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April 7, 2000

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OIL CONSERVATION DIV.

HAND DELIVERED

Ms. Lori Wrotenbery
Oil Conservation Commission
2040 South Pacheco
Santa Fe, New Mexico 87505

Re: ***REQUEST FOR HEARING DENOVO***
NMOCD CASE 12325
Order No. R-11327
Application of Chesapeake Operating, Inc. for compulsory pooling and an unorthodox well location, Lea County, New Mexico

Dear Ms. Wrotenbery:

On behalf of Chesapeake Operating, Inc., a party of record adversely affected herein, please find enclosed our request for a Hearing DeNovo before the New Mexico Oil Conservation Commission in Case 12325.

Very truly yours,

W. Thomas Kellahin

cc: **Mr. Mark Ashley, Examiner**
Oil Conservation Division
Ms. Lyn Hebert, Esq.
Oil Conservation Division
Chesapeake Operating, Inc.
Attn: Lynda Townsend
William F. Carr, Esq.
Attorney for Altura Energy, Ltd. and Southeast Royalties, Inc.

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

CASE NO. 12325 (DeNovo)
Order No. R-11327

APPLICATION OF CHESAPEAKE OPERATING, INC. FOR COMPULSORY POOLING AND AN UNORTHODOX WELL LOCATION, LEA COUNTY, NEW MEXICO

CHESAPEAKE OPERATING, INC.'S APPLICATION FOR A DE NOVO HEARING BEFORE THE NEW MEXICO OIL CONSERVATION COMMISSION

Comes now CHESAPEAKE OPERATING, INC. ("Chesapeake"), a party of record before the New Mexico Oil Conservation Division in Case 12325 and adversely affected by Division Order R-11327 entered March 9, 2000, by its attorneys Kellahin & Kellahin and pursuant to Section 70-2-13 NMSA (1978), hereby requests that the New Mexico Oil Conservation Commission hold a HEARING DENOVO in this matter because Order R-11327 is arbitrary, capricious, contrary to precedents established by the Division and is not supported by substantial evidence because it:

(1) allowed the pooled parties to participate in potential Wolfcamp and Atoka-Morrow production from this well without reimbursing Chesapeake for any of the costs of drilling this well to the base of the Strawn formation;

(2) rejected Chesapeake's proposal to allocate well costs between the Wolfcamp, Strawn and Atoka-Morrow formations based upon the industry accepted method for allocating such costs established in 1965 by COPAS Bulletin No. 2 "Determination of Values for Well Costs Adjustments-Joint Operations"; and

(3) rejected Chesapeake's request for a 200% risk factor penalty to be applied to both drilling and completion costs.

ESSENTIAL FACTS

Chesapeake, by voluntary agreement, consolidated 100% of the working interest owners in the S/2SW/4 of this section and proposed to dedicate this 80-acre tract to a standard 80-acre spacing unit in the Northeast Shoe Bar-Strawn Pool by re-entering a well now redesignated as Chesapeake's College of the Southwest "17" Well No. 1 and directionally drilling it for potential production from this Strawn oil pool.

Chesapeake's reason for re-entering this wellbore was based upon its analysis of 3-D seismic data which indicated a potential Strawn reservoir just to the south of the bottom hole location of the abandoned David Fasken wellbore.

During the drilling of this wellbore, Chesapeake's operational personnel at the well site determined that the Strawn formation was non-productive and elected to continue drilling through the Strawn formation an additional 400 feet to the base of the Atoka/Morrow formation. The well has not been completed but based upon log analysis there is possible gas production from the Atoka-Morrow formation (below the Strawn) and possible oil production from the Wolfcamp formation (above the Strawn).

At the time Chesapeake's operational personnel elected to continue drilling this well, they obtained the concurrence of Fasken Land and Minerals, Ltd and Bonneville Fuels Corporation to continue drilling who they mistakenly believed were all working interests owners. In addition, they were under the mistaken impression that the Wolfcamp was spaced on 40-acre and not on 160-acre spacing units.

After drilling, but prior to completion, Chesapeake determined that while Altura Energy, Ltd. ("Altura") interest in the 80-acre Strawn spacing unit were leased to Chesapeake, Altura's interest in the N/2SW/4 needed to form a 160-acre Wolfcamp spacing unit consisting of the SW/4 and needed to form the 320-acre Atoka/Morrow formation spacing unit consisting of the S/2 were still held by Altura and not by Chesapeake.[1]

In addition, Chesapeake determined that Southeast Royalties owned an undivided 1.666% of the working interest in the 320-acre gas spacing unit to be dedicated to the Atoka formation if it produced.

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[1] As a result of its interest in the N/2SW/4 of Section 17, Altura has a 13.333% working interest in the Wolfcamp formation and a 20% working interest in the Atoka/Morrow formation.

This well is located within one mile of the following pools with the following possible dedications:

(a) S/2 of this section consisting of 320-acres for production Atoka/Morrow formations in the West Lovington-Pennsylvanian Gas Pool ("stateside spacing");

(b) S/2SW/4 of this section consisting of 80-acres for oil production from the Strawn formation in the Northeast Shoe Bar-Strawn Pool (Order R-10848); and

(c) SW/4 of this section consisting of 160-acres for oil production from the Wolfcamp formation of the North Shoe Bar-Wolfcamp Pool (Order R-4657).

THE DIVISION IMPROPERLY DENIED RECOVERY OF DRILLING COSTS

Section 70-2-17.C NMSA (1978) provides that the Division has authority to enter a compulsory pooling order to pool interest owners in a well that has been drilled or is to be drilled. Chesapeake requested Examiner Ashley allow it to recover from Altura a reasonable portion of the drilling and completion costs applicable to the Wolfcamp and to the Atoka-Morrow formations. Altura incorrectly argued that they should not have to pay any of the drilling costs of the wellbore because it amounted to a plugged and abandoned Strawn wellbore and those costs should be borne exclusively by the parties who drilled and abandoned it.

Examiner Ashley agreed with Altura and has allowed Altura to participate as follows:

(a) for the Atoka formation it should pay only its proportionate share of the costs to drill below the base of the Strawn formation to the Atoka formation and then the costs to actually complete that zone;

(b) for the Wolfcamp formation it should pay only its proportionate share of the costs to actually complete that zone if and when a completion is attempted;

In essence, Examiner Ashley treated the wellbore as an abandoned dry hole in the Strawn formation with no value for either the Wolfcamp or Atoka/Morrow formation owners. He has concluded that the working interest owners in the Strawn formation have assumed the entre risk for the costs of the wellbore and are not entitled to any reimbursement for its value even if that wellbore is essential for accessing the Wolfcamp and Atoka-Morrow formations. Examiner Ashley ignored the fact that Chesapeake had not plugged and abandoned this wellbore after penetrating the Strawn, but had continued drilling to the Atoka/Morrow formation. In addition, he either did not know or failed to consider the fact that the Division requires the pooled parties to pay an appropriate share of the value of that existing wellbore if requested by the applicant.

Southeast Royalties contended it is not fair for it to receive a "free well"--- meaning that just because Chesapeake had already drilled the well, that fact should not be used as an excuse by another party to avoid paying a fair and reasonable share of those drilling costs.

In entering his order, Examiner Ashley either did not know or chose to ignore numerous prior orders of the Division which are relevant to this case:

(1) if the Division wants to incorrectly treat the Chesapeake well as a plugged and abandoned Strawn well, then it needs to remember that when an operator has re-entered a plugged and abandoned wellbore and when he has requested reimbursement, the Division has required pooled parties to pay their proportionate share of the value of that existing wellbore in addition to the costs for recompletion. See Order R-10143 (Naumann Oil & Gas Inc. (1994); See R-9996 (Merrion v. Markham-1993); and

(2) while the Division might reduce the risk factor penalty because the well was drilled, the Division has always allowed for the value of the existing wellbore if the applicant asked for it. The issue of pooling additional interest owners into an existing wellbore was reviewed by the Commission on several occasions when it increased the size of spacing units from 320-acres to 640-acres in the Gavilan-Mancos Oil Pool. In all those instances, the new working interest owners were required to compensate the owners of the existing wellbore in order to participate in production. See Order R-8639 (Mesa Grande v. Sun Exploration-1988) , Order R-8641 (Dugan v. Amoco-1988). Order R-8262-A (Oryx v. Mallon-1989)

Chesapeake contended that it should not be required to give Altura a "free wellbore" and asked the Division allocate well costs between the Wolfcamp, Strawn and Atoka-Morrow formation based upon the industry accepted method for allocating such costs established in 1965 by COPAS Bulletin No. 2 "Determination of Values for Well Costs Adjustments-Joint Operations". Examiner Ashley rejected Chesapeake's request and in doing so acted arbitrarily and capriciously.

THE EXAMINER WAS WRONG TO REJECT CHESAPEAKE'S COPAS BASED METHOD FOR ALLOCATING COSTS AMONG OWNERS OF MULTIPLE FORMATIONS

In opposition to Chesapeake, Altura, with a 13.333% interest in the Wolfcamp and a 20% interest in the Atoka/Morrow, sought to participate in both the Wolfcamp and the Atoka/Morrow by only paying $27,000.00 for a completed well which Chesapeake estimated would cost about $840,000. It is interesting to compare the Chesapeake proposed costs with the fact that the estimated dry hole costs for a Wolfcamp well would exceed $600,000 and for an Atoka/Morrow well would exceed $800,000.

Examiner Ashley's order allowed Altura a separate election in the Wolfcamp and in the Atoka/Morrow such that:

> (a) Altura would pay $28,012.00 as its share of the costs remaining to set tubing and perforate/stimulate/log and produce the Wolfcamp formation.[2]
>
> (b) Altura would pay $55,267.29 as its share of the costs spent to drill below the base of the Strawn ($101,836.45) and the costs remaining to set tubing and perforate/stimulate/log, and produce the Atoka/Morrow formation ($174,500).[3]

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[2] Because the well has been drilled but not completed, the following Wolfcamp costs are still to be incurred: tubing, cased hole logging, perforating, stimulation, artificial lift, downhole equipment, etc for a total estimated cost of $210,500 of which Altura's share is 13.333% Examiner Ashley's decision assumes that the tubing is run in the wellbore and used only for the Wolfcamp completion. If the Commission adopts the COPAS allocation method, the estimated costs of the tubing have already been apportioned between the Wolfcamp and Atoka/Morrow formations.

[3] Examiner Ashley's Atoka/Morrow decision assumes that the tubing is run in the wellbore and used only for the Atoka/Morrow completion. The drilling costs below the Strawn are $100,724.25 for intangibles ($478,500 x 21.05%) and

Chesapeake proposed to make the necessary adjustments to its AFE, and to apply the COPAS allocation method such that the total cost allocated to the Atoka/Morrow owners is $549,451.98 and the total cost allocated to the Wolfcamp owners is $290,309.00. If Altura elects to participate in the Atoka/Morrow and Wolfcamp its share is $118,956.84. If they do not then, Chesapeake will pay Altura's share of those costs and be entitled to recover an additional 200% as compensation for carrying Altura's interest.

Thus, Altura should be required to make a single election as to both the Wolfcamp and Atoka/Morrow formations, then Altura's 20% share of the costs allocated to the Atoka/Morrow formation is $109,890.40 and Altura's 13.333% share of the costs allocated to the Wolfcamp formation is $9,066.44. This result occurs because much of the equipment will be utilized for both zones. Chesapeake considers it unfair to allow Altura to "split" its election among the two formations because to do so would allow Altura to benefit from certain expenses which it did not pay for and will result in Altura paying less than its fair share of costs.[4]

However, if the Commission affirms Examiner Ashley's decision, then Altura will have the benefit of a "split election". If Altura goes "non-consent" in the Atoka/Morrow and elects to participate in the Wolfcamp, then Altura should be required to pay $38,706.91 which is $13.33% of $290,309.00 which should be the costs allocated to the Wolfcamp based upon a "split election" option.

The COPAS method for allocating well costs addresses numerous possible situations where drilling and completion costs for drilled wells or proposed wells need to be allocated as a result of ownership changes caused by any number of reasons including different zones with different interests.

The Forward in the COPAS Bulletin No. 2 specifically indicates the applicability of this allocation method to the facts of the Chesapeake case when it states:

$1,112.20 for tangibles ($33,500 x. 3.32%) plus the remaining Atoka/Morrow completion costs are $174,500 (tubing, logging, stimulation/perforation, etc) for a total of $276,336.45

[4] The option of a split election has already been rejected by the Commission. See **Viking Petroleum, Inc. v. Oil Conservation Commisino and Harvey E. Yates**, 100 NM 451 (1983)

"The basic purpose of this bulletin is to set forth what is considered by the industry in general to be the most equitable basis for the determination of values to be used in connection with well costs...occurring as the result of one of the following:

(1) change in size of unit;
(2) recompletion of a well in a different zone;
(3) multiple completion of well in zones of different ownership;
(4) failure to obtain production in original objective zone and completion of well in zone of different ownership;
(5) creation of field wide or reservoir units." [paraphrased]

It is interesting to note that most, if not all, of these items are involved in the subject case.

Specifically, in the Chesapeake case, Chesapeake's AFE for a gas well drilled to a depth of 12,100 feet was estimated to be $856,000 for a producing gas well in the Strawn formation which included $258,000 for tangible costs and $598,000 for intangibles including $50,000 for seismic costs and certain other anticipated but unspent costs associated with producing the Strawn formation had it not been "dry".

Chesapeake proposed to make the necessary adjustments to this AFE, and to apply the COPAS allocation method such that the total costs allocated to the Atoka/Morrow owners is $549,451.98 based upon the following:

(1) the following anticipated intangible costs which were not used in the Strawn, are deducted from the intangibles and allocated 100% to the Atoka/Morrow:

item 430:	completion unit:	$20,000
item 431:	cased hole logging/perf	$10,000
item 434:	formation stimulation	$10,000
	surface rental	$ 1,000
	contingency 10%	$10,000
	supervision	$ 3,500
	TOTAL: $54,500	

(2) the remaining AFE intangibles of $543,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Atoka/Morrow owners were allocated 49.995% being $271,722.83.

(3) an additional $65,000 was added to item 434 for the fracture treatment anticipated for the Atoka/Morrow formation;

(4) the following anticipated tangible costs which were not used in the Strawn, are deducted from the tangibles:

production casing:	$82,000
tubing	$40,000
wellhead equipment	$ 4,000
Downhole equipment	$ 3,000
Artificial lift pump	$50,000
Production Equipment	$30,000
Non-controllable equip.	$ 1,000
contingency 10%	$14,500
Total:	$228,500

(5) the remaining AFE tangibles of $29,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Atoka/Morrow owners were allocated 36.37% being $10,729.15

(6) 100% of the following anticipated tangible costs attributable to the Atoka/Morrow were added:

production casing:	$82,000
tubing	$40,000
wellhead equipment	$ 4,000
Downhole equipment	$ 3,000
Production Equipment	$30,000
Non-controllable equip.	$ 1,000
contingency 10%	$14,500
Total:	$174,500

If Altura elects to participate in **both** the Atoka/Morrow and the Wolfcamp, then its 20% share of the Atoka/Morrow is $109,890.44. Because certain of the costs allocated to the Atoka/Morrow can also be utilized in the Wolfcamp such that the only additional Wolfcamp costs will be the cost of cased hole logging/perforating and stimulation of $18,000 plus $50,000 for artificial lift equipment. Altura's interest in the Wolfcamp formation is 13.333% and thus would pay an additional $9,066.44.

If, however, Altura goes "non-consent" in the Atoka/Morrow and elects to participate in the Wolfcamp, then Altura would be required to pay $38,706.91 being $13.33% of $290,309.00 based upon the following allocation:

(1) the following anticipated intangible costs would be deducted from the intangibles in Chesapeake's AFE and allocated 100% to the Wolfcamp:

item 430:	completion unit:	$20,000
item 431:	cased hole logging/perf	$ 8,000
item 434:	formation stimulation	$10,000
	surface rental	$ 1,000
	contingency 10%	$ 4,000
	supervision	$ 3,500
	Total:	$46,500

(2) the remaining AFE intangibles of $501,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Wolfcamp owners are allocated 21.05% being $105,565.75.

(3) the following anticipated tangible costs are deducted from the tangibles:

Artificial lift pump	$50,000
Non-controllable equip.	$ 1,000
contingency 10%	$ 5,000
Total:	$56,000

(4) the remaining AFE tangibles of $202,000.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Wolfcamp owners were allocated 30.566% being $61,743.32

(5) an additional $20,000 was added for the downhole equipment for the Wolfcamp formation;

(6) 100% of the following anticipated tangible costs attributable to the Wolfcamp were added:

Artificial lift	$50,000
Non-controllable equip.	$ 1,000
contingency 10%	$ 5,000
Total:	$56,500

Chesapeake, using the COPAS allocation method, proposed to exclude those costs chargeable to the Strawn formation so that Altura would pay only those costs directly associated with the Wolfcamp and the Atoka-Morrow formations. For example, instead of paying for 100% of the costs of the wellbore to the Wolfcamp, the Wolfcamp owners would pay for the Wolfcamp completion costs and only one-third of the drilling costs to the base of the Wolfcamp and nothing below that depth.

However, without explanation, Examiner Ashley rejected the application of the COPAS allocation method to this case. Instead, he attempted, without success, to distinguish the Chesapeake case from the Yates case, in which the Division used the COPAS allocation method in a compulsory pooling case. In doing so, he failed to recognize that the COPAS allocation method still applies to the Chesapeake case.

CHESAPEAKE IS STILL ENTITLED TO REIMBURSEMENT FOR DRILLING COSTS FROM ALTURA EVEN THOUGH THE WELL WAS DRILLED PRIOR TO PROPOSING IT TO ALTURA

Chesapeake, by voluntary agreement, consolidated all interest owners in the Strawn formation, and drill the College of Southwest "17" Well No. 1 to the Strawn formation which was "dry". Chesapeake, under the mistaken belief that all of Altura's interest in the Atoka/Morrow formation was also leased by Chesapeake, continued drilling an additional 400 feet to the base of the Morrow formation. Prior to completing the well, Chesapeake recognized its mistake and contacted Altura and proposed that Altura pay its share of reasonable well costs. Altura and Chesapeake have not been able to reach an agreement.

Examiner Ashley has denied Chesapeake the right to recover any of the drilling costs from Altura, in part, because the well was drilled prior to providing Altura with an opportunity to participate.

Case law requires working interest owners to pay for their share of drilled wells even in circumstances where the operator is guilty of trespass. For example, in **Champlin Refining Co. v. Aladdin Petroleum Corp,** 238 P.2d 827 (OKLA 1951) the operator was allowed to recover all well costs for a well drilled as a dry hole, then plugged back to within 300 feet of the surface and drilled directionally to a new bottom hole location and obtained production because "the well was drilled in good faith and the costs thereof, being reasonable and necessary..."

More importantly the Division has already decided this matter in prior decisions. Unfortunately, Examiner Ashley has entered an order contrary to past precedents established by the Division.[5]

THIS ORDER IS CONTRARY TO PRIOR DIVISION ORDERS ADOPTING THE COPAS ALLOCATION SOLUTION IN A COMPULSORY POOLING CASE

Chesapeake reminded Examiner Ashley that in a previous pooling case[6] involving a drilled well the Division had adopted the COPAS allocation method so that the pooled party would pay only those costs properly associated with each formation.

In the Yates case, before the well was drilled, Yates offered to Chevron a chance to participate only in the Bone Springs. After the well was drilled and the Bone Springs determined to be dry, Yates completed the well, up hole, in the San Andres and then offered Chevron a chance to participate in the San Andres production if Chevron would pay its share of the drilling and completion costs for **both** the Bone Springs and the San Andres portions of the wellbore. Yates wanted Chevron to pay its share of the total well costs which included both the Bone Springs which was found to be non-productive and the San Andres which was productive. Chevron contended that pursuant to the COPAS allocation method it should pay only those costs associated with the productive San Andres. The Division agreed with Chevron and adopted the COPAS allocation method.

Examiner Ashley attempted to distinguish the Chesapeake case from the Yates case in five ways, all of which are wrong:

> (a) Examiner Ashley attempted to distinguish the Yates decision because it involved adding an uphole formation while the Chesapeake sought to add a deeper zone. In fact the Chesapeake case involves **both** a shallower (Wolfcamp) and a deeper zone (Atoka Morrow). Examiner Ashley has chosen a difference without a distinction. Why should this difference matter? It does not--the Forward of the COPAS Bulletin addresses both shallower and deeper zone allocation;

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[5] See the following section of this application which discusses Order R-9093-C entered in Case 9998 (Reopened). Also see Order R-8245 entered in Case 8897.

[6] OCD Case 9998 (Reopened), Division Order R-9093-C (Yates Petroleum Corporation v. Chevron (1990)

(b) Examiner Ashley attempted to distinguish the Yates decision because it involved two zones (the Bone Springs (deep zone) and the San Andres (shallow zone) both on 40-acre spacing while the Chesapeake case involved 80-acre (Strawn) 160-acre (Wolfcamp) and 320-acre (Atoka-Morrow) formations. Why should this difference matter? It does not--Examiner Ashley has failed or refused to understand the COPAS Bulletin deals with various sized units. See Conclusion COPAS Bulletin at page 8. In addition, Doyle Hartman increased the size of the spacing unit and pooled Chevron and was allowed to recover from Chevron's share of production the value of the existing wellbore he had on the original spacing unit. See Order R-9332 (1990);

(c) Examiner Ashley attempted to distinguish the Yates decision because, unlike the Chesapeake case, the interest owners were the same in all formations. Presumably, he would apply the COPAS solution only in those cases where ownership is common for all zones. Again, Mr. Ashley has failed to read or understand the COPAS Bulletin which specifically deals with multiple zones of different ownership (See Forward page 2) When there has been a change in the size of the spacing unit, the Division has required payment of well costs. See Order R-8282-D (Marathon v. Davidson-1988) Order R-8071-A (HCW Exploration v. Hartman-1986)

(d) Examiner Ashley attempted to distinguish the Yates case by incorrectly concluding that the pooled parties in the Yates case were provided an opportunity to participate before the well was drilled while in the Chesapeake case the well was drilled first. Examiner Ashley has relied upon a statement which is factually wrong. In the Yates case before the well was drilled, Chevron was offered a chance to participate only in the Bone Springs. After the well was drilled and the Bone Springs determined to be dry, Yates first completed the well in the San Andres and then offered Chevron a chance to participate if Chevron would pay for **both** the Bone Springs and the San Andres cost portions of the wellbore. In the Chesapeake case, Chesapeake had obtained a lease from Altura for Altura's interest in the Strawn formation and drilled the well but **before** completing the well in either the Wolfcamp or the Atoka-Morrow, offered Altura the opportunity to participate if Altura would pay its share of the costs pursuant to the COPAS allocation method. Once, again, Examiner Ashley attempt to distinguish the Yates case is based upon a reason that, frankly, does not matter even if it were factually correct which it is not.

(e) Examiner Ashley incorrectly states that the COPAS allocation method was used to decrease the costs to the pooled parties in the Yates case while in the Chesapeake case it was used in increase the costs to the pooled parties. Nothing could be more incorrect. In **both** cases the COPAS method was used so that the pooled parties paid only for those costs fairly attributed to the zone in which they had an interest and excluded them from paying for costs in zones where they had no interest. In **both** cases it resulted in the pooled parties costs being reduced.

Having attempted to distinguish the Chesapeake case from the Yates case, Examiner Ashley failed to recognize that the COPAS allocation method still applied to the Chesapeake case. None of his reasons for distinguishing Yates case form a logical or rational basis for excusing his failure to apply COPAS allocation method to the Chesapeake case.

The Risk Factor Penalty

Chesapeake recommended to the Division the adoption of a 200% risk factor penalty despite the fact that the well has been drilled[7] and logged because:

(a) there is no Atoka production within 3 miles of this well;

(b) both the original David Fasken which Chesapeake re-entered in Unit M of Section 17 and the Yates' Robert AGX State Well No 1 in Unit A of Section 20 had log indication of the presence of sandstone in the Atoka formation but failed to produce; and that the Atoka log indications for the College of Southwest 1-17 well are poorer than either of those wells.

(c) The nearest well to the subject College of Southwest well is Yates' Robert AGX State Well No 1 in Unit A of Section 20 which has only produced 1,451 barrels of oil from the Wolfcamp since 1996 which is not economic.

(d) The next closest well which produced from the Wolfcamp is located almost a mile away in Unit A of Section 17 and produced 77,776 barrels of oil which was not sufficient to pay for the costs of that well.

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[7] Division Order R-8245 (1986) awarded Mesa Grande a 200% risk factor against Chevron even though the well had been drilled.

(e) a log comparison of the Wolfcamp formation in the subject College of Southwest well with the Yates' well indicates that, at best, the College of Southwest well might be comparable to the Yates well, and if so, then production would not be sufficient to pay for the cost of the College of Southwest Well No. 1.

Altura recommended to the Division that a 100% risk factor penalty be assessed against them only for the costs of completion because:

(a) Chesapeake should be punished for its mistake in failing to consolidate Altura's interest in the Wolfcamp and Atoka formations prior to re-entry of the well.

(b) Altura wanted a chance to participate "risk free" in either the Atoka or Wolfcamp formations.

Examiner Ashley awarded a 100% risk factor only on the completion costs. Chesapeake requests that the Commission enter a DeNovo order awarding a 200% risk factor to be applied to both drilling and completion costs because:

(a) the availability of log data and the drilling of the well has not diminished the risk involved in this well to less than the statutory maximum and the maximum 200% risk factor should be awarded.

(b) Altura has the benefit of having the Chesapeake log data from which to base its decision concerning participation and if it elects not to participate then it will being doing so based upon the conclusion that it is too risky to participate;

(c) If Altura elects not to participate, it will be an admission that the risk is substantial and Altura should be subject to the maximum 200% penalty.

(d) Altura, after using Chesapeake's log data to analyze risk, can avoid any risk factor penalty by electing to participate.

(e) the fact remains that Chesapeake has paid for Altura's share of the costs of the well and should be reasonably compensated for having done so. The form of that compensation is a risk factor penalty.

CONCLUSION

In conclusion, Chesapeake requests that the Commission conduct a DeNovo Hearing, amend Examiner Order R-11327 and find that:

(a) Altura's contention concerning costs is without merit because it seeks to avoid making its fair and reasonable contribution for use of that portion of the wellbore from the surface to the base of the Strawn formation without which it would be impossible for Altura to share in any production from the Atoka formation;

(b) Altura's argument ignores the fact that the Chesapeake well was a continuous drilling operation and did not constitute an abandoned wellbore. (For Example, See Division Order R-10764-A);

(c) Altura's argument fails to address why it should not pay for its share of the costs of drilling to the shallower Wolfcamp formation in exchange for receiving its share of that production;

(d) Altura's argument fails to address why it should not pay for its share of the costs of drilling from the surface to the deeper Atoka/Morrow formation in exchange for receiving its share of that production;

(e) allocation of costs as set forth in the COPAS Bulletin No. 2 is considered by the industry to the most equitable basis for the determination of values to be used in connection with the cost issues involved in this compulsory pooling case;

(f) here is no compelling reason in this case to reject the precedent set by the Division in Order R-9093-C when it allocated costs among multiple formations in a contested compulsory pooling case based upon COPAS Bulletin No. 2;

(g) The Division should adopt the Chesapeake proposed COPAS allocation method; and

(h) there is no compelling reason in this case to reject the precedent set by the Division in Order R-8245 when it awarded a 200% risk factor penalty for a well which had already been drilled but which was awaiting completion. (Also See Division Order R-8282-D)

Respectfully Submitted:

W. Thomas Kellahin, Esq.
Attorney for Chesapeake Operating, Inc.

Allocation of Well Costs - COPAS

A. Intangibles

(1) Using Drilling Day Ratio allocation:

total days – 19

12 day to drill to base of Wolfcamp: 12/19 = 63.16%

3 days to drill to base of Strawn 3/19 = 15.79%

4 days to TD (base of Atoka) 4/19 = 21.05%

(2) allocation to owners of each zone

(a) Wolfcamp WI:	1/3rd of 63.16%	21.05%
(b) Strawn WI:	1/3rd of 63.16% plus ½ of 15.79%	28.945%
(c) Atoka WI:	1/3rd of 63.16% plus ½ of 15.79% plus 100% of 21.05%	49.995%

(3) allocation to Altura

(a) 13.333% of Wolfcamp
(b) 20.0% of Atoka

B. Tangibles:

(1) Using footage Ratio allocation:

total footate = 12,050'

11,050 feet to base of Wolfcamp 11,050/12,050 = 91.7%

600' to base of Strawn 600/12,050 = 4.97%

400' to TD (base of Atoka) 400/12,050 = 3.32%

(2) allocation to owners of each zone:

(a) Wolfcamp WI:	1/3rd of 91.7%	30.566%
(b) Strawn WI:	1/3rd of 91.7% plus ½ of 4.97%	33.051%
(c) Atoka WI:	1/3rd of 91.7% plus ½ of 4.97% plus 100% of 3.32%	36.37%

(3) allocation to Altura:

(a) 13.333% of Wolfcamp
(b) 20% of Atoka

EXHIBIT 7

CHESAPEAKE OPERATING, INC.

AUTHORIZATION FOR EXPENDITURE

Project Area: Lovington
Well Name: College of the SW 1-17 (Re-entry)
Operator: Chesapeake Operating, Inc.
AFE #: 962332
Spacing Unit: S/2 Section 17-16S-36E

County, State: Lea, New Mexico
Date: October 22, 1999
Total Depth: 12,100'
Formation: Strawn/Atoka

CODE		INTANGIBLE COSTS	WORK DESCRIPTION			DRY HOLE	PRODUCER
233400		Location:	Roads, Location, Pits			$20,000.00	$20,000.00
233405			Reclamation			$20,000.00	$20,000.00
233401			Damages			$8,000.00	$8,000.00
233402		Legal:	Governmental Filings			$2,000.00	$2,000.00
233403			Title Opinions			$3,000.00	$3,000.00
233404			Seismic Costs			$50,000.00	$50,000.00
233406		Drilling:	Top Drive			$0.00	$0.00
233408			Pipeline Construction			$0.00	$0.00
233410			Drilling Contractor: 18 days @ $5,300/day			$95,000.00	$95,000.00
233411			Directional Services			$46,000.00	$46,000.00
233413			Rig Mobilization/Demobilization			$20,000.00	$20,000.00
233414			Contract Labor			$10,000.00	$15,000.00
233415			Bits			$30,000.00	$30,000.00
233416			Supplies and Utilities			$1,000.00	$3,000.00
233417			Cement Conductor			$0.00	$0.00
233417			Cement Surface Casing			$0.00	$0.00
233417			Cement Intermediate Casing			$0.00	$0.00
233417			Cement Production Casing			$0.00	$20,000.00
233417			Cement Drilling Liner			$0.00	$0.00
233417			Cement Production Liner			$0.00	$0.00
233418			Mud Logging			$11,000.00	$11,000.00
233419			Drilling Fluids, Mud, Chem.			$20,000.00	$20,000.00
233421			Drill String Inspection			$0.00	$0.00
233423			Open Hole Logging			$22,000.00	$22,000.00
233427			Fishing			$0.00	$0.00
233428			Downhole Rental Equipment			$10,000.00	$10,000.00
233430		Completion:	Completion Unit			$0.00	$20,000.00
233431			Cased Hole Logging/Perforating			$0.00	$10,000.00
233433			Jetting			$0.00	$0.00
233434			Formation Stimulation			$0.00	$10,000.00
233437		General:	Surface Equipment Rental			$18,000.00	$19,000.00
233438			Transportation			$0.00	$3,000.00
233441			Frac Fluid Hauloff			$0.00	$0.00
233442			Blowout/Emergencies			$0.00	$0.00
233443			Company Supervision/Engineering			$10,000.00	$15,000.00
233444			Consultants			$8,000.00	$8,000.00
233446			Company Overhead			$8,000.00	$13,000.00
233447			Insurance			$5,000.00	$5,000.00
233449			Major Construction Overhead			$0.00	$2,000.00
233450			Plug to Abandon			$0.00	$0.00
			20% Contingency			$83,000.00	$100,000.00
TOTAL	INTANGIBLES		Total Intangible Costs			$498,000.00	$598,000.00
CODE		TANGIBLE COSTS	WORK DESCRIPTION				
230100		Tubulars:	Surface Casing:			$0.00	$0.00
230100			Intermediate Casing:			$0.00	$0.00
230100			Production Casing:	12,100'	5 1/2"	$0.00	$82,000.00
230100			Drilling Liner:			$0.00	$0.00
230100			Production Liner:			$0.00	$0.00
230100			Tubing:	11,500'	2 7/8"	$0.00	$40,000.00
230104			Float Equipment			$0.00	$2,000.00
230106		Lease Equipment:	Wellhead Equipment			$3,000.00	$7,000.00
230107			Downhole Equipment			$0.00	$3,000.00
230111			Artificial Lift-Pumping Unit			$0.00	$50,000.00
230113			Production Equipment			$0.00	$30,000.00
230115			Compressor/Compression			$0.00	$0.00
230116			Pipeline Equipment			$0.00	$0.00
230120			Non-Controllable Equipment			$1,000.00	$1,000.00
			20% Contingency			$1,000.00	$43,000.00
TOTAL	TANGIBLES		Total Tangible Costs			$5,000.00	$258,000.00
			Total Costs			$503,000.00	$856,000.00

Prepared by: JKO

Approved by: JML

OPERATOR'S APPROVAL ______________________ DATE ________
Operations/Geology

OPERATOR'S APPROVAL [signature] DATE 10/22/99
Land/Accounting

NON-OPERATOR'S APPROVAL ______________________ DATE ________

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 12325 (DeNovo)

APPLICATIONS OF CHESAPEAKE OPERATING, INC. FOR COMPULSORY POOLING AND AN UNORTHODOX SUBSURFACE LOCATION, LEA COUNTY, NEW MEXICO

PREHEARING STATEMENT FOR CHESAPEAKE OPERATING, INC.

Comes now Chesapeake Operating, Inc. ("Chesapeake"), by and through its attorney, W. Thomas Kellahin, Esq. in accordance with Division rules files this Prehearing Statement:

ISSUES

This DeNovo case is of substantial importance to the Commission because Division Order R-11327 entered in this compulsory pooling case:

(1) established the precedent in compulsory pooling cases that if the well is drilled but not completed before the parties are properly notified and pooled, then the operator only recovers unspent completion costs.

(2) rejected Chesapeake's proposal to allocate well costs between the Wolfcamp, Strawn and Atoka-Morrow formations based upon the industry accepted method for allocating such costs established in 1965 by COPAS Bulletin No. 2 "Determination of Values for Well Costs Adjustments-Joint Operations";

(3) rejected Chesapeake's request for a 200% risk factor penalty to be applied to both drilling and completion costs; and

(4) allowed the pooled parties a "split election" such that they could make separate consent, non-consent elections for the Wolfcamp and for the Atoka/Morrow completions.

Background

(1) Chesapeake is the applicant in Case 12325 and obtained Division Order R-11327 entered March 9, 2000, which approved an unorthodox subsurface location for its College of Southwest "15" Well No. 1 which was an old well, re-entered and drilled as a directional wellbore at a total depth in the Morrow formation within the S/2 of Section 15, T16S, R36E, NMPM. **See Attachment A.**

(2) Order R-11327 approved the compulsory pooling of the interests of Altura Energy, Ltd, and Southeast Royalties **but in doing so included the following**:

(a) allowed the pooled parties to participate in potential Wolfcamp production by paying only their share of Wolfcamp completion costs and rejecting Chesapeake's request to also be reimbursed for a percentage of the costs of drilling this well to the base of the Wolfcamp formation;

(b) allowed the pooled parties to participate in potential Atoka/Morrow production by paying only their share of Atoka/Morrow completion costs and the drilling costs from the base of the Strawn and rejecting Chesapeake's request to also be reimbursed for a percentage of the costs of drilling this well to the base of the Strawn formation;

(c) rejected Chesapeake's proposal to allocate well costs between the Wolfcamp, Strawn and Atoka-Morrow formations based upon the industry accepted method for allocating such costs established in September, 1965 by COPAS Bulletin No. 2 "Determination of Values for Well Costs Adjustments-Joint Operations";

(d) rejected Chesapeake's request for a 200% risk factor penalty to be applied to both drilling and completion costs.

(e) allowed the pooled parties a "split election" such that they could make a separate consent-non-consent election for the Wolfcamp completion and for the Atoka/Morrow completion.

(3) Subsequent to the entry of this order, Altura sold its interest to OXY USA, Inc.

(4) On April 7, 2000, Chesapeake timely filed its application for a DeNovo hearing which summarizes the evidence and sets forth in specific detail the reasons for its contentions that Division Order R-11327 is arbitrary, capricious, contrary to precedents established by the Division and is not supported by substantial evidence.

CHESAPEAKE'S DENOVO APPLICATION

Chesapeake objects to the Division's decision as to each of the 5 items listed in paragraph (2) above.

Chesapeake requests that the Commission conduct a DeNovo Hearing, amend Examiner Order R-11327 and find that:

> (a) Altura's desire to pay only its share of Wolfcamp completion costs is without merit because it seeks to avoid making its fair and reasonable contribution for use of that portion of the wellbore from the surface to the base of the Wolfcamp formation without which it would be impossible for Altura to share in any production from the Wolfcamp formation;
>
> (b) Altura's desire to pay only its share of Atoka/Morrow completion costs is without merit because it seeks to avoid making its fair and reasonable contribution for use of that portion of the wellbore from the surface to the base of the Atoka/Morrow formation without which it would be impossible for Altura to share in any production from the Atoka/Morrow formation;
>
> (c) Altura's argument ignores the fact that the Chesapeake well was a continuous drilling operation and did not constitute an abandoned wellbore. (For Example, See Division Order R-10764-A);
>
> (d) Altura's argument fails to address why it should not pay for its share of the costs of drilling to the shallower Wolfcamp formation in exchange for receiving its share of that production;

(e) Altura's argument fails to address why it should not pay for its share of the costs of drilling from the surface to the deeper Atoka/Morrow formation in exchange for receiving its share of that production;

(f) allocation of costs as set forth in the COPAS Bulletin No. 2 is considered by the industry to the most equitable basis for the determination of values to be used in connection with the cost issues involved in this compulsory pooling case;

(g) here is no compelling reason in this case to reject the precedent set by the Division in Order R-9093-C when it allocated costs among multiple formations in a contested compulsory pooling case based upon COPAS Bulletin No. 2;

(h) The Division should adopt the Chesapeake proposed COPAS allocation method;

(i) there is no compelling reason in this case to reject the precedent set by the Division in Order R-8245 when it awarded a 200% risk factor penalty for a well which had already been drilled but which was awaiting completion. (Also See Division Order R-8282-D); and

(j) there is no compelling reason in this case to reject the precedent set by the Division in **Viking Petroleum, Inc. v. Oil Conservation Commission and Harvey E. Yates,** 100 NM 451 (1983) when it allowed Altura to have separate participation elections for the Wolfcamp and for the Atoka/Morrow completions.

ESSENTIAL FACTS

Chesapeake, by voluntary agreement, consolidated 100% of the working interest owners in the S/2SW/4 of this section and proposed to dedicate this 80-acre tract to a standard 80-acre spacing unit in the Northeast Shoe Bar-Strawn Pool by re-entering a well now redesignated as Chesapeake's College of the Southwest "17" Well No. 1 and directionally drilling it for potential production from this Strawn oil pool.

Chesapeake's reason for re-entering this wellbore was based upon its analysis of 3-D seismic data which indicated a potential Strawn reservoir just to the south of the bottom hole location of the abandoned David Fasken wellbore.

During the drilling of this wellbore, Chesapeake's operational personnel at the well site determined that the Strawn formation was non-productive and elected to continue drilling through the Strawn formation an additional 400 feet to the base of the Atoka/Morrow formation. The well has not been completed but based upon log analysis there is possible gas production from the Atoka-Morrow formation (below the Strawn) and possible oil production from the Wolfcamp formation (above the Strawn).

At the time Chesapeake's operational personnel elected to continue drilling this well, they obtained the concurrence of Fasken Land and Minerals, Ltd and Bonneville Fuels Corporation to continue drilling who they mistakenly believed were all working interests owners. In addition, they were under the mistaken impression that the Wolfcamp was spaced on 40-acre and not on 160-acre spacing units.

After drilling, but prior to completion, Chesapeake determined that while Altura Energy, Ltd. ("Altura") interest in the 80-acre Strawn spacing unit were leased to Chesapeake, Altura's interest in the N/2SW/4 needed to form a 160-acre Wolfcamp spacing unit consisting of the SW/4 and needed to form the 320-acre Atoka/Morrow formation spacing unit consisting of the S/2 were still held by Altura and not by Chesapeake.[1]

In addition, Chesapeake determined that Southeast Royalties owned an undivided 1.666% of the working interest in the 320-acre gas spacing unit to be dedicated to the Atoka formation if it produced.

[1] As a result of its interest in the N/2SW/4 of Section 17, Altura has a 13.333% working interest in the Wolfcamp formation and a 20% working interest in the Atoka/Morrow formation.

THE DIVISION IMPROPERLY DENIED RECOVERY OF DRILLING COSTS

Section 70-2-17.C NMSA (1978) provides that the Division has authority to enter a compulsory pooling order to pool interest owners in a well that has been drilled or is to be drilled. Chesapeake requested Examiner Ashley allow it to recover from Altura a reasonable portion of the drilling and completion costs applicable to the Wolfcamp and to the Atoka-Morrow formations. Altura incorrectly argued that they should not have to pay any of the drilling costs of the wellbore because it amounted to a plugged and abandoned Strawn wellbore and those costs should be borne exclusively by the parties who drilled and abandoned it.

Examiner Ashley agreed with Altura and has allowed Altura to participate as follows:

> (a) for the Atoka formation it should pay only its proportionate share of the costs to drill below the base of the Strawn formation to the Atoka formation and then the costs to actually complete that zone;
>
> (b) for the Wolfcamp formation it should pay only its proportionate share of the costs to actually complete that zone if and when a completion is attempted;

In essence, Examiner Ashley treated the wellbore as an abandoned dry hole in the Strawn formation with no value for either the Wolfcamp or Atoka/Morrow formation owners. He has concluded that the working interest owners in the Strawn formation have assumed the entre risk for the costs of the wellbore and are not entitled to any reimbursement for its value even if that wellbore is essential for accessing the Wolfcamp and Atoka-Morrow formations. Examiner Ashley ignored the fact that Chesapeake had not plugged and abandoned this wellbore after penetrating the Strawn, but had continued drilling to the Atoka/Morrow formation. In addition, he either did not know or failed to consider the fact that the Division requires the pooled parties to pay an appropriate share of the value of that existing wellbore if requested by the applicant.

Southeast Royalties contended it is not fair for it to receive a "free well"---meaning that just because Chesapeake had already drilled the well, that fact should not be used as an excuse by another party to avoid paying a fair and reasonable share of those drilling costs.

In entering his order, Examiner Ashley either did not know or chose to ignore numerous prior orders of the Division which are relevant to this case:

> (1) if the Division wants to incorrectly treat the Chesapeake well as a plugged and abandoned Strawn well, then it needs to remember that when an operator has re-entered a plugged and abandoned wellbore and when he has requested reimbursement, the Division has required pooled parties to pay their proportionate share of the value of that existing wellbore in addition to the costs for recompletion. See Order R-10143 (Naumann Oil & Gas Inc. (1994); See R-9996 (Merrion v. Markham-1993); and
>
> (2) while the Division might reduce the risk factor penalty because the well was drilled, the Division has always allowed for the value of the existing wellbore if the applicant asked for it. The issue of pooling additional interest owners into an existing wellbore was reviewed by the Commission on several occasions when it increased the size of spacing units from 320-acres to 640-acres in the Gavilan-Mancos Oil Pool. In all those instances, the new working interest owners were required to compensate the owners of the existing wellbore in order to participate in production. See Order R-8639 (Mesa Grande v. Sun Exploration-1988) , Order R-8641 (Dugan v. Amoco-1988). Order R-8262-A (Oryx v. Mallon-1989)

Chesapeake contended that it should not be required to give Altura a "free wellbore" and asked the Division allocate well costs between the Wolfcamp, Strawn and Atoka-Morrow formation based upon the industry accepted method for allocating such costs established in 1965 by COPAS Bulletin No. 2 "Determination of Values for Well Costs Adjustments-Joint Operations". **See Attachment B.** Examiner Ashley rejected Chesapeake's request and in doing so acted arbitrarily and capriciously.

THE EXAMINER WAS WRONG TO REJECT CHESAPEAKE'S COPAS BASED METHOD FOR ALLOCATING COSTS AMONG OWNERS OF MULTIPLE FORMATIONS

In opposition to Chesapeake, Altura, with a 13.333% interest in the Wolfcamp and a 20% interest in the Atoka/Morrow, sought to participate in both the Wolfcamp and the Atoka/Morrow by only paying $27,000.00 for a completed well which Chesapeake estimated would cost about $840,000. **See Attachment C for details of COPAS cost allocation for this wellbore.**

Examiner Ashley's order allowed Altura a separate election in the Wolfcamp and in the Atoka/Morrow such that:

> (a) Altura would pay $28,012.00 as its share of the costs remaining to set tubing and perforate/stimulate/log and produce the Wolfcamp formation.[2]
>
> (b) Altura would pay $55,267.29 as its share of the costs spent to drill below the base of the Strawn ($101,836.45) and the costs remaining to set tubing and perforate/stimulate/log, and produce the Atoka/Morrow formation ($174,500).[3]

Chesapeake proposed to make the necessary adjustments to its AFE, and to apply the COPAS allocation method such that the total cost allocated to the Atoka/Morrow owners is $549,451.98 and the total cost allocated to the Wolfcamp owners is $290,309.00. If Altura elects to participate in the Atoka/Morrow and Wolfcamp its share is $118,956.84. If they do not then, Chesapeake will pay Altura's share of those costs and be entitled to recover an additional 200% as compensation for carrying Altura's interest.

Thus, Altura should be required to make a single election as to both the Wolfcamp and Atoka/Morrow formations, then Altura's 20% share of the costs allocated to the Atoka/Morrow formation is $109,890.40 and Altura's 13.333% share of the costs allocated to the Wolfcamp formation is $9,066.44. This result occurs because much of the equipment will be utilized for both zones. Chesapeake considers it unfair to allow Altura to "split" its election among the two formations because to do so would allow

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[2] Because the well has been drilled but not completed, the following Wolfcamp costs are still to be incurred: tubing, cased hole logging, perforating, stimulation, artificial lift, downhole equipment, etc for a total estimated cost of $210,500 of which Altura's share is 13.333% Examiner Ashley's decision assumes that the tubing is run in the wellbore and used only for the Wolfcamp completion. If the Commission adopts the COPAS allocation method, the estimated costs of the tubing have already been apportioned between the Wolfcamp and Atoka/Morrow formations.

[3] Examiner Ashley's Atoka/Morrow decision assumes that the tubing is run in the wellbore and used only for the Atoka/Morrow completion. The drilling costs below the Strawn are $100,724.25 for intangibles ($478,500 x 21.05%) and $1,112.20 for tangibles ($33,500 x. 3.32%) plus the remaining Atoka/Morrow completion costs are $174,500 (tubing, logging, stimulation/perforation, etc) for a total of $276,336.45

Altura to benefit from certain expenses which it did not pay for and will result in Altura paying less than its fair share of costs.[4]

However, if the Commission affirms Examiner Ashley's decision, then Altura will have the benefit of a "split election". If Altura goes "non-consent" in the Atoka/Morrow and elects to participate in the Wolfcamp, then Altura should be required to pay $38,706.91 which is $13.33% of $290,309.00 which should be the costs allocated to the Wolfcamp based upon a "split election" option.

The COPAS method for allocating well costs addresses numerous possible situations where drilling and completion costs for drilled wells or proposed wells need to be allocated as a result of ownership changes caused by any number of reasons including different zones with different interests.

The Forward in the COPAS Bulletin No. 2 specifically indicates the applicability of this allocation method to the facts of the Chesapeake case when it states:

> "The basic purpose of this bulletin is to set forth what is considered by the industry in general to be the most equitable basis for the determination of values to be used in connection with well costs...occurring as the result of one of the following:
>
> (1) change in size of unit;
> (2) recompletion of a well in a different zone;
> (3) multiple completion of well in zones of different ownership;
> (4) failure to obtain production in original objective zone and completion of well in zone of different ownership;
> (5) creation of field wide or reservoir units." [paraphrased]

Chesapeake, using the COPAS allocation method, proposed to exclude those costs chargeable to the Strawn formation so that Altura would pay only those costs directly associated with the Wolfcamp and the Atoka-Morrow formations. For example, instead of paying for 100% of the costs of the wellbore to the Wolfcamp, the Wolfcamp owners would pay for the Wolfcamp completion costs and only one-third of the drilling costs to the base of the Wolfcamp and nothing below that depth.

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[4] The option of a split election has already been rejected by the Commission. See **Viking Petroleum, Inc. v. Oil Conservation Commission and Harvey E. Yates**, 100 NM 451 (1983)

However, without explanation, Examiner Ashley rejected the application of the COPAS allocation method to this case. Instead, he attempted, without success, to distinguish the Chesapeake case from the Yates case, in which the Division used the COPAS allocation method in a compulsory pooling case. In doing so, he failed to recognize that the COPAS allocation method still applies to the Chesapeake case.

CHESAPEAKE IS STILL ENTITLED TO REIMBURSEMENT FOR DRILLING COSTS FROM ALTURA EVEN THOUGH THE WELL WAS DRILLED PRIOR TO PROPOSING IT TO ALTURA

Chesapeake, by voluntary agreement, consolidated all interest owners in the Strawn formation, and drill the College of Southwest "17" Well No. 1 to the Strawn formation which was "dry". Chesapeake, under the mistaken belief that all of Altura's interest in the Atoka/Morrow formation was also leased by Chesapeake, continued drilling an additional 400 feet to the base of the Morrow formation. Prior to completing the well, Chesapeake recognized its mistake and contacted Altura and proposed that Altura pay its share of reasonable well costs. Altura and Chesapeake have not been able to reach an agreement.

Examiner Ashley has denied Chesapeake the right to recover any of the drilling costs from Altura, in part, because the well was drilled prior to providing Altura with an opportunity to participate.

Case law requires working interest owners to pay for their share of drilled wells even in circumstances where the operator is guilty of trespass. For example, in **Champlin Refining Co. v. Aladdin Petroleum Corp,** 238 P.2d 827 (OKLA 1951) the operator was allowed to recover all well costs for a well drilled as a dry hole, then plugged back to within 300 feet of the surface and drilled directionally to a new bottom hole location and obtained production because "the well was drilled in good faith and the costs thereof, being reasonable and necessary..."

More importantly the Division has already decided this matter in prior decisions. Unfortunately, Examiner Ashley has entered an order contrary to past precedents established by the Division.[5]

[5] See the following section of this application which discusses Order R-9093-C entered in Case 9998 (Reopened). Also see Order R-8245 entered in Case 8897.

THIS ORDER IS CONTRARY TO PRIOR DIVISION ORDERS ADOPTING THE COPAS ALLOCATION SOLUTION IN A COMPULSORY POOLING CASE

Chesapeake reminded Examiner Ashley that in **Yates Energy Corporation case 9998 Order R-9093-C**, a previous pooling case[6] involving a drilled well, the Division had adopted the COPAS allocation method so that the pooled party would pay only those costs properly associated with each formation. **See Attachment D.**

In the Yates case, before the well was drilled, Yates offered to Chevron a chance to participate only in the Bone Springs. After the well was drilled and the Bone Springs determined to be dry, Yates completed the well, up hole, in the San Andres and then offered Chevron a chance to participate in the San Andres production if Chevron would pay its share of the drilling and completion costs for **both** the Bone Springs and the San Andres portions of the wellbore. Yates wanted Chevron to pay its share of the total well costs which included both the Bone Springs which was found to be non-productive and the San Andres which was productive. Chevron contended that pursuant to the COPAS allocation method it should pay only those costs associated with the productive San Andres. The Division agreed with Chevron and adopted the COPAS allocation method.

Examiner Ashley attempted to distinguish the Chesapeake case from the Yates case in five ways, all of which are wrong:

(a) Examiner Ashley attempted to distinguish the Yates decision because it involved adding an uphole formation while the Chesapeake sought to add a deeper zone. In fact the Chesapeake case involves **both** a shallower (Wolfcamp) and a deeper zone (Atoka Morrow). Examiner Ashley has chosen a difference without a distinction. Why should this difference matter? It does not--the Forward of the COPAS Bulletin addresses both shallower and deeper zone allocation;

(b) Examiner Ashley attempted to distinguish the Yates decision because it involved two zones (the Bone Springs (deep zone) and the San Andres (shallow zone) both on 40-acre spacing while the Chesapeake case involved 80-acre (Strawn) 160-acre (Wolfcamp) and 320-acre (Atoka-Morrow) formations. Why should this difference matter? It does not--Examiner Ashley has failed or refused to understand the COPAS Bulletin deals with various sized units. See Conclusion COPAS Bulletin at page 8. In addition,

[6] OCD Case 9998 (Reopened), Division Order R-9093-C (Yates Petroleum Corporation v. Chevron (1990)

Doyle Hartman increased the size of the spacing unit and pooled Chevron and was allowed to recover from Chevron's share of production the value of the existing wellbore he had on the original spacing unit. See Order R-9332 (1990);

(c) Examiner Ashley attempted to distinguish the Yates decision because, unlike the Chesapeake case, the interest owners were the same in all formations. Presumably, he would apply the COPAS solution only in those cases where ownership is common for all zones. Again, Mr. Ashley has failed to read or understand the COPAS Bulletin which specifically deals with multiple zones of different ownership (See Forward page 2) When there has been a change in the size of the spacing unit, the Division has required payment of well costs. See Order R-8282-D (Marathon v. Davidson-1988) Order R-8071-A (HCW Exploration v. Hartman-1986)

(d) Examiner Ashley attempted to distinguish the Yates case by incorrectly concluding that the pooled parties in the Yates case were provided an opportunity to participate before the well was drilled while in the Chesapeake case the well was drilled first. Examiner Ashley has relied upon a statement which is factually wrong. In the Yates case before the well was drilled, Chevron was offered a chance to participate only in the Bone Springs. After the well was drilled and the Bone Springs determined to be dry, Yates first completed the well in the San Andres and then offered Chevron a chance to participate if Chevron would pay for **both** the Bone Springs and the San Andres cost portions of the wellbore. In the Chesapeake case, Chesapeake had obtained a lease from Altura for Altura's interest in the Strawn formation and drilled the well but **before** completing the well in either the Wolfcamp or the Atoka-Morrow, offered Altura the opportunity to participate if Altura would pay its share of the costs pursuant to the COPAS allocation method. Once, again, Examiner Ashley attempt to distinguish the Yates case is based upon a reason that, frankly, does not matter even if it were factually correct which it is not.

(e) Examiner Ashley incorrectly states that the COPAS allocation method was used to decrease the costs to the pooled parties in the Yates case while in the Chesapeake case it was used in increase the costs to the pooled parties. Nothing could be more incorrect. In **both** cases the COPAS method was used so that the pooled parties paid only for those costs fairly attributed to the zone in which they had an interest and excluded them from paying for costs in zones where they had no interest. In **both** cases it resulted in the pooled parties costs being reduced.

Having attempted to distinguish the Chesapeake case from the Yates case, Examiner Ashley failed to recognize that the COPAS allocation method still applied to the Chesapeake case. None of his reasons for distinguishing Yates case form a logical or rational basis for excusing his failure to apply COPAS allocation method to the Chesapeake case.

The Risk Factor Penalty

Chesapeake recommended to the Division the adoption of a 200% risk factor penalty despite the fact that the well had been drilled[7] and logged because:

(a) there is no Atoka production within 3 miles of this well;

(b) both the original David Fasken which Chesapeake re-entered in Unit M of Section 17 and the Yates' Robert AGX State Well No 1 in Unit A of Section 20 had log indication of the presence of sandstone in the Atoka formation but failed to produce; and that the Atoka log indications for the College of Southwest 1-17 well are poorer than either of those wells.

(c) The nearest well to the subject College of Southwest well is Yates' Robert AGX State Well No 1 in Unit A of Section 20 which has only produced 1,451 barrels of oil from the Wolfcamp since 1996 which is not economic.

(d) The next closest well which produced from the Wolfcamp is located almost a mile away in Unit A of Section 17 and produced 77,776 barrels of oil which was not sufficient to pay for the costs of that well.

(e) a log comparison of the Wolfcamp formation in the subject College of Southwest well with the Yates' well indicates that, at best, the College of Southwest well might be comparable to the Yates well, and if so, then production would not be sufficient to pay for the cost of the College of Southwest Well No. 1.

[7] Division Order R-8245 (1986) awarded Mesa Grande a 200% risk factor against Chevron even though the well had been drilled.

Altura recommended to the Division that a 100% risk factor penalty be assessed against them only for the costs of completion because:

(a) Chesapeake should be punished for its mistake in failing to consolidate Altura's interest in the Wolfcamp and Atoka formations prior to re-entry of the well.

(b) Altura wanted a chance to participate "risk free" in either the Atoka or Wolfcamp formations.

Examiner Ashley awarded a 100% risk factor only on the completion costs. Chesapeake requests that the Commission enter a DeNovo order awarding a 200% risk factor to be applied to both drilling and completion costs because:

(a) the availability of log data and the drilling of the well has not diminished the risk involved in this well to less than the statutory maximum and the maximum 200% risk factor should be awarded.

(b) Altura has the benefit of having the Chesapeake log data from which to base its decision concerning participation and if it elects not to participate then it will being doing so based upon the conclusion that it is too risky to participate;

(c) If Altura elects not to participate, it will be an admission that the risk is substantial and Altura should be subject to the maximum 200% penalty.

(d) Altura, after using Chesapeake's log data to analyze risk, can avoid any risk factor penalty by electing to participate.

(e) the fact remains that Chesapeake has paid for Altura's share of the costs of the well and should be reasonably compensated for having done so. The form of that compensation is a risk factor penalty.

WITNESSES

Chesapeake reserves the right to call the following potential witnesses

Lynda Townsend (landman)	30 min.	@ 10 exhibits
Robert Hefner (geology)	40 Min.	@ 4 exhibits
Randy Gassaway (PE)	40 Min.	@ 6 exhibits

PROCEDURAL MATTERS

None anticipated

KELLAHIN & KELLAHIN

BY: ____________________
W. Thomas Kellahin

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 12325
ORDER NO. R-11327

APPLICATION OF CHESAPEAKE OPERATING, INC FOR COMPULSORY POOLING AND AN UNORTHODOX WELL LOCATION, LEA COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on January 20, 2000 at Santa Fe, New Mexico, before Examiner Mark W. Ashley.

NOW, on this 9th day of March, 2000, the Division Director, having considered the testimony, the record and the recommendations of the Examiner,

FINDS THAT:

(1) Due public notice has been given and the Division has jurisdiction of this case and its subject matter.

(2) The applicant, Chesapeake Operating, Inc. ("Chesapeake"), seeks an order pooling all uncommitted mineral interests from the surface to the base of the Morrow formation underlying the following acreage in Section 17, Township 16 South, Range 36 East, NMPM, Lea County, New Mexico:

> (a) the S/2 to form a standard 320-acre gas spacing and proration unit for formations or pools developed on 320-acre spacing within that vertical extent, including the Undesignated West Lovington-Pennsylvanian Gas Pool;
>
> (b) the SW/4 to form a standard 160-acre gas spacing and proration unit for formations or pools developed on 160-acre spacing within that vertical extent, including the Undesignated North Shoe Bar-Wolfcamp Gas Pool; and

EXHIBIT
A

> (c) the S/2 SW/4 to form a standard 80-acre oil spacing and proration unit for formations or pools developed on 80-acre spacing within that vertical extent, including the Undesignated Northeast Shoe Bar-Strawn Pool.

NOTE: After pooling, uncommitted working interest owners are referred to as "non-consenting working interest owners."

(3) On September 24, 1999, in accordance with the directional drilling provisions of Division Rule 111, the Division approved Chesapeake's administrative application to re-enter the College of the Southwest "17" Well No. 1 (**API No. 30-025-29535**) and deepen it to the Strawn formation and designated the S/2 SW/4 of the section as an 80-acre project area for this well.

(4) At the time of the hearing Chesapeake testified that all the interests within the 80-acre oil spacing and proration unit had been voluntarily committed; therefore, that portion of the application requesting the pooling of the 80-acre oil spacing and proration unit should be dismissed.

(5) The subject proration units are to be dedicated to the applicant's College of the Southwest "17" Well No. 1, which was directionally drilled to the Morrow formation at a subsurface location 580 feet from the South line and 1085 feet from the West line (Unit M) of Section 17. The applicant drilled the College of the Southwest "17" Well No. 1 by re-entering the plugged and abandoned David Fasken Berry Hobbs Well No.1, located at a surface location 981 feet from the South line and 991 feet from the West line (Unit M) of Section 17.

(6) The West Lovington Pennsylvanian Gas Pool is governed by Rule No. 104.C.(2) of the Division's General Rules, which provides for 320-acre spacing and requires wells to be located no closer than 660 feet from the outer boundary of the quarter section and no closer than 10 feet to any quarter-quarter section line or subdivision inner boundary.

(7) Pursuant to Order No. R-4657, as amended, issued in Case No. 5081 and dated October 17, 1973, the North Shoe Bar-Wolfcamp Gas Pool is governed by Special Pool Rules that provide for 160-acre spacing and proration units and require wells to be located within 150 feet of the center of a governmental quarter-quarter section or lot.

(8) Pursuant to Order No. R-4658, as amended, issued in Case No. 5082 and dated October 17, 1973, the Northeast Shoe Bar-Strawn Pool is governed by Special Pool Rules that provide for 80-acre oil spacing and require wells to be located no closer than 330 feet to any quarter-quarter section line.

(9) The subsurface location of the applicant's College of the Southwest "17" Well No. 1 is unorthodox for the subject proration units.

(10) Chesapeake testified that it is the operator of the offsetting acreage to the south, and no affected party appeared at the hearing or objected to the unorthodox subsurface locations.

(11) The unorthodox locations should be approved.

(12) Chesapeake re-entered this wellbore based upon its analysis of 3-D seismic data, which indicated a potential Strawn reservoir just to the south of the original bottom-hole location. Accordingly, Chesapeake attempted only to combine the interests in and obtain approval from the Division for an 80-acre spacing unit comprising the S/2 SW/4 of Section 17. Chesapeake did not attempt to form a 320-acre spacing unit for the Atoka-Morrow formation, did not obtain a permit for a 320-acre spacing unit from the Division, and did not propose a well to other owners of working interest in a 320-acre spacing unit. Additionally, Chesapeake did not form a 160-acre spacing unit for the Wolfcamp formation, did not obtain a permit from the Division for a 160-acre spacing unit, and did not propose a well to the other owners of working interest in a 160-acre Wolfcamp spacing unit.

(13) The applicant is a working interest owner within the subject proration units and therefore has the right to drill for and develop the minerals underlying these units.

(14) During the drilling of this wellbore, Chesapeake's operational personnel at the well site determined that the Strawn formation was non-productive and elected to continue drilling through the Strawn formation to the base of the Morrow formation. To drill from the Strawn formation to the Atoka-Morrow formation, Chesapeake only had to drill several hundred additional feet. The well has been drilled and logged, and there have been gas shows in the Atoka-Morrow formation on the mud logs of the well.

(15) Chesapeake's operational personnel elected to continue drilling this well without obtaining the concurrence of all working interests owners to continue drilling, without voluntarily consolidating the working interests of all owners in the S/2 of this section, and without authorization from the Division.

(16) There are interest owners in the subject proration units that have not agreed to pool their interests.

(17) After drilling, but prior to completion, Chesapeake determined that the Altura Energy, Ltd. ("Altura") interest in the N/2 SW/4 and in the SE/4 of this section was still held by Altura and not by Chesapeake. In addition, Chesapeake determined that Southeast Royalties, Inc. ("Southeast") owned an undivided 1.666% of the working interest in the 320-acre gas spacing unit to be dedicated to the well if it produced from the Atoka formation.

(18) Altura and Southeast, working interest owners in the Atoka-Morrow and Wolfcamp proration units, appeared at the hearing and objected to the following:

(a) the compulsory pooling portion of Chesapeake's application; and

(b) the costs Chesapeake is now proposing to charge to other owners before they will be able to participate in production from formations it now seeks to pool.

(19) Altura testified that Chesapeake's cost allocation is unreasonable and that for the Atoka-Morrow formation Altura should pay only its proportionate share of the costs to drill below the base of the Strawn formation to the Atoka-Morrow formation and then the costs to complete that zone. Regarding the Wolfcamp formation, Altura testified that it should pay its proportionate share of the costs to complete that zone only if and when a completion is attempted.

(20) Chesapeake asked the Division to allocate the costs incurred in the drilling of the College of the Southeast Well No. 1 to the Atoka-Morrow formation to Altura and Southeast in accordance with the provisions of COPAS Bulletin No. 2, "Determination of Values for Well Cost Adjustments - Joint Operations." Chesapeake cited Order No. R-9093-C, issued in Case No. 9998 and dated November 29, 1990, as a precedent for this request.

(21) The facts and issues presented to the Division in Case No. 9998 are distinguishable from the facts and issues presented to the Division in this case in the following ways:

(a) Case No. 9998 involved the amendment of a compulsory pooling order to add only uphole formations not included in the original order. This case involves an application for a new compulsory pooling order to combine interests in formations below the total depth of the original wellbore.

(b) In Case No. 9998 all affected formations were developed on 40-acre spacing units. This case involves formations developed on larger and different spacing units than those dedicated to the original Strawn well.

(c) In Case No. 9998, the affected parties were the same in the new formations as in the formations subject to the original pooling order. In this case, the interest owners subject to pooling owned no interest in the original wellbore.

(d) Before the original compulsory pooling order was entered in Case No. 9998, the owners who were subject to the pooling application had been offered an opportunity to participate in the well and had declined to do so. In this case, the owners subject to the pooling application were not contacted about participating in the well until in had already been drilled.

(e) In Case No. 9998, the COPAS Bulletin No. 2 formula was used to decrease the costs other interest owners would have to pay to participate in production from the new formations that which were added to the pooling order. In this case Chesapeake is attempting to use the formula in COPAS Bulletin No. 2 to increase the costs other interest owners would have to pay to participate in production from the new formations.

(22) Order No. R-9093-C does not set a precedent for the issues in this case.

(23) Altura testified that if Chesapeake's application is granted and Altura and Southeast are required to pay a share of the costs of Chesapeake's entire wellbore, Altura and Southeast will pay an amount that equals or exceeds the total costs of drilling from the Strawn to the Atoka-Morrow, and Chesapeake will share in Atoka-Morrow production for no additional cost over those incurred in drilling the dry hole in the Strawn.

(24) Requiring Altura and Southeast to pay a share of the costs incurred in drilling the dry hole in the Strawn formation, pursuant to the provisions of COPAS Bulletin No. 2, "Determination of Values for Well Cost Adjustments - Joint Operations," is unreasonable and this portion of Chesapeake's application should be denied.

(25) Altura and Southeast should be afforded the opportunity to participate in Atoka-Morrow production from the College of the Southwest "17" Well No. 1 by paying their proportionate share of the costs of drilling the well from the Strawn formation to the Atoka-Morrow formation and their proportionate share of the completion costs in the Atoka-

Morrow formation. Additionally, Altura and Southeast should be afforded the opportunity to participate in Wolfcamp production from the College of the Southwest "17" Well No. 1 by paying their proportionate share of the costs to complete that zone if and when a completion is attempted.

(26) Chesapeake is requesting a 200 percent risk factor penalty despite the fact that the well has been drilled and logged because there is no Atoka production within three miles of this well and the nearest Wolfcamp well is the Yates Petroleum Corporation Robert AGX State Well No 1 in Unit A of Section 20, which has only produced 1,451 barrels of oil from the Wolfcamp since 1996.

(27) Altura's witness testified that the only risk remaining is the very small risk associated with the completion of the subject well in the Wolfcamp and Atoka-Morrow formations; therefore, Altura has recommended to the Division that the risk factor penalty be reduced to 100 percent.

(28) Chesapeake has assumed the risk associated with drilling the College of the Southwest "17" Well No. 1 from the Strawn formation to the Atoka-Morrow formation without first combining the lands to be dedicated to the well either by voluntary agreement of the interest owners or by obtaining a compulsory pooling order from the Division. The risk factor penalty should therefore be reduced to 100 percent and should be applied only to the costs of completion.

(29) Additionally, Chesapeake is requesting that Altura's and Southeast's period of election should be shortened from 30-days to 15-days.

(30) Since Chesapeake failed to form a 320-acre spacing unit for the Atoka-Morrow formation and a 160-acre spacing unit for the Wolfcamp formation prior to re-entering the subject well, Altura and Southeast should be allowed the full 30-day period of election.

(31) To avoid the drilling of unnecessary wells, protect correlative rights, prevent waste and afford to the owner of each interest in the above-described proration units the opportunity to recover or receive without unnecessary expense its just and fair share of hydrocarbon, this application should be approved by pooling all uncommitted mineral interests, whatever they may be, within the subject proration units.

(32) Chesapeake should be designated the operator of the subject well and units.

(33) Any non-consenting working interest owner should be afforded the opportunity to pay its share of actual drilling costs from the Strawn formation to the Atoka-

Morrow formation and its share of estimated completion costs in the Atoka-Morrow formation to the operator in lieu of paying its share of costs out of production.

(34) Any non-consenting working interest owner who does not pay its share of actual drilling costs from the Strawn formation to the Atoka-Morrow formation and its share of estimated completion costs in the Atoka-Morrow formation should have withheld from production its share of reasonable costs plus an additional 100 percent of the reasonable completion costs as a charge for the risk involved in the completion of the well.

(35) Any non-consenting working interest owner should be afforded the opportunity to object to the actual drilling costs from the Strawn formation to the Atoka-Morrow formation and the actual completion costs in the Atoka-Morrow formation, but actual costs should be adopted as the reasonable costs in the absence of such objection.

(36) Following determination of reasonable costs, any non-consenting working interest owner who has paid its share of actual drilling costs and estimated completion costs should pay to the operator any amount that reasonable costs exceed actual drilling costs and estimated completion costs and should receive from the operator any amount that paid actual drilling costs and estimated completion costs exceed reasonable costs.

(37) Any non-consenting working interest owner should be afforded the opportunity to pay its share of estimated completion costs in the Wolfcamp formation to the operator in lieu of paying its share of costs out of production.

(38) Any non-consenting working interest owner who does not pay its share of estimated completion costs in the Wolfcamp formation should have withheld from production its share of the completion costs plus an additional 100 percent thereof as a charge for the risk involved in the completion of the well.

(39) Any non-consenting working interest owner should be afforded the opportunity to object to the actual completion costs in the Wolfcamp formation, but actual completion costs should be adopted as the reasonable costs in the absence of such objection.

(40) Following determination of reasonable completion costs in the Wolfcamp formation, any non-consenting working interest owner who has paid its share of estimated completion costs should pay to the operator any amount that reasonable costs exceed estimated costs and should receive from the operator any amount that paid estimated costs exceed reasonable costs.

(41) Reasonable charges for supervision (combined fixed rates) should be fixed

at $6,000.00 per month while drilling and completing and $600.00 per month while producing. The operator should be authorized to withhold from production the proportionate share of both the supervision charges and the actual expenditures required for operating the well, not in excess of what are reasonable, attributable to each non-consenting working interest.

(42) All proceeds from production from the well that are not disbursed for any reason should be placed in escrow to be paid to the true owner thereof upon demand and proof of ownership.

(43) If all the parties subject to this forced pooling reach voluntary agreement subsequent to entry of this order, this order should become of no effect.

(44) The operator of the well and units should notify the Division in writing of the subsequent voluntary agreement of all parties subject to the forced pooling provisions of this order.

IT IS THEREFORE ORDERED THAT:

(1) Pursuant to the application of Chesapeake Operating, Inc., all uncommitted mineral interests from the surface to base of the Morrow formation underlying the following acreage in Section 17, Township 16 South, Range 36 East, NMPM, Lea County, New Mexico, are hereby pooled in the following manner:

> (a) the S/2 to form a standard 320-acre gas spacing and proration unit for formations or pools developed on 320-acre spacing within that vertical extent, including the Undesignated South Shoe Bar-Mississippian Gas Pool; and
>
> (b) the SW/4 to form a standard 160-acre gas spacing and proration unit for formations or pools developed on 160-acre spacing within that vertical extent, including the Undesignated North Shoe Bar-Wolfcamp Gas Pool.

NOTE: After pooling, uncommitted working interest owners are referred to as "non-consenting working interest owners."

(2) The portion of the application relating to the 80-acre oil spacing and proration unit is hereby dismissed.

(3) The 320-acre and 160-acre units are to be dedicated to the applicant's College of the Southwest "17" Well No. 1 (**API No. 30-025-29535**), which was directionally drilled to the Morrow formation at an unorthodox subsurface location 580 feet from the South line and 1085 feet from the West line (Unit M) of Section 17. The applicant drilled the College of the Southwest "17" Well No. 1 by re-entering the plugged and abandoned David Fasken Berry Hobbs Well No.1, located at a surface location 981 feet from the South line and 991 feet from the West line (Unit M) of Section 17.

(4) The unorthodox locations for the subject units are hereby approved.

(5) Chesapeake Operating, Inc. is hereby designated the operator of the subject well and units.

(6) The request of Chesapeake Operating, Inc. to allocate the costs incurred in the drilling of the College of the Southeast Well No. 1 to the Atoka-Morrow formation to Altura and Southeast in accordance with the provisions of COPAS Bulletin No. 2, "Determination of Values for Well Cost Adjustments - Joint Operations," is hereby denied.

(7) After the effective date of this order and within 90 days prior to completing the well in the Atoka-Morrow formation, the operator shall furnish the Division and each known working interest owner in the 320-acre unit comprising the S/2 of Section 17 an itemized schedule of the actual costs incurred in drilling the College of the Southwest "17" Well No. 1 from the base of the Strawn formation to total depth of the well and estimated completion costs for the Atoka-Morrow formation.

(8) Within 30 days from the date the schedule of actual costs incurred in drilling from the base of the Strawn formation to total depth of the well and estimated completion costs for the Atoka-Morrow formation is furnished, any working interest owner shall have the right to pay its share of actual drilling costs and actual completion costs to the operator in lieu of paying its share of costs out of production, and any such owner who pays its share of actual drilling costs and actual completion costs as provided above shall remain liable for operating costs but shall not be liable for risk charges.

(9) The operator shall furnish the Division and each known non-consenting working interest owner an itemized schedule of actual completion costs within 90 days following completion of the well in the Atoka-Morrow formation. If no objection to the actual costs incurred in drilling and completing the subject well is received by the Division and the Division has not objected within 45 days following receipt of the schedule, the actual

drilling and completion costs shall be the reasonable costs; provided, however, that if there is an objection to the actual drilling and completion costs within the 45-day period, the Division will determine reasonable costs after public notice and hearing.

(10) Within 60 days following determination of reasonable costs, any non-consenting working interest owner who has paid its share of costs in advance as provided above shall pay to the operator its share of the amount that reasonable costs exceed estimated costs and shall receive from the operator its share of the amount that estimated costs exceed reasonable costs.

(11) After the effective date of this order and within 90 days prior to completing the well in the Wolfcamp formation, the operator shall furnish the Division and each known working interest owner in the 160-acre unit comprising the SW/4 of Section 17 an itemized schedule of the estimated completion costs incurred in completing the College of the Southwest "17" Well No. 1 in the Wolfcamp formation.

(12) Within 30 days from the date the schedule of estimated completion costs incurred for the Wolfcamp formation is furnished, any working interest owner shall have the right to pay its share of estimated completion costs to the operator in lieu of paying its share of estimated completion costs out of production, and any such owner who pays its share of estimated completion costs as provided above shall remain liable for operating costs but shall not be liable for risk charges.

(13) The operator shall furnish the Division and each known non-consenting working interest owner an itemized schedule of actual completion costs within 90 days following completion of the well in the Wolfcamp formation. If no objection to the actual costs incurred in completing the subject well is received by the Division and the Division has not objected within 45 days following receipt of the schedule, the actual completion costs shall be the reasonable completion costs; provided, however, that if there is an objection to actual completion costs within the 45-day period, the Division will determine reasonable completion costs after public notice and hearing.

(14) Within 60 days following determination of reasonable completion costs in the Wolfcamp formation, any non-consenting working interest owner who has paid its share of estimated completion costs in advance as provided above shall pay to the operator its share of the amount that reasonable costs exceed estimated costs and shall receive from the operator its share of the amount that estimated costs exceed reasonable costs.

(15) The operator is hereby authorized to withhold the following costs and charges from production:

(a) the proportionate share of reasonable costs incurred in drilling from the base of the Strawn formation to the total depth of the well attributable to each non-consenting working interest owner who has not paid its share of actual drilling costs within 30 days from the date the schedule of actual drilling costs is furnished;

(b) the proportionate share of reasonable completion costs attributable to each non-consenting working interest owner who has not paid its share of estimated completion costs within 30 days from the date the schedule of estimated completion costs is furnished; and

(c) as a charge for the risk involved in completing the well, 100 percent of the above completion costs.

(16) The operator shall distribute the costs and charges withheld from production to the parties who advanced the costs.

(17) Reasonable charges for supervision (combined fixed rates) are hereby fixed at $6,000.00 per month while drilling and completing and $600.00 per month while producing. The operator is authorized to withhold from production the proportionate share of both the supervision charges and the actual expenditures required for operating the well, not in excess of what are reasonable, attributable to each non-consenting working interest.

(18) Any unleased mineral interest shall be considered a seven-eighths (7/8) working interest and a one-eighth (1/8) royalty interest for the purpose of allocating costs and charges under this order.

(19) Any well costs or charges that are to be paid out of production shall be withheld only from the working interests' share of production, and no costs or charges shall be withheld from production attributable to royalty interests.

(20) All proceeds from production from the well that are not disbursed for any reason shall be placed in escrow in Lea County, New Mexico, to be paid to the true owner thereof upon demand and proof of ownership. The operator shall notify the Division of the name and address of the escrow agent within 30 days from the date of first deposit with the

escrow agent.

(21) Should all the parties to this compulsory pooling order reach voluntary agreement subsequent to entry of this order, this order shall thereafter be of no further effect.

(22) The operator of the well and units shall notify the Division in writing of the subsequent voluntary agreement of all parties subject to the forced pooling provisions of this order.

(23) Jurisdiction of this case is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

Lori Wrotenbery

LORI WROTENBERY
Director

SEAL

BULLETIN NO. 2

DETERMINATION OF VALUES FOR WELL COST ADJUSTMENTS JOINT OPERATIONS

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This bulletin has been reviewed by the Petroleum Accountants Societies through representation on the Council of Petroleum Accountants Societies. It is recommended that the contents of the bulletin be used as a guide to joint interest operations accounting.
The Council is gratified and appreciative to the Petroleum Accountants Society of Denver for research and publication of this bulletin.

EXHIBIT 6

FOREWORD

The basic purpose of this bulletin is to set forth what is considered by the industry in general to be the most equitable basis for the determination of values to be used in connection with well cost adjustments. This is necessitated by the tremendous increase in the various unitizations taking place for which no definite precedent has heretofore been established. The determination of values are normally required as the result of ownership changes which usually occur as the result of one of the following:

1. Change to size of a unit either voluntarily or to conform to edicts of a Regulatory Body.

2. Recompletion of a well in a different zone or formation.

3. Multiple completion of well in zone or zones of different ownership.

4. Failure to obtain production in original objective zone and completion of well in zone of different ownership.

5. The creation of Field-wide or Reservoir Units.

Prior to execution of the Unit Operating Agreement, the value of the unit well should be agreed upon and written into the agreement. In the creation of Voluntary Units it is recognized that because of other considerations such as obsolete equipment, prior production, secondary recovery, reservoir peculiarities etc., it might be desirable to negotiate a stipulated amount or even to contribute intangibles and/or tangible equipment to the unit.

Well cost, as discussed herein, consists of subsurface equipment, wellhead and wellhead equipment and the associated intangible costs through the Xmas Tree. The lease production equipment, including installation costs, should be treated separately in the negotiations and in most instances should be adjusted in accordance with the Accounting Procedure attached to the Operating Agreement. In some instances the nature of the operations may dictate handling wellhead, wellhead equipment and tubing items. For example, a single completion well being dualled, requiring the Xmas Tree to be changed out for a dual tree and the single string tubing to be changed out for a dual string.

The following suggestions are for use as guide lines only. No attempt has been made to include a suggested solution for all of the contingencies that may occur. It is also recognized that there may be more than one equitable solution to each problem. In these instances alternate suggestions have been included.

INTANGIBLE DRILLING COSTS

Intangible Drilling Costs are defined as those expenditures which are non-recoverable and as such have no salvage value. For the purpose of this bulletin material items classified as non-controllable in the Material Classification Manual most recently recommended by the Council of Petroleum Accountants Society of North America should be included as intangible costs. Intangible Drilling Costs are incurred in drilling and preparing wells for the production of oil and gas. Intangible costs normally end at the first down stream connection on the wellhead, and generally include the following expenses:

DRILLING
- Footage-Contract
- Daywork-Contract
- Cost Plus-Contract
- Turnkey Contract
- Company Tools

LABOR
- Company
- Contract

AUTOMOTIVE EXPENSE
- Automobile
- Truck and Service Equipment

ROADS, CANALS AND LOCATIONS

POWER, FUEL AND WATER

MATERIAL AND SUPPLIES
- Bits and Equipment Rental
- Drilling Mud and Chemicals
- Other

SPECIALIZED SERVICES
- Well Surveys and Test Services
- Cementing Casing
- Shooting, Acidizing and Perforating
- Squeeze Jobs

OTHER INTANGIBLE DRILLING COSTS
- Geological and Engineering
- District Expense
- Administrative Overhead
- Loss and Damage
- Vacation, Sickness and other Employee Benefits
- Other Costs

A. DETERMINATION OF INTANGIBLE DRILLING COSTS

1. The operators' historical actual recorded cost is the preferred basis to be used in determining the one-hundred per cent amount to be allocated. Alternate methods are as follows:

   (a) Fixed or agreed sum. This amount would be an arbitrarily assigned amount acceptable by all parties concerned and would be used as the cost only when the operators' actual recorded cost is either unavailable, unrealistic or unacceptable.

   (b) No Value. This method requires no allocation of costs. In using this method it would be pre-determined that each party has contributed a comparable base cost. A no value basis would normally be used in the creation of voluntary Field-wide or Reservoir Units, which have been fully developed.

2. When operators' actual cost is used, it should be noted that these costs include in addition to the direct expenses incurred, allowances for operators' District Expense and Administrative Overhead. District expense would be calculated in accordance with the operators' normal practice of allocating these expenses. Administrative Overhead or Combined Fixed Rates should be the amount charged the joint account if the property for which the cost adjustment is being made was originally jointly owned. If the property for which the cost adjustment is being made was not originally jointly Owned, Administrative Overhead or Combined Fixed Rates should be calculated at the prevailing rate for the area in which the unitization or

change of ownership's taking place. Also included would be any costs incurred in drilling below the unitized formation to a maximum depth of one hundred feet.

Expenses incurred for certain Specialized Services in formations other than the unitized formation should be excluded. Such Specialized Services could include electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc.

3. When operators' actual cost is used such cost should be amortized. The preferred basis is the unit of production method. This factor is determined by a fraction of which the numerator is past production and the denominator is past production plus estimated future reserves.

   In the event both oil and gas are produced from the unit well, then this method of amortization should be amended to use a basis of value rather than unit of production. As an alternate, a straight line method may be used. This factor is determined by a fraction of which the numerator is the number of years produced and the denominator is the number of years produced plus the estimated remaining years of production.

B. ALLOCATION OF INTANGIBLE DRILLING COSTS

This portion of the bulletin pertains to the allocation or association of costs to a portion of the well common to specified zones of operation.

1. The preferred method for the allocation of costs between zones is from a detailed analysis of actual expenditures when practical, utilizing well, drilling and accounting records, Other acceptable methods are as follows:

   (a) A drilling day ratio. This factor for each zone is determined by a fraction of which the numerator is the number of days drilled through that zone and the denominator is the total number of drilling days spent on the well, beginning on the date the well is spudded and terminating when the rig is released. It is desirable to eliminate from this allocation all expenditures known to be applicable to specific producing formations and could include electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc. This would necessitate the elimination of the applicable days required to perform such function, For an illustration, suppose a well completed in three zones required 75 drilling days. If the time from spud date to the base of the first zone, plus the time required to log and set the production string of casing, amounted to 27 days, this zone would receive an allocation of 27/75 or 36% of the intangible drilling costs. If the time required to drill from the base of the first zone to the base of the second zone took eleven days, this zone would receive an allocation of 11/75 or 15%. If the time required to drill from the base of the second zone to the base of the third zone took 37 days, this zone would receive an allocation of 37/75 or 49%.

   (b) A drilling footage ratio. This factor for each zone is determined by a fraction of which the numerator is the footage drilled through that zone and the denominator is the total footage drilled for the entire well. It is desirable to eliminate from this allocation all expenditures known to be applicable to a specific producing formation and could include electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc.

   For an illustration, suppose a well completed in three zones was drilled to a total depth of 14,000 feet. If the footage from surface through the first zone was 12,000 feet, this zone would receive 12,000/14,000 or 85.72% of the intangible drilling costs. If the footage from the bottom of the first zone through the second zone was 1,000 feet, this zone would receive 1,000/14,000 or 7.14%. If the footage from the bottom of the second zone through the third zone was 1,000 feet, this zone would also receive 1,000/14,000 or 7.14%.

2. After the costs have been allocated to the zones by one of the methods described above, assuming there are three zones, these costs should be shared by the owners in the following manner:

(a) Applicable costs identified with the zone from the surface to the base of the first producing formation should be allocated equally to all formations with the owners in each formation standing their proportionate share based on their respective interest in each formation.
(b) Applicable costs identified with the zone between the base of the first producing formation and the base of the second producing formation should be allocated equally to all formations below the base of the first formation with the owners in each formation standing their proportionate share based on their respective interest in each formation.
(c) Applicable costs identified with the area below the base of the second producing formation will be charged to the deeper formation.

TANGIBLE COSTS

Tangible Drilling Costs are defined as those material items installed in connection with drilling and completing a well through the Xmas Tree and which, are ordinarily considered to have salvage value, regardless of whether such items may actually be salvaged after they are installed. Such materials are classified as controllable in the Material Classification Manual most recently recommended by the Council of Petroleum Accountants Society of North America.

A. DETERMINATION OF TANGIBLE COSTS

1. BASE PRICE

(a) Actual recorded cost reduced by a depreciation factor set forth in 2 below. Some companies price material to their 100% properties as well as joint properties on a current market basis, therefore, actual recorded cost would be appropriate. However, some companies price material to their 100% properties on a depreciated or average cost basis, therefore the basis in (b) or (c) below might be more equitable.

(b) Current Market (New) value at date of installation reduced by a depreciation factor set forth in 2 below.

(c) Current Market (New) value at date of unitization reduced by a depreciation factor set forth in 2 below.

2. DEPRECIATION

Depreciation should be limited to such amount so as to produce a value of equipment in an amount not to be less than the salvage value after deducting the cost of salvage.

(a) Unit of production method. The amount of depreciation is determined by a fraction of which the numerator is past production and the denominator is past production plus estimated future reserves. In the event both oil and gas are produced from the unit well, then this method of depreciation should be amended to use a basis of value rather than unit of production.

(b) Straight line method. The amount of depreciation is determined by a fraction of which the numerator is the number of years produced and the denominator is the number of years the well produced plus the estimated remaining years of production.

(c) Agreed condition percentage.

B. ALLOCATION OF TANGIBLE COST

In most unitizations it will be necessary for the operator to allocate the equipment serving the unit and/or units in the same wellbore on an equitable basis. Due to deep drilling in some wells, larger, heavier and more expensive casing, and in some cases a protection string may be set in the well that would not have been required had the well been drilled to the unit sand only. To attempt to adjust for this situation brings up many problems and would require an estimate of the tangible as well as the intangible cost for a hypothetical well to the unit sand which is not recommended. Since the operator assumed all the risks of drilling the well and the non-operator has usually benefited from this, it is suggested that no adjustment be made for these costs in determining the value of the unit well.

To assure adequate penetration through the unit sand, in most adjustments the depth of a unit is considered to be 100' below the base of the unit sand. The total depth of the well may be slightly greater than the 100' and in these cases it is suggested that the adjustment include total depth. A string of casing may consist of casing of different weights and grades set at various depths, but for the purpose of making an allocation to the unit the total average cost of the casing string should be used.

Assuming three completions in a single well bore, the cost of tangible well equipment should be allocated as follows:

1. CASING

   (a) Total average cost of the casing from the surface to the base of the first zone should be allocated equally to all zones in the wellbore.

   (b) Total average cost of the casing from the base of the first zone to the base of the second zone should be allocated equally to the second and third zones.

   (c) Total average cost of the casing from the base of the second zone to the base of the third zone should be allocated entirely to the third zone.

2. WELLHEAD

   Wellhead and wellhead equipment through the Xmas Tree should be allocated equally to all producing formations served.

3. TUBING

   In those instances when each unit reservoir is produced through a separate string of tubing then each unit will be charged with the respective tubing string. In those instances when one unit reservoir is produced through the casing then the total cost of the tubing will be shared proportionately by the units served with the appropriate adjustment for tubing below the individual unit reservoirs.

   Tangible controllable equipment not specifically mentioned above should be allocated on an equitable basis to the zone or zones served.

CONDITIONS OF UNITIZATION

Following are the conditions for which the determination of values for well cost adjustments may be required:

1. Straight up lease well or wells to unit in same reservoir.

A. Originally drilled as 100% or joint well -

(1) Not produced from unit sand.

(2) Produced from unit sand.

2. A. Revision of an existing unit from 100% ownership to joint.

   B. Revision of an existing joint unit - same parties, different interest, or bring in additional interest.

3. Single well completion dualled subsequently into unit reservoir original completion remains 100% and unit completion becomes joint.

4. Dual completion - one or more completions unitized.

5. Single completion depleted and re-completed in higher unitized reservoirs.

6. Single completion depleted and drilled deeper to unitized reservoir.

7. Dry hole reworked into unitized reservoir.

8. Single completion depleted and re-completed for injection or disposal well for unit.

9. Dry hole recompleted for injection or disposal well for unit. Operator furnish substitute well to supplement production from a unit on rental basis.

10. Operator furnish substitute well to supplement production from a unit on rental basis.

INFORMATION TO BE FURNISHED TO NON-OPERATORS BY OPERATOR

Upon completion of the evaluation of the unit well and prior to the execution of the Unit Operating Agreement, the following information should be furnished by the operator to all non-operators:

A. Copy of well record or well completion report.

B. Itemized priced list of tangible controllable equipment and basis of pricing, depreciation and allocation. The well equipment through the Xmas Tree is subject to verification by an audit of the operator's well records and an inventory.

C. Summary of intangible cost by type of expenditure with a brief statement as to how the costs were determined, depreciated and allocated.

D. Brief daily resume of drilling operations including mud weights.

CONCLUSION

It is believed that the most common conditions of unitizations may be resolved by the recommendations set forth above, and the accountants role in the negotiation of unit operating agreements brought to a timely conclusion.

Owners of working interests in new units formed should be charged their proportionate share of the agreed well value based on their respective interest in the unit; and the selling owners should be credited with their proportionate interest sold.

The unit operator should act as a collection and disbursing agent for all parties with appropriate protection authorized by the operating agreement. So as not to place an undue burden on the operator, purchasers of an interest should remit promptly after being billed and the operator should make payment to sellers immediately after receiving payment from all purchasers. All future accounting for the unit should be governed by the provisions of the operating agreement entered into between the parties.

THE EXAMINER WAS WRONG TO REJECT CHESAPEAKE'S COPAS BASED METHOD FOR ALLOCATING COSTS AMONG OWNERS OF MULTIPLE FORMATIONS

In opposition to Chesapeake, Altura, with a 13.333% interest in the Wolfcamp and a 20% interest in the Atoka/Morrow, sought to participate in both the Wolfcamp and the Atoka/Morrow by only paying $27,000.00 for a completed well which Chesapeake estimated would cost about $840,000. It is interesting to compare the Chesapeake proposed costs with the fact that the estimated dry hole costs for a Wolfcamp well would exceed $600,000 and for an Atoka/Morrow well would exceed $800,000.

Examiner Ashley's order allowed Altura a separate election in the Wolfcamp and in the Atoka/Morrow such that:

> (a) Altura would pay $28,012.00 as its share of the costs remaining to set tubing and perforate/stimulate/log and produce the Wolfcamp formation.[8]
>
> (b) Altura would pay $55,267.29 as its share of the costs spent to drill below the base of the Strawn ($101,836.45) and the costs remaining to set tubing and perforate/stimulate/log, and produce the Atoka/Morrow formation ($174,500).[9]

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[8] Because the well has been drilled but not completed, the following Wolfcamp costs are still to be incurred: tubing, cased hole logging, perforating, stimulation, artificial lift, downhole equipment, etc for a total estimated cost of $210,500 of which Altura's share is 13.333% Examiner Ashley's decision assumes that the tubing is run in the wellbore and used only for the Wolfcamp completion. If the Commission adopts the COPAS allocation method, the estimated costs of the tubing have already been apportioned between the Wolfcamp and Atoka/Morrow formations.

[9] Examiner Ashley's Atoka/Morrow decision assumes that the tubing is run in the wellbore and used only for the Atoka/Morrow completion. The drilling costs below the Strawn are $100,724.25 for intangibles ($478,500 x 21.05%) and $1,112.20 for tangibles ($33,500 x. 3.32%) plus the remaining Atoka/Morrow completion costs are $174,500 (tubing, logging, stimulation/perforation, etc) for a total of $276,336.45

EXHIBIT C

Chesapeake proposed to make the necessary adjustments to its AFE, and to apply the COPAS allocation method such that the total cost allocated to the Atoka/Morrow owners is $549,451.98 and the total cost allocated to the Wolfcamp owners is $290,309.00. If Altura elects to participate in the Atoka/Morrow and Wolfcamp its share is $118,956.84. If they do not then, Chesapeake will pay Altura's share of those costs and be entitled to recover an additional 200% as compensation for carrying Altura's interest.

Thus, Altura should be required to make a single election as to both the Wolfcamp and Atoka/Morrow formations, then Altura's 20% share of the costs allocated to the Atoka/Morrow formation is $109,890.40 and Altura's 13.333% share of the costs allocated to the Wolfcamp formation is $9,066.44. This result occurs because much of the equipment will be utilized for both zones. Chesapeake considers it unfair to allow Altura to "split" its election among the two formations because to do so would allow Altura to benefit from certain expenses which it did not pay for and will result in Altura paying less than its fair share of costs.[10]

However, if the Commission affirms Examiner Ashley's decision, then Altura will have the benefit of a "split election". If Altura goes "non-consent" in the Atoka/Morrow and elects to participate in the Wolfcamp, then Altura should be required to pay $38,706.91 which is $13.33% of $290,309.00 which should be the costs allocated to the Wolfcamp based upon a "split election" option.

The COPAS method for allocating well costs addresses numerous possible situations where drilling and completion costs for drilled wells or proposed wells need to be allocated as a result of ownership changes caused by any number of reasons including different zones with different interests.

Specifically, in the Chesapeake case, Chesapeake's AFE for a gas well drilled to a depth of 12,100 feet was estimated to be $856,000 for a producing gas well in the Strawn formation which included $258,000 for tangible costs and $598,000 for intangibles including $50,000 for seismic costs and certain other anticipated but unspent costs associated with producing the Strawn formation had it not been "dry".

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[10] The option of a split election has already been rejected by the Commission. See **Viking Petroleum, Inc. v. Oil Conservation Commission and Harvey E. Yates**, 100 NM 451 (1983)

Chesapeake proposed to make the necessary adjustments to this AFE, and to apply the COPAS allocation method such that the total costs allocated to the Atoka/Morrow owners is $549,451.98 based upon the following:

(1) the following anticipated intangible costs which were not used in the Strawn, are deducted from the intangibles and allocated 100% to the Atoka/Morrow:

item 430:	completion unit:	$20,000
item 431:	cased hole logging/perf	$10,000
item 434:	formation stimulation	$10,000
	surface rental	$ 1,000
	contingency 10%	$10,000
	supervision	$ 3,500
	TOTAL: $54,500	

(2) the remaining AFE intangibles of $543,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Atoka/Morrow owners were allocated 49.995% being $271,722.83.

(3) an additional $65,000 was added to item 434 for the fracture treatment anticipated for the Atoka/Morrow formation;

(4) the following anticipated tangible costs which were not used in the Strawn, are deducted from the tangibles:

production casing:	$82,000
tubing	$40,000
wellhead equipment	$ 4,000
Downhole equipment	$ 3,000
Artificial lift pump	$50,000
Production Equipment	$30,000
Non-controllable equip.	$ 1,000
contingency 10%	$14,500
Total: $228,500	

(5) the remaining AFE tangibles of $29,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Atoka/Morrow owners were allocated 36.37% being $10,729.15

(6) 100% of the following anticipated tangible costs attributable to the Atoka/Morrow were added:

production casing:	$82,000
tubing	$40,000
wellhead equipment	$ 4,000
Downhole equipment	$ 3,000
Production Equipment	$30,000
Non-controllable equip.	$ 1,000
contingency 10%	$14,500
Total: $174,500	

If Altura elects to participate in **both** the Atoka/Morrow and the Wolfcamp, then its 20% share of the Atoka/Morrow is $109,890.44. Because certain of the costs allocated to the Atoka/Morrow can also be utilized in the Wolfcamp such that the only additional Wolfcamp costs will be the cost of cased hole logging/perforating and stimulation of $18,000 plus $50,000 for artificial lift equipment. Altura's interest in the Wolfcamp formation is 13.333% and thus would pay an additional $9,066.44.

If, however, Altura goes "non-consent" in the Atoka/Morrow and elects to participate in the Wolfcamp, then Altura would be required to pay $38,706.91 being $13.33% of $290,309.00 based upon the following allocation:

(1) the following anticipated intangible costs would be deducted from the intangibles in Chesapeake's AFE and allocated 100% to the Wolfcamp:

item 430:	completion unit:	$20,000
item 431:	cased hole logging/perf	$ 8,000
item 434:	formation stimulation	$10,000
	surface rental	$ 1,000
	contingency 10%	$ 4,000
	supervision	$ 3,500
	Total:	$46,500

(2) the remaining AFE intangibles of $501,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Wolfcamp owners are allocated 21.05% being $105,565.75.

(3) the following anticipated tangible costs are deducted from the tangibles:

Artificial lift pump	$50,000
Non-controllable equip.	$ 1,000
contingency 10%	$ 5,000
Total:	$56,000

(4) the remaining AFE tangibles of $202,000.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Wolfcamp owners were allocated 30.566% being $61,743.32

(5) an additional $20,000 was added for the downhole equipment for the Wolfcamp formation;

(6) 100% of the following anticipated tangible costs attributable to the Wolfcamp were added:

Artificial lift	$50,000
Non-controllable equip.	$ 1,000
contingency 10%	$ 5,000
Total:	$56,500

Chesapeake, using the COPAS allocation method, proposed to exclude those costs chargeable to the Strawn formation so that Altura would pay only those costs directly associated with the Wolfcamp and the Atoka-Morrow formations. For example, instead of paying for 100% of the costs of the wellbore to the Wolfcamp, the Wolfcamp owners would pay for the Wolfcamp completion costs and only one-third of the drilling costs to the base of the Wolfcamp and nothing below that depth.

Allocation of Well Costs - COPAS

A. Intangibles

(1) Using Drilling Day Ratio allocation:
total days – 19

12 day to drill to base of Wolfcamp: 12/19 = 63.16%

3 days to drill to base of Strawn 3/19 = 15.79%

4 days to TD (base of Atoka) 4/19 = 21.05%

(2) allocation to owners of each zone

(a) Wolfcamp WI:	1/3rd of 63.16%	21.05%
(b) Strawn WI:	1/3rd of 63.16% plus ½ of 15.79%	28.945%
(c) Atoka WI:	1/3rd of 63.16% plus ½ of 15.79% plus 100% of 21.05%	49.995%

(3) allocation to Altura

(a) 13.333% of Wolfcamp
(b) 20.0% of Atoka

B. Tangibles:

(1) Using footage Ratio allocation:
total footate = 12,050'

11,050 feet to base of Wolfcamp 11,050/12,050 = 91.7%

600' to base of Strawn 600/12,050 = 4.97%

400' to TD (base of Atoka) 400/12,050 = 3.32%

(2) allocation to owners of each zone:

(a) Wolfcamp WI:	1/3rd of 91.7%	30.566%
(b) Strawn WI:	1/3rd of 91.7% plus ½ of 4.97%	33.051%
(c) Atoka WI:	1/3rd of 91.7% plus ½ of 4.97% plus 100% of 3.32%	36.37%

(3) allocation to Altura:

(a) 13.333% of Wolfcamp
(b) 20% of Atoka

EXHIBIT 7

CHESAPEAKE OPERATING, INC.

AUTHORIZATION FOR EXPENDITURE

Project Area: Lovington
Well Name: College of the SW 1-17 (Re-entry)
Operator: Chesapeake Operating, Inc.
AFE #: 962332
Spacing Unit: S/2 Section 17-16S-36E

County, State: Lea, New Mexico
Date: October 22, 1999
Total Depth: 12,100'
Formation: Strawn/Atoka

CODE	INTANGIBLE COSTS	WORK DESCRIPTION			DRY HOLE	PRODUCER
233400	Location:	Roads, Location, Pits			$20,000.00	$20,000.00
233405		Reclamation			$20,000.00	$20,000.00
233401		Damages			$8,000.00	$8,000.00
233402	Legal:	Governmental Filings			$2,000.00	$2,000.00
233403		Title Opinions			$3,000.00	$3,000.00
233404		Seismic Costs			$50,000.00	$50,000.00
233406	Drilling:	Top Drive			$0.00	$0.00
233408		Pipeline Construction			$0.00	$0.00
233410		Drilling Contractor: 18 days @ $5,300/day			$95,000.00	$95,000.00
233411		Directional Services			$46,000.00	$46,000.00
233413		Rig Mobilization/Demobilization			$20,000.00	$20,000.00
233414		Contract Labor			$10,000.00	$15,000.00
233415		Bits			$30,000.00	$30,000.00
233416		Supplies and Utilities			$1,000.00	$3,000.00
233417		Cement Conductor			$0.00	$0.00
233417		Cement Surface Casing			$0.00	$0.00
233417		Cement Intermediate Casing			$0.00	$0.00
233417		Cement Production Casing			$0.00	$20,000.00
233417		Cement Drilling Liner			$0.00	$0.00
233417		Cement Production Liner			$0.00	$0.00
233418		Mud Logging			$11,000.00	$11,000.00
233419		Drilling Fluids, Mud, Chem.			$20,000.00	$20,000.00
233421		Drill String Inspection			$0.00	$0.00
233423		Open Hole Logging			$22,000.00	$22,000.00
233427		Fishing			$0.00	$0.00
233428		Downhole Rental Equipment			$10,000.00	$10,000.00
233430	Completion:	Completion Unit			$0.00	$20,000.00
233431		Cased Hole Logging/Perforating			$0.00	$10,000.00
233433		Jetting			$0.00	$0.00
233434		Formation Stimulation			$0.00	$10,000.00
233437	General:	Surface Equipment Rental			$18,000.00	$19,000.00
233438		Transportation			$0.00	$3,000.00
233441		Frac Fluid Hauloff			$0.00	$0.00
233442		Blowout/Emergencies			$0.00	$0.00
233443		Company Supervision/Engineering			$10,000.00	$15,000.00
233444		Consultants			$8,000.00	$8,000.00
233446		Company Overhead			$8,000.00	$13,000.00
233447		Insurance			$5,000.00	$5,000.00
233449		Major Construction Overhead			$0.00	$2,000.00
233450		Plug to Abandon			$0.00	$0.00
		20% Contingency			$83,000.00	$100,000.00
TOTAL	INTANGIBLES	Total Intangible Costs			$498,000.00	$598,000.00
CODE	TANGIBLE COSTS	WORK DESCRIPTION				
230100	Tubulars:	Surface Casing:			$0.00	$0.00
230100		Intermediate Casing:			$0.00	$0.00
230100		Production Casing:	12,100'	5 1/2"	$0.00	$82,000.00
230100		Drilling Liner:			$0.00	$0.00
230100		Production Liner:			$0.00	$0.00
230100		Tubing:	11,500'	2 7/8"	$0.00	$40,000.00
230104		Float Equipment			$0.00	$2,000.00
230106	Lease Equipment:	Wellhead Equipment			$3,000.00	$7,000.00
230107		Downhole Equipment			$0.00	$3,000.00
230111		Artificial Lift-Pumping Unit			$0.00	$50,000.00
230113		Production Equipment			$0.00	$30,000.00
230115		Compressor/Compression			$0.00	$0.00
230116		Pipeline Equipment			$0.00	$0.00
230120		Non-Controllable Equipment			$1,000.00	$1,000.00
		20% Contingency			$1,000.00	$43,000.00
TOTAL	TANGIBLES	Total Tangible Costs			$5,000.00	$258,000.00
		Total Costs			$503,000.00	$856,000.00

Prepared by: JKO

Approved by: JML

OPERATOR'S APPROVAL ______________________ DATE ________
Operations/Geology

OPERATOR'S APPROVAL ______________________ DATE 10/22/99
Land/Accounting

NON-OPERATOR'S APPROVAL ______________________ DATE ________

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 9998 REOPENED
ORDER NO. R-9093-C

APPLICATION OF YATES ENERGY CORPORATION TO AMEND DIVISION ORDER NO. R-9093, AS AMENDED, EDDY COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 8:15 a.m. on October 31, 1990, at Santa Fe, New Mexico, before Examiner Michael E. Stogner.

NOW, on this 29th day of November, 1990 the Division Director, having considered the testimony, the record and the recommendations of the Examiner, and being fully advised in the premises,

FINDS THAT:

(1) Due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) By Division Order No. R-9093, dated January 8, 1990, issued in Case No. 9845, the Division, upon the application of Yates Energy Corporation, pooled all mineral interests only in the Undesignated Tamano-Bone Spring Pool underlying the SE/4 SW/4 of Section 1, Township 18 South, Range 31 East, NMPM, Eddy County, New Mexico, forming a standard 40-acre oil spacing and proration unit to be dedicated to the applicant's Thornbush Federal Well No. 1 to be drilled at a standard location 330 feet from the South line and 1980 feet from the West line (Unit N) of said Section 1.

(3) By Order R-9093-A, entered on February 27, 1990, the Oil Conservation Commission, pursuant to the request of Spiral, Inc., Explorers Petroleum Corporation and HEYCO Employers, Ltd., as applicants for De Novo hearing, dismissed Case 9845 De Novo and ordered that Order R-9093 continue in full force and effect until further notice.

EXHIBIT
D

(4) By Order R-9093-B, entered on September 19, 1990, the Division temporarily denied Yates Energy Corporation's request to amend said Order No. R-9093 to include a provision pooling all mineral interests within the SE/4 SW/4 of said Section 1 in the expanded interval from the surface to the base of the Undesignated Tamano-Bone Spring Pool, and among other things:

> (a) Ordered applicant to "conduct good faith negotiations with Chevron in order to determine a fair and equitable method whereby Chevron's interest as to the San Andres formation may be consolidated."
>
> (b) Ordered that the matter be reopened on October 31, 1990 should the parties fail to reach a voluntary agreement, "at which time the division shall consider additional evidence regarding conductance of negotiations, the proportionate share of well costs which are allocated to the San Andres completion, and the assignment of a risk penalty which is fair to both parties."

(5) Yates Energy Corporation (Yates) spudded the subject well on February 14, 1990, drilled to a total depth of approximately 9,060 feet, and tested the Bone Spring interval as non-productive.

(6) The applicant subsequently tested the San Andres formation at a depth of approximately 4,637 feet and has completed the subject well as a San Andres producer with an initial potential of 82 barrels of oil per day.

(7) Chevron USA, Inc. (Chevron) a twenty-five percent working interest owner in the subject unit, did not appear in the hearing resulting in said Order R-9093 and elected not to participate in the drilling of the subject well to the Bone Spring formation.

(8) Both Chevron and Yates appeared at the October 31, 1990 hearing and presented evidence to support their positions.

(9) Subsequent to the issuance of Division Order No. R-9093-B, both Yates and Chevron participated in negotiations in an attempt to determine a fair and equitable method of consolidating Chevron's interest in the San Andres formation to the subject 40-acre tract.

(10) Such negotiations were unsuccessful.

(11) Yates proposes at this time that total well costs for completion of the Thornbush Federal Well No. 1 in the San Andres formation should include the cost of drilling and testing the Undesignated Tamano-Bone Spring Pool, including, but not limited to, intermediate casing and any additional reasonable incremental costs and expenses associated with testing the Undesignated Tamano-Bone Spring Pool.

(12) Chevron proposes that the cost of drilling and completing the Thornbush Federal Well No. 1 should be allocated between the San Andres and Bone Spring formations in accordance with the Council of Petroleum Accountants Societies Bulletin No. 2, dated September, 1965, entitled <u>Determination of Values for Well Cost Adjustments Joint Operations</u>, (see Chevron's Exhibit No. 2) as follows:

Section B: ALLOCATION OF INTANGIBLE DRILLING COSTS

Sub-Sections 1 (a) and 2

Section B: ALLOCATION OF TANGIBLE COST

Sub-Sections 1, 2, and 3

and further provided that for this well the drilling day ratio should be ten days to 4800 feet divided by 24 days to 9060 feet or 41.67% for the intangible allocation calculation and the tangible costs attributable to the San Andres formation should be limited to the following:

(a) casing and tubing Heads
(b) surface casing
(c) 5 1/2-inch production casing to 4800 feet
(d) 2 3/8-inch tubing to 4800 feet
(e) production facilities.

(13) Yates' proposed allocation of costs to the San Andres formation *<u>is not</u>* fair and reasonable, Chevron therefore should not be required to pay those actual costs to the subject well attributable to the drilling of this well below 4800 feet; however, such costs attributable to the setting of the intermediate 8 5/8-inch casing should be considered.

(14) The risk penalty factors suggested by Yates and Chevron are 200 and zero, respectively. Neither penalty properly reflects the situation; therefore, the risk penalty in this instance should be 150 percent.

(15) Yates Energy Corporation should continue to be the designated operator of the subject well and unit.

(16) Any non-consenting working interest owner should be afforded the opportunity to pay its share of actual San Andres well costs to the operator in lieu of paying his proportionate share of reasonable well costs attributable to the San Andres out of production.

(17) Any non-consenting interest owner should be afforded the opportunity to object to the actual well costs but actual well costs should be adopted as the reasonable well costs in the absence of such an objection.

(18) Following determination of reasonable well costs, any non-consenting working interest owner should receive from the operator any amount that it paid or was charged which was in excess of reasonable well costs.

(19) Because Order No. R-9998 establishes overhead charges for a Bone Spring well and not a San Andres well, those charges previously approved should be reduced to reflect the overhead rates established by Ernst and Young which are $3200.00 per month while drilling and $320.00 per month while producing which should be fixed as reasonable charges for supervision (combined fixed rates); the operator should be authorized to withhold from production the proportionate share of such supervision charges attributable to each non-consenting working interest and in addition thereto, the operator should be authorized to withhold from production the proportionate share of actual expenditures required for operating the subject well, not in excess of what are reasonable, attributable to each non-consenting working interest.

(20) Should all parties to this forced pooling reach voluntary agreement subsequent to entry of this order, this order shall thereafter be of no further effect.

(21) The operator of the well and unit shall notify the Director of the Division in writing of the subsequent voluntary agreement of all parties subject to the forced pooling provisions of this order.

IT IS THEREFORE ORDERED THAT:

(1) Within 30 days after the effective date of this order, the operator shall furnish the Division, Chevron and all other working interest owners in the subject unit an itemized schedule of actual well costs which shall be allocated between the San Andres and Bone Spring formations in accordance with the Council of Petroleum Accountants Societies Bulletin No. 2, dated September, 1965, entitled Determination of Values for Well Cost Adjustments Joint Operations, (see Chevron's Exhibit No. 2) as follows:

Section B: ALLOCATION OF INTANGIBLE DRILLING COSTS

Sub-Sections 1 (a) and 2

Section B: ALLOCATION OF TANGIBLE COST

Sub-Sections 1, 2, and 3

and the drilling day ratio shall be ten (10) days to 4800 feet divided by twenty-four (24) days to 9060 feet or 41.67% and the tangible costs attributable to the San Andres formation shall include:

(a) casing and tubing Heads
(b) surface casing
(c) 5 1/2-inch production casing to 4800 feet
(d) 2 3/8-inch tubing to 4800 feet
(e) intermediate 8 5/8-inch casing to 4800 feet
(f) production facilities.

(2) Within 30 days from the date the schedule of actual well costs is furnished to Chevron and any other working interest owner, any such non-consenting working interest owner shall have the right to pay his share of actual well costs to the operator in lieu of paying his share of reasonable well costs out of production.

(3) If no objection to the actual well costs is received by the Division from any such non-consenting working interest owner within 45 days following receipt of said schedule, the actual well costs shall be the reasonable well costs; provided however, if there is objection to actual well costs within said 45-day period, the Division will determine reasonable well costs after public notice and hearing.

(4) The operator is hereby designated to withhold the following costs and charges from production: the pro rata share of reasonable well costs attributable to such non-consenting interest to the San Andres formation if it becomes a non-consenting working interest owner who has not paid its share of actual well costs within 30 days from the date the schedule of actual well costs is furnished to it.

(5) $3200.00 per month while drilling and $320.00 per month while producing are hereby fixed as reasonable charges for supervision (combined fixed rates); the operator is hereby authorized to withhold from production the proportionate share of such supervision charges attributable to each non-consenting working interest, and in addition thereto, the operator is hereby authorized to withhold from production the proportionate share of actual expenditures required for operating such well, not in excess of what are reasonable, attributable to each non-consenting working interest.

(6) Any well costs or charges which are to be paid out of production shall be withheld only from the working interest's share of production, and no costs or charges shall be withheld from production attributable to royalty interests.

(7) Proceeds from the sale of production attributable to Chevron's 25% working interest held in escrow pursuant to letter of Division Director dated October 3, 1990 shall be released to Chevron if it elects to join and pay its share of well costs as provided in this order; otherwise such funds shall be released to the operator and applied to costs attributable to Chevron's interest as provided in this order for non-consent interests pooled hereunder.

(8) All proceeds from production from the subject well which are not disbursed for any reason shall be placed in escrow in Eddy County, New Mexico, to be paid to the true owner thereof upon demand and proof of ownership; the operator shall notify the Division of the name and address of said escrow agent within 30 days from the date of first deposit with said escrow agent.

(9) Should all the parties to this force-pooling reach voluntary agreement subsequent to entry of this order, this order shall thereafter be of no further effect.

(10) The operator of the subject well and unit shall notify the Director of the Division in writing of the subsequent voluntary agreement of all parties subject to the force-pooling provisions of this order.

(11) Jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

WILLIAM J. LEMAY
Director

S E A L