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.

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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 Fieldwide 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 as separate 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 Fieldwide 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 is 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 foramtions 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 connectios 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 subseq[illegible]tly into unit reservoir original completion remains 100% and unit completion becomes [illegible]nt.

4. Dual completion — one or more completions unitized.

5. Single completion depleted and recompleted 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 recompleted for injection or disposal well for unit.

9. Dry hole recompleted for injection or disposal well for unit.

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.