

**Stogner, Michael**

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**From:** JamesBruc@aol.com  
**Sent:** Tuesday, November 30, 2004 9:38 AM  
**To:** mstogner@state.nm.us  
**Cc:** shall@mstlaw.com; kellahein@earthlink.net  
**Subject:** Case No. 13359/Mewbourne

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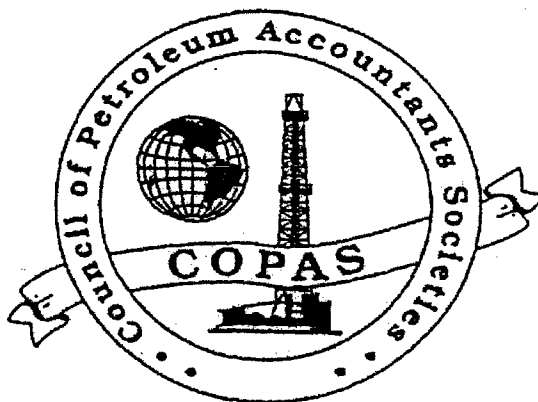
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11/30/2004



# **Well Costs – Allocations and Adjustments**

*(Formerly known as Bulletin 2)*

**Accounting Guideline**

**AG – 1**

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**Council Approved**

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# WELL COST – ALLOCATIONS AND ADJUSTMENTS

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*This document 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 document be used as a guide to joint interest operations accounting. The Council appreciates the contributions of the Petroleum Accountants Society of San Juan Basin for research and publication of this document.*

## **FOREWORD**

The objective of this document is to provide guidance for two accounting issues: 1) equitable apportionment of costs and expenses for Downhole Commingled Wells and Multiple Completion Wells, and 2) equitable Well Cost Adjustments for certain situations. Refer to the COPAS publication "Accounting For Unitizations" (Accounting Guideline AG - 2) for guidance on investments adjustments pertaining to the formation of secondary recovery units, changes in federal exploratory units' participating areas, and changes in drilling or spacing unit sizes.

The information contained in this document is intended to aid in understanding and applying allocations/adjustments as well as negotiating future allocations/adjustments. 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 situation. In these instances, alternate suggestions have been included. The Joint Operating Agreement, Accounting Procedure, and other relevant agreements for a particular property will always take precedence and should always be taken into consideration.

## I. INTRODUCTION

Well cost apportionment and/or adjustment is needed when multiple formations with different ownership share a common wellbore. Cost and expense apportionment is necessary as a result of a Downhole Commingled Well or Multiple Completion Well. These types of wells are designed to economically benefit all the owners of different oil and/or gas producible formations by sharing in the costs and expenses of drilling and/or producing the different formations. Many of the goods acquired and services performed in connection with a Downhole Commingled Well and Multiple Completion Well directly benefit more than one formation. The costs of these goods and services that constitute Direct Charges need to be allocated to the formations that benefit. This document is intended to provide guidance in allocating these costs to the formations or otherwise reaching agreement on an acceptable means of cost reapportionment. Specific topics addressed include cost sharing for drilling a new Downhole Commingled Well and Multiple Completion Well, and cost reapportionment that may be necessary when recompleting an existing wellbore.

Even when the working interest ownership is the same in each of the objective formations in a Downhole Commingled Well and Multiple Completion Well, the issues may eventually need to be addressed. This is necessary because the ownership or participating interest of a formation could change, thus giving rise to equity concerns in the allocation of operating expenses, workover costs and expenses, and abandonment expenses. However, this is not a common occurrence. The governing Operating Agreement or other agreement will often establish the situations giving rise to the need for an adjustment and may provide the method of calculating such adjustment. See Exhibit 1.

Approval for a Downhole Commingled Well and Multiple Completion Well must be obtained from working interest owners of all affected formations under the provisions of the Joint Operating Agreement or pursuant to regulations or order of the agency having jurisdiction, e.g., a force pooling order. The Operating Agreement may further establish whether all working interest owners or only the consenting parties need to approve the Multiple Completions. The proposal to complete the well in more than one formation should separately identify the cost and expense apportioned to each formation and should be submitted to the Non-Operators entitled to such notice pursuant to the terms of the Operating Agreement for approval. If the parties do not have a written agreement establishing the terms for allocating costs between zones, it is advisable to enter into such an agreement prior to performing the operation.

A Cost Allocation Agreement (for a sample Cost Allocation Agreement see the Exhibits in the COPAS publication "Accounting For Unitizations," formerly known as Bulletin 11) can be made a part of the Joint Operating Agreement or it can be a separate, stand-alone agreement. Sometimes there are separate Operating Agreements for each formation, but the working interest owners of all the formations enter into a Cost Allocation Agreement that addresses the rights and obligations of each set of formation owners. Additionally, model form Operating Agreements may contain provisions

concerning certain events that call for cost allocation or an investment adjustment, and sets out how those adjustments should be calculated. See Exhibit 1.

Absent agreement or contractual provisions to the contrary, the scope of audits covering investment adjustments will be limited to verifying the accuracy of the Well Cost Adjustments and the cost and expense apportionment to the Operator's records, and the accuracy of the apportionment decimals. Compliance with Accounting Procedure requirements of the existing owner's Operating Agreements for these historical costs may not be a right of the new owner(s) but rather a right only of the original owners, which may or may not have been exercised. The parties may mutually agree to make such audit rights available to the new owner(s), but such rights should be clearly set forth in the Cost Allocation Agreement or have other contractual basis.

## **II. NEW WELL COST APPORTIONMENT**

This Section addresses cost allocation for new wells being drilled with attempted completions in multiple formations. Well cost allocation may be necessary on new wells for a variety of reasons. Some of those reasons are: ownership could be different between the different objective formations, working interest ownership could be the same and the participating interest might be different for two or more formations. Well cost allocation may also be necessary to calculate a tax basis for each objective formation, to determine the basis from which to separately calculate each producible formation's depletion, to facilitate the calculation of finding costs for each formation, or for a special situation. For example, a special situation would be that under offshore Operating Agreements, it is common to allow a party to limit its participation to the base of the deepest known producible horizon, so that it is non-consent on the deeper drilling, i.e., exploratory tail. This event may give rise to a cost allocation, as described in Section II.A.3.d.

Well costs are composed of the following cost categories:

- A. Intangible Drilling Costs
- B. Tangible Drilling Costs
- C. Surface Equipment
- D. Drilling Overhead

Each of these categories can require a different allocation method to allocate associated costs. Whichever methodology is used, whether listed in this document or not, the intent is for the parties to select an allocation methodology that is equitable for a given situation.

### **A. ALLOCATION OF INTANGIBLE DRILLING COSTS**

Intangible Drilling Costs (IDC) are defined as those expenditures that are non-recoverable and, as such, have no salvage value. These costs are incurred in drilling and preparing wells for the production of oil and gas, and normally end at the first connection

beyond the Wellhead. For allocation purposes, Intangible Drilling Costs are categorized in the following three categories:

1. Shared Pre-drilling costs
2. Shared Drilling Costs
3. Formation Specific Costs

A different allocation method is generally used for each of these Intangible Drilling Costs categories.

1. Shared Pre-drilling Costs

Shared Pre-drilling Costs are IDC that arise from preparing a site for drilling, and they benefit all objective formations in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Pre-drilling Costs are site surveys, site preparation, right-of-way, surface damage payments, water supply wells, etc. These examples are not meant to be all-inclusive. Shared Pre-drilling Costs are typically allocated equally between all objective formations. The parties may agree to another equitable allocation method.

2. Shared Drilling Costs

Shared Drilling Costs are IDC that are intended to benefit more than one formation in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Drilling Costs are rig costs, drilling water, field supervision, Drilling Overhead, etc. These examples are not meant to be all-inclusive. Allocating the Shared Drilling Costs to the objective formations is a two-step process. The first step is to associate the Shared Drilling Costs to the applicable Drilling Interval(s) and the second step is to allocate the applicable Drilling Interval's associated costs to the objective formations. There may be Intangible Drilling Costs that are treated as Formation-Specific Costs in one instance that are allocated as Shared Drilling Costs in other instances. The Operator should make reasonable efforts to charge Formation-Specific Costs to the benefiting formation, see sub-section 3 below, "Formation-Specific Costs."

Listed below are descriptions and examples of several methodologies that may be used to allocate Shared Drilling Costs in a given situation. Whichever methodology is used, whether listed or not, the intent is for the parties to select an allocation methodology that is equitable for a given situation. Some equitable methods of allocating the Shared Drilling Costs are:

- a. **Day Ratio:** The first step is to determine the factor for allocating Shared Drilling Costs for the applicable Drilling Interval(s). The allocation factor is determined by a fraction of which the numerator is the number of days to drill through that Drilling Interval and the denominator is the total number of drilling days spent on the well. The total number of drilling days begins on the spud date and terminates when the completion election is made. Since rig costs are the largest expense and deeper drilling is generally slower than shallower drilling, the drilling Day Ratio may more closely align the costs with the Drilling Interval incurring the costs than will the Footage Ratio methodology.

Step two is to allocate each Drilling Intervals' costs to the objective formations. If using the Day Ratio methodology to allocate Formation-Specific Costs, Step two is not applicable because doing so would improperly result in the lower formation(s) being allocated a portion of the completion costs for the upper formation(s). The first Drilling Interval's costs are allocated equally to all formations with each owner standing a proportionate share based on its respective participating interest in each formation. The second Drilling Interval's costs are allocated equally to all objective formation(s) below the base of the first objective formation. This allocation continues through the last Drilling Interval.

**Illustration:**

A party proposed drilling a well and completing it in three objective formations. The well was drilled in 75 days. If the time from spud date to the base of the first objective formation, the first Drilling Interval, took 27 days, all objective formations would receive  $1/3$  of  $27/75$  of the Shared Drilling Costs. If the time required to drill from the base of the first objective formation to the base of the second objective formation, the second Drilling Interval, took 11 days, then  $11/75$  of the Shared Drilling Costs would be divided equally between the second and third formations. If the time required to drill from the base of the second objective formation to the base of the third objective formation, the third Drilling Interval, took 37 days, then  $37/75$  of the Shared Drilling Costs would be charged to the third objective formation.

- b. **Footage Ratio:** The first step is to determine the cost allocation factors the applicable Drilling Interval(s). The factor used for the first Drilling Interval is determined by a fraction of which the numerator is the footage drilled from the surface to the base of the first objective formation and the denominator is the total footage drilled for the entire well. The factor used for the second Drilling Interval is determined by a fraction of which the numerator is the footage drilled from the base of the first objective formation to the base of the second objective formation and the denominator is the total footage drilled for the entire well. This process continues through the last objective formation. Each factor is multiplied by the costs to be allocated to determine the applicable Drilling Interval's costs. Rather than calculating a unique set of factors for each well, the parties may agree to use an average relative footage by objective formation for similar wells in an area.

Step two is to allocate the applicable Drilling Intervals' costs to the objective formations. The first Drilling Interval's costs are allocated equally to all formations with each owner standing a proportionate share based on its respective participating interest in each formation. The second Drilling Interval's costs are allocated equally to the objective formation(s) below the base of the first objective formation. This allocation process continues through the last Drilling Interval. Rather than calculate a unique set of factors for each well, the parties may agree to use an average relative footage by objective formation for similar wells in an area. It should be noted that deeper drilling is usually slower, and thus more expensive than drilling the shallow portion of the well. Consequently, using Footage Ratios to allocate the costs does not take into account the additional expense involved in deeper drilling and therefore, may not align the costs with the Drilling Interval contributing the most costs.



**Illustration:**

A party proposed drilling a well and completing it in three objective formations. The well was drilled to a total depth of 14,000 feet. If the footage from surface through the first objective formation, the first Drilling Interval, is 12,000 feet, then  $12,000/14,000$  or 85.72% of the Shared Drilling Costs would be allocated equally to all objective formations. If the footage from the bottom of the first objective formation through the second objective formation, the second Drilling Interval, is 1,000 feet, then  $1,000/14,000$  or 7.14% of the Shared Drilling Costs would be allocated equally to the second objective formation and the deeper objective formation. If the footage from the bottom of the second objective formation through the third objective formation, the third and final Drilling Interval, is 1,000 feet, the third objective formation would be allocated  $1,000/14,000$  or 7.14% of the Shared Drilling Costs.

- c. **Percentage of Historical Actual:** The first step is to determine the factor for allocating Shared Drilling Costs to the applicable Drilling Interval(s). First, for each objective formation, take a recent historical sample of Shared Drilling Costs on a stand-alone basis, i.e., as a single completion well. This method requires careful cost comparison between the same geographical area and the same time period as well as consideration of similar well specifications. The factor for a given Drilling Interval is determined by a fraction of which the numerator is the total historical shared expenditures to drill a stand-alone well in a given objective formation and the denominator is the total historical Shared Drilling Costs attributable to all wells in the historical sample. If the drilling operations experienced unusual circumstances that resulted in cost overruns, the cost overruns should be excluded from historical costs in calculating the factors. Likewise, the parties should reach an agreement that any unusual costs, inconsistent with the historical costs, will be borne by the formation or Drilling Interval giving rise to the costs.

Step two is to allocate the applicable Drilling Intervals' costs to the objective formations. If using the Percentage of Historical Actual methodology to allocate Formation-Specific Costs, Step two is not applicable because it improperly results in the lower formation(s) being allocated a portion of the completion costs for the upper formation(s). The first Drilling Interval's costs are allocated equally to all formations with each owner standing a proportionate share based on their respective participating interest in each formation. The second Drilling Interval's costs are allocated equally to the objective formation(s) below the base of the first objective formation. This allocation process continues through the last Drilling Interval.

**Illustration:**

A well is completed in three objective formations. Historical Shared Drilling Costs for stand-alone wells completed or attempted to be completed in three objective formations for the three Drilling Intervals are \$2,000, \$4,000 and \$6,000 respectively. The allocation of the Shared Drilling Costs is as follows: \$2,000 for Drilling Interval one is allocated equally to all three objective formations ( $1/3$  of \$2,000 to each), \$4,000 for Drilling Interval two is allocated equally to the second and third objective formations ( $1/2$  of \$4,000 to each), and \$6,000 for Drilling Interval three is allocated to the third objective formation.

**D Exploratory Tail:** This allocation method is used in special situations. For example, under offshore Operating Agreements, it is common to allow a party to limit its participation to the base of the deepest known productive horizon, so that it is non-consent on the deeper drilling, i.e., exploratory tail. This event may give rise to a cost allocation. There are a variety of ways to allocate the costs of a well with an exploratory tail. The most common way is for the parties participating in the shallow formation to pay the entire well costs to the base of the shallow formation, while the party or parties wishing to test the deep formation pay(s) 100% of the costs below the shallow formation. However, the parties may agree to use any of the other methods provided in this document.

### 3. Formation-Specific Costs

Formation-Specific Costs are intended to benefit a specific formation in a Downhole Commingled Well or Multiple Completion Well and do not benefit another objective formation. Examples of Formation-Specific Costs are electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc. These examples are not meant to be all-inclusive.

Formation-Specific Costs, in the vast majority of cases, are charged directly to the associated formation. These Formation-Specific Costs are identified from a detailed analysis of actual expenditures. This would involve utilizing the well completion records as well as accounting records. This method is time-consuming and subject to getting good information from operations personnel. More importantly, this method of charging Formation-Specific Costs requires information from the vendor regarding what formation it worked on, as well as additional invoice coding. If the parties believe the additional information gathering creates greater opportunity for errors, then the parties may wish to consider another way to collect and allocate these costs on an equitable basis, particularly if there is an allocation basis that will reasonably match the cost to the formations.

The Operator should make reasonable efforts to charge Formation-Specific Costs to the benefiting formation. While this may require additional administrative effort in invoice processing, the objective is to assign costs to specific formations whenever possible because it is the most equitable way to ensure that each owner pays its respective share of the costs attributable to its formation. Charging as many Formation-Specific Costs to the benefiting formation as possible, rather than using an allocation method, will generally result in fewer audit exceptions, unless the parties specifically agreed to use an allocation method.

There may be costs that are treated as Formation-Specific Costs in one instance that are allocated as Shared Drilling Costs in other instances. For example, drill bits often are used to drill through more than one Drilling Interval, because the Operator does not stop to change the drill bit at the base of each Drilling Interval. Therefore, drill bit charges would be treated as Shared Drilling Costs and would be allocated. On the other hand, if one Drilling Interval uses an expensive, or otherwise specialized drill bit, it would result in a more equitable cost apportionment to charge the more expensive bit to the formation(s) that receive(s) the benefit. Other examples of costs that can either be allocated or treated as Formation-Specific Costs are mud, chemicals, or steerable motors to drill horizontal portions of the well. If the mud or chemicals used in the respective Drilling Intervals have little variation, these costs

could be allocated with other shared drilling costs. However, if one Drilling Interval requires specialty mud or chemicals that differ in cost from the mud or chemicals used in the other formation(s), then these costs could be treated as Formation-Specific Costs to more closely match the costs to the benefiting formation(s).

Allocation of Formation-Specific Costs is not common because it does not match costs to the benefiting formation as closely as the detailed analysis and charging to specific formations. It is applicable where the formations have very similar, if not identical, drilling and completion plans. Assuming one has identified a situation where an allocation of Formation-Specific Costs will result in equitable charges to the applicable formations, and the parties are agreeable to using an allocation, there are several ways to allocate the costs.

Only "Step one" of the allocation methods provided in Section II.A.3 for allocating Shared Drilling Costs, may be used to allocate the Formation-Specific Costs. Step one of the allocation methodologies provides for the formation(s) benefiting from the costs to receive an allocated portion of the costs. Step two of the allocation methodology is not applicable because it results in a formation being allocated an unfair amount of the cost. Acceptable methodologies of allocating Formation-Specific Costs are:

- a. **Step one of Day Ratio:** For more information on this methodology, refer to Section II.A.3.a. Although the methodology is the same, the allocation factor used to allocate Formation-Specific Costs will be different from the allocation factor used to allocate Shared Drilling Costs. Only drilling days should be used to calculate the factor for allocating Shared Drilling Costs, while only completion days should be used to determine the allocation factor for Formation-Specific Costs.
- b. **Step one of Percentage of Historical Actual:** For more information on this methodology, refer to Section II.A.3.c. The Formation-Specific Costs allocation factor may differ from the Shared Drilling Costs allocation factor if this method is used to allocate both Shared Drilling Costs and Formation-Specific Costs. In determining the allocation factors for Step one, use Formation-Specific Costs and not Shared Drilling Costs.
- c. **Negotiated Amounts/Rates:** The parties would agree upon a fixed percentage or amount for the Formation-Specific Costs allocated to the applicable formation(s). This percentage could be based on estimates of current costs and/or an analysis of historical costs.

While it is uncommon to allocate Formation-Specific Costs, it is especially uncommon to use footage days methodology for that allocation since the formation depth is not strongly related to the Formation-Specific Costs.

## **B. ALLOCATION OF TANGIBLE COSTS**

Tangible Costs are defined as those material items installed in connection with drilling and completing a well through the Wellhead. Tangible Costs are ordinarily considered to have salvage value regardless of whether such items may actually be salvaged after they are installed. Examples of Tangible Costs are casing and tubing. Tangible Costs

intended to serve one specific objective formation are typically charged to that formation and do not undergo an allocation. Other Tangible Costs intended to serve more than one formation must be allocated to the formations intending to use the equipment. Examples of shared Tangible Costs include: conductor and surface casing, packers that separate the formations in a Multiple Completion Well, or tubing in a Downhole Commingled Well.

Complications may arise in determining the amount of Tangible Costs each formation should bear. For example, casing and/or tubing can change in size and/or quality throughout the total depth of the well. A string of casing and/or tubing consists of materials of different weights and grades set at various depths. For the purpose of making an allocation, the total average cost of the casing and/or tubing string is usually used so that each formation or Drilling Interval is charged the same average cost for its apportioned share of the casing and/or tubing string. However, if the formations have significantly different equipment specifications, the parties may wish to reach agreement on charging the incremental costs to the formation(s) needing the more costly equipment.

Listed below are descriptions and examples of several methodologies that may be used to allocate tangible costs in a given situation. Whichever methodology is used, the intent is for the parties to select an allocation methodology that is equitable for a given situation. Acceptable methods of allocating shared Tangible Costs are:

1. Footage Ratio

For more information on this methodology, refer to Section II.A.3.b.

2. Percentage of Historical Actual

For more information on this methodology, refer to Section II.A.3.c.

3. Negotiated Amounts/Rates

The parties could agree upon a fixed percentage or amount. For example, if one formation requires significantly higher-grade material (for material that is used by both formations), the owner(s) could agree to first apportion the incremental costs to the formation requiring the higher-grade material and then agree upon an allocation for the remainder. Another example is the parties agreeing to share the conductor and surface casing equally – 3 formations agreeing to pay 1/3 each – since each formation receives equal benefit.

It is not common to use drilling days as a factor in allocating Tangible Costs since the number of drilling days is not as strongly related to the amount of equipment used by each Drilling Interval.

If some Tangible Equipment serves only one formation and the costs are clearly identifiable, the costs should be charged only to the benefiting formation. Examples of this are separate tubing strings, submersible pumps in one formation, or a liner that is serving only the deep zone.

### **C. SURFACE EQUIPMENT**

The term “surface equipment” refers to all jointly owned equipment on the surface, beyond the Wellhead, and is not necessarily limited to equipment located within the boundaries of the lease. Examples of off-site surface equipment are gathering lines and processing equipment.

The cost of acquiring and installing surface equipment that serves more than one formation is allocated by an equitable method, i.e., equal shares, or an allocation based on reserves, annual production, etc., to the formations served. Equipment serving only one formation is treated as a Formation-Specific Cost and charged to the associated formation. However, the parties may agree to another method of charging, such as including these costs in the pool of other costs to be allocated as shown above. Also, the parties need to take into account surface equipment required by a party to take its production in-kind since the Operating Agreement may require that extra expenditures incurred in taking production in-kind is borne by the taking party and not the entire Joint Account.

### **D. DRILLING OVERHEAD**

In addition to allocating Direct Costs, it may be necessary to allocate Drilling Overhead. The contract(s) governing the property, whether it is a Joint Operating Agreement or a separate Cost Allocation Agreement, should be thoroughly examined for various provisions that address how Drilling Overhead is to be charged. Most COPAS Accounting Procedures provide for a one-well Drilling Overhead charge for Downhole Commingled Wells. There may be Drilling Overhead provisions in a separate Cost Allocation Agreement or the cost allocation provisions in the JOA, in addition to provisions in the Accounting Procedure. If there are separate Operating Agreements for two or more formations, the parties may require an agreement that “bridges” the individual agreements. Users are cautioned to seek legal advice in the event the provisions of the various agreements conflict.

If charging Drilling Overhead using a Combined Fixed Rate approach, the common practice is to charge Drilling Overhead as if it were a single completion well drilled to test the deepest formation, then allocate the Drilling Overhead to the Drilling Intervals in the same manner as the other Intangible Drilling Costs. If charging Drilling Overhead using a Percentage Basis, the costs are allocated to the Drilling Interval and the development percentage overhead is applied to the respective Drilling Interval’s allocated cost.

## **III. WELL COST ADJUSTMENTS AND OTHER PAYMENTS – EXISTING WELLBORES**

Well Cost Adjustment is a reapportionment of wellbore costs between existing owners and new owners. This compensation is usually for the purchase of an ownership in a wellbore and/or equipment owned by the working interest owners receiving the

compensation. This payment could cause revisions to the payout account balance. The payment of the compensation is usually the result of:

1. Change in size of a unit either voluntarily or to conform to laws, rules, or regulations of a regulatory body
2. Creation of field-wide units or reservoir units
3. Recompletion of a well in one or more new formations
4. Multiple Completion of a well in one or more new formations

The Operating Agreement may prescribe an investment adjustment or payment upon the occurrence of certain events. For example, operations to deepen or sidetrack the well or to recomplete the well at a shallower depth for the purpose of completing additional formations may trigger a Well Cost Adjustment under the terms of the agreement. The Joint Operating Agreement or other separate agreement should be carefully examined for specific provisions governing the handling of these types of investment adjustments as they may differ from the guidelines that follow.

This document does not cover items 1 and 2 above as they are addressed in the COPAS publication "Accounting for Unitizations" Accounting Guideline AG-2.

#### **A. INTANGIBLE DRILLING COST COMPENSATION**

IDC Compensation includes IDC related to the preparation of a wellsite for drilling of a well, but should not include the IDC related to the completion of the formation(s). The fair value of the IDC Compensation should first be established, then apportioned to the producible formation(s) and to formation(s) proposed for completion. In all IDC Compensation methods described below, the compensation will be apportioned to producible formation(s) and to formation(s) proposed for completion. Whichever methodology is used, whether listed or not, the intent is for the parties to select a methodology that is equitable for a given situation. Once the IDC Compensation is determined, the compensation can be apportioned using the methods described in Section II.A.

Methods for determining IDC Compensation include:

##### **METHOD A – Actual or Deemed IDC – Unit of Production Depreciation**

In this method, the parties determine the actual or Deemed IDC and depreciate these costs based on units of production. When determining Deemed IDC, use current market cost for drilling a well similar to the existing well. The parties will have to reach agreement on the Deemed IDC since it is a theoretical number. This method also requires that the parties reach agreement on the estimated reserves. An advantage of Deemed IDC is that it avoids having to identify actual IDC (excluding completion costs) that could be difficult for old wells. A disadvantage of Deemed IDC is that current replacement value may overvalue an older well, even with the depreciation factored in.

**Illustration:**

A working interest owner of a well that is currently producing from only one formation is proposing to add an additional completion in a second formation and thus make the well a Multiple Completion Well or Downhole Commingled Well. Working interest owners A and B are participating parties in formation one and working interest owners C and D are participating parties in formation two. The actual IDC for the wellbore was determined to be \$200,000. The project to complete to formation two will begin on 10/1/2000. Production from formation one from inception through 9/30/2000 is 10,000,000 MCF. Remaining reserves for formation one are estimated to be 7,000,000 MCF. The depreciated value is determined by dividing the actual \$200,000 of IDC by the total estimated reserves to be produced over the life of the well or  $200,000/17,000,000$ . This yields a depreciation rate of \$.011764 per MCF of production. Thus, the depreciated amount is 10,000,000 MCF produced times the depreciation rate of \$.011764 or \$117,647. This leaves a non-depreciated IDC balance of \$82,353. The \$82,353 would then be allocated by an equitable method to formation one and formation two. If the allocation method yielded an equal split, then formation two owners owe formation one owners \$41,176 (50% of \$82,353). The \$41,176 would be paid to owners A and B based upon their working interest in formation one, and owners C and D would share this cost based upon their working interest in formation two.

**METHOD B – Actual or Deemed IDC – Straight Line Depreciation**

In this method, the parties determine the actual or Deemed IDC and depreciate the costs evenly over the economic life of the well or an agreed upon number of years. When determining Deemed IDC, use current market cost for drilling a well similar to the existing well. The parties will have to reach agreement on the Deemed IDC since it is a theoretical number. An advantage of Deemed IDC is that it avoids having to identify actual IDC (excluding completion costs), which could be difficult for old wells. A disadvantage of Deemed IDC is that current replacement value may overvalue an older well, even with the depreciation factored in. This method requires that parties reach agreement on the estimated life of the well or period of time over which to depreciate.

**Illustration:**

A working interest owner of a well that is currently producing from only one formation is proposing to add an additional completion in a second formation and thus make the well a Multiple Completion Well or Downhole Commingled Well. Owners A and B are participating working interest owners in formation one, and owners C and D are participating working interest owners in formation two. The actual IDC for the wellbore was determined to be \$240,000. The project to complete to formation two will begin on 10/1/2000. Production from formation one began on 3/1/1990. The depreciable life of the well is 240 months based on the twenty-year reserve life. The monthly depreciation amount is \$240,000 divided by 240, or \$1000 per month. The well produced from 3/1/1990 to 10/1/2000, or 126 months, resulting in \$126,000 of depreciation. The non-depreciated value is the original IDC of \$240,000 less the \$126,000 depreciation, or \$114,000.

The \$114,000 would then be allocated by an equitable method to formation one and formation two. If the allocation method yielded an equal split, then formation two owners owe formation one owners \$57,000. The \$57,000 would then be paid to owners A and B based upon their working interest in formation one, and owners C and D would share this cost based upon their working interest in formation two.

Note: For methods A& B, both A and B are participating parties, as are Parties C & D. Thus, A and B share the payment in proportion to their working interest in formation one, while Parties C and D pay the adjustment in proportion to their working interest in formation two. That would change if D went non-consent. In that case, only Party C would pay the adjustment. If B were non-consent in the well from the outset and the well had not paid out, only A would receive the payment (assuming the payment did not cause the payout account to reach payout). If B were a participating party in the drilling of the well, but went non-consent at casing point or on a subsequent operation, both A and B would receive the payment. Readers are cautioned to review their agreement carefully as some agreements may deviate from this general practice.

#### **METHOD C – Full Replacement Value IDC Compensation**

In a situation where the wellbore is servicing productive formation(s) that have been profitable, with many more years of production remaining, it may be acceptable for IDC Compensation to be based on Full Replacement Value Compensation. Therefore, the value of the IDC would not be depreciated when determining compensation. To better understand when Full Replacement Value Compensation for IDC may be deemed to be proper, we should hypothetically ask the following question: “If the owners of the current productive formation(s) were faced with the decision to drill a replacement well at this time to enable production of the remaining reserves, would that be economically viable?” An advantage of using this method is that it does not require determining actual IDC, which could be a problem if the records are old. A disadvantage of using this method is that for an old well with a long reserve life, current replacement value may overvalue the asset.

#### **METHOD D – Negotiated Amount**

The parties may simply negotiate a fixed amount as compensation to avoid research of actual costs, estimates on current drilling costs, reserve estimates or well life. The obvious advantage of this method is that it is simple and can be done quickly if the parties have a similar perception of the value. The disadvantage is that the parties have to negotiate in good faith. A mediator or arbitrator can help to facilitate an agreement. This method works particularly well where the same parties own an interest in the affected formations and the ownership percentages do not change significantly. The settlement can range from salvage value to an estimate of current market value, or any other amount established by the parties.

### **B. COMPENSATION FOR SURFACE AND SUBSURFACE TANGIBLE EQUIPMENT**

For some situations such as adding a completion with different working interest ownership, compensation should be paid to the owners in the existing formation(s) for surface equipment and tangible subsurface equipment to the extent it will be used by the owners in the new completion. The Cost Allocation Agreement, if any, Accounting Procedures or any other applicable agreement for the property should be reviewed for any allocation and pricing provisions under this circumstance. When using COPAS Accounting Procedure method of valuing equipment, it will be necessary to determine if



the equipment is in "B, C, D or E condition" and determine the current new price. Alternatively, other agreements may call for other valuation methods such as fair market value. Tangible Equipment Compensation will be apportioned to producible formations and to formations proposed for completion. Methods for apportionment of Tangible Costs are described in Section II.B and II.C.

Other ways to value the equipment include using salvage value or a negotiated amount.

#### **IV. ALLOCATION OF OPERATING EXPENSES**

Operating expenses need to be allocated since many of the costs are shared, and need to be matched and charged to the formations receiving the benefit. Operating expenses fall into two categories: 1) Direct Costs and 2) Indirect Costs. For information on Direct Costs, refer to the provisions of each Accounting Procedure as well as interpretive material in other applicable COPAS publications.

##### **A. DIRECT OPERATING COSTS**

Some Direct Operating Costs are clearly identifiable to, and benefit only, one formation. An example of this would be water disposal when only one formation produces water. Other Direct Operating Costs are not clearly specific to a given formation and benefit more than one formation. Examples of this are routine labor costs or water disposal where all formations produce water.

Operating expenses that are clearly identifiable to a specific formation are normally charged directly to that formation. When an operating expense affects more than one formation, that expense should be allocated on an equitable basis to the formations receiving the benefit. A specific operating expense may be more heavily weighted to one formation over another or the weight of a specific operating expense may fluctuate between formations from one period to the next, but a simple, consistent allocation method will nonetheless result in an equitable allocation over a longer period of time. Bear in mind it is often difficult to measure precisely the extent each formation benefited. Consequently, a fixed allocation percentage is typically used for all Direct Costs unless there is a material discrepancy for a given item or service.

The allocation percentages agreed upon should cover all operating expenses not identifiable to a specific formation. A contract pumper may charge more for a well completed in the Dakota formation than one completed in the Pictured Cliffs formation, but would probably charge a lesser amount than the sum of the two when operating a Multiple Completion Well. Similar examples, when reviewed, should support the premise that the agreed upon percentages should cover all shared operating expenses.

Listed below are descriptions and examples of several methodologies that may be used to allocate Direct Costs in a given situation. Whichever methodology is used, whether listed in this document or not, the intent is for the parties to select an allocation methodology that is equitable for a given situation. Suggested allocation methods include:

1. Equal allocation among all formations
2. A formula based on the state approved production allocation
3. Other agreed upon percentages

The most commonly used method to allocate direct operating expenses is the first method, equal allocation to all formations. Parties are encouraged to reach an agreement on the methodology, especially if using a method other than the first method.

## **B. INDIRECT OPERATING COSTS**

Operating Overhead is discussed in the provisions of each vintage Accounting Procedure, as well as interpretive material in other COPAS publications. **The Joint Operating Agreement, Accounting Procedure, and other relevant agreements for a particular property will always take precedence and should always be taken into consideration.** The contracts that govern the property should be thoroughly examined for various provisions that address overhead. There may be overhead provisions in both the Accounting Procedures and the Cost Allocation Agreement, and users are cautioned to seek legal advice in the event these provisions conflict.

There is no allocation issue if operations are governed by an agreement allowing a one-well Overhead charge for each produced zone. If, however, the Accounting Procedure or Cost Allocation Agreement stipulates the wellbore is only eligible for a one-well Overhead assessment, the charge may be split as follows:

1. Equal allocation among all formations
2. A formula based on the state approved production allocation
3. Other agreed upon percentages

If operations use the Percentage Basis method (versus Fixed Rate method) of assessing Operating Overhead, each zone's share of Operating Overhead is its allocated share of operating cost times the Operating Overhead percentage.

## **V. WORKOVER OPERATIONS**

### **A. ALLOCATION OF COSTS FOR WORKOVER OPERATIONS**

A proposed workover, repair or other operation – excluding routine repair or maintenance work – usually requires approval by the parties owning a participating interest in all formations which are capable of producing in paying quantities, whether or not such formations are to undergo the proposed workover, repair or other operation. However,

some Joint Operating Agreements, particularly unit Operating Agreements, may provide the operation is deemed approved if a certain threshold vote is reached, regardless of whether the formation is capable of producing in paying quantities. The costs and risk of any workover, repair or other operations on such well are borne by the parties electing to participate in such workover, repair or other operations as follows:

- i. The costs and risk of any workover, repair or other operation which is directly related to one formation, including but not limited to operations such as re-perforating the casing or stimulating the formation, are borne by the formation which the workover, repair or other operation is intended to benefit.
- ii. All costs and risk of any workover, repair, or other operation not directly related to one formation, including but not limited to repair and correction of leaks that may result in communication between formations within the wellbore, are borne equally by the formations benefiting from such work unless a different percentage is negotiated between owners.
- iii. For information on allocating workover Overhead costs, refer to Section II.D or IV.B as applicable.
- iv. Any material and equipment acquired by and such expenditures incurred in connection with the workover, repair or other operation are paid and owned by the respective formations so as to be consistent with the ownership of the material and equipment as described in Section II - "New Well Cost Apportionments."

## **B. DAMAGES**

If the producing capacity of the formation(s) not undergoing the workover, repair or other operations is reduced, damages may be deemed to have occurred. When the issue of damages is addressed up front in an agreement, the parties may agree upon a threshold reduction in the damaged formation's capacity before damages are due. Moreover, it is common to limit the liability to the cost of drilling and completing a replacement well. If damages occur, the owners of the formation undergoing workover or repair may agree or otherwise be required to pay damages to the owners of the damaged formation(s) for the loss of production capacity. The damage payment is typically made to the participating owners in the damaged formation, rather than all the working interest owners. Owners are advised that damage payments could affect payout calculations. (Payments that might be owed to royalty owners for damages in this situation are beyond the scope of this document and readers should seek appropriate legal advice on this issue.)

The parties may agree, however, that liability for loss or damages will not accrue if: 1) the loss or damage existed prior to actual commencement of the operations or prior to penetration by recompletion equipment of the damaged formation, or 2) the loss or damage resulted solely from the previously existing poor mechanical condition of the well. **The Joint Operating Agreement, Accounting Procedures, and any other applicable agreements for a particular property will always take precedence and should always be reviewed.**

## **VI. ABANDONMENT**

This section addresses wells having different working interest ownership. It is not intended to address non-consent situations where the working interest ownership is uniform, but the participating interest differs. Also, the term “owners” usually refers to the participating parties in the well or operation, so that payments by and to owners of a formation involve only the consenting parties and the payout account adjusted accordingly. However, the relevant agreements should always be reviewed to ensure the proper accounting treatment.

### **A. PARTIAL ABANDONMENT-NON-PRODUCTIVE FORMATION**

If a well that began with the objective of multiple completions results in discovery of oil and/or gas in paying quantities in one or more formation(s), but is not producible in one or more formation(s), the common practice is for the costs of drilling, testing and completing the well to be allocated as stated in Section II above rather than being retroactively reallocated. Similarly, the costs to equip the well prior to the decision to abandon the non-productive formation(s) are borne by all objective formation(s). All costs of equipping the well subsequent to the decision to abandon the non-productive formation(s) are typically borne by the productive formation(s). If there are two or more productive formations, the owners of these formations share any remaining equipping costs to the extent the equipment benefits both productive formations. The productive formation owner(s) then own(s) all materials and equipment acquired from the non-productive formation owner(s) including non-salvageable material, depending on the agreements reached between the parties.

Typically, the productive formation owner(s) pay to the owner(s) of the non-productive formation(s) that are being abandoned the fair value of any salvageable material and equipment paid for or furnished by the abandoning non-productive formation(s) and that is used in connection with the productive formation(s). Another method of valuing equipment is to use COPAS pricing mechanisms. The value of the equipment is based on its condition at the time the decision is made to abandon the non-productive formation(s). Likewise, the owners of the abandoned formation could agree to take no compensation for materials or equipment in exchange for the productive formation owner(s) paying for plugging costs of the abandoned formation.

The owners of the productive and non-productive formations may negotiate some other method of compensation for equipment acquired from the owner(s) of the non-productive formation. The cost of abandoning the non-productive formation(s) is borne by the owners of the formation(s) being abandoned in accordance with the applicable Operating Agreement. The cost to plug and abandon the rest of the wellbore is typically borne by the productive formation owner(s) when it is time to abandon the wellbore. The parties could agree that the owners of the non-productive formation(s) will share some of the costs to plug and abandon the rest of the wellbore at the time it is plugged but this treatment is uncommon.

If the well being drilled had an exploratory tail and the upper interval is non-productive, the parties may need to negotiate a Well Cost Adjustment or disproportionate spending

arrangement to compensate the shallow owners for takeover of the wellbore owned by the upper interval owners.

In any event, the Joint Operating Agreement, Accounting Procedure, Cost Allocation Agreement or other relevant agreements for a particular property will always take precedence and should always be reviewed.

## **B. PARTIAL ABANDONMENT AFTER COMPLETION OF WELL IN MULTIPLE FORMATIONS**

If fewer than all formations are abandoned in a Multiple Completion Well or Downhole Commingled Well, and the formation(s) being abandoned previously produced, then it is common for the remaining producible formation owner(s) to pay the abandoned formation(s) salvage value of any materials or equipment belonging to the abandoned formation(s) that are used in connection with the producible formation(s). If payment is made and there is more than one producible formation, payment is apportioned between the formations so as to be consistent with the ownership of material and equipment previously allocated. Once payment is made, the owners of the remaining productive formation(s) own all materials and equipment so acquired. Less commonly, the owners of the abandoned formation(s) could agree to take no compensation for materials or equipment in exchange for the owners of the productive formation(s) paying for plugging costs of the abandoned formation(s).

The cost of abandoning the formation(s) that is/are no longer producible or economic is borne by the owners of the formation(s) being abandoned in accordance with the applicable Operating Agreement. The cost to plug and abandon the rest of the wellbore is typically borne by the owners of the remaining productive formation(s) when it is time to abandon the wellbore. Uncommonly, the parties could agree that the owners of the non-productive formation(s) will share some of the costs to plug and abandon the rest of the wellbore at the time it is plugged. **The Joint Operating Agreement, Accounting Procedure, Cost Allocation Agreement or other relevant agreements for a particular property will always take precedence and should always be reviewed.**

## **C. ABANDONMENT IN ALL FORMATIONS**

If all formations in a Multiple Completion Well or Downhole Commingled Well are plugged and abandoned at the same time, a common practice is to allocate the costs by charging Formation-Specific Costs for plugging and abandonment to the affected formation and sharing the nonspecific costs equally. This could be accomplished by a detailed review of the plugging reports and vendor invoices, which can be tedious. Another way to allocate the plugging and abandonment costs is to allocate the costs based on rig days incurred for specific formations. Yet another way is to agree to a flat amount or percentage split. If using this approach, the parties need to take into account technical problems that could occur with any of the formations and charge the additional costs to the formation giving rise to the extra costs.

## **VII. CONCLUSION**

A review of the various Model Form Operating Agreements, Cost Allocation Agreements, and industry practice reveals a variety of ways Well Cost Adjustments are handled. The conclusion drawn from that variety is that there is no singular “right way” to make adjustments. Rather, it is a matter of discussion and negotiation among the parties acting in good faith to reach an allocation or settlement of costs that is equitable to all parties. Despite the terms of an existing agreement that clearly establishes an adjustment method, the parties can always reach mutual agreement to do otherwise. The parties are continuing to find ways to improve and/or streamline the adjustments.

## GLOSSARY

The definitions provided in this glossary or in other sections are not intended to conflict with their generally accepted meaning as used by the oil and gas industry, but are provided here as a matter of convenience and clarification as to their specific meaning under this document:

**ACCOUNTING PROCEDURE** – An agreement between the parties to a Joint Operations, often an attachment to the Operating Agreement, that establishes the terms and conditions for accounting for the Joint Operations.

**COST ALLOCATION AGREEMENT** – An agreement that establishes the terms and conditions for cost and expense apportionment among formations in a Downhole Commingled Well or Multiple Completion Well. A Cost Allocation Agreement is usually made a part of the Joint Operating Agreement but it may be a separate agreement, particularly if each formation has its own, separate Joint Operating Agreement. For a sample see the COPAS publication “Accounting For Unitizations” (formerly known as Bulletin 11).

**DEEMED IDC** – An estimate of Intangible Drilling Costs to drill a replacement or like well in the current market for that given area.

**DIRECT COSTS** – Those costs chargeable to the Joint Account under the Direct Charges section of the Accounting Procedure, i.e., Section II of the 1962, 1968, 1974, 1976, 1984, 1986 and Project Team COPAS Accounting Procedures, and Sections III and IV of the 1995 Accounting Procedures. For information on Direct Costs, refer to the provisions of each Accounting Procedure as well as interpretive material in other applicable COPAS publications.

**DOWNHOLE COMMINGLED WELL** – A well that produces hydrocarbons from two or more hydrocarbon-bearing formations through a common wellbore, mixed in the wellbore and produced through a single tubing string. This type of well is distinguished from a Multiple Completion Well, which produces from two or more formations through separate tubing strings to each formation. There are usually two reasons to downhole commingle hydrocarbon production and produce it through a single tubing string: 1) a governmental regulatory agency requires the hydrocarbon production from two or more formations to be pooled and the production reported as a single well, or 2) the owners believe it is economically beneficial to all owners for the hydrocarbons to be mixed in the wellbore and produced through a single tubing string. A well can be both a Downhole Commingled Well and a Multiple Completion Well. A well can have two formations that are downhole commingled and produced through a common tubing string while another formation in the same well is produced through a separate tubing string.

**DRILLING INTERVAL** – In a Multiple Completion Well or Downhole Commingled Well, the drilling process is broken down into Drilling Intervals. The first Drilling Interval is the drilling zone from the surface to the base of the first objective formation. The second Drilling Interval is the drilling zone from the base

of the first objective formation to the base of the second objective formation. This process of breaking down the Drilling Intervals continues through the last objective formation.

**DRILLING OVERHEAD** – The amount billed by the Operator to recoup costs not directly chargeable to drilling, recompletion, or workover operations under the Accounting Procedures. For information on Drilling Overhead, refer to the provisions of each Accounting Procedure as well as interpretive material in applicable COPAS publications.

**FORMATION-SPECIFIC COSTS** – Those costs intended to benefit a specific formation in a Downhole Commingled Well and/or Multiple Completion Well and which do not benefit another objective formation. Examples of Formation-Specific Costs are electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc. These examples are not meant to be all-inclusive.

**INDIRECT COSTS** - All costs, other than those deemed specifically to be Direct Costs. For information, refer to the provisions of each Accounting Procedure as well as interpretive material in other applicable COPAS publications.

**INTANGIBLE DRILLING COSTS (IDC)** – All costs, which in themselves, have no salvage value and are necessary for and incident to drilling a well, attempting to complete a well in a formation, and preparing the well for production. Intangible Drilling Costs also occur when deepening, sidetracking, or plugging back a previously drilled oil or gas well, or an abandoned well, to a different formation.

**JOINT OPERATING AGREEMENT (JOA)** – An agreement between two or more parties providing for the development and operation of a tract or leasehold for the purpose of oil, gas or other minerals extraction. The parties to the agreement share in the expenses of the operations and the production. The Joint Operating Agreement defines the rights and obligations of the co-owners of the working interest of a property in connection with the joint development and operation of the lease.

**MULTIPLE COMPLETION WELL** – A well producing from two or more formations by means of separate tubing strings run inside the wellbore, each of which carries hydrocarbons from a separate and distinct productive formation. In some cases, hydrocarbons may be produced through the angular space between the casing and tubing string instead of through a separate tubing string. The separate production strings distinguish this form of well from a Downhole Commingled Well that produces from two or more hydrocarbon formations through a single tubing string in the common wellbore. A dual completion well is a Multiple Completion Well having only two hydrocarbon productive formations. A well can be both a Downhole Commingled Well and a Multiple Completion Well. A well can have two formations that are downhole commingled and produced through a common tubing string while another formation in the same well is produced through a separate tubing string.

**OPERATING AGREEMENT** – See Joint Operating Agreement.



**OPERATING OVERHEAD** – The amount billed by the Operator to recoup costs not directly chargeable to the routine operation of the Joint Property under the provisions of the Accounting Procedure and /or other agreements governing the property. For information on Operating Overhead, refer to the provisions of each Accounting Procedure as well as interpretive material in other COPAS publications.

**OPERATOR** – The entity responsible for physical maintenance and operation of the well and other responsibilities as covered in the Joint Operating Agreement, unit agreement, force pooling order or other governing document, and recognized as such by the agency having jurisdiction.

**SHARED DRILLING COSTS** – Intangible Drilling Costs that are intended to benefit more than one formation in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Drilling Costs are rig costs, drilling water, field supervision, Drilling Overhead, etc. These examples are not meant to be all-inclusive.

**SHARED PRE-DRILLING COSTS** – Intangible Drilling Costs that arise from preparing a site for drilling and benefit all objective formations in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Pre-drilling Costs are site surveys, site preparation, right-of-way, surface damage payments, etc. These examples are not meant to be all-inclusive.

**TANGIBLE COSTS** – Those material items installed in connection with drilling and completing a well through the Wellhead, or deepening, sidetracking, or plugging back operations. Tangible Costs are ordinarily considered to have salvage value regardless of whether such items may actually be salvaged after they are installed.

**TANGIBLE EQUIPMENT COMPENSATION** - Compensation paid to the existing owners of a well for the fair value of the Tangible Equipment associated with the existing well.

**WELL COST ADJUSTMENT**– Represents compensation paid by one set of working interest owners to another set of working interest owners. This compensation is usually for the purchase of an ownership in a wellbore and/or equipment owned by the working interest owners receiving the compensation.

**WELLHEAD** – A term applied to the valves and fittings assembled at the top of a well to control the flow of production.

## **Exhibit 1**

### **Well Cost/Investment Adjustments**

#### **LA C.U. - 1**

##### **Article 4 – Investment Adjustment (new well)**

Payment is based on the original cost of the Unit Well, including casing, tubing and in-hole equipment, up to and including the wellhead connections. Also, pay for original cost of lease and operating equipment beyond the wellhead connections that is necessary for operations.

##### **Article 14 – Revision of Unit Area**

Adjustment is made on the depreciated value of the Unit Well, equipment & material on the effective date of the revision. The depreciated value of the Unit Well, equipment & material is calculated on the basis of the original investment costs (to the base of the Unitized Sand) and the charges and credits made to the joint account for investment items from inception to the effective date of the revision, including tangible and intangible drilling & equipping costs, but excluding operating costs. Depreciation is calculated on unit of production – the amount produced by the well from the Unitized Sand & any other sands prior to the revision effective date in proportion to the total reserves obtained by adding the amount so produced & the estimated recoverable reserves to be produced from the Unitized Sand from such well. However, the recoverable controlled tangible investment shall not decline in value below the condition percentage determined per the Accounting Procedure.

##### **Article 18 – Abandonment**

18.1 – If fewer than all parties want to P&A, the non-abandoning parties pay the abandoning parties for the estimated salvage value of materials & equipment, less estimated salvaging costs.

##### **18.3 – Turning over unit well to wellsite owner**

- Payment is based on the estimated salvage value of unit well, equipment & materials, determined per the Accounting Procedure, less estimated salvaging costs.
- Or investment adjustment is based on total depreciated value of the Unit Well, equipment & material applicable to that portion of the well used by the well-site owner. Depreciated value of the Unit Well, equipment and material is calculated on original investment costs (including charges and credits for investment items from inception to effective date well-site owner takes over, & including tangible & intangible drilling & equipping costs, but excluding operating costs). Depreciation is based on unit of production, provided the depreciated value of recoverable controlled tangible investment is not depreciated below the condition percentage determined per the Accounting Procedure.

##### **Article 19 – Release of Lease**

The non-releasing party pays the party wishing to release the lease for the equipment and material on the assigned lease based on the estimated salvage value, determined per the Accounting Procedure, less the estimated cost of salvaging.

#### **AAPL Form 610-1977**

Article VI.E – Abandonment; Article VIII.A – Surrender of Lease

The non-abandoning (non-surrendering) party pays the abandoning (surrendering) party for the salvable material and equipment, determined per the Accounting Procedure, less the estimated cost of salvaging, plugging and abandoning.

#### **AAPL Form 610-1982**

##### **Article VI.B.4 – Sidetracking**

Dry hole - Payment is based on actual costs incurred in drilling the well to the depth at which sidetracking is initiated.

Producer – Payment is based on the well's salvable materials & equipment to the depth at which sidetracking is initiated, determined per the Accounting Procedure, less the estimated cost of salvaging, plugging and abandoning.

##### **Article VI.E – Abandonment ; Article VIII.A – Surrender**

Payment is based on the value of the salvable material and equipment, determined per Accounting Procedure, less the estimated salvaging, plugging and abandoning costs.

#### **AAPL Form 610-1989**

##### **Article VI.B.4 – Deepening; Article VI.B.5 – Sidetracking**

Dry hole – Payment is based on actual costs incurred in drilling the well to depth at which deepening/sidetracking is initiated.

Producer – Payment is based on actual cost incurred in drilling, completing and equipping, to depth at which deepening/sidetracking starts. The cost of salvable materials and equipment in the well and salvable surface equipment shall be determined per Accounting Procedure. Note: Deduct from the payment any amounts recouped out of proceeds of production, up to 100% of the costs.

##### **Article VI.E – Abandonment, Article VIII.A – Surrender**

Payment is based on the value of the salvable material and equipment, determined per the Accounting Procedure, less the estimated salvaging, plugging and abandoning costs, and surface restoration costs. If this calculation results in a negative value, the abandoning party pays the non-abandoning party.

Article VI.C.1 – An adjustment takes place if a drilling party non-consents a completion attempt and prior to payout the well is recompleted. If the party that non-consented the completion attempt participates in the recompletion, it must pay the consenting parties for the cost of salvable materials and equipment in the well pursuant to the completion attempt, insofar as the materials and equipment benefits the formation in which the previously non-consenting party is participating.

#### **Rocky Mountain Unit Operating Agreement – Form 2, 1994**

Article 1 – Salvage Value means the value of the materials and equipment in or appurtenant to a well, determined per the Accounting Procedure, less the reasonably estimated Costs of salvaging the same and plugging and abandoning (including reclamation of the surface) of the well.

##### **Article 11 – Abandonment; Article 27 - Surrender**

Payment is based on the Salvage Value.

#### **Article 12 – Relinquishment by Non-Drilling Party**

In the case of a deepening, sidetracking, or plugging back operations, if a non-drilling party owned an interest in the well immediately prior to the deepening, sidetracking, or plugging back, the consenting parties pay the non-consenting party its share of Salvage Value of the well.

#### **Article 13.3 – Adjustment on Establishment or Enlargement of Participating Area**

**Intangible Value** – The Costs incurred in drilling, completing and equipping that contribute to the production of unitized substances from the resulting area. The Costs are reduced for each month the well was operated prior to the effective date of the resulting area by: X% per month for cumulative total of Y months, and Z% per month for each month in excess of the cumulative total.

**Tangible Value** – The Costs incurred in the construction or installation of Tangible Property are reduced at X% per month for each month during which well was operated prior to the effective date of the resulting area.

**Article 13.4 – Adjustment on Contraction of Participating Area** – See form.

#### **API Model Form Offshore Operating Agreement - 1984**

##### **Article 12.3 – Deepening a Non-Consent Well**

A non-participating party in a drilling that is joining a deepening operation pays the participating parties in the well for its share of actual costs incurred in drilling and casing the well.

##### **Article 12.8 – Allocation of Costs Between Zones (Single Completions)**

For purposes of allocating costs on any well completed in only 1 zone in which ownership is not the same for the entire depth or the completion:

- Intangible drilling, completion & material costs from the surface to 100' below the base of the completed zone charged to participating parties in that zone.
- Intangible drilling, completion, casing string, and material costs (except tubing) from 100' below base of completed zone to TD charged to parties participating to total depth.

##### **Article 12.9 – Allocation of Costs Between Zones (Multiple Completions)**

- Intangible drilling, completion, and material costs (except tubing) from surface to 100' below base of upper completed zone are divided equally between completed zones.
- Intangible drilling, completion, casing string, and material costs (except tubing) from 100' below base of upper zone to 100' below base of 2<sup>nd</sup> completed zone are divided equally between 2<sup>nd</sup> zone and any other deeper completed zone. If the well is completed in additional zones, use the same process.
- Intangible drilling, completion, casing, and material costs (except tubing) from 100' below base of lowest zone to total depth are charged to parties participating to total depth.
- Tubing serving each separate zone is charged to the participating parties in that zone.
- If the zones are less than 100' apart, the distance between the base of the upper zone to top of next lower zone is allocated equally between the zones.

##### **Article 12.10 – Allocation of Costs Between Zones (Dry Hole)**

- Costs to drill, plug and abandon are charged to participating parties in each zone, same as if completed in all zones as proposed.
- Plugging and abandoning following a deepening, completion attempt or other operation, is at sole risk & expense of participating parties, subject to Section 11.5.

#### Article 12.11 – Intangible Drilling and Completion Allocations

For purposes of allocating costs under Articles 12.8 – 12.10, intangible drilling and completion costs, including non-controllable material, is allocated to the zones based on a drilling day ratio basis. The factor for each zone is based on a fraction for which the numerator is the number of drilling and completion days applicable to that zone and the denominator is the total number of days spent on the well, beginning on the day the rig arrives on location and terminating when the rig is released.

#### Article 14 – Abandonment

Payment is based on the current value of the well's salvageable material and equipment, determined per Accounting Procedure, less the estimated cost of salvaging, plugging and abandoning.

#### Article 15 – Withdrawal

Payment is based on the current salvage value less the estimated current cost of salvaging, plugging and abandoning, and removing all platforms and facilities.

### **AAPL Form 710, The Continental Shelf Operating Agreement (formerly the API Model Form Offshore Operating Agreement – 1996)**

#### Article 10.10 – Wells Proposed Below Deepest Producing Reservoir

If there is a proposal to drill an exploratory well below the base of the deepest producing reservoir, a party may elect to limit its participation to the base of the deepest producing reservoir. If the well is completed and produces from deep zone, the deep participant reimburses the shallow participant for its share of actual well costs to the base of the deepest producing reservoir. The shallow participant reimburses the deep participant for its share of the actual well costs to the base of the deepest producing reservoir, in accordance with Article 12.4 upon (a) the well being plugged back to a horizon above the base of the deepest producing reservoir, or (b) the well is plugged and abandoned, or (c) the deep operation reaching payout.

#### 12.4 – Deepening or Sidetracking Cost Adjustments

- (a) Intangible drilling costs are valued at the actual cost incurred by the Participating Party.
- (b) Tangible materials are valued as transfers of new material per the Accounting Procedure.
- (c) For sidetracking, the values are reduced by the amount allocated to that portion of the well down to 100' below the point of sidetracking. The allocations are to be made in accordance with COPAS Bulletin No. 2, as amended from time to time.
- (d) Amortization/depreciation is applied to the intangible and tangible values at the rate of X% per annum from the date the well commenced production to the date deepening or sidetracking operations commenced, provided the value of tangible materials shall not be depreciated below Y% of the value determined in subsection 12.4 (b).

#### Article 14 – Abandonment, Salvage, and Surplus

Payment is based on salvage value, determined per the Accounting Procedure, less the estimated cost salvaging and plugging.

#### Article 15 – Withdrawal

The Withdrawing party pays the estimated cost of plugging and abandoning and removing platforms and facilities, less the estimated salvage value, as determined per the Accounting Procedure. If the salvage value is greater than the estimated share of costs, non-withdrawing parties pay difference to the withdrawing parties.

## **AAPL Form 810, Deepwater Operating Agreement**

### **11.2.5 Participation in a Sidetrack or Deepening by a Non-Participating Party in an Appraisal Well at Initial Objective Depth.**

A former non-participating party joining in the deepening or sidetracking of an appraisal well becomes under invested in an amount equal to its share of carried costs in the well to the objective depth prior to deepening or sidetracking. The original parties become overinvested. The underinvestment is eliminated through disproportionate spending.

### **13.2.5 Participating in a Sidetrack or Deepening by a Non-Participating Party in a Development Well at Initial Objective Depth**

A former non-participating party joining in the deepening or sidetracking of a development well becomes under invested in an amount equal to its share of the carried in the well to the objective depth prior to the deepening or sidetracking. The original participating parties become overinvested. The underinvestment is eliminated through disproportionate spending.

### **13.3.1 Multiple Completion Alternatives Above and Below the Deepest Producing Reservoir**

A party may elect to limit its participation in a well to the base of the deepest producing reservoir.

(a) If all parties agree to multiple completions both above and below the base of the deepest producing reservoir, the parties in the deeper drilling bear 100% of the costs of drilling below the deepest producing reservoir in excess of the original costs to drill and complete the well in the deepest producing reservoir.

(b) If the parties do not agree that multiple completions are possible, the first completion shall be in the deep zone and the non-participating parties in the deeper drilling are overinvested in the amount of their share costs to drill to the base of the deepest producing reservoir. The participating parties in the deep zone are under invested for that amount. The underinvestment is eliminated through disproportionate spending.

Once certain events occur (see agreement), the non-participating parties in the deep zone are deemed under invested and the participants in the deep zone are overinvested. The over/underinvestment is the amount equal to the carried party's share of the well cost down to the deepest producing reservoir, depreciated at the rate of 1/2% per month from the date deeper drilling commences until the date the non-participating party is entitled to share in the hydrocarbons from the deep zones. The depreciated value will not be reduced below Y% of the original underinvestment. The underinvestment is eliminated through disproportionate spending.

## **Article 17 – Withdrawal**

A withdrawing party pays the non-withdrawing parties their estimated share of plugging and abandoning all wells, production systems, facilities and other equipment serving the property, less their share of estimated salvage value. The costs and salvage value are determined per the Accounting Procedure.

## **Article 18 – Abandonment**

If fewer than all parties wish to abandon a well, the abandoning party pays the non-abandoning parties its proportionate share of the well's estimated plugging and abandonment costs, less the estimated salvage value. If the salvage value exceeds the plugging costs, the non-abandoning parties pay the abandoning party its share of the difference.

If fewer than all parties wish to abandon a production system or facility, the abandoning party pays the non-abandoning parties its proportionate share of the estimated cost to abandon the production system or facilities, less the salvage value. If the salvage value exceeds the abandonment costs, the non-abandoning parties pay the abandoning party its share of the difference.