Exhibit No. MGP-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MoGas Pipeline LLC **Docket No. RP09- -000**

Prepared Direct Testimony of Alan R. Lovinger

I. Introduction

Q. Please state your name and business address.

A. My name is Alan R. Lovinger, and my business address is 1155 15th Street, N.W., Suite 400, Washington, D.C. 20005.

Q. By whom are you employed and in what capacity?

A. I am a Vice President with the firm of Brown, Williams, Moorhead & Quinn, Inc., and I have been employed by the firm since March 1, 1998.

Q. What are the services offered by Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ")?

A. BWMQ is a leading energy-consulting firm that has been providing advice and assistance to clients for over twenty years. BWMQ provides comprehensive energy-related services on business and regulatory matters to over one hundred clients, including gas and oil pipelines, electric transmission providers, local distribution companies, energy producers, energy trade associations, pipeline shippers and federal and state agencies.

Q. Please briefly describe your education and prior employment.

A. I graduated from Bryant University in 1965 with a B.S. Degree in Business Management. In 1965, I enrolled in an MBA program at Texas Tech University majoring in Accounting. Prior to joining BWMQ, I was employed by the Federal Energy Regulatory

Commission ("FERC") as a Senior Accountant. I was employed by FERC for twenty-five years, from 1966 to the end of 1969 and from 1976 to 1998. My work at FERC was primarily related to cost of service issues with an emphasis on income tax matters, gas storage accounting, allocation of shared services and rate base matters. I provided accounting and tax advice on the rate treatment of storage gas in rate proceedings and I participated in proceedings involving the determination of purchased gas costs in PGA matters. I represented the Commission in dealings with the Internal Revenue Service ("IRS") on income tax issues that arose in various rate proceedings. I also assisted the Commission on rulemakings on various cost of service matters such as tax normalization, cash working capital, and Post Retirement Benefits Other than Pensions. Between 1970 and 1976, I was employed by the IRS as an Internal Revenue Agent. As an agent, I was involved in the auditing of individuals, partnerships and publicly held corporations.

Q. Have you testified previously in proceedings before FERC and state regulatory commissions?

A. Yes. While employed at FERC, I presented expert testimony on cost of service matters and on accounting and accounting-related policy matters on behalf of FERC Trial Staff. Since beginning my employment with BWMQ, I also have testified extensively before FERC and several state regulatory commissions on behalf of our clients. My previous testimony is listed in Exhibit No. MGP-2.

II. Background

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and support the cost-of-service used by MoGas Pipeline LLC ("MoGas") and to develop transportation rates for services rendered on its natural gas pipeline system. The cost-of-service analysis and related supporting schedules are identified as Exhibit No. MGP-3 through MGP-55. My testimony will address and support the policy and ratemaking considerations supporting MoGas' use of the Straight Fixed Variable ("SFV") method of cost classification, cost allocation and rate design. In this regard, I am sponsoring Statement G, Schedules G-1 through G-6, Schedule I-2, Statement J and Schedules J-1 and J-2. I will support the revenue and billing determinants reflected on those schedules.

The cost-of-service study and rate design consists of the following Statements and their related Schedules, all of which I am sponsoring:

Statement A - Total Cost-of-Service (MGP-3)

Statement B – Computation of Rate Base (MGP-4)

Schedule B-1 – Accumulated Deferred Income Taxes (MGP-5)

Statement C – Cost of Plant (MGP-6)

Schedule C-1 – Plant by Account and Function (MGP-7)

Schedule C-4 – Procedures Followed for AFUDC (MGP-8)

Statement D – Accumulated Provisions for Depreciation (MGP-9)

Schedule D-2 – Description of Depreciation and Amortization Policy (MGP-10)

Statement E – Working Capital (MGP-11)

Schedule E-1 – Working Capital (MGP-12)

Statement F-1 – Rate of Return Claimed (MGP-13)

Statement F-2 – Capital Structure (MGP-14)

Statement F-3 – Debt Capital (MGP-15)

Statement G – Revenues, Credits and Billing Determinants (MGP-16)

Schedule H-2(1) – Depreciation, Amortization and Negative Salvage Expenses (MGP-37)

Statement H-3 – Federal, State, and Local Income Taxes (MGP-38)

Schedule H-3(1) – Income Tax by State (MGP-39)

Schedule H-3(2) – Reconciliation of Book & Tax Depreciable Plant and ADIT (MGP-40)

Statement H-4 – Computation of Adjusted Taxes Other than Income (MGP-41)

Schedule I-1(a) – Functionalization of Cost and Allocation Factors (MGP-42)

Schedule I-1(d) – KN Functionalization of G&A Costs (MGP-43)

Schedule I-2 – Classification of Cost of Service Detail (MGP-44)

Schedule I-3 – Schedule of Compressor Station Allowances (MGP-45)

Schedule I-5 – Schedule of Gas Balances (MGP-46)

Statement J – Comparison & Reconciliation of Estimated Operating Revenue & Cost of Service (MGP-47)

Statement J.1 – Compressor Station Roll-in Analysis (MGP-48)

Schedule J-1 – Summary of Billing Determinants (MGP-49)

Schedule J-2 – Computation of Rates (MGP-50)

Statement L – Balance Sheet (MGP-51)

Statement M – Ordinary Income/Expense Income (MGP-52)

Statement O-1 – System Map (MGP-53)

Statement O-2 – Major Expansions and Abandonments (MGP-54)

Statement O-3 – System Design and Operation (MGP-55).

Q. What services does MoGas presently offer its shippers?

A. MoGas provides firm transportation service under Rate Schedule FT and interruptible transportation service under Rate Schedule IT for both Zone I and Zone II shippers. MoGas also provides an authorized overrun service.

Q. Please summarize the results of your cost-of-service analysis.

A. My cost-of-service analysis indicates a total cost-of-service of $18,613,964 and when netting the cost of service by the proposed discount adjustment the total is $13,848,197. The cost of service is $9,471,086 for Zone I and $4,377,111 for Zone II. The cost of service for both zones results in a monthly reservation rate of $12.713, and a 100% load factor interruptible transportation rate of $0.440, for Zone I and a monthly reservation rate for Zone II of $25.463, and a 100% load factor interruptible rate of $0.837. These rates represent an increase from the currently effective rates for both Zones.

Q. Please provide a brief background of the MoGas System.

A. Parts of the MoGas current Zone I system were originally part of an oil pipeline constructed by Amoco in the late 1940's, and operated as such until the early 1980's. In 1989, Amoco sold certain segments of its pipeline system. The majority of the pipeline was converted to natural gas use for the first time in 1989 and commenced natural gas service as Missouri Pipeline Company ("MPC"), a Missouri-regulated intrastate pipeline. The remainder of the pipeline assets purchased in 1989 were physically separated from the MPC portion and were decommissioned. This section of pipe crossed the Mississippi River into Illinois and was not placed into service until 2003. In 2003, the river crossing was physically reconnected to MPC, extended to a connection with Mississippi River Transmission ("MRT"), and placed into service, operating as Missouri Interstate Gas Company, LLC, ("MIG") a FERC jurisdictional gas pipeline pursuant to a certificate issued in Docket No. CP02-399. In 1992, MPC expanded service to Franklin County, Missouri with the construction of 59 miles of new pipeline.

Zone II begins in Southern Franklin County, Missouri, at the former terminus of MPC, runs for 66 miles, and terminates at Fort Leonard Wood Military Base. This part of the pipeline formerly was operated as Missouri Gas Company ("MGC"), a Missouri-regulated gas pipeline.

Q. What were the significant provisions of the Commission's Order in CP02-399 that certificated the former MIG system?

A. The Commission found that because the certificated facilities were devoted to FERC jurisdictional service for the first time, MIG's purchase price of $10.088 million was appropriate for recording plant investment in FERC Account No. 101, Plant Investment, and for ratemaking purposes in establishing jurisdictional transportation rates. The Order established a depreciation rate of 2.5%. The Commission further found that MIG met the threshold requirement of the Commission's Policy Statement of September 15, 1999 and that no subsidization existed.

Q. When were MIG, MPC and MGC combined?

A. The combining of MIG, MPC, and MGC was approved by a Commission Order in Docket No. CP06-407, issued April 20, 2007, 119 FERC ¶ 61,074. The new entity, now named MoGas Pipeline LLC, commenced interstate service on June 1, 2008.

Q. What benefits did this combination provide?

A. The business combination combined the assets into a single interstate pipeline system that allowed MoGas to provide open access, non-discriminatory transportation consistent with the NGA and the Commission's regulations and policies. As an integrated interstate company, MoGas is better able to serve Missouri and Illinois customers and to respond to interstate demand, particularly in Illinois. MoGas was able to eliminate inefficiencies, which enable MoGas to improve service to existing and potential new customers. Since MoGas became a single interstate pipeline, shippers have utilized the Commission's capacity release program, an option that was not available under the former structure.

Q. Did the April 2007 order in the certificate docket contain any conditions relevant to this rate case?

A. MoGas agreed in its application that it would file a Section 4 rate case no later than 18 months after commencing operations. The Commission included such a requirement in the certificate order. The instant rate filing complies with MoGas' commitment and the certificate order. The Order deferred the issues of whether MoGas can include financing and loan fees in rate base, what the proper level of ADIT should be and a purported acquisition premium to this case. The financing and loan fees that were at issue in the certificate order have been removed from MoGas' books and, accordingly, should not be an issue in this proceeding. The other issues are addressed later in my testimony.

Q. Is there another Commission certificate docket that is relevant to this rate proceeding?

A. Yes, Docket No. CP07-450, in which the Commission issued an order on September 25, 2008, 124 FERC ¶ 61,287. In that proceeding, the Commission certificated the Curryville Compressor Station. MoGas submitted a prior notice filing to install compression on its system to both serve new contractual commitments and to ensure reliable service to MoGas' existing customers. MoGas stated that the design was intended to utilize three of the four compressor units for peak flow and have one unit for standby service. At the time, MoGas stated that 1,824 hp of the added compression was necessary to ensure reliability of existing services.

The Commission granted a presumption favoring rolled-in rate treatment for costs of both the increment of compression that ensures reliability of existing service and that associated with the provision of additional service. The Order further stated that because the expansion shipper's transportation rate was subject to a negotiated rate:

> MoGas must also maintain separate and identifiable accounts for volumes transported, billing determinants, rate components, surcharges and revenues associated with any negotiated rates in sufficient detail so that they can be identified in Statements G, I, and J in any future section 4 or 5 rate case.

Q. Is there a negotiated rate shipper?

A. No. The expansion shipper's contract that was discussed by the Commission in the September 25, 2008 Order is not subject to a negotiated rate. The shipper executed a standard form of service agreement. The shipper's contract provided for one rate through March 2009 and then a discounted rate of $4.56 or the recourse rate if lower. The delay in certificating the project means that for all but one month of the contract, the shipper will pay the discounted rate of $4.56. All of the expansion shippers that were added after the Commission's order was issued are recourse rate shippers and the one shipper addressed above, has a discount rate. My testimony and the supporting exhibits will nevertheless show that MoGas has complied with the conditions set by the Commission and that existing pre-expansion shippers benefit from the added compressor units when considering both the increased billing determinants and added costs in developing roll-in rates because the rates are reduced.

Q. Please support the test year used by MoGas in this proceeding.

A. In general, the test year concept refers to the analysis of costs and revenues, for a base period consisting of a consecutive 12-month period followed by a 9-month adjustment period. The costs and revenue considered in this 21-month period are used as a basis for establishing just and reasonable rates. MoGas' base period uses actual data for the twelve-months ending March 31, 2009. The base period data has been taken directly from the books of MoGas. In no instances are costs being allocated to MoGas from an affiliate or parent. The cost reflected in Statement A, Exhibit No. MGP-3, is MoGas' own cost of providing interstate transportation on its system. The test period incorporates adjustments to the base period that are known and measurable with reasonable accuracy and will occur during the 9-months following the end of the base period, or by December 31, 2009.

III. Cost of Service

Q. Identify the total jurisdictional cost-of-service in this proceeding, as shown on Statement A (Exhibit No. MGP-3), and provide an overall view of what the Statement includes.

A. Statement A summarizes the cost component included in the cost-of-service for the test period. The components of the cost-of-service are developed in the other Statements attached to my testimony. The reference column (b) identifies the other Statements and Schedules that provide the necessary support for the indicated line items.

Q. Are you responsible for all components of the cost-of-service study?

A. I am responsible for all components of the cost-of-service study except for the cost of equity capital, depreciation and the negative salvage rates. The capital structure and cost of debt were taken directly from MoGas' financial statements. The cost of equity of

14.34% is supported in the Direct Testimony of MoGas' witness Franklin Knight. Witness Feinstein supports depreciation rates and Witness Taylor supports the negative salvage study along with the calculation of an appropriate negative salvage rate for the transmission facilities.

Q. Who is responsible for developing fuel and lost and unaccounted for gas rates?

A. Witness Feinstein is responsible for those areas.

Q. Will you please explain Statement B (Exhibit No. MGP-4).

A. This Statement summarizes MoGas' overall rate base for both zones. Details of items included in rate base are shown in the Statements and Schedules identified in the reference column (b). Line 8 shows the claimed overall return on rate base.

Q. How did you develop the cost of net plant used to compute the rate base shown on Schedule B?

A. The cost of plant is based upon actual book amounts recorded by MoGas, which are supported on Statement C (Exhibit No. MGP-6) and with more detail on Schedule C-1 (Exhibit No. MGP-7) for Zone I and for Zone II. The accumulated depreciation projected through the end of the test period for both zones is shown on Statement D (Exhibit No. MGP-9). The cost of net plant represents the actual acquisition and construction costs incurred by MoGas and prior owners in constructing its pipeline facilities. MoGas maintains cost centers for both Zone I and Zone II. As will be discussed later in my testimony, common capital costs are allocated based on a direct gross plant ratio.

Q. Is there an acquisition adjustment included in the rate base?

A. No. In the February 19, 2008 order, in Docket No. CP06-407, *et al.*, the Commission responded to the allegation that there is an acquisition premium included in the rate base related to the cost of the former MIG facilities. The Commission pointed out that the original MIG certificate order allowed the full purchase price to be included in rate base. The Commission refused to disturb their finding in the Section 7 proceeding.

Q. Was the Commission correct?

A. Yes, there is no acquisition premium included in rate base. The cost of the MIG facilities included in rate base is the original cost incurred when the facilities first entered interstate service.

Q. Continue with your explanation of Statement B.

A. The working capital on line 4 represents a composite of several prepayments as reflected on Statement E (Exhibit No. MGP-11) and Schedule E-2 (Exhibit No. MGP-12). The balance of accumulated deferred income tax ("ADIT") is reflected on line 6. The computation of the amount of ADIT reflected on line 6 was prepared in accordance with the Commission's policy of full normalization and the provision for ADIT represents full recognition of book/tax timing differences. Schedule B-1 (Exhibit No. MGP-5) begins the computation of ADIT on April of 2008, and ADIT is computed for each month of the test period and projected through December 2009.

IV. Deferred Income Taxes

Q. Was there a significant event that affected MoGas' computation of ADIT?

A. Yes.

Q. Please explain.

A. A change in ownership occurred in February 2007, before the joining of MPC, MGC and MIG, which was deemed an asset purchase; accordingly, a taxable event occurred causing the ADIT balance to go to zero on the date ownership changed.

Q. Was this event previously reported to the Commission?

A. Yes. On February 22, 2007, MoGas filed a letter advising the Commission of the transaction and submitted revised exhibits to the then-pending certificate application.

Q. Please describe the ownership change.

A. EIF Gateway Inc., a Delaware C Corp., purchased 100% of the stock of DES Energy, LTD, a Kansas S Corp. DES Energy, LTD owned 83.5% of the partnership interest in D&D Energy, LLC. D&D Energy, LLC owned 100% of the partnership interest in Mogas Energy, LLC, a Delaware limited liability company, which owns 100% of the partnership interest in United Pipeline Systems, LLC and in the new MoGas Pipeline LLC. As will be explained in detail later in my testimony, because more than 50% of the partnership interest in the above named limited liability companies was transferred in 2007, a technical termination occurred giving rise to a taxable event. *See* Internal Revenue Code of 1954 ("Code"), §708(b)(1)(B). Accordingly, MPC, MGC and MIG made a Section 754 election under the Code with the filing of their tax returns for 2007 that resulted in a step-up in the depreciable basis for MPC, MGC and MIG and their recorded ADIT balance reverted to zero on the date of the sale.

Q. Why are LLC's subject to partnership Federal Tax Regulations?

A. LLCs are entities that are not mandatorily classified as corporations. The IRS Chief Counsel Advice 200235023 states, in pertinent part, that where there has been no corporate election as in the case of a multi-member LLC, "the multi-member LLC is taxed as a partnership which means that the partners will be liable for the income tax….If there has been no corporate election [for a single member LLC], the LLC is disregarded for tax purposes and the single member owner is the taxpayer." Accordingly, under the check-the-box rules of the Code, the default classification of a multimember business entity organized as an LLC is a partnership and is subject to partnership tax regulations.

Code Section 703(b) dealing with partnership elections states, in pertinent part, "Any election affecting the computation of taxable income derived from a partnership shall be made by the partnership…"

Section 754 of the Code provides that if a partnership files an election, the basis of partnership property shall be adjusted, in the case of a transfer of a partnership interest, in the manner provided in Code Section 743(b). Such election shall apply with respect to all transfers of interests in the partnership during the taxable year with respect to which such election was filed and all subsequent years.

Section 743(a) of the Code provides the general rule that the basis of partnership property shall not be adjusted as the result of a transfer of an interest in a partnership by sale or exchange or on the death of a partner unless the election provided by section 754 is in effect with respect to such partnership.

Revenue Ruling 87-115, 1987-2 C.B. 163, holds that in essence, if an election under section 754 is not in effect, the partnership is treated as an independent entity, separate from its partners. The ruling states:

> absent a section 754 election, even though the transferee receives a cost basis for the acquired partnership interest, the partnership does not adjust the transferee's share of the adjusted basis of partnership property. If, however, an election under section 754 is in effect, the partnership is treated more like an aggregate of its partners, and the transferee's overall basis in the assets of the partnership is generally the same as it would have been had the transferee acquired a direct interest in its share of those assets.

Q. Now that it has been established that LLCs are governed by partnership tax law, please explain the issue related to the composition of ADIT used for ratemaking.

A. Code Section 167 provides a deduction for a reasonable allowance for the exhaustion, wear and tear of using property in a trade or business. Section 167 cross-references Section 168 for determining depreciation deductions for most property placed in service after 1980. Section 168 was added in 1981 to provide for more liberal methods and lives than previously allowed under Section 167. Section 168 was amended in 1986 and provides for the Modified Accelerated Cost Recovery System ("MACRS"). MACRS generally applies to tangible property placed in service after 1986. Both MoGas and the previous owner of MoGas' assets used MACRS in the computation of depreciation expense in their respective income tax returns. For ratemaking purposes, utilities use a straight-line method for determining depreciation expense, which results in collection of depreciation dollars from customers before the tax is due, but the accumulated sum is available to pay tax in later years when the asset is fully depreciated for tax purposes. Consequently, the different methods of calculating annual depreciation expense for tax and financial purposes on utility depreciable assets produce what is commonly termed book/tax timing differences. The current ratemaking method used by MoGas to recognize book/tax timing differences prescribed by Section 168 is tax normalization.

Q. Can you please explain the background of the Internal Revenue Service normalization requirement?

A. Yes. To understand the IRS tax normalization requirement, it is helpful to begin with the background of the rule. Congress enacted accelerated depreciation in 1954 to encourage industrial expansion. Accelerated depreciation defers taxes that a company would otherwise pay. Congress perceived this deferral of taxes as an interest free loan, which can be used by companies for capital improvements and expansion that would stimulate the economy.

Q. How did regulatory bodies treat accelerated depreciation after Congress enacted it in 1954?

A. Initially, regulators had two choices. They could choose either a "flow-through method" of regulation or a "normalization method."

Q. Could you explain these two methods of handling accelerated depreciation?

A. Yes. Let me first explain the flow-through method. In this method, the regulators allow the regulated utility to collect tax expense in the cost of service only when the utility actually pays income taxes. In the early years of an asset, the lower income taxes that result from accelerated depreciation "flow-through" to the utility's customers. In essence, the regulator gives the customers the government "loan" to use. Under this method, later customers will have to pay the higher tax bill because while accelerated depreciation results in lower taxes initially, ultimately those lower taxes are paid to the IRS in the later years of the assets' useful life.

Q. Can you explain the other method known as "normalization"?

A. Yes. Under the Normalization Method, the utility customers pay the same amount for tax expense in the cost of service that they would have paid had the taxes paid by the utility been calculated using straight line depreciation. Under this method, the utility collects from its customers more in taxes than it pays the IRS during the early years of the assets' useful life. The income tax effect of the book/tax timing difference is recorded in a deferred tax account. The deferred tax account for utilities subject to the Federal Energy Regulatory Commission's Uniform System of Accounts is Account No. 282, Accumulated Deferred Income Taxes. The "deferred" taxes are removed from Account No. 282 in the later years of the asset life when the utility pays higher taxes to the IRS than it collects from its customers in rates. The point in time when the utility begins to draw down on the ADIT associated with a particular asset is referred to as the "cross-over" point.

Q. So under the normalization method, is it correct that the utility keeps the IRS "loan"?

A. Not entirely. Under the normalization method, the utility does not keep the full advantage of the IRS "loan" because the amount of ADIT is deducted from rate base; however, the utility has the unrestricted use of the funds until the loan is paid back. The ratepayers share in the benefit of normalization because this cost free capital, ADIT, is used as a reduction to rate base; consequently, ratepayers do not pay a return on the funds that the utility received as a loan from the IRS. The utility's deduction of ADIT from rate base in later years decreases, after the "cross-over" period, as prior period deferred taxes are paid to the government.

Q. Which method did regulators use -- the flow-through method or the normalization method?

A. For many years after Congress introduced accelerated depreciation, regulatory agencies did not hold consistent positions regarding rate treatment. Regulators handled accelerated depreciation differently, depending upon how they viewed accelerated depreciation and whether the advantages of this "loan" should accrue to the customers or to the utility and depending upon the regulator's view of the need to match expense with the time-period it was incurred.

Q. Did that change?

A. Yes. Ultimately, Congress became concerned that “flow-through” decisions by regulators, which passed on the tax deferral to the customers, resulted in a “doubling of the Government's loss of revenue, from the use of accelerated methods of depreciation for tax purposes. This is because the current tax reduction reduces the rates charged to customers, which in turn reduces the utility's taxable income and therefore reduces its income tax. This second level of tax reduction is passed on to the utility's customers, with the same effect. H.R. Rep. 91-413 (1969), *reprinted in* 1969 U.S.C.C.A.N. 1645, 1782..

Q. So what did Congress do about this concern related to flow-through treatment by regulators?

A. In the Tax Reform Act of 1969, Congress enacted a rule in Section 441 of the Tax Reform Act, which added § 167(l) to the Internal Revenue Code. This rule basically provided that if a taxpayer is taking accelerated depreciation and is not normalizing its deferred taxes, then it must use the straight line method when determining its depreciation expense for federal income tax purposes. The legislative history reflects that Congress intended to remove regulatory agencies’ ability to require flow-through of deferred taxes. As stated in the legislative history, regulatory agencies “will be permitted to in effect force the taxpayer to straight line depreciation by not permitting normalization. The regulatory agency will not, in such cases, be permitted to require flow through of deferred taxes.” H.R. Rep. 91-413 (1969), *reprinted in* 1969 U.S.C.C.A.N. 1645, 1784. In other words, as a practical matter, Congress took away a regulatory agency’s ability to order flow-through of deferred taxes by taking away the utilities' ability to use accelerated depreciation in the event the regulator ordered the flow-through method of accounting.

Q. Did Congress believe that accelerated depreciation was good for both the utility and its customers?

A. Yes. The 1969 tax change was at issue in a case that went to the United States Supreme Court. This case involved Texas Gas Transmission Corp.'s request for permission from the FPC to use accelerated depreciation with normalization with respect to its post-1969 expansion property. *Federal Power Commission v. Memphis Light, Gas, and Water Division*, 411 U.S. 458 (1973). The Supreme Court opinion discussed the fact that accelerated depreciation is good for both the customers and the company:

> [Accelerated depreciation with] normalization in computing the tax allowance for rate purposes . . . offers more hope for stability of rates for its customers and more assurance that the company can earn its fair rate of return without future rate increases. Further benefits of normalization are that it will improve the company's before tax coverage of interest, thereby enhancing the quality of its securities, and that it will help alleviate present day cash shortages. *Id.* at 465.

Q. Are you aware of any additional significant events related to tax normalization?

A. There are two other significant events: the Economic Recovery Tax Act of 1981 ("1981 Act") and the IRS Normalization Regulations.

Q. Could you explain how the 1981 Act relates to accelerated depreciation?

A. Yes. The 1981 Act requires the normalization approach by regulators as a condition for accelerated depreciation by public utilities of post-1981 properties. S.Rep. 97-144, at 56 (1981), as reprinted in 1981 U.S.C.C.A.N. 105, 161. The purpose of the 1981 amendment was to provide an investment stimulus that Congress viewed as essential for economic expansion. Congress viewed accelerated depreciation as a way of increasing the profitability of investment and encouraging businesses to replace old equipment and structures with modern assets that reflect better technology. Congress was trying to restructure the depreciation deduction as a way of "stimulating capital formation, increasing productivity and improving the nation's competitiveness in international trade." *Id.* at 47, *reprinted in* 1981 U.S.C.C.A.N. 105, 152.

Congress was also trying to make the rules simpler. The legislative history of the 1981 Act makes it clear that Congress viewed "deferred taxes" as an interest-free loan to the utility. *Id.* at 43, *reprinted in* 1981 U.S.C.C.A.N. 105, 149. The utility is able to use this money in lieu of funds that otherwise would have to be obtained by borrowing or raising equity capital. *Id.* Thus, Congress did not want to allow accelerated depreciation unless the regulatory body used the normalization method to account for it. This is why the 1981 Act states that the amount of capital that is deducted from rate base must not exceed the amount of the deferred taxes recorded in compliance with tax normalization.

Q. With that background, could you explain the IRS Normalization Rule?

A. Yes. Section 1.167(l)1(h) of the IRS' regulations, requires a utility that uses accelerated depreciation to use the straight-line method of depreciation (a straight-line method that matches annual book depreciation expense, i.e. service life and rate) in computing its tax expense and its depreciation expense for establishing cost of service for ratemaking purposes. The regulations further require the utility to calculate the annual tax effect of book/tax timing differences and record the increase or decrease on its books in a deferred tax account. The regulations further require that the ADIT balance be used as a reduction to the utility's rate base.

However, if the regulator requires the utility to continue to carry an ADIT balance on its books when that ADIT balance has been eliminated, the utility would be prevented from using accelerated depreciation in current and future years. Thus, the utility would not get the benefit of any tax savings from accelerated depreciation and the cost free capital associated with the book/timing difference.

Q. Please provide more details as to the harm a utility would incur if the IRS determined that a violation of the tax normalization rules were to occur in this rate case.

A. As stated above, Congress originally enacted the normalization rules to ensure that the capital formation benefits of accelerated depreciation can be retained by the utility and for the ratepayer to benefit from reduced rates through the adjustment to rate base. The goal of tax normalization is to prevent regulators from discouraging investment by passing the benefits of accelerated depreciation to ratepayers by reducing the income tax allowance. The normalization rules dictate that accelerated depreciation deductions determined under Section 168 do not apply to any utility property if the taxpayer does not use normalization method of accounting. Tax normalization rules also require that the ADIT reserve be reduced to reflect asset retirement.

Q. Does that complete your explanation of the background?

A. Yes.

Q. Please describe the transaction that resulted in EIF Gateway acquiring DES Energy, Ltd. that owned 83.5% of D&D Energy, LLC.

A. EIF Gateway Inc ("EIF"), a Delaware Corp., was formed in 2007, and is owned by a private equity fund managed by Energy Investor Funds, a private equity fund manager that invests in independent power and the electric utility industry. All assets are privately owned, including the EIF managed fund. When the sale was closed, EIF became the owner of 100% of the limited liability interests of DES Energy, LTD ("DES"), which in turn owned 83.5% of D&D Energy, LLC ("D&D"). D&D is 100% owner of Mogas Energy, LLC ("ME"), which is 100% owner of MoGas Pipeline LLC. Consequently, 100% of the limited liability interest of the FERC jurisdictional MoGas Pipeline LLC, the predecessor of MPC, MGC and MIG, was sold in February 2007.

Q. What were the tax consequences to both the seller and buyer with the acquisition as described above?

A. The acquisition of DES and the subsequent change in ownership of more than 50% for income tax purposes resulted in a technical termination of D&D, ME, and MoGas. The practical implication of the termination to the LLCs is that the sale is treated as an asset sale for federal income tax purposes. Accordingly, the sale was recognized as a taxable transaction resulting in taxable gain or loss to the former owner of DES. Under the Code, gain is determined by the amount realized reduced by the seller's adjusted tax basis in the asset sold and is reportable by the seller under Code Section 1001.

MoGas has further obligations under tax normalization rules. When a company that owns public utility property that it depreciates under an accelerated method for tax purposes sells public utility assets, it is required by the normalization rules to reduce its deferred tax reserve to reflect the retirement of those assets. Accordingly, the ADIT balance associated with the sold assets is removed from the seller's regulatory books of account. This removal reflects the fact that the interest free loan to the utility in the form of deferred taxes is now payable to the IRS to recognize the seller's gain or loss on the sale of utility assets, pursuant to Code Section 1001. The buyer takes a new basis in the acquired utility assets that reflects the buyer's asset purchase price (referred to as a step-up cost basis to reflect the fact that the new buyer has a higher basis than the previous owner). As such, on the purchase date the buyer will have a beginning zero ADIT reserve.

Q. What is the significance of the step-up in the tax basis of the utility property for MoGas ?

A. As a result of the acquisition by EIF, the ADIT balance on MoGas' regulatory books was reduced to zero in recognition of the former owner's taxable gain on its sale of utility assets. Consequently, the purchased assets were recorded on MoGas' books with a zero balance in the deferred tax account, Account No. 282. In addition, since the transaction was treated as an asset purchase, the basis of MoGas' depreciable assets for tax purposes increased from the depreciated balance reflected prior to the acquisition to the buyer's tax cost for those assets, which was determined to be equal to the remaining net regulatory book basis of the depreciable plant on the date of purchase. The new tax basis established for MoGas' depreciable assets exceeded the prior remaining tax basis on its books prior to the sale. Accordingly, on a going forward basis, MoGas will recognize higher tax depreciation expense that will generate more ADIT over the assets' depreciable lives than MoGas would have had if the sale did not take place.

Q. Is there another reason why MoGas will recognize annual increases to accumulated deferred taxes above what MoGas would have generated on an annual basis prior to the sale?

A. Yes. Besides the fact that MoGas has a larger tax depreciable basis than that available to it prior to the sale, MoGas depreciates the balance at an accelerated rate due to MoGas' election to use MACRS. MACRS establishes a depreciable life for most of the acquired assets of 15 years. MACRS, in the early years, uses accelerated rates that decrease in each succeeding year. Thus, MoGas has recognized significantly more tax depreciation and accordingly higher yearly deferred tax accruals than would have been previously recorded by MoGas had the acquisition not taken place.

Q. Did MoGas' regulatory books also begin with a zero balance in the reserve for depreciation?

A. No. The depreciable basis and the reserve for depreciation for rate purposes and accordingly for MoGas' regulatory books remained consistent with the depreciable basis and reserve reflected on the books of MoGas prior to the acquisition. These balances are maintained to be consistent with the "original cost" regulatory concept.

Q. What are the rate and tax implications if a regulator does not recognize the full implementation of tax normalization rules?

A. The normalization rules dictate the regulatory treatment of income tax expense and accumulated deferred income tax reserves or ADIT. The Code further provides that accelerated depreciation determined under Section 168 does not apply to any public utility property if the taxpayer does not use a tax normalization method of accounting. Thus, a utility cannot use accelerated methods of depreciation for utility property if that taxpayer does not comply with the tax normalization rules.

Simply stated, the tax normalization rules require a utility to maintain an ADIT account for the tax effect of the difference between regulatory book depreciation and accelerated depreciation. The ADIT recorded on the utility’s regulatory books must be maintained in accordance with tax normalization rules. The Code further requires that the ADIT balance be maintained in accordance with Section 168 and that such balance be used in the determination of rate base. Thus, if regulators were to require a flow-through of tax benefits or the use of the prior owner's ADIT balance in the computation of rate base, this act would cause a violation of IRS regulations and the utility would be prevented from computing accelerated depreciation pursuant to Code Section 168. As a result, ratepayers would pay higher rates in the future due to the increase in rate base caused by the loss of accelerated tax depreciation. Further, the utility would need to raise additional capital since it could not count on interest free loans generated from the use of accelerated tax depreciation.

Q. Please identify the specific IRC reference that prescribes the method used to determine tax depreciation if IRS determines that a violation of tax normalization has occurred?

A. The specific reference is Internal Revenue Code Section 168(i)(9)(C), which provides:

> Public Utility Property Which Does Not Meet Normalization Rules – In the case of any public utility property to which this section does not apply by reason of subsection (f)(2), the allowance for depreciation under section 167(a) shall be an amount computed using the method and periods referred to in subparagraph (A)(i).

Subparagraph (A)(i) of Section 168(i)(9) provides:

> the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is no shorter than the method and period used to compute its depreciation expense for such purposes.

Thus, the Internal Revenue Code restricts tax depreciation to the utility's regulatory depreciation method when there is a normalization violation.

Q. Are you aware of any IRS ruling in which a regulated utility involved in a deemed sale of assets would have incurred a normalization violation?

A. Yes, I am. On August 4, 1994, the IRS, in Private Letter Ruling 9447009, ruled that there would be a normalization violation if, subsequent to the date of the acquisition and deemed sale of assets of a natural gas transmission company, the natural gas company's rate base was reduced for the balance in the reserve for the ADIT attributable to accelerated depreciation on public utility property before the acquisition date. In that case the parent sold the gas company to the buyer pursuant to a Section 338(h)(10) transaction. Such transaction, although structured as a stock sale, was treated as an asset sale by the selling and buying corporations for tax purposes. The IRS ruled that because of the deemed sale of the seller's assets, the seller's ADIT balance ceased to exist and had to be removed from the seller's regulated books of account and could not be flowed through to customers. Further, the IRS ruled that a normalization violation would occur if the seller's ADIT balance that existed before the acquisition were used to reduce the buyer's rate base.

Q. Has FERC addressed a regulated utility's income tax implications upon the sale of more than 50% partnership interest that was deemed to be an asset sale?

A. Yes. In *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 (2002), Midcoast Energy Resources, Inc. ("Midcoast") purchased 100 percent of the partnership interest in Kansas Pipeline Company ("KPC"), a partnership (prior to the Commission's order, Midcoast was purchased by Enbridge). Upon the sale, KPC made an election under Section 754 of the Internal Revenue Code. The implications of the election were that KPC was deemed to have sold its assets rather than its partnership interest to the ultimate purchaser, Midcoast. Midcoast was permitted to step-up the tax basis of KPC assets to an amount equivalent to the purchase price of the partnership interest. Upon the recognition of the taxable event, KPC's deferred income tax balance became zero on the date of the purchase. The Commission found that a taxable event occurred, taxes were due, and the existing ADIT balances were properly reduced to zero as the result of the deemed sale. In *Enbridge* the Commission further stated:

> Thus, tax normalization consideration comes into play in determining the correct amount of ADIT. In order to continue to qualify for accelerated depreciation, a company must follow IRS normalization rules concerning ADIT. Accordingly, the Commission must keep these tax considerations in mind in the examination of ADIT. As a result, when a sale results in a company recording a taxable event, the company has recognized this event and eliminated the ADIT balance in accordance with the normalization rules.

100 FERC ¶ 61,260, at p. 61,954.

Q. **How does the Federal Energy Regulatory Commission's Uniform System of Accounts addresses the acquisition of assets with respect to ADIT?**

A. The tax effect of the book/tax timing differences for plant investment is recorded in FERC Account No. 282. With respect to the regulations, Part 201, Account No. 282, Part D, the FERC specifically restricts the use of Account No. 282 to the purpose for which the account was established. Deferred income tax recorded in Account No. 282 must represent the tax liability due because of the recognition of book/tax timing differences. Further, the regulations specifically restrict transferring any balance to retained earnings or making any other use thereof, except as provided by instructions to Account No. 282. The instructions state that:

> Upon the disposition by sale, exchange, transfer, abandonment or premature retirement of plant on which there is a related balance herein, this account shall be charged with an amount equal to the related income tax expense, if any, arising from such disposition ...

Thus, the FERC rules recognize that upon an asset sale (or a deemed asset sale for income tax purposes as is the case with MoGas), the seller's ADIT balance is extinguished since any deferred taxes are due and payable by the seller at the time of sale.

Q. Have you discussed the procedures used by MoGas in the computation of ADIT recorded in Account No. 282 to be used in the computation of rate base in this proceeding and, if so, what is your conclusion?

A. Yes, I have discussed those procedures and it is my opinion that MoGas has put in place on its books all of the necessary steps needed to properly determine an ADIT balance that will be fully compliant with the requirements of tax normalization, the Uniform System of Accounts, and Commission precedent.

Q. Please continue your discussion of Statement B.

A. Line 7, Column (d) and (e) shows the net rate base for Zones I and II. Line 8 of Statement B reflects the total return for both Zones I and II, which is calculated by multiplying the net rate base by the overall return rate, as calculated on Statement F-2 (Exhibit No. MGP-14).

Q. Please describe Schedule B-1 (Exhibit No. MGP-5).

A. Schedule B-1 shows the monthly balances for ADIT for Account Nos. 190, 282 and 283. Account No. 190 involves an interest swap that MoGas entered into in 2007 in the process of refinancing its current debt. The swap essentially converted the financial instrument from a variable interest rate to a fixed interest rate. The swap was executed at no cost to MoGas; consequently, the computation of MoGas' debt cost in the instant proceeding was unaffected by MoGas entering into the swap. However, there is a book/tax difference between MoGas' generally accepted accounting principles ("GAAP") books and its tax return that accounts for the ADIT debit balance of $1,262,942. The $1,262,942 balance is not appropriate to add to MoGas' rate base because the entire transaction does not affect MoGas' rates. Thus, a test period adjustment for $1,262,942 was made. Test period adjustments were also made to Account Nos. 282 and 283 to update through the end of the test period.

Q. Please explain why MoGas' entering into the swap arrangement does not affect rates.

A. As stated above MoGas entered into the swap at no cost to MoGas. The swap stabilized MoGas' annual debt cost. Any cost incurred should be combined with other debt acquisition costs in the calculation of the utility's cost of debt. Since MoGas had no cost related to the swap, the calculation of MoGas' debt was unaffected by the swap and the related ADIT should not be included in the computation of rate base.

Q. Do the Commission's regulations discuss this issue?

A. Yes. 18 C.F.R. § 154.305(c)(2) specifies that any reductions or additions to rate base are limited to deferred taxes related to rate base, construction or other costs and revenues affecting jurisdictional cost of service. This transaction does not fit any of those categories; thus, no rate base adjustment is appropriate here.

Q. Please provide an explanation for Statement C (Exhibit No. MGP-6) and Schedule C-1 (Exhibit No. MGP-7).

A. Column (d) of Statement C reflects plant additions for Zone I. Column (d) also shows that Zone II had no plant additions. Schedule C-1, which encompasses both Zones I and

II, shows plant additions through the end of the test period that include compressor stations additions, metering and pipeline interconnects.

Q. Do these schedules reflect reductions in general plant?

A. Yes, there were substantial reductions in the recorded amounts for general plant for both zones. MoGas' predecessor purchased the pipeline from Utilicorp through a stock purchase in 2002 and maintained Utilicorp's original regulatory costs on MoGas' regulated utility books. Upon a review of MoGas' books after the Commission approved MoGas' business combination, it became evident that the amounts recorded by MoGas for general plant did not agree with the general plant in MoGas' possession. Upon further review, MoGas determined that some of the general plant, for which amounts were recorded on MoGas' regulated books post-acquisition, may not actually have been acquired as part of the 2002 stock purchase transaction. The review also disclosed that some of the general plant items that were acquired in the 2002 stock purchase transaction had since been disposed of. Therefore, MoGas prepared an inventory of its general plant and corrected the amounts recorded for general plant to reflect only the cost of the general plant actually acquired in the 2002 stock purchase transaction that it still owns and to properly state asset values in the accounts at an amount equal to MoGas' GAAP books. MoGas also recognized a retirement for the general plant that was not supported by the physical inventory. The net result was that general plant for Zone 1 was reduced by $1.5 million and for Zone II by $.96 million with a corresponding adjustment to the owners' equity.

Q. Please describe Statement D (Exhibit No. MGP-9).

A. Statement D reflects accumulated depreciation expense for both zones. The accumulated balances were projected through the end of the test period.

Q. Please describe Statement F-2 (Exhibit No. MGP-14).

A. Statement F-2 reflects MoGas' proposed capitalization that includes both the cost of debt and equity. MoGas' witness Franklin Knight will be supporting the return on equity and I am supporting MoGas' capitalization and the cost of debt. The debt and equity ratios shown on the capitalization come directly from MoGas' financial statements. Both debt and equity shown on Column (d) were projected through the end of the test period, December 31, 2009.

Q. How was debt cost computed?

A. The computation of debt cost is shown on Statement F-3 (Exhibit No. MGP-15) along with details on MoGas current debt outstanding. To calculate the debt cost used in MoGas' capitalization, I determined the annual interest cost by multiplying debt outstanding times the coupon rate on the debt of 6.596%. I then calculated the annual amortization of the debt acquisition cost ($721,432/5 = $144,286). I then summed the amortized debt acquisition cost and the annual interest cost. That number was divided by MoGas' net proceeds (outstanding debt less the debt acquisition cost) from the loan to arrive at the cost of debt of 7.24%.

Q. Explain why you netted the debt outstanding by the debt acquisition cost.

A. The computation was performed to determine MoGas' true cost of its borrowed funds. The proceeds received were net of the debt acquisition cost (the acquisition cost is as much a cost of debt as the interest costs), consequently to determine the true cost of the debt, the annual cost of the net proceeds must be divided by the net proceeds. If MoGas's cost of debt is not calculated in this manner MoGas would not be able to recover its actual cost of the debt and consequently, would not be able to earn its allowed return on equity.

V. Revenue and Billing Determinants

Q. Please provide an explanation of Statement G (Exhibit No. MGP-16) and the accompanying schedules.

A. Schedule G-1 contains the base period billing determinants by month and by individual shipper contracts and Schedule G-1.1 reflects the monthly revenue earned by individual contracts. The base period begins in April 2008 and ends March 2009. The contracts are separated between Zone I and Zone II. A separate commodity activity for the twelve month period for each zone is shown. The commodity volumes represent the actual throughput by month for each IT contract. The transportation contract with Laclede Gas Company has a discounted maximum monthly reservation rate of $6.324. Because the transportation rate is at a discount with an unaffiliated shipper, MoGas is seeking a discount adjustment, the mechanics of which are discussed in more detail later in my testimony. As shown under the Column labeled "term" in both Schedules G-1 and G-1.1, all contracts exceeded a one-year term. MoGas has no affiliated entities that are in the business of marketing gas. Pursuant to the Commission's regulations, the proposed discount is not reflected in the calculation of billing determinants on either Schedule G-1 or Schedule G-2 (Exhibit No. MGP-18), which provides adjustment period revenues.

MoGas generally experiences minor IT volumes. However, the base period IT volumes were an exception due to unusual circumstances experienced by MoGas in 2008. In 2008, the western portion of the Rockies Express Pipeline ("REX") terminated at the Panhandle system-interconnection in the State of Missouri upstream of MoGas' interconnection with Panhandle. Shippers wanted to move their REX gas to points east of Missouri and one of the transportation options was IT transportation on MoGas. Thus, MoGas experienced significant IT volumes during the base period that were transported through Zone I into Laclede and MRT. However, once the eastern leg of REX is placed into service, this temporary opportunity will not be available. REX has announced that it will go into service in late June 2009. The issue of the appropriate IT volumes that I have imputed in my rate design will be discussed later in my testimony.

Q. Please explain why there are relatively higher commodity revenues for Zones I and II in April and May of 2008 in comparison to the other base period months.

A. MoGas became FERC jurisdictional on June 1, 2008 and the computation of its rates under FERC regulation was under the SFV rate design. Prior to June 1, 2008, MoGas rates were determined using MFV rate design, which allocated a certain amount of fixed costs to the commodity rate in both zones. Therefore, under SFV all fixed costs are collected in the reservation rates, which increased, and the commodity rates only recovered variable costs, which were lower, resulting in lower commodity revenues after June 1, 2008.

Q. Please provide an explanation of Schedule G-2 (Exhibit No. MGP-17).

A. There were virtually no changes in billing determinants between the base and adjustment periods with the exception of the added billing determinants for the expansion shippers (the compression went into service on March 1, 2009, the last month of the base period and the commencement of service for the expansion shippers). Consequently, no adjustments are being proposed to the base period billing determinants, as reflected in Schedule G-3 (Exhibit No. MGP-19). Schedule G-2 reflects the test period revenues and billing determinants. The IT revenues experienced by MoGas in the latter part of 2008 and the first 5 months of 2009 indicate that there is little interest for such services. Consequently, IT volumes of 70 Dth/day were imputed at a level that represented the expected IT volumes from MoGas' only current active IT contract that is not expected to terminate once REX enters operation.

MoGas has no seasonal transport services and the recognition of MoGas' transportation revenue reflects little change from month to month. For that reason, calculating monthly revenue for the contracted services would be of no benefit because each of the twelve months would be identical. Thus, Schedule G-2 only projects the yearly revenue for each transportation contract, reflected on the last right hand column

Q. Please describe Schedules G-3 through G-6 (Exhibit Nos. MGP-19, MGP-20, and MGP-21).

A. The Commission regulations require the utility to identify and explain on Schedule G-3 detail for the test period adjustments made to the base period billing determinants. Because MoGas is not proposing adjustments to base period billing determinants the completion of Schedule G-3 is not applicable to MoGas, as reflected in Exhibit No. MGP-19. Schedule G-4 (Exhibit No. MGP-20) requires a presentation of revenue by customer for certificated facilities that the Commission designated such facilities to be "at risk." MoGas does not have any facilities that meet this criterion. However, Schedule G-4 is a convenient venue to report projected revenue by the expansion shippers on the new compression and to demonstrate that there has been no significant change that would justify changing the presumption of rolled-in rate treatment for the Curryville Compressor Station. This is discussed below. Schedule G-5 (MGP-21) is not applicable because MoGas does not have other revenue sources that would apply as credits to the cost of service. Finally, Schedule G-6 is not applicable to MoGas because the pipeline generates no miscellaneous revenues. Thus, Schedule G-6 is omitted.

Q. Discuss your computation of revenue for expansion shippers presented on Schedule G-4 (Exhibit No. MGP-20).

A. The Commission found that the compression facilities authorized in Docket No. CP07-450 were entitled to the presumption of rolled-in rate treatment. However, the Commission did point out that if MoGas did not secure the revenues projected in the order, the Commission could remove the presumption of rolled-in rate treatment.

Q. What revenues have you calculated for the expansion shippers?

A. The compression was placed into service in March 2009. Thus, MoGas had only one month of expansion revenue in the base period. For the adjustment period, revenues for Laclede Energy Resources' 20,000 Dth/day were determined using the monthly reservation rate of $4.56. The total calculated revenue is $1,094,400, as shown in the last column on Schedule G-4. The remaining expansion capacity revenue was determined using the rates for Zone 1 calculated on Schedule J-2 (Exhibit No. MGP-50). The rates calculated on Schedule J-2 were also used to determine the revenue for Zone II. Schedule G-4 also reflects an increase in the expansion capacity found in the Commission's September 25, 2008 order in Docket No. CP07-450. At that time, the contracted expansion capacity was 20,000 Dth/day for Zone I and 0 Dth/day for Zone II. These amounts have expanded to 22,364 Dth for Zone I and 1,364 Dth for Zone II.

Q. Did the projected revenue level change?

A. Yes. As the Commission noted, the original shippers' precedent agreement had a higher rate for a 15-month period, from January 1, 2008 to March 30, 2009. Because the Commission took almost a year to act on the application, the shipper only paid the higher rate for one month. The original revenue that the Commission considered in the certificate proceeding in Docket No. CP07-450 was $1,421,645. The current rate from that shipper generates revenue of $1,094,400. However, subsequent shippers have signed up for additional expansion capacity. As shown on Schedule G-4, this additional capacity increases the revenue to an amount in excess of $1.8 million. All of the dollar amounts addressed above are annual numbers.

Q. Does this change affect the presumption of rolled in rates?

A. No, there has been no significant change that warrants revisiting that presumption.

Operation and Maintenance Expense

Q. Please provide an explanation for Statement H-1 (Exhibit No. MGP-22), Schedules H-1(1) (Exhibit No. MGP-23), H-1(1)(a) (Exhibit No. MGP-24), H-1(1)(b) (Exhibit No. MGP-25), and H-1(2) (Exhibit No .MGP-26).

A. Statement H-1 includes operation and maintenance expenses for both Zone I and Zone II. Column (n) of Statement H-1 shows MoGas' proposed test period adjustments. Workpapers labeled Workpapers 1-4, provide materials and supplies and labor costs by zone.

The Commission regulations require that Schedule H-1(1) reflect the utility's cost for labor and other charged to Account Nos. 810 through 812. MoGas did not purchase gas in the base period and has no cost recorded in those accounts.

Schedule H-1(1)(a) includes MoGas' labor cost for each month of the base period.

Column (n) of Schedule H-1(1)(a) reflects the test period adjustments to labor. Schedule H-1(1)(b) reflects twelve months of materials and supplies for the base period. The test period adjustments are shown on Column (n) of that schedule. Schedule H-1(2) reflects the test period adjustments.

Q. Please explain the test period adjustments.

A. The first adjustment is labor cost. MoGas pay period is every two weeks or 26 pay periods in a year. On June 12, 2009, the non-owner employees of MoGas received a pay increase. To determine the appropriate level of labor that was representative of the test period, I used the June 12 payroll as my starting point. I next eliminated overtime pay that was included in the payroll. I then multiplied the net payroll by 26 to get a full year of labor cost. I then added the latest twelve months of overtime labor arriving at a total labor number of $1,163,016, which when compared to the base period labor of $887,696. This results in a test period adjustment of $275,320. The computation for the labor adjustment is shown on Workpaper 5.

Q. Please provide background to support the labor increase.

A. There are a number of factors that account for the increase. MoGas added two employees during the base period to operate and maintain the compressor station. Other employees were hired to operate MoGas' gas control, which formerly was maintained by an outside contractor. The outside contractor chose not to renew their contract; hence, requiring MoGas to perform the service on its own. Most of the new employees were hired in the early part of the base period, but several changes occurred throughout the base period. MoGas also capitalized certain labor cost while the compressor station was under construction. Now that the construction is completed, MoGas does not anticipate that it would incur any capitalized labor during the balance of the test period. Because little construction is budgeted for the coming years, MoGas is not likely to capitalize labor in the near future.

Q. Please provide an explanation of Schedule H-1(2)(a) (Exhibit No. MGP-27).

A. This schedule is set up to reflect the cost of retained gas for fuel use and unaccounted for gas. MoGas reflects no entries on this schedule. MoGas physically accounts for retained gas but does not currently account for retained gas on its financial books. MoGas has undertaken the duty to perform the necessary financial accounting of retained fuel that will be consistent with the Uniform System of Accounts.

Depreciation

Q. Please support Statement H-2 (MGP-36) and Schedule H-2(1) (MGP-37).

A. Statement H-2 reflects MoGas base period plant in service and test period plant in service and the corresponding depreciation and amortization rates. Mr. Feinstein is supporting an increase to MoGas' transmission depreciation rate from 2.5% to 2.9%. I am proposing to use this same 2.9% rate to amortize intangible plant. The majority of the intangible plant is an interconnect with MRT that was paid for by MoGas but constructed by MRT. Thus, MoGas treated the transaction as a contribution-in-aid-of-construction and recorded the expenditure in Account No. 303. The general plant rates are based on MoGas' test period plant and the new recommended depreciation and amortization rates MoGas depreciation and amortization expense is $3,731,206 for both zones, which is computed by adding the totals for Zones I and II in column (g) of Statement H-2.

Schedule H-2(1) is a reconciliation between plant numbers shown on H-2 and plant numbers reflected on Statement C (Exhibit No. MGP-6). The purpose of the reconciliation is to make sure plant investment that is not subject to depreciation or amortization is included on Statement H-2. MoGas' reconciliation shows that plant not subject to depreciation is in fact not included in Statement H-2.

Federal and State Income Tax Allowance

Q. Please support Statement H-3 (MGP-38).

A. Statement H-3 computes the federal and state income tax allowance. MoGas is primarily located in the State of Missouri and pays state income taxes to Missouri and Illinois. Because the state income taxes paid to the State of Illinois is relatively minor, it was ignored for purposes of calculating the state income tax on Schedule H-3. The allowance is calculated by first eliminating debt cost and adding the depreciation of equity AFUDC. The above adjustments results in the computation of MoGas' tax base. The federal and state income tax allowances are calculated by multiplying the composite federal and state tax rate times the tax base.

Q. Do MoGas owners incur a Federal income tax liability?

A. Yes. MoGas is ultimately wholly owned by C corporations that are liable for corporate income taxes.

Ad Valorem Taxes

Q. Please describe Statement H-4 (Exhibit No. MGP-39).

A. Statement H-4 reflects ad valorem property taxes and the employer's share of employment taxes. The test period adjustment for ad valorem taxes represents MoGas' estimate of additional ad valorem taxes for plant additions through the end of the test period. These additions are included on the county tax rolls in which MoGas' plant is physically located. The proposed adjustment does not reflect an increase to ad valorem taxes for proposed test period additions.

The increase to employments taxes are those increases that are related to new employees and employee wage increases.

Cost Classification, Cost Allocation and Rate Design

Q. Please provide an explanation of Schedule I-1(a) (MGP-42), I-1(b) and I-1(c).

A. Schedule I-1 encompasses Schedules I-1(a), I-1(b), I-1(c), and I-1(d). Schedule I-1(a) is a functionalized cost of service for both Zone I and Zone II, supported by Statements B, C, D, E, G and H. Schedule I-1(b) is not applicable because MoGas only has a transmission function. Schedule I-1(c) also does not apply for the same reason.

Q. Please support Schedule I-1(d) (MGP-43).

A. Schedule I-1(d) reflects the functionalization of administrative and general costs between the two zones based on the Commission's preferred KN method. Other common costs such as operating and maintenance costs are directly assigned to the zones and each zone has its own general and transportation facilities. The few cost items that are allocated to both zones, such as ADIT, Working Capital and ad valorem taxes are allocated based on a gross plant ratio, and those allocation ratios are reflected on Schedule B-1 (Exhibit No. MGP-5), Statement E (Exhibit No. MGP-11) and Statement H-4 (Exhibit No. MGP-41).

Q. With respect to the cost classification shown on Schedule I-2 (Exhibit No. MGP-44), does the Commission require the use of a particular cost classification method for cost allocation and rate design?

A. Pursuant to Order No. 636, the Commission required pipelines to recover their transportation costs under the Straight Fixed Variable ("SFV") method.

Q. Please describe how the system costs are classified under the SFV method.

A. System costs have been classified in relationship to their characteristics as either fixed or variable. Fixed costs are those which do not vary materially with gas throughput and variable costs are those costs which vary directly with system throughput. Once costs have been identified as either fixed or variable, the costs are then classified for purposes of cost allocation and rate design as either reservation charge-related or usage charge-related.

Q. Does MoGas have any cost that is classified as variable?

A. MoGas has variable costs for Zone I but no variable costs for Zone II. The only cost that MoGas incurred on Zone I prior to adding compression that varied with throughput is a chemical odorant placed into the gas stream. With respect to gas used for compression, MoGas is proposing to include in its tariff rates a retainage charge of .52% based on a study performed by witness Feinstein. Because gas will be retained for this purpose, MoGas will incur no variable gas costs.

Q. Are there any variable compressor station costs?

A. Yes. Materials and supplies charged to Account No. 853, Compressor Station Labor and Expense, and Account No. 864, Maintenance of Compressor Station Equipment, are classified as variable cost. Consequently, the commodity rate for Zone I will increase from the current rate.

Q. Are MoGas' current transportation rates designed based on the SFV method?

A. Yes.

Q. Does MoGas propose to continue to design its rates using the SFV method of cost classification, cost allocation and rate design?

A. Yes. The rates proposed in this proceeding will continue the use of the SFV methodology.

Cost Allocation

Q. Please describe MoGas' manner of maintaining zone costs and the Commission's label for the method.

A. The label that the Commission would use to describe MoGas' manner of maintaining zone costs is a Zone Gate method. This is a variation upon the zoned approach that is not directly "mileaged." With this method, costs are directly assigned to each zone based upon actual cost of service data for operations and maintenance incurred by the facilities located in each of the zones. A Zone Gate method requires that for any shipper transaction crossing a particular zone that shipper would be responsible to pay the rate for that zone since that transaction has actually utilized the facilities in that zone. Thus rates are additive for this methodology (i.e., a transaction from Zone 1 to Zone 2 would incur an additive rate consisting of rates for Zone 1 + Zone 2). Consequently, Zone II shippers must pay for the full Zone I rate and the full Zone II rate.

Q. Please explain the purpose of Schedule I-3 (MGP-45).

A. The schedule starts with the functionalized cost of service for both Zone I and Zone II from Schedule I-1and from these totals certain adjustment are made for the purpose of developing rates for this proceeding. The proposed adjustments reflect an allocation of certain costs that are located in Zone I but because transportation services are being provided in Zone II using pipeline and compression facilities in Zone I, a fair allocation of pipeline and compressor station costs to Zone II must be calculated.

Q. What are these services?

A. The former MIG facilities provide a benefit to both zones since they enable all shippers to move gas to and from MRT, yet the entire facility and operating costs are recorded on MoGas' books in Zone I. It is unreasonable for Zone I shippers to pay for the full cost of when there is a benefit to Zone II from the Zone II shipper, Omega, that uses the MIG facilities. Omega has 6,000 Dth/day sourced from MRT; accordingly, these billing determinants are included in both Zone I and Zone II. Thus, all Zone II shippers derive a benefit from Omega's use of MIG facilities because the Omega billing determinants are used in the calculation of Zone II rates yet there are no costs for MIG's Zone I facilities and operating costs. The added billing determinants for Omega of 6,000 Dth/day would not have been available without the ability to receive gas from MRT through the Zone I MIG interconnection. It is unreasonable for Zone I shippers to pay all of the MIG costs when the MIG facilities provide a benefit to both zones, that would result in a subsidy to Zone II shippers.

Q. How do you propose to allocate MIG cost to Zone II?

A. I propose to allocate the MIG cost based on a ratio of billing determinants that are sourced from MRT. Billing determinants measure the value to both zones and are an integral measurement in determining ultimate transportation rates. I composed the ratio using a numerator of Omega's Zone II billing determinants of 6,000 Dth/day with the denominator being the combined billing determinants for both zones of 17,000 Dth/day. This calculation produces a percentage factor that is used to allocate MIG costs of 35.29% from Zone I to Zone II. The Zone I cost of service reflected on Statement A of $9,471,086 is accordingly reduced by $763,975 and the cost of service for Zone II of

$4,377,111, as shown on Statement A (Exhibit No. MGP-3), is increased by a like amount.

Q. Please explain your other proposed cost allocation issue related to Zone I.

A. The other issue concerns the proper allocation of compression costs. The compression facilities are located in Zone I and the compressor operating and facility costs are recorded on MoGas' books as Zone I costs, yet compression benefits Zone II customers as well, since their gas has to travel through Zone I. The compression also insures that Zone II delivery pressure is maintained. The Commission recognized in certificating the compressor that it would increase system reliability. Mr. Feinstein's testimony reinforces that conclusion.

Q. Do you have a proposal that would make a reasonable and equitable allocation of compression costs?

A. Yes. I believe that the allocation should be made based on a ratio of billing determinants. However, the allocation should consider that Zone II ratepayers are already paying for a share of compression in the Zone I rate. To factor in this consideration, I propose to count the Zone II billing determinants twice in developing the denominator used to calculate the ratio. The Zone II billing determinants should be counted twice, once to recognize their use of Zone I facilities and once to reflect their use of Zone II. Thus, the allocation factor would have a numerator consisting of the Zone II contractual volumes of 18,119 Dth/day and the denominator should consist of 114,146 Dth/day for Zone I and double the Zone II billing determinants of 18,119 Dth/day for a total of 150,384 Dth/day. The resulting percentage is 12.048%. Accordingly, 12.048% of the compression cost is allocated to Zone II. Multiplying the compression cost of $3,458,641 by 12.048% results in an allocation of $416,714, which is netted against the Zone I cost of service. The same amount is added to the Zone II cost of service.

The above-described adjustments are included in the computation of the cost of service numbers reflected on Schedule J-2 (Exhibit No, MGP-50), line 4.

Q. What rates are presently being charged for expansion service on both Zones I and II?

A. Pursuant to a Commission order, issued on September 25, 2008 in Docket No. CP07-450, MoGas was authorized to use its existing Part 284 rates for the expansion service. The Commission granted MoGas a presumption of rolled-in rate treatment. The Commission found incremental compression necessary to ensure reliability of existing service and incremental service. Witness Feinstein presents a study of the total installed compression authorized in Docket No. CP07-450 that determines the amount of compression that is needed to ensure reliable service for MoGas' existing shippers and the compression needed to provide the expansion shippers.

This detailed engineering study that concludes that system reliability is significantly enhanced by the added compression. Further, MoGas' stopgap alternatives used in prior years were not adequate to ensure reliability. Before adding compression, MoGas was entirely dependent on the delivered pressure from Panhandle. Mr. Feinstein has reviewed delivery pressures from Panhandle and concluded that MoGas was at risk of not being able to meet its contracted capacity on certain winter days. Mr. Feinstein's study demonstrates that customers in Zone II are benefited by the compression because without the new compression, those customers were the most exposed to a service interruption. Mr. Feinstein's studies are based on current conditions, which recognize changes in gas flow resulting from new contracts.

Q. What did the Commission say about rolling in the cost of the compressor?

A. The Commission granted MoGas a presumption of rolled-in rate treatment for the compression needed to ensure reliability to existing shippers and for the additional services in paragraph 51 of the September 25, 2008 order in Docket No. CP07-450.

Q. Have you performed a rate study to determine the presumption should not be disturbed?

A. Yes. I have prepared a study that is included on Schedule J.1 (Exhibit No. MGP-48). The first step in determining the cost of compression was to isolate MoGas' investment in the new compressor station. I then calculated the accumulated depreciation expense and ADIT cost. With this information, I calculated a rate base. I then calculated a return and income tax allowance. The operating cost comes directly from MoGas' books, which are recorded in Account Nos. 853 and 864. I used A&G cost for Zone I as calculated from the KN formula. I allocated A&G to compression based on a ratio of total Zone I plant investment as the denominator with the numerator being compression plant investment. The ad valorem taxes were determined using a ratio of plant investment. Based on the above I calculated a separate cost of service for the compressor station. I then allocated the cost based on a ratio of the designated compression that services the expansion shippers.

Q. Did you consider fuel cost used for compression in your analysis and if so how did you compute fuel cost?

A. Yes. The first step was the use of Mr. Feinstein's fuel retention rate of .52%. I then used the Zone I commodity volumes from Schedule G-2 (Exhibit No. MGP-18). By multiplying the retention rate by the commodity, I determined the retained volumes. I then multiplied the retained volumes by the Panhandle June market rate of $2.5222, as reported by ICE Market Exchange, to arrive at a cost for fuel of $268,826.

Q. What ratio did you use to allocate the compression cost of service between the expansion and existing shippers?

A. For illustrative purposes, I used the Commission's ratio of 62.9% determined in Docket No. CP07-450.

Q. Please continue.

A. I created a worksheet in which I calculated rates for both Zone I and Zone II that was copied from Schedule J-2 (Exibit No. MGP-50). Using the same Schedule J-2 numbers, I created a second computation of rates for Zone I and Zone II, eliminated the expansion billing determinants for both zones, and eliminated the allocated cost of service as described above from the J-2 cost of service. Using the numbers in the second J-2 analysis new rates are computed. Rates from the second J-2 analysis for both the demand and IT rates are higher for both zones. Thus, Schedule J-1.1 demonstrates that the Zone I and the Zone II rates would be higher without the expansion billing determinants; consequently, the analysis shows that the presumption of rolled-in rate treatment should not be disturbed.

Billing Determinants

Q. Describe how you projected firm service billing determinants for the mainline facilities as reflected on Schedule J-1.

A. The only projection of billing determinants is for the expansion service. The new expansion went into service March 2009, consequently Schedule G-2 (Exhibit No. MGP-18) reflects only 10 months of service for both Zones I and II, and a projection was made to reflect an annual amount. Schedule G-2 demonstrates a total level of billing determinants for Zone I of 110,369 Dth/day. However, as shown in column (b) of Schedule J-1, the billing determinants projected to be in effect at the end of the test period for Zone 1 are 114,146 Dth/day. Thus, the appropriate billing determinants for Zone I are 114,146 Dth/day and not the 12-month total as appears on Schedule G-2. A similar situation is present on Zone II; therefore, the appropriate billing determinants for Zone II are 18,119 Dth/day and not the 12-month total from of 17,838 Dth/day, reflected in Schedule G-2. As shown on Schedule G-4 (Exhibit No, MGP-20), the total expansion billing determinants in Zone I are 22,364 Dth/day and 1,364 Dth/day for Zone II. As all of the non-expansion shipper contracts remained the same, no base or test period adjustments were proposed in Schedule J-1.

Q. How does the Commission's findings in its April 3, 2009 Order in Docket No. CP06-407, 127 FERC ¶ 61,011 affect the determination of billing determinants for Zone I in this proceeding?

A. The Commission's findings in the cited reference only apply to the rates approved in the certificate proceeding. This is a proceeding to set just and reasonable rates for the future based on actual base and test period experience.

Q. Please explain the issue.

A. The Commission simply added the subscribed capacity for the former MPC and MIG for purposes of calculating Zone I rates. The resulting billing determinants for Zone I of 104,977 Dth/day were not only significantly higher than MoGas's system capacity they exceeded MoGas' actual experience by more than 10,000 Dth/day. Furthermore, the Commission's foremost concern with the treatment of MIG cost is being addressed in the proposed rate design.

Q. Please explain.

A. Paragraph 28 of the Commission Order of April 3, 2009 noted that one customer has contracted for 5,930 Dth/day of service on both the former MPC and MIG, and undeniably, gas was transported on both systems. The Commission addressed its concern as follows:

> Although there was only a single increment of gas involved in the transactions, the fact remains that before the merger of the three pipelines, service under two agreements was contributing billing determinants and, therefore, revenues, to the future Zone 1. It is true if the customer continues to ship on the merged pipeline, there will be only one increment of 5,930 Dth/d shipped and the customer will pay only a single Zone 1 rate. However, some costs of service associated with the former Missouri Interstate system remains, and if the billing determinants for the former Missouri Interstate service are not included in the new Zone 1 rate, the resultant unit rate will be higher causing the Zone 1 shippers not using the former Missouri Interstate facilities to subsidize shippers who do. Accordingly, we will deny MoGas' request that it not be required to increase its Zone I billing determinants by 5,930 Dth/d.

It is most evident from the cited language that the Commission was concerned that Zone I shippers that do not use the MIG facilities would subsidize those Zone I shippers that use MIG. The contract quantity discussed in the order of 5,930 Dth/day (though contract quantity changes the billing determinant are now 6,000 Dth/day) are delivered in Zone II; accordingly, those volumes pay both a Zone I and a Zone II transportation rate. To address the Commission's concerns that some Zone I shippers that are inappropriately paying for the former MIG costs, an appropriate allocation of MIG costs was made to shift cost responsibility from Zone I to Zone II. This shift assures Zone I shippers that they are paying the appropriate MIG costs.

Q. Is the shift in the MIG cost from Zone I to Zone II the same as you described above in your explanation of Schedule I-3 (Exhibit No. MGP-45).

A. Yes.

Q. Do the Zone I shippers that receive gas from Panhandle and not from MRT benefit from MIG and, if so, explain the benefit.

A. Yes, there is a benefit for those shippers through capacity release. There is significant capacity release by Zone I shippers, who source gas from Panhandle, and the released capacity is transported through the MIG facilities to MRT. In fact, in June 2009, AmerenUE, the second largest Zone I shipper, released 80%.

Q. Please discuss the additional contract for 12,500 Dth/day that the Commission addressed in Paragraph 29.

A. The 12,500 Dth/day, a contract with Laclede Gas Company, has been changed to 5,000 Dth/day. This contract provides for transportation just on Zone I.

Q. Do the former MIG facilities provide benefits to Zone I Shippers that do not use those facilities?

A. Yes. The Commission established a design capacity of 20,000 Dth/day for the MIG facilities in the Commission's order of September 24, 2002, in Docket No. CP02-399. The 20,000 Dth/day of capacity is fully utilized with the 11,000 Dth/day for Laclede and

Omega sourced from MRT and the expansion capacity sourced from Panhandle in the amount of 21,000 Dth/day is delivered through MIG to MRT. Thus, the bi-directional capabilities of the MIG facilities results in far more capacity flowing through than the original designed capacity of 20,000 Dth/day and accordingly is fully utilized. Further, the expansion shippers' use of the MIG facilities lowers the Zone I rates for all Zone I shippers.

Q. What was MoGas' contracted capacity on Zone I after the combination?

A. The Schedule G-1 (Exhibit No. MGP-16) shows a contracted level of billing determinants of 92,078 through 11 months of the base period and with compression added in the last month of the base period the contracted level increased to 94,078 Dth/day. Both numbers include 11,426 Dth/day received from MRT.

Q. Are there separate contracts for the former MIG facilities?

A. No. After the merger, shippers combined their capacity into one contract on Zone I.

Calculation of Rates

Q. Did you compute a discount adjustment?

A. Yes. MoGas is discounting its transportation contract with Laclede Gas Company ("Laclede"), a company not affiliated with MoGas. Laclede has a maximum monthly demand charge of $6.324 for the Zone I rate and by including Laclede's billing determinants, exceeds the demand charge paid by Laclede, thus triggering the need to reflect a discount adjustment. The discount adjustment is calculated by eliminating the revenue and billing determinants from the Laclede contract on Schedule J-2 for the computation of transportation rates for Zone I. Laclede's contractual billing determinants are multiplied by the monthly reservation rate of $6.324 and the proceeds calculated is used as a revenue credit to the Zone I cost of service.

Q. What level of IT volumes are you projecting for the test period?

A. As explained earlier in my testimony, MoGas had significant IT volumes in 2008 due to unusual circumstances; the partially complete REX pipeline. However, once REX enters service all the way to Ohio, there will no longer be a need to use MoGas to move volumes further east. There is no reason to believe that MoGas will experience IT volumes in excess of the 70 Dth/day shown on Schedule G-2 in the future. Because the one contract reflected on Schedule G-2 uses both zones the same 70 Dth/day was used for both zones.

Q. Please discuss the IT revenue for Centerpoint Energy Service Inc. listed on Schedule G-2.

A. MoGas believes that the contract will not be used once REX East goes into service, thus it is appropriate to delete these revenues.

Q. Do you have any additional comments?

A. There are a number of schedules that the Commission lists under § 154.312, Composition of Statements, that are not included in the instant rate filing. These schedules were not included because they do not pertain to MoGas' due to MoGas' system or costs reflected in the rate filing. Schedule B-2 was not included because MoGas does not propose to include regulatory assets in the rate filing. Schedule C-2 was not included because there is sufficient data on work-in-process on Schedule C-1. Schedule C-3 was not included because MoGas has no storage. Schedule E-1 was not included because MoGas is not requesting cash working capital and Schedule E-3 was not included because MoGas has no storage or working gas recorded on its books. Schedule F-4 was not included because MoGas has no preferred stock. Schedule I-1(b) was not included because MoGas only has a transmission function. Finally, I-1(c) was not included because MoGas uses a Zone Gate method to calculate its zone rates.

Q. Does that conclude your direct testimony in this proceeding?

A. Yes.

IN THE DISTRICT)

OF COLUMBIA)

Before me, the undersigned Notary Public, in and for the District of Columbia, personally appeared Alan R. Lovinger, who being by me first duly sworn, deposes and says that he is the individual identified and responding to the questions in the attached direct testimony and that the same is true and correct to the best of his knowledge, information and belief.

Alan R. Lovinger

Alan R. Lovinger

Sworn to and subscribed before me on this 30 day of June 2009.

Notary Public

My Commission expires: 12/14/2012