Index of Wexpro II Agreement Canyon Creek Acquisition
Guideline Letters

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QUESTAR

Wexpro Company
333 South State Street
PO Box 45003
Salt Lake City, UT 84145-0003
Tel 801-324-2534

July 20, 2016

Chris Parker
Utah Division of Public Utilities
Heber Wells Building
160 East 300 South
Salt Lake City, UT 84145

Bryce Freeman
Wyoming Office of Consumer Advocate
Hansen Building, Suite 304
2515 Warren Avenue
Cheyenne, WY 82002

John Burbridge
Wyoming Public Service Commission
Hansen Building, Suite 300
2515 Warren Avenue
Cheyenne, WY 82002

Craig C. Wagstaff
Questar Gas Company
333 South State Street
Salt Lake City, UT 84145

Re: Guideline Letter Governing Commercial Well Designations Under Section I-20 of the Wexpro Agreement and Section I-11 of the Wexpro II Agreement

The Utah and Wyoming Public Service Commissions approved the Wexpro I Agreement in 1981, the Wexpro II Agreement in 2013, the Trail Unit Settlement Stipulation in 2014 and the Canyon Creek Settlement Stipulation in 2015 (collectively the "Wexpro Agreement").

The Wexpro Agreement defines the procedure for classification of a "Commercial Well" in Section I-20 of the Wexpro I Agreement and Section I-11of the Wexpro II Agreement (the "Commercial Well Test"). A Commercial Well is one that "(i) clearly produces sufficient quantities to pay at market prices for the products, all costs of drilling, development and operation of the well, or (ii) requires further determination for classification as a commercial well or a dry hole." Modern drilling and completion techniques, such as hydraulic fracturing and horizontal drilling have become pervasive in the industry and have enabled completion in previously uneconomical formations. These newer techniques are reasonably necessary to efficiently and more fully produce the hydrocarbons in the properties subject to the Wexpro Agreement. However, the Commercial Well Test guidelines as set out in the Wexpro Agreement are not compatible with the newer completion techniques. Longer testing times are often necessary to evaluate new completions, which usually have multiple zones each requiring individual fracture treatment. Sufficient production time after completion is necessary to unload fracture fluids, remediate wet zones, install compression, and address other issues that may occur before reliable decline trends can be established to evaluate the well.

During the current Hydrocarbon Monitor's tenure, which began in 1999, procedures for classifying a well under the Wexpro I Agreement, Section I-20 (i) as "clearly" commercial included using a minimum 10 percent discount rate and oil and gas prices based on the NYMEX 12-month forward strip, adjusted to the location of the well. This process was used because Section I-20 only specified the use of "market prices" without further definition. The same procedures were used for classifying a well that requires "further determination" under I-20 (ii), but this Section has a 30-day testing limit after stimulation, with only the last 10 days of production to be used to evaluate the well.

The parties to the Wexpro Agreement will benefit from specifying procedures and timing to be used for performing a Commercial Well designation which comply with all aspects of the Wexpro Agreement. The following procedures will be utilized during the Commercial Well Test, on a well by well basis, for wells that are clearly commercial and for wells that require further determination for classification as a commercial well, a non-commercial well or dry hole:

Discount Rate: A before-tax industry-standard[1] discount rate (currently 10 percent) will be required under the Commercial Well Test.

Pricing: The price to be used for the Commercial Well Test will be the Rockies Adjusted Price, as of the date production begins then held flat thereafter. Rockies Adjusted Price is defined in the Canyon Creek Settlement Stipulation, paragraph 14. However, for the Commercial Well Test, the Rockies Adjusted Price will use a NYMEX 12-month forward curve instead of the NYMEX 5-year forward curve that is used to determine future drilling plans. All other calculations and terms will remain the same for the Commercial Well Test as they are defined in paragraph 14 of the Canyon Creek Settlement Stipulation.[2]

Production Testing: Beginning upon the date a well is first ready to produce hydrocarbons; each well will be produced for 90 days prior to analysis for classification under the Commercial Well Test. If a well is not "clearly commercial" and requires remedial work, Wexpro will notify the Hydrocarbon Monitor prior to the end of the 90-day initial production period and request one additional 90-day production period. Wexpro will describe its plans for remediation and increasing production. The Wexpro remediation plan will include anticipated costs and time duration. If the Hydrocarbon Monitor agrees to an additional 90-day production period, Wexpro will be granted a maximum of 30 days for remedial work ("Remediation Period") before the second 90-day production period begins. If a permit(s) for additional work is required, Wexpro will notify the Hydrocarbon Monitor and the start of the 30-day Remediation Period will not begin until the day after Wexpro receives the permit(s). The second 90-day production period will begin no later than 30 days after the beginning of the Remediation Period.

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[1] FASB Statement of Standards, FAS69-8.

[2] This Guideline Letter does not change the Cost-of-Service-Test required prior to drilling investment as defined in paragraph 14 of the Canyon Creek Stipulation.

Adoption of this Guideline Letter will provide for application of a Commercial Well Test in a manner and time frame most likely to result in an accurate analysis of a well's potential performance.

The guidelines contained herein will be in effect and binding upon the parties who sign this letter until such time as they are either modified or terminated. However, the guideline would still be in effect for all actions taken prior to any modification or termination.

Please indicate your acceptance of this Guideline Letter as an appropriate means to perform Commercial Well determinations in the future on all Wexpro Agreement properties.

APPROVED:

WEXPRO COMPANY

By: Brady B Rasmussen Date: 7/20/16
Brady R. Rasmussen
Executive Vice President &
Chief Operating Officer

UTAH DIVISION OF PUBLIC UTILITIES

By: __________ Date: 8/1/16
Chris Parker
Director

WYOMING OFFICE OF CONSUMER ADVOCATE

By: Bryce J. Freeman Date: July 27, 2016
Bryce Freeman
Administrator

WYOMING PUBLIC SERVICE COMMISSION STAFF

By: ______________________________ Date: 7-28-16
John Burbridge
Attorney Supervisor

QUESTAR GAS COMPANY

By: ______________________________ Date: 7/21/16
Craig C. Wagstaff
Executive Vice President &
President, Questar Gas Company

QUESTAR

Wexpro Company
180 East 100 South
P.O. Box 45601
Salt Lake City, UT 84145-0601
Tel 801 324 2600 · Fax 801 324 2637

July 26, 2004

Evans Consulting Company
2002 Cimarron Court
Mission, TX 78572-7432
Attn: David Evans

Re: 3D Seismic, Canyon Creek Unit

Dear David:

Wexpro requests pre-participation approval by the hydrocarbon monitor to participate in a 3D seismic program over Canyon Creek Unit as discussed below. This request is based on the guideline letter of October 17, 1994 which requires Wexpro to get pre-participation review and approval by the hydrocarbon monitor for future 3D seismic programs.

Overview

Canyon Creek Unit has production from shallow Wasatch and Fort Union Formations, intermediate depth Mesaverde Formation, and deep Frontier and Dakota Formations. Because of the multiple stratigraphic horizons that are productive and the diverse ownership, the unit is horizontally segregated into different participating areas. Wexpro operates the Canyon Creek Unit (approximately T12N-13N, R101W, Sweetwater, Wyoming), but has designated QEP as sub-operator for the shallower Fort Union and Wasatch producing zones in which Wexpro has no ownership. Wexpro's primary ownership is only within the Mesaverde Formation, with limited additional ownership in other formations within 1980' circles. QEP in addition to ownership in the shallow formations, also has rights to zones deeper than the Mesaverde, but not in the Mesaverde. Neither Wexpro nor QEP has 100% ownership in any zone, but rather is a partner with other companies.

Wexpro has been cautiously, but successfully developing additional Mesaverde reserves by infill drilling in Canyon Creek. It appears that if all potential locations can be drilled, there may be approximately 40 additional infill and step out locations available. The infill drilling is based on completing different sandstones than are completed in the existing offset wells. These additional sandstones have more limited drainage areas than higher quality sandstones completed in the original wells. These additional sandstones are not "blanket" type sandstones and part of the success of infill wells is the ability to predict the presence of individual sandstones at a given location. Seismic may provide some additional insight into presence or absence of individual sandstones, especially in step out well locations. Additionally, because Canyon Creek Unit is located a large structural anticline, it likely has a system of faults and fractures similar to those found on nearby structures. These faults and fractures are not recognized based on the limited well control currently available. Seismic may provide insight as to the location and trend of fractures and faults which may allow better interpretation of compartmentalization of the reservoir as well as any directionality of drainage, rather than the simple drainage circles we now use. This knowledge will enable better placement of future wells to maximize reserves and perhaps lessen the risk of drilling poor performing wells.

3D Seismic Program

QEP and its partners have decided to conduct a 51 square mile 3D seismic survey over the Canyon Creek area to image all the known productive reservoirs and have invited Wexpro to participate. The seismic survey is designed to enable mapping of individual Mesaverde sandstone bodies if they are thicker than 15 feet, map major packages of Mesaverde sandstones, predict reservoir quality, map faults with throw greater than 25 feet and accurately map depth between existing control points. Additionally, it will provide detailed imaging of the Frontier, Dakota, and Baxter formations in which Wexpro has ownership within selected 1980 foot circles.

Geophysicists believe that there is little risk of getting unusable data because similar surveys with similar geology and topography nearby have had good results.

The total survey cost, including processing, is projected to be $1,264,800. Based on thickness of interval to be imaged and ownership within the interval, it is determined that Wexpro should have 21% of the total cost or $265,608. This was calculated using the depth to the base of the Wexpro ownership (base Mesaverde) at approximately 7,000' in Canyon Creek Unit 34. Modeling of the seismic indicates that the deepest depth which can be imaged is 17,500', thus 60% of the beneficial seismic is at depths greater than Wexpro ownership (17500-7000)/17500 = 60%). Of the remaining 40%, the very shallow derives little benefit from the seismic data and is allocated 10% of the cost with 30% remaining for the Mesaverde interval. With approximately 70% working interest ownership in this interval, Wexpro total share of the seismic would then be 21%. This methodology assigns no share of the cost of the deep seismic to Wexpro, but Wexpro does have some limited ownership in the deep intervals.

Recommendation

Wexpro should participate for its calculated share ($265,608) of the Canyon Creek seismic program. This participation is in order that Wexpro might lower its risk in future development wells and might be able to better predict directional drainage patterns and sand terminations.

Please indicate your approval of Wexpro's participation in the above discussed 3D seismic program by signing in the signature box below. If you wish to discuss this further, please let me know.

Respectfully Yours,

James R. Livsey

James R. Livsey,
Vice President

Approved:
David E. Evans, Evans Consulting Company
Hydrocarbon Monitor for Wexpro
By: David E. Evans Date: August 2, 2004

cc: Darrell Hanson, Utah Division of Public Utilities

QUESTAR

Wexpro Company
180 East 100 South
P.O. Box 45601
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Tel 801 324 2600 · Fax 801 324 2637

February 20, 2004

Darrell S. Hanson
Utah Division of Public Utilities
Heber M. Wells Building
160 East 300 South
P.O. Box 45802
Salt Lake City, Utah 84145

Dear Mr. Hanson:

Re: *Guideline Letter Governing the Adoption of Financial Accounting Standards Board Statement No. 143, Accounting for Asset Retirement Obligations, under the Wexpro Agreement*

INTRODUCTION. The operational and legal necessity of conducting physical reclamation activities at and near oil or gas well-site locations and related facilities generally requires expenditures after production is terminated. This reclamation activity can include dismantling or removing facilities, plugging and abandoning wells, and reconditioning and restoring terrain. These obligations are referred to as asset retirement obligations or "AROs."

In particular, the Bureau of Land Management, as well as other federal and state regulatory agencies, has established specific reclamation requirements associated with leasing and operating oil and gas properties. The costs associated with these reclamation activities are reasonable and necessary "common business expenses" as that term is used in paragraph 1 in each of Exhibit A and Exhibit E of the Wexpro Agreement ("the Agreement").

SFAS 143 REQUIREMENTS. Wexpro Company ("Wexpro") has historically billed ARO costs through the Agreement when actual costs in excess of salvage value received are paid during asset-retirement operations. However, Wexpro is now required to adopt procedures consistent with Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143"), to comply with Generally Accepted Accounting Principles. Under SFAS 143, effective for fiscal years beginning after June 15, 2002, entities are required to recognize and account for certain AROs, as defined by SFAS 143, on a basis different from that used historically by Wexpro.

Specifically, if a legally enforceable ARO is deemed to exist, a company must determine and record the value of the liability for the ARO in its accounting records. Also, under SFAS 143, at the time the liability is recorded, a corresponding and equivalent ARO asset will be recorded on the company's books as part of the cost of the associated tangible asset. The ARO asset is then depreciated together with the associated tangible asset over the life of that asset.

An annual "accretion" expense is also added to the ARO liability to account for the risk adjusted time value of money. This is necessary so that, at the time of the asset's future retirement, the total recorded ARO liability will equal the cash required to meet the legal obligation.[1]

In addition to the forward-looking requirements of SFAS 143 outlined above, companies are required to recognize the "cumulative effect" on their financial statements resulting from the implementation of SFAS 143 on a retrospective basis. Thus, under SFAS 143, it is necessary to reconstruct over past years the effects that would have resulted if the requirements of SFAS 143 had always been followed. This cumulative effect requires a one-time transition entry on Wexpro's books as of January 1, 2003, so that future financial statements will properly reflect the ARO cost effects.

SFAS 143 UNDER THE WEXPRO AGREEMENT. In order to coordinate SFAS 143 compliance with contractual requirements under the Wexpro Agreement, Wexpro proposes to:

- Incorporate ARO costs as ongoing, necessary operating expenses under the terms, conditions and procedures of the Agreement, as described below;
- Collect ARO costs attributable to historical periods up to January 1, 2003 ("transition costs");
- Set up a trust account for the deposit of all funds (net of taxes) related to ARO costs collected from Questar Gas Company and Wexpro (funding of the trust account to be borne in the same proportion as ARO costs); and
- Pay the ARO costs when they come due with accumulated trust account funds.

In addition to providing guidance on adopting SFAS 143 for the Wexpro Agreement AROs, this Guideline Letter provides for establishing a secure source of funds to retire the Wexpro Agreement Properties (Article II and Article III assets) and a procedure to account for and true-up the ARO funding for each individual asset as may be necessary to reflect changes in economic factors, applicable tax rates and estimated cleanup costs.

The initial ARO accretion rate shall be 6.6%; the initial ARO rate of inflation

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[1]For example, assuming a discount rate of 6.6%, an ARO valued at $10,000 in 2003, but which will not be paid until 2005, will cost $11,364 when actually paid. The accretion required in this example would be $660 the first year and $704 the second.

shall be 2.3%. The accretion rate represents the estimated rate at which Wexpro could borrow to fund future ARO obligations. The ARO rate of inflation represents Wexpro's best estimate of current pricing inflation associated with future ARO obligations. Strictly for purposes of this Guideline Letter, Wexpro's collection of funds in the trust account to provide for future ARO costs will be net of applicable estimated salvage values.

Accretion and Depreciation, Future Charges. SFAS 143 accounting requires the following monthly expense entries related to AROs: (i) the monthly increase in the ARO liability from the accretion charge; (ii) the monthly depreciation of the associated ARO asset over its remaining life; and changes in estimates affecting items (i) and (ii). The treatment and allocation of ARO depreciation and accretion expenses shall follow established accounting practices historically used by Wexpro except as set forth below.

The Wexpro oil properties have been highly profitable resulting in over $88 million of oil sharing under Exhibit E of the Wexpro Agreement (the Operator Service Fee, "OSF.") The $88 million of cumulative oil sharing to date represents approximately 94% of the estimated total oil sharing. However, due to the discounting treatment under SFAS 143 (which "loads" the ARO expense toward the end of an asset's life), approximately 50% of the ARO expense is yet to be recouped from the remaining 6% of the estimated total oil sharing. Even though Questar Gas's share (54%) of the estimated future AROs will amount only to an estimated $0.9 million (net of salvage), this may cause "negative sharing"[2] in the later years of oil revenue sharing. These necessary expenses should be absorbed by the revenue stream generated over the life of the Wexpro oil properties. Therefore, to the extent of any negative sharing directly attributeable to ARO expenses, 54 % of the ARO costs will be a direct increase to the OSF.

Transition Costs. For assets in use as of the adoption of SFAS 143, Wexpro has calculated the cumulative effect of past ARO costs through December 31, 2002, to be $7,458,129 (net of salvage). This was determined by conducting a well-by-well engineering analysis and applying an accretion rate of 6.6% and an inflation rate of 2.3% over the expected life of all the properties subject to the Agreement.

This amount will be recovered as follows:

(a) $5,734,966 (net of salvage) in equal monthly charges over an 18-year period as a part of the OSF. This amount is related to (i) all gas produced from Article

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2 "Negative sharing" occurs when 54/46 revenues are not sufficient to effect a payout to the sharing parties.

III properties (Productive Gas Reservoirs), and (ii) gas produced from Article II properties (Productive Oil Reservoirs) subject to the cost-of-service treatment of § II-5 of the Agreement. Notwithstanding the foregoing, for an asset retired prior to the 18-year period, Wexpro will accelerate the collection of the proportionate share of the above amortized amount pertaining to that asset. Any accelerated collections will reduce the total of the monthly collections for transition costs for the remaining time periods by an amount equal to the accelerated collections.

(b) The remaining $1,723,163 (net of salvage) in ARO transition costs is related to (i) oil produced from Productive Oil Reservoirs subject to the 54-46 formula and (ii) "new oil" produced from Productive Gas Reservoirs subject to the 54-46 formula. Of this amount, 54% is to be charged to Questar Gas ($930,508) and 46% to Wexpro ($792,655). Questar Gas's 54% obligation will be reflected and charged as an operating expense under the OSF.

The 18-year straight-line amortization and the one-time charge and allocation for the cumulative effect are consistent with the prior treatment of excess deferred-tax refunds under the Agreement when the U.S. corporate tax rate changed from 46% to 34% in 1986, as agreed to by the parties in a guideline letter dated May 29, 1992.

Trust Account. As funds are received from Questar Gas by Wexpro, both from the charges for the cumulative effect and the annual depreciation and accretion expenses (net of salvage), such funds, net of income taxes as described in paragraph (a) below, will be deposited in an interest-bearing trust account established by Wexpro. Wexpro will also fund its share of the ARO costs, as determined in paragraph (b) above and by application of the "54-46 formula," by making corresponding deposits to the dedicated trust account.

This trust account will be maintained with a reputable financial institution solely for the purpose of accumulating and dispensing funds related to Wexpro's AROs under the Wexpro Agreement. The funds in this account will be specifically dedicated to Wexpro's SFAS 143 AROs and will not be commingled with any other funds of Wexpro or any other entity in order that these funds are not subject to creditor claims. The trust account will be funded and drawn down under the following procedures:

(a) From the payments collected from Questar Gas for the cumulative-effect charges (net of salvage) and ongoing depreciation and accretion charges (net of salvage), Wexpro will deposit and accumulate such funds in the trust account, except Wexpro will retain such amounts as are required for Wexpro to pay its current income-tax obligation related to those payments.[3] The initial tax rate will be the current marginal composite income tax rate (MCTR), as determined pursuant to § I-38 of the Wexpro Agreement, and shall be adjusted annually.

(b) The balance in the trust account will be credited with interest at the customary rate paid on such an account by the financial institution where the account is located. Periodically, but not less than annually, interest accumulated in the trust account shall be disbursed and paid to the OSF or Wexpro, as earned by their relative contributions to the account balance.

(c) When a facility is retired (such as plugging and abandoning a well), the ARO costs will be funded by an appropriate withdrawal from the trust account, and an amount contributed by Wexpro representing the gross up for taxes at the MCTR, regardless of Wexpro's actual tax treatment. If the amounts needed to fund any actual ARO costs are less than or exceed the allocated current trust account balance, Wexpro will determine the allocation of such deficiency or excess amount and will charge or refund the difference to the OSF, with Wexpro to bear or receive its corresponding share, if applicable.

(d) Any salvage value (net of taxes calculated at the MCTR) shall be credited to the OSF when the useable equipment is sold or transferred, with Wexpro to receive its corresponding share, if applicable.

(e) As necessary from time to time to remain in compliance with SFAS 143 and with audited financial reporting requirements (but not more often than annually), Wexpro will review and redetermine:

(i) The engineering estimates of Wexpro's AROs and related salvage values. If there are material changes in the values so determined, Wexpro will implement the necessary changes to the accounting and billing under the Agreement.

(ii) The inflation rates used in determining the accretion expense. If there is a material change in the ARO costs due to changes in expected economic conditions, Wexpro will implement the necessary changes to the accounting and billing under the Agreement.

[3] Because actual ARO expenses are not tax-deductible until paid, the collection of ARO-related expenses in years before the expense is incurred will create a current tax obligation. The tax will be calculated based on the MCTR allowed for under the Wexpro Agreement. Accordingly, all fund increases or decreases will be adjusted for taxes at the then current MCTR, to achieve the intended result of keeping Wexpro neutral on income taxes while passing any future benefit (or determent) of tax rate changes back through the OSF.

(f) An example of the accounting and funding treatment (including income tax gross up) pursuant to this Guideline Letter is attached as Schedule A.

CONCLUSION. Adoption of this Guideline Letter will provide an ongoing methodology that will recognize the costs associated with funding end-of-asset retirement obligations over the life of the properties. Funding based on implementation of SFAS 143 will allow the costs to be spread over the period of time that oil and gas are produced, thus mitigating their one-time impacts. As these funds will be accounted for in a separate, non-commingled interest-bearing account, the principal amounts will have no effect on Wexpro's investment base, and it will not be necessary to adjust Wexpro's investment base in connection with this treatment. It is understood that, under the current requirements imposed on Wexpro by SFAS 143, the treatment of AROs, salvage values and abandonment costs in this Guideline Letter is not contrary to §§ II-7 and III-10 of the Wexpro Agreement.

Please indicate your acceptance of this guideline letter as an appropriate means to respond to the requirements of SFAS 143 as applied to the terms of the Wexpro Agreement.

WEXPRO COMPANY
James R. Livsey
James R. Livsey
Vice President

Approved:
UTAH DIVISION OF PUBLIC UTILITIES

By: Irene Rees Date 2/24/04
Irene Rees, Director

Staff of Wyoming Public Service Commission

By: ______________________ Date: ______________

EVANS CONSULTING COMPANY
(Hydrocarbon Monitor)

By: David E. Evans Date: February 21, 2004
David E. Evans, President

Wexpro Company
Schedule A

ARO example with actual P&A Costs equal to ARO liability, 2.5% inflation, 6.25% accretion and UOP depreciation

January 1, 2003

ARO Asset	31,417	
ARO Liability		31,417
To record ARO fair value		

December 31, 2003 - 2012

ARO Depreciation Exp. Per Example Schedule
ARO Accum. Depr. Per Example Schedule
To record units-of-production depr. on ARO per year (Total $31,417)

Accretion Expense Per Example Schedule
ARO Liab.- Accretion Per Example Schedule
To record accretion expense (Total $26,188)

Year	Beg. Fund Balance	ARO Depr.	Accretion	ARO Depr & Accretion	Tax 35.9%	Net Fund Addition	Interest * 3%	Interest Returned	Net Interest	End Fund Balance	OSF Billed	Cost per Mcfe
2003	-	7,697	1,964	9,661	3,468	6,193	93	(93)	-	6,193	9,568	0.024
2004	6,193	4,618	2,086	6,704	2,407	4,297	250	(250)	-	10,490	6,454	0.027
2005	10,490	3,926	2,217	6,143	2,205	3,938	374	(374)	-	14,428	5,769	0.028
2006	14,428	3,337	2,355	5,692	2,043	3,649	488	(488)	-	18,077	5,204	0.030
2007	18,077	2,836	2,502	5,338	1,916	3,422	594	(594)	-	21,499	4,745	0.032
2008	21,499	2,411	2,659	5,070	1,820	3,250	694	(694)	-	24,749	4,376	0.035
2009	24,749	2,049	2,825	4,874	1,750	3,124	789	(789)	-	27,873	4,085	0.038
2010	27,873	1,742	3,002	4,744	1,703	3,041	882	(882)	-	30,914	3,862	0.042
2011	30,914	1,481	3,189	4,670	1,676	2,994	972	(972)	-	33,907	3,697	0.048
2012	33,907	1,321	3,389	4,710	1,691	3,019	1,062	(1,062)	-	36,926	3,647	0.053
		31,417	26,188	57,605	20,679	36,926	6,198	(6,198)	-		51,407	0.031

* Assumes mid-year additions.

December 31, 2012

ARO Liability	57,605	
P&A Payable		57,605
To record settlement of the ARO liability		

Units of Production Information (Mcfe)

Year	Reserve Balance	Production
2003	1,645,857	403,235
2004	1,242,622	241,941
2005	1,000,681	205,650
2006	795,031	174,802
2007	620,229	148,582
2008	471,647	126,295
2009	345,352	107,350
2010	238,002	91,248
2011	146,754	77,561
2012	69,193	69,193

ARO cost calculation:

	Expected Cash Flows 1/1/2003
Expected clean-up costs	$ 45,000
Inflation factor assuming 2.5 percent rate for 10 years	1.2801
Expected cash flows adjusted for inflation	$ 57,605
Present value using credit-adjusted risk-free rate of 6.25 percent for 10 years	$ 31,417

To settle ARO Fund:

Fund balance		$ 36,926
Net plugging costs		
Gross	$ 57,605	
Tax	(20,679)	36,926
Fund Balance		$ 0

To reconcile cash paid

ARO Depreciation	$ 31,417
ARO Accretion	26,188
Total ARO amounts	$ 57,605
Gross plugging costs	57,605
Refund	$ 0

QUESTAR

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180 East 100 South
P.O. Box 45601
Salt Lake City, UT 84145-0601
Tel 801 324 2600
Fax 801 324 2637

MAY 3 7 35 AM '99

April 27, 1999

Darrell S. Hanson
Utah Division of Public Utilities
Heber M. Wells Building
160 East 300 South
P.O. Box 45802
Salt Lake City, Utah 84145

RE: I-47 Product Allocation Ratio

Dear Mr. Hanson:

The Utah Division of Public Utilities (Division) as well as Wexpro have recently had discussions regarding the intent of Paragraph I-47 in the Wexpro Agreement (Agreement). As a result of these discussions the Division and Wexpro have agreed to the following methodology effective January 1, 1999 forward. The parties further agree that the methodology used prior to January 1, 1999 will not be subject to change. It is proposed that effective January 1, 1999 Wexpro will calculate a new equivalent ratio to be used for that year. This ratio will be determined by dividing the actual weighted average price per barrel received for oil, condensate and natural gas liquids for the twelve financial months ending December 31st of the previous year by the weighted average wellhead royalty valuation per Mcf of gas produced by Wexpro in the twelve financial months ended December 31st of the previous year. This ratio will then be recalculated each subsequent year in the same manner (see Attachment "A" for the 1999 Product Allocation calculation based on 12-31-98 data). The calculation will be subject to verification by the Accounting Monitor as part of its annual review of Wexpro's compliance with the terms of the Agreement.

Please indicate your approval of the proposed guidelines in the signature area.

Very respectfully yours,

G.L. Nordloh
President and CEO

Approved:
Utah Division of Public Utilities

By: ______________________ Date: 5-14-99

1999 Product Allocation Ratio
Based on 12-31-98 Results

1/ Weighted average oil, condensate and natural gas liquid price received by Wexpro for twelve months ended 12-31-98	$12.64
2/ Weighted average price used for royalty wellhead gas valuation per Mcf for twelve months ended 12-31-98	$2.06

$12.64 / $2.06 = 6.14

Round to 6.1 to 1 Equivalent Ratio

1/ From year end Wexpro financial statements page containing operating statistics for the total average liquid price. (See page 2 of Attachment A)

2/ Represents Wexpro/Questar Gas net working interest volumes and royalty value reflected in the 410.210, 410.220 and 410.230 general ledger accounts plus any clearing well eliminations associated with the above accounts for the 12 months ended 12-31-98. (See Note below)

$$\frac{\text{Net working interest volume per month x royalty price per month}}{\text{Net working interest volume}} = \frac{\$76,176,759}{36,986,602} = \$2.06$$

Note:

	Value	Volume (MCF)
Net Working Interest (Accounts 410.210 - 410.230) (See pages 3 - 4 of Attachment A)	$100,250	29,742
Clearing Well Eliminations (See pages 5 - 6 of Attachment A)	$76,076,509	36,956,860
	$76,176,759	36,986,602

WEXPRO COMPANY
OPERATING STATISTICS
December 1998 vs December 1997

Current Month 1998	Current Month 1997	Current Month Increase (Decrease)	Current Month Percent	OPERATING STATISTICS	Year to Date 1998	Year to Date 1997	Year to Date Increase (Decrease)	Year to Date Percent
				OIL				
$384,056	$714,571	($330,515)	-46%	Revenue	$6,207,325	$9,403,187	($3,195,862)	-34%
40,441	30,259	10,182	34%	Production	459,305	443,659	15,646	4%
$9.50	$23.62	($14.12)	-60%	Price	$13.51	$21.19	($7.68)	-36%
				NGL				
$138,740	($48,305)	$187,045	387%	Revenue	$803,188	$2,068,808	($1,265,620)	-61%
16,415	(1,611)	18,026	1119%	Production	95,282	116,874	(21,592)	-18%
$8.45	$29.98	($21.53)	-72%	Price	$8.43	$17.70	($9.27)	-52%
				TOTAL LIQUIDS				
$522,796	$666,266	($143,470)	-22%	Revenue	$7,010,513	$11,471,995	($4,461,482)	-39%
56,856	28,648	28,208	98%	Production	554,587	560,533	(5,946)	-1%
$9.20	$23.26	($14.06)	-60%	Price	$12.64	$20.47	($7.83)	-38%

NET WORKING INTEREST YEAR END BALANCE WORKSHEET

RIOD	POSTED DATE	TX TYP	JRL SRC	VOUCHER	PROPERTY	COST CENTER	DESCRIPTION	DEBIT	CREDIT	BALANCE
.410.210	GS GAS SALES WI						TRANSACTION HISTORY FILE			
/98	01/04/99	AA	RV	12-RV-19	242109	242109	BRADY UNIT - SEPT 1998 - GA	13,122.89		
/98	01/04/99	AA	RV	12-RV-19	242409	242409	BRADY UNIT - SEPT 1998 - GA	3,486.79		
/98	01/04/99	AA	RV	12-RV-19	415933	415933	BRADY UNIT - SEPT 1998 - GA	73,083.35		
/98	01/04/99	AA	RV	12-RV-19	437433	437433	BRADY UNIT - SEPT 1998 - GA	67,399.33		
/98	01/04/99	AA	RV	12-RV-19	710001	710001	BRADY UNIT - SEPT 1998 - GA		463,138.38-	
/98	01/04/99	AA	RV	12-RV-20	239602	239602	BRADY UNIT - NOV 98 GAS EST		10,288.75-	
/98	01/04/99	AA	RV	12-RV-20	239902	239902	BRADY UNIT - NOV 98 GAS EST		16,656.95-	
/98	01/04/99	AA	RV	12-RV-20	240033	240033	BRADY UNIT - NOV 98 GAS EST		100,637.84-	
/98	01/04/99	AA	RV	12-RV-20	240312	240312	BRADY UNIT - NOV 98 GAS EST		162,819.00-	
/98	01/04/99	AA	RV	12-RV-20	240333	240333	BRADY UNIT - NOV 98 GAS EST		14,209.30-	
/98	01/04/99	AA	RV	12-RV-20	240509	240509	BRADY UNIT - NOV 98 GAS EST		5,703.77-	
/98	01/04/99	AA	RV	12-RV-20	240702	240702	BRADY UNIT - NOV 98 GAS EST		1,473.54-	
./98	01/04/99	AA	RV	12-RV-20	240802	240802	BRADY UNIT - NOV 98 GAS EST		9,261.33-	
./98	01/04/99	AA	RV	12-RV-20	241309	241309	BRADY UNIT - NOV 98 GAS EST		3,996.07-	
:/98	01/04/99	AA	RV	12-RV-20	241409	241409	BRADY UNIT - NOV 98 GAS EST		118,701.70-	
:/98	01/04/99	AA	RV	12-RV-20	241702	241702	BRADY UNIT - NOV 98 GAS EST		9,995.57-	
:/98	01/04/99	AA	RV	12-RV-20	242009	242009	BRADY UNIT - NOV 98 GAS EST		7,732.59-	
:/98	01/04/99	AA	RV	12-RV-20	242109	242109	BRADY UNIT - NOV 98 GAS EST		21,223.52-	
:/98	01/04/99	AA	RV	12-RV-20	242409	242409	BRADY UNIT - NOV 98 GAS EST		5,159.29-	
:/98	01/04/99	AA	RV	12-RV-20	415933	415933	BRADY UNIT - NOV 98 GAS EST		145,639.78-	
:/98	01/04/99	AA	RV	12-RV-20	437433	437433	BRADY UNIT - NOV 98 GAS EST		68,378.02-	
:/98	01/04/99	AA	RV	12-RV-20	710001	710001	BRADY UNIT - NOV 98 GAS EST	701,877.02		
:/98	02/17/99	AA	GJ	P&L			P & L CLOSING ENTRY	100,250.24		
							ACTIVITY TOTAL	8,738,871.03	8,648,969.28-	89,901.75
							12/31/98 ACCOUNT BALANCE			0.00

expro Net Working Interest Royalty Value "Dollars" in
eneral ledger accounts 410.210, 410.220 and 410.230

expro Net Working Interest "Volumes" in general
edger accounts 410.210, 410.220 and 410.230 → 29,742

*** SUMMARY *** THROUGH 12/31/93

NET WORKING INTEREST YEAR END BALANCE WORKSHEET

...PTION	JUL	AUG	SEP	OCT	NOV	DEC	YTD	CUM-TO-DATE
S... ------								
ALES	514-	1,419	15,713-	11,086	75,342	10,348	$\boxed{100,250}$	52,609,092
ALES	503,346	429,847	583,255	465,298	527,994	384,056	6,207,325	28,111,061
CTION PLANT SALES	48,818	59,073	59,013	121,322	47,403	138,740	803,188	5,110,794
. REVENUE	484	480	23,008	597	1,011	1,324	29,712	37,054
, SALES	552,133	490,819	649,563	598,303	651,749	534,468	7,140,475	85,868,001
-VOLUMES-----								
- MCF	2,850	47,802	537-	1,609	22,640	2,331	$\boxed{29,742}$	20,978,260
- BBL	44,645	34,789	41,176	31,321	43,743	39,702	459,358	1,479,386
JCTION PLANT SALES	8,154	8,579	7,143	20,789	6,711	16,415	95,280	407,382
R REVENUE								
-PRICING-----								
AGE PRICE PER MCF	0.18-	0.03	29.23	6.89	3.33	4.44	3.37	2.51
AGE PRICE PER BBL	11.27	12.36	14.17	14.86	12.07	9.67	13.51	19.00
AGE PRICE PLANT PRODUCTS	5.99	6.89	8.26	5.84	7.06	8.45	8.43	12.55
AGE FOR OTHER PRODUCTS								

Wexpro Net Working Interest Royalty Value "Dollars" in general ledger accounts 410.210, 410.220 and 410.230

Wexpro Net Working Interest "Volumes" in general ledger accounts 410.210, 410.220 and 410.230

CLEARING WELL ELIMINATIONS WORKSHEET

Month	Net Vol	Net Dol
1: 710001 DUMMY REVENUE ONLY!!! WY		
Account: 410.210 GS GAS SALES WI		
	2488284.83-	8163039.64
	2521386.86-	5187410.44
03/98	2405823.71-	5344207.51
04/98	2205770.69-	3928570.71
05/98	2130822.54-	4364719.13
06/98	2599087.04-	5238293.86
07/98	2153416.70-	4582342.47
08/98	2084250.58-	3610704.89
09/98	2102628.27-	3745686.36
10/98	2466094.26-	4400133.28
11/98	2616053.00-	4278927.88
12/98	2532409.10-	4647450.25
Total	8306027.58-	57491486.42
GL Account: 410.220 GS GAS SALES RI		
01/98	0.00	17279.53
02/98	0.00	9859.57
03/98	0.00	10018.79
04/98	0.00	7217.53
06/98	0.00	14960.93
Total	0.00	59336.35
GL Account: 410.230 GS GAS SALES OR		
01/98	0.00	45062.81
02/98	0.00	30393.63
03/98	0.00	30046.48
04/98	0.00	22674.02
06/98	0.00	46122.75
07/98	0.00	5878.62
9	0.00	36504.01
1	0.00	10891.37
1_/98	0.00	16912.92
12/98	0.00	23969.99
Total	0.00	268456.60
Total	28306027.58-	57819279.37

Operator: 75 WEXPRO COMPANY

Total "Volumes" and Royalty Value "Dollars" for general ledger accounts 410.210, 410.220 and 410.230 for Wyoming

Month	Net Vol	Net Dol
11: 710101 DUMMY REVENUE ONLY!!!! CO		
GL Account: 410.210 GS GAS SALES WI		
01/98	871193.31-	2751642.38
02/98	875248.52-	1832871.35
03/98	946365.45-	1997477.45
04/98	1060071.38-	1905469.27
05/98	932556.76-	1874335.22
06/98	810036.13-	1544041.39
07/98	204967.92-	349821.01
08/98	266250.77-	457215.96
09/98	22524.25-	24122.80
10/98	120106.26	156364.69-
11/98	38666.85-	21106.76
12/98	403824.18-	707045.31
Total	6311599.26-	13308784.21
GL Account: 410.220 GS GAS SALES RI		
GL Account: 410.230 GS GAS SALES OR		
Total	6311599.26-	13308784.21

Operator: 75 WEXPRO COMPANY

Total "Volumes" and Royalty Value "Dollars" for general ledger accounts 410.210, 410.220 and 410.230 for Colorado

11: 710201 DUMMY REVENUE ONLY !!!! UT   Operator: 75 WEXPRO COMPANY
GL Account: 410.210 GS GAS SALES WI

CLEARING WELLS ELIMINATIONS WORKSHEET (cont'd)

Month	Net Vol	Net Dol
01/98	382055.05-	1177899.17
'98	273106.57-	541062.62
3	267676.58-	567300.26
.98	232750.77-	399143.86
05/98	308485.06-	593832.17
06/98	410887.06-	803302.36
07/98	200639.81-	408276.54
08/98	124632.00-	229953.73
09/98	121177.53-	198626.97
10/98	2715.75-	4620.23
11/98	3082.75-	4796.08
12/98	12024.64-	19631.58
Total	2339233.57-	4948445.57

GL Account: 410.220 GS GAS SALES RI

GL Account: 410.230 GS GAS SALES OR

Total	2339233.57-	4948445.57
tal	36956860.41-	76076509.15

Total "Volumes" and Royalty Value "Dollars" for general ledger accounts 410.210, 410.220 and 410.230 for Utah

Sum of Wexpro/Questar Gas Net Working Interest Royalty Value "Dollars" in general ledger accounts 410.210, 410.220 and 410.230 for Wyoming, Colorado and Utah

Sum of Wexpro/Questar Gas Net Working Interest "Volumes" in general ledger accounts 410.210, 410.220 and 410.230 for Wyoming, Colorado and Utah

May 29, 1992

Mr. Darrell S. Hanson
Manager, Gas & Water
Division of Public Utilities
Heber Wells Building
160 East 300 South
Salt Lake City, UT 84111

Re: Refund of Excess Deferred Taxes

Whole-Well Approach for Determining Commerciality in the Church Buttes Unit

Replacement Index Method for Determining Base Rate of Return

Dear Mr. Hanson:

This guideline letter confirms the agreement between the Utah Division of Public Utilities (Division) and Wexpro Company (Wexpro) regarding the above referenced items. These guidelines are part of a combined settlement of these issues agreed to in principle on February 5, 1992. The items agreed to are as follows:

Refund of Excess Deferred Taxes

The 1986 Federal Income Tax Reform Act resulted in a reduction in corporate tax rates from 46% to 34%. As a result, deferred tax balances which Wexpro had been carrying for future tax obligations were overstated. This resulted in a potential refund to Mountain Fuel Supply Company (Mountain Fuel). Wexpro agrees to refund to Mountain Fuel that portion which relates to cost-of-service gas (development gas, prior company, and casinghead gas from development oil investment) on a straight-line basis over 15 years (180 months) effective January 1, 1987.

That portion which results from the "54-46 formula" (prior Wexpro, development oil, enhanced recovery, and "new oil" from development gas investment) will be refunded immediately (retroactive to January 1, 1987) 54% to Mountain Fuel and 46% to Wexpro.

Wexpro will recognize an increase to investment base commensurate with effecting the refund for both the cost-of-service gas and the 54-46 formula. As a result, Wexpro will also earn a return on the increased investment base. The refund to Mountain Fuel relating to the 54-46 formula will be reduced by that portion of excess deferred taxes created in months when (but only to the extent of) negative sharing occurred (i.e., 54-46 formula revenues were not sufficient to effect a payout to the sharing parties when the excess accrued). This reduced portion of Mountain Fuel's refund shall be distributed to Wexpro. Other than provided above, there shall be no recalculation of Wexpro's return or the sharing amounts.

Future changes in corporate tax rates (up or down) will be handled in a like manner. Deferred tax balance adjustments required for cost-of-service gas will be effected over a 15-year period from the effective date of the change in tax rates. Mountain Fuel shall receive any refund and bear the expense of over/under accrual for cost-of-service gas. Deferred tax balance adjustments required for the 54-46 formula will be handled via immediate recognition. Future adjustments to the deferred tax balances for the 54-46 formula will account for negative sharing positions as previously mentioned (i.e., to the extent of negative sharing during a prior month of over/under accrual, Wexpro shall, to the extent of the negative amount, receive the refund or bear the expense of the adjustment, as the case may be). For prior months of positive sharing in which there was an over/under accrual, Mountain Fuel shall receive the refund or bear the expense of 54% of the adjustment.

Upon a change in tax rates, the deferred tax balances for the two categories listed above will be compared to what they should be as a result of the new tax rates and any under/over accrual will be recovered/refunded as indicated above. Other than determining the amount of negative sharing for prior months of over/under accruals, the related recovery/refund will be outside the calculation and not dependent upon past or current 54-46 sharing revenues or operations. For example, if there has been an under accrual in a prior positive sharing month due to a tax rate change, Mountain Fuel will bear 54% of the adjustment regardless of whether the current month is in negative sharing. Moreover, there will be no recalculation of the prior month's return to Wexpro or sharing for the parties. If the prior month is a negative sharing month, Wexpro will bear the burden and benefit of the adjustment, but only to the extent of the negative sharing and thereafter 46%.

Mountain Fuel and Wexpro Company waive adjustments to the return calculation for the pre tax-rate change period only as it applies to this deferred tax issue.

Wexpro is currently studying the correctness of reducing Wexpro's investment base for calculating the 54-46 formula as set forth in Exhibit B of the Wexpro Agreement. This guideline letter shall not be construed as precluding or prejudicing any rights or claims which Wexpro may have, if any, from asserting that deferred taxes should not reduce Wexpro's investment base for the 54-46 formula calculation.

Wexpro also agrees to reverse out the effects of any 1990 year-end adjustments pertaining to the deferred tax issue.

Whole Well Approach for Determining Commerciality in the Church Buttes Unit

The Frontier and Dakota Formations are present throughout the Church Buttes Unit as well as other locations in the Moxa Arch area of southwestern Wyoming. The Church Buttes Unit, for purposes of this guideline, shall include the Church Buttes Unit and any lands outside the unit which are communitized with unit lands. Both of these formations are identified as "productive gas reservoirs" in Schedule 3(a) of the Wexpro Agreement for the Church Buttes Unit. Prudent operators in this area generally consider the Frontier and Dakota Formations as a single objective when drilling a well.

An operator will typically drill to the Dakota Formation, but may perforate and produce from either the Dakota or the Frontier Formation or sometimes both. The incremental drilling costs incurred to drill below the Frontier and obtain the additional reserves in the Dakota Formation are modest as compared to drilling a separate well to the Dakota, and the benefit to Mountain Fuel has been substantial. Through the 3rd quarter of 1991, the estimated finding costs related to new Dakota reserves is estimated to be less than $0.25 per Mcf of gas. The probability for commercial production from the Dakota Formation for any given well is low. Consequently, Wexpro lacks the necessary "economic incentive" to routinely drill to the Dakota if the commerciality test of the Wexpro Agreement were applied separately to the Frontier and Dakota Formations rather than to the development well as a whole.

Wexpro and the Division agree that the whole well approach for Church Buttes has been beneficial for both Mountain Fuel as well as Wexpro and is consistent with industry practice. Therefore, in the Church Buttes Unit and all communitized border lands, if production from the Dakota or Frontier Formations or combination of these formations is sufficient to meet commerciality for the entire well investment, as defined by I-20 of the Wexpro Agreement, then Wexpro will be entitled to earn on its entire investment in that well. If the well is not commercial, it will be treated as a dry hole and Wexpro will bear all the risk and costs of the well unless Mountain Fuel elects to take the well under the provisions of I-20(d).

Wexpro agrees to perform an annual update of cumulative estimated incremental Dakota finding costs according to the methodology indicated in attachment #1. If the estimated cumulative incremental Dakota finding costs reach $.75 Mcf then Wexpro and the Division will agree to review future incremental Dakota drilling in the Church Buttes Unit. Wexpro's estimated cumulative finding cost will include all activity commencing from January 1, 1989, and will thereafter revert to a five-year rolling average for years effective after 1993.

This guideline is based upon the assumption that there will be no future drilling of Church Buttes Unit wells to the Morgan Formation, which is also recognized as a "productive gas reservoir" in Schedule 3(a) of the Wexpro Agreement for the Church Buttes Unit. Therefore, the "whole well approach" in this guideline would not be applicable to a future Church Buttes Unit well if the well were drilled to the Morgan Formation.

Furthermore, both Wexpro and the Division specifically agree that this guideline will not be considered either a limitation or precedent to investments and/or commerciality determinations for wells outside the Church Buttes Unit.

<u>Replacement Index Methodology for Determining Base Rate of Return</u>

As background, Schedule 1 (Base Rate of Return Index Companies) of the Wexpro Agreement lists 20 regulated companies. The percentage return on equity ("ROE") from these companies is used to calculate the base rate of return index. In recent years, a reduced number of these original index companies still have stated ROE's. Those without stated ROE's have received composite dollar settlements or the applicable PSC/FERC Rate Order states an overall cost of capital. Wexpro is desirous to restore the 20-point index as originally intended in the agreement. Accordingly, a "replacement index methodology" has been designed to allow for a 20-point index. If an original Schedule 1 company is not available for use in the calculation, for any reason including lack of a stated ROE, then a replacement index, by category, will be used in lieu of the company. This replacement index will be used to the extent required to bring the total number of companies up to twenty (i.e., if three gas distribution companies are unable to be used, the replacement index for gas distribution companies will be used three times). The gas distribution and gas transmission index shall be combined into a single index to be used for both categories.

The replacement indices shall be derived by using all utilities in 17 western states (original eight Schedule 1 states plus a one-state stepout of contiguous states) which had stated returns on common equity as of May 31, 1981, as well as May 31, 1990. On May 31, 1990, this consisted of 78 utilities in the three basic categories (gas, electric, and telephone). No Questar affiliated companies or original Schedule 1 companies are used in the replacement indices.

The sources used to compile the replacement index were threefold:

- NARUC Annual Report on Utility and Carrier Regulation.
- Public Utilities Fortnightly.
- Texas Eastern Transmission Corporation Capitalization - Rate of Return Study.

Future changes to the replacement index will be based exclusively upon these sources. If these sources no longer are available, Wexpro and the Division will select alternative sources as required. For local gas, electric, and telephone utilities, precedence will be given to the NARUC report first and Public Utilities Fortnightly second. For FERC pipelines, precedence will be given to the Texas Eastern Transmission Corporation Capitalization Rate of Return Study first and the NARUC report second. For purposes of this agreement, the parties agree that the appropriate return to use for U. S. West Colorado for the 1991-1992 period will be 13.00%, which represents a halfway point between 12.5% and 13.5% incentive rate structure. This incentive rate methodology will not necessarily be used for all situations in the future.

An additional 29 utilities had stated returns on equity as of May 31, 1981, but not as of May 31, 1990. If any of these 29 companies receive stated returns on common equity in the future, they will be added on a prospective basis to the respective index categories. Likewise, if the companies making up the index lose a stated return then they will be deleted from the index calculation until they once again receive a stated return on common equity. These 107 companies are the finite population from which future replacement index calculations will be derived. It is not contemplated that additional companies will be added later. These companies were compiled without regard to any factor other than they had a stated return on equity as of May 31, 1981. Updates were made to the indices as needed to calculate the 1991-1992 index.

Adoption of this new methodology is expressly conditioned upon the understanding that if either Wexpro or the Division of Public Utilities is no longer satisfied with this method of index calculation then the proposed index calculation method will end and the parties will negotiate an alternative solution for future periods. Wexpro and the Division agree that based upon the above procedures, the base rate of return for 1990-1991 shall be 14.92% and for 1991-1992 14.70% (see schedules attached). These return numbers shall be considered fully agreed to by both parties for the applicable years and not subject to subsequent revision for any reason.

Wexpro and the Division also reaffirm that the base rate of return for the periods 1989-1990 was 15.23%.

Interest

The parties agree that in resolution of the above matters a nine percent, compounded annually, time value of money reimbursement will be applied to all cash flows related to these items. This time value of money reimbursement will not be considered a precedent for other Wexpro Agreement related matters.

Please indicate your approval of the items discussed above in the signature boxes below.

Very truly yours,

James R. Livsey
Coordinator, Wexpro Agreement

JRL/smw

APPROVED:
WEXPRO COMPANY

By: ______________________ 5/29/92
G. L. Nordloh (Date)
President and CEO

APPROVED:
UTAH DIVISION OF PUBLIC UTILITIES

By: Frank Johnson   June 1, 1992
(Date)

APPROVED:
[redacted] WYOMING PUBLIC SERVICE COMMISSION

By: Bil Tucker   June 15, 1992
(Date)

PROVED:
CE WATERHOUSE

By: David W. Campbell   June 2, 1992
(Date)

APPROVED:
ROBERT L. MAGNIE AND ASSOCIATES, INC.

By: Robert L. Magnie   June 9, 1992
(Date)

ATTACHMENT 1

METHODOLOGY FOR ESTIMATING

INCREMENTAL DAKOTA FINDING COST

AT WORKING INTEREST

CUMULATIVE FOR ALL COSTS

FROM JANUARY 1, 1989 FORWARD

Well #1	Estimated Incremental Drilling Cost No Test/No Completion	$ 15,500
Well #2	Estimated Incremental Drilling Cost Test and Complete	63,500
Well #3	Estimated Incremental Drilling Cost Test/No Completion	63,500
	Total Costs	$142,500
	Booked Reserves (Mcf) (Includes New Reserves and Revisions)	850,000
	Estimated Incremental Finding Costs	$.16 Mcf

Estimated Incremental Drilling Cost Includes	Estimated Incremental Testing/Completion Includes	
Drilling Rig Charges	Casing	Wireline
Cement	Tubing	Perforation
Mud	Stimulation	Rig
Water	Packers	Rental Equipment
Rental Equipment	Nitrogen	Pressure Buildup
Supervision	Completion Fluids	Zone Abandonment
	Supervision	

These items represent only expenses incurred to drill, test, and complete below the Frontier Formation.

We: o Agreement

8–1–90 through 7–31–91 Base rate of return calculation using replacement index companies

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	May 31 1990	Last Known Order Date May 31 1981	May 31 1990	Change in Return 81 to 90
Arizona Public Service Co.	Electric Services	Arizona Corporation Commission	15.00%	12.50%	05/24/80	04/01/88	–2.50%
Idaho Power Company	Electric Services	Idaho Public Service Commission	14.50%	12.25%	03/26/80	12/12/86	–2.25%
Montana Power Company	Electric Services	Montana Public Service Commission	13.45%	12.50%	02/09/81	08/14/89	–0.95%
Nevada Power Company	Electric Services	Nevada Public Service Commission	15.00%	14.75%	08/10/80	09/29/87	–0.25%
Public Service Co. of New Mexico	Electric Services	New Mexico Public Service Commission	15.50%	12.52%	05/29/81	04/12/90	–2.98%
Replacement–Electric	Electric Services	Replacement	14.35%	13.13%	N/A	N/A	–1.22%
Utah Power & Light Co. (Utah)	Electric Services	Utah Public Service Commission	16.80%	12.10%	04/21/81	02/09/90	–4.70%
Intermountain Gas Company	Gas Distribution	Idaho Public Service Commission	14.50%	14.85%	10/31/80	12/05/85	0.35%
Montana–Dakota Utilities Co.	Gas Distribution	Montana Public Service Commission	13.50%	12.50%	04/27/81	12/08/89	–1.00%
Gas Company of New Mexico	Gas Distribution	New Mexico Public Service Commission	15.50%	12.74%	Agreement	08/08/88	–2.76%
Public Service Co. of Colorado	Gas Distribution	Colorado Public Service Commission	15.45%	14.40%	12/10/80	05/22/84	–1.05%
Replacement–Gas	Gas Distribution	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Replacement–Gas	Gas Distribution	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Replacement–Gas	Gas Distribution	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Northwest Pipeline Corp.	Gas Transmission	Federal Energy Regulatory Commission	13.75%	13.00%	05/15/80	10/19/89	–0.75%
Replacement–Gas Transmission	Gas Transmission	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Replacement–Gas Transmission	Gas Transmission	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Replacement–Gas Transmission	Gas Transmission	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
US West (Colorado)	Telecommunications	Colorado Public Service Commission	11.90%	13.70%	09/16/80	05/23/86	1.80%
US West (Utah)	Telecommunications	Utah Public Service Commission	14.50%	11.80%	Agreement	10/18/89	–2.70%
Wexpro Agreement Rate of Return	14.92%	Avg	14.23%	13.15%			–1.08%

Original Wexpro Agreement Companies Without a Current Authorized Return on Equity

Company Name	Activity	Regulatory Agency	Authorized Return
Colorado Interstate Corp.	Gas Transmission	Federal Energy Regulatory Commission	13.25%
Transwestern Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.00%
Kansas Nebraska Natural Gas Co.	Gas Transmission	Federal Energy Regulatory Commission	13.00%
Southwest Gas Corp.	Gas Distribution	Arizona Corporation Commission	15.00%
Southwest Gas Corp.	Gas Distribution	Nevada Public Service Commission	15.20%
Northern Utilities Inc.	Gas Distribution	Wyoming Public Service Commission	13.50%
Pacific Power & Light	Electric Services	Wyoming Public Service Commission	14.64%

Wexpro Agreement—Replacement Index for 8-1-90 through 7-31-91 Period
Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1990	Last Known Order Date May 31 1981	Last Known Order Date May 31 1990	Change in Return '81 to 90
Central Power & Light	Electric Services	Texas Public Utility Commission	15.50%	14.90%	01/23/80	03/07/86	−0.60%
Citizens Utilities Co. (Idaho)	Electric Services	Idaho Public Service Commission	14.11%	12.42%	03/09/80	01/09/89	−1.69%
Dalles Power & Light Co.	Electric Services	Texas Public Utility Commission	16.00%	15.80%	02/26/81	01/16/84	−0.20%
El Paso Electric	Electric Services	Texas Public Utility Commission	14.23%	12.40%	11/09/78	05/05/89	−1.83%
El Paso Electric (New Mexico)	Electric Services	New Mexico Public Service Commission	14.75%	12.60%	06/08/79	05/01/90	−2.15%
Gulf States Utilities	Electric Services	Texas Public Utility Commission	16.10%	13.00%	10/16/80	05/16/88	−3.10%
Houston Lighting & Power	Electric Services	Texas Public Utility Commission	15.80%	14.44%	09/15/80	11/14/86	−1.36%
Iowa Public Service Company	Electric Services	South Dakota Public Util. Commission	11.50%	13.25%	04/07/78	03/01/84	1.75%
Kansas City Power & Light	Electric Services	Kansas State Corporation Commission	14.00%	12.00%	03/13/79	07/07/87	−2.00%
Kansas Gas & Electric	Electric Services	Kansas State Corporation Commission	13.93%	12.03%	09/24/79	02/13/90	−1.90%
Kansas Power & Light Co.	Electric Services	Kansas State Corporation Commission	13.71%	12.98%	08/23/79	07/31/87	−0.73%
Montana Dakota Utilities	Electric Services	North Dakota Public Service Commission	11.94%	12.71%	04/26/77	01/27/87	0.77%
Northern States Power	Electric Services	North Dakota Public Service Commission	13.39%	11.24%	12/31/80	03/24/88	−2.15%
Northern States Power Co.	Electric Services	South Dakota Public Util. Commission	13.00%	12.00%	11/19/80	01/01/89	−1.00%
Northwestern Public Service	Electric Services	South Dakota Public Utilities Commission	13.10%	13.00%	01/23/81	11/15/86	−0.10%
Oklahoma Gas & Electric Company	Electric Services	Oklahoma Corporation Commission	14.00%	13.50%	12/31/79	06/24/87	−0.50%
Otter Tail Power Company	Electric Services	North Dakota Public Service Commission	11.80%	14.50%	04/22/77	04/19/83	2.70%
Pacific Gas & Electric	Electric Services	California Public Utilities Commission	13.90%	12.90%	12/19/79	12/20/89	−1.00%
Pacific Power & Light	Electric Services	Oregon Public Utility Commisssion	16.25%	12.73%	05/07/81	02/01/88	−3.52%
Pacific Power & Light	Electric Services	Washington Util. & Transp. Commission	13.75%	13.25%	11/05/80	09/19/86	−0.50%
Pacific Power & Light (Montana)	Electric Services	Montana Public Service Commission	13.75%	12.30%	05/27/81	07/09/86	−1.45%
Portland General Electric Co.	Electric Services	Oregon Public Utility Commisssion	16.25%	12.73%	05/07/81	10/14/87	−3.52%
Public Service Co. of Colorado	Electric Services	Colorado Public Service Commission	15.45%	14.40%	12/10/80	05/22/84	−1.05%
Public Service Company of Oklahoma	Electric Services	Oklahoma Corporation Commission	15.00%	13.50%	05/07/80	09/28/87	−1.50%
Puget Sound Power & Light	Electric Services	Washington Util. & Transp. Commission	15.25%	12.80%	01/09/81	03/30/90	−2.45%
San Diego Gas & Electric	Electric Services	California Public Utilities Commission	14.50%	12.90%	12/30/80	11/22/89	−1.60%
Southern California Edison	Electric Services	California Public Utilities Commission	14.95%	13.00%	12/30/80	12/19/88	−1.95%
Southwestern Electric Services Co.	Electric Services	Texas Public Utility Commission	15.00%	12.50%	01/21/80	03/07/90	−2.50%
Southwestern Public Service	Electric Services	New Mexico Public Service Commission	16.33%	14.50%	08/18/80	12/21/87	−1.83%
Texas Electric Service Company	Electric Services	Texas Public Utility Commission	15.50%	15.56%	10/03/80	12/15/83	0.06%
Utah Power & Light Co. (Wyoming)	Electric Services	Wyoming Public Service Commission	12.90%	12.85%	10/27/78	10/12/89	−0.05%
Washington Water Power Company	Electric Services	Washington Util. & Transp. Commission	12.75%	12.90%	03/24/78	02/24/87	0.15%
Washington Water Power Co. (Idaho)	Electric Services	Idaho Public Service Commission	14.00%	12.90%	06/04/80	12/03/86	−1.10%
West Texas Utilities Company	Electric Services	Texas Public Utility Commission	15.35%	12.00%	12/09/80	11/30/87	−3.35%
		Avg	14.35%	13.13%			

Wexpro Agreement–Replacement Index for 8–1–90 through 7–31–91 Period
Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1990	Last Known Order Date May 31 1981	Last Known Order Date May 31 1990	Change in Return 81 to 90
Cascade Natural Gas Corp.	Gas Distribution	Oregon Public Utility Commisssion	14.85%	12.25%	11/19/80	02/12/90	−2.60%
Cascade Natural Gas Corp.	Gas Distribution	Washington Util. & Transp. Commission	14.25%	13.25%	04/28/81	11/29/89	−1.00%
Citizens Utilities Co. (Colorado)	Gas Distribution	Colorado Public Service Commission	11.91%	13.20%	05/05/80	06/30/87	1.29%
Greely Gas Co.	Gas Distribution	Colorado Public Service Commission	14.10%	15.00%	01/08/81	05/09/85	0.90%
Iowa Public Service Company	Gas Distribution	South Dakota Public Util. Commission	12.50%	13.00%	04/06/79	06/01/86	0.50%
Kansas Gas Suppply	Gas Distribution	Kansas State Corporation Commission	11.28%	14.50%	06/20/80	06/06/84	3.22%
Kansas Power & Light Co.	Gas Distribution	Kansas State Corporation Commission	14.19%	12.40%	06/20/80	09/26/88	−1.79%
Lonestar Gas Co.	Gas Distribution	Texas Railroad Commission	13.70%	13.20%	02/11/80	10/20/89	−0.50%
Minnegasco	Gas Distribution	South Dakota Public Utilities Commission	13.50%	12.50%	11/26/80	11/07/89	−1.00%
Montana Dakota Utilities	Gas Distribution	North Dakota Public Service Commission	12.58%	12.71%	05/23/79	01/21/87	0.13%
Montana Dakota Utilities	Gas Distribution	South Dakota Public Util. Commission	13.10%	14.25%	11/14/80	11/08/83	1.15%
Montana Power Company	Gas Distribution	Montana Public Service Commission	13.45%	12.50%	02/09/81	08/14/89	−0.95%
Montana–Dakota Utilities Co.	Gas Distribution	Wyoming Public Service Commission	13.64%	14.28%	04/28/81	04/17/84	0.64%
Northern States Power Company	Gas Distribution	North Dakota Public Service Commission	11.43%	14.00%	04/18/78	10/01/84	2.57%
Northwest Natural Gas	Gas Distribution	Washington Util. & Transp. Commission	13.50%	13.25%	11/10/77	09/15/86	−0.25%
Northwest Natural Gas	Gas Distribution	Oregon Public Utility Commisssion	15.30%	13.25%	04/01/81	11/01/89	−2.05%
Northwestern Public Service	Gas Distribution	South Dakota Public Utilities Commission	13.10%	13.00%	01/23/81	10/06/86	−0.10%
Oklahoma Natural Gas Co.	Gas Distribution	Oklahoma Corporation Commission	14.50%	13.50%	02/11/81	06/30/87	−1.00%
Peoples Natural Gas Company	Gas Distribution	Kansas State Corporation Commission	14.50%	14.65%	04/28/80	04/17/86	0.15%
Rocky Mountain Natural Gas Co.	Gas Distribution	Colorado Public Service Commission	14.40%	14.40%	02/24/81	09/18/85	0.00%
San Deigo Gas & Electric	Gas Distribution	California Public Utilities Commission	14.50%	12.90%	06/05/79	11/22/89	−1.60%
Southern California Gas Co.	Gas Distribution	California Public Utilities Commission	14.60%	13.00%	12/05/80	01/09/90	−1.60%
Southern Union Gas	Gas Distribution	Texas Railroad Commission	14.50%	15.50%	10/11/79	05/24/84	1.00%
Southern Union Gas Co.	Gas Distribution	Oklahoma Corporation Commission	14.50%	12.00%	04/27/81	11/23/88	−2.50%
Union Gas System	Gas Distribution	Kansas State Corporation Commission	13.50%	13.62%	11/21/79	09/15/89	0.12%
Washington Natural Gas Corp.	Gas Distribution	Washington Util. & Transp. Commission	13.50%	16.25%	11/19/80	12/28/84	2.75%
Washington Water Power	Gas Distribution	Idaho Public Service Commission	13.25%	12.75%	10/01/79	11/08/89	−0.50%
ANR Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.88%	12.75%	07/17/80	11/12/87	−0.13%
Mississippi River Transmission	Gas Transmission	Federal Energy Regulatory Commission	13.25%	10.49%	04/09/81	04/08/89	−2.76%
Northern Natural Gas	Gas Transmission	Federal Energy Regulatory Commission	12.50%	13.23%	02/20/81	12/29/89	0.73%
Panhandle Eastern	Gas Transmission	Federal Energy Regulatory Commission	13.25%	13.00%	01/27/81	01/08/87	−0.25%
Texas Eastern Gas Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.50%	13.00%	04/04/80	08/29/89	0.50%
Trunkline Gas Co.	Gas Transmission	Federal Energy Regulatory Commission	12.25%	13.25%	11/22/78	12/21/89	1.00%
		Avg	13.48%	13.36%			

Wexpro Agreement–Replaceme index for 8–1–90 through 7–31–91 Period

Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1990	Last Known Order Date May 31 1981	Last Known Order Date May 31 1990	Change in Return 81 to 90
Continental Tel Co. of California	Telecommunications	California Public Utilities Commission	11.70%	15.50%	01/05/77	03/20/85	3.80%
Continental Telephone/Northwest	Telecommunications	Washington Util. & Transp. Commission	14.40%	11.90%	12/12/80	10/26/87	−2.50%
GTE California	Telecommunications	California Public Utilities Commission	14.10%	11.50%	10/22/80	01/01/90	−2.60%
GTE Southwest Inc.	Telecommunications	Texas Public Utility Commission	14.00%	11.99%	08/05/80	02/23/89	−2.01%
Mountain Bell–Idaho (US West)	Telecommunications	Idaho Public Service Commission	12.50%	14.00%	12/11/80	05/18/84	1.50%
Northwestern Bell	Telecommunications	Nebraska Public Service Commission	11.81%	13.79%	05/06/80	12/23/86	1.98%
Pacific Northwest Bell	Telecommunications	Washington Util. & Transp. Commission	13.69%	11.90%	08/06/80	05/16/86	−1.79%
Pacific Northwest Bell	Telecommunications	Oregon Public Utility Commission	13.20%	12.35%	08/29/80	05/01/87	−0.85%
Southwestern Bell	Telecommunications	Kansas State Corporation Commission	13.62%	14.50%	02/24/81	01/07/85	0.88%
Southwestern Bell	Telecommunications	Texas Public Utility Commission	14.10%	14.20%	01/29/81	06/26/86	0.10%
Southwestern Bell Telephone Co.	Telecommunications	Oklahoma Corporation Commission	12.02%	13.50%	07/01/80	09/20/89	1.48%
		Avg	13.19%	13.19%			

Wexpro Agreement–Replaceme Index for 8–1–90 through 7–31–91 Period
Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1990	Last Known Order Date May 31 1981	Last Known Order Date May 31 1990	Change in Return 81 to 90
Companies with a 5–31–81 Rate of Return but no authorized return as of 5–31–90							
These will be used if they receive stated returns on equity in the future							
Idaho Power Co.	Electric Services	Idaho Public Service Commission	14.50%		03/26/80		
Central Kansas Power Co.	Electric Services	Kansas State Corporation Commission	20.00%		12/21/79		
Montana–Dakota Utilities Co.	Electric Services	Montana Public Service Commission	12.00%		05/28/80		
Sierra Pacific Power (Westpac)	Electric Services	Nevada Public Service Commission	15.00%		10/29/80		
Empire Dist. Elect. Co.	Electric Services	Oklahoma Corporation Commission	14.00%		04/16/79		
Black Hills Power & Light	Electric Services	South Dakota Public Util. Commission	13.10%		11/19/80		
Montana Dakota Utilities	Electric Services	South Dakota Public Util. Commission	11.82%		12/28/78		
Community Public Service Co.	Electric Services	Texas Public Utility Commission	15.80%		12/18/80		
Gas Service Co.	Gas Distribution	Oklahoma Corporation Commission	12.00%		08/25/77		
California Pacific Utility	Gas Distribution	Oregon Public Utility Commission	13.50%		06/13/77		
CP Natural Corp.	Gas Distribution	Oregon Public Utility Commission	14.07%		09/30/80		
Cheyenne Light, Fuel & Elec.	Gas Distribution	Wyoming Public Service Commission	13.50%		11/26/80		
Natural Gas Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	13.25%		10/04/79		
El Paso Natural Gas. Corp.	Gas Transmission	Federal Energy Regulatory Commission	14.00%		07/20/79		
Williams Natural Gas Co.	Gas Transmission	Federal Energy Regulatory Commission	12.33%		09/11/80		
Texas Gas Transmission Corp.	Gas Transmission	Federal Energy Regulatory Commission	13.00%		10/11/79		
Transcontinental Gas Pipe Line	Gas Transmission	Federal Energy Regulatory Commission	14.50%		10/11/79		
United Gas Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.50%		10/10/80		
Mountain States Telephone	Telecommunications	Idaho Public Service Commission	12.50%		04/13/79		
General Telephone Co./Northwest	Telecommunications	Idaho Public Service Commission	13.03%		09/19/80		
United Tel. of Kansas	Telecommunications	Kansas State Corporation Commission	16.36%		05/19/81		
Northwestern Telephone Systems	Telecommunications	Montana Public Service Commission	12.52%		04/04/78		
Mountain States Telephone	Telecommunications	Montana Public Service Commission	12.60%		07/16/80		
Lincoln Tel. & Tel.	Telecommunications	Nebraska Public Service Commission	11.59%		10/07/80		
United Tel. Co./Northwest	Telecommunications	Oregon Public Utility Commission	14.05%		09/08/80		
Central Tel. of Texas	Telecommunications	Texas Public Utility Commission	13.92%		04/20/81		
Continental Tel. Co.	Telecommunications	Texas Public Utility Commission	12.89%		05/30/78		
Mountain States Tel. & Tel.	Telecommunications	Texas Public Utility Commission	13.40%		11/05/80		
Mountain Bell (US West)	Telecommunications	Wyoming Public Service Commission	13.00%		01/28/81		

Wexpro Agreement

8–1–91 through 7–31–92 base rate of return calculation using replacement index companies

Printed: 04/20/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1991	Last Known Order Date May 31 1981	Last Known Order Date May 31 1991	Change in Return 81 to 91
Original Wexpro Agreement Companies With a Current Authorized Return on Equity							
Arizona Public Service Co.	Electric Services	Arizona Corporation Commission	15.00%	12.50%	05/24/80	04/01/88	–2.50%
Idaho Power Company	Electric Services	Idaho Public Service Commission	14.50%	12.25%	03/26/80	12/12/86	–2.25%
Montana Power Company	Electric Services	Montana Public Service Commission	13.45%	12.50%	02/09/81	08/14/89	–0.95%
Public Service Co. of New Mexico	Electric Services	New Mexico Public Service Commission	15.50%	12.52%	05/29/81	04/12/90	–2.98%
Replacement–Electric	Electric Services	Replacement	14.35%	13.07%	N/A	N/A	–1.28%
Replacement–Electric	Electric Services	Replacement	14.35%	13.07%	N/A	N/A	–1.28%
Utah Power & Light Co. (Utah)	Electric Services	Utah Public Service Commission	16.80%	12.10%	04/21/81	02/09/90	–4.70%
Southwest Gas Corp.	Gas Distribution	Arizona Corporation Commission	16.00%	12.50%	Agreement	08/31/90	–3.50%
Public Service Co. of Colorado	Gas Distribution	Colorado Public Service Commission	15.45%	14.40%	12/10/80	05/22/84	–1.05%
Intermountain Gas Company	Gas Distribution	Idaho Public Service Commission	14.50%	14.85%	10/31/80	12/05/85	0.35%
Montana–Dakota Utilities Co.	Gas Distribution	Montana Public Service Commission	13.50%	12.50%	04/27/81	12/08/89	–1.00%
Gas Company of New Mexico	Gas Distribution	New Mexico Public Service Commission	15.50%	12.38%	Agreement	08/03/90	–3.12%
Replacement–Gas Distribution	Gas Distribution	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Replacement–Gas Distribution	Gas Distribution	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Transwestern Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.00%	13.00%	07/09/79	06/22/90	1.00%
Northwest Pipeline Corp.	Gas Transmission	Federal Energy Regulatory Commission	13.75%	13.00%	05/15/80	10/19/89	–0.75%
Replacement–Gas Transmission	Gas Transmission	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
Replacement–Gas Transmission	Gas Transmission	Replacement	13.48%	13.36%	N/A	N/A	–0.12%
US West (Colorado)	Telecommunications	Colorado Public Service Commission	11.90%	13.00%	09/16/80	04/11/91	1.10%
US West (Utah)	Telecommunications	Utah Public Service Commission	14.50%	11.80%	Agreement	10/18/89	–2.70%
Wexpro Agreement Rate of Return	14.70%		Avg 14.25%	12.94%			–1.30%
Original Wexpro Agreement Companies Without a Current Authorized Return on Equity							
Nevada Power Company	Electric Services	Nevada Public Service Commission	15.00%				
Pacific Power & Light	Electric Services	Wyoming Public Service Commission	14.64%				
Northern Utilities Inc.	Gas Distribution	Wyoming Public Service Commission	13.50%				
Southwest Gas Corp	Gas Distribution	Nevada Public Service Commission	15.20%				
Colorado Interstate Corp.	Gas Transmission	Federal Energy Regulatory Commission	13.25%				
Kansas Nebraska Natural Gas Co.	Gas Transmission	Federal Energy Regulatory Commission	13.00%				

Wexpro Agreement–Replacem Index for 8–1–91 through 7–31–92 Period
Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1991	Last Known Order Date May 31 1981	Last Known Order Date May 31 1991	Change in Return 81 to 91
Southern California Edison	Electric Services	California Public Utilities Commission	14.95%	13.00%	12/30/80	12/19/88	-1.95%
San Diego Gas & Electric	Electric Services	California Public Utilities Commission	14.50%	12.90%	12/30/80	11/22/89	-1.60%
Pacific Gas & Electric	Electric Services	California Public Utilities Commission	13.90%	12.90%	12/19/79	12/20/89	-1.00%
Public Service Co. of Colorado	Electric Services	Colorado Public Service Commission	15.45%	14.40%	12/10/80	05/22/84	-1.05%
Citizens Utilities Co. (Idaho)	Electric Services	Idaho Public Service Commission	14.11%	12.42%	03/09/80	01/09/89	-1.69%
Washington Water Power Co. (Idaho)	Electric Services	Idaho Public Service Commission	14.00%	12.90%	06/04/80	12/03/86	-1.10%
Kansas City Power & Light	Electric Services	Kansas State Corporation Commission	14.00%	12.00%	03/13/79	07/07/87	-2.00%
Kansas Gas & Electric	Electric Services	Kansas State Corporation Commission	13.93%	12.03%	09/24/79	02/13/90	-1.90%
Kansas Power & Light Co.	Electric Services	Kansas State Corporation Commission	13.71%	12.98%	08/23/79	07/31/87	-0.73%
Pacific Power & Light (Montana)	Electric Services	Montana Public Service Commission	13.75%	12.30%	05/27/81	07/09/86	-1.45%
Southwestern Public Service	Electric Services	New Mexico Public Service Commission	16.33%	14.50%	08/18/80	12/21/87	-1.83%
El Paso Electric (New Mexico)	Electric Services	New Mexico Public Service Commission	14.75%	12.60%	06/08/79	05/01/90	-2.15%
Montana Dakota Utilities	Electric Services	North Dakota Public Service Commission	11.94%	12.71%	04/26/77	01/27/87	0.77%
Otter Tail Power Company	Electric Services	North Dakota Public Service Commission	11.80%	14.50%	04/20/77	04/19/83	2.70%
Northern States Power	Electric Services	North Dakota Public Service Commission	13.39%	11.24%	12/31/80	03/24/88	-2.15%
Oklahoma Gas & Electric Company	Electric Services	Oklahoma Corporation Commission	14.00%	13.50%	12/31/79	06/24/87	-0.50%
Public Service Company of Oklahoma	Electric Services	Oklahoma Corporation Commission	15.00%	13.50%	05/07/80	09/28/87	-1.50%
Pacific Power & Light	Electric Services	Oregon Public Utility Commission	16.25%	12.73%	05/07/81	02/01/88	-3.52%
Portland General Electric Co.	Electric Services	Oregon Public Utility Commission	16.25%	12.50%	05/07/81	02/05/91	-3.75%
Northwestern Public Service	Electric Services	South Dakota Public Utilities Commission	13.10%	13.00%	01/23/81	11/15/86	-0.10%
Iowa Public Service Company	Electric Services	South Dakota Public Util. Commission	11.50%	13.25%	04/07/78	03/01/84	1.75%
Northern States Power Co.	Electric Services	South Dakota Public Util. Commission	13.00%	12.00%	11/19/80	01/01/91	-1.00%
Gulf States Utilities	Electric Services	Texas Public Utility Commission	16.10%	13.85%	10/16/80	03/22/91	-2.25%
Houston Lighting & Power	Electric Services	Texas Public Utility Commission	15.80%	12.92%	09/15/80	06/20/90	-2.88%
Central Power & Light	Electric Services	Texas Public Utility Commission	15.50%	13.00%	01/23/80	12/19/90	-2.50%
Texas Electric Service Company	Electric Services	Texas Public Utility Commission	15.50%	15.56%	10/03/80	12/15/83	0.06%
El Paso Electric	Electric Services	Texas Public Utility Commission	14.23%	13.10%	11/09/78	08/22/90	-1.13%
West Texas Utilities Company	Electric Services	Texas Public Utility Commission	15.35%	12.00%	12/09/80	11/30/87	-3.35%
Southwestern Electric Services Co.	Electric Services	Texas Public Utility Commission	15.00%	12.50%	01/21/80	03/07/90	-2.50%
Dallas Power & Light Co.	Electric Services	Texas Public Utility Commission	16.00%	15.80%	02/26/81	01/16/84	-0.20%
Pacific Power & Light	Electric Services	Washington Util. & Transp. Commission	13.75%	13.25%	11/05/80	09/19/86	-0.50%
Washington Water Power Company	Electric Services	Washington Util. & Transp. Commission	12.75%	12.90%	03/24/78	02/24/87	0.15%
Puget Sound Power & Light	Electric Services	Washington Util. & Transp. Commission	15.25%	12.80%	01/09/81	03/30/90	-2.45%
Utah Power & Light Co. (Wyoming)	Electric Services	Wyoming Public Service Commission	12.90%	12.85%	10/27/78	10/12/89	-0.05%
		Avg	14.35%	13.07%			

Wexpro Agreement–Replacem Index for 8–1–91 through 7–31–92 Period
Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1991	Last Known Order Date May 31 1981	Last Known Order Date May 31 1991	Change in Return 81 to 91
San Deigo Gas & Electric	Gas Distribution	California Public Utilities Commission	14.50%	12.90%	06/05/79	11/22/89	−1.60%
Southern California Gas Co.	Gas Distribution	California Public Utilities Commission	14.60%	13.00%	12/05/80	01/09/90	−1.60%
Greely Gas Co.	Gas Distribution	Colorado Public Service Commission	14.10%	15.00%	01/08/81	05/09/85	0.90%
Citizens Utilities Co. (Colorado)	Gas Distribution	Colorado Public Service Commission	11.91%	13.20%	05/05/80	06/30/87	1.29%
Rocky Mountain Natural Gas Co.	Gas Distribution	Colorado Public Service Commission	14.40%	14.40%	02/24/81	09/18/85	0.00%
Washington Water Power	Gas Distribution	Idaho Public Service Commission	13.25%	12.75%	10/01/79	11/03/89	−0.50%
Peoples Natural Gas Company	Gas Distribution	Kansas State Corporation Commission	14.50%	14.65%	04/28/80	04/17/86	0.15%
Union Gas System	Gas Distribution	Kansas State Corporation Commission	13.50%	13.62%	11/21/79	09/15/89	0.12%
Kansas Power & Light Co.	Gas Distribution	Kansas State Corporation Commission	14.19%	12.40%	06/20/80	09/26/88	−1.79%
Kansas Gas Suppply	Gas Distribution	Kansas State Corporation Commission	11.28%	14.50%	06/20/80	06/06/84	3.22%
Montana Power Company	Gas Distribution	Montana Public Service Commission	13.45%	12.50%	02/09/81	08/14/89	−0.95%
Northern States Power Company	Gas Distribution	North Dakota Public Service Commission	11.43%	14.00%	04/18/78	10/01/84	2.57%
Montana Dakota Utilities	Gas Distribution	North Dakota Public Service Commission	12.58%	12.71%	05/23/79	01/21/87	0.13%
Southern Union Gas Co.	Gas Distribution	Oklahoma Corporation Commission	14.50%	12.00%	04/27/81	11/23/88	−2.50%
Oklahoma Natural Gas Co.	Gas Distribution	Oklahoma Corporation Commission	14.50%	13.50%	02/11/81	06/30/87	−1.00%
Northwest Natural Gas	Gas Distribution	Oregon Public Utility Commission	15.30%	13.25%	04/01/81	11/01/89	−2.05%
Cascade Natural Gas Corp.	Gas Distribution	Oregon Public Utility Commisssion	14.85%	12.25%	11/19/80	02/12/90	−2.60%
Northwestern Public Service	Gas Distribution	South Dakota Public Utilities Commission	13.10%	13.00%	01/23/81	10/06/86	−0.10%
Minnegasco	Gas Distribution	South Dakota Public Utilities Commission	13.50%	12.50%	11/26/80	11/07/89	−1.00%
Iowa Public Service Company	Gas Distribution	South Dakota Public Util. Commission	12.50%	13.00%	04/06/79	06/01/86	0.50%
Montana Dakota Utilities	Gas Distribution	South Dakota Public Util. Commission	13.10%	14.25%	11/14/80	11/08/83	1.15%
Southern Union Gas	Gas Distribution	Texas Railroad Commission	14.50%	15.50%	10/11/79	05/21/84	1.00%
Lonestar Gas Co.	Gas Distribution	Texas Railroad Commission	13.70%	13.20%	02/11/80	10/20/89	−0.50%
Cascade Natural Gas Corp.	Gas Distribution	Washington Util. & Transp. Commission	14.25%	13.25%	04/28/81	11/29/89	−1.00%
Northwest Natural Gas	Gas Distribution	Washington Util. & Transp. Commission	13.50%	13.25%	11/10/77	09/15/86	−0.25%
Washington Natural Gas Corp.	Gas Distribution	Washington Util. & Transp. Commission	13.50%	16.25%	11/19/80	12/28/84	2.75%
Montana–Dakota Utilities Co.	Gas Distribution	Wyoming Public Service Commission	13.64%	14.28%	04/28/81	04/17/84	0.64%
Texas Eastern Gas Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.50%	13.00%	04/04/80	08/29/89	0.50%
Trunkline Gas Co.	Gas Transmission	Federal Energy Regulatory Commission	12.25%	13.25%	11/22/78	12/21/89	1.00%
Panhandle Eastern	Gas Transmission	Federal Energy Regulatory Commission	13.25%	13.00%	01/27/81	01/08/87	−0.25%
Mississippi River Transmission	Gas Transmission	Federal Energy Regulatory Commission	13.25%	10.49%	04/09/81	04/08/89	−2.76%
ANR Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.88%	12.75%	07/17/80	11/12/87	−0.13%
Northern Natural Gas	Gas Transmission	Federal Energy Regulatory Commission	12.50%	13.23%	02/20/81	12/29/89	0.73%
		Avg	13.48%	13.36%			

Wexpro Agreement–Replacem. Index for 8–1–91 through 7–31–92 Period
Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1991	Last Known Order Date May 31 1981	Last Known Order Date May 31 1991	Change in Return 81 to 91
GTE California	Telecommunications	California Public Utilities Commission	14.10%	11.50%	10/22/80	01/01/90	−2.60%
Continental Tel Co. of California	Telecommunications	California Public Utilities Commission	11.70%	15.50%	01/05/77	03/20/85	3.80%
Mountain Bell–Idaho (US West)	Telecommunications	Idaho Public Service Commission	12.50%	14.00%	12/11/80	05/18/84	1.50%
Southwestern Bell	Telecommunications	Kansas State Corporation Commission	13.62%	14.50%	02/24/81	01/07/85	0.88%
Northwestern Bell	Telecommunications	Nebraska Public Service Commission	11.81%	13.79%	05/06/80	12/23/86	1.98%
Southwestern Bell Telephone Co.	Telecommunications	Oklahoma Corporation Commission	12.02%	13.50%	07/01/80	09/20/89	1.48%
Pacific Northwest Bell	Telecommunications	Oregon Public Utility Commission	13.20%	12.35%	08/29/80	05/01/87	−0.85%
GTE Southwest Inc.	Telecommunications	Texas Public Utility Commission	14.00%	11.99%	08/05/80	02/23/89	−2.01%
Southwestern Bell	Telecommunications	Texas Public Utility Commission	14.10%	14.20%	01/29/81	06/26/86	0.10%
Continental Telephone/Northwest	Telecommunications	Washington Util. & Transp. Commission	14.40%	11.90%	12/12/80	10/26/87	−2.50%
Pacific Northwest Bell	Telecommunications	Washington Util. & Transp. Commission	13.69%	11.90%	08/06/80	05/16/86	−1.79%
		Avg	13.19%	13.19%			

Wexpro Agreement–Replacem . Index for 8–1–91 through 7–31–92 Period
Includes Both Within Existing and One State Step Out Outside Existing Agreement States

Printed: 04/16/92

Company Name	Activity	Regulatory Agency	Authorized Return as of May 31 1981	Authorized Return as of May 31 1991	Last Known Order Date May 31 1981	Last Known Order Date May 31 1991	Change in Return 81 to 91
Companies with a 5–31–81 Rate of Return but no authorized return as of 5–31–91							
These will be used if they receive stated returns on equity in the future							
Idaho Power Co.	Electric Services	Idaho Public Service Commission	14.50%		03/26/80		
Central Kansas Power Co.	Electric Services	Kansas State Corporation Commission	20.00%		12/21/79		
Montana–Dakota Utilities Co.	Electric Services	Montana Public Service Commission	12.00%		05/28/80		
Sierra Pacific Power (Westpac)	Electric Services	Nevada Public Service Commission	15.00%		10/29/80		
Empire Dist. Elect. Co.	Electric Services	Oklahoma Corporation Commission	14.00%		04/16/79		
Black Hills Power & Light	Electric Services	South Dakota Public Util. Commission	13.10%		11/19/80		
Montana Dakota Utilities	Electric Services	South Dakota Public Util. Commission	11.82%		12/28/78		
Community Public Service Co.	Electric Services	Texas Public Utility Commission	15.80%		12/18/80		
Gas Service Co.	Gas Distribution	Oklahoma Corporation Commission	12.00%		08/25/77		
California Pacific Utility	Gas Distribution	Oregon Public Utility Commission	13.50%		06/13/77		
CP Natural Corp.	Gas Distribution	Oregon Public Utility Commission	14.07%		09/30/80		
Cheyenne Light, Fuel & Elec.	Gas Distribution	Wyoming Public Service Commission	13.50%		11/26/80		
Natural Gas Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	13.25%		10/04/79		
El Paso Natural Gas. Corp.	Gas Transmission	Federal Energy Regulatory Commission	14.00%		07/20/79		
Williams Natural Gas Co.	Gas Transmission	Federal Energy Regulatory Commission	12.33%		09/11/80		
Texas Gas Transmission Corp.	Gas Transmission	Federal Energy Regulatory Commission	13.00%		10/11/79		
Transcontinental Gas Pipe Line	Gas Transmission	Federal Energy Regulatory Commission	14.50%		10/11/79		
United Gas Pipeline Co.	Gas Transmission	Federal Energy Regulatory Commission	12.50%		10/10/80		
Mountain States Telephone	Telecommunications	Idaho Public Service Commission	12.50%		04/13/79		
General Telephone Co./Northwest	Telecommunications	Idaho Public Service Commission	13.03%		09/19/80		
United Tel. of Kansas	Telecommunications	Kansas State Corporation Commission	16.36%		05/19/81		
Northwestern Telephone Systems	Telecommunications	Montana Public Service Commission	12.52%		04/04/78		
Mountain States Telephone	Telecommunications	Montana Public Service Commission	12.60%		07/16/80		
Lincoln Tel. & Tel.	Telecommunications	Nebraska Public Service Commission	11.59%		10/07/80		
United Tel. Co./Northwest	Telecommunications	Oregon Public Utility Commission	14.05%		09/08/80		
Central Tel. of Texas	Telecommunications	Texas Public Utility Commission	13.92%		04/20/81		
Continental Tel. Co.	Telecommunications	Texas Public Utility Commission	12.89%		05/30/78		
Mountain States Tel. & Tel.	Telecommunications	Texas Public Utility Commission	13.40%		11/05/80		
Mountain Bell (US West)	Telecommunications	Wyoming Public Service Commission	13.00%		01/28/81		

WEXPRO COMPANY

79 SOUTH STATE STREET • P. O. BOX 11070 • SALT LAKE CITY, UTAH 84147 • PHONE (801) 530-2600

October 27, 1988

Mr. Robert Lake
Mr. Gary Myers
Price Waterhouse
175 East 400 South Suite 700
Salt Lake City, UT 84111

Gentlemen:

Re: Wexpro Agreement Guideline for Expanding Participating Areas Inside Federal Units

The Division has requested a clarification of the Participating Area Guideline letter which was approved by the Accounting and Hydrocarbon Monitors on June 15, 1983.

The only portion of that letter which was intended by Wexpro as a guideline is found on page 5 entitled the "Wexpro Proposed Solution." All other portions of the guideline letter should be considered as background material only and not an integral part of the guideline. The relevant portion of the guideline for which we request Division approval is found on page 5 and reads as follows:

> To properly account between Mountain Fuel and Wexpro and solely for allocation of investment adjustments (whether debits or credits) and for allocation of oil, natural gas liquids and natural gas from drilling which results in expanding any participating area for royalty purposes or in expanding pooled areas (or similar expansion of multi-party individual ownership areas -- each of which originally qualifies as a development drilling area under the Wexpro Agreement) after July 31, 1981, then as between the company and Wexpro/Celsius:
>
> 1. The 101/105 and transferred leaseholds within the participating area or pooled (or similar) area as it existed on July 31, 1981, shall be considered as "company leaseholds" and the 101/105 or transferred leaseholds outside of such areas shall be owned by Wexpro or Celsius as provided in the Wexpro Agreement.
>
> 2. Wexpro will fund or cause to be funded all capital investment additions or debit investment adjustments on such "company leaseholds" required by such expansion and earn the base rate of return (r) plus the applicable risk premium of 8% for gas and 5% for oil wells.

Mr. Robert Lake
Mr. Gary Myers
October 27, 1988
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3. Credit investment adjustments attributable to pre-July 31, 1981 capitalization and Post-July 31, 1981 Facilities and Development Gas or Oil Drilling will be paid to Wexpro.

4. As far as the Unit Operator is concerned, the allocation of production to MFS/Wexpro is consistent with allocations to other interest owners. After this allocation is made, an inhouse division of revenues between Wexpro and Mountain Fuel occurs in compliance with the Wexpro Agreement.

We hope this removes any confusion created by using the Henry Unit as an example of how federal unit participating areas are created and expand. Please deliver a copy of this letter to Jon Strawn of the Division at your earliest convenience. Your cooperation will be appreciated.

Very truly yours,

Ruland J. Gill, Jr.
Managing Attorney

pf

cc: M. A. Howerton
M. R. Jensen
J. W. King
R. M. Kirsch

APPROVED THIS ___ day of ______________, 1988.

UTAH DIVISION OF PUBLIC UTILITIES	STAFF OF WYOMING PUBLIC SERVICE COMMISSION
By:______________________	By:______________________
Date:______________________	Date:______________________

fil 208

WEXPRO AGREEMENT MONITORING
June 23, 1983

Expanding Participating Areas
Inside Federal Units
The Henry Unit Example

PROBLEM: Wexpro Company hereby requests monitor approval of a method of accounting for production and for certain drilling costs (called investment adjustments) resulting from participating area expansions inside "Federal Exploratory Units."

FACTS:

What is a Federal Unit.

A "Federal Exploratory Unit" is a creature of Federal laws and regulations. A Unit Agreement is authorized by 30 U.S.C. §226(j) (attached as Exhibit 1) and the exact words of the Unit Agreement are promulgated in Regulation in 30 CFR §226.12 (attached as Exhibit 2). Unit Agreements embracing Federally supervised leases including all or part of an oil and/or gas pool, field or like area may be classified as exploratory or developmental in nature. The request of Wexpro only applies to exploratory units and does not apply to developmental and secondary recovery units. These latter units are usually tailor made after considerable drilling and development has occurred.

The objective of unitization, per se, is to provide for the unified development and operation of an entire structure or field area so that drilling and production can proceed in the most efficient and economical manner. Establishment of Cooperative and Unit Plans or Operations under the Mineral Leasing Act of February 25, 1920, as amended, is governed by the regulations set forth in 30 CFR §226.

The standard Federal Competitive Oil and Gas Lease (Form 3120-7) in Section 2 requires the lessee:

> Within thirty (30) days of demand, ... to subscribe to and operate under such reasonable cooperative or unit plan for the development and operation of the area, field, or pool, or part thereof, embracing the lands included herein as the Secretary of the Interior may then determine to be practicable and necessary or advisable, which plan shall adequately protect the rights of all parties in interest including the United States.

Other Federal leases have similar or identical language. BLM Regulations found in 43 CFR, Part 3100 contain several sections relative to unitization.

To initiate the formation of a Federal exploratory unit, the proponent of the unit files an application with the appropriate office of the BLM (previously supervised by the U. S. Geological Survey and the Minerals Management Service) formally requesting the State BLM Director to (1) designate the proposed area as logically subject to development under a unit plan of operations; (2) approve the maximum depth and objective formation proposed for the initial test well(s) and/or development obligations (if the area contains a discovery but is not fully developed); and (3) approve the text of the proposed form of agreement. The request for designation must be accompanied by a map or diagram showing the area sought to be designated and indicating the type of land. The application is usually accompanied by a report giving all available geological and geophysical information.

After consideration of the application by the BLM, the applicant will be advised of the decision reached with respect to the designation of the area, the specific form of agreement, and the initial wells required.

What is a Participating Area.

After a well capable of producing unitized substances (i.e. oil and/or gas) in paying quantities is completed, a "participating area" must be established in accordance with the "Participating After Discovery" section of the Unit Agreement (Section 11 of the model form, 30 CFR 226.12, See Exhibit 2). The only land to be included in a participating area is that land reasonably proven capable of producing unitized substances in paying quantities, or, if so provided in the Unit Agreement, that additional land necessary for unit operations (most older units, i.e., prior to 1968, do not so provide for additional lands). The initial participating area causes the unit to convert to a producing status and all subsequent unit wells and operations are to be conducted under a "Plan of Operations."

Under the Wexpro Settlement Agreement, Section I-26(a)(ii), the participating area as it existed on July 31, 1981 is a "development drilling area" and is determined as follows:

> (a) For each prior Wexpro or prior Company well in a pool, ... and all additional surface area covered by: (ii) The U. S. Geological Survey-approved participating area determined for royalty purposes for that pool, if the well is in a Federal unit, ...

Revision of Participating Areas.

A participating area will be revised, in accordance with Sections 11 and 12 of the Unit Agreement, when additional paying wells are completed in the formation or pool for which the participating area has been established. Although additional geological and engineering information obtained by the completion of each such well is used, the amount of acreage that is brought into the participating area by a revision is dependent on the same criteria used in determining the initial participating area. Likewise, land included in a participating area which is reasonably proven to be nonproductive in paying quantities by the subsequent completion of a dry hole on the land is eliminated from the participating area.

Separate participating areas may be established for each separate productive reservoir, pool or formation covered by a Unit Agreement. In some instances, separate participating areas may be established for the same producing horizon when there is uncertainty as to whether the production is continuous between the two areas.

Allocation of Production.

Oil and/or gas produced under unitized operations is allocated to the working interest owners of the unitized lands on the basis of the factors and formulas prescribed in the "Unit Operating Agreement." Normally, a standard preprinted form of Unit Operating Agreement prepared by the Rocky Mountain Mineral Law Foundation is used. Production under an exploratory unit agreement is normally allocated to each tract of unitized land within the controlling participating areas on the basis of the number of tract surface acres included within the participating area as compared to the total number of unitized surface acres within the participating area. Therefore, allocation of unitized substances is made on a surface acreage basis without regard to any particular well. However, the Wexpro Settlement Agreement provides for allocation on a well by well basis which is inapplicable inside a unit participating area.

The use of a "development drilling area" in the Wexpro Settlement Agreement was a means to differentiate between developmental and wildcat (exploratory) drilling. The "development drilling area," in turn, is used to further define the various benefits which results from the various types of Wexpro's developmental or exploratory drilling activity. To avoid a difficult subjective analysis on every "prior well," the parties selected a distance around prior wells which would be considered "development" drilling. In the case of each pool within Federal units, this included the 1,980 feet around the prior well plus the participating area for royalty purposes for that pool. This method works well for all participating areas which are never enlarged and which contained a prior well, because all production is allocated to all lands inside the "development drilling area", i.e. participating area for royalty purposes within the federal unit. However, if the participating area is enlarged after July 31, 1981, part of the production from prior wells is allocated to other lands subject to "exploratory drilling" under the Wexpro Settlement Agreement and possibly subject to interests of other third parties. Likewise, some production from "exploratory drilling" is allocated to lands inside of the participating area.

Therein lies the problem in which Wexpro seeks monitor assistance. The Wexpro Settlement Agreement allocates production on a well basis but in Federal unit participating area expansions, the allocation of production is based on an acreage basis.

Identical problems could be created when third parties or state government agencies request or require expansion of pooling agreements or state approved unit or spacing areas in which production is shared on an acreage basis. It is entirely possible that a participating area expansion may include only third party acreage and not include any Wexpro/Celsius acreage. In that case, the Wexpro proposed solution would be equally applicable.

Investment Adjustments; a Hypothetical Example

Between the working interest owners under the unit operating agreement, there is an investment adjustment so that each working interest owner pays a fair proportion of the cost of all wells in which it receives an allocated share of production. Attached as Exhibit 3 is an example of the typical language in a unit operating agreement. The following example illustrates how an investment adjustment would be accounted for between Celsius (Wexpro) and Mountain Fuel ("MFS") or Celsius/Wexpro and any other third party (such as Exxon in the hypothetical):

ORIGINAL PARTICIPATING AREA - MFS ACRES

1. Acres = 1,000
2. Investment (1 well) = $1,000,000 (depreciated ½% per month for 60 months)
3. Production = 500 BBLS/Day
4. MFS Original Share = 100%

EXPANSION CELSIUS/EXXON ACRES

1. Acres added = 1,000
2. Investment (1 well) = $2,000,000
3. Production = 350 BBLS/Day
4. Celsius/Exxon Interest = 100%

EXPANDED PARTICIPATING AREA

1. Acres = 2,000

2. Investment - Net total at time of expansion (Assume Depr. 10 mos. @ .5% monthly per unit agreement)

.95 x 1,000,000 =	$ 950,000
Celsius =	2,000,000
Total =	$2,950,000

3. Production = 850 BBLS/Day

4. Interest = MFS $\frac{(1,000 \text{ acres})}{(2,000 \text{ acres})}$ = 50%

   Celsius/Exxon= $\frac{(1,000 \text{ acres})}{(2,000 \text{ acres})}$ = 50%

5. Investment = $2,950,000

MFS Share	=	$1,475,000
Credit for 1st well	=	950,000
INVESTMENT ADJ.		$ 525,000*

Celsius/Exxon Share	=	$1,475,000
Credit for 2nd well	=	2,000,000
INVESTMENT ADJ.		$ (525,000)

6. Production Allocation
   MFS 50% = 425 BBLS/Day
   Celsius 50% = 425 BBLS/Day

*Wexpro picks up MFS investment adjustment (because the Wexpro Settlement Agreement requires Wexpro to make all future investments, See Section III-4) of $525,000 and capitalizes it in an account subject to the developmental gas (24%) or oil drilling (21%) rate of return. Amortization based upon units of production - MFS share of production and reserves.

No provision of the Wexpro Settlement Agreement squarely addresses these problems.

The Henry Unit Example

The Henry Unit Agreement, Uinta County, Wyoming was approved by the U. S. Geological Survey on April 30, 1980 and included approximately 13,415.89 gross acres. The agreement has been designated No. 14-08-0001-18150, and was effective the date of approval. To drill the initial test well called for under the provisions of the Unit Agreement, MFS entered a farmout agreement dated July 14, 1980 with Forest Oil Company ("Forest") and a pooling agreement dated July 14, 1980 with Forest and other companies. The pooling agreement pooled four sections around the initial test well. Such pooling was on a surface acre undivided basis. MFS's interest within the four sections was 21.16111%. MFS viewed the initial test well as an extremely high risk venture. Therefore, MFS farmed-out to Forest. Forest earned one-half of MFS's interest within the four section pooled area by paying all MFS's share of cost in that well. MFS retained a small overriding royalty interest in the initial test well until Forest had recovered its costs of drilling, completing, equipping and operating the initial test well. On October 7, 1980, the initial test well, Henry Unit No. 1, was completed as a gas well in the Dakota formation. The Henry Unit Well No.1 is not shown as a prior company well in the schedules to the Wexpro Settlement Agreement. Wexpro proposes to deem it so for purposes of the participating area expansion.

On October 5, 1981, the USGS approved an initial Dakota Participating Area "A" embracing 637.81 acres based upon the completion of the Henry Unit Well No. 1. In April, 1982 the Unit Well No. 1 had reached its payout with Forest and MFS's retained overriding royalty interest was converted to a 10.58056% gross working interest.

The Henry Unit Well Nos. 2 and 3 were drilled as dry holes. The Unit Well No. 4A was completed as a gas condensate well from the Dakota formation in March 1982. On September 9, 1982, the MMS (formerly USGS) approved the first revision of the Dakota Participating Area "A", enlarging the participating area from 637.81 acres to 1429.38 acres based upon completion of Unit Well No. 4A. MFS's interest in the first revised participating area was decreased from 10.8056% to 4.7210% gross working interest (also called a "participating interest" under the pooling agreement).

As a result of the first revision and under the Wexpro proposal herein, MFS would change from a 10.8056% interest in only the Henry Unit Well No. 1 to a 4.7210% interest in both the No. 1 and 4A wells. Depending on whether one or the other well is a larger producer at any given period of time, the dollar receipts by MFS from both wells in the Henry Unit could increase or decrease as compared with MFS's share in only the Henry Unit No. 1 Well. Wexpro's proposal would result in the same accounting treatment in all similar federal unit or pooled area situations without regard to the benefits attributable to MFS or Wexpro or third parties.

WEXPRO PROPOSED SOLUTION:

To properly account between Mountain Fuel and Wexpro and solely for allocation of investment adjustments (whether debits or credits) and for allocation of oil, natural gas liquids and natural gas from drilling which results in expanding any participating area for royalty purposes or in expanding pooled areas (or similar expansion of multiparty individual ownership areas--each of which originally qualifies as a development drilling area under the Wexpro Settlement Agreement) after July 31, 1981, then as between the Company and Wexpro/Celsius:

1. The 101/105 and transferred leaseholds within the participating area or pooled (or similar area) as it existed on July 31, 1981 shall be considered as "Company leaseholds" and the 101/105 or transferred leaseholds outside of such areas shall be owned by Wexpro or Celsius as provided in the Wexpro Settlement Agreement.

2. Wexpro will fund or cause to be funded all capital investment additions and debit investment adjustments on such "company leaseholds" required by such expansion and earn the base rate of return (r) plus the applicable risk premium of 8% for gas and 5% for oil wells.

3. Credit investment adjustments attributable to pre-July 31, 1981 capitalization and Post-July 31, 1981 Facilities and Development Gas or Oil Drilling will be paid to Wexpro.

4. As far as the Unit Operator is concerned, the allocation of production to MFS/Wexpro is consistent with allocations to other interest owners. After this allocation is made, an in-house division of revenues between Wexpro and Mountain Fuel occurs in compliance with the Wexpro Settlement Agreement

This would result in the same fair treatment of production allocation as if Exxon or some independent producer owned an interest in the prior Company well or prior Wexpro well. Stated another way, Wexpro's proposal in this situation would follow standard industry practice and treat Mountain Fuel's interest in a prior Company or prior Wexpro well the same as independent third parties. The only difference would be the amount Wexpro could earn under the Wexpro Agreement on investment adjustments.

Excerpted from: Mineral Leasing Act of 1920 (As Amended)

Section 17.

"(j) For the purpose of more properly conserving the natural resources of any oil or gas pool, field, or like area, or any part thereof (whether or not any part of said oil or gas pool, field, or like area, is then subject to any cooperative or unit plan of development or operation), lessees thereof and their representatives may unite with each other, or jointly or separately with others, in collectively adopting and operating under a cooperative or unit plan of development or operation of such, pool, field, or like area, or any part thereof, whenever determined and certified by the Secretary of the Interior to be necessary or advisable in the public interest. The Secretary is thereunto authorized, in his discretion, with the consent of the holders of leases involved, to establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of such leases and to make such regulations with reference to such leases, with like consent on the part of the lessees, in connection with the institution and operation of any such cooperative or unit plan as he may deem necessary or proper to secure the proper protection of the public interest. The Secretary may provide that oil and gas leases hereafter issued under this Act shall contain a provision requiring the lessee to operate under such a reasonable cooperative or unit plan, and he may prescribe such a plan under which such lessee shall operate, which shall adequately protect the rights of all parties in interest, including the United States.

"Any plan authorized by the preceding paragraph which includes lands owned by the United States may, in the discretion of the Secretary, contain a provision whereby authority is vested in the Secretary of the Interior, or any such person, committee, or State or Federal officer or agency as may be designated in the plan, to alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under such plan. All leases operated under any such plan approved or prescribed by the Secretary shall be excepted in determining holdings or control under the provisions of any section of this Act.

"Any lease issued for a term of twenty years, or any renewal thereof, or any portion of such lease that has become the subject of a cooperative or unit plan of development or operation of a pool, field, or like area, which plan has the approval of the Secretary of the Interior, shall continue in force until the termination of such plan. Any other lease issued under any section of this Act which has heretofore or may hereafter be committed to any such plan that contains a general provision for allocation of oil or gas shall continue in force and effect as to the land committed so long as the lease remains subject to the plan: Provided, That production is had in paying quantities under the plan prior to the expiration date of the term of such lease. Any lease heretofore or hereafter committed to any such plan embracing lands that are in part within and in part outside of the area covered by any such plan shall be segregated into separate leases as to the lands committed and the lands not committed as of the effective date of unitization: Provided, however, That any such lease as to the nonunitized portion shall continue in force and effect for the term thereof but for not less than two years from the date of such segregation and so long thereafter as oil or gas is produced in paying quantities. The minimum royalty or discovery rental under any lease that has become subject to any cooperative or unit plan of development or operation, or other plan that contains a general provision for allocation of oil or gas, shall be payable only with respect to the lands subject to such lease to which oil or gas shall be allocated under such plan. Any lease which shall be eliminated from any such approved or prescribed plan, or from any communitization or drilling agreement authorized by this section, and any lease which shall be in effect at the termination of any such approved or prescribed plan, or at the termination of any such communitization or drilling agreement, unless relinquished, shall continue in effect for the original term thereof, but for not less than two years, and so long thereafter as oil or gas is produced in paying quantities."

Pursuant to the Mineral Leasing Act for Acquired Lands (August 7, 1947) and the regulations promulgated thereunder, acquired land may be leased under the same terms and conditions as are contained in the Mineral Leasing Act. The regulations prescribed under the Mineral Leasing Laws pertaining to unitization are applicable to acquired lands.

(b) When Indian lands are included, modification of the unit agreement will be required by the DMM. Approval of an agreement containing Indian lands by the Bureau of Indian Affairs must be obtained prior to submission to the DMM for final approval.

§ 226.8 Approval of unit agreement.

A unit agreement will be approved by the DMM upon a determination that such agreement is necessary or advisable in the public interest and is for the purpose of more properly conserving natural resources. Such approval will be incorporated in a Certification-Determination document appended to the agreement (example in § 226.12). No such agreement will be approved unless the parties signatory to the agreement hold sufficient interests in the unit area to provide reasonably effective control of operations. Any modification of an approval agreement will require the prior approved of the DMM.

§ 226.9 Filing of papers and number of counterparts.

(a) All papers, instruments, documents, and proposals submitted under this part should be filed in the office of the DMM for the region in which the unit area is situated.

(b) An application for designation of a proposed unit area and determination of the required depth of test well shall be filed in duplicate. A like number of counterparts should be filed of any geologic data and any other information submitted in support of such application.

(c) Where a duly executed agreement is submitted for final approval, a minimum of four signed counterparts should be filed. The number of counterparts to be filed for supplementing, modifying, or amending an existing agreement, including change of operator, designation of new operator, designation of a participating area, and termination shall be prescribed by the DMM.

(d) Two counterparts of a substantiating geologic report, including structure-contour map, cross sections, and pertinent data, shall accompany each application for approval of a participating area or revision thereof under an approved agreement.

(e) Three counterparts of all plans of development and operation shall be submitted for approval under an approved agreement.

(f) One approved counterpart of each instrument or document submitted for approval will be returned to the operator by the DMM or his representative, together with such additional counterparts as may have been furnished for that purpose.

§ 226.9–1 Retroactive approval of a communitization agreement.

(a) Generally, no communitization agreement shall be given an effective date that is prior to the date of its filing with the Deputy Minerals Manager (DMM). However, under circumstances of good faith mistake or error by lessee or operator, and in the absence of intervening third party rights, the effective date of a communitization agreement may be fixed as far back as the date of execution of the agreement between the lessees or operators.

(b) No retroactive approval of a communitization agreement may be made where the lease expired prior to execution of the agreement. The agreement need not be in a form required for approval by the Minerals Management Service to qualify for this equitable relief, but may be any agreement between lessees or operators, such as an operating agreement evidencing the intent of the parties to combine, and having the effect of combining, their leases or interests for operational purposes. If the agreement that combined such leases or interests is other then a formal communitization agreement acceptable for filing and approval as such, the DMM may require the parties to submit such an agreement in proper form, which, if submitted and approved, shall be deemed effective as of the date of the earlier agreement between the parties that combined their leases or interests.

§ 226.10 Bonds.

In lieu of separate bonds required for each Federal lease committed to a unit agreement, the unit operator may furnish and maintain a collective corporate surety bond or a personal bond conditioned upon faithful performance of the duties and obligations of the agreement and the terms of the Federal leases subject thereto. Personal bonds shall be accompanied by a deposit of negotiable Federal securities in a sum equal at their par value to the amount of the bonds, and by a proper conveyance to the Secretary of full authority to sell such securities in case of default in the performance of the obligations assumed. The liability under the bond shall be for such amount as the DMM shall determine to be adequate to protect the interests of the United States, and additional bond may be required whenever deemed necessary. The bond shall be filed with the State Director of the Bureau of Land Management having jurisdiction over the Federal leases in the unit. Evidence must be furnished to the DMM that such bond has been accepted by the Bureau of Land Management before operations will be authorized. A form of corporate surety bond is set forth in § 226.15. In case of change of unit operator, a new bond must be filed or consent of surety to such change of operator must be furnished.

§ 226.11 Appeals.

A technical and procedural review may be requested pursuant to 30 CFR 221.82 and/or an appeal may be taken as provided in 30 CFR Part 290 of this chapter from any order or decision issued under the regulations in this part.

§ 226.12 Model onshore unit agreement for unproven areas.

Introductory Section.
Section 1—Enabling Act and regulations.
Section 2—Unit area.
Section 3—Unitized land and unitized substances.
Section 4—Unit Operator.
Section 5—Resignation or removal of Unit Operator.
Section 6—Successor Unit Operator.
Section 7—Accounting provisions and unit operating agreement.
Section 8—Rights and obligations of Unit Operator.
Section 9—Drilling to discovery.
** Section 9a—Multiple well requirements.
Section 10—Plan of further development and operation.
Section 11—Participation after discovery.
Section 12—Allocation of production.
Section 13—Development or operation of nonparticipating land or formations.
Section 14—Royalty settlement.
Section 15—Rental settlement.
Section 16—Conservation.
Section 17—Drainage.
Section 18—Leases and contracts conformed and extended.
Section 19—Covenants run with land.
Section 20—Effective date and term.
Section 21—Rate of prospecting, development, and production.
Section 22—Appearances.
Section 23—Notices.
Section 24—No waiver of certain rights.
Section 25—Unavoidable delay.
Section 26—Nondiscrimination.
Section 27—Loss of title.
Section 28—Nonjoinder and subsequent joinder.
Section 29—Counterparts.
* Section 30—Surrender.
*Section 31—Taxes.
*Section 32—No partnership.
Concluding Section—in witness whereof.
General Guidelines.
Certification—Determination.

** Paragraph included when more than one obligation well is to be drilled.
* Optional sections (in addition, paragraph (h) of section 18 is optional).

Unit Agreement for the Development and Operation of the

Unit area ______
County of ______
State of ______

No. ______

This agreement, entered into as of the ______ day of ______, 19__, by and between the parties subscribing, ratifying, or consenting hereto, and herein referred to as the "parties hereto,"

Witnesseth

Whereas, the parties hereto are the owners of working, royalty, or other oil and gas interests in the unit area subject to this agreement; and

Whereas the Mineral Leasing Act of February 25, 1920, 41 Stat. 437, as amended, 30 U.S.C. Sec. 181 et seq., authorizes Federal lessees and their representatives to unit with each other, or jointly or separately with others, in collectively adopting and operating a unit plan of development or operations of any oil and gas pool, field, or like area, or any part thereof for the purpose of more properly conserving the natural resources thereof whenever determined and certified by the Secretary of the Interior to be necessary or advisable in the public interest; and

Whereas the parties hereto hold sufficient interests in the ______ Unit Area covering the land hereinafter described to give reasonably effective control of operations therein; and

Whereas, it is the purpose of the parties hereto to conserve natural resources, prevent waste, and secure other benefits obtainable through development and operation of the area subject to this agreement under the terms, conditions, and limitations herein set forth:

Now, therefore, in consideration of the premises and the promises herein contained, the parties hereto commit to this agreement their respective interests in the below-defined unit area, and agree severally among themselves as follows:

1. Enabling Act and regulations. The Mineral Leasing Act of February 25, 1920, as amended, supra, and all valid pertinent regulations including operating and unit plan regulations, heretofore issued thereunder or valid, pertinent, and reasonable regulations hereafter issued thereunder are accepted and made a part of this agreement as to Federal lands, provided such regulations are not inconsistent with the terms of this agreement; and as to non-Federal lands, the oil and gas operating regulations in effect as of the effective date hereof governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State in which the non-Federal land is located, are hereby accepted and made a part of this agreement.

2. Unit area. The area specified on the map attached hereto marked Exhibit A is hereby designated and recognized as constituting the unit area, containing ______ acres, more or less.

Exhibit A shows, in addition to the boundary of the unit area, the boundaries and identity of tracts and leases in said area to the extent known to the Unit Operator. Exhibit B attached hereto is a schedule showing to the extent known to the Unit Operator, the acreage, percentage, and kind of ownership of oil and gas interests in all lands in the unit area. However, nothing herein or in Exhibits A or B shall be construed as a representation by any party hereto as to the ownership of any interest other than such interest or interests as are shown in the Exhibits as owned by such party. Exhibits A and B shall be revised by the Unit Operator whenever changes in the unit area or in the ownership interest of the individual tracts render such revision necessary, or when requested by the Deputy Minerals Manager—Oil and Gas,[1] hereinafter referred to as "DMM," and not less than four copies of the revised Exhibits shall be filed with the DMM.

The above-described unit area shall when practicable be expanded to include therein any additional lands or shall be contracted to exclude lands whenever such expansion or contraction is deemed to be necessary or advisable to conform with the purposes of this agreement. Such expansion or contraction shall be effected in the following manner:

(a) Unit Operator, on its own motion (after preliminary concurrence by the DMM), or on demand of the DMM, shall prepare a notice of proposed expansion or contraction describing the contemplated changes in the boundaries of the unit area, the reasons therefore, any plans for additional drilling, and the proposed effective date of the expansion or contraction, preferably the first day of a month subsequent to the date of notice.

(b) Said notice shall be delivered to the DMM, and copies thereof mialed to the last known address of each working interest owner, lessee, and lessor whose interests are affected, advising that 30 days will be allowed for submission to the Unit Operator of any objections.

(c) Upon expiration of the 30-day period provided in the preceding item (b) hereof, Unit Operator shall file with the DMM evidence of mailing of the notice of expansion or contraction and a copy of any objections thereto which have been filed with Unit Operator, together with an application in triplicate, for approval of such expansion or contraction and with appropriate joinders.

(d) After due consideration of all pertinent information, the expansion or contraction shall, upon approval by the DMM, become effective as of the date prescribed in the notice thereof or such other appropriate date.

(e) All legal subdivisions of lands (i.e., 40 acres by Government survey or its nearest lot or tract equivalent; in instances of irregular surveys, unusually large lots or tracts shall be considered in multiples of 40 acres or the nearest aliquot equivalent thereof), no parts of which are in or entitled to be in a participating area on or before the fifth anniversary of the effective date of the first initial participating area established under this unit agreement, shall be eliminated automatically from this agreement, effective as of said fifth anniversary, and such lands shall no longer be a part of the unit area and shall no longer be subject to this agreement, unless diligent drilling operations are in progress on unitized lands not entitled to participation on said fifth anniversary, in which event all such lands shall remain subject hereto for so long as such drilling operations are continued diligently, with not more than 90-days time elapsing between the completion of one such well and the commencement of the next such well. All legal subdivisions of lands not entitled to be in a participating area within 10 years after the effective date of the first initial participating area approved under this agreement shall be automatically eliminated from this agreement as of said tenth anniversary. The Unit Operator shall, within 90 days after the effective date of any elimination hereunder, describe the area so eliminated to the satisfaction of the DMM and promptly notify all parties in interest. All lands proved productive of unitized substances in paying quantities by diligent drilling operations after the aforesaid 5-year period shall become participating in the same manner as during said first 5-year period. However, when such diligent drilling operations cease, all nonparticipating lands shall be automatically eliminated effective as the 91st day thereafter.

Any expansion of the unit area pursuant to this section which embraces lands theretofore eliminated pursuant to this subsection 2(e) shall not be considered automatic commitment or recommitment of such lands.

3. Unitized land and unitized substances. All land now or hereafter committed to this agreement shall constitute land referred to herein as "unitized land" or "land subject to this agreement." All oil and gas in any and all formations of the unitized land are unitized under the terms of this agreement and herein are called "unitized substances."

4. Unit Operator. ______ is hereby designated as Unit Operator and by signature hereto as Unit Operator agrees and consents to accept the duties and obligations of Unit Operator for the discovery, development, and production of unitized substances as herein provided. Whenever reference is made herein to the Unit Operator, such reference means the Unit Operator acting in that capacity and not as an owner of interest in unitized substances, and the term "working interest owner" when used herein shall include or refer to Unit Operator as the owner of a working interest only when such an interest is owned by it.

5. Resignation or removal of Unit Operator. Unit Operator shall have the right to resign at any time prior to the establishment of a participating area or areas hereunder, but such resignation shall not become effective so as to release Unit Operator from the duties and obligations of Unit Operator and terminate Unit Operator's rights as such for a period of 6 months after notice of intention to resign has been served by Unit Operator on all working interest owners and the DMM, and until all wells then drilled hereunder are placed in a satisfactory condition for suspension or abandonment, whichever is required by the DMM, unless a new Unit

[1] In the Eastern Region and the Alaska Region, the responsible official is the Deputy Minerals Manager—Onshore Minerals.

rator shall have been selected and approved and shall have taken over and assumed the duties and obligations of Unit Operator prior to the expiration of said period.

Unit Operator shall have the right to resign in like manner and subject to like limitations as above provided at any time after a participating area established hereunder is in existence, but in all instances of resignation or removal, until a successor Unit Operator is selected and approved as hereinafter provided, the working interest owners shall be jointly responsible for performance of the duties of Unit Operator, and shall not later than 30 days before such resignation or removal becomes effective appoint a common agent to represent them in any action to be taken hereunder.

The resignation of Unit Operator shall not release Unit Operator from any liability for any default by it hereunder occurring prior to the effective date of its resignation.

The Unit Operator may, upon default or failure in the performance of its duties or obligations hereunder, be subject to removal by the same percentage vote of the owners of working interests as herein provided for the selection of a new Unit Operator. Such removal shall be effective upon notice thereof to the DMM.

The resignation or removal of Unit Operator under this agreement shall not ...inate its right, title, or interest as the ...er of working interest or other interest in ...ed substances, but upon the resignation ...moval of Unit Operator becoming effective, such Unit Operator shall deliver possession of all wells, equipment, materials, and appurtenances used in conducting the unit operations to the new duly qualified successor Unit Operator or to the common agent, if no such new Unit Operator is elected, to be used for the purpose of conducting unit operations hereunder. Nothing herein shall be construed as authorizing removal of any material, equipment, and appurtenances needed for the preservation of any wells.

6. Successor Unit Operator. Whenever the Unit Operator shall tender his or its resignation as Unit Operator or shall be removed as hereinabove provided, or a change of Unit Operator is negotiated by working interest owners, the owners of the working interests according to their respective acreage interests in all unitized land shall, pursuant to the Approval of Parties requirements of the unit operating agreement, select a successor Unit Operator. Such selection shall not become effective until:

(a) a Unit Operator so selected shall accept in writing the duties and responsibilities of Unit Operator, and

(b) the selection shall have been approved by the DMM.

If no successor Unit Operator is selected qualified as herein provided, the DMM at ...lection may declare this unit agreement ...ated.

...ccounting provisions and unit operating agreement. If the Unit Operator is not the sole owner of working interests, costs and expenses incurred by Unit Operator in conducting unit operations hereunder shall be paid and apportioned among and borne by the owners of working interests, all in accordance with the agreement or agreements entered into by and between the Unit Operator and the owners of working interests, whether one or more, separately or collectively. Any agreement or agreements entered into between the working interest owners and the Unit Operator as provided in this section, whether one or more, are herein referred to as the "unit operating agreement." Such unit operating agreement shall also provide the manner in which the working interest owners shall be entitled to receive their respective proportionate and allocated share of the benefits accuring hereto in conforming with their underlying operating agreements, leases, or other independent contracts, and such other rights and obligations as between Unit Operator and the working interest owners as may be agreed upon by Unit Operator and the working interest owners; however, no such unit operating agreement shall be deemed either to modify any of the terms and conditions of this unit agreement or to relieve the Unit Operator of any right or obligation established under this unit agreement, and in case of any inconsistency or conflict between this agreement and the unit operating agreement, this agreement shall govern. Two copies of any unit operating agreement executed pursuant to this section shall be filed with the DMM prior to approval of this unit agreement.

8. Rights and obligations of Unit Operator. Except as otherwise specifically provided herein, the exclusive right, privilege, and duty of exercising any and all rights of the parties hereto which are necessary or convenient for prospecting for, producing, storing, allocating, and distributing the unitized substances are hereby delegated to and shall be exercised by the Unit Operator as herein provided. Acceptable evidence of title to said rights shall be deposited with said Unit Operator and, together with this agreement shall constitute and define the rights, privileges, and obligations of Unit Operator. Nothing herein, however, shall be construed to transfer title to any land or to any lease or operating agreement, it being understood that under this agreement the Unit Operator, in its capacity as Unit Operator, shall exercise the rights of possession and use vested in the parties hereto only for the purposes herein specified.

9. Drilling to discovery. Within 6 months after the effective date hereof, the Unit Operator shall begin to drill an adequate test well at a location approved by the DMM, unless on such effective date a well is being drilled in conformity with the terms hereof, and thereafter continue such drilling diligently until the ——— formation has been penetrated or until at a lesser depth unitized substances shall be discovered which can be produced in paying quantities (to wit: quantities sufficient to repay the costs of drilling, completing, and producing operations, with a reasonable profit) or the Unit Operator shall at any time establish to the satisfaction of the DMM that further drilling of said well would be unwarranted or impracticable, provided, however, that Unit Operator shall not in any event be required to drill said well to a depth in excess of —— feet. Until discovery of unitized substances capable of being produced in paying quantities, the Unit Operator shall continue drilling one well at a time, allowing not more than 6 months between the completion of one well and the commencement (spudding) of the next well, until a well capable of producing unitized substances in paying quantities is completed to the satisfaction of the DMM or until it is reasonably proved that the unitized land is incapable of producing unitized substances in paying quantities in the formations drilled hereunder. Nothing in this section shall be deemed to limit the right of the Unit Operator to resign as provided in Section 5, hereof, or as requiring Unit Operator to commence or continue any drilling during the period pending such resignation becoming effective in order to comply with the requirements of this section.

The DMM may modify the drilling requirements of this section as follows:

(a) For the initial obligation well or wells, a single extension as provided in Section 25, Unavoidable delay, may be granted; and

(b) For all other wells, a single extension, not to exceed 6 months, may be granted, in addition to any extension granted under Section 25.

** 9a. Multiple well requirements. Notwithstanding anything in this unit agreement to the contrary, except Section 25, Unavoidable delay, —— wells shall be drilled with not more than 6-months time elapsing between the completion of the first well and commencement of the second well and with not more than 6-months time elapsing between completion of the second well and the commencement of the third well, . . . regardless of whether a discovery has been made in any well drilled under this provision. Both the initial well and the second well must be drilled in compliance with the above specified formation or depth requirements in order the meet the dictates of this section; and the second well must be located a minimum of —— miles from the initial well in order to be accepted by the DMM as the second unit test well, within the meaning of this section. The third test well shall be diligently drilled, at a location approved by the DMM, to penetrate the ——— formation or to a depth of —— feet and must be located a minimum of —— miles from either the initial or second test well. Nevertheless, in the event of the discovery of unitized substances in paying quantities by any well, the unit agreement shall not terminate for failure to complete the ——— well program, but the unit area shall be contracted automatically, effective the first day of the month following the default, to eliminate by subdivisions (as defined in Section 2(e) hereof) all lands not then entitled to participation.**

Upon failure to commence any well as provided for in this (these) section(s) within the time allowed, prior to the establishment

**Provision is included when multiple wells are to be drilled.

of a participating area, including any extension of time granted by the DMM, this agreement will automatically terminate. Upon failure to continue drilling diligently any well commenced hereunder, the DMM may, after 15-days notice to the Unit Operator, declare this unit agreement terminated. The parties to this agreement may not initiate a request to voluntarily terminate during the first year of its term unless at least one obligation well has been drilled in accordance with the provisions of this (these) section(s).[a]

10. Plan of further development and operation. Within 6 months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the DMM an acceptable plan of development and operation for the unitized land which, when approved by the DMM, shall constitute the further drilling and development obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the DMM a plan for an additional specified period for the development and operation and subsequent plans should normally be filed on a calender year basis not later than March 1 each year. Any proposed modification or addition to the existing plan should be filed as a supplement to the plan.

Any plan submitted pursuant to this section shall provide for the timely exploration of the unitized area, and for the diligent drilling necessary for determination of the area of areas capable of producing unitized substances in paying quantities in each and every productive formation, shall be as complete and adequate as the DMM may determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized area and shall:

(a) Specify the number and locations of any wells to be drilled and the proposed order and time for such drilling; and

(b) Provide a summary of operations and production for the previous year.

Plans shall be modified or supplemented when necessary to meet changed conditions or to protect the interests of all parties to this agreement. Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development and operation. The DMN is authorized to grant a reasonable extension of the 6-month period herein prescribed for submission of an initial plan of development and operation where such action is justified because of unusual conditions or circumstances.

After completion of a well capable of producing unitized substances in paying quantities, no further wells, except such as may be necessary to afford protection against operations not under this agreement and such as may be specifically approved by the DMM, shall be drilled except in accordance with an approved plan of development and operation.

11. Participation after discovery. Upon completion of a well capable of producing unitized substances in paying quantities, or as soon thereafter as required by the DMM, the Unit Operator shall submit for approval by the DMM a schedule, based on subdivisions of the public-land survey or aliquot parts thereof, of all land then regarded as reasonably proved to be productive of unitized substances in paying quantities. These lands shall constitute a participating area on approval of the DMM, effective as of the date of completion of such well or the effective date of this unit agreement, whichever is later. The acreages of both Federal and non-Federal lands shall be based upon appropriate computations from the courses and distances shown on the last approved public-land survey as of the effective date of each initial participating area. The schedule shall also set forth the percentage of unitized substances to be allocated, as provided in Section 12, to each tract in the participating area so established, and shall govern the allocation of production commencing with the effective date of the participating area. A different participating area shall be established for each separate pool or deposit of unitized substances or for any group thereof which is produced as a single pool or zone, and any two or more participating areas so established may be combined into one, on approval of the DMN. When production from two or more participating areas is subsequently found to be from a common pool or deposit, the participating areas shall be combined into one, effective as of such appropriate date as may be approved or prescribed by the DMM. The participating area or areas so established shall be revised from time to time, subject to the approval of the DMM, to include additional lands then regarded as reasonably proved to be productive of unitized substances in paying quantities or which are necessary for unit operations, or to exclude land then regarded as reasonably proved not to be productive of unitized substances in paying quantities, and the schedule of allocation percentages shall be revised accordingly. The effective date of any revision shall be the first of the month in which the knowledge or information is obtained on which such revision is predicated; provided, however, that a more appropriate effective date may be used if justified by Unit Operator and approved by the DMM. No land be excluded from a participating area on account of depletion of its unitized substances, except that any participating area established under the provisions of this unit agreement shall terminate automatically whenever all completions in the formation on which the participating area is based are abandoned.

It is the intent of this section that a participating area shall represent the area known or reasonably estimated to be productive in paying quantities; but, regardless of any revision of the participating area, nothing herein contained shall be construed as requiring any retroactive adjustment for production obtained prior to the effective date of the revision of the participating area.

In the absence of agreement at any time between the Unit Operator and the DMM as to the proper definition or redefinition of a participating area, or until a participating area has, or areas have, been established, the portion of all payments affected thereby shall, except royalty due the United States, be impounded in a manner mutually acceptable to the owners of committed working interests. Royalties due the United States shall be determined by the DMM and the amount thereof shall be deposited, as directed by the DMM, until a participating area is finally approved and then adjusted in accordance with a determination of the sum due as Federal royalty on the basis of such approved participating area.

Whenever it is determined, subject to the approval of the DMM, that a well drilled under this agreement is not capable of production in paying quantities and inclusion of the land on which it is situated in a participating area is unwarranted, production from such well shall, for the purposes of settlement among all parties other than working interest owners, be allocated to the land on which the well is located, unless such land is already within the participating area established for the pool or deposit from which such production is obtained. Settlement for working interest benefits from such a nonpaying unit well shall be made as provided in the unit operating agreement.

12. Allocation of production. All unitized substances produced from each participating area established under this agreement, except any part thereof used in conformity with good operating practices within the unitized area for drilling, operating, and other production or development purposes, for repressuring or recycling in accordance with a plan of development and operations first approved by the DMM, or unavoidably lost, shall be deemed to be produced equally on an acreage basis from the several tracts of unitized land of the participating area established for such production. For the purpose of determining any benefits accruing under this agreement, each such tract of unitized land shall have allocated to it such percentage of said production as the number of acres of such tract included in said participating area bears to the total acres of unitized land in said participating area, except that allocation of production hereunder for purposes other than for settlement of the royalty, overriding royalty, or payment out of production obligations of the respective working interest owners, shall be on the basis prescribed in the unit operating agreement whether in conformity with the basis of allocation herein set forth or otherwise. It is hereby agreed that production of unitized substances from a participating area shall be allocated as provided herein regardless of whether any wells are drilled on any particular part or tract of the participating area. If any gas produced from one participating area is used for repressuring or recycling purposes in another participating area, the first gas withdrawn from the latter participating area for sale during the life of this agreement, shall be considered to be the gas so transferred, until an amount equal to that transferred shall be so produced for sale and such gas shall be allocated to the participating area from which initially produced as such area was defined

[a] If mutiple well provision (9a) is not included, this paragraph shall be the last paragraph of Section 9.

at the time that such transferred gas is finally produced and sold.

13. Development or operation of nonparticipating land or formations. Any party hereto owning or controlling the working interest in any unitized land having thereon a regular well location may with the approval of the DMM, at such party's sole risk, costs, and expense, drill a well to test any formation provided the well is outside any participating area established for the formation, unless within 90 days of receipt of notice from said party of his intention to drill the well, the Unit Operator elects and commences to drill the well in a like manner as other wells are drilled by the Unit Operator under this agreement.

If any well drilled under this section by a working interest owner results in production such that the land upon which it is situated may properly be included in a participating area, such participating area shall be established or enlarged as provided in this agreement and the well shall thereafter be operated by the Unit Operator in accordance with the terms of this agreement and the unit operating agreement.

If any well drilled under this section by a working interest owner that obtains production in quantities insufficient to justify the inclusion of the land upon which such well is situated in a participating area, such well may be operated and produced by the party drilling the same, subject to the conservation requirements of this agreement. The royalties in amount or value of production from any such well shall be paid as specified in the underlying lease and agreements affected.

14. Royalty settlement. The United States and any State and any royalty owner who is entitled to take in kind a share of the substances now unitized hereunder shall hereafter be entitled to the right to take in kind its share of the unitized substances, and Unit Operator, or the working interest owner in case of the operation of a well by a working interest owner as herein provided for in special cases, shall make deliveries of such royalty share taken in kind in conformity with the applicable contracts, laws, and regulations. Settlement for royalty interest not taken in kind shall be made by working interest owners responsible therefor under existing contracts, laws and regulations, or by the Unit Operator on or before the last day of each month for unitized substances produced during the preceding calendar month; provided, however, that nothing in this section shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any royalties due under their leases.

If gas obtained from lands not subject to this agreement is introduced into any participating area hereunder, for use in repressuring, stimulation of production, or increasing ultimate recovery, in conformity with a plan of development and operation approved by the DMM, a like amount of gas, after settlement as herein provided for any gas transferred from any other participating area and with appropriate deduction for loss from any cause, may be withdrawn from the formation into which the gas is introduced, royalty free as to dry gas, but not as to any products which may be extracted therefrom; provided that such withdrawal shall be at such time as may be provided in the approved plan of development and operation or as may otherwise be consented to by the DMM as conforming to good petroleum engineering practice; and provided further, that such right of withdrawal shall terminate on the termination of this unit agreement.

Royalty due the United States shall be computed as provided in 30 CFR Part 221 and paid in value or delivered in kind as to all unitized substances on the basis of the amounts thereof allocated to unitized Federal land as provided in Section 12 at the rates specified in the respective Federal leases, or at such other rate or rates as may be authorized by law or regulation and approved by the DMM; provided, that for leases on which the royalty rate depends on the daily average production per well, said average production shall be determined in accordance with the operating regulations as though each participating area were a single consolidated lease.

15. Rental settlement. Rental or minimum royalties due on leases committed hereto shall be paid by appropriate working interest owners under existing contracts, laws, and regulations, provided that nothing herein contained shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any rental or minimum royalty due under their leases. Rental or minimum royalty for lands of the United States subject to this agreement shall be paid at the rate specified in the respective leases from the United States unless such rental or minimum royalty is waived, suspended, or reduced by law or by approval of the Secretary or his duly authorized representative.

With respect to any lease on non-Federal land containing provisions which would terminate such lease unless drilling operations are commenced upon the land covered thereby within the time therein specified or rentals are paid for the privilege of deferring such drilling operations, the rentals required thereby shall, notwithstanding any other provision of this agreement, be deemed to accrue and become payable during the term thereof as extended by this agreement and until the required drilling operations are commenced upon the land covered thereby, or until some portion of such land is included within a participating area.

16. Conservation. Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to State or Federal law or regulation.

17. Drainage. The Unit Operator shall take such measures as the DMM deems appropriate and adequate to prevent drainage of unitized substances from unitized land by wells on land not subject to this agreement.

18. Leases and contracts conformed and extended. The terms, conditions, and provisions of all leases, subleases, and other contracts relating to exploration, drilling, development, or operation for oil or gas on lands committed to this agreement are hereby expressly modified and amended to the extent necessary to make the same conform to the provisions hereof, but otherwise to remain in full force and effect; and the parties hereto hereby consent that the Secretary shall and by his approval hereof, or by the approval hereof by his duly authorized representative, does hereby establish, alter, change, or revoke the drilling, producing, rental, minimum royalty, and royalty requirements of Federal leases committed hereto and the regulations in respect thereto, to conform said requirements to the provisions of this agreement, and, without limiting the generality of the foregoing, all leases, subleases, and contracts are particularly modified in accordance with the following:

(a) The development and operation of lands subject to this agreement under the terms hereof shall be deemed full performance of all obligations for development and operation with respect to each and every separately owned tract subject to this agreement, regardless of whether there is any development of any particular tract of the unit area.

(b) Drilling and producing operations performed hereunder upon any at that time, such lease shall be extended for 2 years, and so tract of unitized lands will be accepted and deemed to be performed upon and for the benefit of each and every tract of unitized land, and no lease shall be deemed to expire by reason of failure to drill or produce wells situated on the land therein embraced.

(c) Suspension of drilling or producing operations on all unitized lands pursuant to direction or consent of the DMM shall be deemed to constitute such suspension pursuant to such direction or consent as to each and every tract of unitized land. A suspension of drilling or producing operations limited to specified lands shall be applicable only to such lands.

(d) Each lease, sublease, or contract relating to the exploration, drilling, development, or operation for oil or gas of lands other than those of the United States committed to this agreement which, by its terms might expire prior to the termination of this agreement, is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term of this agreement.

(e) Any Federal lease committed hereto shall continue in force beyond the term so provided therein or by law as to the land committed so long as such lease remains subject hereto, provided that production is had in paying quantities under this unit agreement prior to the expiration date of the term of such lease, or in the event actual drilling operations are commenced on unitized land, in accordance with the provisions of this agreement, prior to the end of the primary term of such lease and are being diligently prosecuted long thereafter as oil or gas is produced in paying quantities in accordance with the provisions of the Mineral Leasing Act, as amended.

(f) Each sublease or contract relating to the operation and development of unitized substances from lands of the United States committed to this agreement, which by its terms would expire prior to the time at which the underlying lease, as extended by the immediately preceding paragraph, will expire is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term of the underlying lease as such term is herein extended.

(g) The segregation of any Federal lease committed to this agreement is governed by the following provision in the fourth paragraph of sec. 17(j) of the Mineral Leasing Act, as amended by the Act of September 2, 1960 (74 Stat. 781–784) (30 U.S.C. 226(j)):

Any [Federal] lease heretofore or hereafter committed to any such [unit] plan embracing lands that are in part within and in part outside of the area covered by any such plan shall be segregated into separate leases as to lands committed and the lands not committed as of the effective date of unitization: *Provided, however*, That any such lease as to the nonunitized portion shall continue in force and effect for the term thereof but for not less than two years from the date of such segregation and so long thereafter as oil or gas is produced in paying quantities.

*(h) Any lease, other than a Federal lease, having only a portion of its lands committed hereto shall be segregated as to the portion committed and the portion not committed, and the provisions of such lease shall apply separately to such segregated portions commencing as of the effective date hereof. In the event any such lease provides for a lump-sum rental payment, such payment shall be prorated between the portions so segregated in proportion to the acreage of the respective tracts.

19. Covenants run with land. The covenants herein shall be construed to be covenants running with the land with respect to the interest of the parties hereto and their successors in interest until this agreement terminates, and any grant, transfer, or conveyance of interest in land or leases subject hereto shall be and hereby is conditioned upon the assumption of all privileges and obligations hereunder by the grantee, transferee, or other successor in interest. No assignment or transfer of any working interest, royalty, or other interest subject hereto shall be binding upon Unit Operator until the first day of the calendar month after Unit Operator is furnished with the original, photostatic, or certified copy of the instrument of transfer.

20. Effective date and term. This agreement shall become effective upon approval by the DMM and shall automatically terminate 5 years from said effective date unless:

(a) Upon application by the Unit Operator, such date of expiration is extended by the DMM, or

(b) It is reasonably determined prior to the expiration of the fixed term or any extension thereof that the unitized land is incapable of production of unitized substances in paying quantities in the formations tested hereunder, and after notice of intention to terminate this agreement on such ground is given by the Unit Operator to all parties in interest at their last known addresses, this agreement is terminated with the approval of the DMM, or

(c) A valuable discovery of unitized substances has been made or accepted on unitized land during said initial term or any extension thereof, in which event this agreement shall remain in effect for such term and so long thereafter as unitized substances can be produced in quantities sufficient to pay for the cost of producing same from wells on unitized land within any participating area established hereunder. Should production cease and diligent drilling operations to restore production or new production are not in progress during the period of nonproduction, and production is not restored or should new production not be obtained in paying quantities on committed lands within this unit area, this agreement will automatically terminate effective the last day of the month in which the last unitized production occurred, or

(d) It is voluntarily terminated as provided in this agreement. This agreement may be terminated at any time prior to the discovery of unitized substances which can be produced in paying quantities by not less than 75 per centum, on an acreage basis of the working interest owners signatory hereto, with the approval of the DMM. The Unit Operator shall give notice of any such approval to all parties hereto. Voluntary termination may not occur during the first year of this agreement unless at least one obligation well has been drilled in accordance with Section 9.

21. Rate of prospecting, development, and production. The DMM is hereby vested with authority to alter or modify from time to time, in his discretion, the quantity and rate of production under this agreement when such quantity and rate is not fixed pursuant to Federal or State law, or does not conform to any Statewide voluntary conservation or allocation program which is establish, recognized, and generally adhered to by the majority of operators in such State. The above authority is hereby limited to alteration or modifications which are in the public interest and the purpose thereof, and the public interest to be served must be stated in the order of alteration or modification. Without regard to the foregoing, the DMM is also hereby vested with authority to alter or modify from time to time, in his discretion, the rate of prospecting and development and the quantity and rate of production under this agreement when such alteration or modification is in the interest of attaining the conservation objectives stated in this agreement and is not in violation of any applicable Federal or State law.

Powers is this section vested in the DMM shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than 15 days from notice.

22. Appearances. Unit Operator shall, after notice to other parties affected, have the right to appear for and on behalf of any and all interests affected hereby before the Department of the Interior and to appeal from orders issued under the regulations of said Department, or to apply for relief from any of said regulations, or in any proceedings relative to operations before the Department, or any other legally constituted authority; provided, however, that any other interested party shall also have the right at his own expense to be heard in any such proceeding.

23. Notices. All notices, demands, or statements required hereunder to be given or rendered to the parties hereto shall be in writing and shall be personally delivered to the party or parties, or sent by postpaid registered or certified mail, to the last-known address of the party or parties.

24. No waiver of certain rights. Nothing contained in this agreement shall be construed as a waiver by any party hereto of the right to assert any legal or constitutional right or defense as to the validity or invalidity of any law of the State where the unitized lands are located, or of the United States, or regulations issued thereunder in any way affecting such party, or as a waiver by any such party of any right beyond his or its authority to waive.

25. Unavoidable delay. All obligations under this agreement requiring the Unit Operator to commence or continue drilling, or to operate on or produce unitized substances from any of the lands covered by this agreement, shall be suspended while the Unit Operator, despite the exercise of due care and diligence, is prevented from complying with such obligations, in whole or in part, by strikes, acts of God, Federal, State, or municipal law or agencies, unavoidable accidents, uncontrollable delays in transportation, inability to obtain necessary materials or equipment in the open market, or other matters beyond the reasonable control of the Unit Operator whether similar to matters herein enumerated or not.

26. Nondiscrimination. In connection with the performance of work under this agreement, the Unit Operator agrees to comply with all the provisions of section 202 (1) to (7) inclusive, of Executive Order 11246 (30 FR 12319), as amended, which are hereby incorporated by reference in this agreement.

27. Loss of title. In the event title to any tract of unitized land shall fail and the true owner cannot be induced to join in this unit agreement, such tract shall be automatically regarded as not committed hereto, and there shall be such readjustment of future costs and benefits as may be required on account of the loss of such title. In the event of a dispute as to title to any royalty, working interest, or other interests subject thereto, payment or delivery on account thereof may be withheld without liability for interest until the dispute is finally settled; provided, that, as to Federal lands or leases, no payments of funds due the United States shall be withheld, but such funds shall be deposited as directed by the DMM to be held as unearned money pending final settlement of the title dispute, and then applied as earned or returned in accordance with such final settlement.

Unit Operator as such is relieved from any responsibility for any defect or failure of any title hereunder.

28. Nonjoinder and subsequent joinder. If the owner of any substantial interest in a tract within the unit area fails or refuses to subscribe or consent to this agreement, the owner of the working interest in that tract may withdraw the tract from this agreement by written notice delivered to the DMM and the Unit Operator prior to the approval of this agreement by the DMM. Any oil or gas

*Optional subsection.

interests in lands within the unit area not committed hereto prior to final approval may thereafter be committed hereto by the owner or owners thereof subscribing or consenting to this agreement, and, if the interest is a working interest, by the owner of such interest also subscribing to the unit operating agreement. After operations are commenced hereunder, the right of subsequent joinder, as provided in this section, by a working interest owner is subject to such requirements or approval(s), if any, pertaining to such joinder, as may be provided for in the unit operating agreement. After final approval hereof, joinder by a nonworking interest owner must be consented to in writing by the working interest owner committed hereto and responsible for the payment of any benefits that may accrue hereunder in behalf of such nonworking interest. A nonworking interest may not be committed to this unit agreement unless the corresponding working interest is committed hereto. Joinder to the unit agreement by a working interest owner, at any time, must be accompanied by appropriate joinder to the unit operating agreement, in order for the interest to be regarded as committed to this agreement. Except as may otherwise herein be provided, subsequent joinders to this agreement shall be effective as of the date of the filing with the DMM of duly executed counterparts of all or any papers necessary to establish effective commitment of any tract to this agreement.

29. Counterparts. This agreement may be executed in any number of counterparts, no one of which needs to be executed by all parties or may be ratified or consented to by separate instrument in writing specifically referring hereto and shall be binding upon all those parties who have executed such a counterpart, ratification, or consent hereto with the same force and effect as if all such parties had signed the same document, and regardless of whether or not it is executed by all other parties owning or claiming an interest in the lands within the above-described unit area.

* Surrender. Nothing in this agreement shall prohibit the exercise by any working interest owner of the right to surrender vested in such party by any lease, sublease, or operating agreement as to all or any part of the lands covered thereby, provided that each party who will or might acquire such working interest by such surrender or by forfeiture as hereafter set forth, is bound by the terms of this agreement.

If as a result of any such surrender, the working interest rights as to such lands become vested in any party other than the fee owner of the unitized substances, said party may forfeit such rights and further benefits from operation hereunder as to said land to the party next in the chain of title who shall be and become the owner of such working interest.

If as the result of any such surrender of forfeiture working interest rights become vested in the fee owner of the unitized substances, such owner may:

(1) Accept those working interest rights subject to this agreement and the unit operating agreement; or

(2) Lease the portion of such land as is included in a participating area established hereunder subject to this agreement and the unit operating agreement; or

(3) Provide for the independent operation of any part of such land that is not then included within a participating area established hereunder.

If the fee owner of the unitized substances does not accept the working interest rights subject to this agreement and the unit operating agreement or lease such lands as above provided within 6 months after surrendered or forfeited, working interest rights become vested in the fee owner, the benefits and obligations of operations accruing to such lands under this agreement and the unit operating agreement shall be shared by the remaining owners of unitized working interests in accordance with their respective working interest ownerships, and such owners of working interests shall compensate the fee owner of unitized substances in such lands by paying sums to the rentals, minimum royalties, and royalties applicable to such lands under the lease in effect when the lands were unitized.

An appropriate accounting and settlement shall be made for all benefits accruing to or payments and expenditures made or incurred on behalf of such surrendered or forfeited working interest subsequent to the date of surrender or forfeiture, and payment of any moneys found to be owing by such an accounting shall be made as between the parties within 30 days.

The exercise of any right vested in a working interest owner to reassign such working interest to the party from whom obtained shall be subject to the same conditions as set forth in this section in regard to the exercise of a right to surrender.

*31. Taxes. The working interest owners shall render and pay for their account and the account of the royalty owners all valid taxes on or measured by the unitized substances in and under or that may be produced, gathered and sold from the land covered by this agreement after its effective date, or upon the proceeds derived therefrom. The working interest owners on each tract shall and may charge the proper proportion of said taxes to royalty owners having interests in said tract, and may currently retain and deduct sufficient amount of the unitized substances or derivative products, or net proceeds thereof from the allocated share of each royalty owner to secure reimbursement for the taxes so paid. No such taxes shall be charged to the United States or the State of ——— or to any lessor who has a contract with his lessee which requires the lessee to pay such taxes.

*32. No partnership. It is expressly agreed that the relation of the parties hereto is that of independent contractors and nothing contained in this agreement, expressed or implied, nor any operations conducted hereunder, shall create or be deemed to have created a partnerhip or association between the parties hereto or any of them.

In witness whereof, the parties hereto have caused this agreement to be executed and have set opposite their respective names the date of execution.

Unit Operator; Working Interest Owners

General Guidelines

1. Executed agreement to be legally complete.

2. Agreement submitted for approval must contain Exhibit A and B in accordance with models shown in §§ 226.13 and 226.14.

3. Consents should be identified (in pencil) by tract numbers as listed in Exhibit B and assembled in that order as far as practical. Unit agreements submitted for approval shall include a list of the overriding royalty interest owners who have executed ratifications of the unit agreement. Subsequent joinders by overriding royalty interest owners shall be submitted in the same manner, except each must include or be accompanied by a statement that the corresponding working interest owner has consented in writing. Original ratifications of overriding royalty owners will be kept on file by the Unit Operator or his designated agent.

4. All leases held by option should be noted on Exhibit B with an explanation as to the type of option, i.e., whether for operating rights only, for full leasehold record title, or for certain interests to be earned by performance. In all instances, optionee committing such interests is expected to exercise option promptly.

5. All owners of mineral interests must be invited to join the unit agreement, and statement to that effect must accompany executed agreement, together with summary of results of such invitations. A written reason for all interest owners who have not joined shall be furnished by the unit operator.

6. In the event fish and wildlife lands are included, add the following section:

"Wildlife Stipulation. Nothing in this unit agreement shall modify the special Federal lease stipulations applicable to lands under the jurisdiction of the United States Fish and Wildlife Service."

7. In the event National Forest System lands are included within the unit area, add the following section:

"Forest Land Stipulation. Notwithstanding any other terms and conditions contained in this agreement, all of the stipulations and conditions of the individual leases between the United States and its lessees or their successors or assigns embracing lands within the unit area included for the protection of lands or fucntions under the jurisdiction of the Secretary of Agriculture shall remain in full force and effect the same as though this agreement had not been entered into, and no modification thereof is authorized except with the prior consent in writing of the Regional Forester, United States Forest Service, ———.

8. In the event National Forest System lands within the Jackson Hole Area of Wyoming are included within the unit area, additional "special" stipulations may be required to be included in the unit agreement by the U.S. Forest Service, including the Jackson Hole Special Stipulation.

9. In the event reclamation lands are included, add the following as a new section:

*Optional sections and subsection. (Agreements submitted for final approval should not identify any provision as "optional.")

"Reclamation Lands. Nothing in this agreement shall modify the special, Federal lease stipulations applicable to lands under the jurisdiction of the Bureau of Reclamation."

10. In the event a powersite is embraced in the proposed area, the following section should be added:

"Powersite. Nothing in this agreement shall modify the special, Federal lease stipulations applicable to lands under the jurisdiction of the Federal Energy Regulatory Commission."

11. In the event special surface stipulations have been attached to any of the Federal oil and gas leases to be included, add the following section:

"Special surface stipulations. Nothing in this agreement shall modify the special Federal lease stipulations attached to the individual Federal oil and gas leases."

12. In the event State lands are included in the proposed area, add the appropriate State Lands Section as a new section.
(See 30 CFR 228.7(a))

13. In the event restricted Indian lands are involved, consult the DMM regarding appropriate requirements under 30 CFR 228.7(b).

Certification—Determination

Pursuant to the authority vested in the Secretary of the Interior, under the act approved February 25, 1920, 41 Stat. 437, as amended, 30 U.S.C. sec. 181, et seq., and delegated to the appropriate Deputy Minerals Manager of the Minerals Management Service under the authority of 30 CFR 228, I do hereby:

A. Approve the attached agreement for the development and operation of the ———, Unit Area, State of ———.

B. Certify and determine that the unit plan of development and operation contemplated in the attached agreement is necessary and advisable in the public interest for the purpose of more properly conserving the natural resources.

C. Certify and determine that the drilling, producing, rental minimum royalty, and royalty requirements of all Federal lease committed to said agreement are hereby established, altered, changed, or revoked to conform with the terms and conditions of this agreement.

Dated ———.

Deputy Minerals Manager—Oil and Gas,* Minerals Management Service.

*In Eastern and Alaska Regions, Deputy Minerals Manager—Onshore Minerals.

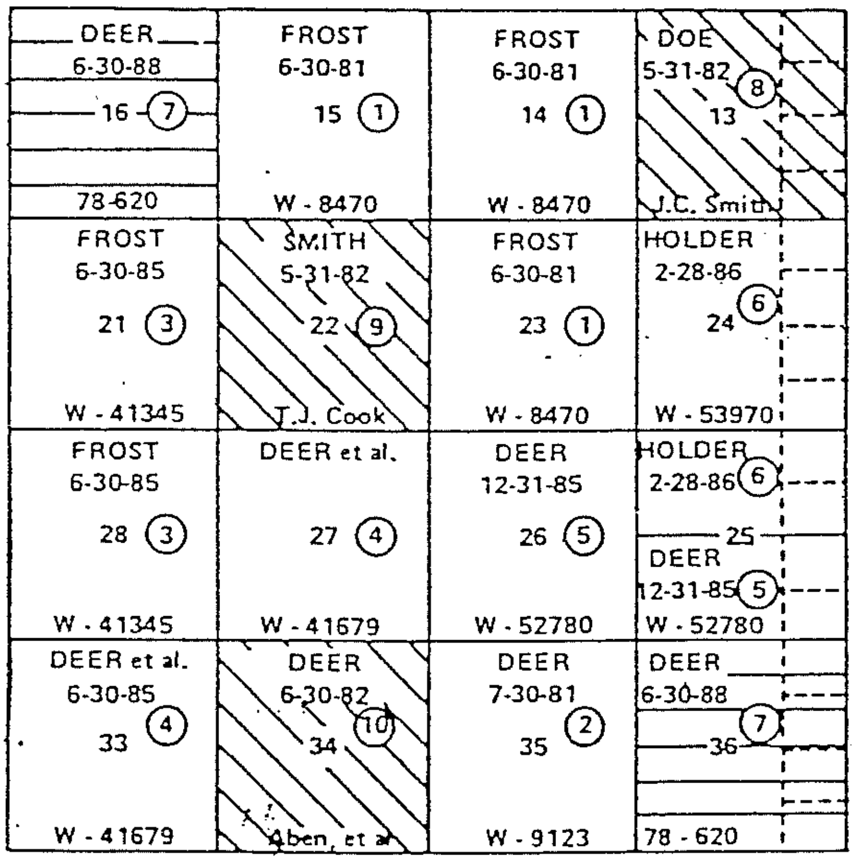
Contract Number———

BILLING CODE 4310-MR-M

§ 226.13 Model of exhibit A.

Company Name
Exhibit A
Swan Unit Area
Campbell County, Wyoming

R. 59 W.



T.
54
N.

(1) Means tract number as listed on Exhibit B

Public Land

State Land

Patented Land

Scale - Generally 2" = 1 mile.

Include acreage for all irregular sections and lots.

BILLING CODE 4310-MR-C

§ 226.14 Model of Exhibit B

EXHIBIT B.—SWAN UNIT AREA, CAMPBELL COUNTY, WYO.

Tract No.	Description of land	Number of acres	Serial No. and expiration date of lease	Basic royalty and ownership percentage	Lessee of record (percent)	Overriding royalty and percentage	Working interest and percentage
	All in the area of T54N-R59W, 6th P.M.						
	Federal Land						
1	Sec. 14: All	1,920.00	W-8470, June 30, 1981	U.S.: All	T. J. Cook 100	T. J. Cook 2	Frost Oil Co. 100.
	Sec. 15: All						
	Sec. 23: All						
2	Sec. 35: All	640.00	W-9123, July 30, 1981	U.S.: All	O. M. Odom 100	O. M. Odom 1	Deer Oil Co. 100.
3	Sec. 21: All	1,280.00	W-41345, June 30, 1985	U.S.: All	Max Pen 50	Max Pen 1	Frost Oil Co. 100.
	Sec. 28: All				Sam Small 50	Sam Small 1	
4	Sec. 27: All	1,280.00	W-41679, June 30, 1985	U.S.: All	Al Preen 100	Al Preen 2	Deer Oil Co. 50.
	Sec. 33: All						Deer Oil Co. 50.
5	Sec. 26: All	961.50	W-52780	U.S.: All	Deer Oil Co. 100	J. G. Goodin 2	Deer Oil Co. 100.
	Sec. 25: Lots 3,4, SW/4,W/2SE/4.						
6	Sec. 24: Lots 1,2,3,4,W/2,W/2E/2 (All).	965.80	W-53970, Feb. 28, 1986	U.S.: All	T. H. Holder 100		T. H. Holder 100.
	Sec. 25: Lots 1,2,NW/4,W/2NE/4.						
	6 Federal tracts 7,047.30 acres or 68.76 pct of unit area.						
	State Land						
7	Sec. 16: All	1,280.60	65-87430, Aug. 31, 1985	State: All	Deer Oil Co. 100	T. T. Timo 2	Deer Oil Co. 100.
	Sec. 36: Lots 1,2,3,4,W/2,W/2E/2 (All).						
	1 State tract 1,280.60 acres or 12.49 pct of unit area.						
	Patented Land						
8	Sec. 13: Lots 1,2,3,4,W/2,W/2E/2 (All).	641.20	Aug. 2, 1974	J. C. Smith: 100	Doe Oil Co. 100		Doe Oil Co. 100.
9	Sec. 22: All	640.00	Sept. 15, 1976	T. J. Cook: 100	W. W. Smith 100	Sam Spade 1	W. W. Smith 100.
10	Sec. 34: All	640.00	June 1, 1975	A. A. Aben: 75	Deer Oil Co. 100		Deer Oil Co. 100.
				L. P. Carr: 25			
	3 patented tracts 1,921.20 acres or 18.75 pct of unit area.						
	Total: 11 tracts 10,249.10 acres in entire unit area.						

§ 226.15 Model collective bond.

Collective Corporate Surety Bond

Know all men by these presents. That we, ——— (Name of unit operator), signing as Principal, for and on behalf of the record owners of unitized substances now or hereafter covered by the unit agreement for the ——— (Name of unit), approved ——— (Date) ——— (Name and address of Surety), as Surety are jointly and severally held and firmly bound unto the United States of America in the sum of ——— (Amount of bond) Dollars, lawful money of the United States, for the use and benefit of and to be paid to the United States and any entryman or patentee of any portion of the unitized land here-to-fore entered or patented with the reservation of the oil or gas deposits to the United States, for which payment, well and truly to be made, we bind ourselves, and each of us, and each of our heirs, executors, administrators, successors, and assigns by these presents.

The condition of the foregoing obligation is such, that, whereas the Secretary of the Interior on ——— (Date) approved under the provisions of the Act of February 25, 1920, 41 Stat. 437, 30 U.S.C. secs. 181, *et seq.*, as amended by the Act of August 8, 1946, 60 Stat. 950, a unit agreement for the development and operation of the ——— (Name of unit and State); and

Whereas said Principal and record owners of unitized substances, pursuant to said unit agreement, have entered into certain covenants and agreements as set forth therein, under which operations are to be conducted; and

Whereas said Principal as Unit Operator has assumed the duties and obligations of the respective owners of unitized substances as defined in said unit agreement; and

Whereas said Principal and Surety agree to remain bound in the full amount of the bond for failure to comply with the terms of the unit agreement, and the payment of rentals, minimum royalties, and royalties due under the Federal leases committed to said unit agreement; and

Whereas the Surety hereby waives any right of notice of and agrees that this bond may remain in force and effect notwithstanding:

(a) Any additions to or change in the ownership of the unitized substances herein described;

(b) Any suspension of the drilling or producing requirements or waiver, suspension, or reduction of rental or minimum royalty payments or reduction of royalties pursuant to applicable laws or regulations thereunder; and

Whereas said Principal and Surety agree to the payment of compensatory royalty under the regulations of the Interior Department in lieu of drilling necessary offset wells in the event of drainage; and

Whereas nothing herein contained shall preclude the United States (from requiring an additional bond at any time when deemed necessary:

Now, therefore, if the said Principal shall faithfully comply with all of the provisions of the above-indentified unit agreement and with the terms of the leases committed thereto, then the above obligation is to be of no effect; otherwise to remain in full force and virtue.

Signed, sealed, and delivered this —— day of ———, 19—, in the presence of:

Witnesses:

____

(Principal)

____

(Surety)

§ 226.16 Model for designation of successor unit operator by working interest owners.

Designation of successor Unit Operator ——— Unit Area, County of ———, State of ———, No. ——.

This indenture, dated as of the — day of ———, 19—, by and between ———, hereinafter designated as "First Party," and the owners of unitized working interests, hereinafter designated as "Second Parties."

Witnesseth: Whereas under the provisions of the Act of February 25, 1920, 41 Stat. 437, 30 U.S.C. secs. 181, *et seq.*, as amended by the Act of August 8, 1946, 60 Stat. 950, the Secretary of the Interior, on the — day of ———, 19—, approve a unit agreement for the ——— Unit Area, wherein ——— is designated as Unit Operator; and

Whereas said ——— has resigned as such Operator,[1] and the designation of a successor

[1] Where the designation of a successor Unit Operator is required for any reason other than resignation, such reason shall be substituted for the one stated.

Re: Expanding Participating Areas Inside Federal Units, The Henry Unit Example

APPROVED this ______ day of _______________, 1985.

BALL ASSOCIATES, LTD.

By ______________________________
Date ______________________________

PRICE WATERHOUSE

By ______________________________
Date ______________________________

UTAH DIVISION OF PUBLIC UTILITIES

By ______________________________
Date ______________________________

STAFF OF WYOMING PUBLIC SERVICE COMMISSION

By ______________________________
Date ______________________________

WEXPRO COMPANY
79 SOUTH STATE STREET · P.O. BOX 11070 · SALT LAKE CITY, UTAH 84147 · 801 530-2700

R. M. KIRSCH
PRESIDENT

December 14, 1983

Wexpro Settlement Agreement Monitors

Gentlemen:

RE: Delivery Point at the Butcher Knife and Church Buttes Fields
Sweetwater County, Wyoming

Wexpro Company respectfully requests concurrence from the Hydrocarbon Monitor and Accounting Monitor to Wexpro's interpretation of the delivery points in the captioned fields.

FACTS

The Butcher Knife Springs field consists of wells 1, 2, 4, 5 and 6 and a Butcher Knife sweetening plant. Wells 1, 2, 4 and 5 produce sour gas thus necessitating sweetening and well No. 6 produces sweet natural gas and oil. Attached Exhibits 1 and 2 are maps showing the well facilities and the related production equipment, plants and laterals.

The Church Buttes field consists of wells 1, 2, 3, 4, 7, 8, 9, 10, 11, 13, 16, 19, 20, 21, 22, 25, 26, 27, 28, 29 and 30 at the time of the execution of the Wexpro Settlement Agreement and also the Church Buttes absorption plant.

Gathering laterals are installed in both fields and a collection lateral No. 703 runs from the Butcher Knife sweetening plant to the Church Buttes absorption plant.

PROBLEM

Because of the joint ownership with others of many of the facilities and the overlapping necessity of two sweetening and absorption plants, Wexpro desires confirmation from the Monitors of the appropriate delivery point in the Butcher Knife and Church Buttes fields. Wexpro also seeks confirmation of the appropriateness of Wexpro's undertaking of operating responsibilities and of investment in post-July 1981 facilities upstream from the delivery point.

WEXPRO COMPANY

79 SOUTH STATE STREET · P.O. BOX 11070 · SALT LAKE CITY, UTAH 84147 · 801 530-2700

R. M. KIRSCH
PRESIDENT

RECEIVED
DEC 09 1987
DIVISION OF
PUBLIC UTILITIES

December 14, 1983

Wexpro Settlement Agreement Monitors

Gentlemen:

RE: Delivery Point at the Butcher Knife and Church Buttes Fields
Sweetwater County, Wyoming

Wexpro Company respectfully requests concurrence from the Hydrocarbon Monitor and Accounting Monitor to Wexpro's interpretation of the delivery points in the captioned fields.

FACTS

The Butcher Knife Springs field consists of wells 1, 2, 4, 5 and 6 and a Butcher Knife sweetening plant. Wells 1, 2, 4 and 5 produce sour gas thus necessitating sweetening and well No. 6 produces sweet natural gas and oil. Attached Exhibits 1 and 2 are maps showing the well facilities and the related production equipment, plants and laterals.

The Church Buttes field consists of wells 1, 2, 3, 4, 7, 8, 9, 10, 11, 13, 16, 19, 20, 21, 22, 25, 26, 27, 28, 29 and 30 at the time of the execution of the Wexpro Settlement Agreement and also the Church Buttes absorption plant.

Gathering laterals are installed in both fields and a collection lateral No. 703 runs from the Butcher Knife sweetening plant to the Church Buttes absorption plant.

PROBLEM

Because of the joint ownership with others of many of the facilities and the overlapping necessity of two sweetening and absorption plants, Wexpro desires confirmation from the Monitors of the appropriate delivery point in the Butcher Knife and Church Buttes fields. Wexpro also seeks confirmation of the appropriateness of Wexpro's undertaking of operating responsibilities and of investment in post-July 1981 facilities upstream from the delivery point.

WEXPRO AGREEMENT LANGUAGE

With respect to the production of hydrocarbons from certain natural gas wells and reservoirs designated "prior Company wells," 1/ and "productive gas reservoirs," 2/ the Wexpro Agreement provides:

> Wexpro will own all operating rights and will be the operator of all facilities related to [Account 101/105] leaseholds. Wexpro will fund and drill or cause to be funded and drilled all necessary and appropriate development wells on these properties and provide the necessary facilities which in its opinion will be reasonably and prudently necessary to efficiently produce the hydrocarbons in the productive gas reservoirs.
>
> Wexpro Agreement Section III-2(b).

The Agreement further provides:

> Although Wexpro will have no ownership in the natural gas, natural gas liquids or oil produced from productive gas reservoirs, as operator it will bill the Company for the services it performs and for the use of the facilities it has installed to produce the Company's natural gas, natural gas liquids and oil.
>
> Wexpro Agreement Section III-5(a).

The operator service fee provisions of the Wexpro Agreement set forth in Exhibit E provide that Wexpro will be reimbursed for its operating expenses including:

> Reasonable and necessary operating expenses incurred by Wexpro and allocated to the production, gathering, treatment and disposition of hydrocarbons.
>
> Wexpro Agreement, Exhibit E, Para. 1.

1/"Prior Company well" is defined as "A well completed on or before July 31, 1981, and capitalized in the Company's utility accounts on that date. All prior Company wells are identified and listed on Schedule 3(b)." Wexpro Agreement, Section I-22.

2/"Productive gas reservoir" is defined as "A portion of a pool underlying an Account 101/105 leasehold or a transferred leasehold into which a prior Company well was completed on or before July 31, 1981. All productive gas reservoirs are identified on Schedule 3(a)." Wexpro Agreement, Section I-25.

Among the wells designated prior Company wells under the terms of the Wexpro Agreement were Butcher Knife wells numbered 1, 2, 4, 5 and 6 and Church Buttes wells numbered 1, 2, 3, 4, 7, 8, 9, 10, 11, 13, 16, 19, 20, 21, 22, 25, 26, 27, 28, 29 and 30.

Wexpro Agreement, Schedule 3(b).

The Wexpro Agreement defines "well" as follows:

> The well bore and all underground and surface materials and facilities installed in connection with drilling into the earth's surface for the production or injection of hydrocarbons and substances. The term "well" includes all the appurtenant facilities.

Wexpro Agreement, Section I-14.

The appurtenant facilities referred to above include:

> Those facilities, downstream from the well head, to and including the delivery point, that are necessary to make the products acceptable for delivery including, but not limited to, compression, transportation, gathering, separation, treating and certain processing facilities.

Wexpro Agreement, Section I-15.

The "delivery point" is defined as:

> That point under standard industry practice, at which a purchaser of oil or natural gas liquids or natural gas takes delivery from the producer. This will generally be (i) at the inlet side of the dehydration unit for gas deliveries and (ii) at the outlet side of tankage or other storage facilities for oil or natural gas liquid deliveries.

Wexpro Agreement, Section I-16.

Concerning post-July 1981 investments in productive gas reservoirs or commercial development gas wells, Section III-4 of the Agreement provides:

> Any investment made in the productive gas reservoirs after July 31, 1981, and in commercial development gas wells (including appurtenant facilities), will not be capitalized into the Company's utility accounts but will be capitalized by Wexpro and Wexpro will be compensated for these investments by the Company as provided in Section III-5. Necessary facilities installed downstream from the delivery point will be capitalized in the Company's utility account.

The Wexpro Agreement also states:

> The delivery of natural gas and natural gas liquids produced under the provisions of this Article III will be at the delivery point (defined in Section I-16), and all costs of receiving, processing and gathering the natural gas and natural gas liquids and all the necessary investment at and downstream from such a point will be the responsibility of the Company.
>
> Wexpro Agreement, Section III-7. 3/

BUTCHER KNIFE AND CHURCH BUTTES

With respect to the Butcher Knife sweetening plant, it has been determined by Wexpro that additional investments are necessary to the gas treatment facilities. The plant provides treatment of sour gas produced from five wells including four of the Company's Butcher Knife wells. Through five separate gathering pipe lines, sour oil and gas production is transported to the Butcher Knife plant where the liquids and gas are separated and then metered at five separate inlet meters. These inlet meters are points where the third party unit participants deliver possession of gas production to Mountain Fuel (or its designate, Mountain Fuel Resources, Inc., "Resources") for processing. The inlet meters are used to allocate production proceeds at the tail gate of the plant.

Under a typical gas purchase agreement involving sour gas at the Butcher Knife plant, the following definition for the "delivery point" of purchased gas is found:

> The delivery point of gas deliverable hereunder shall be at a central delivery point located on the discharge side of buyer's processing plant and/or at such other point(s) as may be mutually designated in writing by the parties hereto. The volumes of gas purchased hereunder will be sellers pro-rata share of the total

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3/With respect to natural gas produced from prior Wexpro wells and productive oil reservoirs, the Wexpro Agreement similarly provides:

> The delivery of natural gas produced under the provisions of this Article II will be at the delivery point (defined in Section I-16), and all costs of receiving the natural gas and all the necessary investment at and downstream from such a point will be the responsibility of the Company.
>
> Wexpro Agreement, Section II-10.

> volume of gas delivered to the inlet of Buyer's processing plant. Title to and ownership of such gas shall pass to an absolutely vest in Buyer at the prescribed point(s) of delivery. 4/
>
> Aminoil USA, Inc., Morgan-Gas Purchase Agreement dated March 4, 1980, Section VII-1.

After Resources takes title to the purchased gas and possession of Mountain Fuel gas at the discharge side of the Butcher Knife plant, the gas is commingled with gas from Butcher Knife well No. 6 and from the Henry Unit and the Hank's Hollow area and transported through lateral No. 703 to Church Buttes.

Butcher Knife Well No. 6 and these two other areas have their own meters and "delivery points" at the inlet side of the respective dehydration units. Gas production from lateral No. 703 is commingled with Church Buttes gas production and then processed through the Church Buttes absorption plant. Here additional processing removes some of the heavier hydrocarbons from the Butcher Knife gas. The "delivery point" for Church Buttes purchased gas has been designated at the discharge side of the Church Buttes plant under the Church Buttes gas purchase agreements. Gas is then transported to Resources' main transmission lines for further transportation and ultimate distribution.

4/The language of one of the typical gas and condensate processing contracts states:

> The point of delivery of gas and condensate per measurement, sampling and for allocation of stabilized plant condensate purposes shall be at the measurement stations installed by Processor on the overhead gas discharge and bottom condensate, respectively, of each of the producers' primary separators.
>
> Redelivery of residue gas by Processor to Producer shall be at the residue gas measurement station installed by Processor at the discharge side of the plant.
>
> Aminoil USA, Inc., Gas and Condensate Processing Contract, dated March 4, 1980, Section III-3, 4; Yates Petroleum Corporation, Gas and Condensate Processing Contract, dated August 21, 1979, Section III-3, 4.

While this language accurately describes the delivery and processing responsibilities in a producer/processor relationship, it does not directly deal with "that point . . . at which a purchaser of oil or natural gas liquids or natural gas takes delivery from the producer."

A geographic map of the Church Buttes and Butcher Knife areas has been prepared and amplified with additional information concerning the physical facilities which are located in the area showing the wells, separation, dehydration, sweetening and absorption facilities. The flow of gas, whether it be Company-owned production or gas purchased from other sources is also shown. With respect to purchased gas, the delivery points specified in each of the pertinent gas purchase agreements for such gas purchases are shown.

Delivery Point at the Outlet of the Butcher Knife Plant.

The delivery point for Company-owned gas production coincides with the delivery point for purchased gas production. 5/ The line drawn between Wexpro responsibilities and Mountain Fuel responsibilities is consistent regardless of the source of gas. The delivery point also coincides with the gas purchase agreements for gas purchases from the Butcher Knife field. Thus, the delivery point determination in the Butcher Knife situation can be objectively made by looking to the delivery point in co-producer gas purchase agreements.

CONCLUSION

The Wexpro Agreement assigns Wexpro the operating and investment responsibilities for facilities needed in the production of Company-owned hydrocarbons from prior Company wells for any appurtenant facilities that lie upstream from the "delivery point." The Agreement defines that "delivery point" as being the point under standard industry practice at which a purchaser takes delivery of gas production from the producer. The delivery points which already exist with respect to gas being purchased from co-producers are the best evidence of where the delivery points defined in the Wexpro Agreement should be.

As applied to the Butcher Knife/Church Buttes area, this determination of the "delivery point" would mean that the delivery point for Company-owned gas processed through the Butcher Knife plant would be at the outlet of that

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5/The language of a typical gas purchase agreement in the Butcher Knife area involving sweet gas, not requiring processing or treatment through the Butcher Knife plant, states:

> The delivery point for gas deliverable hereunder shall be located on the inlet side of the dehydration unit installed by Buyer at the well head . . . .

Aminoil, USA, Inc., Dakota-Gas Purchase Agreement, dated August 29, 1979, Section VII-1.

plant. Gas produced in the Church Buttes area would have a delivery point at the outlet of the Church Buttes plant. The resulting assignment of operating responsibilities between Wexpro and Mountain Fuel pursuant to the Wexpro Agreement would mean that Wexpro would assume initial responsibility for the operation of the Butcher Knife and Church Buttes plants. The responsibility for new investments in sweetening facilities at the Butcher Knife plant also falls to Wexpro.

The language used in such gas purchase agreements fits the definition of "delivery point" as used in the Wexpro Agreement and constitutes one of the examples used in defining delivery point.

Sincerely,

MKeisch

ckb

APPROVED this _______ day of ____________, 1985.

BALL ASSOCIATES, LTD.

By Douglas Ball
Date 85-9-25

PRICE WATERHOUSE

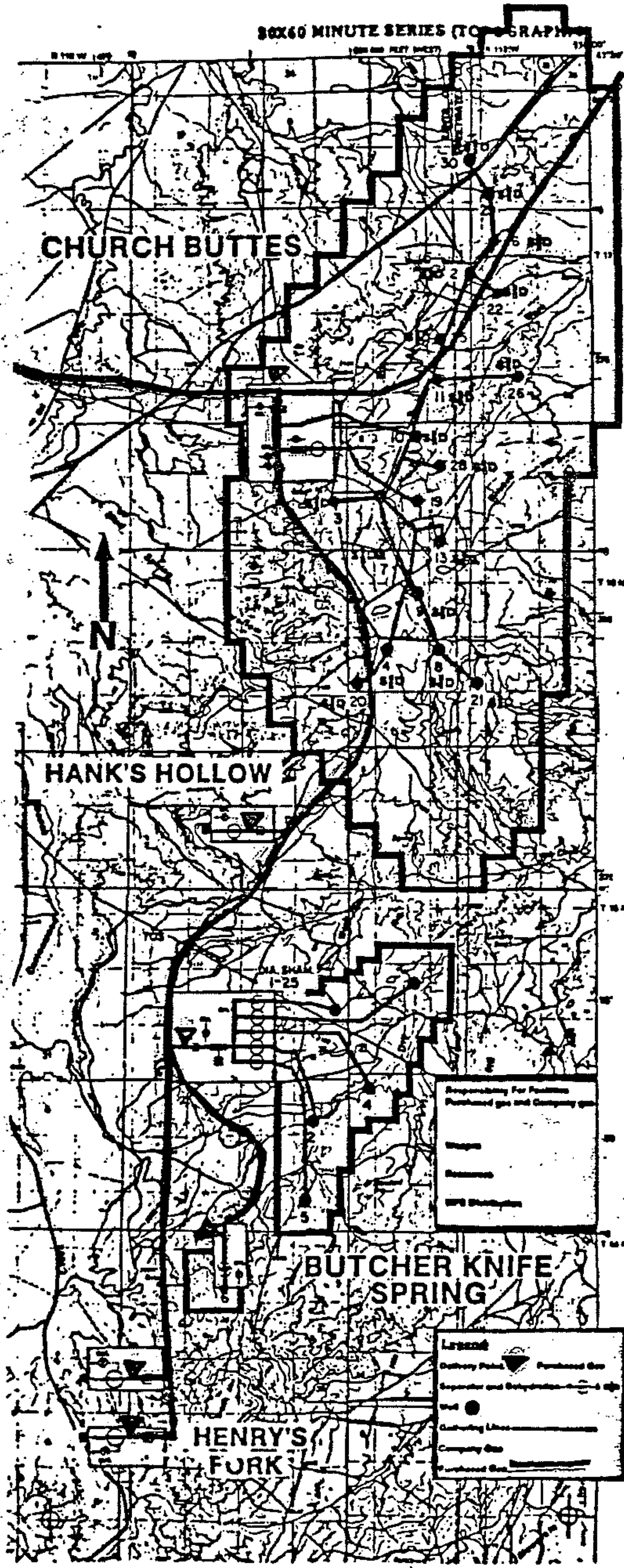
By Kent Watson
Date October 29, 1985

UTAH DIVISION OF PUBLIC UTILITY

By ____________________
Date ____________________

STAFF OF WYOMING PUBLIC SERVICE COMMISSTION

By ____________________
Date ____________________



COMPANY OWNED GAS PRODUCTION AND PURCHASED GAS PRODUCTION WITH PURCHASED GAS DELIVERY POINTS.