to severance tax (helium and sulfur). For example, the Division pointed out that TAXPAYER took out 30% of plant costs for helium and sulfur for purposes of determining the federal royalty. Exhibit R-53. However, NAME-2 only allocated 10.15% of costs to helium and zero percent to sulfur when allocating cost to determine the net-back values its oil, residue gas, and NGLs.

119. NAME-2 stated that the helium costs and gas lift costs were not incorporated into his netback calculation. Tr., p. 569. However, he incorporated the sulfur costs into the net-back calculation because sulfur has to be removed from the production. Tr., pp. 573 - 574. NAME-2 stated that in his accounting experience, companies usually try to dispose of the sulfur in the cheapest way possible. Tr., pp. 815 - 816. For these reasons, even though TAXPAYER sells the sulfur, NAME-2 allocated the costs associated with the sulfur removal and production to the other products.

120. The net-back approach that NAME-2 derived in Exhibit P-34 included calculations not only for the UNIT-2, but also the UNIT-1. Because TAXPAYER decided to concede some liability for

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[13] It appears that this "agreement" to allocate costs on the basis of revenue may have occurred between the Taxpayer Services Division and NAME-2 around the time that TAXPAYER submitted its initial refund request (in 1997) and that the Taxpayer Services Division decided (in 1998) to refund the severance tax that TAXPAYER had reported and paid for the 1st Audit Period.

the UNIT-1 production near the date of the Formal Hearing, NAME-2 stated that the UNIT-1 costs would need to be removed from his net-back calculations to determine the value of the UNIT-2 production alone. NAME-2 admitted that he had not prepared a net-back report that would show only the UNIT-2costs once the UNIT-1 costs were removed. However, he stated that he determined the proposed taxes for the UNIT-2production, as shown on Exhibit P-17, by removing the UNIT-1 costs from the net-back calculation found in Exhibit P-34. Tr., pp. 578 - 581.

121. Once NAME-2 made the adjustments described in the preceding paragraph, he determined that the net-back method would result in a zero value for TAXPAYER's UNIT-2 oil for all years at issue and that it would result in a zero value for its UNIT-2 residue gas for all years except 1998 and 1999.[14] Exhibit P-17.

122. For purposes of his net-back calculation, NAME-2 determined that the PLANT-1 investments totaled $$$$$ and the FIELD-1 investments totaled $$$$$. Exhibit P-36; Tr., pp. 554 - 555. The Division criticized the 12% rate that NAME-2 used to estimate the ROI costs in his net-back approach. It also criticized NAME-2's use of a 14-year life to derive the depreciation costs associated with the PLANT-1 additions.

123. NAME-2 used a 12% rate to estimate the ROI costs in his net-back approach. He considered this to be a "conservative" rate because one AFE ("authority for expenditure") for the PLANT-1 showed an ROI of 15% and another an ROI of 13.4%. Tr., pp. 556 - 561; Exhibit P-37. NAME-2 explained that he used a 14-year life to depreciate the PLANT-1 additions because there were only 14 years of expected remaining production life left in the field when the AFEs were approved.

[14] He also determined that the UNIT-2 NGLs would have a zero value for all years at issue. As discussed earlier, the value of TAXPAYER UNIT-2 NGLs has already been determined in the Commission's 2007 Decision.

124. The Division submitted a document that TAXPAYER had initially provided for its net-back approach for NGLs for 1997, on which it reported $$$$$ of annual depreciation and a 7.73% rate of return ("ROR"). Exhibit R-53. NAME-3 testified that this information does not correspond with NAME-2's use of a 12% ROI or a 14-year life in his net-back calculations. NAME-3 stated that the $$$$$ amount of depreciation was based on a depreciation life of approximately 18.5 years. The Division did not know where TAXPAYER obtained either the 7.73% ROR or the 18.5-year life it used to depreciate its assets.

125. TAXPAYER has documents to support the 12% ROI that NAME-2 used in his net-back calculations. However, no documents were submitted to show where TAXPAYER obtained the 7.73% ROR found on the 1997 document it had submitted to the Tax Commission around 1997. NAME-2 stated that he has used rates in other states that support his 12% rate better than they support the 7.73% rate provided by the County and that he believes the ROI rate should be somewhere in between 12% and 14%. Tr., p. 836. Based on this evidence, the 12% rate used by NAME-2 is more convincing.

126. TAXPAYER provided no documents to support NAME-2's claim that there were only 14 years of expected remaining production life left in the field when the AFEs were approved. Because TAXPAYER reported depreciation based on an 18.5-year life in 1997, after the plant was built, TAXPAYER has not met its burden to show that the 14-year life used by NAME-2 was appropriate.[15] Thus, to the extent that the Commission finds that NAME-2's processing or plant deductions may be used to determine the value of TAXPAYER's UNIT-2 oil and/or residue gas, the net-back calculation should be revised to reflect an 18.5-year life for the plant's depreciation costs.

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[15] Later in the hearing, NAME-2 testified that he had "run" new net-back calculations using an 18.5-year life to depreciation the plant. With this change, he testified that the $$$$$ of taxes he had determined to be due from UNIT-2 residue gas, as shown on Exhibit P-17, would increase to $$$$$. Tr., p. 836 - 838. However, he did not provide his revised calculations for review. This testimony concerning the change in taxes has no effect on the Commission's finding that the 18.5-year life should be used to depreciate the plant.

127. Finally, the Division criticized NAME-2's net-back approach because it is inconsistent with the way costs are calculated for federal royalty purposes. NAME-3 testified the processing costs should be calculated the same for Utah severance tax purposes as they are for federal royalty purposes. Tr., pp. 731 - 732. NAME-3 also testified that processing costs cannot be deducted for oil. Tr., p. 743. Furthermore, she testified that for the gas stream, processing costs can only be taken against NGLs and not against residue gas. Tr., p. 777.

128. TAXPAYER, on the other hand, contends that the Utah definition of "processing costs" provides that a producer performing the processing for itself (as in this case) may deduct from the net-back approach reasonable costs associated with the operation and maintenance of its processing plant, including depreciation and investments costs. Tr., p. 850 – 851.

129. Initially, NAME-3 stated that one could deduct field gathering costs from the well to the plant if the plant is located off of the unit. Tr., p. 732. Later, however, she stated that the assessment would be the same, even if the plant was not on the participating area, because the mixed production stream is separated at the plant, which is the measurement point (regardless of whether it was also measured at the well). Tr., p. 753; pp. 775 - 776.

UNIT-2 Oil

130. For the 1st Audit Period (1994 through 1997), the Division valued the UNIT-2 oil using the arm's-length contract prices at which the oil sold at the lease automatic custody transfer ("LACT") meter at the tailgate of the PLANT-1 after processing. Tr., p. 272.

131. TAXPAYER claims that these contract prices are for the UNIT-2 oil after it has been processed into sweet oil and do not properly reflect its value near the well head, where it is sour oil. As mentioned in Finding of Fact 31, TAXPAYER's witness, NAME-1, testified that sales of oil sometimes occur at the wellhead. NAME-1 admitted, however, that he had never negotiated oil contracts. Tr., p.

797. TAXPAYER admitted that there are no arm's-length contracts at the wellhead for the production from the UNIT-2. Tr., p. 53.

132. For the 2nd Audit Period (1998 – 1999), the Division valued the UNIT-2 oil using posted spot prices for AREA-1 sweet oil. Tr., p. 272; Exhibit P-14. The posted prices the Division used to value the UNIT-2 oil for 1998 and 1999 were adjusted for gravity. Tr., pp. 293, 728.

133. TAXPAYER argued that the Division did not adjust the sweet oil posted prices it used for 1998 and 1999 for transportation, for basic sediment and water ("BS&W"), or for sour versus sweet oil. As a result, TAXPAYER argues that these posted prices are for sweet oil that is not of like-quality to its sour UNIT-2 oil and, thus, cannot be used to value it.

134. When NAME-4 questioned NAME-3 about the posted prices the Division used for 1998 and 1999, he asked her whether the Division had made any adjustment for transportation to STATION-1, where delivery would occur. NAME-3 admitted that the Division did not make any adjustment for transportation to the STATION-1. NAME-3 explained that the Division "just put in a price" because TAXPAYER had made no filings for these years. Tr., p. 728. TAXPAYER, however, did not provide any information to show what the transportation costs to STATION-1 would be or what transportation adjustment would be appropriate.

135. TAXPAYER pointed out that the posted prices might also be adjusted for BS&W. NAME-3 acknowledged that the Division did not make any adjustment to the sweet oil posted prices to account for BS&W. Tr., pp. 727 – 728. However, she also said that most postings allow oil to be accepted with a BS&W up to 1%, which is supported by information the Division provided in Exhibit R-13. TAXPAYER did not provide any information to show that prior to processing, the UNIT-2 oil had a BS&W level in excess of 1%. Accordingly, the Commission finds that TAXPAYER has not shown that a

BS&W adjustment was necessary. In addition, TAXPAYER did not provide any information to show what the BS&W adjustment should have been, had the BS&W level been in excess of 1%.

136. NAME-3 also acknowledged that the Division did not make any adjustment to the sweet oil posted prices to account for the UNIT-2 oil being sour oil. Tr., pp. 727 – 728. NAME-3, however, explained that a lot of wells in STATION-1 also produce sour crude and, thus, are of like-quality to TAXPAYER's sour UNIT-2 oil. Although NAME-3 would not admit that these STATION-1 wells had the same contaminants at the same level as the UNIT-2 production, she stated that these contaminants were in the gas stream, and she was talking about the oil stream. She stated that what is left in the oil stream after separation "is of like quality to STATION-1." Tr., p. 758 - 763.

137. NAME-3, unlike NAME-1, has extensive expertise concerning oil contracts and the valuation of oil for federal and state purposes. While TAXPAYER submitted composition analyses of the UNIT-2 gas stream to show the level of the contaminants in it, it did not provide composition analyses of the UNIT-2 oil stream to show that this sour oil was more contaminated than other sour oil for which posted prices are available. For these reasons, NAME-3's statement that the UNIT-2 oil, after separation from the UNIT-2 gas stream, is of like quality to STATION-1 oil is convincing.

138. Regardless, the Division used sweet postings to value the sour UNIT-2 oil, not sour postings. TAXPAYER did not show what adjustment would be necessary to adjust a posted price of sweet oil to reflect the price of sour oil. The Division, on the other hand, provided prices from Phillips 66 Company's Crude Oil Price Bulletin ("Phillips Bulletin") to compare the prices of "intermediate" crude and sour crude oil in STATE-1 and STATE-2 for each month of the Consolidated Audit Period. Exhibit R-13 (Crude Oil Price Comparison tab). NAME-3 testified that these prices show the difference in price between sweet oil and sour oil. Tr., pp. 660 - 661. During the Consolidated Audit Period, the difference in price between the intermediate crude and sour crude in STATE-1 and STATE-2 ranged between $$$$$

and $$$$$ per barrel. For the vast majority of the months in the Consolidated Audit Period, the difference in price ranged between $$$$$ and $$$$$ per barrel.

139. The Division provided REMOVED NAME from different months throughout the audit period to verify the price differences it had calculated between the intermediate oil and sour crude. These bulletins also showed the prices of STATE-3 Sweet and STATE-4 Sour oil. In all cases, the STATE-1 and STATE-2 Sour oil and STATE-4 Sour oil had lower prices than the other oils listed. However, in no instance was the difference between one of the "sour" oils and one of the other oils more than the price differential of $$$$$ to $$$$$ per barrel that the Division had shown as the price difference between STATE-1 and STATE-2 intermediate oil and sour oil.

140. The Division also provided information to show that the posted prices for AREA-1 sweet oil that it used to assess the UNIT-2 oil for the 2nd Audit Period are similar to the STATE-1 and STATE-2 intermediate prices that it used to calculate the price difference between sweet and sour oil. Exhibit R-13 (Oil Posted Prices tab). Accordingly, the $$$$$ to $$$$$ per barrel price difference the Division determined from the STATE-1 and STATE-2 intermediate and sour crude prices is a reasonable reflection of the adjustment that needs to be made to the AREA-1 sweet oil prices to reflect the sour condition of the UNIT-2 oil. It is also a reasonable reflection of the adjustment that should also be made to the sweet oil contract prices at which the Division assessed the UNIT-2 oil for the 1st Audit Period.

141. Based on the prior three paragraphs, the sweet oil prices the Division used to assess the sour UNIT-2 oil at issue for both the 1st and 2nd Audit Periods should be reduced somewhere in between $$$$$ and $$$$$ per barrel to reflect its sour state upon separation from the gas stream near the wellhead. TAXPAYER has not shown that adjustments somewhere in this range are insufficient to reflect the value of its sour UNIT-2 oil once it is separated from the gas stream at the meter near the wellhead.

142. Because there is some question as to whether a transportation adjustment should also be made to the posted prices used by the Division, the Commission finds that it would be appropriate to use the "higher" end of the $$$$$ to $$$$$ per barrel adjustment range to adjust the sweet prices the Division used to value TAXPAYER's sour UNIT-2 oil for the Consolidated Audit Period. An adjustment rate of $$$$$ per barrel would account for all adjustments that have been shown to be appropriate.

143. For the years at issue, the Division valued the UNIT-2 oil with prices that ranged from $$$$$ per barrel (for 1999) to $$$$$ per barrel (for 1996). Reducing these sweet oil prices by $$$$$ per barrel would result in revised prices for the sour UNIT-2 oil that range from $$$$$ to $$$$$ per barrel for the different years at issue. TAXPAYER has not shown that these revised prices are inappropriate to value its sour UNIT-2 oil. During the Consolidated Audit Period, the monthly posted prices of STATE-1 and STATE-2 sour oil ranged between $$$$$ and $$$$$ per barrel. For the months during the Consolidated Audit Period that are available, the posted price of STATE-4 sour oil was never less than $$$$$ per barrel. Exhibit R-13 (Crude Oil Price Comparison tab). TAXPAYER has not provided any posted prices or other public information to show that sour oil sold for prices that are less than the $$$$$ to $$$$$ per barrel range determined above. Furthermore, TAXPAYER has not shown that any sour oil sold for prices to support the zero value it proposes for its sour UNIT-2 oil. For these reasons, the Division's audit of TAXPAYER's UNIT-2 oil should be revised by reducing the prices it used to value this oil by $$$$$ per barrel.

144. <u>TAXPAYER's net-back approach for UNIT-2 oil</u>. NAME-2 compared the reported revenue of oil at the tailgate of the PLANT-1 to the total of field gathering costs (operation expenses, depreciation, and ROI) and plant processing costs (operation expenses, depreciation, and ROI) that he had calculated. With this net-back approach, NAME-2 determined a negative combined value for TAXPAYER's UNIT-1 and UNIT-2 oil for all years except 1997. Exhibit P-34, p. 9. After removing the

costs associated with the UNIT-1 production, NAME-2 stated that he determined a zero value for UNIT-2 oil for all years at issue, as shown on Exhibit P-17.

145. TAXPAYER has not submitted documents showing the changes NAME-2 made to his Exhibit P-34 net-back calculations when he removed the costs associated with the UNIT-1 oil production. Specifically, TAXPAYER has not shown either the field operating expenses or the plant operating expenses for UNIT-2 oil *only*, which NAME-2 would have used when determining a net-back value of zero for the UNIT-2 oil for all years. However, it is assumed that NAME-2 used a majority of the combined field operating costs and plant processing costs shown for the combined oil, as shown in Exhibit P-34 (p. 9), to estimate the net-back value of the UNIT-2 oil alone because he allocated costs on the basis of revenues and because the UNIT-2 oil revenues appear to exceed the UNIT-1 oil revenues, as shown in the Statutory Notices (Exhibits P-13 and P-14.)

146. TAXPAYER owns the pipelines and other equipment that it uses to gather and transport the UNIT-2 oil from the UNIT-2 wells to the PLANT-1 to be processed. In any case, no contracts were submitted to show that TAXPAYER incurs costs under an arm's length transportation contract to gather and/or transport the UNIT-2 oil to the PLANT-1.

147. NAME-3 also testified that one problem with NAME-2's net-back calculations is that he took processing costs and deducted them from the price obtained from oil and that "our statute doesn't allow for processing costs against oil." Tr., p. 743.

UNIT-2 Gas

148. For all periods, the Division used the arm's-length contract prices of gas at the tailgate of the PLANT-1 (after processing) to value TAXPAYER's UNIT-2 residue gas. Tr., pp. 210 - 211. As a result, the Division did not determine a value for the unprocessed, sour UNIT-2 gas stream. It determined values for this gas stream after it was processed at the PLANT-1 into residue gas and NGLs. NAME-3

explained that gas in its raw natural state at the well site, if separated, is "wet" gas as opposed to a "dry" residue gas after it has been processed and had all of the NGLs "drop off." Tr., p. 213.

149. TAXPAYER used the net-back method to value its UNIT-2 gas steam. For this approach, NAME-2 took the reported revenue of the residue gas at the tailgate of the PLANT-1 (after processing) and deducted field gathering costs (operation expenses, depreciation, and ROI) and plant processing costs (operation expenses, depreciation, and ROI). As a result, TAXPAYER, like the Division, did not determine a value for the "wet" UNIT-2 gas stream before it was processed, but determined values for products produced from the gas stream after it was processed at the plant into residue gas and NGLs.

150. NAME-3 stated that gas could be sold at the custody transfer or metering point that typically occurs before entering a gas plant for processing. If sold there, severance tax could be imposed at the price received there. Tr., pp. 240 - 241. NAME-3 also testified that if the plant is not on the participating area, then the proper point of valuation would be before it went into the plant. Tr., pp. 353 - 354.

151. NAME-1 testified that the PLANT-1 &UNIT-2 gas is "very unusual gas" and that he would be surprised if one could find another plant to "fit" this gas. NAME-1 stated that the PLANT-1 is one of the most expensive plants he has seen in his experience because it had to deal with the three major contaminants found in the UNIT-2 gas stream. He explained that TAXPAYER had no other options other than to build the PLANT-1 to process this gas. Tr., p. 451.

152. NAME-1 explained that the UNIT-2 gas could not be put on the PIPELINE or sold until it was "cleaned up," or processed. Tr., pp. 455 - 456. Later, NAME-1 testified that a gas stream with three major contaminants, like the UNIT-2 gas, could be sold at the wellhead. Tr., pp. 528 - 529.

153. There is no evidence of arm's-length or non-arm's length contracts for the sale of UNIT-2 gas prior to the tailgate of the PLANT-1. In addition, neither party presented evidence of posted prices or other public information with which a value could be established for the UNIT-2 gas.

154. Although the UNIT-2 gas was never sold from the wellhead, NAME-3 admitted that gas was sold from the wellhead for wells in the STATION-1 field, which is about 50 miles south of the FIELD-1. She stated that the gas was then delivered by "a little pipeline" to the STATION-1 Plant. Tr., p. 711 - 713. NAME-1 testified that he had experience with STATION-1 gas and knew that the CO_2 levels in the STATION-1 gas, unlike the UNIT-2 gas, meets the quality specifications of the pipeline. Tr., pp. 787, 808 - 809.

155. TAXPAYER also admits that there are no sales of UNIT-2 gas near the wellhead. However, it argues that the UNIT-2 gas should, nevertheless, be valued at the wellhead because there were some sales for UNIT-1 gas at the wellhead for an earlier period, 1991 through 1993. TAXPAYER admitted, however, that the UNIT-1 gas is almost pure methane and is pipeline quality. Tr., pp. 852-853, 861 - 866.

156. <u>TAXPAYER's Net-Back Approach for Residue Gas</u>. Initially, NAME-2 calculated a combined net-back approach for both the UNIT-1 residue gas and UNIT-2 residue gas. With this approach, he determined a negative combined value for the UNIT-1 residue gas and UNIT-2 residue gas for 1994, 1995, and 1996, and a positive value for 1997, 1998, and 1999. Exhibit P-34, p. 7. After removing the costs associated with the UNIT-1 production, NAME-2 stated that he calculated a zero value for the UNIT-2 residue gas for all years except for 1998 and 1999, as shown on Exhibit P-17.

157. TAXPAYER has not submitted documents showing the changes NAME-2 made to his Exhibit P-34 net-back calculations when he removed the costs associated with the UNIT-1 residue gas oil production. Specifically, TAXPAYER has not shown either the field operating expenses or the plant

operating expenses for UNIT-2 residue gas *only* that NAME-2 used to determine his net-back values for the UNIT-2 residue gas oil as shown on Exhibit P-17. However, it is assumed that NAME-2 used a large majority of the combined field operating costs and plant processing costs, as shown in Exhibit P-34 (p. 9) for the combined residue gas, to estimate the net-back value of the UNIT-2 residue gas alone because he allocated costs on the basis of revenues and because the UNIT-2 residue gas revenues appear to greatly exceed the UNIT-1 residue gas revenues, as shown in the Statutory Notices (Exhibits P-13 and P-14) and Exhibit P-17.

158. NAME-3 criticized NAME-2's net-back approach because he allocated and deducted processing costs when determining a net-back value for both residue gas and NGLs. NAME-3 indicated that when the gas stream is valued, all of your processing costs are deducted against NGLs in most cases, and no costs are allocated against residue gas value. Tr. pp. 246, 341.

159. There is no evidence to show that TAXPAYER requested and/or received permission from the MMS to deduct processing costs against the value of residue gas. TAXPAYER submitted evidence showing that it applied for and received permission from the MMS to deduct excess processing costs from the value of NGLs for 1996, 1997, 1998, and 1999. Exhibit P-16. However, the MMS letter for 1996 specifically grants TAXPAYER permission to deduct excess processing costs "not to exceed 99 percent of the value of sulfur and NGL's produced at the PLANT-1[,]" while the MMS letters for 1997, 1998, and 1999 specifically grant TAXPAYER permission to deduct excess processing costs "not to exceed 99 percent of the value of the liquid plant products and sulfur processed at PLANT-1[.]" None of the letters make any mention of granting TAXPAYER permission to deduct any processing costs against the value of residue gas produced at the plant.

160. In regards to transportation costs in a net-back approach, NAME-3 also testified that if the plant is off the unit, you can deduct transportation costs to get back to a point on the unit. NAME-3

admitted that the Division did not allow any adjustment for transportation off the field in its audit. Tr., pp. 251 – 252, 254, 261.

161. <u>NAME-1's Price Estimate for UNIT-2 Residue Gas</u>. NAME-1 testified that the price TAXPAYER received for the UNIT-2 residue gas at the tailgate (after processing) would not be the same price that TAXPAYER would have hypothetically received for the UNIT-2 gas had it been sold at the wellhead (prior to processing). Tr., p. 383.

162. NAME-1 estimated the price at which the UNIT-2 residue gas might have sold near the wellhead during the 1st Audit Period (1994 through 1997) by taking a tailgate price and adjusting it downward for transportation, shrinkage, processing, etc. Exhibit P-26. NAME-1 started with a tailgate price of $$$$$ per MMBtu.[16] From this price, he deducted transportation costs of $$$$$ to arrive at a preliminary value of $$$$$ per MMBtu before reducing the price for shrinkage, processing, etc. NAME-1 stated that his transportation deduction to estimate a value near the wellhead "is an average" transportation cost. Tr., p. 396.

163. After making these adjustments, NAME-1 determined that the UNIT-2 gas had a negative value of approximately -$$$$$ per MMBtu and was "worthless." As a result, he believes that TAXPAYER's position of a zero value for the UNIT-2 residue gas for severance tax purposes is reasonable. NAME-1 stated that during "this time period," it was a "tough time" because of the low prices for gas. Tr., p. 410.

164. NAME-1 testified that prices went up in 1998 and 1999. However, he stated that would have still reached a negative value for the UNIT-2 gas for the 2nd Audit Period because his adjustments

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[16] For the four years of the 1st Audit Period, the Division used prices to assess the UNIT-2 residue gas that ranged between $$$$$ per unit in 1995 and $$$$$ per unit in 1997. Exhibit P-13.

were conservative. He stated that residue gas would need to sell somewhere between $$$$$ and $$$$$ per MMBtu to break even. Tr., pp. 437 - 438.[17]

165. NAME-1's price estimate is not one of the four valuation methods with which gas can be valued under UCA §59-5-103(1). It is not an arm's length or non-arm's length contract for the sale of the UNIT-2 residue gas at the well. In addition, it is not a posted price or other reliable public source of price or market information. Furthermore, it is not a value established using the net-back method, in which actual allowable costs are deducted from the proceeds received after processing.

166. TAXPAYER has not shown that sales of gas as contaminated as the UNIT-2 gas have ever occurred near the wellhead before such gas is processed.

APPLICABLE LAW

1. Utah Code Ann. §59-5-102(1999)[18] imposes a severance tax on oil and gas produced from a well in Utah, as follows in pertinent part:

> (1) (a) Each person owning an interest, working interest, royalty interest, payments out of production, or any other interest, in oil or gas produced from a well in the state, or in the proceeds of the production, shall pay to the state a severance tax equal to 4% of the value, at the well, of the oil or gas produced, saved, and sold or transported from the field where the substance was produced.
> . . . .
> (f) If the oil or gas is stockpiled, the tax is not applicable until it is sold, transported, or delivered. However, oil or gas that is stockpiled for more than two years is subject to the severance tax.
>
> . . . .

2. During the Consolidated Audit Period, UCA §59-5-103 provides that the value of oil or gas shall be determined, as follows:

> (1) For purposes of computing the severance tax, the value of oil or gas at the well is the value established under an arm's-length contract for the purchase of production at the

[17] For the two years of the 2nd Audit Period, the Division assessed the UNIT-2 residue gas using prices of $$$$$ per MMBtu in 1998 and $$$$$ per MMBtu in 1999. Exhibit P-14.

[18] All citations are to the 1999 version of Utah law, unless otherwise indicated.

> well, or in the absence of such a contract, by the value established in accordance with the first applicable of the following methods:
>
> (a) the value at the well established under a non-arm's length contract for the purchase of production at the well, provided that the value is equivalent to the value received under comparable arm's-length contracts for purchases or sales of like-quality oil or gas in the same field;
>
> (b) the value at the well determined by consideration of information relevant in valuing like-quality oil or gas at the well in the same field or nearby fields or areas such as: posted prices, prices received in arm's-length spot sales, or other reliable public sources of price or market information;
>
> (c) the value established using the net-back method as defined in Section 59-5-101.
>
> . . . .
>
> (3) Any contract between a parent and a subsidiary company, or between companies wholly or partially owned by a common parent, or between companies otherwise affiliated that specifies the value of oil or gas is not arm's-length unless the value of oil or gas specified is comparable to its fair market value as defined under Section 59-2-102. If there is a controversy, the commission shall determine the value of the oil or gas.

3. UCA §59-5-101 provides definitions pertaining to Utah's severance tax, as follows in relevant part:

> . . . .
>
> (7) "Net-back method" means a method for calculating the fair market value of oil or gas at the well. Under this method, costs of transportation, not to exceed 50% of the value of the oil or gas, and processing shall be deducted from the proceeds received for the oil or gas and any extracted or processed products, or from the value of the oil or gas or any extracted or processed products at the first point at which the fair-market value for those products is determined by a sale pursuant to an arm's-length contract or comparison to other sales of those products. Processing and transportation costs shall be deducted only from the value of the processed or transported product.
>
> . . . .
>
> (9) "Oil or gas field" means a geographical area overlying oil or gas structures. The boundaries of oil or gas fields shall conform with the boundaries as fixed by the Board and Division of Oil, Gas and Mining under Title 40, Chapter 6.
>
> . . . .
>
> (11) "Processing costs" means the reasonable actual costs of processing gas. Processing costs determined by an arm's-length contract are the actual costs. Where processing costs are not determined by an arm's-length contract, including those situations where the producer performs the processing for himself, the actual costs of processing shall be those reasonable costs associated with the actual operating and maintenance expenses, overhead directly attributable and allocable to the operation and maintenance, and either depreciation and a return on undepreciated capital investment, or a cost equal to a return on the investment in the processing facilities as determined by the tax commission. The tax commission shall adopt rules to implement this definition, and may adopt federal regulations where applicable.

> . . . .
> (17) “Transportation costs” means the reasonable actual costs of transporting oil or gas products from the well to the point of sale except the transportation allowance deduction may not exceed 50% of the value of the oil or gas. Transportation costs determined by an arm's-length contract are the actual costs. Where transportation costs are not determined by an arm's-length contract, including those situations where the producer performs the transportation service for himself, the actual costs of transportation shall be those reasonable costs associated with the actual operating and maintenance expenses, overhead costs directly attributable and allocable to the operation and maintenance, and either depreciation and a return on undepreciated capital investment, or a cost equal to a return on the investment in the transportation system as determined by the tax commission. The tax commission shall adopt rules to implement this definition, and may adopt federal regulations where applicable.
> . . . .
> (19) “Value at the well” means the value of oil or gas at the point production is completed.
> (20) “Well or wells” means any extractive means from which oil or gas is produced or extracted, located within an oil or gas field, and operated by one person.
> . . . .

4. In 1990, the Utah Legislature passed House Bill 63 (“H.B. 63), entitled “Oil and Gas Severance Tax Amendments.” Although not codified, H.B. 63 provides in Section 4 that “[t]he applicable federal regulations remain in effect until the commission makes the rules authorized by this chapter.” 1990 Laws of Utah, ch. 247, sec. 4.

5. The 2007 version of the MMS federal regulations[19] provides guidance concerning the valuation of oil and gas. The MMS federal regulations define a “field” to mean “a geographic region situated over one or more subsurface oil and gas reservoirs and encompassing at least outermost boundaries of an all and gas accumulations known within those reservoirs . . .” 30 C.F.R. §206.101 (for oil) and 30 C.F.R. §206.151 (for gas).

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19 The parties have quoted limited portions of the 1999 version of the MMS federal regulations in their briefs and in other evidence. The Commission notes that the 1999 regulations the parties quoted are identical to those found in the 2007 version of the regulations. For this reason and because there is no evidence to suggest that the federal regulations in effect for the years at issue are different from the regulations in effect at the time of the 2007 Formal Hearing, the Commission has relied on the 2007 version of the federal regulations.

6. For the valuation of oil, 30 C.F.R. §206.101 also provides other definitions, as follows in pertinent part:

> . . . .
> *Gathering* means the movement of lease production to a central accumulation or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS approves for onshore and offshore leases, respectively.
> . . . .
> *Transportation allowance* means a deduction in determining royalty value for the reasonable, actual costs of moving oil to a point of sale or delivery off the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.
> . . . .

7. 30 C.F.R. §206.102(a) provides that "[t]he value of oil under this section is the gross proceeds accruing to the seller under the arm's length contract, less applicable allowances determined under §§206.110 or 206.111."

8. 30 C.F.R. §206.110 provides for a transportation allowance for oil where an arm's-length transportation contract exists. If there is no arm's-length transportation contract, 30 C.F.R. §206.111(a) and (b) provide that the transportation allowance is based on "reasonable, actual costs for transportation," which include operating and maintenance expenses, overhead, depreciation, and a return on undepreciated capital investment.

9. For the valuation of gas, 30 C.F.R. §206.151 also provides other definitions, as follows in pertinent part:

> *Allowance* means a deduction in determining value for royalty purposes. *Processing allowance* means an allowance for the reasonable, actual costs of processing gas determined under this subpart. *Transportation allowance* means an allowance for the reasonable, actual costs of moving unprocessed gas, residue gas, or gas plant products to a point of sale or delivery off the lease, unit area, or communitized area, or away from a processing plant. The transportation allowance does not include gathering costs.
> . . . .
> *Gathering* means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively.

10. Separate federal regulations exist for the valuation of gas that has not been processed and gas that has been processed. For gas that has been processed, like the UNIT-2gas at issue, 30 C.F.R. §206.153(2) provides that its value "shall be the combined value of the residue gas and all gas products . . . less applicable transportation allowances and processing allowances. . . ."

11. 30 C.F.R. §206.156 provides for a transportation allowance for gas, as follows in pertinent part:

> (a) . . . MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from a lease to a gas processing plant off the lease and from the plant to a point away from the plant.
> (b) Transportation costs must be allocated among all products produced and transported as provided in §206.157.
> (c) (1) . . . .
> (2) . . . for gas production valued in accordance with §206.153 of this subpart the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the residue gas or gas plant product determined in accordance with §206.153 of this subpart. For purposes of this section, natural gas liquids shall be considered one product.

12. For gas that has been processed, 30 C.F.R. §206.158 provides a processing allowance, as follows in pertinent part:

> (a) Where the value of gas is determined pursuant to §206.153 of this subpart, a deduction shall be allowed for the reasonable actual costs of processing.
> . . . .
> (c) (1) Except as provided in paragraph (d)(2) of this section, the processing allowance shall not be applied against the value of residue gas. Where there is no residue gas MMS may designate an appropriate gas plant product against which no allowance may be applied.
> (2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an individual product shall not exceed 66 2/3 percent of the value of each gas plant product determined in accordance with §206.153 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by §206.156 of this subpart).
> (3) Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An

> application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.
>
> (d) . . . .
> (2) (i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pursuant to this section. . . .

13. UCA §40-6-14 imposes a "conservation fee" on the value of oil and gas produced in Utah, as follows in pertinent part:

> (1) There is levied a fee of .002 of the value at the well of oil and gas:
> (a) produced and saved;
> (b) sold; or
> (c) transported from the premises in Utah where the oil or gas is produced.

<u>DISCUSSION</u>

The remaining issues primarily concern the value of the oil and residue gas that TAXPAYER produced from the UNIT-2 during the 1994 through 1999 tax years. Section 59-5-102 imposes "a severance tax equal to 4% of the value, at the well, of the oil or gas produced, saved, and sold or transported from the field where the substance was produced." Section 59-5-101(19) defines "value at the well" to mean "the value of oil or gas at the point production is completed."

In addition, Section 59-5-103(1) provides different methods with which the "value of oil or gas at the well" may be determined. The preferred method for determining "the value of oil or gas at the well is the value established under an arm's-length contract for the purchase of production at the well . . . ." If the value cannot be established by such a contract, Section 59-5-103(1) provides that value shall be determined by the first applicable of the following three methods:

> (a) the value at the well established under a non-arm's length contract for the purchase of production at the well, provided that the value is equivalent to the value received under comparable arm's-length contracts for purchases or sales of like-quality oil or gas in the same field;

> (b) the value at the well determined by consideration of information relevant in valuing like-quality oil or gas at the well in the same field or nearby fields or areas such as: posted prices, prices received in arm's-length spot sales, or other reliable public sources of price or market information;
> (c) the value established using the net-back method as defined in Section 59-5-101.

The UNIT-2 oil and gas that TAXPAYER produced is considered to be "sour oil" and "sour gas" when removed from the ground and remained so until it was processed into sweet oil and sweet gas at the PLANT-1. TAXPAYER asks the Commission to use the net-back method described in Section 59-5-103(1)(c) to value this oil and residue gas at the meter near the wellhead where it is first separated and measured (prior to its being taken to the PLANT-1 for processing). TAXPAYER admits that there are actual contracts for the sale of its UNIT-2 oil and gas once it has been processed into sweet oil and sweet gas at the PLANT-1. TAXPAYER contends, however, that these contracts do not reflect "value at the well" and, thus, are inappropriate to value the UNIT-2 oil and gas for severance tax purposes. TAXPAYER also contends that there are no non-arm's length contracts at the well or any posted prices or other public information relevant in valuing its UNIT-2 oil and gas. Accordingly, TAXPAYER argues that the UNIT-2 oil and gas cannot be valued under either Section 59-5-102(1)(a) or (1)(b) and that the only method left to value the UNIT-2 oil and gas is the net-back method under Section 59-5-102(1)(c).

The Division, on the other hand, contends that the UNIT-2 oil and gas at issue should be valued after it has been processed at the PLANT-1, specifically when it is sold as sweet oil and sweet gas. The Division contends that valuing the products after processing properly values the products "at the point production is completed." The Division argues that production was not, as TAXPAYER contends, completed at the meter near the wellhead because TAXPAYER did not sell its UNIT-2 oil and gas at this point. For these reasons, the Division contends that the UNIT-2 oil and gas can be valued with actual contracts, the preferred method.

The Division also admitted that there are no non-arm's length contracts to value either the UNIT-2 oil or gas under Section 59-5-102(1)(a). In addition, the Division provided no posted prices or other public information with which the UNIT-2 gas could be valued under Section 59-5-102(1)(b). However, it did provide some posted prices for sweet oil and sour oil in various locations in the south and the southwest to use in valuing the UNIT-2 oil under Section 59-5-102(1)(b). Finally, should the Commission agree with TAXPAYER that the net-back method must be used to value the UNIT-2 oil and/or gas, the Division contends that TAXPAYER's net-back calculations are flawed for several reasons.

Neither party's position is entirely satisfying. Severance tax is a tax charged on the removal of nonrenewable resources from the earth. Severance tax is not a sales tax or an income tax. As a result, the severance tax is not always equal to the price at which the product is first sold or, conceivably, could have been sold. In addition, a producer may still be liable for a severance tax even if it does not realize a profit on its investment. That being said, it appears evident that sour oil and sour gas would generally sell for a lower price than sweet oil and sweet gas. The Division's position would result in the UNIT-2 sour oil and sour gas at issue being taxed at the same rate as sweet oil and sweet gas. On the other hand, the Division's position uses actual contracts to value the UNIT-2 oil and gas, which is preferred. TAXPAYER does not sell any of the UNIT-2 sour oil and sour gas near the wellhead, unlike its UNIT-1 sweet oil and sweet gas. Accordingly, there are no actual contracts for the UNIT-2 oil and gas other than the ones relied on by the Division.

Moreover, TAXPAYER's position is based on the net-back approach, which is the least preferred method to value oil and gas. Nevertheless, TAXPAYER's approach produces values for its UNIT-2 sour oil and sour gas that are lower than the values of its UNIT-1 sweet oil and sweet gas. Further complicating the matter is whether the sour oil and sour gas at issue have little or no value for severance tax purposes, which would be the effect of accepting TAXPAYER's net-back calculations. TAXPAYER contends that the net-back method results in a zero value for its UNIT-2 oil for all six years at issue and in a zero value for its UNIT-2 residue gas for four of the six years at issue.

The first issue for the Commission to decide is the point at which the UNIT-2 oil and gas should be valued for severance tax purposes. TAXPAYER contends that both should be valued at the meter near the wellhead, while the Division contends that both should be valued when they are first sold, which in this case is at the tailgate of the PLANT-1 after being processed into sweet oil and sweet residue gas. If the Commission agrees with the Division's position concerning the point of valuation for both the UNIT-2 oil and residue gas, the Division's audits in regards to these products will be sustained.

However, if the Commission agrees with TAXPAYER's argument that valuation should occur before the UNIT-2 oil and gas is processed into sweet oil and sweet gas, it would be inappropriate to value these products with actual contracts at the tailgate of the plant. In addition, because there are no actual contracts for the sale of the UNIT-2 oil and gas prior to processing, a second issue would arise. Specifically, the Commission would need to determine a value derived with one of three alternative valuation methods and, if the net-back method is the appropriate method, whether TAXPAYER net-back calculations are appropriate.

I. Should the value of the UNIT-2 oil and residue gas be determined before or after it is processed at the PLANT-1?

The Utah Supreme Court has provided some guidance on the point of valuation of oil and gas in *ExxonMobil*. In that case, the parties also disagreed on the point at which ExxonMobil's oil and gas should be valued. The Division argued that it should be valued at the point at which it was first sold, regardless of whether it had been refined prior to the sale, whereas the taxpayer argued that it should be valued at the point where it was extracted from the ground.

The Court found that because the statutory language in question was “not plain,” its interpretation needed to be based on “policy considerations and our mandate that taxing statutes be construed in favor of the taxpayer.” The Court found that neither party’s position “completely reconcile[d] with the valuation provision of the severance tax statutes.” The Court criticized the Commission’s position, stating:

> Accepting the Tax Commission's position would lead to a widely disparate tax, based not on the value of oil or gas actually removed from the ground and thus taken from the state's pool of natural resources, but based on the sales and marketing strategies of the various interest holders. A producer with testing facilities on site could sell directly from the well's valve structure and pay a much smaller tax than one who removes impurities or otherwise refines the oil to sell at the battery facility.

The Court also rejected the taxpayer’s position because it “ignores the clear legislative preference for valuation by reference to actual contracts for sale.” For this reason and based on the Tax Commission’s unchallenged factual finding that “sales rarely occur without at least some separation in a separator tank or some further refinement,” the Court held that:

> valuation does not necessarily occur at the point of sale, wherever that may be, but rather in the immediate vicinity of the point at which the oil or gas is physically removed from the earth. However, to qualify as the point at which production is complete, that point must be one at which sales of the oil and gas may actually occur.

The Court explained that “[t]he language of the statute contemplates calculation within the immediate vicinity of the point of removal from the earth, but it also compels calculation at some point where sales are not a distinct rarity.” The Court noted that:

> The nature of the industry is such that sales rarely, if ever, occur directly from the valve structure. . . . The statute, however, assumes a market for oil and gas at the point of valuation. Thus, although we hold that valuation is to occur in the immediate vicinity of the point of removal, it need not necessarily occur at the point of physical removal from the earth. There appears to be a market for oil and gas taken from the separator tanks near the well head. The Tax Commission so found, although it apparently believed the failure of ExxonMobil to sell much of its oil and gas at that point was fatal to its claim for valuation there. This was error. Valuation of the oil and gas at the separator tank allows valuation to occur while the oil and gas are in a relatively raw state, at the earliest possible, yet practicable, point of sale. Where no separator tank is used, valuation may still occur by reference to the value of similar oil at separator tanks in the same field.

On remand to the Commission, the Division argued that because there are generally no separation tanks at ExxonMobil's wellheads, the Court's decision supported its valuation of ExxonMobil's oil and gas at the point of eventual sale. The Commission rejected the Division's argument, noting that the Court recognized that although ExxonMobil did not sell much of its oil and gas at near the wellhead, there were sufficient sales to create a market at that point. The Commission found that other methods to value ExxonMobil's oil and gas had not been provided and accepted the net-back approach that ExxonMobil had developed to value its oil and gas. The Commission noted that "it has no choice but to accept" ExxonMobil's net-back approach because the "Division did not substantially refute ExxonMobil's value other than to ask now, at this late point in the proceeding, for time to audit the numbers."

In *ExxonMobil*, the Court found that "[t]he language of the statute **contemplates** calculation within the immediate vicinity of the point of removal from the earth, but it also **compels** calculation at some point where sales are not a distinct rarity" (emphasis added). When the Court uses the word 'compels,' the Commission understands the Court to be giving greater importance to the point at which sales are made than the Court gives to valuation 'within immediate vicinity of the point of removal from the earth,' which was only 'contemplated' by the statute. For these reasons, the Commission determines that the point of valuation should be made at the earliest possible, yet practicable point of sale or the earliest point where sales are not a distinct rarity.

Points of valuation may be different for oil and gas because of differences in the points at which they are sold and because the oil stream is often separated from the gas stream near the well for measurement or other purposes. Accordingly, the Commission will determine the points of valuation separately for the UNIT-2 oil and gas.

UNIT-2 Oil. TAXPAYER did not sell the UNIT-2 oil at issue prior to its being processed at the PLANT-1. In fact, there were no tanks near the UNIT-2 wellheads at which the UNIT-2 oil could be sold and delivered to a buyer. Nevertheless, the evidence clearly shows that oil is sometimes sold and delivered to a buyer at tanks located near the wellhead. In fact, some of the UNIT-1 oil from the same field[20] as the UNIT-2 oil was sold at the tanks that are near the UNIT-1 wellheads. In addition, the Commission has previously found that the sour UNIT-2 oil, once separated from the UNIT-2 gas, is of like quality to other oil in the STATION-1 area (Finding of Fact #137). For these reasons, the Commission finds that there is a market for TAXPAYER's UNIT-2 oil at the meter near the wellhead. Accordingly, the Commission finds that the value of the UNIT-2 oil should be determined at the meter near the wellhead, as TAXPAYER proposes.

UNIT-2 Gas. TAXPAYER also did not sell the UNIT-2 gas at issue prior to its being processed at the PLANT-1. Although it is clear that sales of unprocessed gas sometimes occur in other fields and even in the FIELD-1 (i.e., TAXPAYER claims that it sold some UNIT-1 gas at the wellhead prior to the audit period, which the Division did not refute), it does not appear that there was a market for the UNIT-2 gas prior to processing. NAME-1 testified that the UNIT-2 gas could be sold prior to processing. However, TAXPAYER did not convincingly show that there was a market for gas as unique and as contaminated as the UNIT-2 gas. The sales of gas that actually occurred prior to processing appear to have been sales of gas that were "pipeline ready." The UNIT-2 gas, prior to processing, was clearly not pipeline ready. Accordingly, for gas as contaminated as the UNIT-2 gas, it appears that sales prior to processing are not only a distinct rarity, they are non-existent.

If there had been no sales of any gas on the FIELD-1 prior to processing and if the PLANT-1 had been located on the FIELD-1, it is likely that the Commission would have found that even under *ExxonMobil*, "the earliest possible, yet practicable, point of sale" would have been after processing at the

[20] The MMS federal regulations define a "field" to mean "a geographic region situated over **one or more** subsurface oil and gas reservoirs . . . ." (emphasis added). 30 C.F.R. 206.101(3) (for oil) and 30 C.F.R. 206.151(3) (for gas).

PLANT-1. However, the facts of this case are different. First, TAXPAYER claimed that sales of UNIT-1 gas occurred at the meter near the wellhead and, though rare, these sales would have occurred in the same field as the UNIT-2 gas. In *ExxonMobil*, the Court found that "[w]here no separator tank is used, valuation may still occur by reference to the value of similar oil at separator tanks **in the same field**" (emphasis added). Although the Court referred to oil in this specific statement, the principal concerning "the same field" would also apply to gas.

Second, the UNIT-2 gas at issue is gathered on the FIELD-1 and transported off of the field to the PLANT-1 for processing. Section 59-5-102(1)(a) imposes the severance tax on the value of "gas produced, saved, and sold or **transported from the field** where the substance was produced" (emphasis added). Furthermore, it is clear that the Division was not aware that the PLANT-1 was located off of the FIELD-1 when it issued its assessments. The Division's positions concerning the point of valuation seemed contradictory because it indicated, at various times, that value might occur when the product left the lease or at the meter at the entrance of the plant, both of which would be prior to processing and different than the Division's ultimate position that valuation would occur at the tailgate of the plant (after processing). For these reasons, the Commission finds that the UNIT-2 gas should be valued at the meter near the wellhead, as TAXPAYER proposes.

II. Given the points of valuation the Commission has determined for the UNIT-2 oil and gas, how should these products be valued based on the available evidence?

The Commission has determined that the point of valuation for both the UNIT-2 oil and the UNIT-2 gas is different from the tailgate of the PLANT-1, which the Division used in its assessments for these products. Accordingly, actual contracts (after processing) at the tailgate of the PLANT-1 should not be used to value the UNIT-2 oil and gas. Furthermore, there are no arm's-length contracts for the sale of either the UNIT-2 oil or the UNIT-2 gas at the point of valuation determined by the Commission.

Accordingly, the Commission will determine the value of these products with one of the three alternative valuation methods found in Section 59-5-103(1).

Both parties agree that the first alternative valuation method concerning non-arm's length contracts, as found in Section 59-5-103(1)(a), cannot be used for either UNIT-2 oil or gas because no such contracts exists. Remaining at issue is whether the UNIT-2 oil and gas should be valued with either the second alternative method concerning posted prices or other public information, as found in Section 59-5-103(1)(b), or the third alternative method concerning the net-back approach, as found in Section 59-5-103(1)(c). The Division provided posted prices or other public information concerning the UNIT-2 oil, but not the UNIT-2 gas. As a result, the Commission will separately address the evidence provided for the UNIT-2 oil and gas.

UNIT-2 Oil. For UNIT-2 oil, the Commission has determined that the preferred method of using actual contracts at the meter near the wellhead is not available. It has also determined that the first alternative method of using non-arm's length contracts at the meter near the wellhead is not available. Remaining at issue is whether the UNIT-2 oil should be valued with posted prices or other public information (the second alternative method) or with the net-back approach (the third alternative method). Of these two methods, the use of posted prices or other public information is preferred. Pursuant to Section 59-5-103(1)(b), value can be determined with this method "by consideration of information relevant in valuing like-quality oil or gas at the well in the same field or nearby fields or areas such as: posted prices, prices received in arm's-length spot sales, or other reliable public sources of price or market information[.]"

In addition to actual contract prices, the Division used posted prices in the nearby area to assess the value of the UNIT-2 oil after it was processed into sweet oil at the PLANT-1. The Division's use of posted prices for sweet oil, however, overestimates the value of the sour UNIT-2 oil at the meter near the wellhead. Neither party provided posted prices of sour oil in the immediate area of the FIELD-1. The Division, however, has provided information that shows the differences in prices for sweet and sour oil in other areas of the south and the southwest. TAXPAYER has argued that this information should not be used because its UNIT-2 oil is more contaminated than other oil and, thus, there are no posted prices or other publically-available data for like-quality production; and because the Division has not made sufficient adjustments to these prices to reflect the quality of the UNIT-2 oil. The Commission, however, finds the Division's evidence to be persuasive.

First, NAME-3, an expert in both oil and gas valuation, indicated that once the UNIT-2 oil is separated from the gas stream, the contaminants remain in the gas stream and that the remaining UNIT-2 oil is of like quality to other oil in the STATION-1 area. NAME-1 was clearly an expert in negotiating contracts for the sale of gas, but admitted that he had never negotiated oil contracts. Second, TAXPAYER did not submit composition analyses of the UNIT-2 oil stream to show the level of its contaminants after its separation from the UNIT-2 gas stream. As a result, TAXPAYER has not shown that its sour UNIT-2 oil is sufficiently different from other sour oil for which the Division provided posted prices or other public information.

The Commission recognizes that the sour oil prices that the Division submitted where not in the immediate area of the FIELD-1. However, the Division proffered two sets of sour oil prices in the south and the southwest to show the differences in prices for sweet and sour oil. TAXPAYER did not contend that the differences in prices between sweet and sour oil nearer to the FIELD-1 would be greater than the differences shown by this information. As a result, the Commission finds that the sweet oil prices the Division used in its assessments should be reduced by $$$$$ per barrel (near the upper end of the differences in prices between sweet and sour oil) to account for all needed adjustments and to reflect the value of TAXPAYER's UNIT-2 oil at the meter near the wellhead.

Furthermore, based on the testimony of NAME-3 and the evidence that shows that sour oil sells for prices "relatively" close to the prices of sweet oil, the Commission is not convinced that the value of the UNIT-2 oil, once separated from the gas stream, has a zero value for severance tax purposes, which would be the result of the net-back approach proposed by TAXPAYER. Although the Commission has determined that the value of the UNIT-2 oil should be determined by revising the Division's assessments for all years to reflect a $$$$$ per barrel reduction in price, the Commission will address TAXPAYER's proposed net-back approach and explain why a lower value would not be derived with this approach.

First, the Commission rejects TAXPAYER's position that the net-back approach should be determined using the definitions of "processing costs" and "transportation costs" as found in Section 59-5-101, without consideration of the MMS federal regulations. When the Commission determined the value of TAXPAYER's NGLs in the 2007 Decision, it specifically found as follows (pp. 35 - 36):

> The Commission agrees with the Division that Utah law requires it to apply the federal regulations. First, the definitions of "processing costs" and "transportation costs" in Section 59-5-101 each include the following statement: "The tax commission shall adopt rules to implement this definition, and may adopt federal regulations where applicable." Second, Section 4 of H.B. 63 provides that the "applicable federal regulations remain in effect until the commission makes the rules authorized by [the Utah Oil and Gas Severance Tax Act]." Because the Commission has never adopted rules implementing the definitions of "processing costs" and "transportation costs," **the Commission finds that it is bound by the federal regulations. However, if the federal regulations are silent as to an issue, the Commission finds that it may employ the guidance found in the Section 59-5-101 net-back definitions**. (emphasis added) (footnote omitted).

Even though the Commission had previously found in the 2007 Decision that it would consider the federal regulations in this case and even though the Utah Supreme Court appears to have upheld the Commission use of the federal regulations in determining the value of NGLs, the taxpayer argues in its most recent proposed Findings of Fact and Conclusion of Law that it would be inappropriate to apply the federal regulations when determining the value of its remaining UNIT-2 production.[21]

Second, TAXPAYER has not shown the exact amount of field operating costs or plant processing costs that NAME-2 used in its net-back approach to estimate a zero value for the UNIT-2 oil for all years at issue. However, for UNIT-1 oil and UNIT-2 oil combined, TAXPAYER showed the field operating costs to be more than $$$$$ and the plant processing costs to be more than $$$$$ for the years at issue. Exhibit P-34, p. 9. More than half of these combined oil costs would appear to relate to the UNIT-2 oil, based on a comparison of the UNIT-2 oil revenues versus the UNIT-1 oil revenues. As a result, it would appear that NAME-2 deducted more than $$$$$ in processing costs and $$$$$ in transportation costs throughout the years at issue to determine a net-back value of zero for the UNIT-2 oil for each year.

NAME-3 stated that processing costs cannot be deducted against oil revenues to determine value. She appears to be correct. Although the federal regulations allow for processing costs associated with the gas stream to be deducted from revenues to determine the value of the gas products (30 C.F.R. §§206.150 to 206.158), they do not provide for processing costs to be deducted when determining the value of oil (30 C.F.R. §§206.100 to 206.111). It appears that this result is also supported by Utah statutes. Section 59-5-101(11) provides that "'processing costs' means the reasonable actual costs of processing gas[,]" but makes no mention of oil. It appears that the decision of the Legislature to exclude oil from the definition of "processing costs" was deliberate because in Section 59-5-101(17), it defined "transportation costs" to include the actual costs of transporting *both* oil and gas. For these reasons, the net-back approach

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21 Furthermore, in the Division's most recent proposed Findings of Fact and Conclusions of Law, it concentrates on its argument that the point of valuation of the UNIT-2 production should be *after* it has been processed at the PLANT-1. It provides little help in determining how the federal regulations would apply to the valuation of the UNIT-2 oil and residue gas should the Commission agree with TAXPAYER that value should be established at the meter near the wellhead. Accordingly, the Commission has spent time and effort reviewing and applying the federal regulations without much guidance from the parties.

TAXPAYER proposed to value its UNIT-2 oil should be revised to remove the processing costs that NAME-2 deducted from UNIT-2 oil revenues.

Third, it is not clear that the "field gathering costs" that NAME-2 also deducted from his net-back approach are fully allowable, if at all. NAME-2 testified that of the total costs he calculated for TAXPAYER for the net-back approach, those costs were divided between ones TAXPAYER spent on the "plant" and on the "field gathering system." Tr, p. 547; Exhibit P-34, p. 3. Again, NAME-2 did not provide the exact costs he used to determine that the UNIT-2 oil would have a zero value for each year at issue. Nevertheless, it appears that NAME-2 deducted more than $$$$$ in field expenses throughout the years at issue to determine a net-back value of zero for the UNIT-2 oil for each year.

Under the federal regulations, as well as the state statutes, certain transportation costs are allowed as deductions when using the net-back method to value oil. In federal regulation §206.101, "transportation allowance" is defined to mean "a deduction in determining royalty value for the reasonable, actual costs of moving oil to a point of sale or delivery off the lease, unit area, or communitized area. **The transportation allowance does not include gathering costs**" (emphasis added). "Gathering" is defined in the same subsection as "the movement of lease production to a central accumulation or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS approves for onshore and offshore leases, respectively."

TAXPAYER has shown that the PLANT-1 is not located on the PLANT-1 Unit. "Transportation allowance" is defined to include those costs associated with moving oil to a point of sale or delivery off the unit. At the hearing, NAME-3 first testified that it would be allowable to deduct certain transportation costs if the plant was off on the unit, but she later stated that it would not affect the assessment.

Accordingly, her testimony is not helpful in distinguishing between those transportation costs that are gathering costs and those that may be allowable transportation costs.

Regardless, NAME-2 stated that he deducted "field gathering costs" in his net-back approach. In addition, TAXPAYER shows that its total "post production costs" were divided between "field gathering costs" and "plant costs" and that the "field gathering" costs were associated with three "gathering" lines that bring the full well stream to the plant. Exhibit P-34, pp. 1, 3. Furthermore, TAXPAYER indicates that from 1975 through 1997, TAXPAYER's total investment in the PLANT-1 Unit "field" is approximately 15% of its total investment in the PLANT-1 Unit "plant" and "field" together. Exhibit P-36. However, TAXPAYER has not identified what portion of the "field gathering costs" NAME-2 deducted in his net-back approach are associated with those "gathering" costs that are not deductable as a transportation allowance under the federal regulations.[22] For these reasons, the Commission finds that TAXPAYER has not shown what amount of transportation costs may be deducted when valuing the UNIT-2 oil for the years at issue.[23] For these reasons, the net-back approach TAXPAYER proposed to value its UNIT-2 oil should also be revised to remove the field gathering costs that NAME-2 deducted from UNIT-2 oil revenues.

Once TAXPAYER's net-back approach for UNIT-2 oil is revised to reflect the removal of the processing costs and field gathering costs that NAME-2 deducted from revenue, the remaining net-back values should be similar to values imposed by the Division in its assessments and clearly higher than the

[22] Another concern with NAME-2 field gathering deduction is that after he revised it to remove the UNIT-1 production, TAXPAYER did not provide the amounts of the field gathering deductions that NAME-2 allocated to the UNIT-2 oil for each year. Had the Commission found that some portion of NAME-2 field gathering costs were transportation costs that could have been deducted in the net-back method, it would be important to know the exact amounts of these costs because both the federal regulations and Utah law limit the transportation allowance to 50% of the value of the oil. 30 C.F.R. §206.109(c); UCA §59-5-101(7) and (17).

[23] This ruling is consistent with the Commission's ruling in the 2007 Decision (p. 38) that transportation costs could not be deducted when determining the value of TAXPAYER NGLs with the net-back method.

values the Commission determined for the UNIT-2 oil earlier with posted prices and other public information.

UNIT-2 Gas. Information is not available to value TAXPAYER's residue gas with any of the first three valuation methods set forth in Section 59-5-103(1). Neither arm's-length nor non-arm's length contracts for the sale of the UNIT-2 gas at the meter near the wellhead are available. In addition, neither party provided posted prices or other reliable public information relevant in valuing the UNIT-2 gas.[24] The remaining method with which the UNIT-2 residue gas can be valued is the net-back method found in Section 59-5-103(1)(c).

As explained below, however, TAXPAYER's net-back approach does not show that the value of its UNIT-2 residue gas is zero for 1994, 1995, 1996, and 1997, and less than $$$$$, combined, for 1998 and 1999, as it proposes in Exhibit P-17. First, the Commission again rejects TAXPAYER's position that the net-back approach should be determined using the definitions of "processing costs" and "transportation costs" as found in Section 59-5-101, without consideration of the MMS federal regulations.

Second, TAXPAYER has again not shown the exact amount of field operating costs or plant processing costs that NAME-2 used in its net-back approach to estimate its proposed values for the UNIT-2 residue gas. However, for UNIT-1 residue gas and UNIT-2 residue gas combined, TAXPAYER showed the field operating costs to be more than $$$$$ and the plant processing costs to be more than $$$$$ for the years at issue. Exhibit P-34, p. 7. A significant majority of these combined costs would appear to relate to the UNIT-2 residue gas, based on a comparison of the UNIT-2 residue gas revenues versus the UNIT-1 residue gas revenues.

[24] TAXPAYER submitted an estimated wellhead price for the UNIT-2 residue gas, as calculated by NAME-1. However, NAME-1's knowledge about gas contracts is not "public" information. His adjustments to his starting price are based on his own knowledge and opinions. There is no evidence to suggest that his adjustments were obtained from public sources.

NAME-3 stated that when valuing the gas stream, processing costs are deducted against NGLs revenue, but not against residue gas revenue. As a result, the Division contends that NAME-2 improperly deducted processing costs when determining the value of the residue gas portion of the UNIT-2 gas stream. The Division appears to be correct.

The federal regulations provide different valuation standards for "unprocessed gas" and "processed gas." In this case, TAXPAYER processes the UNIT-2 gas prior to selling it. In addition, both parties have used the prices received for the UNIT-2 gas products (residue gas and NGLs) after processing in their respective valuations. Accordingly, the valuation standard for "processed gas" appears to be federal regulation §206.153. §206.153(2) indicates that the value of processed gas "shall be the combined value of the residue gas and all gas products . . . less applicable transportation allowances and processing allowances. . . ."

Where the value of processed gas is determined under §206.153, federal regulations §206.158(c) and (d) provide that the processing allowance shall not be applied against the value of residue gas and shall not exceed 66 2/3 percent of the value of the NGLs, unless the producer applies for and receives an exception to these limitations. In this case, TAXPAYER applied for and received an exception to deduct a processing allowance of 99% of the value of the NGLs, but there is no evidence to show that TAXPAYER either applied for or received an exception under §206.158(d)(2)(i) that would permit it to deduct a processing allowance against its residue gas. For these reasons, in determining the value of its UNIT-2 "gas," TAXPAYER may deduct processing costs against the value of its NGLs (which reflects the 2007 Decision), but it may not deduct any processing costs against the value of its residue gas. For these reasons, the net-back approach TAXPAYER proposes to value its UNIT-2 residue gas should be revised to remove the processing costs that NAME-2 deducted from the UNIT-2 residue gas revenues.

Third, it is again not clear that the "field gathering costs" that NAME-2 also deducted from his net-back approach are fully allowable, if at all. NAME-2 testified that of the total costs he calculated for TAXPAYER for the net-back approach, those costs were divided between ones TAXPAYER spent on the "plant" and on the "field gathering system." Tr, p. 547; Exhibit P-34, p. 3. Again, NAME-2 did not provide the exact costs he used to determine his net-back values for the UNIT-2residue gas for each year at issue. Nevertheless, it appears that NAME-2 must have deducted between $$$$$ and $$$$$ in field expenses for each year in determining the value the UNIT-2 residue gas.

Under the federal regulations, as well as the state statutes, certain transportation costs are allowed as deductions when using the net-back method to value processed gas. In federal regulation §206.151, "transportation allowance" is defined to mean " an allowance for the reasonable, actual costs of moving unprocessed gas, residue gas, or gas plant products to a point of sale or delivery off the lease, unit area, or communitized area, or away from a processing plant. **The transportation allowance does not include gathering costs**" (emphasis added). "Gathering" is defined in the same subsection as "the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively."

TAXPAYER has shown that the PLANT-1 is not located on the PLANT-1 Unit. "Transportation allowance" is defined to include those costs associated with moving gas to a point of sale or delivery off the unit. Again, at the hearing, NAME-3 first testified that it would allowable to deduct certain transportation costs if the plant was off on the unit, but she later stated that it would not affect the assessment. Accordingly, her testimony is not helpful in distinguishing between those transportation costs that are gathering costs and those that may be allowable transportation costs.

Again, however, NAME-2 stated that he deducted "field gathering costs." In addition, TAXPAYER shows that its total "post production costs" were divided between "field gathering costs" and "plant costs" and that the "field gathering" costs were associated with three "gathering" lines that bring the full well stream to the plant. Exhibit P-34, pp. 1, 3. Furthermore, TAXPAYER indicates that from 1975 through 1997, TAXPAYER's total investment in the PLANT-1 Unit "field" is approximately 15% of its total investment in the PLANT-1 Unit "plant" and "field" together. Exhibit P-36. However, TAXPAYER has not identified what portion of the "field gathering costs" NAME-2 deducted in his net-back approach are associated with those "gathering" costs that are not deductable as a transportation allowance under the federal regulations.[25] For these reasons, the Commission finds that TAXPAYER has not shown what amount of transportation costs may be deducted when valuing the UNIT-2 residue gas for the years at issue.[26] For these reasons, the net-back approach TAXPAYER proposed to value its UNIT-2 residue gas should also be revised to remove the field gathering costs that NAME-2 deducted from UNIT-2 residue gas revenues.

Once TAXPAYER's net-back approach for UNIT-2 residue gas is revised to reflect the removal of the processing costs and field gathering costs that NAME-2 deducted from UNIT-2 residue gas revenue, the remaining net-back values should be similar to values imposed by the Division in its

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25 TAXPAYER, again, did not provide the amounts of the field gathering deductions that NAME-2 allocated to the UNIT-2 residue gas for each year once be removed the UNIT-1 production, which could be important because both the federal regulations and Utah law limit the transportation allowance to 50% of the value of gas. 30 C.F.R. §206.156(c); UCA §59-5-101(7) and (17).

In addition, the Commission notes that federal regulation §206.156(b) provides that the transportation costs for gas must be allocated among all products. NAME-2 deducted transportation costs against residue gas revenues, but not against NGLs revenues. Exhibit P-34, tab 4. Because TAXPAYER has not provided NAME-2 revised transportation costs (once the UNIT-1 production was removed), the Commission cannot determine whether NAME-2 properly allocated the transportation costs to all gas products (i.e., both residue gas and NGLs).

26 Again, this ruling is consistent with the Commission's ruling in the 2007 Decision (p. 38) that transportation costs could not be deducted when determining the value of TAXPAYER NGLs with the net-back method.

assessments. For these reasons, TAXPAYER has not shown that the Division's assessments of UNIT-2 residue gas are incorrect.

The taxpayer argues that this ruling results in similar values for UNIT-1 and UNIT-2 residue gas, even though the UNIT-1 gas is clearly superior to the sour UNIT-2 gas at the meter near the wellhead. TAXPAYER argues that this clearly violates the Utah Supreme Court's direction to value the UNIT-2 residue gas at the well. The Commission believes, however, that when comparing values of gas, the entire gas stream must be considered (both residue gas and NGLs) instead of the residue gas or NGLs alone. This comports with the federal regulations that Utah must consider in valuing the gas stream.

III. UNIT-2 NGLs.

In the 2007 Decision, the Commission determined how TAXPAYER's NGLs should be valued. In TAXPAYER's most recent proposed Findings of Fact and Conclusions of Law, it included a revised version of Exhibit P-17, on which it appears to indicate that its tax liability for UNIT-2 NGLs *alone* is, based on the 2007 Decision. The Commission has already determined the tax liability for the UNIT-1 NGLs when it determined a combined tax liability for the UNIT-1 gas stream in Finding of Fact #114 (based on TAXPAYER's indication that the UNIT-1 residue gas liability it proposed on Exhibit P-17 included the UNIT-1 NGLs.)

On page 2 of TAXPAYER's revised Exhibit P-17, it provided its calculations for "Tax Amounts Due on NGLs," on which it showed how it calculated its proposed UNIT-2 NGL tax liability for each year. TAXPAYER's calculations of NGLs tax liability are inexact because they incorporate the annual exemptions that the Division calculated and used in its Statutory Notices. In its Statutory Notices, the Division allocated the annual exemptions on the basis of values imposed in the assessments. Because those values have now changed (most dramatically in regards to the reductions of values of NGLs for 1996, 1997, 1998, and 1999), those annual exemption allocations are no longer correct.

In addition, it appears that TAXPAYER improperly calculated the "new" NGLs values for 1996 and 1997 by mistakenly determining a "gross value" with a reciprocal of 70% instead of 66 2/3%. For 1996 and 1997, the Division originally assessed TAXPAYER with a net-back approach in which it allowed a 66 2/3% processing allowance. Finally, the taxable amounts of NGLs that TAXPAYER started with in its calculations for 1998 and 1999 do not match the taxable amounts of UNIT-2 NGLs as shown in the Division's Statutory Notice for the 2nd Audit Period.

Accordingly, it appears that TAXPAYER may have underestimated its severance tax liability for its UNIT-2 NGLs for 1994, 1995, and 1996. However, it appears that it may have overestimated its liability for UNIT-2 NGLs by an even greater extent for 1996, 1997, and 1998. Overall, TAXPAYER's combined proposed tax liability for UNIT-2 NGLs for all years does not appear to be too low. In any case, the Division had an opportunity to audit these calculations and did not do so. Accordingly, the Commission finds that TAXPAYER's total severance tax liability for its UNIT-2 NGLs is $$$$$ for the Consolidated Audit Period.

IV. Conservation Fee.

Section 40-6-14(1) imposes a conservation fee of .002 on the value at the well of oil and gas. TAXPAYER contends that the "conservation fee" is largely a "piggyback tax" to the severance tax and that it is imposed at a rate of 0.2% (or 1/5 of 1%). Tr., p. 35. TAXPAYER's interpretation of the conservation fee statute appears to be correct. In any case, the Division has not argued otherwise. Accordingly, the Commission finds that a conservation fee equal to 0.2% of the severance tax values arrived at in this decision for oil and residue gas and in the 2007 Decision for NGLs is appropriate for those years for which the conservation fee is properly before the Commission.

In the original version of Exhibit P-17, which TAXPAYER submitted at the 2007 Hearing, it showed amounts of conservation fees that it proposed to be due for each of the six years at issue in the

Consolidated Audit Period. These proposed conservation fees were based on the severance tax values that TAXPAYER proposed for its production for each year. When TAXPAYER submitted its most recent proposed Findings of Fact and Conclusions of Law, it included a revised Exhibit P-17, in which it deleted the proposed conservation fees for 1994 through 1997 (the years in the 1st Audit Period). TAXPAYER indicated that no conservation fee is due for the 1st Audit Period because the Division did not issue a conservation fee assessment for these years. TAXPAYER admits, however, that a conservation fee is due for 1998 and 1999 (the 2nd Audit Period) because the Division did issue a conservation fee assessment for these years. The Commission agrees with TAXPAYER that the conservation fees are not before the Commission for 1994, 1995, 1996, and 1997 and that TAXPAYER owes no conservation fee liability for these years.

However, for 1998 and 1999, TAXPAYER owes a conservation fee based on 0.2% of the values determined by the Commission in this decision for oil and residue gas and in the 2007 Decision for NGLs. However, the amounts of the conservation fees will be different from the amounts shown on TAXPAYER's revised version of Exhibit P-17. First, the amounts of conservation fees TAXPAYER calculated for its UNIT-2 production are based on severance tax values that are different from the ones established by the Commission. Second, TAXPAYER neglected to recalculate its proposed conservation fees to include value for UNIT-2 NGLs that it admits it owes. Third, for the conservation fees associated with the UNIT-1 production, TAXPAYER has improperly calculated the conservation fee on the basis of its proposed "tax," not proposed "value." Accordingly, the parties will need to recalculate the conservation fee so that it is equal to 0.2 percent of the severance tax value established by the Commission in this decision and in its 2007 Decision, as appropriate.

V. Interest.

On October 17, 2011, TAXPAYER submitted its Response to the Division's Objections and its Objections to the Division's Proposed Findings of Fact and Conclusions of Law. This was the last submission in this case. The Commission, however, has not issued this Final Decision until 2014. The parties are partially responsible for the delay because they did not provide and discuss the applicable federal regulations in a manner that would have expedited the Commission's determination of the issues. Nevertheless, the Commission has, on occasion, tolled interest when there is a significant period between the hearing date and the date of the issuance of a decision, pursuant to the authority given in Utah Code Ann. §59-1-401(13) and Utah Admin. Rule R861-1A-42(2). Accordingly, the Commission finds that reasonable cause exists to toll or waive any interest that would have otherwise accrued for the period beginning October 17, 2011, and ending 30 days after the date of this Final Decision.

CONCLUSIONS OF LAW

1. TAXPAYER's total severance tax liability for UNIT-1 oil for the Consolidated Audit Period is $$$$$. TAXPAYER's total severance tax liability for UNIT-1 gas (both residue gas and NGLs) for the Consolidated Audit Period is $$$$$.

2. The point of valuation for the UNIT-2 oil is at the meter near the wellhead, as TAXPAYER proposes.

3. The point of valuation for the UNIT-2 residue gas is at the meter near the wellhead, also as TAXPAYER proposes.

4. The Commission finds that it is bound by the federal regulations in determining severance tax values for oil and gas with the net-back method. However, if the federal regulations are silent as to an issue, the Commission again finds that it may employ the guidance found in the Section 59-5-101 net-back definitions.

5. To value UNIT-2 oil at the meter near the wellhead, the Commission finds that the first applicable valuation method is found in Section 59-5-103(1)(b), which provides for the severance tax value to be determined with posted prices and other reliable public sources of price or market information. With this method, the Commission finds that sweet oil prices the Division used in its assessments to value the UNIT-2 oil for all six years should be reduced by $$$$$ per barrel.

6. If the net-back approach, the last available valuation method, had been used to value the UNIT-2 oil, it would not have resulted in a lower value for the UNIT-2 oil than the method described in Conclusion of Law #5. The Commission finds that processing costs cannot be deducted from the net-back method when determining the value of oil. Accordingly, TAXPAYER's proposed net-back approach for UNIT-2 oil would need to be revised to remove the processing costs it deducted. In addition, TAXPAYER has not shown what portion, if any, of the field gathering costs it deducted from the net-back approach qualify for the transportation allowance that is authorized under the federal regulations and Utah law. Accordingly, TAXPAYER's proposed net-back approach for UNIT-2 oil would also need to be revised to remove the field gathering costs it deducted.

7. To value the UNIT-2 residue gas at the meter near the wellhead, the Commission finds that the only available valuation method is the net-back approach found in Section 59-5-103(1)(c). However, TAXPAYER's proposed net-back calculations to value the UNIT-2 residue gas do not comply with the federal regulations that must be used. First, when valuing gas, the federal regulations allow a processing allowance against the value of NGLs, but not residue gas unless the producer has applied for an exception. TAXPAYER has not shown that it applied for or received an exception allowing it to deduct a processing allowance against the value of the UNIT-2 residue gas. Accordingly, TAXPAYER's proposed net-back approach for UNIT-2 residue gas would need to be revised to remove the processing costs it deducted.

8. Second, TAXPAYER has not shown what portion, if any, of the field gathering costs it deducted from its UNIT-2 residue gas net-back approach qualify for the transportation allowance that is authorized under the federal regulations and Utah law. Accordingly, TAXPAYER's proposed net-back approach for UNIT-2 residue gas would also need to be revised to remove the field gathering costs it deducted. Once these revisions are made to TAXPAYER's proposed net-back approach, the net-back approach for the UNIT-2 residue gas produces values that are equivalent to those assessed by the Division. For these reasons, the Commission sustains the Division's assessments of UNIT-2 residue gas for all years at issue.

9. The Commission finds that TAXPAYER's total severance tax liability for its UNIT-2 NGLs is $$$$$ for the Consolidated Audit Period.

10. For the 1998 and 1999 tax years, TAXPAYER owes conservation fees equal to 0.2% of the severance tax value determined for its oil and gas (both residue gas and NGLs). These conservation fees are to be determined once the severance tax values of all of TAXPAYER's oil, residue gas, and NGLs is known for 1998 and 1999. Because the Division did not assess any conservation fees for the 1st Audit Period, the Commission does not have jurisdiction to impose any conservation fees upon TAXPAYER for the 1994, 1995, 1996, and 1997 tax years.

11. Reasonable cause exists to toll or waive any interest that would have otherwise accrued for the period beginning October 17, 2011, and ending 30 days after the date of this Final Decision.

Kerry R. Chapman
Administrative Law Judge

DECISION AND ORDER

Based on the foregoing, the Commission finds that TAXPAYER's severance tax liability for the Consolidated Audit Period is: 1) $$$$$ for UNIT-1 oil; 2) $$$$$ for UNIT-1 gas (both residue gas and NGLs); and 3) $$$$$ for UNIT-2 NGLs.

For all years of the Consolidated Audit Period, the Commission sustains the Division's assessments of UNIT-2 residue gas, but finds that the Division's assessments for UNIT-2 oil should be revised to reflect a $$$$$ per barrel reduction in the prices the Division used to value the oil.

Furthermore, the Commission finds that TAXPAYER owes conservation fees for the 1998 and 1999 tax years only. After all severance tax values have been determined for the 1998 and 1999 tax years in accordance with this decision, conservation fees are to be calculated at 0.2% of these values.

Finally, the Commission tolls or waives any interest that would have otherwise accrued for the period beginning October 17, 2011, and ending 30 days after the date of this Final Decision.

It is so ordered.

DATED this _____ day of ____________, 2014.

R. Bruce Johnson
Commission Chair

D'Arcy Dixon Pignanelli
Commissioner

Michael J. Cragun
Commissioner

Robert P. Pero
Commissioner

Notice of Appeal Rights: You have twenty (20) days after the date of this order to file a Request for Reconsideration with the Tax Commission Appeals Unit pursuant to Utah Code Ann. §63G-4-302. A Request for Reconsideration must allege newly discovered evidence or a mistake of law or fact. If you do not file a Request for Reconsideration with the Commission, this order constitutes final agency action. You have thirty (30) days after the date of this order to pursue judicial review of this order in accordance with Utah Code Ann. §§59-1-601et seq. and 63G-4-401 et seq.