Exhibit No. MGP-59

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MoGas Pipeline LLC	**)**	**Docket No. RP09-___**
	)	

PREPARED DIRECT TESTIMONY OF
EDWARD H. FEINSTEIN
ON BEHALF OF
MOGAS PIPELINE LLC

Q. Please state your name and business address.

A. My name is Edward H. Feinstein and my business address is 1155 15th Street, N.W., Suite 400, Washington, D.C. 20005.

Q. Please state your occupation.

A. I am a consulting petroleum engineer with the firm of Brown, Williams, Moorhead & Quinn, Inc.

Q. Please briefly describe your education, background and training.

A. I received my Bachelor of Petroleum Engineering degree from the University of Tulsa in May 1963. From July 1963 to February 1998, I worked at the Federal Energy Regulatory Commission ("FERC") and its predecessor, the Federal Power Commission ("FPC"). From the time of my employment at the FPC until approximately 1970, I was engaged in work involving economic feasibility studies in certificate proceedings under the Natural Gas Act ("NGA"). This work was concerned primarily with market, engineering, and financial analyses for the purpose of determining the economic feasibility of pipeline projects proposed in certificate applications. From 1970 to the present, my efforts have been concentrated on determining the appropriate depreciation rates for oil and gas pipeline facilities, including the determination of potential supplies of oil and natural gas, and with other rate issues such as storage utilization, operations and cost allocation and gathering rates. During my nearly 35 years with the Commission, I earned positions of increasing responsibility, including Chief of the Depreciation Branch. In

March 1998, I joined the firm of Brown, Williams, Scarbrough and Quinn, Inc., precursor to Brown, Williams, Moorhead & Quinn, Inc.

Q. Are you a member of any professional societies?

A. Yes, I am a member of the Society of Depreciation Professionals and the Society of Petroleum Engineers.

Q. Have you testified in proceedings before the FPC and the FERC?

A. Yes, I have presented testimony in many different areas, including gas supply and deliverability, depreciation, gathering issues and storage operations and cost allocation. A list of such testimony is shown in Exhibit No. MGP-60.

Q. On whose behalf are you presenting testimony in this proceeding?

A. I am presenting testimony on behalf of MoGas Pipeline LLC ("MoGas"). MoGas requested that I perform an analysis to see if its current depreciation and negative salvage rates are reasonable, realistic and practical at this time. My testimony addresses the determination of the justness and reasonableness of the depreciation and negative salvage rates that are currently applied to MoGas's depreciable transmission plant. As part of the support for my determinations, I performed a detailed depreciation study.

Further, I am presenting testimony concerning various capacity and flow issues and the need for certain natural gas compression. With respect to compression and the operation of the pipeline system, I am recommending rates for fuel use and lost and unaccounted for gas.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit Nos. MGP-60 through MGP-63.

Q. Would you please summarize the results of your depreciation determination?

A. As a result of my studies and analysis, I have determined that MoGas could support an increase in its depreciation rate for its transmission function. The rate, as a percentage of plant in service, is determined to be 2.9 percent. I am also recommending a negative salvage rate of 0.87 percent.

Q. Would you please summarize how you performed your studies?

A. I analyzed MoGas' system operations along with its markets and sources of supply. I determined average service lives based on the physical lives of its facilities. I employed the straight-line method, average remaining life technique with a life span approach. The life span approach considered projected gas supplies of the Midcontinent Area and Northern Rocky Mountain Area, which does not include the San Juan Basin. I also considered how competition in the natural gas industry affects the economic life of MoGas' facilities. I applied the average remaining life to each of its plant accounts to determine the applicable depreciation rate. With respect to general plant, I determined the appropriateness of MoGas' current depreciation rate for each account using the average service life approach.

The methodology I employed for determining MoGas's just and reasonable depreciation rates is fully consistent with Commission precedent.

DEPRECIATION

Q. Let us turn first to a definition of depreciation. Would you please define and describe depreciation?

A. Depreciation is the allocation of the original cost of tangible facilities in service over their useful lives. Stated another way, depreciation is the mechanism by which the plant investment is recouped in an orderly fashion over the useful life of the investment. For rate purposes it is treated as an operating expense. Depreciation is intended to systematically recover the invested capital over the useful life of the universe of relevant assets.

I used the average remaining life approach and recommend that MoGas's transmission plant depreciation rate in this case be based on this approach. This approach is the most widely used of all the methods to determine depreciation rates for major transmission pipeline and natural gas storage systems. The average service life approach, or whole life approach, was employed to determine depreciation rates for the high-turnover general plant accounts. This approach is commonly employed throughout the industry for such general plant accounts. It establishes a rate that covers the life of an asset from inception to retirement. This contrasts with the remaining life approach that determines the useful life of an asset from a current point in time to its estimated retirement.

Depreciation rates depend on estimates of expected service life of plant investment. Because natural gas pipeline systems are made up of a host of different complex property units, it would be impractical to calculate and apply separate depreciation rates for each unit of a facility. This calculation would place an undue burden on the accounting system for depreciation purposes by requiring the maintenance of records for each unit of property. Consequently, the normal approach for developing depreciation rates is to calculate the rates for groups of plant based upon average service lives for those groups, which are determined through studies of the forces affecting the lives of the pipeline's facilities. Under this method, individual facilities booked to each relevant FERC account are treated as a single group within those accounts.

DETERMINATION OF DEPRECIATION - THE SERVICE LIFE FACTORS

Q. Would you please discuss the relationship between useful life and depreciation?

A. The measurement of depreciation recognizes that all plant will ultimately reach the end of its useful life. The end of the useful life and retirement from service may be caused by the following factors:

- wear and tear,

- action of the elements,
- deterioration,
- inadequacy,
- obsolescence,
- requirements of public authorities, and
- adequacy of supply or market.

The physical causes, such as wear and tear and deterioration, are the most readily observed reasons for retirements. Functional causes, such as inadequacy, obsolescence, requirements of public authorities and inadequacy of supplies or markets are the more prevalent causes of retirements in the pipeline industry.

However, adequacy of supply or market is unrelated to the physical characteristics of the property or the action of public authorities. Because adequacy of supply or market, referred to as the economic life in a depreciation study, is one of the primary causes of premature retirements, this subject is addressed in greater detail below.

MoGas is affected by all of the above causes of retirement, whether physical or functional.

THE DEPRECIATION MODEL

Q. Would you please describe the depreciation model that you employed in your study?

A. I employed the straight line average remaining life method as traditionally adopted by the Commission. It is described as follows:

$$\mathbf{DE} = \frac{\mathbf{DB} - (\mathbf{S} - \mathbf{COR}) - \mathbf{DR}}{\mathbf{ARL}}$$

Where,

DB = the depreciation base or original cost
S = the future gross salvage
COR = the cost of removal
DR = the accumulated depreciation reserve
ARL = the average remaining life

And, the gross salvage and cost of removal are related specifically to the **DB**.

The determination of depreciation using the above equation serves three purposes:

(1) capital recovery - rateably allocates a known fixed cost,

(2) cost of removal - rateably allocates a future obligation, and

(3) salvage - rateably reflects recognition of future value.

Q. Would you describe the average remaining life approach?

A. The concept of an average service life or remaining service life for a property group implies that the various units in the group have different lives. The average life of any group of plant items will be an estimate until all the items in that group have been finally retired. The goal is to determine the average life before complete retirement of all units occurs. The average remaining service life method determines the average period of time the facilities will be in service. This is normally done by first determining the historical life of the plant group and then estimating the life expectancy for the items remaining in service. The life experienced plus the expected life comprises the average life for the group. This analysis can be done by determining the separate lives for each of the property units or by constructing a survivor curve for the entire group. In this testimony, I employed the group method and I used a survivor curve for each group of facilities.

Q. What is a survivor curve?

A. A survivor curve, fitted to a particular type of plant, predicts the average remaining service life and normal retirement pattern of that plant. A survivor curve graphically reflects the percent of capital investment existing at each age throughout the entire physical life of an original group of property. From the survivor curve, the average service life or average remaining life can be calculated.

The survivor curves are referred to as Iowa type survivor curves. See Schedule No. 1 of Exhibit No. MGP-61. They were originally developed at the Iowa State College Engineering Experiment Station and refined through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa survivor curves are used to account for the normal retirements that occur over the life of a specific type of plant.

Standard Iowa survivor curves also include reference to R, L and S type survival patterns, which simply refer to the shape of the curve.

The determination and use of a survivor curve to determine the physical life of facilities requires a great deal of experience and knowledge in the interpretation of the results of such a study. The use of judgment must include investigation into whether future normal retirements can be predicted based on the past performance of those facilities. For MoGas, plant additions and retirements are very sparse. Thus, industry average along with my judgment was applied to determine the most appropriate curve to use as the physical life.

ECONOMIC LIFE OF THE MOGAS SYSTEM

Q. Would you please describe your studies, analysis and determination of the economic life of the MoGas system?

A. The economic life of the MoGas system is dependent primarily upon the productive capability of the supply areas from which it receives gas for transmission. The expected longevity of the markets served by MoGas is another significant factor in its facilities' economic life. MoGas's markets are made up of various local distribution companies serving town border customers. Generally, the life of MoGas's markets, in and of themselves, is expected to be relatively long-term. However, any potential loss of markets may affect the useful life of a particular facility or some portion thereof.

Adequate supply of gas for shipment is crucial to the remaining life of a pipeline system. In the case of MoGas, the gas supplies of the Northern Rocky Mountain Region and the Midcontinent area are the primary sources of gas. I analyzed how these supply sources would affect the MoGas system by performing studies concerning the supply life. The results of those studies, when directly related to MoGas's existing facilities, indicate an economic end life of 30 years. The economic life of MoGas's facilities, which I will discuss further in my testimony, should be used to determine the life span and average remaining life in the calculation of depreciation for transmission plant in this proceeding.

GAS SUPPLY

Q. Would you please describe your gas supply studies?

A. I studied, analyzed and modeled the gas supply of the Midcontinent area and the Northern Rocky Mountain area. The future of these gas supply sources may affect the life of the MoGas system.

With respect to the gas supply areas, I analyzed data available concerning proven reserves of natural gas as well as the various estimates of potential gas resources. I constructed a model, which forecasts the availability of gas from supply sources in the future. The gas reserve and resource base from which to forecast the availability is sourced from the Energy Information Administration of the Department of Energy and the Potential Gas

Committee. The purpose of my gas supply analysis is to determine a realistic economic life of pipeline facilities that are dependent upon such supplies. The results of this analysis are found in Schedule Nos. 2 and 3 of Exhibit No. MGP-61. The detailed gas supply determination is shown in Exhibit No. MGP-62, "The Assessment of the Availability Of Natural Gas in The Northern Rocky Mountain Area and The Midcontinent Area."

Q. How did you go about determining the supplies of gas that are realistically accessible through MoGas's existing facilities?

A. Gas resources can be categorized as proven reserves and undiscovered resources. Natural gas resources occur in porous and permeable reservoir rock, which, at a particular period in time, can be technically and economically produced using normal production practices. However, production from area to area differs because the size, location, physical properties and depth of each reservoir varies widely.

Q. Would you please discuss the analysis, determination and results of your gas supply studies?

A. Schedule No. 4 of Exhibit No. MGP-61 illustrates the concept of the gas supply model. Estimates of future annual gas discoveries were made employing an effectiveness of exploration discovery – process model. Productive capacity decline rates were applied to determine the availability of gas from new supply sources.

One measure of the discoverability of resources is the effectiveness of exploration. The effectiveness of exploration compares the drilling footage in a particular year with the related discoveries. This method depicts the normal stage of events that take place when a gas-bearing province graduates past its initial discovery stage and enters its more or less mature stage. The degree of maturity of the producing life of the supply areas can be determined by comparing the amount of gas resources already discovered with an estimate of the ultimate resources.

Q. What can you conclude as to the economic life of MoGas's existing facilities from the results of your gas supply studies?

A. The results of the gas supply studies coupled with MoGas's position as a pipeline largely dependent on specific domestic gas supplies, strongly indicate an average remaining economic life for MoGas's pipeline system of 27 years. Thus, I employed an average remaining economic life of 27 years in order to determine MoGas's just and reasonable depreciation rate. The analysis of the economic life of a pipeline system, such as MoGas, involves consideration of not only the related gas supply, but, the company's markets and competitive position also. My determination of a 27 year remaining economic life is based upon the potential for serious underutilization of pipeline facilities generally, due to depletion of traditional gas supply sources and competition, making them candidates for major retirements. Such underutilization is supported by the analysis of the relationship between the amount of gas available in MoGas's traditional supply sources and the level of utilization of its facilities. This determination is shown in conceptual form in Schedule No. 5 of Exhibit No. MGP-61. The actual calculations are shown in Schedule Nos. 6, 7 and 8 of Exhibit No. MGP-61.

Q. What are major retirements and how do you conceptualize them with respect to economic life?

A. Major retirements are comprised of severely underutilized facilities due to economic forces (rather than physical forces), such as gas supply depletion, which causes changes in system operations. It is my experience, in analyzing retirements of pipeline properties, that major retirements take place in varying degrees. In supply areas, depletion of gas reserves and competition are typical causes of underutilization and eventual retirement.

Q. Can you provide examples of major retirements, which have taken place in recent years in the pipeline industry?

A. Yes I can. For example:

1) Offshore Gulf of Mexico facilities are constantly being retired as the depletion of gas reserves causes underutilization.

2) On March 9, 2000, Trunkline Gas Company, after exhibiting underutilization on its south Louisiana to Tuscola, Illinois mainline system, retired an entire 700-mile loop line.

3) Trans-Northern Pipelines Inc. sought, and was granted, abandonment authority by the National Energy Board of Canada for its entire Don Valley to Toronto Harbour Lateral because the facility was in a "serious deficit position" due to reduced throughput.

4) Florida Gas Transmission Company (Florida Gas) has retired pipeline and compressor facilities in its South Texas Gulf Coast production area due to decreasing gas availability. While the facilities were sold for $2.3 million, a fraction of their replacement cost or original cost, the fact remains that they were no longer useful to Florida Gas' operations.

5) CenterPoint Energy – Mississippi River Transmission Corporation (Docket No. CP04-334-000) recently abandoned 307 miles of its Main Line No. 1, consisting of 22-inch diameter pipeline and other equipment such as compressor engines. It appears that the facilities were underutilized given that they were not replaced.

Q. In your economic life analysis of MoGas's facilities, are you estimating the precise year of retirement?

A. No, the exact date that MoGas actually retires such facilities is not relevant. It is not necessary that an actual physical retirement take place in order to qualify a facility as underutilized in the determination of the economic life. However, certain facilities, such as compressor station equipment, may actually be physically retired at points in time as underutilization continues. For example, when a compressor unit or a loop line is no longer used for its intended purpose, for repair or for emergency purposes, it should be fully accrued (depreciated). However, such a facility may linger in service for a period of time as an emergency back-up; it may be put in mothball status waiting for the appropriate time to physically retire the facility when abandonment is formally approved; or it may simply not be used because it is a component of a larger facility, a portion of which is still used and useful. The illustration of this very concept of underutilization of facilities, sometimes referred to in this case as "major retirements," along with the economic life concept is found in the aforementioned Schedule No. 5 of Exhibit No. MGP-61.

THE DETERMINATION OF DEPRECIATION FOR MOGAS'S GAS TRANSMISSION SYSTEM

Q. How did you apply the 27-year average remaining economic life to the depreciation model?

A. The 27-year average remaining economic life plays a key role in the determination of the ARL (average remaining life). The 27-year average remaining economic life represents the average year of the final investment recoupment. Said another way, it reflects a point in time around which major retirements can be expected to occur. The best way to describe the relationship of the economic life to the ARL is to overlay it with the normal retirement survivor curve (physical life). This is illustrated for the compressor station equipment Account 368 in Schedule No. 9 of Exhibit No. MGP-61.

Q. Please describe how you determined the physical life normal retirement survivor curve.

A. The survivor curve represents the pattern of annual normal retirements that will occur in the future. I determined the normal retirement curve for MoGas's transmission accounts. For example, I determined that Account 367 (Mains) has an average service life of 55 years, with an R_3 survival pattern. This is illustrated on Schedule No. 1 and shown on Schedule No. 10 of Exhibit No. MGP-61. Mains make-up approximately 72 percent of MoGas's transmission system. This determination was made in part by employing the statistical assembling techniques of historical additions and retirements. In cases where there is very limited historical data, I also relied upon an analysis of the type of equipment, its usage and condition, as well as its age and survivor curve retirement patterns that are typical in the industry for such facilities. I determined the survivor curve and resulting average service life that best applies for each of the other accounts as follows:

Account No.	Description	Average Service Life	Survivor Pattern
Transmission Plant			
365.2	Rights-of-way	60	R_5
366.1	Structures	38	R_3
367	Mains	55	R_3
368	Compressor Sta.	30	R_2
369	Meas. & Reg Sta. Eq.	25	L_1
371	Other Equipment	15	R_2

Q. How did you calculate the average remaining life from the information described above?

A. When the economic life is applied to the plant survivor pattern, future normal retirements beyond the 27-year period are truncated. Integrating or calculating the area under the truncated survivor curve determines the average remaining life. For the transmission compressor station equipment, the ARL was determined to be 23.3 years. This is shown in the diagram in Schedule No. 9, Page 2 of Exhibit No. MGP-61. Similar determinations were made for the rest of the accounts in the transmission function.

Q. Would you please explain the mechanics of your calculation of the depreciation rate for the transmission plant?

A. After determining the individual ARL's for each account, I then divided each ARL into the difference between the depreciable plant and the accumulated reserve for depreciation, thus arriving at the indicated depreciation expense. I performed this operation for each account. This is shown on Schedule No. 13 of Exhibit No. MGP-61. This process is shown in the diagram in Schedule No. 12 of Exhibit No. MGP-61.

Q. What is the source of the gross depreciable plant shown on that schedule?

A. The gross depreciable plant as of December 31, 2008, as adjusted was provided to me by the company as booked plant.

Q. What is the source of the accumulated reserve for depreciation used in your rate determination shown on Schedule No. 13 of Exhibit No. MGP-61?

A. The December 31, 2008 reserve for depreciation for the transmission function was provided to me by the company.

GENERAL PLANT DEPRECIATION

Q. Would you please discuss your determination of the depreciation rates for the general plant accounts? What accounts make up the general plant?

A. The general plant is made up of the following accounts:

Account No.	Description
391.1	Computer Software and Hardware.

392.1	Transportation Equipment
394	Tools, Shop and Garage Equip.
396	Power Operated Equipment

Q. Please explain how you determined the average service life and why you made a separate determination for each individual account.

A. I determined the appropriate average service life that best applies to each type of equipment in the individual accounts. These average service lives were developed based upon analysis of the properties in each account, along with historical retirement experience, where available. My analysis also was based on discussions with MoGas personnel, as well as the experience of similar properties of other pipeline companies. The determination of the above depreciation rates differs from the mechanics employed for the transmission plant. Because of the high turnover rate of the facilities in the general plant, the whole life method was used to determine depreciation instead of the remaining life method. The reason for this treatment is that the turnover rate for general plant facilities is so much higher than that of the transmission plant. These lives, along with their respective depreciation rates, are also shown on Schedule No. 14 of Exhibit No. MGP-61.

NET SALVAGE

Q. Would you please now turn to the salvage component of the depreciation formula? What is net salvage?

Net salvage is the net amount of funds necessary to retire a specific facility or group of facilities. It is the difference between the gross salvage, if any, and the cost of removal. Gross salvage may be in the form of value of the facilities stored in a warehouse for reuse or the proceeds from a sale of such facilities. Net salvage may be positive or negative. Salvage is a factor in most of the transmission accounts. Salvage for those accounts was determined to be net negative.

Q. What is a negative salvage rate?

A. A negative salvage rate is the annual rate, as a percent of the gross plant (traditional Commission approach), subject to retirement that will accrue enough funds in an orderly and fair manner to cover the cost of retirement. I used the same straight line remaining life method that I employed to determine the depreciation rates to accrue negative salvage funds.

In determining the future net salvage, I examined the historical activity, where available, and the actual experience of other companies operating similar facilities. For the transmission plant, historical activity was not available. I therefore based the determination of future net salvage upon the experience of other pipeline companies that operate similar equipment.

Q. How did you determine negative salvage rate?

A. I began by using MoGas witness Mr. James Taylor's decommissioning estimate, which is Exhibit No. MGP-64. Mr. Taylor estimated the cost of decommissioning (in today's dollars) to be $22,394,544.

Q. Did you rely on any other studies to determine the negative salvage rate?

A. A terminal negative salvage ("TNS") study encompassing MoGas's pipeline facilities was prepared by Mr. Taylor.

In addition to Mr. Taylor's study, I determined the cost of removal of interim retirements that will take place during the service life of the pipeline facilities. The difference between the two studies is that Mr. Taylor's TNS study determines the decommissioning cost (in current dollars) of MoGas's entire pipeline system, considering today's facilities in service; while my study of the cost of removal of interim retirements reflects the cost of retiring plant that will not be in service at the TNS point in time.

Based on my analysis of interim retirements, and their related cost of removal, along with a TNS study performed by Mr. Taylor, I determined a composite underground storage plant net negative salvage rate to be 0.87 percent.

Q. Can you provide a more detailed description of your determination?

A. My determination of the appropriate negative salvage rate for the transmission facilities began by my analysis of MoGas's existing facilities, along with the decommissioning process of such facilities and familiarizing myself with Mr. Taylor's terminal salvage and cost of removal study. The summary of the TNS estimate is shown on Schedule No. 15 of Exhibit No. MGP-61.

My determination of the negative salvage rate is a combination of two distinct annual negative salvage accrual calculations – interim negative salvage and terminal negative salvage. The negative salvage rate is the quotient of the estimated annual negative salvage accruals, divided by the gross plant. I determined the negative salvage base for the ongoing normal, interim retirements separately from the final closure ("TNS"), because each has an associated average life different from the other.

Q. How did you employ Mr. Taylor's TNS estimate in your negative salvage rate determination?

A. I adjusted the TNS estimate to account for the amount of current plant no longer in service 27 years due to interim retirements. Normal retirements will occur from 2009 for a period of an average of 27 years. That is, of today's plant approximately 35 percent will be replaced due to their normal physical life over a 27 year period. The remaining facilities will be subject to the final closure at the 27-year average remaining economic life. This reduces the magnitude of Mr. Taylor's estimate. This calculation is shown on Schedule No. 16 of Exhibit No. MGP-61.

The adjusted TNS estimate is then combined with the negative salvage of the interim retirements to arrive at the recommended overall negative salvage rate for MoGas' transmission plant. The procedure of combining the two negative salvage increments is shown in Schedule No. 17 of Exhibit No. MGP-61. The average remaining economic life was applied to the final closure estimate. I then created a composite of the 27-year accrual period for the final closure with the 13.8-year accrual period for the interim retirements to arrive at an average period of 23.8 years. This is shown on Schedule No. 18 of Exhibit No. MGP-61.

The 23.8-year period of time is the result of direct weighting of the net negative salvage cost and the number of years to retirement.

Q. Can you describe the mathematical calculations used to determine the negative salvage rate?

A. Schedule No. 18 of Exhibit No. MGP-61 shows the calculation of the negative salvage rate for MoGas' transmission plant. I divided the estimated amount of negative salvage by the 23.8-year accrual period. I then divided that quotient by the transmission plant in service to arrive at 0.87 percent.

Q. Would you please describe the determination of the negative salvage increment of the interim retirements?

A. I determined the retirements for each plant account from the same survivor curves that I developed earlier for depreciation purposes. Recall that the survivor curve is actually a graphic representation of normal retirements over a period of time. The 27-year period of interim retirements for each relevant account in the transmission plant is determined. I combined all the interim retirements and determined a weighted average remaining life of 13.8 years that would apply as the average period of time to accrue the negative salvage for the interim retirements. This is also shown on Schedule No. 16 of Exhibit No. MGP-61.

After I determined the future annual normal or interim retirements for each account that would be affected by negative salvage, I then applied various net negative salvage values ranging from 10 to 23 percent as factors to the anticipated facility retirements. These factors are supported by observation of the historical retirement process, Mr. Taylor's analysis and determination, and by the experience of other gas companies operating underground storage systems.

Q. Mr. Feinstein, would you please describe the process of retiring a typical pipeline facility on an ongoing basis, that is an interim retirement?

A. My determination of the negative salvage for interim retirements is based on the sequence of events that take place during the retirement process. Interim retirements will take place during the useful life of MoGas's storage system. During that time frame, I have assumed that the retirements will be replaced. The cost of a retirement that will be replaced is less than one that is not replaced because of certain costs that are shared. This contrasts with Mr. Taylor's analysis where there are no replacements.

A simplified example of the sequence of events that could possibly take place during a pipeline replacement is as follows:

<u>Planning and Mobilization</u>

- Engineering workup
- Mobilization to site

<u>Clean and Purge</u>

- Isolate line segment
- Blow down
- Evacuation

<u>Remove Pipe from trench</u>

- Trench excavation
- Cutting pipe into sections

The above process might involve the following type of equipment and labor:

Equipment

- Dozers (at least a D-6 Cat)
- Backhoes (Cat 325B)
- Flatbed trucks
- Half ton pickup trucks
- Assortment of tools

Labor

- operators
- teamsters
- laborers
- foreman

Remove pipe from trench, cut, load on trucks and haul to storage yard. The following is necessary:

Equipment

- 30 ton Grove Hydrocrane
- Pipelayer (572-R Cat with 20 foot boom)
- Pipe trucks
- Low boy
- ¾ ton pickup truck with trailer
- ½ ton pickup
- Various tools

Labor

- Hydrocrane operator
- Operators
- Teamsters
- Pipefitters/welders
- Helpers
- Laborers
- Foreman

Other

- Environmental contractor
- Storage company inspection
- ROW damages
- Storage company management and overhead

<u>Pipe Handling and Storage</u>

This covers the unloading of pipe from trucks, store pipe in temporary storage yard, loading pipe onto carriers for transport to scrap yard and loading pipe in storage yard onto contractor's carriers. The following is necessary:

Equipment

- Grove 30 ton hydrocrane
- ½ ton pickups
- Various tools

Labor

- Operators
- Foreman
- Operator (hydrocrane)

Q. Mr. Feinstein, is it possible that for each interim retirement unit there will be no cost of removal or negative salvage?

A. No. It is not possible. The cost of labor and equipment, necessary to retire today and for the foreseeable future, will be significantly higher than any possible gross salvage. This is supported by Mr. Taylor's study, as well as my investigation into the procedure and actual cost of retirement.

I adjusted the terminal negative salvage estimate to reflect the fact that some of the facilities will not be retired at final closure, but as normal (interim) retirements over a previous period of time. Thus, the overall negative salvage estimate related to current plant in service is based on two elements: the terminal negative salvage estimate from current plant remaining in service at the time of decommissioning and the negative salvage estimate for the interim retirements.

Q. Is it proper to provide for the cost of retirements through a net negative salvage component?

A. The net negative salvage component reflects the future obligation of removal when the plant is retired. Like depreciation, the cost of retiring facilities is a legitimate cost of doing business. It is both reasonable and necessary for the ratepayers who are receiving service from these facilities to fund the additional costs of retirements through a negative salvage increment in the depreciation rates. In order to ensure that an adequate reserve will be on hand to decommission the facilities when they are retired, and to restore the land to its original condition, it is imperative that MoGas be able to collect such an amount in addition to depreciation rates over the estimated remaining useful life. Failing to include such an expense in current rates will force a subsequent generation of ratepayers to subsidize service provided to current ratepayers. Furthermore, a negative salvage allowance requires current ratepayers to pay the full cost of using these facilities by bearing their fair share of these costs.

Q. Is there a clear requirement for MoGas to provide financial assurance for decommissioning its pipeline facilities?

A. Yes. Authorization under Section 7 of the Natural Gas Act for the abandonment of natural gas facilities requires an environmental assessment by the FERC that will be incorporated into any abandonment order. (See 18 C.F.R. § 380.5(b)(1) (2008)). It is this assessment, which describes the manner in which the abandonment is to take place. This places a monetary burden on MoGas to correctly decommission its facilities and restore the land to its original condition.

Q. Is there evidence that MoGas will have to retire its pipeline facilities?

A. Yes. MoGas's pipeline facilities will have to be decommissioned. All pipeline facilities eventually wear out, become obsolete or uneconomic. This fact is demonstrated by my plant retirement and survivor curve analysis, discussed earlier, which reflects retirements due to physical causes. Gas supply and facility utilization studies reflect retirements that occur due to specific pipeline facilities becoming obsolete, redundant or otherwise unnecessary. At some point, each pipeline reaches the end of its economic life.

Q. How should MoGas account for its annual negative salvage allowance?

A. MoGas has established a sub-account to Account 108 called Accumulated Provision for Depreciation of Gas Utility Plant. Negative salvage accruals and net salvage (gross salvage and cost of removal) will be entered into this sub-account. This sub-account will enable the negative salvage accruals and the actual net salvage costs resulting from retirements to be identified separately from the accumulated depreciation accruals.

Q. Why do you recommend the establishment of a negative salvage reserve, which is separate and distinct from the reserve for depreciation?

A. There are two reasons for this. First, the negative salvage reserve could be reviewed periodically with ease. This would allow the detection of deficiencies or excesses in the accumulated reserve. Second, when negative salvage accruals and net salvage costs from retirements are reflected in the depreciation reserve, such reserve is distorted by the negative salvage amounts. This obscures the data in the reserve when making capital recovery depreciation analyses.

Q. Are there any factors, other than technological, that could affect the negative salvage allowance?

A. Yes, there are. Inflation, environmental and political considerations may result in future negative salvage costs that may differ from today's estimates.

Q. Would you please summarize the results of your depreciation rate determination?

A. As a result of my studies, I found that MoGas's existing transmission plant depreciation rate should be changed and a negative salvage rate for transmission plant be established. Schedule No. 13 of Exhibit No. MGP-61 shows the results of my updated determination of depreciation and negative salvage.

SYSTEM OPERATIONS

Q. Did you analyze MoGas' system operations, especially the need for specific compression in order to fulfill the contract demand of MoGas's pre-expansion customers?

A. Yes. I found that 1,824 horsepower compression was necessary to meet pre-expansion shippers' contract demand. Prior to the installation of the compression, MoGas had a contract demand totaling 92,208 Mcf per day. This demand was met by receipts from two upstream pipelines: Panhandle Eastern Pipe Line Company (Panhandle) and Mississippi River Transmission Company (MRT). In the western portion of MoGas' system, 80,782 Mcf per day was sourced from Panhandle. However, Panhandle has no specific delivery pressure requirement and MoGas was entirely dependent upon Panhandle's pressures to meet its customers' contract demands. Since 2002, the receipt pressure from Panhandle has ranged from 800 down to below 600 psig. The lower figure is important in this case. On extremely cold days when pressure dropped below 600 psig, MoGas was not able to meet its total contract demand.

To meet its customers' contractual requirements, MoGas requires 300 psig of pressure at the terminus of its system. Prior to the installation of the compressors, without assistance from Laclede, MoGas could not maintain that pressure.

Q. What did MoGas do?

A. MoGas sought and received authorization from the Commission to construct and operate compression facilities at Curryville, Missouri. Such compression would boost the low line pressure at the Panhandle receipt point into the MoGas pipeline, allow for hourly volume fluctuation and provide sufficient line pack for transient flows.

In FERC Docket No. CP07-450, MoGas received authority to install 4 compressor units each rated at 1230 horsepower. Although 1824 horsepower is required to meet the pre-expansion volumes, due to cylinder size and piston displacement limitations, this requires the operation of 3 of the 4 engines.

Q. Does the added compression facilitate deliveries to MRT?

A. The added compression will contribute to the continuing flexibility of the MoGas system by allowing sufficient pressure for gas to flow from MoGas into the MRT system. This benefits all shippers because they can use flexible point rights to move gas to MRT.

Q. How much compression is needed to serve the pre-existing and the new shippers?

A. MoGas now has more expansion volumes than at the time the certificate was issued. MoGas now has 22,364 dth/d of additional contracted capacity. Total compression needed for both existing and expansion customers is 3036 horsepower. Three units are still required to be in operation to generate this horsepower. One compressor unit will be held in reserve or standby for change outs and emergency.

Q. Please describe pipeline flows generally.

A. Physically, any pipeline system can perform only up to a certain level. The size (diameter), the length, the receipt pressure and the desired delivery pressures, along with characteristics of the flowing gas dictate the flow capacity of a pipeline system. If any of those items change, so will the ability to flow natural gas. The diameter and length of pipe are what they are and will not change. The temperature of the gas and the atmospheric temperature and pressure will essentially remain the same. A common gas pipeline flow formula is the Panhandle Formula:

$$Q = 435.87e\left(\frac{T_0}{P_0}\right)^{1.079}\left(\frac{\left(P_1^2 - P_2^2\right)}{G^{0.854}T_f L}\right)^{0.5394} d^{2.6182}$$

Where,

Q = Flow Rate in cubic feet per day
T_0 and P_0 = Base Temp and Pressure
T_f = Flowing temperature
G = Gravity of gas
P_1= Initial Pressure, psia
P_2= Finale pressure, psia
L = Length of the line in miles
D = diameter of the pipe in inches
e = Experience factor

What can change the flow in the above formula, and specifically for MoGas is the pressure at the beginning of its system or where gas enters its system.

Q. How much receipt pressure was needed at the interconnection with Panhandle prior to the expansion?

A. On a peak day, in order to maintain a pressure of 300 psig at the southern end of the system, Panhandle delivery pressure must be 795 psig. As illustrated on Schedule A of Exhibit No. MGP-63, 1824 horsepower is required when Panhandle delivery pressure drops to 600 psig. As discussed earlier, 3 of the units are required to run to meet this pressure.

Q. Have you examined other cases?

A. Yes. Exhibit No. MGP-63, Schedule B shows that at a delivery pressure from Panhandle of 681 psig, gas will not flow to customers at the south end of the MoGas system because of insufficient pressure. Absent compression, the only way to maintain deliveries at the southern end of the system is to curtail deliveries. For illustrative purposes, Schedule C of Exhibit No. MGP-63 shows the operations as they are presently projected on a peak day if Panhandles deliveries are at 600 psig.

Q. How common is it to for a pipeline system to have extra compression, over and above the contract capacity?

A. It is very common. Compressor units periodically require routine maintenance as well as major overhaul. If such maintenance or overhaul is necessary during peak periods the standby unit will provide uninterrupted service to all of MoGas' customers. MoGas' system operation is no exception. Some pipeline systems have standby units while others (mostly large long distance interstate pipeline systems) have additional compression capacity available for change outs or emergency purposes.

Q. Does the foregoing change the rate treatment of the compression?

A. No. As discussed in Mr. Lovinger's testimony, MoGas has a presumption of rolled in rate treatment for the expansion, which should not be disturbed. The foregoing studies demonstrate that there has been no significant operational change that warrants revisiting that presumption. Indeed, these studies demonstrate that it is entirely appropriate to allocate these costs on a system wide basis including to the Zone II shippers since the compression ensures service to the terminus of the system, which is in Zone II.

Q. Do you recommend a specific fuel use and lost and unaccounted for rate?

A. Yes. I recommend a 0.52 percent fuel use rate and a 0.47 percent lost and unaccounted for rate on the basis of a fixed retention.

Q. How did you determine a 0.52 percent fuel use rate?

A. Since there is no fuel use experience with the new compressor units, I estimated the fuel use based upon a calculation of the fuel consumption in terms of heating value (BTU per BHP-hour) as rated by the manufacturer, Dresser – Waukesha, along with the expected horsepower use of the compressors and applied throughput with a 50% load factor. I arrived at 0.52

percent of the throughput is required for fuel. The calculations are shown in Schedule D of Exhibit No. MGP-63.

Q. How did you determine the lost and unaccounted for rate?

A. MoGas' most recent 12 months experience with lost and unaccounted for volumes indicates a 0.47 percent rate and thus that is the rate that I recommend MoGas use. This is shown in Schedule E of Exhibit No. MGP-63. The calculated lost and unaccounted for value is well within the range of other pipeline systems.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit No. MGP-59

IN THE DISTRICT)

OF COLUMBIA)

Before me, the undersigned Notary Public, in and for the District of Columbia, personally appeared Edward H. Feinstein, 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.

Edward H. Feinstein

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

Notary Public

My Commission expires: 12/14/2012