UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Kern River Gas Transmission Company) **Docket No. RP04-__-000**

PREPARD DIRECT TESTIMONY OF
EDWARD H. FEINSTEIN
ON BEHALF OF
KERN RIVER GAS TRANSMISSION COMPANY

Q. Please state your name, occupation 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. I am a consulting petroleum engineer with the firm of Brown, Williams, Moorhead & Quinn, Inc.

Q. Please describe your business experience and educational background.

A. I received my Bachelor of Petroleum Engineering degree at 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., predecessor to Brown, Williams, Moorhead & Quinn, Inc. I am a member of the Society of Depreciation Professionals and the Society of Petroleum Engineers. I have presented testimony on many different subjects, including gas supply and deliverability, depreciation, gathering issues, and storage operations and cost allocation.

Q. What is the purpose of your testimony?

A. My testimony addresses the determination of the just and reasonable depreciation rates to be applied to Kern River Gas Transmission Company's ("Kern River's") depreciable transmission and general plant, as well as for the first time an appropriate allowance for negative salvage. As part of the support for my determinations, I am presenting a detailed depreciation study as well as an assessment of Rocky Mountain gas supplies as they relate to the useful life of Kern River's pipeline system.

My testimony does not address Kern River's levelization models or the ratemaking treatment of depreciation of transmission plant other than compressor engines in the models. Those elements of Kern River's proposed rates are explained in the direct testimony of Mr. Bruce Warner and Mr. Martin Hansen. It is important to understand that my several recommended depreciation rates will have different purposes. My recommended depreciation rate for transmission plant; other than compressor engines is a book depreciation rate. It will not be used directly for ratemaking purposes because Kern River's levelized rate model adjusts the annual depreciation expense for other transmission plant within the computation of the levelized cost of service. Similarly, my recommended depreciation rate for the Big Horn Lateral is for book accounting only, since the cost of service is a levelized computation. I also recommend a depreciation rate for the High Desert Lateral, which is used in this filing for the determination of a recourse rate only, since the rates charged to the anchor tenant on the lateral are negotiated rates. I also present in this testimony recommended amortization rates for intangible plant which are also book depreciation rate recommendations since Kern River includes intangible plant within the levelization of transmission plant in determining cost of service.

As part of the depreciation study, I am recommending that for regulatory and book purposes transmission compressor engines and all general plant be depreciated separately and apart from the levelization process. I recommend traditional straight line depreciation of compressor engines and general plant. The description of such facilities, support for my recommended change in methodology and the proposed procedure for removing such categories of plant from the levelized cost of service are enumerated in my testimony. I also discuss the determination of the reuglatory assets related to general plant and the compressor engines.

Q. Please describe the depreciation rates you have calculated to be applied to Kern River's depreciable transmission and general plant.

A. As a result of my studies and determinations, I am recommending the following depreciation rates:

INTANGIBLE PLANT

Amortization – High Desert Lateral	4.76 percent
Amortization – Blue Diamond	3.92 percent

TRANSMISSION PLANT

Depreciation - Compressor Engines	9.92 percent
Depreciation - Other Transmission	3.39 percent
Depreciation – Big Horn Lateral	6.67 percent
Depreciation – High Desert Lateral	4.76 percent
Negative Salvage - Other	0.21 percent

GENERAL PLANT

Acct. 391 Office Furniture and Equipment	
Office Furniture	6.67 percent
Computer Hardware	20.00 percent
PCs and Laptops	33.33 percent
Computer Software	20.00 percent
Office Equipment	6.67 percent
Acct. 397 Communication Equipment	10.00 percent

Acct. 392	Transportation Equipment	18.00 percent
Acct. 394	Tools, Shop and Garage Equipment	4.00 percent
Acct. 396	Power Operated Equipment	4.00 percent

<u>Overview</u>

Q. Please explain your depreciation analysis for Kern River with respect to transmission plant other than compressor engines.

A. The methodology I employed for determining Kern River's just and reasonable depreciation rates and negative salvage rates is fully consistent with Commission precedent. I analyzed Kern River's system operations, along with its markets and sources of gas supply. I determined an average remaining life of Kern River's transmission plant based on the expected physical lives of its transmission facilities, as well as an economic life of its pipeline based upon projected Rocky Mountain Area gas supplies. I also considered how competition in the natural gas industry affects the economic life of Kern River's facilities. I applied the average remaining life to each of its plant accounts to determine the composite depreciation rate for the transmission plant function.

I determined the negative salvage rate by employing the total negative salvage amount provided to me by Mr. Barrie McCullough, a former operations engineer, and now a consultant, for Kern River, to the same physical lives and economic life used to determine the transmission plant depreciation rate. I independently reviewed Mr. McCullough's negative salvage analysis and I determined that the calculation used by Mr. McCullough reflects conventional/standard industry practice. Mr. McCullough's analysis is attached to my testimony as Exhibit No. KR-8.

Q. Can you explain the reason for the differences between Kern River's existing transmission plant depreciation rates and the proposed rates?

A. Schedule No. 1 of Exhibit No. KR-6 shows a comparison of Kern River's existing transmission depreciation rates with the proposed rates. The differences in the proposed transmission plant depreciation rates compared to Kern River's existing rates are due to the addition of new, relatively undepreciated facilities, along with an evaluation of the gas supply and competition environment as it affects the useful life of Kern River's existing pipeline facilities.

<u>Depreciation Generally</u>

Q. Please explain what depreciation is and how it is used for rate purposes.

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 accounting and rate purposes, it is treated as an operating expense. Depreciation is intended to recover the invested capital systematically over the useful life of the universe of relevant assets.

Q. What method or approach did you use to determine Kern River's proposed depreciation rates?

A. I used the Average Service Life approach for all classes of transmission property and recommend that Kern River's depreciation rates 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 onshore transmission pipeline systems.

Q. Why did you choose the Average Service Life approach?

A. Depreciation rates depend on estimates of 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 property. This calculation would place an undue burden on the accounting system for depreciation purposes, requiring the maintenance of records for each individual 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 to be appropriate 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 classified by each account.

<u>Remaining Life Factors</u>

Q. What causes a plant unit to reach the end of its useful life and retirement?

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
- adequacy of supply or market.

Q. Please describe these factors in more detail and explain which are the most common causes of retirement.

A. 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 probably the more prevalent causes of retirements in the pipeline industry.

Q. What is the "adequacy of supply or market" factor and what is its significance

A. For a pipeline system such as Kern River, all of the above causes of retirement, whether physical or functional, have one thing in common: they are ever-occurring and affect individual facilities. In contrast to factors such as physical deterioration or obsolescence, the adequacy of supply or market is unrelated to the physical characteristics of the property or the action of public authorities. Adequacy of supply or market is probably the single most important factor resulting in premature retirements because this factor may affect a large portion of a pipeline system; therefore, I will treat this subject in more detail. In a depreciation study, the adequacy of supply and markets is referred to as the economic life.

The Depreciation Model

Q. What model did you use for determining depreciation?

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,

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

Q. What is the purpose of using the above equation to determine depreciation?

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

- capital recovery - ratably allocates a known fixed cost,
- cost of removal - ratably allocates a future obligation,
- salvage - ratably reflects recognition of future value.

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 is a matter of estimate until all the items in that group have been finally retired. The issue here, therefore, 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 my analysis for Kern River, I employed the group method and I used a survivor curve for each group of facilities.

Q. What is a survivor curve and what is its purpose?

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 remaining 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. 2 of Exhibit No. KR-6). 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.

Q. How accurate are survivor curves in determining the physical life of facilities?

A. 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 example, research on my part, along with discussions with Kern River's operating personnel, indicate certain pipeline and appurtenant facilities may be subject to premature retirement relative to that predicted by the survivor curve study.

<u>Economic Life of the Kern River System</u>

Q. Please describe the economic life of the Kern River system.

A. The economic life of the Kern River system is dependent primarily upon the productive capability of the supply areas from which it receives gas for transmission. On the other hand, Kern River's markets are made up of a combination of municipalities, an assortment of industrial concerns, cogeneration and other natural gas-fired power generators, local distribution companies,and various other pipeline shippers who seek to transport gas produced in the Rocky Mountain region to their end use markets or facilities. Generally, the lives of Kern River's markets, in and of themselves, are relatively long-term. However, any potential loss of markets may affect the useful life of a particular facility or of some portion thereof.

Adequate supply of gas for shipment is crucial to the remaining life of a pipeline system. Essentially, the sole source of gas for transportation in Kern River's pipeline facilities are the gas supplies of the Overthrust Belt and the Green River Basin of the Rocky Mountain Area. These two gas producing provinces are confined to a pocket located in northeast Utah and southwest Wyoming. I analyzed Kern River's Rocky Mountain gas supply as it would affect its system and performed studies concerning the supply life. The results of those studies, when directly related to Kern River's existing facilities, indicate an economic life of approximately 25 to 30 years. The average economic life of Kern River's facilities, which I will discuss further in my testimony, should be used to determine the average remaining life for the calculation of depreciation in this proceeding.

<u>Gas Supply</u>

Q. Please describe the gas supply analysis you performed and its purpose.

A. I studied, analyzed and modeled the gas supply of the Rocky Mountain area. I analyzed available data on existing, proven reserves of natural gas, as well as the various estimates of potential gas resources. I constructed a model to forecast the future availability of gas from the relevant supply sources. The purpose of my gas supply analysis is to determine a realistic economic life of pipeline facilities that are dependent upon such supplies.

In order to go about determining the supplies of gas that are realistically accessible through Kern River, I recognized the gas resources that are 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. The analysis and results of my gas supply study are summarized below.

Q. Please describe the results of your gas supply analysis.

A. The results of the model indicate a certain amount of risk for pipelines that rely disproportionately upon a single area, however broad, for their long-term future supplies. The western Rocky Mountain area is presently the main source of gas for transportation through Kern River's pipeline system.

Kern River transports gas produced from two major producing areas of the Rocky Mountain Area (Utah-Wyoming Thrust Belt and Moxa Arch). These areas are located in the Overthrust Belt and the western portion of the Green River Basin. While Kern River's present facilities and sources of supply are principally confined to the Overthrust Belt and Western Green River Basin, there are also other significant supply areas in the Rocky Mountain Area that, in the future, it logically would attempt to access.

Q. Did you evaluate other potential gas supplies accessible to Kern River?

A. Yes. Although there are other viable supply areas of the Rocky Mountain Area in which Kern River could possibly source available gas, the farther the producing area is from Kern River's pipeline system, the more uncertain is the potential to connect such supplies. Distance from Kern River's pipeline, of course, is not the only gas supply risk factor. Other factors such as gas price differential and the California delivery cost of transportation on Kern River compared to other pipelines must be considered. Further, the certainty of connecting gas supplies from other producing areas in the future is not assured, as Kern River would be confronted with an array of competitive forces already ensconced in the area.

Other supply areas from which Kern River could potentially source its throughput are the Central and Eastern portions of the Green River Basin and other Rocky Mountain basins located one interconnection charge away from its current sources. Such producing areas are the San Juan Basin, Uinta Basin and Piceance Basin. These basins have some potential as promising supply sources, but there is significant uncertainty about their viability as long term sources of throughput for Kern River.

Q. What is that uncertainty?

A. For one thing, gas supply data for specific areas is highly proprietary, making it difficult to evaluate the extent and economics of supplies. In addition, there is a significant uncertainty which new areas, if any, that Kern River could economically source for future available gas. It is for these reasons that I employed the entire states of Wyoming, Utah and Colorado as a surrogate area in which to determine the future supplies of gas that could flow in Kern River's system. As described above, by employing the entire Colorado, Utah and Wyoming producing regions in my study, my determination of the remaining economic life of Kern River's facilities is very conservative.

My determination of the amount of productive capacity of gas for which Kern River could compete to obtain gas to flow through its system is summarized in Schedule No. 4 of Exhibit No. KR-6 and derived in the Assessment of Natural Gas Supplies, which is included as part of Exhibit No. KR-7. The premise of my gas supply model is to estimate the quantities of gas available from both existing and future sources. The quantity of gas available from existing sources is generally the product of studies published by the Energy Information Administration ("EIA"). With respect to the availability of gas from future discoveries, I applied an Effectiveness of Exploration Model. The basis of the model is shown on Schedule No. 3 of KR-6 and is more fully explained in the Assessment. Comparing the results of the determination of the availability from future discoveries with the estimates of potential resources made by the Potential Gas Committee (PGC) indicate that the Effectiveness of Exploration approach is reasonable, as its estimates are actually greater than those of the PGC (see Schedule No. 13 of Exhibit No. KR-6).

Q. How did you use the results of the gas supply study?

A. I used the results of my gas supply study to determine the economic life of Kern River's gas transportation system. There are clear trends, as pointed out in this presentation, suggesting that the Rocky Mountain gas supply market is moving from a supply/demand balance controlled by demand to one controlled by supply. The production profiles I developed indicate deficiencies in the ability of the Rocky Mountain area to maintain high levels of throughput in all available pipeline capacity. As can be observed from the availability profiles I developed, supply/demand deficiencies are projected to begin in the second decade of the 21st century. This may create situations where major retirements of pipeline facilities take place. By the year 2030, my studies further indicate, the Rocky Mountain area could provide less than 60 percent of its current productive capacity. In the meantime, new pipeline capacity nevertheless is being proposed and, at least in the near future, will continue to be added in order to move the system's presently increasing gas production to markets. However, after gas availability reaches a peak and begins to decline, underutilization of some pipelines is certain to occur. In other words, there will be excess pipeline capacity in the region at that time. The production profile of the Rocky Mountain basins calculated under the supply model is shown on Schedule No. 4 of Exhibit No. KR-6.

Q. What did these results tell you about the economic life of Kern River's system?

A. The results of my gas supply model, coupled with Kern River's position as a pipeline largely dependent on specific sources of Rocky Mountain gas, strongly indicate an economic life for Kern River's pipeline system of approximately 25 to 30 years. The analysis of the economic life of a major interstate pipeline system involves consideration of not only the related gas supply, but the company's markets and competitive position. (See further discussion below.) Therefore, in my opinion, at this time, using an economic life of 25 to 30 years to determine Kern River's depreciation rate for transmission plant would certainly be just and reasonable.

Q. What conclusions did you reach concerning Kern River's remaining economic life?

A. As a result of my analysis of Kern River's system operation, the nature of its markets and the gas supply comprising its throughput, I determined the economic life to be 26 years. This conclusion is based upon the likelihood of major retirements due to depletion of its traditional gas supply sources and the effects of competition.

Q. Please describe the competition for markets and the competition for supply.

A. The competition for markets is illustrated on Schedule No. 14 of Exhibit No. KR-6. Competition for the California market emanates from several present sources and one important potential source. Large volumes of natural gas enter the California market from (1) the San Juan Basin and West Texas and (2) from western Canada. In addition, potentially large LNG supplies from the Pacific Rim (possibly including Alaska) are presently proposed for the California market. California also has certain, though less significant, gas supplies within the state.

With respect to the competition for supply, there is an air of uncertainty as supplies deplete within Kern River's confined area of interest, geologically, the

Utah-Wyoming Thrust Belt and the Moxa Arch, forcing Kern River to expand its reach into other areas to obtain supplies for its shippers. These other areas are distant (involving additional costs just to maintain throughput) and traditionally the hunting ground for other entrenched pipelines. However, by employing the entirety of Colorado, Utah and Wyoming as the supply indicator for Kern River's economic life, I have conservatively related supply to the economic limit horizon.

Q. What are "major retirements"?

A. Major retirements are retirements of facilities due to economic forces (rather than physical forces) such as gas supply depletion that cause underutilization and changes in system operations.

Q. How did you determine project these major retirements?

A. I determined major retirements that would take place along Kern River's system from the results of my gas availability study. The results are shown on Schedule No. 5 of Exhibit No. KR-6.

Q. How did you determine the effect the combined supply areas would have on Kern River's facilities?

A. I determined the effect that the combined supply areas would have on Kern River's facilities by assuming the decline in supply would result in an equal percentage of underutilization of Kern River's pipeline. I performed the calculations for the supply availability from the Rocky Mountain Area using the results of the Effectiveness of Exploration Model. The recommended economic life is an average life. Major retirements take place before and after the 26 year period. I estimated the major retirements to take place in three-year increments, in direct proportion to the decline in gas availability. I then determined the average remaining economic life by directly weighting the retirements with the corresponding number of years from 2003 to retirement. By reciprocal weighting, the average remaining economic life is shorter. I employed the direct weighting process which results in a longer, more conservative economic life. To test the sensitivity of the three-year increment approach, I applied, instead, the same method on a yearly basis. This test indicated a somewhat lower remaining economic life.

Q. How significant can these major retirements be to a system?

A. It is my experience in analyzing retirements of pipeline properties that major retirements take place in varying degrees. In market areas, loss of customer base can cause underutilization and eventual retirement from such economic forces. In supply areas, depletion of gas reserves and competition are typical causes of underutilization and eventual retirement. For example, offshore Gulf of Mexico facilities are constantly being retired. Further, on March 9, 2000, Trunkline Gas Company retired an entire 700-mile loop line on its mainline system from south Louisiana to Tuscola, Illinois. Trunkline retired the pipeline loops because of severe underutilization of its mainline system. Trans-Northern Pipelines Inc. similarly has sought and obtained abandonment authority from Canada’s National Energy Board for Trans-Northern’s entire Don Valley Lateral to Toronto Harbour pipeline. The company sought the retirement because the facility was in a "serious deficit position" due to reduced throughput.

Another aspect of the economic life component in the determination of depreciation is the capital recovery objective. In addition to providing an adequate opportunity to recoup the investment in pipeline facilities and appropriately matching revenues to the costs of providing gas transportation services, which have already been described, another important factor in establishing depreciation rates is the long-term fairness of the depreciation component. Specifically, the objective in this regard is to minimize intergenerational inequities in the consumption of service value (depreciation).

An important part of regulatory depreciation is the need to maintain long-term intergenerational equity among users of Kern River's pipeline system. If the recovery of invested capital was unnecessarily deferred, an unfair burden would be placed upon future customers. Inherent in regulatory depreciation is the premise that the ratepayers who are using the pipeline system should pay for their use. If certain (compressor engines and general plant) of Kern River's depreciation rates remain approximately the same as within current depreciation rates, further deferral of the recovery of invested capital will increase costs to future users of the system beyond the value of the service that they will consume.

Thus, as facilities become underutilized due to declining throughput, a depreciation rate which does not take such declines into consideration would result in inequitable treatment of future ratepayers, as the unit cost of depreciation would be many times higher than that for current ratepayers. This is an important concept that must be considered.

The Court of Appeals in the landmark Memphis decision on depreciation emphasized, "Even assuming continued serviceable life, declining use of pipeline facilities might conceivably lead in future years to depreciation dollars per unit of gas so high as to be unreasonable." Memphis Light, Gas and Water v. FPC, 504 F.2d 225, 234 (D.C. Cir. 1974).

Q. Are there other methods you could have used to determine the gas resources available and which would have produced better results?

A. While other methodologies may also produce defensible results, in my opinion, my study represents a reasonable method of estimating the size and characteristics of the Rocky Mountain region's gas resource base.

Q. Why did you reject these other potential methodologies?

A. For a study that ultimately determines the recovery of a pipeline's investment in facilities, it is important that projections of gas production take into consideration only that portion of the ultimate resource that can reasonably be expected to be delivered to markets. By applying various estimates without recognizing the constraints, such as surface location restrictions, that not all pools below the surface will be discovered, and the economic realities of small pools, any production projections will surely overstate the future supply availability.

The purpose of depreciation is to recover investment over a reasonable period of time. I do not believe it would be in the public interest to set a depreciation rate for Kern River based upon sources of supply, the availability of which to Kern River and its customers is highly uncertain. Therefore, I think it would be unreasonable to include in the economic life evaluation other gas resources outside the Rocky Mountain region, which likely are not economic to attach to Kern River.

Q. Did you examine the economic life of Kern River's transmission assets from any other perspective?

A. Yes. I also simulated a realistic relationship between Kern River's existing facilities and the amount of future gas available in the Rocky Mountain area. The Rocky Mountain area is unique among the lower 48 gas producing states with respect to pipeline capacity. It represents the last frontier for lower 48 gas supplies and new pipeline take-away capacity.

Expanding production in this area has occasionally outpaced the installation of new interstate take-away capacity. The Commission's present policy is to encourage and expedite, if possible, applications for a new capacity, specifically, in the Rocky Mountain area. (See Mr. John Smith's direct testimony for additional information.) Surplus productive capacity in the Rocky Mountain area is forecasted and shown on Schedule No. 18 of Exhibit No. KR-6.

With the above in mind, my main assumption in the simulation of a realistic relationship between Kern River's existing facilities and the amount of gas available in the Rocky Mountain area, is that any surplus or excess productive capacity will be attached and transported to market by newly constructed pipeline capacity. That is, producers will not husband surplus productive capacity to wait for existing pipeline capacity to become available to them. Therefore, utilization of Kern River's existing facilities will depend on future productive capacity. Kern River's 2003 share of the productive capacity of the Rocky Mountain area was 13.03 percent. However, as the annual production in the area increases, and new pipeline capacity is built, Kern River's share of total production declines. When the area's production peaks (expected in **2015**), Kern River's share of the total supply decreases to 11.52 percent. The profile of Kern River's throughput related to its existing capacity, as forecasted using the area-wide productive capacity as developed in Exhibit No. KR-6, is shown in Schedule No. 20 of Exhibit No. KR-6. In summary, there will come a time in the future when gas supplies in the Rocky Mountains will fall below aggregate pipeline capacity. This could occur as soon as 2015 as my simulation demonstrates.

Further, the result of the simulation indicates that, by 2030, Kern River's pipeline capacity relative to total Rocky Mountain production capacity, could be less than one-third of what it is today. These results are conservative, as the forecast of future gas availability includes 18 percent more potential gas supplies than the PGC's most recent estimates.

Determination of Depreciation Rate for Kern River's Transmission Plant

Q. What is the significance of the average remaining life factor in determining depreciation and what is its relationship to the economic life?

A. The 26-year economic life of Kern River's transmission system plays a key role in the determination of the average remaining life ("ARL") factor in the depreciation formula I described above. ARL represents the average year of the final investment recoupment. More precisely, it reflects a point in time around which major retirements will 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).

The survivor curve represents the pattern of normal, annual retirements that will occur out to 50 years. I determined the normal retirement curve for each of Kern River's transmission accounts. For example, I determined that Account 367 (Mains) has an average service life of 60 years, with an R4 survival pattern. This is shown on Schedule No. 2, page 1 of Exhibit No. KR-6. Mains make up over 85 percent of Kern River's mainline transmission system. This determination was made in part by employing an analysis of the type of equipment, its usage and condition, as well as its age and survivor curve retirement patterns of such facilities that are typical in the industry. I determined the survivor curve and resulting average service life which best applies for the plant in each of the other accounts as follows:

Account No.	Description	Average Service Life	Survivor Pattern
365.2	Rights-of-way	60	R3
366.2	Structures	40	R4
368	Compressor Sta.- Other	25	R3
369	Meas. & Reg Sta. Eq.	40	R2
370	Communication Equip.	10	R2

Q. How is the survivor curve used to determine the ARL?

A. When the economic life is applied to the survivor pattern, future normal retirements beyond the 26-year period are truncated. The average remaining life is determined by integrating or calculating the area under the truncated survivor curve. For the transmission mains, the ARL was determined to be 24.3 years. This is shown on Schedule No. 6 of Exhibit No. KR-6. Similar determinations were made for the rest of the accounts in the transmission function.

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. The indicated depreciation expense for each account was totaled. This is the indicated depreciation expense for the total transmission plant. I performed this operation for the years 2004 to 2006. This is shown on Schedule No. 6 of Exhibit No. KR-6. The indicated depreciation rate for Kern River's transmission plant is 3.39 percent.

Q. How did you reflect near-term plant additions and retirements?

A. In order to reflect near-term plant additions and retirements for purposes of depreciation rate stability, I performed a three-year depreciation rate determination, employing plant additions and retirements for 2004 through 2006. This also is shown on Schedule No. 6 of Exhibit No. KR-6. The indicated depreciation rate was then calculated by dividing the total indicated 3-year expense by the depreciable plant.

The gross depreciable plant as of January 31, 2004, as adjusted through the end of the test period, was provided to me by the company. With respect to actual and very near-term additions of plant, I estimated various amounts. Near-term retirements also were estimated. Schedule No. 6 of Exhibit No. KR-6 shows the gross and net plant balances for depreciation determination purposes.

Q. How did you determine the January 31, 2004, as adjusted, reserve for depreciation for the transmission function?

A. The January 31, 2004, as adjusted, reserve for depreciation for the transmission function was provided to me by the company. Kern River, like most interstate gas pipeline companies, books depreciation on a functional basis. Therefore, I determined a theoretical reserve for depreciation for each account for calculation purposes, all the while maintaining the actual total booked reserve figure. The depreciation rate determination in summary form for Kern River's facilities is shown on Schedule No. 6 of Exhibit No. KR-6.

Negative Salvage Rate

Q. Please explain the term "negative salvage."

A. Negative 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.

Q. What is a negative salvage rate?

A. A negative salvage rate is the annual rate, as a percent of the gross plant 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.

The negative salvage rate 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 negative salvage depreciation rates. 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, I recommend that Kern River propose to collect such an amount in rates over the estimated remaining useful life of its plant. 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. What determines the manner in which abandonment takes place?

A. Authorization under Section 7 of the Natural Gas Act for the abandonment of natural gas facilities provides for actions that require an environmental assessment by the FERC (18 C.F.R. § 380.5). It is this assessment that describes the manner in which the abandonment is to take place. This places a monetary burden on Kern River to decommission its facilities correctly and restore the land to its original condition.

Q. In your view, will Kern River's facilities eventually be decommissioned?

A. Kern River's pipeline facilities will have to be decommissioned. Pipeline facilities eventually wear out, become obsolete or uneconomic. This fact is demonstrated by my plant retirement and survivor curve analysis, 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. What did you calculate Kern River's negative salvage rate to be and how did you determine that rate?

A. I analyzed Kern River's historical retirements, conversed with company personnel and reviewed the experiences of other companies. I found that the cost of removal will out-pace any gross salvage received for such retirements. Based on that analysis, I determined net negative salvage values that vary with each type of facility and age at retirement.

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

A. My determination of the appropriate negative salvage rate began by familiarizing myself with Mr. Barrie McCullough's engineering determination of salvage and cost of removal for Kern River.

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

Normal retirements will occur from 2004 for a period of an average of 26 years. The remaining facilities will be subject to final closure at the end of the 26-year economic life. 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 26-year period of retirements for each account is shown on

Schedule No. 8 of Exhibit No. KR-6. I combined all the interim retirements and determined an average remaining life of 17.25 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. 8 of Exhibit No. KR-6.

After I determined the future annual normal or interim retirements for each account that would be affected by negative salvage, I applied various net negative salvage values, ranging from 0 to 10 percent, to the anticipated facility retirements. These factors are supported by observation of Kern River's historical retirement experience referred to earlier, discussion with Kern River operating personnel and the experience of other pipeline companies.

I adjusted Mr. McCullough's total 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 period of time. The difference between Mr. McCullough's negative salvage estimate and that for the interim retirements represents the negative salvage at the final closure. This is shown on Schedule No. 9 of Exhibit No. KR-6. The 26-year average economic life was applied to the final closure estimate. I then created a composite of the 26-year accrual period for the final closure with the 17.25-year accrual period for the interim retirements to arrive at an average period of 25.55 years. This is shown on Schedule No. 10 of Exhibit No. KR-6. The 25.55 years is the result of direct weighting of the net negative salvage cost and the number of years to retirement. When they are reciprocally weighted, the result is 25.33 years. I employed direct weighting in order to be consistent with my other conservative direct weighting factors.

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

A. Schedule No. 11 of Exhibit No. KR-6 shows the calculation of the negative salvage rate for Kern River's transmission plant (other than compressor engines). I divided the estimated amount of negative salvage by the accrual period of 25.55 years. I then divided that quotient by the transmission plant in service to arrive at 0.21 percent.

Q. How do you recommend net salvage be reflected for accounting purposes?

A. I recommend that Kern River establish a sub-account for negative salvage in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant. Negative salvage accruals and net salvage (gross salvage and cost of removal) will be recorded in this sub-account. This treatment will enable the negative salvage accruals and the actual net salvage costs resulting from retirements to be identified separately, apart from the accumulated depreciation accruals.

Q. What is the reason for creating this sub-account?

A. There are two reasons for it. First, a sub-account allows the negative salvage reserve to be reviewed periodically with ease. This allows 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. Inflation, environmental and political considerations may result in future negative salvage costs that may differ from today's estimates.

Q. Based on your analysis, what did you determine Kern River's net negative salvage for each dollar of plant retired to be?

A. Analysis of Kern River's operations, facility configuration, and actual retirements indicates future retirements will result in a cost of removal in excess of any gross salvage for such facilities. I expect that Kern River will average approximately 5 percent net negative salvage for each dollar of plant retired.

<u>Depreciation of Compressor Engines</u>

Q. How did you determine the average service life of Kern River's compressor engines?

A. As Mr. Michael Falk explains in his testimony, each of Kern River's gas turbine compressor engines is periodically replaced pursuant to a maintenance agreement with the engine manufacturer. While the average service life of the compressor engines is only 2.91 years, the retirement returns a positive net salvage value of over 70 percent of the original cost, with relatively little cost of removal. Specifically, a new compressor engine involves an investment of about $3,400,000. However, as shown in my study, the actual cost of each compressor varies over its full service life based on fired-hours in use, salvage received upon retirement, cost of removal, and AFUDC, overhead and freight costs incurred.

My determination of the three-year average service life for the compressor engines is based on the actual additions and retirements experienced by Kern River my analysis of the actual service lives of the compressor units, as shown on Schedule No. 15 of Exhibit No. KR-6; and on the testimony of Mr. Falk. Mr. Falk discusses the operational history of Kern River's compressor engines and identifies the number, types and locations of the engines. A summary of the costs and salvage is shown on lines 1, 2, 3 and 4 of Schedule No. 7 of Exhibit No. KR-6. Additional support is also found on Schedule No. 17 of Exhibit No. KR-6, which is a graphical representation of the history of each engine by compressor station.

My analysis centered on the high load factor use of the Solar Mars compressor engines. Mr. Falk explains the differences in operations of the Mars units and Kern River's other compressors in his testimony.

Based on analysis of operations of the Solar Mars units, Kern River's engineers have determined that the Mars engines should be replaced approximately every 30,000 to 35,000 fired hours, or within the general range of 2.5 to 4 years after initial installation. This is not unusual for such equipment. Equipment with moving parts can theoretically last for an extended period of time, as long as it is regularly overhauled and parts are replaced. However, the overhaul and replacement of integral parts is costly. It is the duty of the operations engineers to determine the best operational cycle by weighing the cost of continuous overhauling and heavy maintenance versus replacement of the equipment. This balance includes considering the salvage value that can be received at various replacement intervals (e.g., the shorter the useful life, the higher the salvage value). It is this type of analysis that Mr. Falk and his engineers have performed. Based on a careful, engine-by-engine analysis of Kern River's actual history of retirements of Mars turbine compressors, I have determined that the useful life of the turbine engines averages 2.91 years. Schedule No. 15 of Exhibit No. KR-6 illustrates portions of my determination of the depreciation rate for the turbine engine sub-account of Account 368, Compressor Station Equipment.

Q. How does the 2.91 year service life and high positive salvage value for the compressor engines translate into a depreciation rate?

A. Recall the depreciation formula I described earlier:

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

Because of the high turnover rate of the compressor engines, the following formula should be used:

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

Where, ASL is the average service life (i.e., whole life rather than remaining life).

Q. What is the whole life method and why did you use it to determine the depreciation expense for the compressor engines and the various properties in the general plant accounts?

A. The whole life method, or vintage year accounting method, determines the depreciation rate for a particular property based upon its full service life rather than its remaining life. Whole life depreciation results in the allocation of a gross plant base over the total life of the investment. This method is particularly useful for short-lived, high turnover properties, such as those found in the general plant function. Because of the short-lived and high turnover ratio of the compressor engines (2.5 to 4 years), it is an ideal approach to determining the depreciation expense.

The use of the remaining life approach for the compressor engines and general plant would seriously under-accrue any new plant unless it is reviewed and revised more often than the rate at which the facilities are turned over.

Net salvage plays a significant role in the depreciation determination the compressor engines. The reason for this is that net salvage can be more than 70 percent of the original cost of plant retired.

Thus, my investigation and analysis of the average service lives of Kern River’s compressor engines reveals that a 2.91 year life is just and reasonable. The resulting annual depreciation rate for the compressors, which includes the large amount of positive salvage, is calculated to be 9.92 percent. This is shown on

Schedule No. 7 of Exhibit No. KR-6, Compressor Station Engines. Other appurtenant equipment in Account 368, Compressor Station Equipment, will be depreciated on a much longer term basis (average service life of approximately 25 years with a composite transmission plant depreciation rate of 3.39%).

Q. How do you recommend the compressors be treated for ratemaking purposes?

A. Because of the high investment turnover and short service life, I believe that, for ratemaking purposes, the compressors should be removed from the gas plant investment that Kern River uses to levelize its cost of service and treated separately on a traditional, straight line depreciation basis. The inclusion of these short-lived compressors in the levelized cost of service approach does not allow Kern River to recoup such capital investment over a reasonable period of time. The levelized cost of service employs a total plant life far higher than the 2.91 year service life of the compressor engines. To include the investment in the short-lived compressor engines in the levelized cost of service would also causes significant intergenerational inequities to rate payers.

Q. Even though the compressor engines have a service life of only about three years, wouldn’t the investment be fully recouped eventually even if a long-life depreciation rate were used?

A. Yes, eventually the investment would be fully recovered. However, the recovery would not be in a reasonable and orderly fashion, thereby placing a burden on the company in the financing of replacements. In addition, because most of the recovery of the investment (via depreciation) would be pushed forward in time, future ratepayers would be burdened with depreciation expense associated with facilities that had long since been retired. In fact, by employing a long-life depreciation rate for the compressor engines, future ratepayers might very well pay for several generations of units at each station that were no longer in service.

Q. Please explain how depreciation expense for such short-lived properties would be pushed forward and paid by future ratepayers.

A. For example, the original Muddy Creek #1 Solar Mars unit was put in service in February 1992 and was retired in November 1995, a total service life of 45 months. Over those 45 months, Kern River accumulated depreciation of the engine at annual rates of 0.67 percent, 1.34 percent, 2.1 percent and 2.60 percent, recording total depreciation of $115,900. However, if depreciation expense fully matched cost incurrence Kern River would have accumulated an amount equal to the gross investment in the unit of $1,890,440, less gross salvage value at the time of replacement, plus the cost of removal. For the original Muddy Creek #1 unit, the gross salvage received was $1,183,448 and the cost of removal was $5,000. Thus, over that unit's 45-month service life, Kern River should have accumulated depreciation of $711,992 ($1,890,440 less $1,183,448 plus $5,000), or nearly $600,000 more than it actually recouped.

Q. But isn't it true that, under the average service life approach, there will be units of property which will be retired earlier than other similar units and that, at any particular point in time, there will be some retired units in which depreciation was not completely accrued?

A. Yes, under the average service life approach, that does occur. The reason is that that method applies an average life to large groups of long-lived facilities, some of which are retired after less than the average life span, and others after more than the average life span. In the end, however, the total investment is fully recouped. This method (average service life or average remaining life), while not absolutely precise, is particularly adaptable to pipeline systems, which contain large numbers of plant units. It would be a horrendous task with inherently uncertain accuracy to determine and assign a life to each of the hundreds of units of pipeline system property. Nevertheless, the average service life method must be applied judiciously by treating short-lived facilities separate from long lived facilities.

Q. Did Kern River always capitalize the investment cost of replacement turbine engines?

A. It appears that the replacement engines were always capitalized, rather than expensed. I am informed by Kern River's personnel that all books and records available to them indicate the units were capitalized. It is important to note that each replacement unit carries a different serial number. This indicates that a new or refurbished unit was installed as a replacement for each unit that was removed.

Q. Please explain how you determined the appropriate amount of depreciation reserve attributable to the compressor engines that must be removed from the levelized cost of service.

A. I determined the true reserve for depreciation for each of the compressor engines that has been in service during Kern River's history. I applied the actual, levelized depreciation rate that Kern River applied to each unit when it was in service to determine the total depreciation accrued on all engines from 1992 to 2004. I then determined the balance of the depreciation reserve, which includes the accruals, retirements, salvage and cost of removal. I determined the balance employing a depreciation rate that fully recoups the investment. Comparing the reserve under the levelized approach and the reserve that recoups the total actual investments results in a regulatory asset related to the levelized depreciation of its investments in turbine compressor engines. I recommend that Kern River recover this regulatory asset over the remaining life of the 10-year and 15-year shipper contracts so that the asset is fully recovered from the current, original generation of shippers. The regulatory asset is specifically determined on Schedule No. 16 of Exhibit No. KR-6 as the difference between depreciation reserve actually recouped by revenues and the precise recoupment rate based on service life of each engine unit.

While Kern River did not recover its investment in some of the compressor engines over their service lives, my recommended approach is fair to the existing shippers, as it recovers the regulatory asset over the entire life of the shipper contracts, a considerably larger period of time than the life of the facilities. It also is fair to Kern River because it allows the company to recoup over a reasonable period of time the portions of its investments that it has not previously recovered.

Q. Why are there unrecouped amounts in the reserve for depreciation for the compressor engines?

A. The regulatory asset exists because: (a) the depreciation rate that was applied to the short-lived engines was based on long-lived transmission properties, such as mains, and (b) the differences between the cost of retired property, salvage and cost of removal, when applied to the reserve, resulted in a negative reserve. The reserve for depreciation is accrued as a credit to plant in service. Retirements are debited, positive salvage is credited and cost of removal is debited.

Q. Why is it appropriate to establish a regulatory asset related to the compressor engines?

A. Left uncorrected, accumulated depreciation, the compressor engine investments would cause the reserve for depreciation for transmission plant other than compressor engines to be seriously distorted. This distortion would arise because large debits for retirements of compressors would continually be applied to the reserve, but only very small depreciation accruals (credits) would be applied during the engines' useful lives. To avoid this, I am recommending that the difference between the actual accumulated depreciation accruals and the balance of the reserve for depreciation for the compressor engines be recouped separately in the form of a regulatory asset. Specifically, I recommend that Kern River allocate the regulatory asset to 10-year and 15-year shipper groups and amortize it over the full remaining lives of the contracts.

Depreciation Rate for General Plant

Q. What accounts make up the general plant?

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

Account No.	Description
391	Office Furniture & Equip.
392	Transportation Equipment
394	Tools, Shop and Garage Equip.
396	Power Operated Equipment
397	Communication 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 the equipment in the individual accounts. These lives, along with their respective depreciation rates, are shown on Schedule No. 12 of Exhibit No. KR-6. These average service lives were developed based upon analysis of the properties in each account. For example, I analyzed 139 units of transportation equipment, all of which were put in service after inception of Kern River's operations and retired before the end of 2003. The result of that study indicated a depreciation rate for transportation equipment of 17.95 percent (see Schedule No. 21, p. 2, of Exhibit No. KR-6). In my recommendation, I rounded this percentage to 18.00 percent. My analysis was also based on discussions with Kern River personnel, as well as the experience of similar properties of other pipeline companies.

The methodology for determining the depreciation rates for general plant differs from the mechanics employed for the transmission plant depreciation rates. 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.

Q. How do you recommend the investment in the accounts for the general plant function be treated?

A. Because of the high turnover rate of the facilities in Kern River's general plant, I recommend that the investment in all the general plant accounts be removed from the cost of service levelization and be treated separately. With respect to the compressor engines and the general plant, the task then remains to estimate the amount of reduction in the levelized cost of service depreciation reserve due to the elimination of such investment.

Q. How did you determine the amount of depreciation related to general plant to remove from the levelized reserve and any deficiencies?

A. I determined the depreciation that was accrued based on the actual depreciation rates historically employed in Kern River's levelization models. As of October 31, 2004, that amount is $5,298,508. With retirements, salvage and cost of removal applied, I found that depreciation on the short-lived general plant properties was substantially under-accrued. The reserve for depreciation was negative $3,630,936. The negative $3,630,936 indicates that not only were the levelized depreciation accruals for general plant not recouped, but because of the effect of retirements, salvage and cost of removal on the reserve for depreciation, the company is presently in arrears to the extent of the negative balance in the reserve. The determination of this deficiency is shown on Schedule No. 22 of Exhibit No. KR-6.

If the general plant remains in the levelized rate determination, the present deficit of $3,630,936 in the depreciation reserve will eventually be fully recouped over the life of the long-lived transmission plant. However, most of the general plant properties have useful lives of less than five years. The deficit of accumulated depreciation would continue to increase over time, pushing ever larger amounts of depreciation expense to be collected well after the relevant plant units had been retired.

Q. How do you recommend that Kern River rectify the deficiency?

A. I believe depreciation of general plant should be removed from Kern River’s levelized rate determination and treated separately, similar to the treatment I recommend with respect to depreciation of compressor engines.

Therefore, I recommend that the difference between the deficit of $3,630,936 in the accumulated reserve for depreciation of general plant and the actual book depreciation reserve of $19,421,646 be recouped as a regulatory asset.

The recovery as a regulatory asset will be somewhat similar to that recommended for the compressor engines. Specifically, the $23,052,582 ($3,630,936 plus $19,421,646) will be amortized over the remaining life of the firm shippers' contracts. The purpose of the regulatory asset treatment is to allow the recovery of the asset in a more reasonable manner, rather than burden future generations of ratepayers with depreciation accumulated from earlier operations.

Q. Please explain your recommendation for the depreciation/amortization rate for Kern River's intangible plant.

A. Kern River's intangible plant is made up of investment in contributions in aid of construction (CIAC) for two separate projects, the High Desert Lateral and the Blue Diamond delivery point. For the recoupment of the High Desert CIAC, I believe the most prudent approach is to recover such funds over the term of the relevant transportation contract. For the High Desert Lateral, the contract term is 21 years, indicating a 4.76 percent amortization rate. Further, the Commission in Docket No. CP01-405 authorized a 4.76 percent rate. With respect to the Blue Diamond project, the life of the transmission system itself is most relevant, indicating a 3.92 percent amortization rate.

Q. Would you please explain your recommendation for depreciation rates for the incremental Big Horn and High Desert Laterals?

A. The Big Horn Lateral and the High Desert Lateral are transportation laterals off of Kern River's mainline system. For example, the High Desert Lateral provides natural gas to a 720 megawatt electricity generating plant near Victorville, California. Both laterals provide service to specific electric generation markets and for that reason, I believe the primary terms of the gas service agreements under which the laterals were constructed should be the basis for the number of years to recoup the plant investment. Thus, for the High Desert Lateral, the primary term for the Victorville gas service agreement is 21 years. A 21-year depreciable life results in a rate of 4.76 percent (100 percent divided by 21 years) for recourse rate calculation purposes.

The Commission in Docket No. CP01-405 authorized the use of a 4.76 percent depreciation rate for the High Desert Lateral. In that order, the Commission stated: "The 21-year depreciation life coincides with the primary term for the Victorville – Gas service agreement and appears reasonable." And the Commission further states: "Therefore the Commission will approve Kern River's proposed use of a 4.76 percent depreciation rate for initial recourse rates."

Similarly, the term of the facility cost reimbursement agreement related to the Big Horn Lateral is 15 years, which results in an indicated book depreciation rate of 6.67 percent (100 percent divided by 15 years).

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Kern River Gas Transmission Company) Docket No. RP04-___-000

AFFIDAVIT OF
EDWARD H. FEINSTEIN

Edward H. Feinstein, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Edward H. Feinstein on behalf of Kern River Gas Transmission Company;" that, if asked the same questions that appear in the text of said direct testimony, he would give the answers that are herein set forth; and that he adopts the aforesaid testimony as his sworn, direct testimony in this proceeding.

Edward H. Feinstein

Subscribed and sworn to me, a Notary Public, in and for the District of Columbia, this 22nd day of April, 2004.

My commission expires: April 30, 2004

k\kern\rp04-xx\final direct testimony\Feinstein Affidavit

Exhibit No. KR-6
Docket No. RP04-___-000

SCHEDULES
TO THE
TESTIMONY OF
EDWARD FEINSTEIN

Schedule No. 1
Exhibit No. KR-6
Docket No. RP04-___-000

KERN RIVER GAS TRANSMISSION COMPANY

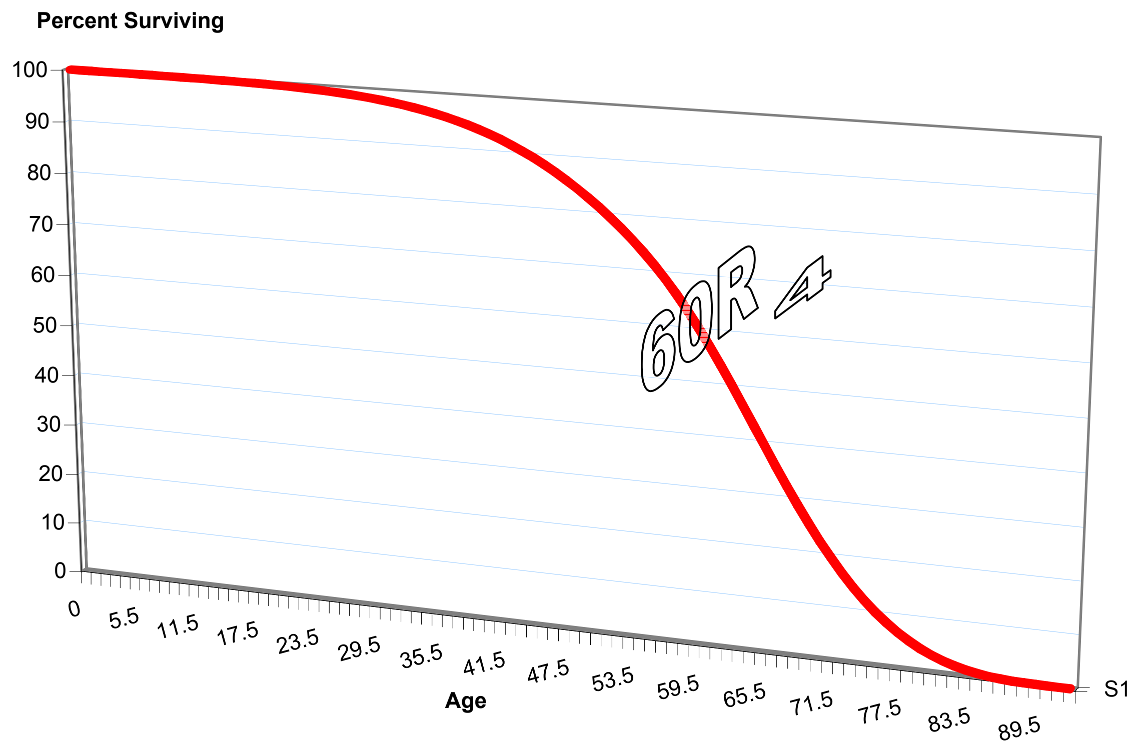
COMPARISON OF KERN RIVER'S EXISTING TRANSMISSION DEPRECIATION RATES WITH INDICATED RATES
For Book and Recourse Rates

Transmission Plant	Gross Depreciable Plant	Existing Rates		Indicated Rates	
		Depreciation Capital Recovery	Depreciation Negative Salvage	Depreciation Capital Recovery	Depreciation Negative Salvage
	$	%	%	%	%
Transmission - Other	2,206,981,891	2	0	3.39%	0.21%
Transmission - Compressor Engines	57,111,874	2	0	9.92%	Built into depreciaton rate
Transmission - High Desert Lateral	29,130,734	4.76	0	4.76%	0.21%
Transmission - Big Horn Lateral	3,564,222	6.67	0	6.67%	0.21%
Total Transmission Plant	2,296,788,721				

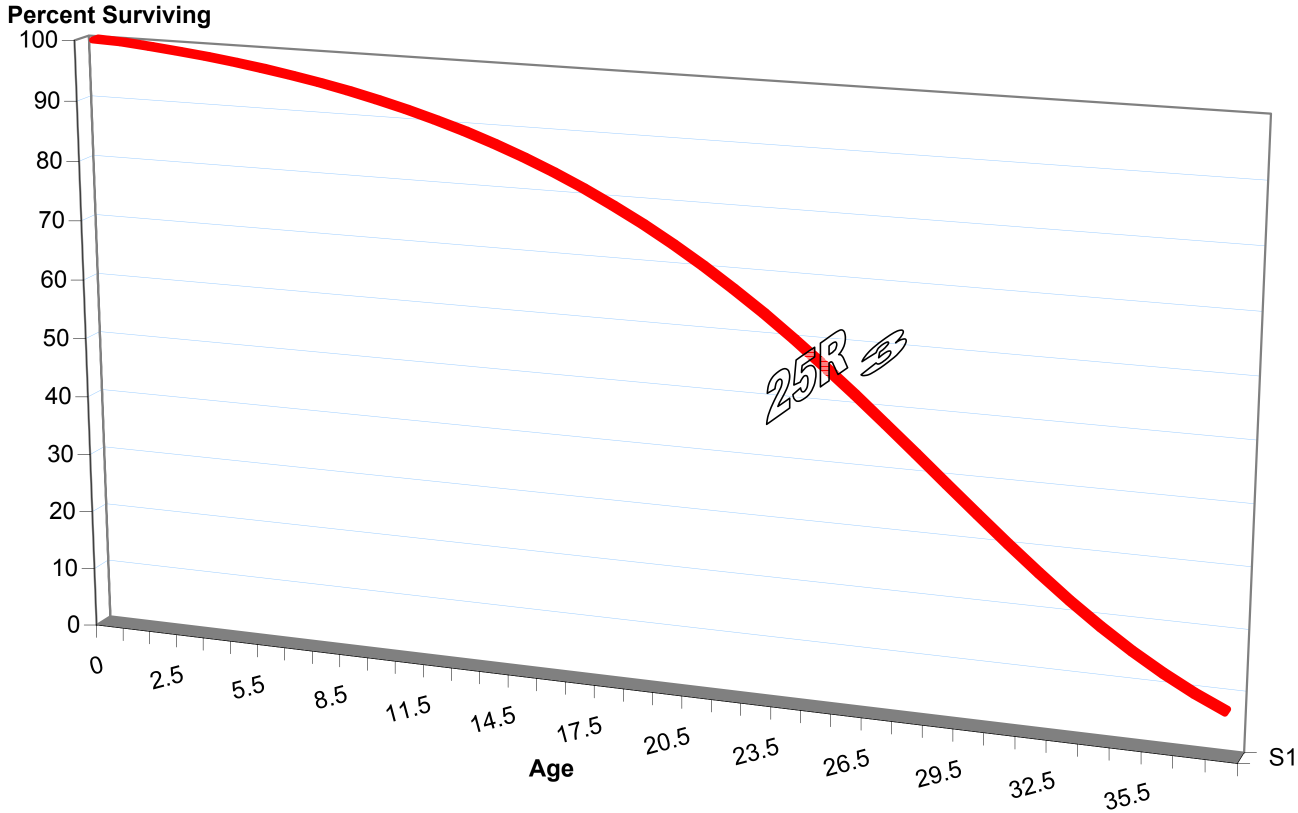
Survivor Curve
Account 367 Mains

Schedule No. 2

Exhibit No. KR-6
Docket No. RP04-___-000

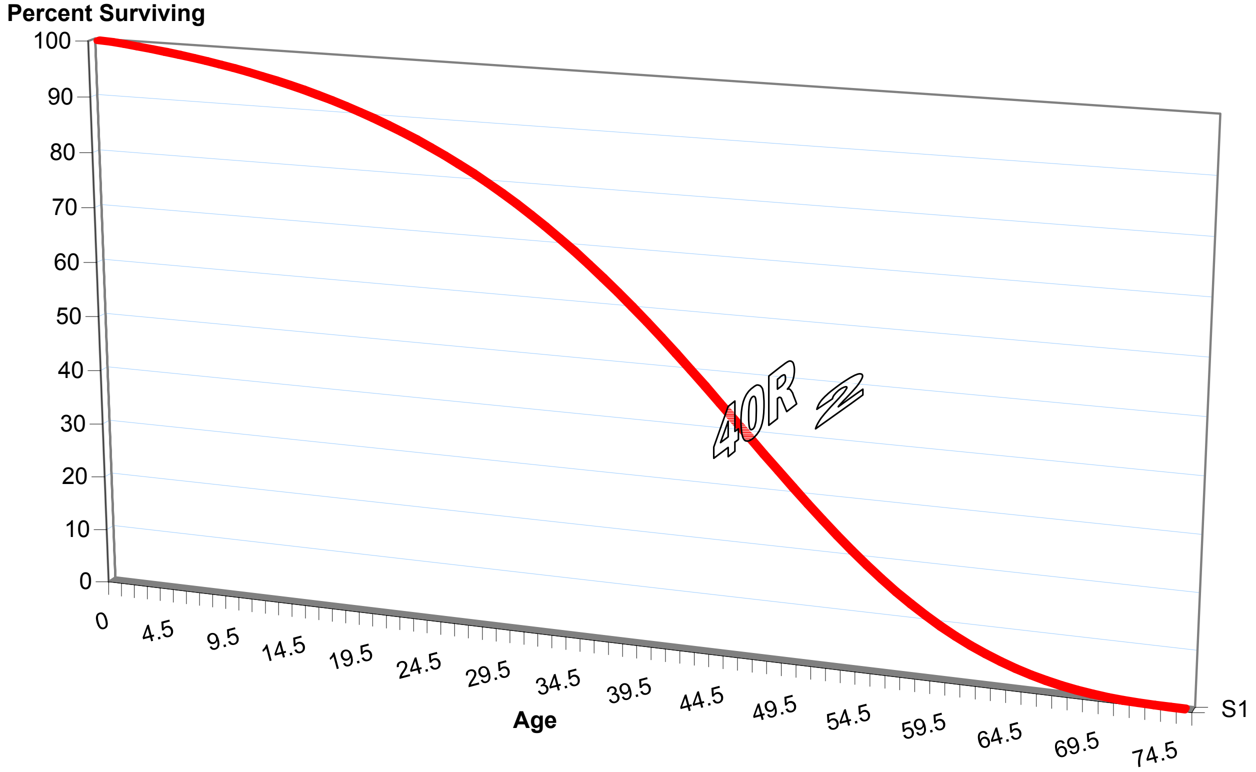


Survivor Curve
Account 368 Compressor Station Equip

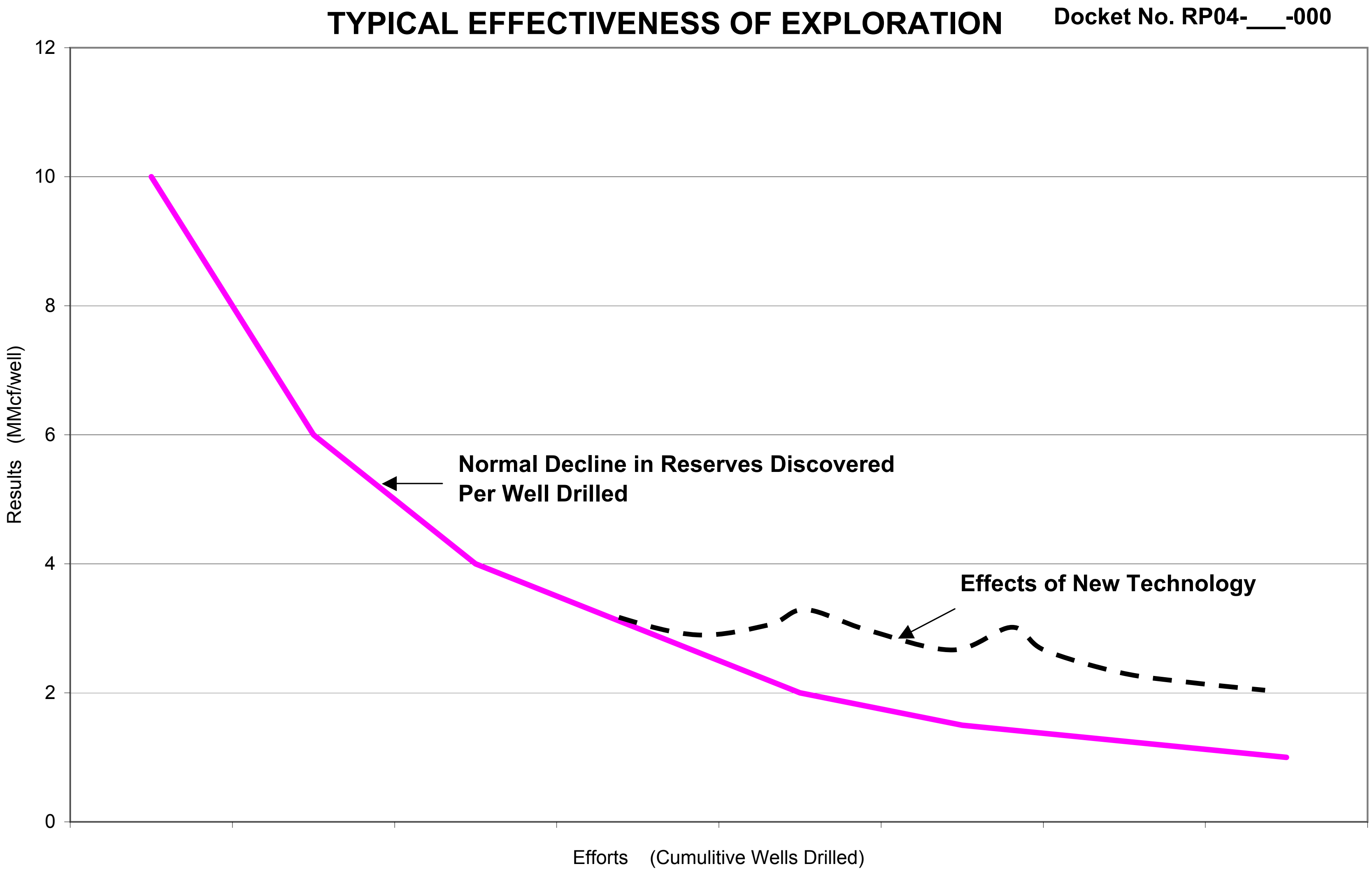


Survivor Curve
Account 369 Measuring & Regulating Sta. Equip.

Schedule No. 2
Page 3 of 3
Exhibit No. KR-6
Docket No. RP04-___-000



Schedule No. 3
Exhibit No. KR-6
Docket No. RP04-___-000



Schedule No.4
Exhibit No. KR-6
Page 1
Docket No. RP04-___-000

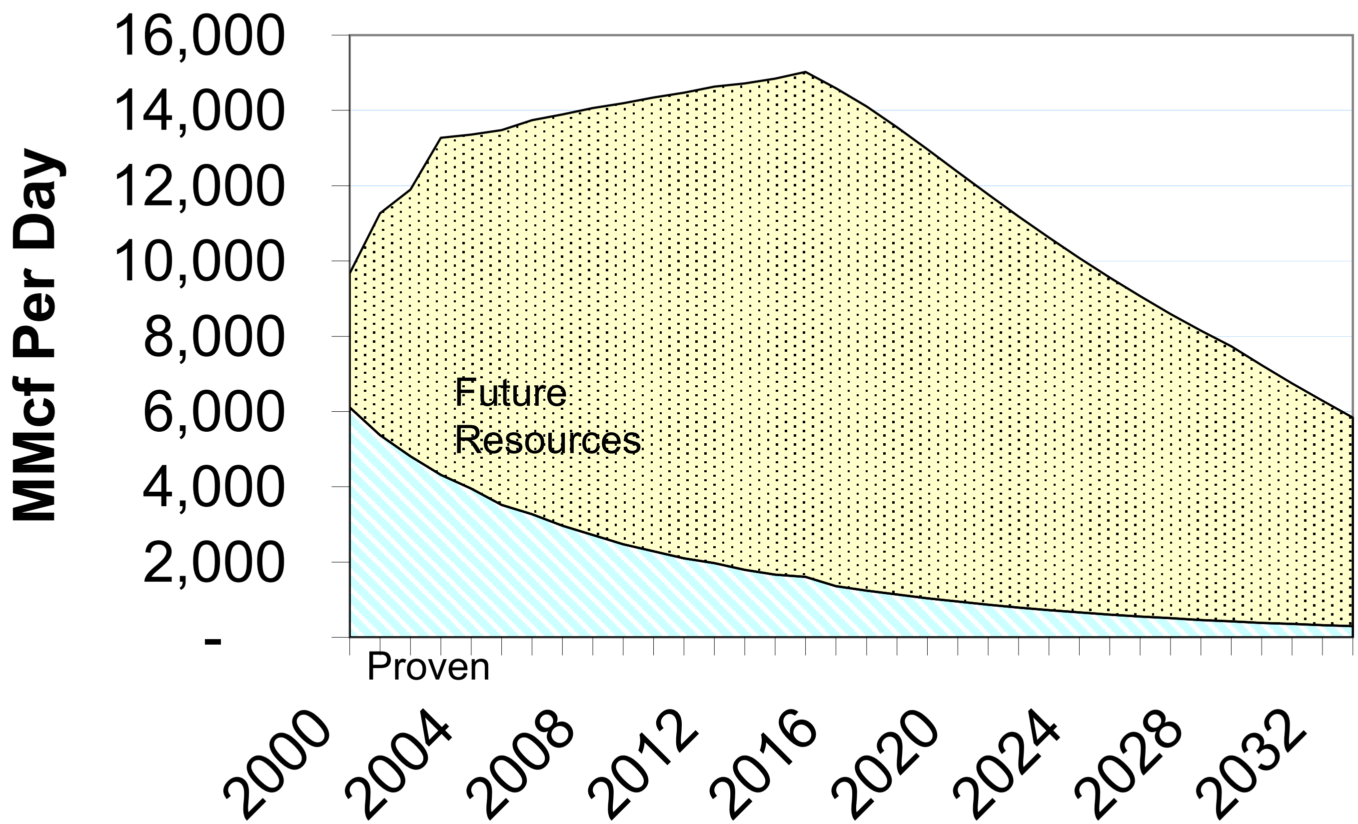
PRODUCTIVE CAPACITY
ROCKY MOUNTAIN AREA

Year	Productive Capacity 1999 Reserves MMcf/day	Productive Capacity 2000 - 2002 And Future Reserves MMcf/day	Productive Capacity Total MMcf/day	Actual Production MMcf/day
1999				6,033
2000	6,109	3,564	9,674	6,438
2001	5,369	5,895	11,264	6,279
2002	4,814	7,083	11,896	7,227
2003	4,320	8,955	13,275	
2004	3,950	9,407	13,356	
2005	3,518	9,960	13,477	
2006	3,271	10,471	13,741	
2007	2,962	10,930	13,892	
2008	2,715	11,343	14,059	
2009	2,468	11,717	14,186	
2010	2,283	12,059	14,342	
2011	2,098	12,372	14,470	
2012	1,975	12,661	14,636	
2013	1,790	12,929	14,719	
2014	1,666	13,180	14,846	
2015	1,605	13,414	15,019	
2016	1,362	13,226	14,587	
2017	1,244	12,865	14,109	
2018	1,137	12,418	13,555	
2019	1,039	11,926	12,966	
2020	950	11,416	12,366	
2021	868	10,901	11,769	
2022	793	10,391	11,185	
2023	725	9,894	10,619	
2024	663	9,413	10,076	
2025	606	8,951	9,556	
2026	554	8,509	9,062	
2027	506	8,088	8,594	
2028	462	7,689	8,151	
2029	423	7,310	7,733	
2030	386	6,849	7,235	
2031	353	6,394	6,747	
2032	323	5,969	6,292	
2033	295	5,539	5,833	

Schedule No. 4
Exhibit No. KR-6
Page 2
Docket No. RP04-___-000

Natural Gas Productive Capacity

Colorado, Utah and Wyoming



Schedule No. 5
Exhibit No. KR-6
Docket No. RP04-___-000

DETERMINATION OF THE AVERAGE ECONOMIC LIFE OF KERN RIVER'S PIPELINE FACILITIES

Year	Productive Capability (Relative Throughput) MMcf/day	Deficient Productive Capability as a % of 2003 Capacity 13,275	Facility Redundancy of Current Plant Facilities $ 2,171,240,899	Underutilization of Facilities	3-Year Increments of Underutilization of Facilities	Years Remaining From 2004	Weighted Years *Year-to-Year Direct Weighting*	Weighted Years *3-Year Increments Direct Weighting*	Weighted Years *Year-to-Year Reciprical Weighting*
2000									
2001									
2002	11,896								
2003	13,275								
2004	13,356					1			
2005	13,477					2			
2006	13,741					3			
2007	13,892		-			4			
2008	14,059		-	-		5			
2009	14,186		-	-	-	6	-		
2010	14,342		-	-		7			
2011	14,470		-	-		8			
2012	14,636		-	-	-	9	-		
2013	14,719		-	-		10			
2014	14,846		-	-		11			
2015	15,019		-	-	-	12	-		
2016	14,587		-	-		13			
2017	14,109					14			
2018	13,555	1.02		-	-	15	-		
2019	12,966	0.98	2,120,635,336	50,605,563		16	809,689,013		3,162,848
2020	12,366	0.93	2,022,471,997	98,163,338		17	1,668,776,754		5,774,314
2021	11,769	0.89	1,924,879,660	97,592,337	246,361,239	18	1,756,662,065	4,434,502,297	5,421,796
2022	11,185	0.84	1,829,355,891	95,523,769		19	1,814,951,614		5,027,567
2023	10,619	0.80	1,736,850,748	92,505,143		20	1,850,102,854		4,625,257
2024	10,076	0.76	1,647,954,658	88,896,090	276,925,002	21	1,866,817,892	5,815,425,041	4,233,147
2025	9,556	0.72	1,563,014,134	84,940,524		22	1,868,691,532		3,860,933
2026	9,062	0.68	1,482,206,870	80,807,264		23	1,858,567,067		3,513,359
2027	8,594	0.65	1,405,592,403	76,614,468	242,362,256	24	1,838,747,228	5,816,694,140	3,192,269
2028	8,151	0.61	1,333,147,294	72,445,108		25	1,811,127,700		2,897,804
2029	7,733	0.58	1,264,790,121	68,357,173		26	1,777,286,504		2,629,122
2030	7,235	0.55	1,183,347,803	81,442,318	222,244,600	27	2,198,942,594	6,000,604,187	3,016,382
2031	6,747	0.51	1,103,477,540	79,870,263		28	2,236,367,375		2,852,509
2032	6,292	0.47	1,029,061,733	74,415,807		29	2,158,058,398		2,566,062
2033	5,833			1,029,061,733	1,183,347,803	30	30,871,851,983	35,500,434,089	34,302,058
				2,171,240,899		25.97	56,386,640,573	57,567,659,754	87,075,429
	Weighted Average Economic Life							26.51	
									24.94

Direct Weighting

Direct Weighting 3- Year Increments

Reciprical Weighting

Schedule No. 6
Exhibit No. KR-6
Docket No. RP04-___-000

KERN RIVER GAS TRANSMISSION COMPANY

DETERMINATION OF THE DEPRECIATION RATE
TRANSMISSION PLANT

Account No.	Description	Gross Plant Investment January 31, As Adjusted	Accumulated Reserve for Depreciation January 31, As Adjusted	Net Depreciable Plant January 31, As Adjusted	Average Remaining Life	Indicated Depreciation Expense	Depreciation Rate
		$	$	$	Years	$	%
	Transmission Plant						
2004							
365.2	Rights-of-way	36,759,166	1,464,190	35,294,976	25.0	1,411,799	
366	Structures	19,960,006	5,300,310	14,659,696	23.0	637,378	
367	Mains	1,786,326,536	384,510,352	1,401,816,184	24.3	57,687,909	
368	Compressor Station Equipment (W/O Engines)	315,684,881	44,371,537	271,313,344	20.3	13,365,189	
369	Meas. & Regulating Sta. Equip.	41,481,493	10,211,647	31,269,846	22.0	1,421,357	
370	Communication Equipment	6,733,570	2,950,325	3,783,245	10.0	378,324	
371	Other Equipment	36,239	5,094	31,145	13.6	2,290	
	Post 2003 Plant Additions Balance @ 1/31/04	31,935,455		31,935,455	25.5	1,252,371	
	Post 2003 Plant Retirements Balance @ 1/31/04	5,000,000	(5,000,000)				
	Subtotal	2,233,917,346	443,813,454	1,790,103,892		76,156,617	3.41%
2005							
365.2	Rights-of-way	36,759,166	2,875,989	33,883,177	24.2	1,400,131	
366	Structures	19,960,006	5,937,688	14,022,318	22.2	631,636	
367	Mains	1,786,326,536	442,198,260	1,344,128,276	23.5	57,196,948	
368	Compressor Station Equipment (W/O Engines)	315,684,881	57,736,726	257,948,155	19.5	13,228,111	
369	Meas. & Regulating Sta. Equip.	41,481,493	11,633,003	29,848,490	21.2	1,407,948	
370	Communication Equipment	6,733,570	3,328,650	3,404,920	9.1	374,167	
371	Other Equipment	36,239	7,384	28,855	12.8	2,254	
	Post 2003 Plant Additions Balance @ 12/31/05	50,271,719	1,252,371	49,019,348	24.5	2,000,790	
	Post 2003 Plant Retirements Balance @ 12/31/05	10,000,000	(10,000,000)	-			
	Subtotal	2,247,253,610	514,970,071	1,732,283,539		76,241,984	3.39%
2006							
365.2	Rights-of-way	36,759,166	4,276,121	32,483,045	23.4	1,388,164	
366	Structures	19,960,006	6,569,324	13,390,682	21.4	625,733	
367	Mains	1,786,326,536	499,395,208	1,286,931,328	22.7	56,693,010	
368	Compressor Station Equipment (W/O Engines)	315,684,881	70,964,837	244,720,044	18.7	13,086,633	
369	Meas. & Regulating Sta. Equip.	41,481,493	13,040,951	28,440,542	20.4	1,394,144	
370	Communication Equipment	6,733,570	3,702,817	3,030,753	8.2	369,604	
371	Other Equipment	36,239	9,638	26,601	12	2,217	
	Post 2003 Plant Additions Balance @ 12/31/06	62,989,898	2,000,790	60,989,108	23.5	2,595,281	
	Post 2003 Plant Retirements Balance @ 12/31/06	15,000,000	(15,000,000)				
	Subtotal	2,254,971,789	584,959,685	1,670,012,104		76,154,787	3.38%

COMPOSITE DEPRECIATION RATE = 3.39%

Schedule No. 7
Exhibit No. KR-6
Docket No. RP04-___-00

Determination of Depreciation

Compressor Station Engines

Actual Historical Experience

1	Cost of Plant Retired ($)	37,997,301
2	Salvage ($)	26,950,587
3	Cost of Removal ($)	70,000
4	Net Salvage as a Percent of Cost of Plant Retired (%)	(71.11)

Determination of Depreciation Rate for Compressor Engines

5	Gross Plant ($)	57,111,874
6	Less Salvage ($)	(40,613,315)
7	Plant to be Recouped by Depreciation ($)	16,498,559
8	Average Service Life (Years)	2.91
9	Depreciation Expense ($)	5,667,086
10	Depreciation Rate (%) *Based on Actual Retirements*	9.92

Kern River Gas Transmission Company

Transmission
DETERMINATION OF THE REMAINING LIFE OF FACILITIES SUBJECT TO NORMAL RETIREMENT

		Normal Retirements					Estimated	Number of	Weight
		Acct 367	Acct 368	Acct 369	Total	Adjust For Major Ret.	Negative Salvage	Years Remaining in Service	
1	2003	22,739	1,114,281	164,211	1,301,231	1,301,231	16,421	0.5	650,616
2	2004	32,201	1,694,286	188,995	1,915,481	1,915,481	18,899	1.5	2,873,222
3	2005	39,694	1,903,820	203,153	2,146,667	2,146,667	20,315	2.5	5,366,668
4	2006	56,292	2,136,229	217,813	2,410,334	2,410,334	21,781	3.5	8,436,168
5	2007	70,358	2,386,413	233,534	2,690,305	2,690,305	23,353	4.5	12,106,374
6	2008	82,403	2,659,625	250,148	2,992,176	2,992,176	52,435	5.5	16,456,970
7	2009	109,406	2,957,126	267,474	3,334,007	3,334,007	57,413	6.5	21,671,045
8	2010	140,232	3,276,901	285,885	3,703,017	3,703,017	62,760	7.5	27,772,628
9	2011	160,428	3,619,481	305,051	4,084,959	4,084,959	68,304	8.5	34,722,155
10	2012	193,316	3,984,623	325,276	4,503,215	4,503,215	74,307	9.5	42,780,545
11	2013	243,700	4,378,921	346,724	4,969,345	4,969,345	127,125	10.5	52,178,117
12	2014	301,182	4,789,813	368,948	5,459,943	5,459,943	138,715	11.5	62,789,341
13	2015	359,625	5,221,686	392,331	5,973,642	5,973,642	150,859	12.5	74,670,527
14	2016	427,527	5,675,354	416,849	6,519,730	6,519,730	163,743	13.5	88,016,357
15	2017	517,348	6,140,799	442,184	7,100,332	7,100,332	177,381	14.5	102,954,811
16	2018	613,309	6,619,454	468,669	7,701,432	7,434,047	263,850	15.5	119,372,200
17	2019	722,741	7,101,066	496,360	8,320,167	7,935,894	284,350	16.5	137,282,754
18	2020	862,136	7,587,250	524,879	8,974,266	8,704,137	305,970	17.5	157,049,647
19	2021	1,019,282	8,063,275	554,559	9,637,116	9,290,248	327,933	18.5	178,286,654
20	2022	1,189,200	8,528,915	584,977	10,303,093	9,956,867	350,041	19.5	200,910,311
21	2023	1,387,047	8,970,885	616,195	10,974,128	10,619,334	475,937	20.5	224,969,616
22	2024	1,624,703	9,390,088	648,119	11,662,910	11,298,851	505,404	21.5	250,752,573
23	2025	1,885,706	9,768,372	680,524	12,334,601	11,965,290	534,215	22.5	277,528,528
24	2026	2,167,679	10,100,656	713,460	12,981,795	12,607,579	562,079	23.5	305,072,182
25	2027	2,510,289	10,375,940	746,459	13,632,688	13,252,736	590,095	24.5	334,000,866
26	2028	2,889,188	10,584,462	779,277	14,252,928	13,871,579	751,610	25.5	363,449,663
27	2029	3,296,276	10,707,876	811,561	14,815,713	14,433,463	781,364	26.5	392,616,390
28	2030	3,764,660	13,117,924	437,403	17,319,987	16,889,677	887,870	27.5	476,299,646
29	2031	4,278,938	10,157,673	223,463	14,660,074	14,622,717	744,177	28.5	417,812,103
30	2032	4,845,861	9,973,441	229,140	15,048,442	6,180,910	763,879	29.5	443,929,050
30 Year Total		35,813,467	192,986,638	12,923,621	241,723,726	228,167,714	9,302,585	19.99	4,832,777,727
26 Year Total		19,627,732	149,029,723	11,222,054	179,879,510	176,040,946	6,125,296	17.25	3,102,120,537

Schedule No. 9
Exhibit No. KR-6
Docket No. RP04-___-000

Kern River Gas Transmission Company

DETERMINATION OF NEGATIVE SALVAGE COST OF FINAL CLOSURE

	Gross Plant	Normal Retirements	Total Norm Ret To Gross Plant	Gross Plant Subject to Final Retirement	Gross Salvage	Demolition/Abandon	Adj Cost of Final Retirement	Adj Gross Salvage Amount	Line Pack Credit	Negative Salvage Cost Final Retirement	Contingency @ 10%	Total Neg Salv Cost Final Retirement
	$	$		$	$	$	$	$		$	$	$
Mains	1,823,135,600	26,688,668	0.01	1,796,446,932	337,738	107,862,719	106,283,729	332,794	17,768,306	88,182,629		
Compressors	221,457,594	98,810,205	0.45	122,647,389	-	25,501,401	14,123,156	6,318,350		7,804,806		
Meters	45,598,470	7,654,216	0.17	37,944,254	707,476	7,545,257	6,278,701	588,718		5,689,983		
										101,677,419		
	2,090,191,664	133,153,089			1,045,214	140,909,377	126,685,587	7,239,862	17,768,306	101,677,419	10,167,742	111,845,160
Line Pack Credit					17,768,306							

Kern River Gas Transmission Company

Transmission Plant

AVERAGE REMAINING LIFE OF PLANT SUBJECT TO RETIREMENT

	Net Negative Salvage Cost	Average Number of Years to Retirement	Weight Direct	Weight Reciprical
	$	Years		
Interim Retirements	6,125,296	17.25	105,634,080	355,181.31
Final Closure	111,845,160	26	2,907,974,169	4,301,736.94
Total and Composite Direct Wt.	117,970,456	25.55	3,013,608,249	4,656,918.25
Reciprical Wt.		25.33		

Schedule No. 11
Exhibit No. KR-6
Docket No. RP04-___-000

Kern River Gas Transmission Company

DETERMINATION OF NEGATIVE SALVAGE RATE
Transmission Plant

1	Total Depreciable Transmission Plant ($)	2,171,240,899
2	Negative Salvage ($)	117,970,456
3	Accumulated Reserve for Negative Salvage ($)	-
4	Unaccrued Negative Salvage ($)	117,970,456
5	Average Remaining Life (Years)	25.5
6	Annual Accrual ($)	4,618,062
7	Negative Salvage Rate (%)	0.21%

Schedule No. 12
Exhibit No. KR-6
Docket No. RP04-___-000

KERN RIVER GAS TRANSMISSION COMPANY
General Plant
Recommended Depreciation Rates

Account No.	Description	Percent
391	Office Furniture and Equipment	
	Office Furniture	6.67
	Computer Hardware	20.00
	PCs and Laptops	33.33
	Computer Software	20.00
	Leashold Improvements	6.67
	Office Equipment	6.67
397	Communication Equipment	10.00
392	Transportation Equipment	18.00
394	Tools, Shop and Garage Equipment	4.00
396	Power Operated Equipment	4.00

Schedule No. 13
Exhibit No. KR-6
Docket No. RP04-___-000

COMPARISON OF RESOURCE ESTIMATES

USED TO DETERMINE THE USEFUL LIFE OF KERN RIVER'S PIPELINE FACILITIES

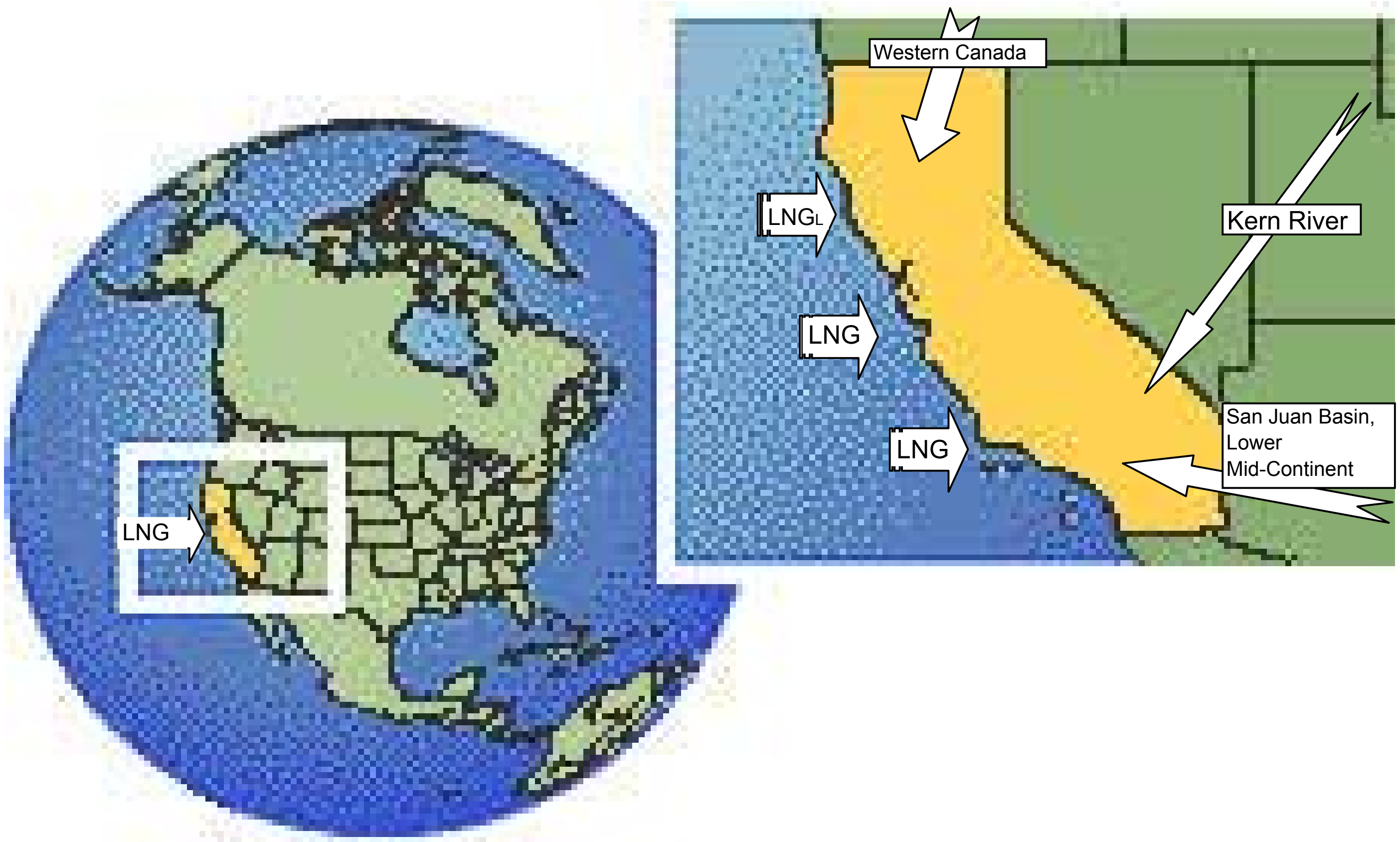
As of the End of 2000

Volumes in Bcf

	Rocky Mountain Area Colo, Utah and Wyo
Feinstein	**122,785**
PGC	**104,130**

Schedule No. 14
Exhibit No. KR-6
Docket No. RP04-___-000

Kern River Competition for Markets



Schedule No. 15
Exhibit No. KR-6
Docket No. RP04-___-000

DETERMINATION OF THE AVERAGE SERVICE LIFE OF COMPRESSOR ENGINES
Actual Plant and Service Life Data

Compressor Unit	Gross Plant In Service	Cost of Plant Retired	Salvage	Cost of Removal	Service Life	
					Months	Weight
Muddy Creek #1	3,718,870	7,709,784	5,820,914	15,000	38.25	294,899,238
Muddy Creek #2	3,718,870	7,709,784	4,861,414	15,000	38.25	294,899,238
Muddy Creek #3	3,160,470					
Muddy Creek #4	3,222,666					
Muddy Creek #5	3,222,666					
Coyote Creek #1	3,252,866					
Salt Lake #1	3,270,366					
Salt Lake #2	3,270,366					
Elberta #1A		2,884,230	2,093,400	5,000	22	63,453,060
Elberta #1B	42,600					
Fillmore #1	3,744,370	11,136,513	8,369,443	20,000	27.5	306,254,108
Fillmore #2	3,244,566					
Veyo #1	3,127,802					
Veyo #2	3,123,066					
Veyo #3	3,252,166					
Dry Lake #1	3,289,566					
Goodsprings #1	3,871,466	8,556,990	5,805,416	15,000	43	367,950,570
Goodsprings #2	3,289,566					
Goodsprings #3	3,289,566					
Daggett #1						
Total	57,111,874	37,997,301	26,950,587	70,000	34.94	1,327,456,214

Schedule No. 16
Exhibit No. KR-6
Docket No. RP04-___-000

DETERMINATION OF THE REGULATORY ASSET FOR LEVELIZED DEPRECIATION FOR THE THE COMPRESSOR ENGINES

Compressor Unit	Difference in Depreciation Reserve Actually Recouped by Revenues and Precise Rate Based on Service Life		
	Total	2003 Expansion	Original System
Muddy Creek #1	(2,163,734)	-	(2,163,734)
Muddy Creek #2	(3,134,578)	-	(3,134,578)
Muddy Creek #3	(652,584)	-	(652,584)
Muddy Creek #4	(365,128)	(365,128)	
Muddy Creek #5	(365,128)	-	(365,128)
Salt Lake #1	(370,532)	(370,532)	
Salt Lake #2	(370,532)	(370,532)	
Elberta #1A	(699,064)	-	(699,064)
Elberta #1B	(4,827)	-	(4,827)
Fillmore #1	(3,057,533)	-	(3,057,533)
Fillmore #2	(367,609)	(367,609)	
Veyo #1	(841,692)	-	(841,692)
Veyo #2	(353,843)	(353,843)	
Veyo #3	(368,470)	(368,470)	
Dry Lake #1	(372,708)	(372,708)	
Goodsprings #1	(2,531,869)	-	(2,531,869)
Goodsprings #2	(372,708)	(372,708)	
Goodsprings #3	(372,708)	(372,708)	
Coyote Creek #1	(377,051)		(377,051)
Total	(17,142,299)	(3,314,240)	(13,828,059)
2003 Expansion		(3,314,240)	
Original System			(13,828,059)

Schedule No.17
Exhibit No. KR-6
Page 1
Docket No. RP04-___-000

KERN RIVER COMPRESSOR ENGINE HISTORY

Station		MUDDY CREEK					PAINTER		ANSCHUTZ		COYOTE CRK
Location		Lincoln Co, WY					Uinta Co, WY		Uinta Co, WY		Uinta Co, WY
Unit #		**#1**	**#2**	**#3**	**#4**	**#5**	**#1**	**#2**	**#1**	**#2**	**#1**
Type		Turbine	Turbine	Turbine	Turbine	Turbine	Turbine	Turbine	Recip	Recip	Turbine
Make		Solar	Solar	Solar	Solar	Solar	Solar	Solar	Ajax	Ajax	Solar
Model		Mars	Mars	Mars	Mars	Mars	Centaur	Centaur	SPC	SPC	Mars
Model		100S	100S	100S	100S	100S	50	50	360LE	360LE	100S
Horsepower		15,000	15,000	15,000	15,000	15,000	5,500	5,500	360	360	15,000
1992		0202M Feb 92	0203M Feb 92				0207H Feb 92	0271H Feb 92	Feb 92	Feb 92	
1993											
1994											
1995		0203M Nov 95	0205M Aug 95								
1996							0206H Dec 96				
1997								0207H Mar 97			
1998											
1999	0163M Nov 99	0292M Dec 99	0096M Mar 99								
2000											
2001		0095M May 01	0014M Apr 01								
2002				0749M May 02							
2003					0810M May 03	0817M May 03					0816M May 03
2004							Feb 04?	May 04?			

KERN RIVER COMPRESSOR ENGINE HISTORY

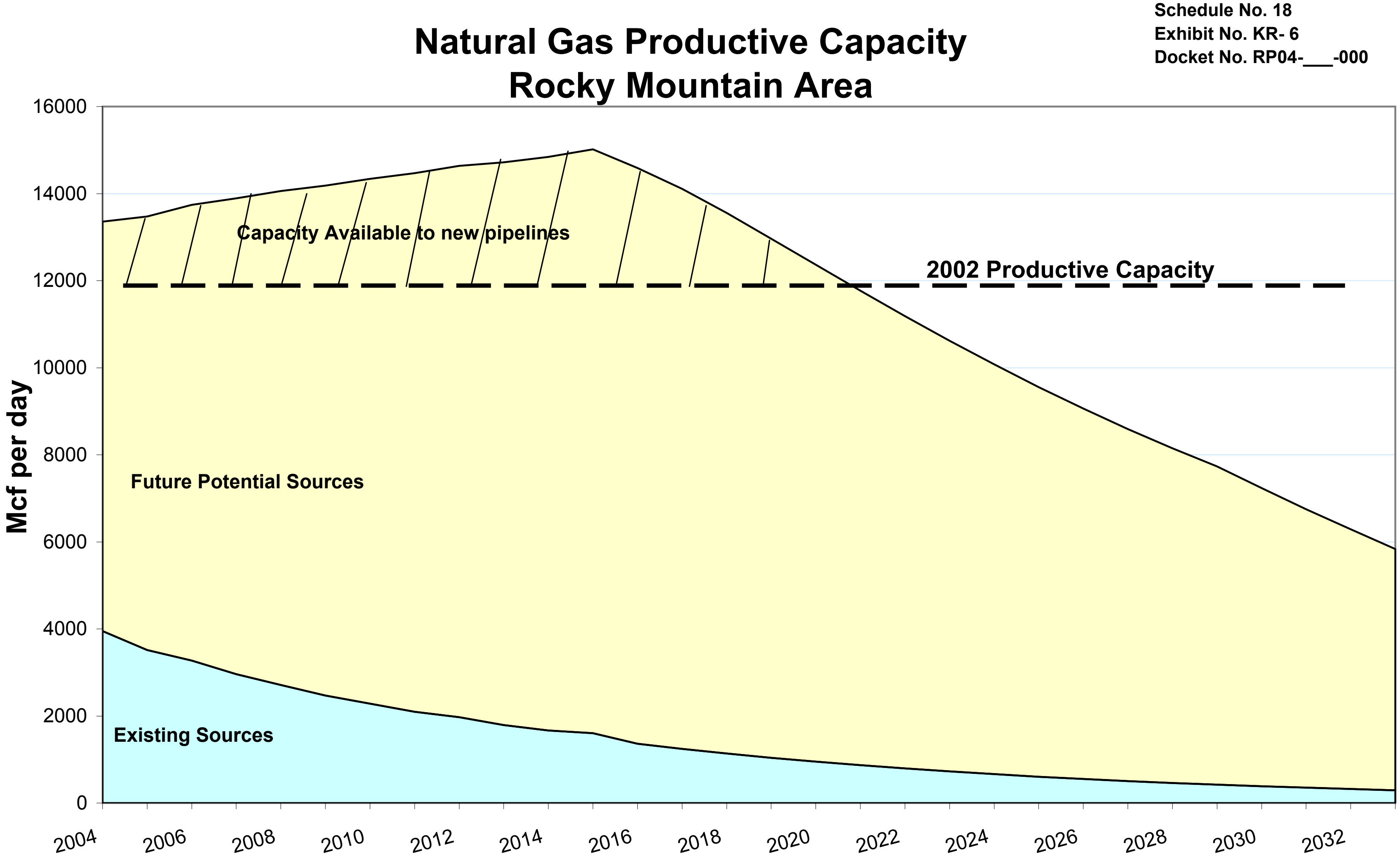
Station	SALT LAKE		ELBERTA		FILLMORE		VEYO		
Location	Salt Lake Co, UT		Utah Co, UT		Millard Co, UT		Washington Co, UT		
Unit #	#1	#2	#1	#2	#1	#2	#1	#2	#3
Type	Turbine	Turbine	Turbine		Turbine	Turbine	Turbine	Turbine	Turbine
Make	Solar	Solar	Solar		Solar	Solar	Solar	Solar	Solar
Model	Mars	Mars	Mars		Mars	Mars	Mars	Mars	Mars
Model	100S	100S	100S		100S	100S	100S	100S	100S
Horsepower	15,000	15,000	15,000	n/a	15,000	15,000	15,000	15,000	15,000
1992					0205M Feb 92				
1993									
1994									
1995					0274M Apr 95				
1996					0396M Sep & Nov	Failed Twice			
1997					0209M Apr 97				
1998									
1999									
2000					0316M Nov 00				
2001			Taurus 60 Jul 01 T1412	Taurus 60 Jul 01 T1413	0736M Apr 01	0142M Failed	0662M Jul 01		
2002			Retired	Retired					
2003	0812M May 03	0811M May 03	0820M May 03			0751M May 03 0853M Oct 03		0665M May 03	0809M May 03
2004									

Schedule No. 17
Exhibit No. KR-6
Page 3
Docket No. RP04-___-000

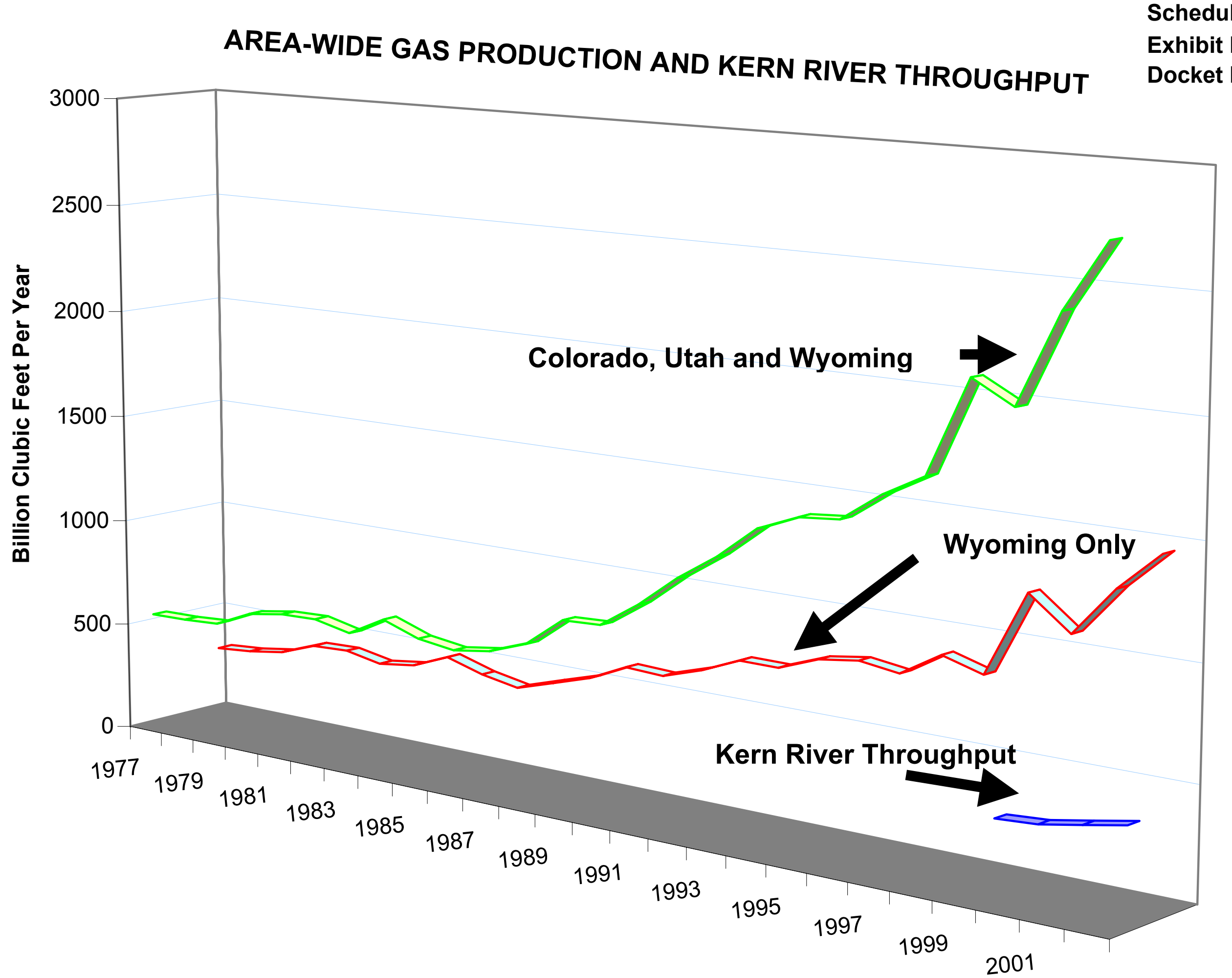
KERN RIVER COMPRESSOR ENGINE HISTORY

Station	DRY LAKE	GOODSPRINGS			DAGGETT	SPARE	TOTALS
Location	Clark Co, NV	Clark Co, NV			SB Co, CA		11 Stations
Unit #	#1	#1	#2	#3	#1	#1	24 Compressors
Type	Turbine	Turbine	Turbine	Turbine	Electric	Turbine	(w/ spare)
Make	Solar	Solar	Solar	Solar	Solar	Solar	
Model	Mars	Mars	Mars	Mars		Mars	
Model	100S	100S	100S	100S		100S	Total HP
Horsepower	15,000	15,000	15,000	15,000	4,000	15,000	#REF!
1992		0204M Feb 92					
1993							
1994							
1995							
1996		0202M Mar 96					
1997		0274M Apr 97	0202M Nov 97				
1998							
1999							
2000							
2001		0316M May 01					
2002		0292M Nov 02			Electric		
2003	0316M May 03		0824M May 03	0814M May 03		Las Vegas District	
2004							

Schedule No. 18
Exhibit No. KR- 6
Docket No. RP04-___-000

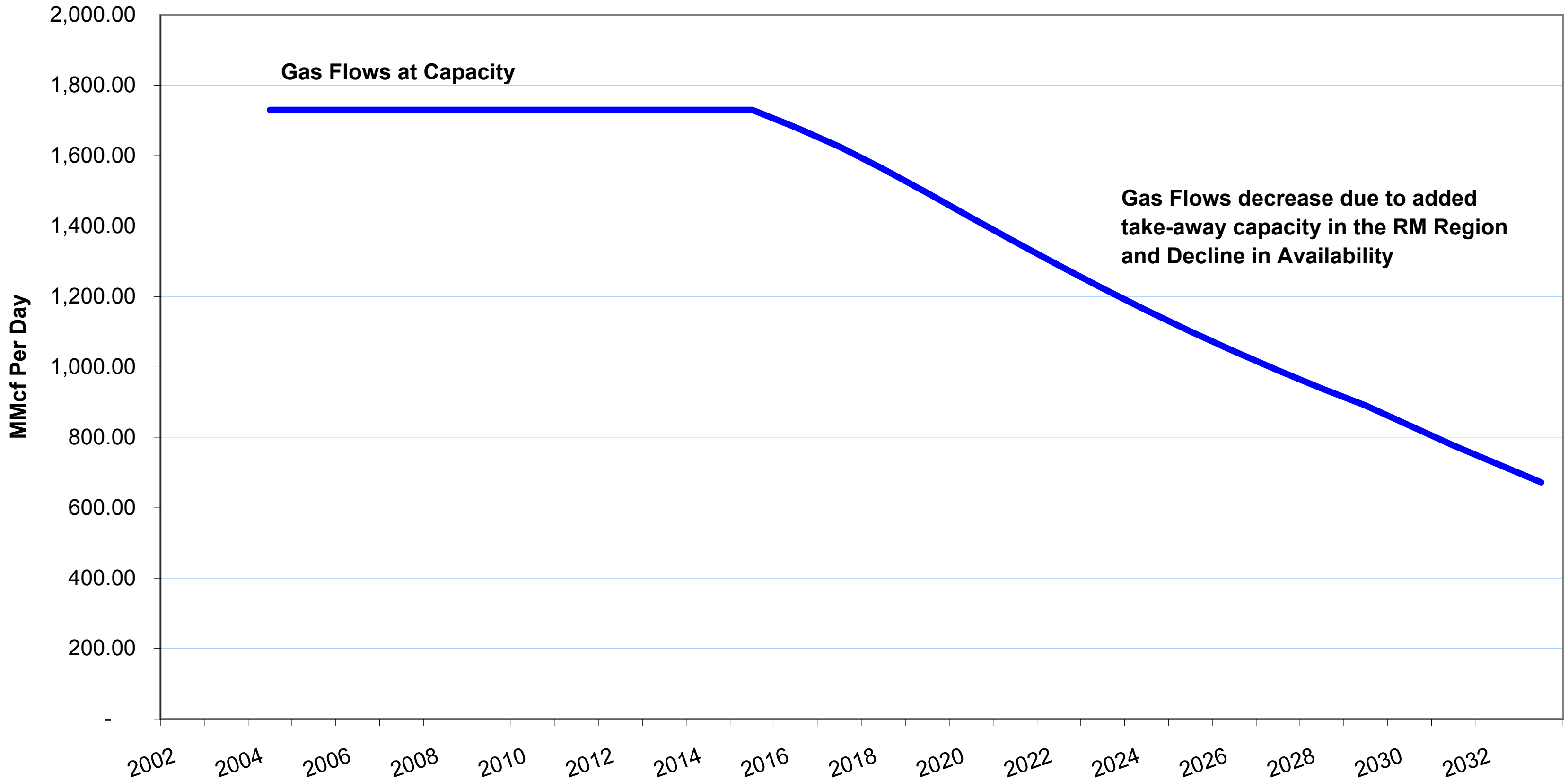


Schedule No. 19
Exhibit No. KR- 6
Docket No. RP04-___-000



Schedule No. 20
Exhibit No. KR-6
Docket No. RP04-___-000

Forecast of Kern River Throughput At Capacity



Determination of the Depreciation Rate For Transportation Equipment

$$\text{Depreciation Rate} = \frac{\frac{GP - S + COR}{\text{Service Life}}}{GP}$$

Unit Number	Cost of Retirement (Gross Plant)	Service Life Years	Gross Salvage	Cost of Removal	Depreciation Rate	Cost-Rate Weight
1	(19,593.40)	5	(7,227.00)	0.00	12.62	(247,328)
2	(18,359.88)	5.166	(8,000.00)	0.00	10.92	(200,540)
3	(16,251.83)	4.75	(4,912.00)	0.00	14.69	(238,733)
4	(19,574.70)	5.166	(8,500.00)	0.00	10.95	(214,377)
5	(19,407.46)	5.33	(9,075.00)	50.00	10.04	(194,793)
6	(19,407.46)	5.33	(8,325.00)	50.00	10.76	(208,864)
7	(18,518.89)	5.33	(9,012.00)	50.00	9.68	(179,304)
8	(18,518.89)	5	(10,427.00)	50.00	8.79	(162,838)
9	(20,664.43)	5	(8,862.00)	50.00	11.47	(237,049)
10	(19,742.91)	5	(10,512.00)	50.00	9.40	(185,618)
11	(19,407.46)	5	(9,277.00)	50.00	10.49	(203,609)
12	(20,664.43)	5.33	(7,126.00)	50.00	12.34	(254,942)
13	(19,742.91)	5.33	(7,196.00)	50.00	11.97	(236,340)
14	(19,407.46)	5	(8,512.00)	50.00	11.28	(218,909)
15	(18,802.13)	5.33	(6,000.00)	50.00	12.82	(241,128)
16	(21,062.87)	5	(6,227.00)	0.00	14.09	(296,717)
17	(20,850.37)	4.66	(8,262.00)	0.00	12.96	(270,137)
18	(1,665.58)	4.9167	0.00	0.00	20.34	(33,876)
19	(1,665.58)	5.0833	0.00	0.00	19.67	(32,766)
20	(1,472.89)	4.66	0.00	0.00	21.46	(31,607)
21	(1,758.39)	5.0833	0.00	0.00	19.67	(34,592)
22	(1,042.10)	4.9167	0.00	0.00	20.34	(21,195)
23	(1,106.94)	4.9167	0.00	0.00	20.34	(22,514)
24	(1,106.94)	4.66	0.00	0.00	21.46	(23,754)
25	(7.00)	4.5	0.00	0.00	22.22	(156)
26	500.00	3.9167	0.00	0.00	25.53	12,766
27	(19,181.52)	2.5833	(7,300.00)	50.00	24.08	(461,871)
28	(19,181.52)	2.5833	(12,577.00)	50.00	13.43	(257,598)
29	(100.00)	2.166	0.00	0.00	46.17	(4,617)
30	10,563.64	1.833	0.00	0.00	54.56	576,303
31	100.00	2	0.00	0.00	50.00	5,000
32	(15,179.06)	1.833	(12,630.63)	0.00	9.16	(139,031)
33	(10,563.64)	1.75	0.00	0.00	57.14	(603,637)
34	(28,540.03)	2.0833	(11,700.00)	150.00	28.58	(815,534)
35	(17,528.58)	1.333	(9,227.80)	0.00	35.53	(622,714)
36	(19,947.42)	2.5	(9,924.90)	0.00	20.10	(400,901)
37	(20,234.62)	2.0833	(14,592.90)	0.00	13.38	(270,807)
38	(22,218.87)	2.0833	(15,963.15)	0.00	13.51	(300,279)
39	(24,495.35)	2	(17,455.10)	0.00	14.37	(352,013)
40	(28,540.03)	1.25	(11,700.00)	0.00	47.20	(1,347,202)
41	(24,356.90)	2.9167	0.00	0.00	34.29	(835,084)
42	(24,260.29)	5.25	(8,699.00)	0.00	12.22	(296,406)
43	(24,260.29)	5.25	(8,250.00)	0.00	12.57	(304,958)
44	(24,260.29)	5.25	(5,126.50)	0.00	15.02	(364,453)
45	(21,565.20)	2	(13,692.27)	0.00	18.25	(393,647)
46	(29,098.21)	2.75	(18,034.65)	0.00	13.83	(402,311)
47	(22,996.87)	1.5833	(17,564.40)	0.00	14.92	(343,111)
48	(22,167.82)	1.33	(18,753.62)	0.00	11.58	(256,707)
49	(22,799.91)	1.33	(19,041.75)	0.00	12.39	(282,568)
50	(24,414.18)	1.33	(18,981.90)	0.00	16.73	(408,442)
51	(23,051.49)	1.33	(19,503.75)	0.00	11.57	(266,747)
52	(22,192.79)	1.33	(19,139.40)	0.00	10.34	(229,578)
53	(22,035.52)	1.33	(19,754.10)	0.00	7.78	(171,535)
54	(24,220.46)	1.33	(20,071.35)	0.00	12.88	(311,963)
55	(23,558.97)	1.33	(18,696.60)	0.00	15.52	(365,592)
56	(23,558.97)	1.33	(19,542.60)	0.00	12.82	(301,983)
57	(24,541.83)	0.9167	(18,305.00)	0.00	27.72	(680,357)
58	(24,381.91)	1.33	(17,591.71)	0.00	20.94	(510,541)
59	(24,809.72)	1.33	(16,135.49)	0.00	26.29	(652,198)
60	(18,070.68)	5.75	(2,529.50)	0.00	14.96	(270,281)
61	(18,279.33)	6.833	(3,000.00)	125.00	12.33	(225,440)
Sub total	(1,043,231.53)				1,148.48	(16,847,721)

Schedule No. 21
Exhibit No. KR-6
Page 2
Docket No. RP04-___-000

Determination of the Depreciation Rate For Transportation Equipment

$$\text{Depreciation Rate} = \frac{\dfrac{GP - S + COR}{\text{Service Life}}}{GP}$$

Unit Number	Cost of Retirement (Gross Plant)	Service Life Years	Gross Salvage	Cost of Removal	Depreciation Rate	Cost-Rate Weight
62	(18,070.69)	6.833	(1,950.00)	125.00	13.16	(237,753)
63	(24,816.17)	1.25	(17,968.35)	0.00	22.08	(547,826)
64	(24,330.63)	1.25	(18,503.35)	0.00	19.16	(466,182)
65	(24,668.72)	1.25	(16,200.71)	0.00	27.46	(677,441)
66	(18,282.63)	1.33	(14,107.00)	0.00	17.17	(313,957)
67	(22,791.95)	6.75	(5,100.00)	141.10	11.59	(264,193)
68	(10,151.90)	6.5	(3,356.74)	0.00	10.30	(104,541)
69	(12,600.39)	6.25	(4,166.33)	0.00	10.71	(134,945)
70	(12,600.38)	6.25	(4,166.33)	0.00	10.71	(134,945)
71	(17,247.96)	4.667	(7,504.50)	0.00	12.10	(208,774)
72	(22,037.70)	1.41667	(19,237.00)	0.00	8.97	(197,696)
73	(23,658.94)	2.5	(10,179.26)	0.00	22.79	(539,187)
74	(23,177.68)	5.75	(5,100.00)	141.10	13.67	(316,848)
75	(20,785.59)	5.75	(8,000.00)	125.00	10.80	(224,532)
76	(24,784.66)	5.75	(6,500.00)	125.00	12.92	(320,168)
77	(16,412.61)	5.75	(5,400.00)	125.00	11.80	(193,698)
78	(17,126.33)	5.75	(6,000.00)	125.00	11.43	(195,675)
79	(19,500.28)	5.75	(5,000.00)	141.10	13.06	(254,633)
80	(23,191.67)	5.75	(5,400.00)	591.10	13.79	(319,700)
81	(19,128.63)	1.25	(16,751.44)	0.00	9.94	(190,175)
82	(19,974.63)	1.25	(14,514.19)	0.00	21.87	(436,835)
83	(18,784.19)	1.25	(15,783.19)	100.00	13.21	(248,080)
84	(18,784.68)	2.5	(13,468.72)	0.00	11.32	(212,638)
85	(17,452.58)	5.5833	(6,100.00)	125.00	11.78	(205,570)
86	(19,175.57)	5.5833	(5,100.00)	758.95	13.86	(265,694)
87	(22,771.28)	4.33	(8,267.00)	0.00	14.71	(334,972)
88	(22,771.28)	3.0833	(11,499.00)	0.00	16.05	(365,591)
89	(22,781.28)	3.166	(11,455.00)	0.00	15.70	(357,747)
90	(22,781.28)	4.33	(7,272.06)	0.00	15.72	(358,181)
91	(22,771.25)	5.5	(5,950.00)	125.00	13.53	(308,114)
92	(24,474.04)	2.9167	(6,600.00)	105.00	25.19	(616,417)
93	(24,474.04)	2.9167	(8,250.00)	105.00	22.88	(559,846)
94	(24,474.04)	2.9167	(8,000.00)	125.00	23.25	(569,103)
95	(19,079.04)	3.25	(5,100.00)	141.10	22.77	(434,466)
96	(24,869.96)	3.166	(9,500.00)	125.00	19.68	(489,418)
97	(24,806.59)	3.166	(9,400.00)	125.00	19.78	(490,575)
98	(18,691.25)	5	(6,577.00)	0.00	12.96	(242,285)
99	(1,919.00)	4.9167	0.00	0.00	20.34	(39,030)
100	(1,922.16)	5.0833	0.00	0.00	19.67	(37,813)
101	(1,922.16)	4.9167	0.00	0.00	20.34	(39,095)
102	(1,922.16)	4.9167	0.00	0.00	20.34	(39,095)
103	(1,922.16)	4.9167	0.00	0.00	20.34	(39,095)
104	(1,063.92)	4.9167	0.00	0.00	20.34	(21,639)
105	(65.80)	4.833	0.00	0.00	20.69	(1,361)
106	(22,212.53)	5	(6,800.00)	0.00	13.88	(308,251)
107	(22,156.53)	4.75	(5,000.00)	0.00	16.30	(361,190)
108	(22,212.53)	4.75	(5,000.00)	0.00	16.31	(362,369)
109	(22,212.53)	4.75	(6,367.00)	0.00	15.02	(333,590)
110	(23,004.27)	4.75	(7,582.00)	0.00	14.11	(324,679)
111	(23,004.57)	4.75	(8,182.00)	0.00	13.56	(312,054)
112	(24,239.20)	4.5	(10,135.00)	100.00	13.02	(315,649)
113	(24,239.20)	4.5	(9,935.00)	100.00	13.21	(320,093)
114	(20,242.56)	5.166	(6,500.00)	50.00	13.19	(266,987)
115	(21,583.54)	4.5833	(9,335.00)	100.00	12.48	(269,425)
116	(22,745.54)	4.833	(8,632.00)	50.00	12.88	(293,059)
117	(31.82)	4.75	0.00	0.00	21.05	(670)
118	(31.82)	4.75	0.00	0.00	21.05	(670)
119	(65.88)	4.5	0.00	0.00	22.22	(1,464)
120	(65.87)	4.5	0.00	0.00	22.22	(1,464)
121	(18,568.44)	4.75	(8,455.00)	0.00	11.47	(212,915)
122	(1,337.30)	4.5	0.00	0.00	22.22	(29,718)
123	(1,402.62)	4.75	0.00	0.00	21.05	(29,529)
124	(5.00)	4.4167	0.00	0.00	22.64	(113)
125	(24,691.36)	3.833	(12,000.00)	50.00	13.46	(332,412)
126	(22,309.22)	3.0833	(7,300.00)	0.00	21.82	(486,791)
127	(206.68)	3	0.00	0.00	33.33	(6,889)
128	(1,458.87)	2.833	0.00	0.00	35.30	(51,496)
129	(29,865.07)	2.75	(14,000.00)	50.00	19.38	(578,730)
130	(19,181.52)	2.667	(12,000.00)	50.00	14.14	(271,148)
131	(1,665.55)	2.33	0.00	0.00	42.92	(71,483)
132	(23,358.23)	2.0833	(14,196.94)	0.00	18.83	(439,749)
133	(23,358.23)	2	(14,196.94)	0.00	19.61	(458,065)
134	(24,802.55)	1.4167	(17,000.00)	50.00	22.35	(554,285)
135	(31,342.70)	1.4167	(21,310.00)	50.00	22.71	(711,703)
136	(31,342.70)	1.4167	(21,260.00)	50.00	22.82	(715,233)
137	(28,423.34)	4.5	(22,651.65)	0.00	4.51	(128,260)
138	(10,151.89)	6.25	(7,650.00)	500.00	4.73	(48,030)
139	(27,201.30)	5.33	(7,800.00)	125.00	13.47	(366,347)
Sub total	(1,343,740.81)				1,347.19	(21,520,038)
Total	(2,386,972.34)					(38,367,759)

Arithmetic Mean Rate	17.95
Weighted Average Rate	16.07

Schedule No. 22
Exhibit No. KR- 6
Docket No. RP04-___-000

Regulatory Asset Determination -- General Plant

Accumulated Depreciation

Year	Beginning of Year Plant Balance	End of Year Plant Balance	Average Balance	Average Yearly Levelized Rate	Yearly Depreciation	Accumulated Depreciation
1992	-	6,174,036	3,087,018	0.670%	18,959	18,959
1993	6,174,036	7,279,610	6,726,823	1.340%	90,139	109,099
1994	7,279,610	7,691,828	7,485,719	2.010%	150,463	259,562
1995	7,691,828	8,432,883	8,062,356	2.620%	211,234	470,796
1996	8,432,883	9,114,374	8,773,629	3.170%	278,124	748,920
1997	9,114,374	9,045,400	9,079,887	3.670%	333,232	1,082,151
1998	9,045,400	9,886,683	9,466,042	4.130%	390,948	1,473,099
1999	9,886,683	18,975,385	14,431,034	4.590%	662,384	2,135,483
2000	18,975,385	21,301,371	20,138,378	5.010%	1,008,933	3,144,416
2001	21,301,371	21,875,432	21,588,402	4.430%	956,366	4,100,782
2002	21,875,432	26,175,109	24,025,271	1.250%	300,316	4,401,098
2003	26,175,109	26,585,268	26,380,189	1.610%	424,721	4,825,819
2004	26,585,268	30,422,404	28,503,836	1.990%	472,689	5,298,508

Retirements

Year	Retirements During Year
1992	(4,517)
1993	(127,770)
1994	(24,216)
1995	(39,787)
1996	(198,330)
1997	(1,987,558)
1998	(179,082)
1999	(4,942,979)
2000	(42,444)
2001	(527,495)
2002	(901,906)
2003	(1,054,378)
2004	(35,353)
Total	(10,065,815)

Cost of Plant Retired	Salvage	Cost of Removal
(10,065,815)	1,210,709	(74,338)

Determination of Regulatory Asset

Book Balance - Reserve	19,421,646
Accumulated Depreciation	5,298,508
Cost of Plant Retired	(10,065,815)
Salvage	1,210,709
Cost of Removal	(74,338)
Net	(3,630,936)
Regulatory Asset	23,052,582

EXHIBIT NO. KR-7

Assessment of the Availability of Natural Gas in the Rocky Mountain Area

Edward H. Feinstein

April, 2004

I. INTRODUCTION

Edward H. Feinstein has prepared this report on conventional natural gas supplies of the Rocky Mountain Area. In this task, specific reviews were made of the history, gas production, estimates of proven reserves and estimates of undiscovered resources.

The principal purpose of this report is to present estimates of the availability or productive capability of natural gas in certain regions of the Rocky Mountain Area. Forecasts of the area-wide natural gas productive capability were based upon estimates of proven reserves, discovery process estimates of reserve additions, pipeline connection parameters and deliverability profiles. Discovery process is the relationship between the efforts (drilling) and the potential for natural gas discoveries. The analysis is largely based upon information and data which are in the public domain.

II. SUMMARY AND CONCLUSIONS

The gas supply regions of the Rocky Mountain Area are in both an intermediate and mature stage of development. The assessment of gas supply herein is based on three ingredients: remaining reserves, reserves appreciation and undiscovered resources. Remaining reserves are the proved and economically producible gas discoveries. Reserves appreciation are resources believed to exist that are directly related to reserves already discovered. Undiscovered resources are estimated gas accumulations that are believed to exist, but have not yet been proven by drilling.

The productive capacities of proven gas reserves of each producing region of the Rocky Mountain Area vary considerably. Reserves-to-production ratios in each area are at their lowest level, reflecting only modest surplus pipeline gas.

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.

The availability of supplies from future sources was added to the availability of current proven sources to arrive at the overall productive capability of natural gas supplies from the various Rocky Mountain areas.

These supply areas are currently reliable, active and viable in providing adequate throughput for the network of pipelines connected to them. In the long-term, however, the current grade of natural gas accumulations will be exhausted, giving way to the discovery of smaller deposits. The result will be a gradual decline in the productive capability from existing and future connected supply sources. (See Figures -1 through -3).

III. BACKGROUND

The Rocky Mountain area of Colorado, Utah and Wyoming is one of only two oil and gas provinces in North America that have been growing in gas production over the past 10 years. The Rocky Mountain region will continue to grow in gas production for 10 more years. The Rocky Mountain area is a large, gas prone, geologically heterogeneous area that contains numerous gas productive basins. Numerous oil and gas prone formations and prospective reservoirs are present. Productive reservoirs include carbonates (limestone) and sandstones with all types of porosity and permeability as well as naturally fractured reservoirs and coalbed methane reservoirs. The Potential Gas Committee (PGC) has estimated (2002) potential gas resources of 104 Tcf.

The exploration and exploitation of these gas resources will depend heavily upon the price of the produced gas and the application of new and developing technology that will lower the cost of exploration and economic exploitation. A challenge for certain gas resources is to exploit technically available gas in locations where reserves are characterized by "tight" matrix porosity and permeability, naturally fractured reservoirs and coalbed methane and make them economically recoverable resources.

IV. METHODOLOGY

Proven Reserves

An analysis of the producibility of proven gas reserves was made using information obtained from the Energy Information Administration (EIA) and the Potential Gas Committee (PGC). EIA's proven reserves are as of the end of 2002. The productive availability of those proven reserves was obtained from data assembled by the (PGC) and extrapolated employing a constant percentage decline until the reserves curve are exhausted. The EIA provided the proven gas reserves. The PGC provided the production rate of those reserves.

Future Reserve Additions

A characteristic observed in the petroleum producing areas of the Rocky Mountain Area is a rapid drop off in size from the largest known field to the smaller ones. Hydrocarbon accumulations are the result of complex geological processes. Furthermore, the actual quantities of producible reserves are further defined on the basis of technological and economic considerations. As a consequence of all these independent influences and the multiplicative nature of the factors affecting the size of a gas accumulation, field sizes in producing basins are typically log normally distributed (Figure 3). That is, a few very large fields contain the bulk of the reserves and many, many small fields contain, in aggregate, a smaller portion of the reserves. Also, another characteristic of gas supply basins is that large fields are discovered early in the exploration process, and subsequent discoveries are smaller and the product of increasingly greater efforts (Figures 1). Since the Rocky Mountain Area, unlike other producing regions, is not yet in the mature stage of exploration, large field discoveries likely remain undiscovered and will become available for exploitation.

The Effectiveness of Exploration Model

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.

The nature of oil and gas accumulations creates a distribution of fields and reservoirs made up of a small number of large fields, a larger number of medium size fields and a seemingly unending amount of small fields. The Rocky Mountain Area is no exception. An example of the distribution of gas reserves in the a portion of the Rocky Mountain Area referred to as the Greater Green River Basin is shown on Figure 3. This is typical of the exploratory events of an oil and gas province.

The basic concept of this exploration model is shown on Figure 1. At times, the declining effectiveness of exploration is mitigated by: better technologies for discovery and resource recovery, greater understanding of the geophysics, and reservoir performance of the field in the province. This mitigation is also shown on Figure 1.

I first determined if the supply areas paralleled the premise of this model (that large initial field discoveries give way to smaller ones). In addition to the field size facts cited earlier, further analysis confirmed that indeed most, if not all, of the larger fields have been discovered as well as many of the medium size fields. This can be observed by inspecting the relationship between the new fields discovered and the exploratory efforts as shown on Figure 2 of Exhibit No. KR-7. This can also be seen by analysis of the effectiveness of exploration in terms of exploratory effort. Most of the significant gas discoveries are actually associated with fields previously discovered. See the historical data shown on Tables 1 and 2 and Figure 2. The exploratory effect is the accumulation of wells drilled over time. The above effectiveness data is a 3-year snapshot of a long trend from higher levels of effectiveness in prior years. I observed both exploratory wells and development wells. Development wells do not reflect the effort to find new discoveries. However, they contribute significantly to the reserve base. “Results” (in terms of annual gas discoveries) of the drilling effort are also shown on Tables 1 and 2 for all the areas. When these “results” or annual gas discoveries are divided by the annual exploratory wells drilled, a more focused relationship develops as to the size of the discovery for the effort expended. This confirms that the large fields have already been discovered and that new discoveries are going to be generally confined to a considerably more moderate size. This concept of discoveries per well drilled is referred to as the effectiveness of exploration.

The model used the relationship between annual reserve additions and both exploratory and development well drilling over time in years and cumulative feet drilled from a base of 1990. For the most likely case, I extrapolated the exploratory effectiveness at a constant level using the 3-year Mean value developed in Tables 1 and 2 until a point is reached where 90 percent of the total endowment is reached. The total endowment is defined as all the gas that will eventually be discovered (past discoveries plus the PGC's estimates of potential resources). PGC's estimates of potential gas resources are shown on Table 8. Table 8 shows the total endowment as of 2002 for the gas provinces of Colorado, Utah and Wyoming. I used the same procedure for the effectiveness of development drilling.

The most likely level represents the mean value of effectiveness from 2000 through 2002.

I employed a constant level of effectiveness until 90 percent of the ultimate resources are discovered as I expect some occasional increases in the effectiveness due to forces not directly indicated in the data. As mentioned earlier, any decline in the effectiveness curve will be mitigated by technological increases in the exploration and drilling techniques along with an increased awareness of the geophysics and reservoir mechanics. Technological increases are included in the 1990-2002 data. I am assuming that future technological increases will occur at the same rate as in the historical statistics. I found, in some cases unsurprisingly, that as drilling exceeds certain levels, the effectiveness declines. This is due most likely to the drilling of lower grade prospects in a particular year. See Figures 4 and 5 for the footage drilled and Figures 8 and 9 for the relationship between footage and effectiveness.

I determined the future discoveries from exploratory drilling by applying a representative constant level of drilling activity to the corresponding effectiveness. For my determination of the discoveries from development drilling, I also applied a constant level of annual drilling activity, based upon the most recent 3-year period, to reflect the development drilling activity response to increases in the wellhead price of gas. This period included very significant increases in the price of gas at the wellhead and only one modest decrease. I believe that in the future such similar increases and decreases will occur eventually leading to a gradual overall price increase. The EIA projects wellhead price to be $5.25 by 2025. The EIA studies are based upon a sophisticated econometric price model. I concur in their wellhead price estimates and believe my choice of exploratory and development drilling levels fully reflects such overall price increases, all the while daily, monthly and yearly prices will fluctuate both up and down. Specifically, based on my experience and studies, I found a relationship to exist between the price of gas at the wellhead and development drilling effort. No such clear relationship occurs for exploratory drilling as drilling prospects differ considerably in many respects as well as inherent risk factors. As such, many factors come into play with respect to the exploratory drilling response. While an increase in wellhead gas prices is an inducement to increase exploratory drilling efforts, the fact is that for the producing areas involved in this proceeding, there is no clear and concise relationship between wellhead price and the number of exploratory wells drilled. The graphs shown on Figures 13 and 14 of Exhibit No. KR-7, of wellhead gas price and drilling effort, illustrate this point. Exploratory wells differ considerably from development wells in the Rocky Mountain area. Exploratory wells are relatively high risk. They are drilled relatively far from existing discoveries. They are high cost. They must rely upon financing much different from development wells, e.g., the expenditure of money for geological and geophysical studies. Many factors affect the decision to drill exploratory wells, including the prevailing wellhead price.

With respect to development wells and price, the annual relationship between them is not sufficient to forecast future drilling efforts. Instead, I employed high values of such efforts in my calculations. The Most Likely Case level of wells drilled and footage attained was based on an average value for the 1998-2002 period.

The Future Discoveries resulting from the application of the drilling effort to the effectiveness of drilling are shown on Table 3 for exploratory discoveries and Table 4 for development discoveries

To determine the future gas availability, I applied to each determined annual future reserve addition, a production rate based on studies performed by the EIA from data derived from Petroleum Information/Dwights LLG (See Figure 15 of Exhibit No. KR-7).

This results in the production capacity from new reserves beginning in 2002.

To the production profile of future reserves, I added the production profile for the beginning of year 2000 proven gas reserves. This is shown on Table 6.

V. DETERMINATION AND RESULTS

The Rocky Mountain area that I analyzed occupies the states of Wyoming, Utah and Colorado. This is one of the major oil and gas producing regions of the United States. Gas production will come from mostly non-associated gas reservoirs. New field discoveries are expected to be found in deposits ranging from 1 to 200 Bcf, with most in the 2 to 20 Bcf range. The profile of the future productive capacity from this area is graphically illustrated on Figure 11 of Exhibit No. KR-7.

Exhibit No. KR-7
Docket No. RP04-___-000

TABLES
TO THE
ASSESSMENT OF GAS SUPPLY

Table 1
Exhibit No. KR-7
Docket No. RP04-___-000

Success Ratio and Effectiveness of Drilling Exploratory Wells

Rocky Mountain Area

Year	Wells Drilled				Success Ratio	Gas Target Wells	Gas Target Footage	Gas Target Wells as a % of Total	Discoveries		Effectiveness	Cumulative Exploratory Wells	Effectiveness	Exploratory Wells Drilled	Cumulative Exploratory Footage
	Oil	Gas	Dry	Total			1,000 Ft		Total Bcf	Per Gas Compl. Bcf/Well					
1990	112	332	420	864	0.514	646	1982	74.77	835	2.52	1.292	646	1.292	646	1982
1991	62	264	324	650	0.502	526	1642	80.98	513	1.94	0.975	1172	0.975	526	3624
1992	47	182	315	544	0.421	432	1329	79.48	993	5.46	2.297	1605	2.297	432	4954
1993	30	224	270	524	0.485	462	1566	88.19	1,046	4.67	2.264	2067	2.264	462	6519
1994	37	437	212	686	0.691	632	1447	92.19	960	2.20	1.518	2699	1.518	632	7966
1995	36	450	213	699	0.695	647	1545	92.59	508	1.13	0.785	3347	0.785	647	9511
1996	38	279	186	503	0.630	443	1287	88.01	688	2.47	1.554	3789	1.554	443	10798
1997	40	195	209	444	0.529	368	1431	82.98	2,377	12.19	6.452	4158	6.452	368	12229
1998	40	294	201	535	0.624	471	1901	88.02	1,352	4.60	2.871	4629	2.871	471	14131
1999	39	156	126	321	0.607	257	1630	80.00	1,855	11.89	7.224	4885	7.224	257	15760
2000	27	91	116	234	0.504	180	1299	77.12	3,051	33.53	16.907	5066	16.907	180	17059
2001	34	191	142	367	0.613	312	2139	84.89	5,076	26.58	16.293	5377	16.293	312	19199
2002	17	125	92	234	0.607	206	1521	88.03	4,735	37.88	22.987	5583	22.987	206	20720
2003	18	242	86	345	0.752	321	2,951	93.06		0.00		5904	0.000	321	23670
						255					18.729				

Table 2
Exhibit No. KR-7
Docket No. RP04-___-000

Success Ratio and Effectiveness of Drilling Development

Rocky Mountain Area

Year	Wells Drilled				Success	Gas	Gas	Gas Target	Discoveries		Effectiveness	Effectiveness	Cumulative	Effectiveness	Gas	Cumulative
	Oil	Gas	Dry	Total	Ratio	Target Wells	Target Footage	Wells as a % of Total	Total Bcf	Per Gas Compl. Bcf/Well		Per Well Drilled	Development Wells		Target Wells	Development Footage
							1,000 Ft									
1990	409	866	184	1459	0.874	991	5068	67.92	150	0.17	0.151	0.000153	991	0.151	991	5068
1991	320	943	182	1445	0.874	1079	5654	74.66	701	0.74	0.650	0.000602	2070	0.650	1079	10722
1992	263	1468	140	1871	0.925	1587	8800	84.81	632	0.43	0.398	0.000251	3657	0.398	1587	19522
1993	324	2018	117	2459	0.952	2119	12671	86.17	927	0.46	0.438	0.000206	5775	0.438	2119	32193
1994	257	1619	138	2014	0.931	1738	10933	86.30	459	0.28	0.264	0.000152	7514	0.264	1738	43126
1995	310	909	128	1347	0.905	1004	6314	74.57	2,101	2.31	2.092	0.002082	8518	2.092	1004	49440
1996	325	723	148	1196	0.876	825	5112	68.99	1,074	1.49	1.302	0.001578	9343	1.302	825	54552
1997	434	1326	217	1977	0.890	1489	9254	75.34	215	0.16	0.144	0.000097	10833	0.144	1489	63806
1998	335	1831	134	2300	0.942	1944	12045	84.53	1,699	0.93	0.874	0.005121	12777	0.874	1944	75851
1999	100	2879	109	3088	0.965	2984	14541	96.64	2,607	0.91	0.874	0.010090	15761	0.874	2984	90393
2000	241	5731	140	6112	0.977	5865	28189	95.96	2,118	0.37	0.361	0.019578	21627	0.361	5865	118582
2001	222	7108	155	7485	0.979	7258	36212	96.97	940	0.13	0.130	0.000018	28885	0.130	7258	154794
2002	126	4417	114	4657	0.976	4528	25003	97.23	918	0.21	0.203	0.000045	33413	0.203	4528	179797
2003	231	4,266	143	4640	0.969	4401	27,935	94.86								
						5007					0.231					

Table 3
Exhibit No. KR-7
Docket No. RP04-___-000

DETERMINATION OF NEW RESERVE ADDITIONS
ROCKY MOUNTAIN AREA
EXPLORATORY

Year	Wells Drilled	Cumulative Wells	Effectiveness	Reserve Additions
	1,000	1,000	Bcf/1,000 Feet	Bcf
1990	646	646	1.29	835
1991	526	1,172	0.97	513
1992	432	1,605	2.30	993
1993	462	2,067	2.26	1,046
1994	632	2,699	1.52	960
1995	647	3,347	0.78	508
1996	443	3,789	1.55	688
1997	368	4,158	6.45	2,377
1998	471	4,629	2.87	1,352
1999	257	4,885	7.22	1,855
2000	180	5,066	16.91	3,051
2001	312	5,377	16.29	5,076
2002	206	5,583	22.99	4,735
2003	321	5,904	18.73	6,013
2004	255	6,160	18.73	4,779
2005	255	6,415	18.73	4,779
2006	255	6,670	18.73	4,779
2007	255	6,925	18.73	4,779
2008	255	7,180	18.73	4,779
2009	255	7,436	18.73	4,779
2010	255	7,691	18.73	4,779
2011	255	7,946	18.73	4,779
2012	255	8,201	18.73	4,779
2013	255	8,456	18.73	4,779
2014	255	8,711	18.73	4,779
2015	255	8,967	18.73	4,779
2016	255	9,222	16.86	4,301
2017	255	9,477	15.17	3,871
2018	255	9,732	13.65	3,484
2019	255	9,987	12.29	3,136
2020	255	10,242	11.06	2,822
2021	255	10,498	9.95	2,540
2022	255	10,753	8.96	2,286
2023	255	11,008	8.06	2,057
2024	255	11,263	7.26	1,852
2025	255	11,518	6.53	1,666
2026	255	11,773	5.88	1,500
2027	255	12,029	5.29	1,350
2028	255	12,284	4.76	1,215
2029	255	12,539	4.28	1,093
2030	255	12,794	3.86	984
2031	255	13,049	3.47	886
2032	255	13,304	3.12	797
2033	255	13,560	2.81	717
				99,919

Table 4
Exhibit No. KR-7
Docket No. RP04-___-000

DETERMINATION OF NEW RESERVE ADDITIONS
ROCKY MOUNTAIN AREA
DEVELOPMENT

Year	Wells Drilled	Cumulative Wells	Effectiveness	Reserve Additions
	1,000	1,000	Bcf/1,000 Feet	Bcf
1990	991	991	0.15	150
1991	1,079	2,070	0.65	701
1992	1,587	3,657	0.40	632
1993	2,119	5,775	0.44	927
1994	1,738	7,514	0.26	459
1995	1,004	8,518	2.09	2,101
1996	825	9,343	1.30	1,074
1997	1,489	10,833	0.14	215
1998	1,944	12,777	0.87	1,699
1999	2,984	15,761	0.87	2,607
2000	5,865	21,627	0.36	2,118
2001	7,258	28,885	0.13	940
2002	4,528	33,413	0.20	918
2003	4,401	37,814	0.23	1,017
2004	5,007	42,821	0.23	1,157
2005	5,007	47,829	0.23	1,157
2006	5,007	52,836	0.23	1,157
2007	5,007	57,843	0.23	1,157
2008	5,007	62,851	0.23	1,157
2009	5,007	67,858	0.23	1,157
2010	5,007	72,866	0.23	1,157
2011	5,007	77,873	0.23	1,157
2012	5,007	82,880	0.23	1,157
2013	5,007	87,888	0.23	1,157
2014	5,007	92,895	0.23	1,157
2015	5,007	97,903	0.23	1,157
2016	5,007	102,910	0.21	1,042
2017	5,007	107,917	0.19	937
2018	5,007	112,925	0.17	844
2019	5,007	117,932	0.15	759
2020	5,007	122,940	0.14	683
2021	5,007	127,947	0.12	615
2022	5,007	132,954	0.11	554
2023	5,007	137,962	0.10	498
2024	5,007	142,969	0.09	448
2025	5,007	147,977	0.08	404
2026	5,007	152,984	0.07	363
2027	5,007	157,992	0.07	327
2028	5,007	162,999	0.06	294
2029	5,007	168,006	0.05	265
2030	5,007	173,014	0.05	238
2031	5,007	178,021	0.04	214
2032	5,007	183,029	0.04	193
2033	5,007	188,036	0.03	174
				23,757

Table 5
Exhibit No. KR-7
Docket No. RP04-___-000

DETERMINATION OF NEW RESERVE ADDITIONS
ROCKY MOUNTAIN AREA

Volumes in Bcf

Year	New Exploratory Additions	New Development Additions	New Total Additions	Accumulated Ultimate Reserves	Percent of Ultimate Resources
					-
2000	3,051	2,118	5,169		-
2001	5,076	940	6,016		-
2002	4,735	918	5,653	84,738	44.9
2003	6,013	1,017	7,031	91,769	48.6
2004	4,779	1,157	5,936	97,705	51.7
2005	4,779	1,157	5,936	103,641	54.9
2006	4,779	1,157	5,936	109,578	58.0
2007	4,779	1,157	5,936	115,514	61.2
2008	4,779	1,157	5,936	121,451	64.3
2009	4,779	1,157	5,936	127,387	67.4
2010	4,779	1,157	5,936	133,323	70.6
2011	4,779	1,157	5,936	139,260	73.7
2012	4,779	1,157	5,936	145,196	76.9
2013	4,779	1,157	5,936	151,133	80.0
2014	4,779	1,157	5,936	157,069	83.2
2015	4,779	1,157	5,936	163,006	86.3
2016	4,301	1,042	5,343	168,348	89.1
2017	3,871	937	4,808	173,157	91.7
2018	3,484	844	4,328	177,484	94.0
2019	3,136	759	3,895	181,379	96.0
2020	2,822	683	3,505	184,885	97.9
2021	2,540	615	3,155	188,040	99.6
2022	2,286	554	2,839	190,879	101.1
2023	2,057	498	2,555	193,434	102.4
2024	1,852	448	2,300	195,734	103.6
2025	1,666	404	2,070	197,804	104.7
2026	1,500	363	1,863	199,667	105.7
2027	1,350	327	1,677	201,344	106.6
2028	1,215	294	1,509	202,853	107.4
2029	1,093	265	1,358	204,211	108.1
2030	984	238	1,222	205,433	108.8
2031	886	214	1,100	206,533	109.4
2032	797	193	990	207,523	109.9
2033	717	174	891	208,414	110.3
	99,201	23,584	122,785		

Cumulative Prod to 12/31/2002	**46,188**
Remaining Reserves at 12/31/2002	**38,550**
Ultimate Reserves at 12/31/2002	**84,738**
PGC Potential Resources	**104,130**
Ultimate Resources at 12/31/2002	**188,868**

Table 6
Exhibit No. KR-7
Docket No. RP04-___-000

PRODUCTIVE CAPACITY
ROCKY MOUNTAIN AREA

Year	Productive Capability 1999 Reserves MMcf/day	Productive Capability 2000 - 2002 And Future Reserves MMcf/day	Productive Capability Total MMcf/day	Actual Production MMcf/day
1999				6,033
2000	6,109	3,564	9,674	6,438
2001	5,369	5,895	11,264	6,279
2002	4,814	7,083	11,896	7,227
2003	4,320	8,955	13,275	
2004	3,950	9,407	13,356	
2005	3,518	9,960	13,477	
2006	3,271	10,471	13,741	
2007	2,962	10,930	13,892	
2008	2,715	11,343	14,059	
2009	2,468	11,717	14,186	
2010	2,283	12,059	14,342	
2011	2,098	12,372	14,470	
2012	1,975	12,661	14,636	
2013	1,790	12,929	14,719	
2014	1,666	13,180	14,846	
2015	1,605	13,414	15,019	
2016	1,362	13,226	14,587	
2017	1,244	12,865	14,109	
2018	1,137	12,418	13,555	
2019	1,039	11,926	12,966	
2020	950	11,416	12,366	
2021	868	10,901	11,769	
2022	793	10,391	11,185	
2023	725	9,894	10,619	
2024	663	9,413	10,076	
2025	606	8,951	9,556	
2026	554	8,509	9,062	
2027	506	8,088	8,594	
2028	462	7,689	8,151	
2029	423	7,310	7,733	
2030	386	6,849	7,235	
2031	353	6,394	6,747	
2032	323	5,969	6,292	
2033	295	5,539	5,833	

Table 7
Exhibit No. KR-7
Docket No. RP04-___-000

ULTIMATE REMAINING GAS RESOURCES

Volumes in Trillion Cubic Feet

		Rocky Mountain Area Colo, Utah and Wyo
1	Cumulative Production to 12/31/1988	23.96
2	Incremental Production 1989 to 12/31/2002	22.23
3	Remaining Proved Reserves at 12/31/2002	38.55
4	Potential Gas Resources Estimated at 12/31/2002	104.13
5	Ultimate Estimated Resources (12/31/2000)	188.87
6	Gas Discoveries to 12/31/2002	84.74
7	Percent Remaining to be Discovered	55.13

Table 8
Exhibit No. KR-
Docket No. RP04-___-000

Estimate of Potential Gas Resources
As of End of 2002
Volumes in Bcf

Producing Province	Resource Estimate						Total Resource Estimate
	Growth in Reserves			New Fields			
	0-15,000 Feet	15,000-30,000 Ft	CBM	0-15,000 Feet	15,000-30,000 Ft	CBM	
Powder River Basin	1,435	-	6,672	2,153	-	20,015	30,275
Big Horn Basin	672	170	-	530	616	25	2,013
Wind River Basin	2,115	1,527	-	4,497	3,401	50	11,590
Greater Green River Basin	8,632	979	-	5,940	5,696	375	21,622
Denver Basin and Environs	1,380	-	-	1,012	-	-	2,392
Uinta/Piceance Basin and Environs	14,568	500	133	14,922	200	4,115	34,438
Thrust Belt	800	-	-	1,000	-	-	1,800
Total	29,602	3,176	6,805	30,054	9,913	24,580	104,130

Source: Potential Gas Committee

Note: CBM - Coalbed Methane

Exhibit No. KR-7
Docket RP04-___-000

FIGURES
TO THE
ASSESSMENT OF GAS SUPPLY

Figure 1
Exhibit No. KR-7
Docket No. RP04-___000

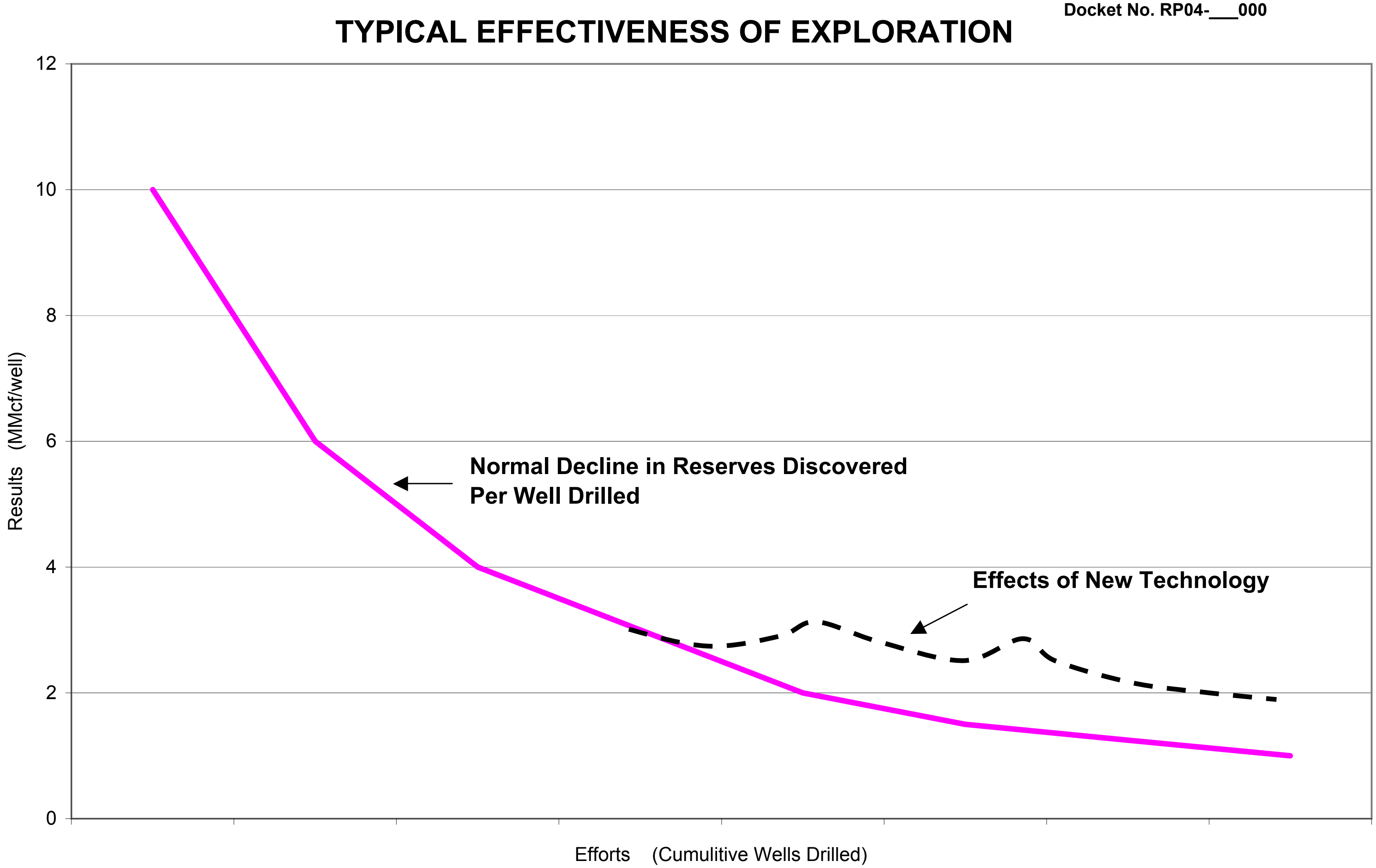


Figure 2
Exhibit No. KR-7
Docket No. RP04-___000

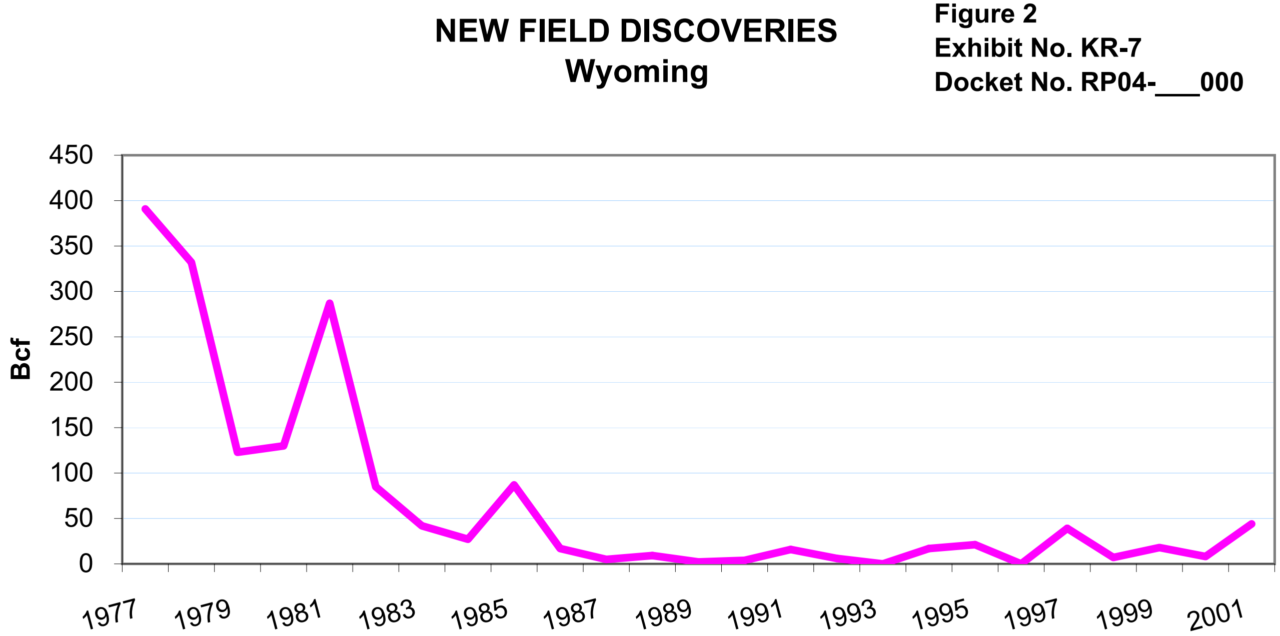


Figure 3
Exhibit No. KR-7
Docket No. RP04-___000

Size Distribution of Gas Fields
Green River Basin

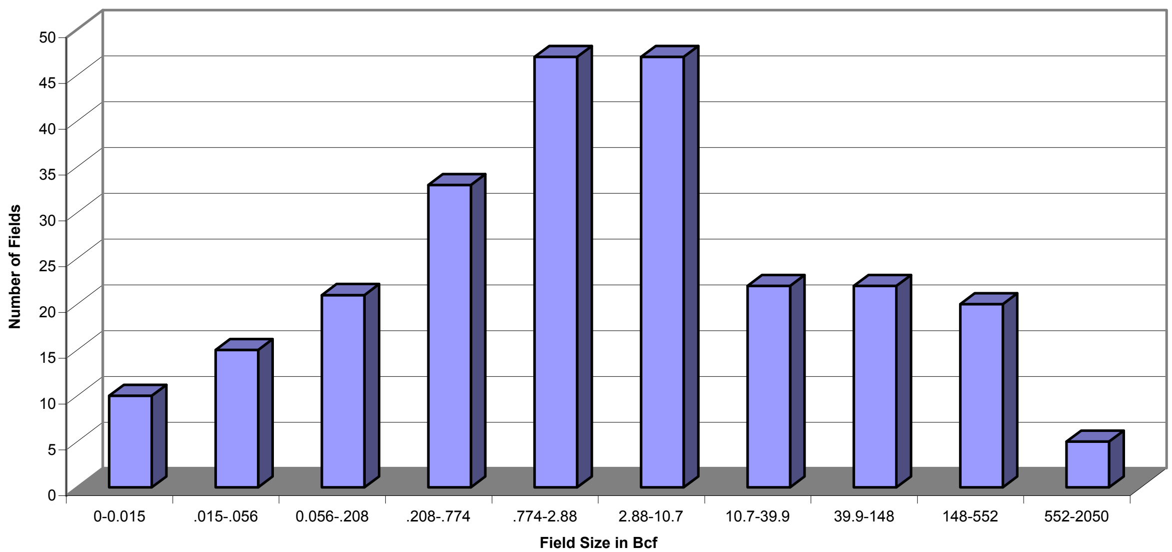


Figure 4
Exhibit No. KR-7
Docket No. RP04-___-000

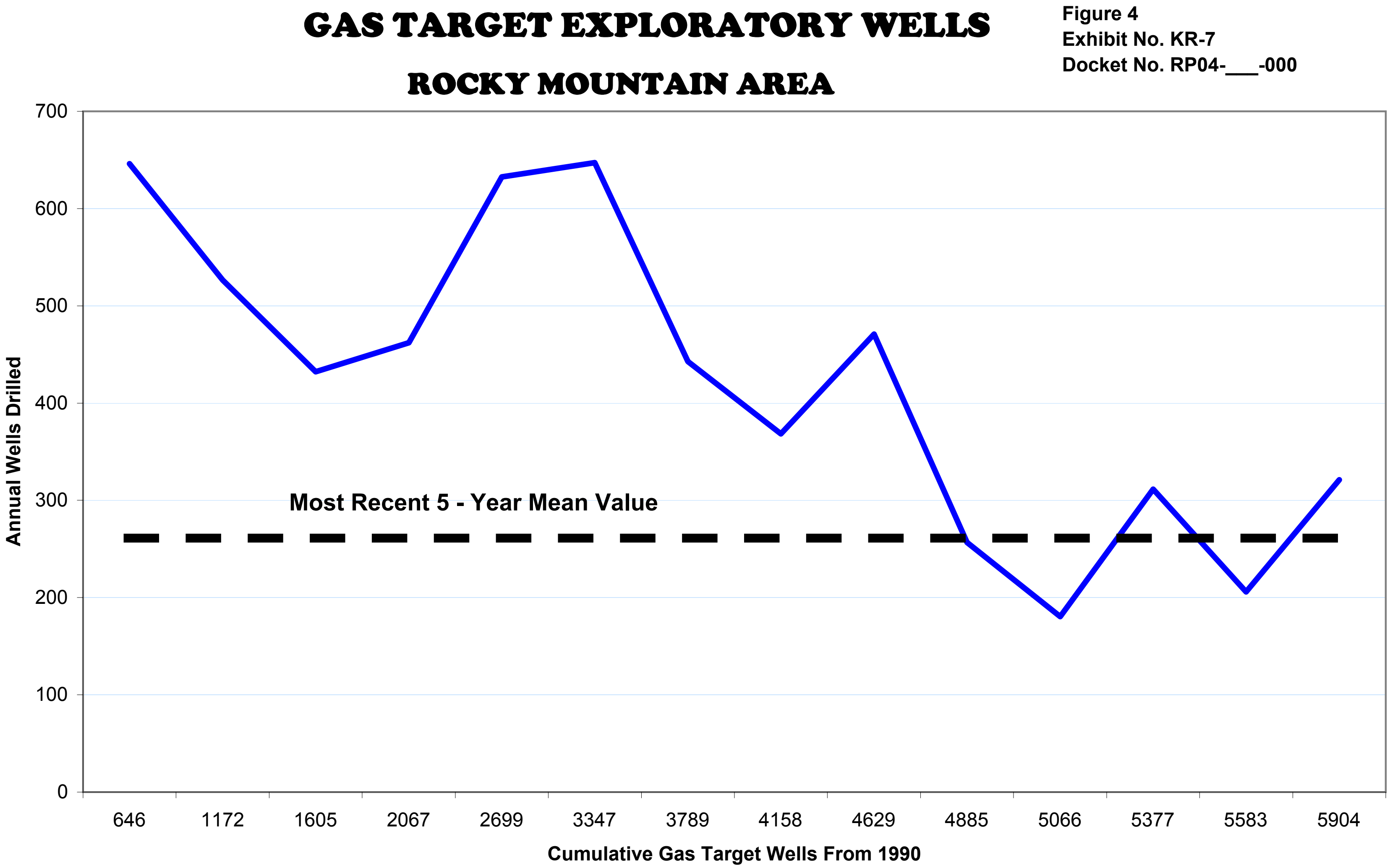
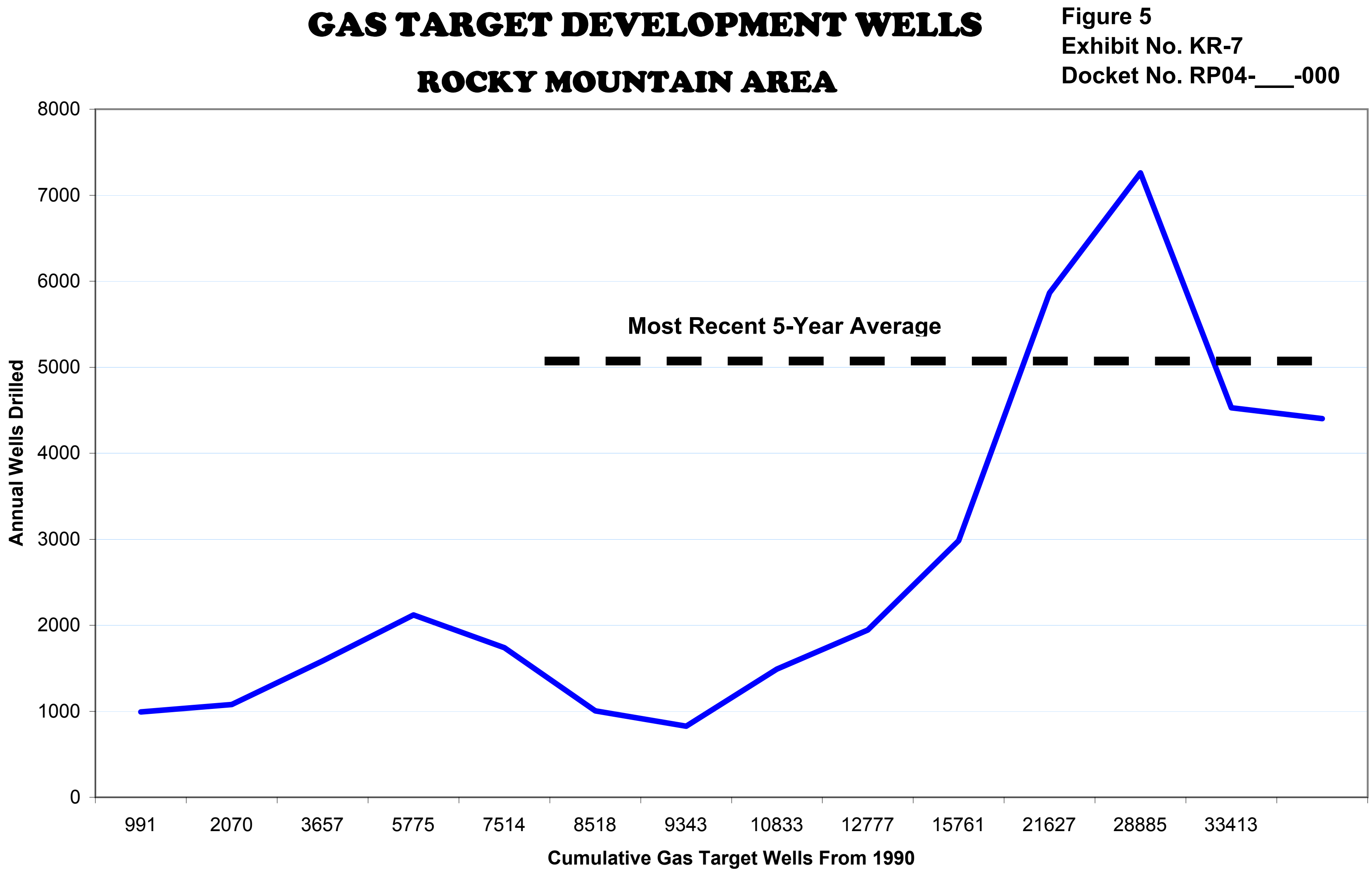
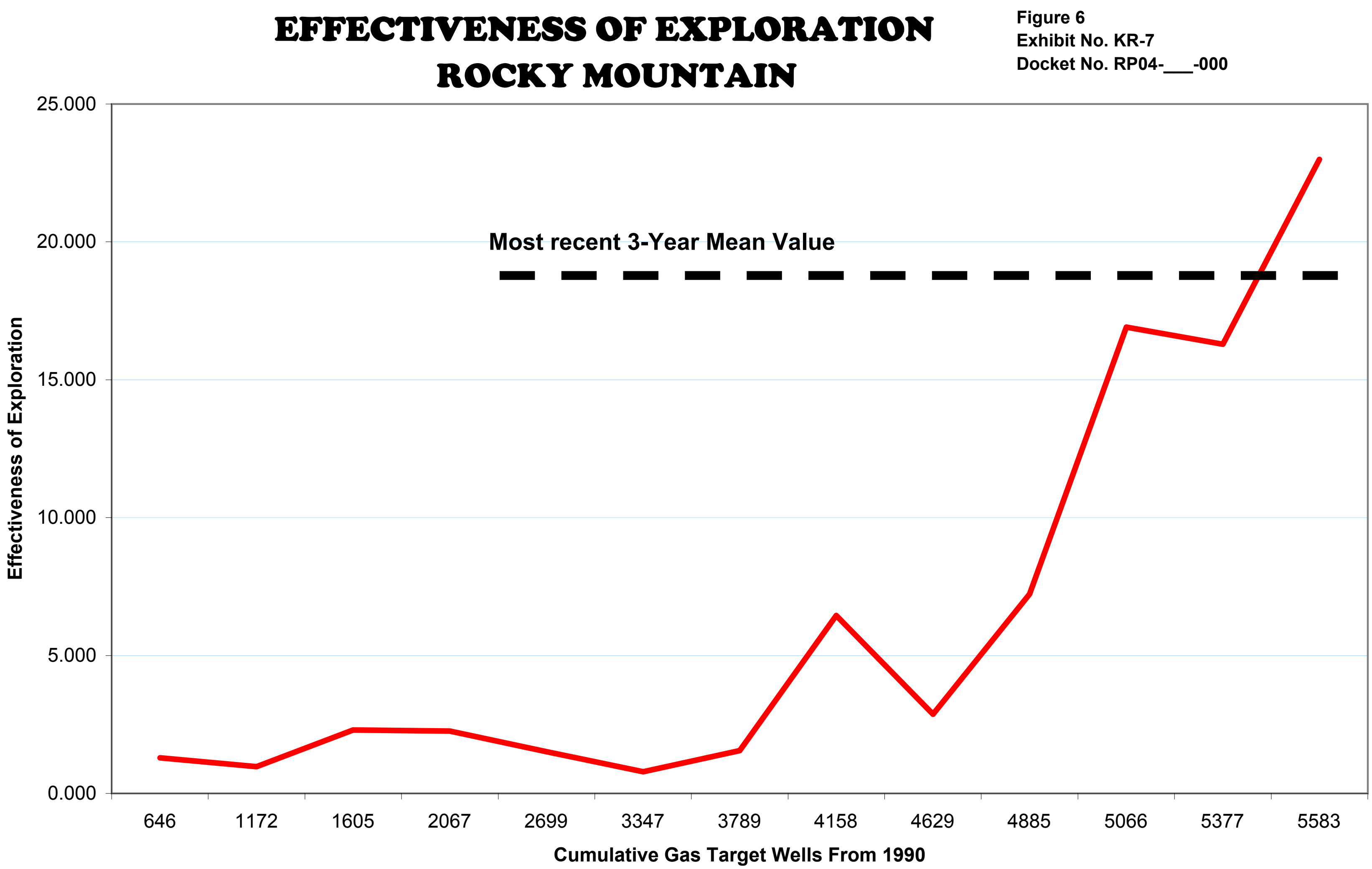


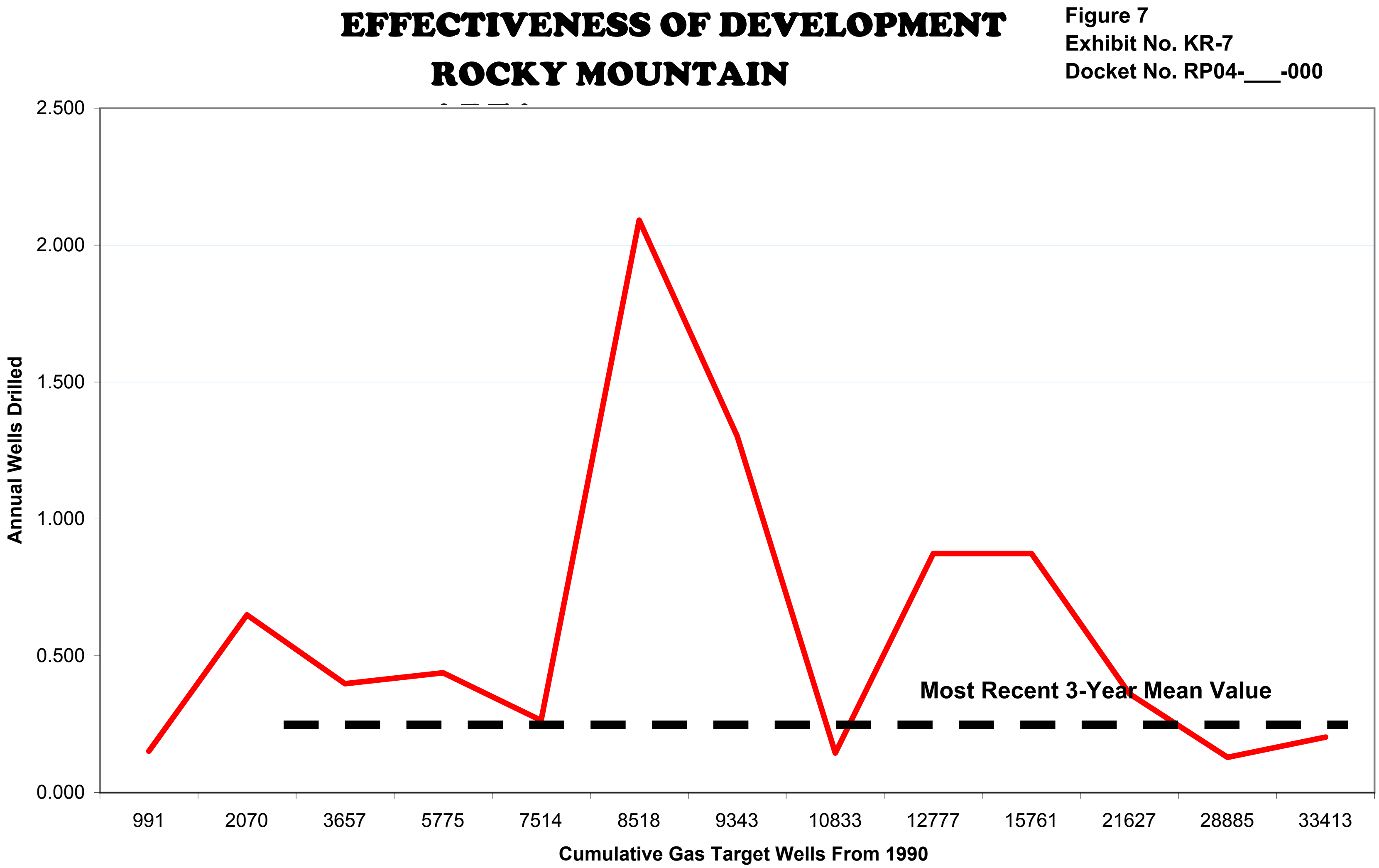
Figure 5
Exhibit No. KR-7
Docket No. RP04-___-000





EFFECTIVENESS OF EXPLORATION
ROCKY MOUNTAIN
Figure 6
Exhibit No. KR-7
Docket No. RP04-___-000
Most recent 3-Year Mean Value
Effectiveness of Exploration
25.000
20.000
15.000
10.000
5.000
0.000
646
1172
1605
2067
2699
3347
3789
4158
4629
4885
5066
5377
5583
Cumulative Gas Target Wells From 1990

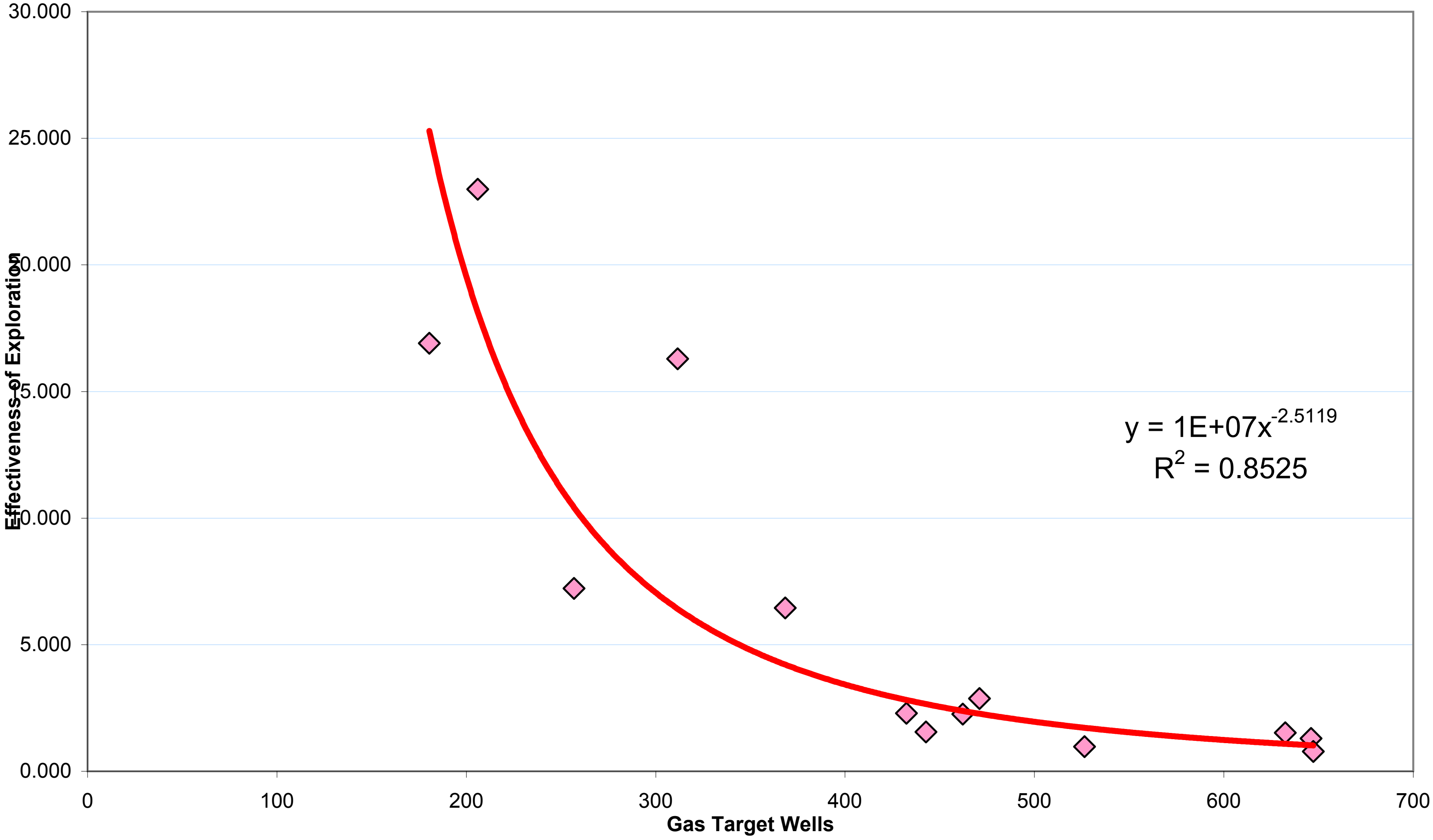
Figure 7
Exhibit No. KR-7
Docket No. RP04-___-000



RELATIONSHIP BETWEEN GAS TARGET EXPLORATORY FOOTAGE DRILLED AND THE EFFECTIVENESS OF EXPLORATION

Figure 8
Exhibit No. KR-7
Docket No. RP04-___-000

ROCKY MOUNTAIN AREA



RELATIONSHIP BETWEEN GAS TARGET EXPLORATORY FOOTAGE DRILLED AND THE EFFECTIVENESS OF DEVELOPMENT

Figure 9
Exhibit No. KR-7
Docket No. RP04-___-000

ROCKY MOUNTAIN AREA

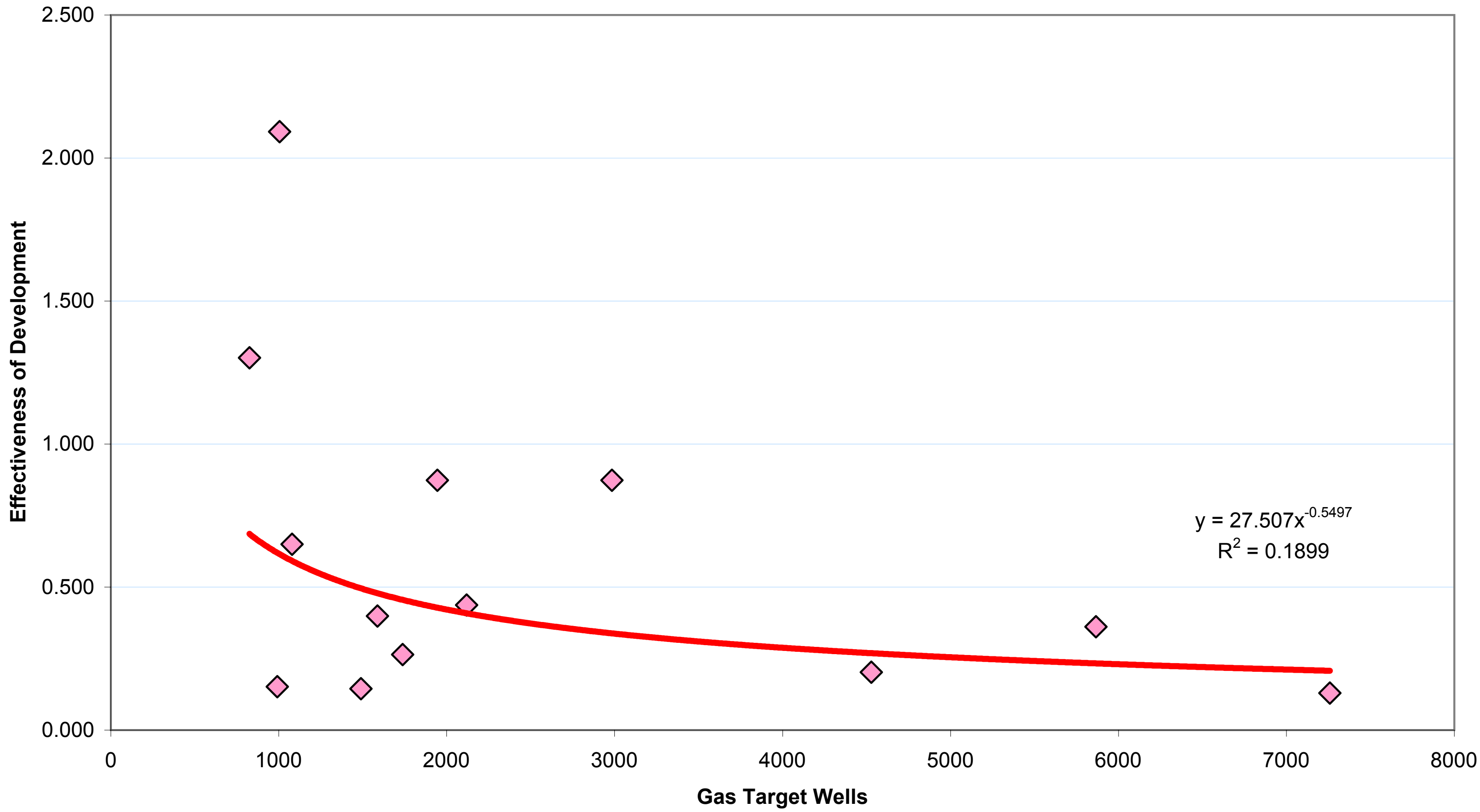


Figure 10
Exhibit No. KR-7
Docket No. RP04-___-000

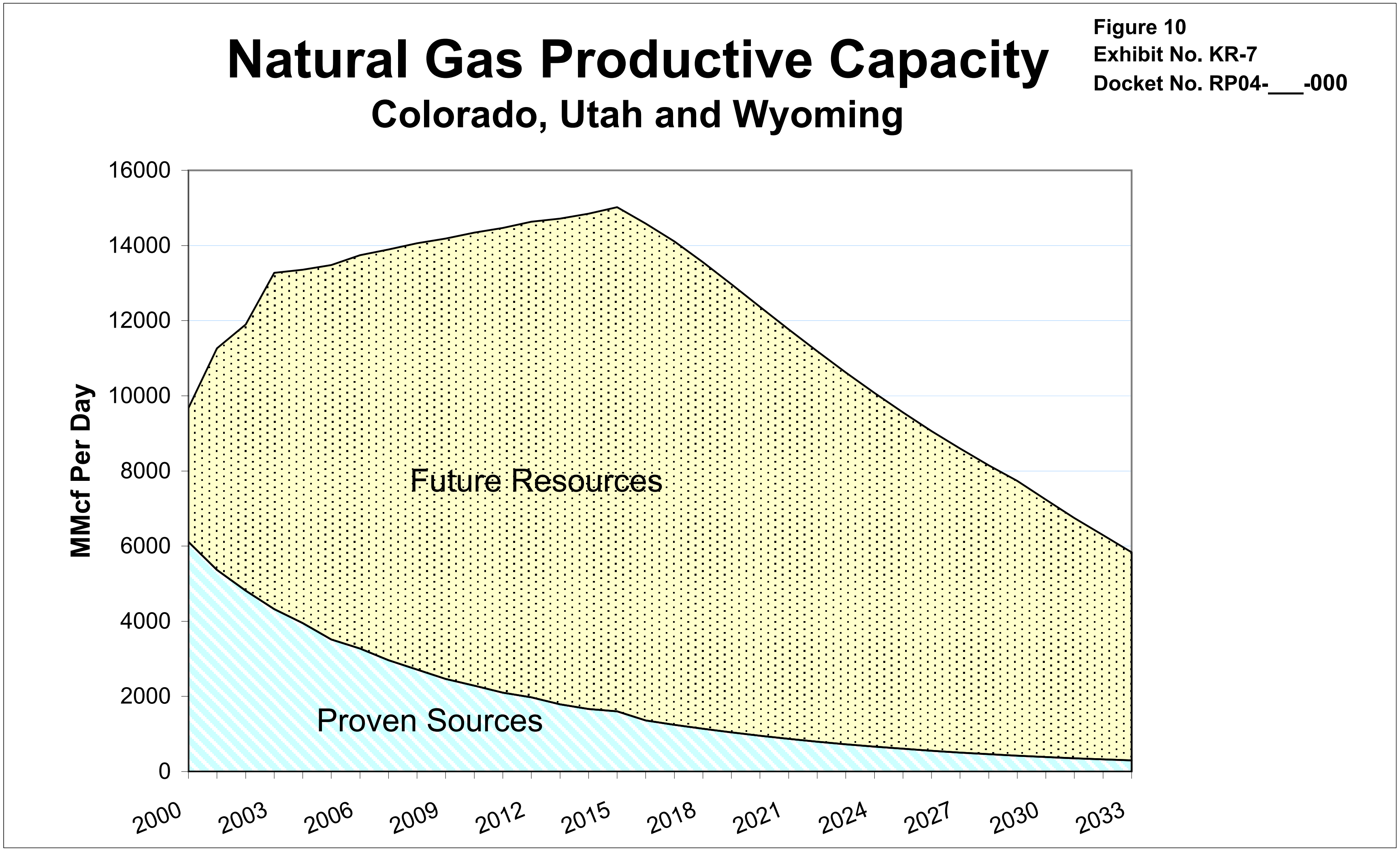


Figure 11
Exhibit No. KR-7
Docket RP04-___-000

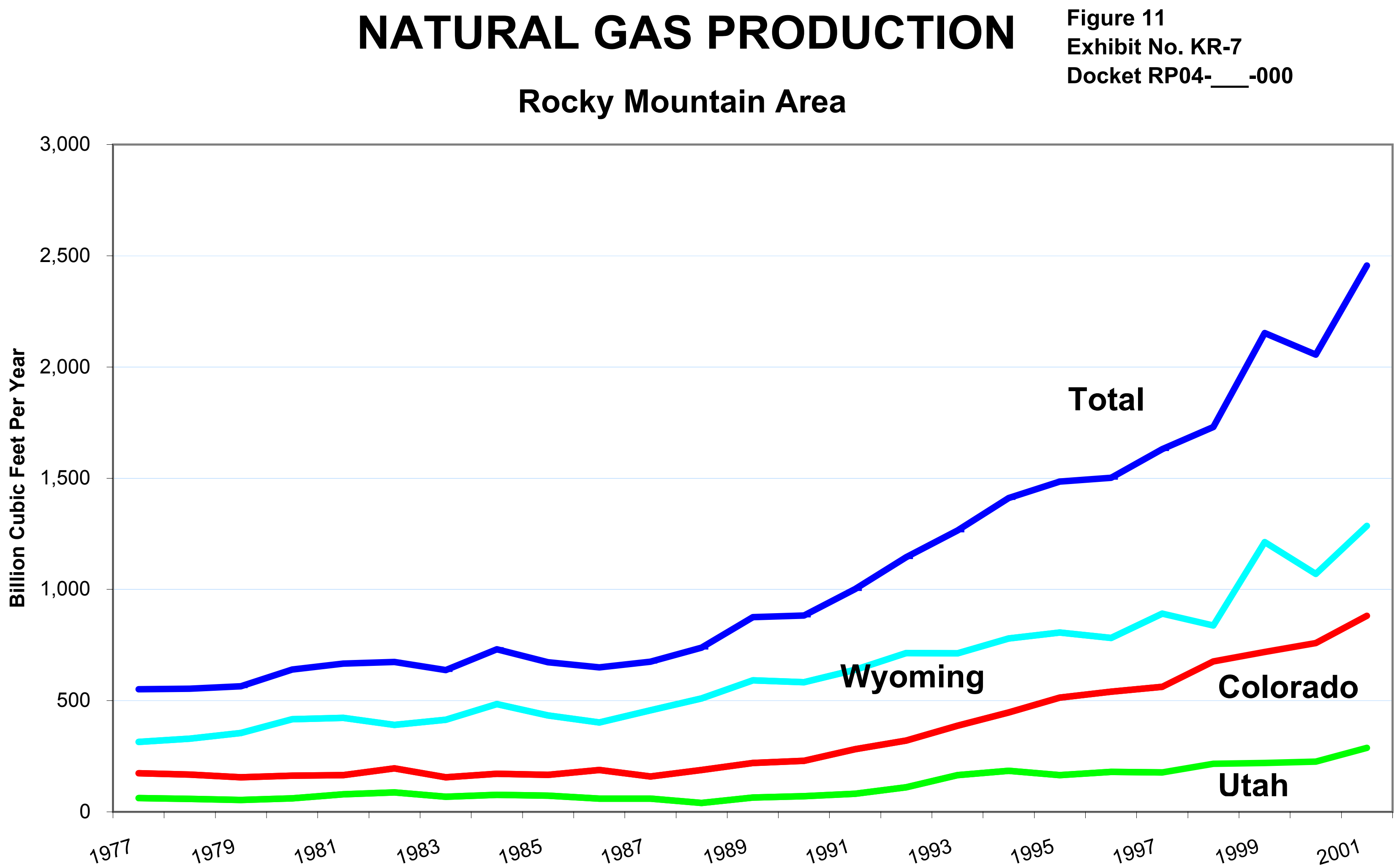


Figure 12
Exhibit No. KR-7
Docket No. RP04-___-000

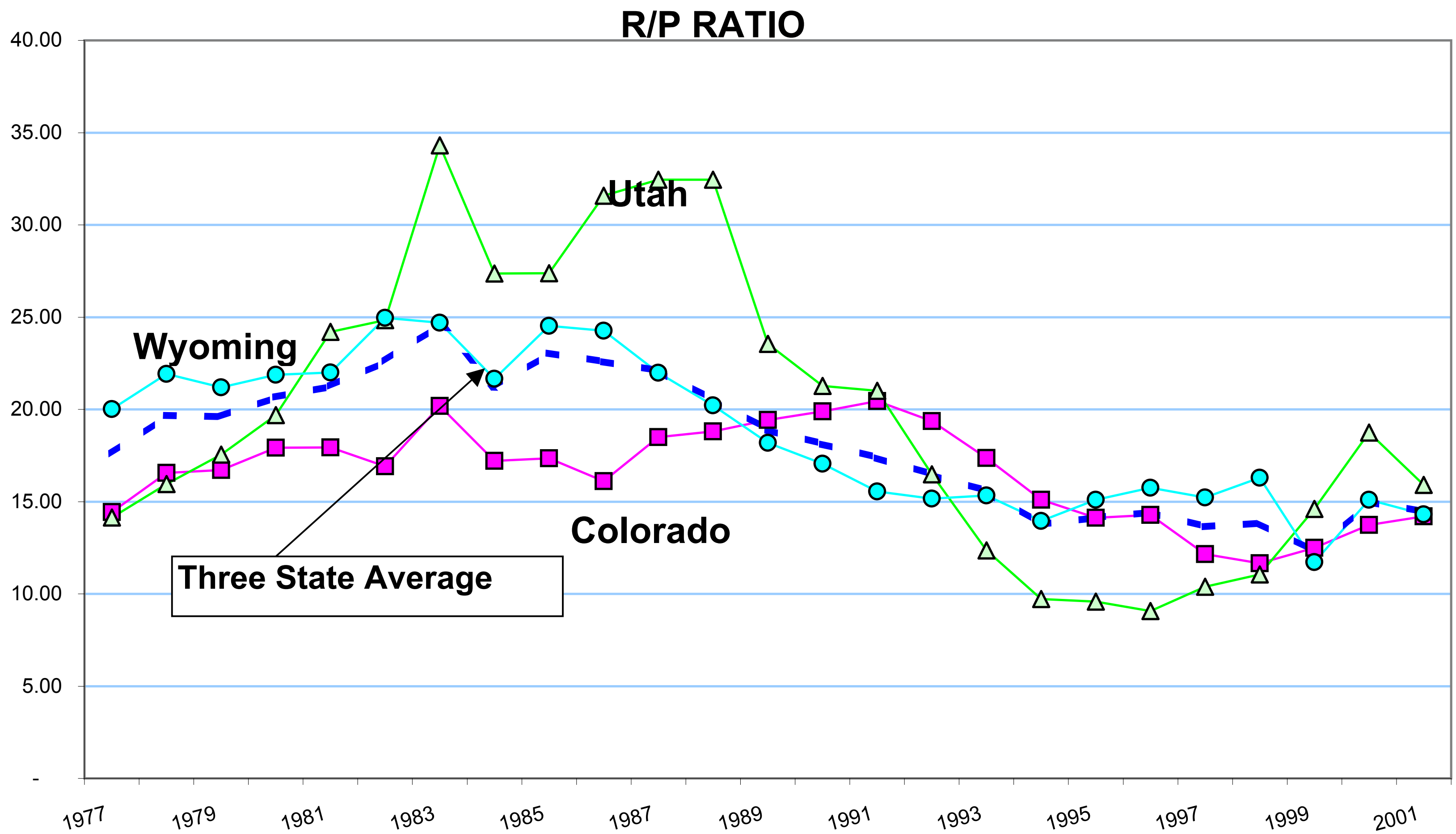


Figure 13
Exhibit No. KR-7
Docket No. RP04-___-000

Relationship Between Wellhead Price and Exploratory Drilling
Rocky Mountain Area

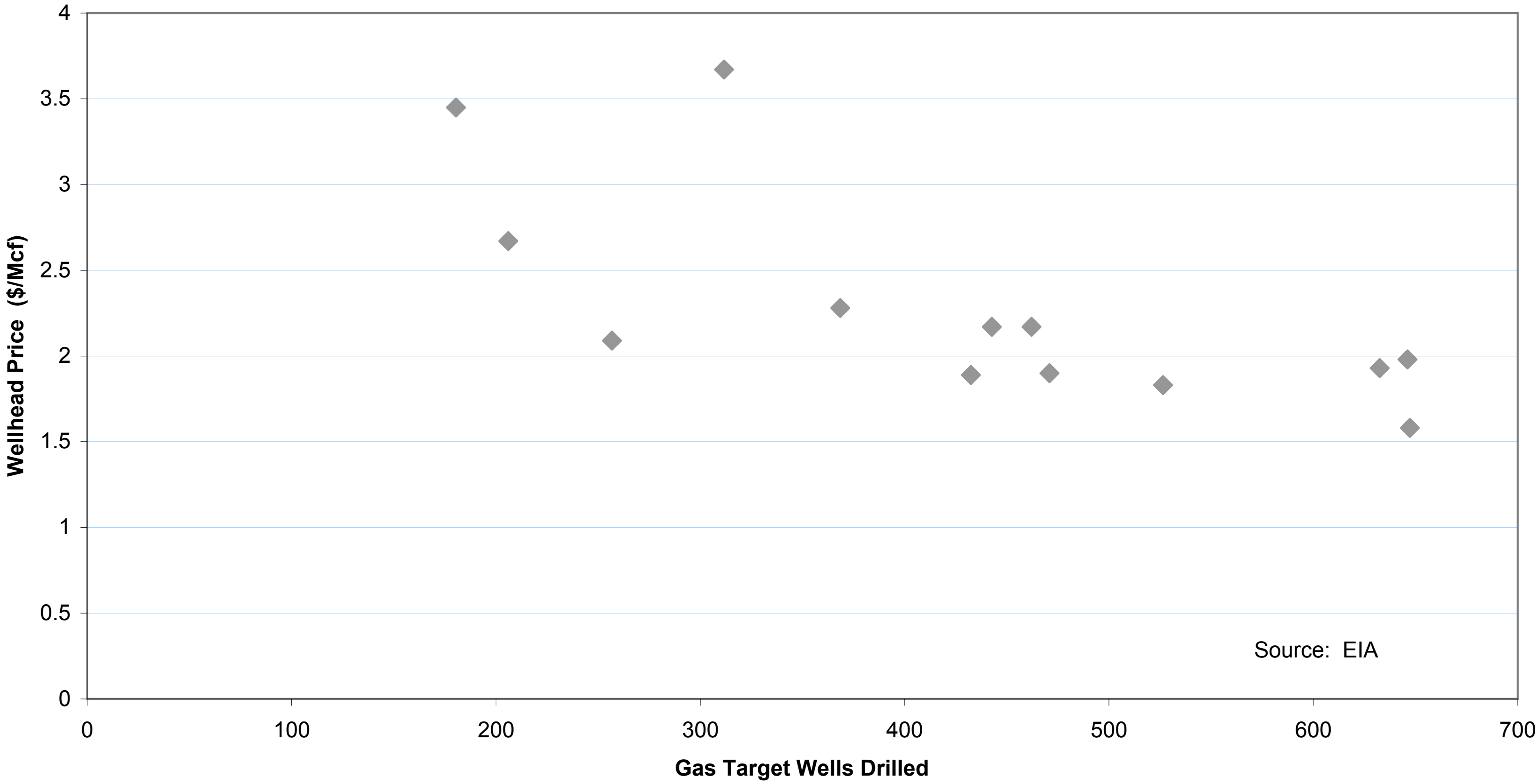


Figure 14
Exhibit No. KR-7
Docket No. RP04- -000

Relationship Between Wellhead Price and Development Drilling Rocky Mountain Area

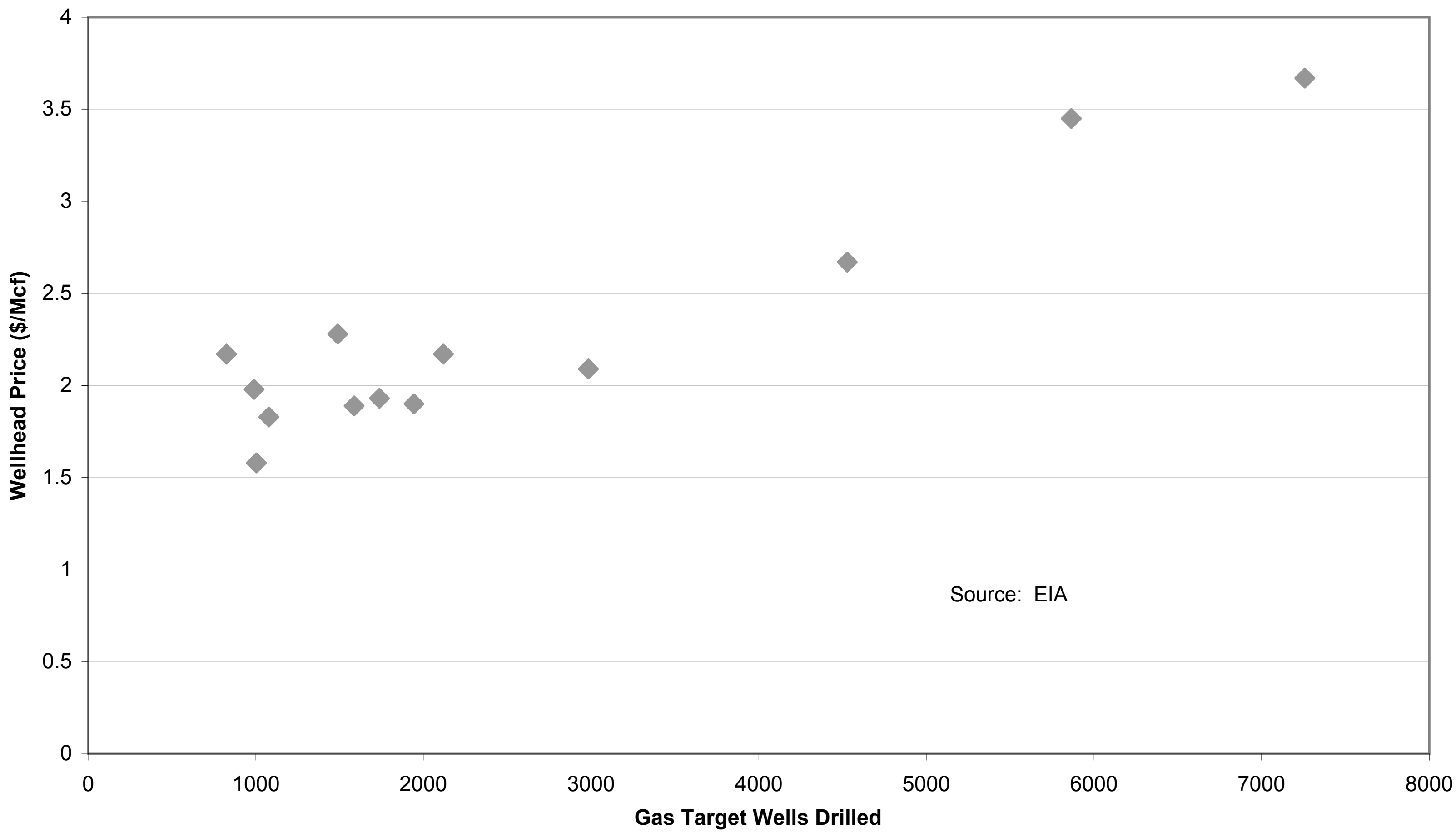


Figure 15
Exhibit No. KR-7
Docket No. RP04-___-000

Hyperbolic Productive Capacity
Rocky Mountain Region Gas Wells

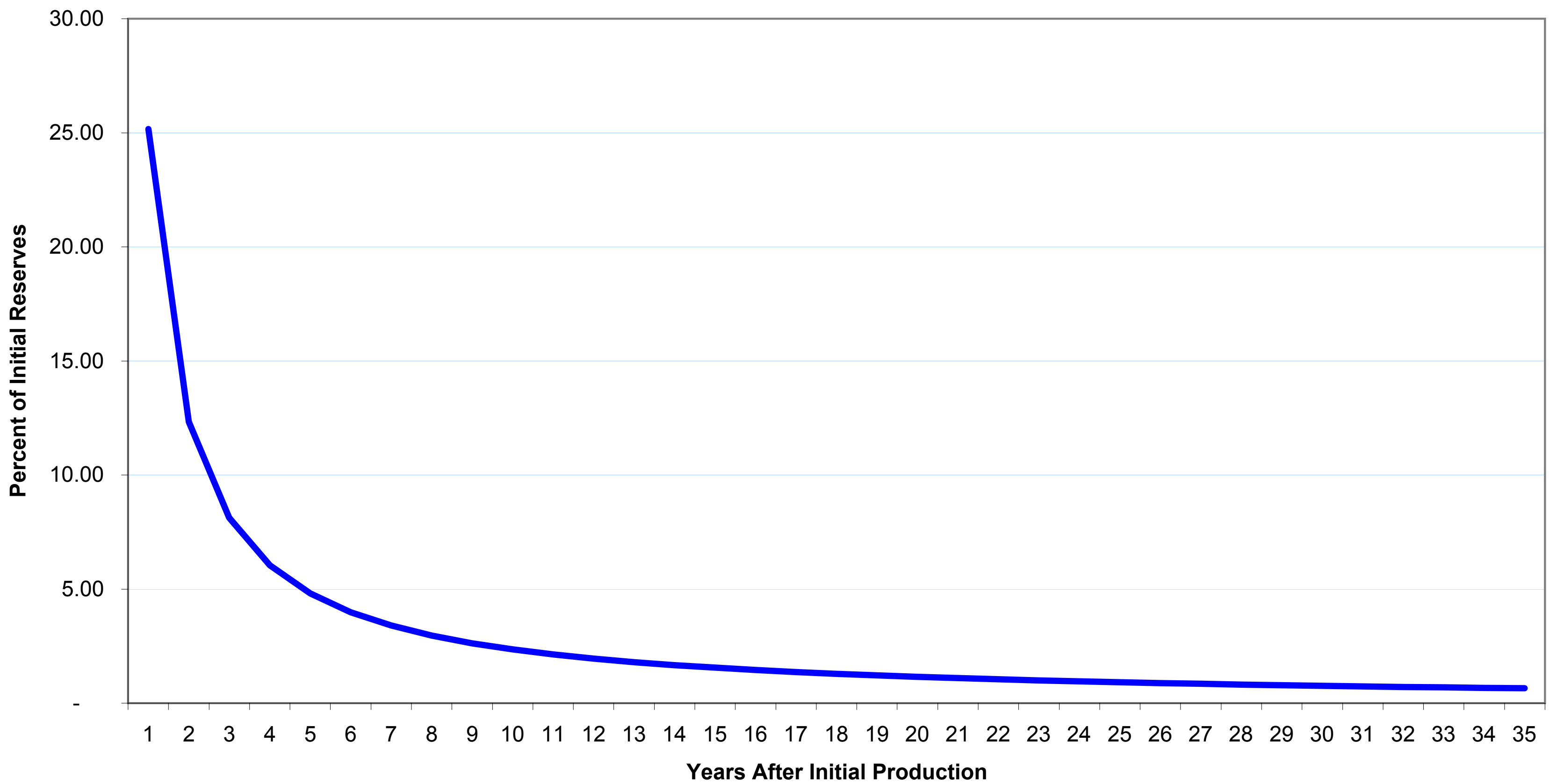


EXHIBIT NO. KR-8
Docket No. RP04-____-000

Kern River Gas Transmission Net Salvage Value

General Assumptions
Total Abandonment Costs
Abandonment of Pipeline Facilities
Abandonment of Compression Facilities
Abandonment of Measurement Facilities

Kern River Gas Transmission Net Salvage Value

August 2003

General Assumptions

1. All above ground facilities would be removed and the disturbed area restored.

2. All below ground gas piping abandoned in place would be cleaned and purged with Nitrogen and then capped. Road and water tributary crossings would be filled with grout before capping.

3. All hazardous material generated from the cleaning process and present at any of the facilities would be properly contained and disposed.

4. 95% of the line pack in the transmission lines would be recovered at a value of $4.24 per MMBtu (average price forecast at Opal for 2003 by PIRA and DRI-WEFA Natural Gas Monthly) less the cost of portable compression to remove it.

5. All fee land parcels over one acre would be sold and fee land parcels under an acre would be revert back to the surrounding landowner(s).

6. All right-of-way (ROW) easements would revert back to the current landowners.

7. A "Plan of Abandonment" would be prepared for state and federal agencies.

8. Kern River will file a FERC Section 7(b) Abandonment filing that would include an Environmental Report similar to the report required for the construction of new facilities.

9. The salvage value of reusable equipment and material is based on the projected value at the end of the facilities' useful life.

10. The salvage value of scrap metal material is $60 per ton.

11. The abandonment construction costs and salvage values are based on recent Kern River experience or in consultation with contractors and suppliers.

12. AFUDC is not included in the estimate but a corporate overhead of 8% would be.

13. The jointly-owned facilities on the south end of the system were included in the study and costs were allocated to Kern River at 68.448%, KRGT ownership interest as of December 31, 2002.

14. All cost estimates are expressed in constant 2003 dollars.

15. Interim abandonment of some facilities (primarily compression) will occur in advance of the final system abandonment due to obsolescence, market changes and gas supply declines.

16. The most qualified resource to validate this study is Kern River's senior technical personnel that are familiar with the condition, operations and construction of the Kern River system.

Why Does The Abandonment and Replacement of Natural Gas Pipeline Facilities Typically Have A Negative Salvage Value?

Natural gas transmission facilities like those owned by Kern River are unique customized facilities designed to meet specific flow rates, pressures, natural gas characteristics and specific site conditions (i.e. ambient temperatures and elevation). These customized facilities are designed to last for 50 years or more unless replacement is required because of obsolescence, wear, changes in customer requirements, regulatory mandates or changes in site conditions (i.e. class location change). The cost of removing and abandoning facilities to meet these objectives almost always exceeds the credits realized from salvaged material and equipment that has a very limited market for resale.

As an industry, gas transmission facilities are designed and built and modified using only new equipment and material. Consequently, the market for used equipment and material unique to gas transmission facilities is virtually nonexistent (except for scrap). The reason only new equipment is used is to achieve the high degree of reliability and integrity required of the industry.

Retirement Process

When a pipeline facility is retired to accommodate a replacement, or it is simply no longer needed, the following steps are required. Abandonment drawings have to be prepared to describe to a contractor or permitting agency how the equipment or components are to be removed. Any facilities related to the abandonment also need to be described on the drawings such as piping, conduit and foundations that need to be removed/modified to accommodate a replacement or simply because it is no longer needed. To perform retirement work along the pipeline right-of-way, the pipeline needs to obtain the same landowner easements and regulatory approvals as for new construction. The contractor costs for removal of the abandoned facilities are segregated from the installation of replacement facilities if the facilities are being replaced.

Reconfiguration of Facilities Because of Expansions

If an expansion required some existing valves to be removed, the opportunity to sell the valves significantly above junk value would be very limited. Typically the purchaser of a used valve would have it reconditioned before putting it in service and the cost of refurbishing a valve is approximately 70% of a new valve cost. Consequently the cost of removing the valves by a contractor would far exceed the credit from its sale. The case is similar for piping modifications, where the cost of removing pipe fittings (flanges, tees, elbows, etc.) in manner that they could be reused costs more than using new material.

Most of the equipment in a meter station and a compressor station is engineered for specific operating and customer requirements. Therefore it very unlikely that those unique operating conditions would be the same for other pipeline facility requirements (i.e. a gas after cooler is custom designed for a specific flow rate, gas conditions, temperature range, elevation and ambient conditions). Electrical equipment like switch gear, motor control centers, control panels, etc. are all engineered items designed and manufactured for a unique application and would have no or little value except for scrap when they are retired from service.

The only equipment that may result in a positive credit if it is removed as part of an expansion or retirement would be a limited amount of equipment with common uses in other industries and applications like an air compressor or generator.

Logically, most gas transmission operators design facilities using the same manufacturer for common components used throughout the system such as valve operators, relief valves, control valves, instruments, etc. The reason for this practice is to reduce training and knowledge required of field personnel, facilitate spare parts inventories and provide a single source of supply for field support. Therefore, the market to sell this equipment to other users is further limited to those companies that standardize on the manufacturer of your equipment.

Replacement Due to Wear and Tear

Mechanical equipment (i.e. generator, air compressor, etc.) that can no longer meet the required reliability or performance through maintenance or overhaul has reached the end of its economic life. This equipment would only have scrap value. The cost to remove the equipment, foundation and other appurtenances to accommodate any replacement equipment and accessories would far exceed the scrap value.

Regulatory Requirements

A change in class location of a section of pipeline could require the pipeline to be replaced. In this case it is more economical to abandon the pipe in place than remove it because the cost of removal can cost more than three times the cost of new pipe. Also, if the pipe were removed it would have to be reconditioned by cleaning, beveling for re-welding and recoating.

Obsolescence and Age

Generally the equipment currently installed at Kern River pipeline compressor and meter stations would be obsolete when any of the facilities are abandoned because the load on the system had significantly declined. Consequently the potential credit to offset the cost of removing the facilities from operations is very small. As an example, gas turbine compressor units manufactured 30 years ago by the same manufacturer as Kern River's equipment, only have a market value of 3% of the cost of buying the same model unit available today. The reason this value is so low is because of the significant improvement the manufacturer has made in equipment automation, efficiency of operation and environmental controls.

Other industry technologies have also made significant improvements. The measurement of gas on pipelines has evolved using changing technologies such as turbine meters in place of orifice meters and electronic records over paper chart recorders. As these new technologies are developed in the gas industry, typically they are applied to new faculties first and only when they are economically justified do they replace the old technologies. Therefore, when Kern River facilities are abandoned in the future the current facilities will not have the latest technology in most cases.

Instrumentation and control of a pipeline system historically has evolved where significant improvements can justify replacement in about 10-15 year cycles. An example of equipment that fits in this category is fire eyes, gas detectors, flow measurement, supervisory control_and data acquisition, communications, emergency shutdown systems and other pipeline control systems. Because of the continuous progress in instrumentation and controls technology, new equipment installed tends to become obsolete soon after it is installed. Consequently when this equipment is retired and replaced, it has no market value for resale except as scrap.

Kern River Negative Salvage Value Study
August 2003

The Kern River "Negative Salvage Value Study" was prepared using the following resources:

Barrie McCullough – Former Williams employee with 32 years experience in the Oil & Gas Industry. Positions held included responsibilities for performing and managing engineering, design, operations, construction and inspection of oil and gas facilities.

Kern River personnel consulted for the study:

Chris Bias – Engineering Manager
Dave Maxwell – Electrical Engineer
Christian Johnson - Designer
Boyd Schow – Technical Specialist
Alan Nielson – Senior Engineer
Jill Braun – Senior Engineer
Stephen Knubel – Land Records
Dave Donnelly – Land Representative
Derek Forsberg – Environmental Specialist
Garth Tyler – Senior Accountant
Chris Healy – Senior Accountant
Ben Mates – Regulatory Analyst
Desiree Lewis - Purchasing
Candice Karpakis – Business Development
Jeff Valentine – Manager of Tax & Property Accounting
Rob Harmon – Manager Gas Control & Analysis

Contractors and Suppliers consulted for the study;

Red Man Supply - Pipe, valve and fitting supplier
Gregory and Cook – Pipeline Contractor
Snelson Companies (through 1996 Northwest Pipeline Study) – Station and pipeline contractor
Barnard Pipeline – Pipeline contractor
Associated Pipeline Contractors – Pipeline contractor
Continental Engineering – Building supplier and erector
UCISCO – A Praxair Service Company that provides nitrogen and nitrogen purging services
Reserve Equipment – Provides pipeline evacuation services

KRGT System Abandonment Summary	
Final Abandonment Cost	
Facility Type	**Abandonment Cost**
Pipeline Abandon In Place	$89,756,675
Compression	$4,429,152
Measurement	$6,837,781
Interim Abandonment Cost	
Compression	$13,346,089
Total Abandonment Cost	**$114,369,697**

Kern River Gas Transmission Net Salvage Value
August 2003

Abandonment of Pipeline Facilities

In general the requirement for the abandonment of the pipeline facilities is to leave the below ground facilities in place and remove only the surface facilities. The Kern River right-of-way (ROW) department has reviewed the systems easement agreements and determined there that there are no requirements to remove underground facilities. The lines would be cleaned, purged with nitrogen and then sealed. All work would meet the requirements of DOT CRF Part 192.727, Abandonment or Inactivation of Facilities.

The pipeline cleaning costs were primarily based on Northwest Pipeline's experience during the requalification of 89 miles of 26" line in 1992. In order to avoid the cost of disposal of millions of gallons of contaminated hydro test water, the pipeline was cleaned using 12,000-gallon batches of cleaning solution. This process proved to be sufficiently effective so that the hydro test water could be dispersed on the ground.

The Kern River system is equipped with pig launchers and receivers so that batches of cleaning solution can be moved through the system without modification of system appurtenances. The cleaning process is not expected to remove all hydrocarbon materials from the interior walls. Therefore it is necessary to purge all piping that is to be left in place with Nitrogen and then seal the ends. The estimated costs for the nitrogen purging was based on consultation with a contractor that regularly performs this work

In order to effectively run cleaning batches through the pipeline, all tapes over two inches in size would be removed. The above ground pig launching and receiving facilities would be removed after the cleaning operation is completed.

All pipeline markers would be removed and other miscellaneous above ground facilities. Also, all of the cathodic protection site surface facilities would be removed

The pipeline crossings of public roads and railroads would be cut at the crossing ROW and filled with grout. Water tributaries (streams, rivers, canals and other water bodies) crossed by the pipeline would be cut, filled with grout up to the high water marks. The reason this procedure is necessary at water crossings is to prevent water flow from being directed down the old pipeline right-of-way (as pipe corrodes and eventually fails) and possibly artificially change its natural course of flow. Grouting water crossings also prevents possible water contamination from hydrocarbons that may still remain in the piping even after the cleaning. Also, it will prevent canals from collapsing as the pipe corrodes and will not damage to surrounding property as occurred along Utah's Wasatch front where homes were flooded, filled with mud and Exhibit structurally damaged when a canal above the subdivision failed. The estimated cost for this work was obtained through consultation with Associated Pipe Line Contactors and Barnard Pipeline, pipeline construction contractors.

All of the disturbed ROW would be restored in accordance with the FERC Plan & Procedures and requirements of state and local regulatory bodies. The state of the abandoned facilities would be documented by the as-builts in the demolition drawings.

Pipeline Abandonment Summary of Costs	Rev 8/13/03
Compression to Remove Line Pack 1)	$1,701,704
Pipeline Cleaning Costs 2)	$20,492,559
Fill Public Road and Water Crossings With Grout 3)	$53,287,201
Nitrogen Purging 4)	$3,214,446
Remove 60 Taps Over 2" 5)	$648,744
Remove Pigging Facilities 6)	$2,340,000
Remove CPS System Surface Facilities 7)	$995,093
Remove All Miscellaneous Surface Facilities & Markers.8)	$820,550
Sub-Total Direct Contractor Costs	$83,500,297
Misc Sales & Use Taxes @ 6.6% 9)	$275,551
Project Management @ 8% 10)	$6,680,024
Engr Design & Drafting @ 2.5% 11)	$2,087,507
Inspection 12)	$3,238,224
Overhead @ 8% 13)	$6,680,024
FERC 7B Filing & Permitting 14)	$2,573,300
ROW Access & Damages 15)	$2,827,792
TOTAL	**$107,862,719**
Credit for Salvaged Pipe & Valves	(337,738)
Credit for Salvaged Line Pack	(17,768,306)
Sub-Total	($18,106,044)
Net Total	**$89,756,675**

Notes: 1) See pages 11-12 for compression to remove line pack.
2) See pages 13-14 for pipeline cleaning costs.
3) See pages 15-17 for public road and water crossings that require capping and grouting
4) See pages 18-19 for nitrogen purging.
5) See page 20 for cost to remove 60 taps over 2".
6) See page 21 for cost to remove pigging facilites.
7) See page 22 for cost to remove system CPS system surface facilities
8) The cost for removing all other miscellaneous surfac facilites and markers is $500 per mile.
9) Miscellaneous Sales & Use Tax of 6.6% represents an approximate average over the four state area of Kern River's facilites and was applied to 5% of the the sub-total of direct costs that would be subject to this tax..
10) Project Management of 8% represents Nothwest Pipeline's past experience (per 1996 study) and was applied to the sub-total of direct costs.
11) Design and drafting for the preparation of abandonment drawings was calculated to be 2.5% of the sub-total direct costs which is half of the rate to complete a new pipeline design.
12) See page 23 for inspection costs.
13) The corporate overhead rate of 8% was applied to direct costs.
14) The portion of the FERC 7B filing and permitting cost allocated to compression was calculated at 3% of the sub-total direct costs.
15) Right-of-way costs for the relinquishment of easments that includes damages, fees, title work and legal fees (Cost for common facilities adjusted for Kern River's portion of common facilities)

Recovered Line Pack Credit			8/13/2003
System	**Recoverable Line Pack MMSCF**	**Selling Price**	**Total**
KRGT	3544.14	4.24	$15,027,154
Common Facilities	944.51	4.24	$4,004,722
KRGT Portion @ 68.448%			$2,741,152
Total Line Pack Credit			**$17,768,306**
Cost To Remove Line Pack			
KRGT			$1,424,900
Common Facilities			$404,400
KRGT Portion @ 68.448%			$276,804
Total Removal Cost			**$1,701,704**

Notes: 1) Line price for selling line pack is based on the average 2003 price at Opal per PIRA and DRI-WEFA
2) The cost to remove the line pack was determined through consultation with Reserve Equipment who provides portable compresssor specifically for this purpose.

Expansion II Line Pack

Spread	Volume MCF	Cost
1	245,000	$1,004,500
2	100,000	$400,000
3	200,000	$800,000
4	200,000	$800,000
5	200,000	$800,000
6	200,000	$800,000
7	200,766	$801,741
8	217,000	$568,758
9	135,000	$738,885
10	223,000	$908,315
Total	1,920,766	$7,622,199

Cost per Dth =	$3.968	
Cost per Dth per Opal PIRA and DRI-WEFA average for 2003=	$4.24	
The line pack volume of gas in the Northern pipe system operated by KRGT 3746.9 MMSCF		
Approximately 95% would be recovered or 3544.14 MMSCF at $4.24 per Dth or		$15,027,154
The line pack of the common system is 998.5 MMSCF.		
Approximately 95% would be recovered or 944.51 MMSCF at $4.24 per Dth or		$4,004,722
KRGT portion at 68.448% would be		$2,741,152
Total Line Pack Credit		$17,768,306

Cost to remove line pack using blowdown compressors.

North system	$1,424,900
South System (KRGT share)	$276,804
Total	$1,701,704

Pipeline Cleaning Costs			8/13/2003
Pipe Sizes	**Length Miles**	**Cleaning Cost Per Mile**	**Total Cost**
36"	1318.9	$13,145	$17,336,941
30"	6.0	$9,476	$56,856
20"	13.0	$5,124	$66,612
12"	2.0	$2,653	$5,306
Sub-Total Cleaning Costs			**$17,465,715**
Common Facilities			
42"	220.3	$16,882	$3,719,105
30"	70.5	$9,476	$668,248
16"	6.4	$3,761	$23,958
12"	4.1	$2,653	$10,798
Sub-Total Cleaning Costs			**$4,422,107**
KRGT Portion at 68.448%			$3,026,844
Total Cleaning Costs			**$20,492,559**

Base Pipeline Cleaning Costs(from NWP 1996 study)		Amount That Applies to Kern River	36"	42"	30"	20"	16"	8/13/2003 12"
Contractor Mobilization/Demobilation	$435,000	$145,000	$174,000	$191,400	$155,150	130,500	116,000	101,500
Fabricate Cleaning Heads	$72,000	$0	$0	$0	$0	$0	$0	$0
Install Cleaning Heads, Remove and Replace w/Pipe	$409,800	$0	$0	$0	$0	$0	$0	$0
Cleaning Runs (21) in Six Sections	$925,000	$308,000	$585,000	$796,250	$410,059	$182,249	$116,639	$65,609
Sub-Total	$1,841,800	$453,000	$759,000	$987,650	$565,209	$312,749	$232,639	$167,109
Inflation from 1992 to 1996 @ 13%	$239,434	$144,960	$242,880	$316,048	$180,867	$100,080	$74,444	$53,475
Sub-Total	$2,081,234	$597,960	$1,001,880	$1,303,698	$746,076	$412,828	$307,084	$220,584
Disposal of Oily Water (1996 Rates @ $1.15/Gal)	$289,800	$84,000	$168,000	$198,841	$97,247	$43,221	$27,661	$15,560
TOTAL	$2,371,034	$681,960	$1,169,880	$1,502,539	$843,323	$456,049	$334,745	$236,144
Average Cost per Mile	$26,641	**$7,662**	**$13,145**	**$16,882**	**$9,476**	**$5,124**	**$3,761**	**$2,653**

Notes:

1) The following note is an excerpt from a 1996 Northwest Pipeline study that is being used as a basis for the Kern River cleaning costs. The Kern River system has pigging facilities has pigging facilties so these cost have been reduced to recognize that fact. "Most of Northwest's gas transmission pipelines are not piggable and over its forty years of operation, large amounts of compressor oil and other hydrocarbon contaminants have accumulated inside the pipelines. Also, there has been sufficient low levels of H2S contained in gas delivered from Canada over the years, creating some accumulation of iron sulfide in the pipeline (iron sulfide will auto-ignite when exposed to air). At points where gas processing plants have delivered into the system, there has been upset situations where some contaminants have carried over to the pipeline. Some form of cleaning is required to abandon the pipeline in place in order to remove a majority of these accumulated contaminants.

The pipeline cleaning costs were primarily based on Northwest's experience during the requalification of 89 miles of 26" pipeline in 1992. In order to avoid the cost of disposal of millions of gallons of contaminated hydro test water, the pipeline was cleaned using 12,000 gallon batches of cleaning solution. This process proved to be sufficiently effective so that the hydrostatic test water could be dispersed on the ground."

2) Inflation costs from 1992 to 1996 was calculated by compounding 3% per year for four years for a total escalator of 13%. For 2003, Kern River's costs were escalated 32%.

3) Disposal of 252,000 gallons of oily water at the current 1996 rate of $1.15 per gallon. For Kern River 2003 costs of $1.00 per gallon was used.

4) The costs that apply to a Kern River system with pigging facilities will significantly reduce this cost.

Crossing Costs			8/21/03
Crossing Type	**Quantity**	**Unit Cost**	**Total**
36" Uncased			
RR,Road,Water	676	$59,499	$40,221,324
Freeway	16	$63,600	$1,017,600
30" Uncased	5	$54,694	$273,470
20" Uncased	8	$44,565	$356,520
16" Uncased	1	$39,786	$39,786
12" Uncased	6	$34,604	$207,624
Sub_Total	712		**$42,116,324**
Common Facilities			
42" Uncased	84	$60,455	$5,078,220
42" Cased			
RR,Road,Water	39	$118,378	$4,616,742
Freeway	4	$130,499	$521,996
30" Uncased	12	$54,694	$656,328
30" Cased	51	$106,803	$5,446,953
Sub_Total	190		**$16,320,239**
KRGT Portion at 68.448%			**$11,170,877**
Total Crossing Cost			**$53,287,201**

Crossing Unit Costs					8/21/2003
RR, Road, Water Crossing	**Construction Cost**	**Grout**	**Total Unit Cost**	**Additional Grout For Freeway**	**Total Freeway Cost**
42" Uncased	$56,765	$3,690	$60,455	$5,535	$65,990
42" Cased	$113,529	$4,849	$118,378	$12,122	$130,499
36" Uncased	$56,765	$2,734	$59,499	$4,101	$63,600
36" Cased	$113,529	$3,746	$117,275	NA	NA
30" Uncased	$52,034	$2,660	$54,694	$2,912	$57,605
30" Cased	$104,068	$2,734	$106,803	$4,101	$110,903
20" Uncased	$43,362	$1,203	$44,565	NA	NA
16" Uncased	$39,026	$760	$39,786	NA	NA
12" Uncased	$34,147	$456	$34,604	NA	NA

Note: 1) The cost to excavate, remove carrier pipe from cased crossings, fill with grout and cap crossings was determined through consultation with Associate Pipe Line Contractors and Barnard Pipeline, pipeline contractors.

Crossings That Require Capping and Grouting

	Railroad		Road		Freeway		Water	
	Mainline	Loop	Mainline	Loop	Mainline	Loop	Mainline	Loop
KRGT 36"	26	26	189	189	8	8	123	123
Big Horn 12"	1	0	1	0	1	0	0	0
Moapa 16"	0	0	1	0	0	0	0	0
High Desert 20"	0	0	6	0	0	0	0	0
Whitney Canyon 20"	0	0	1	0	0	0	1	0
Anshutz 12"	0	0	1	0	0	0	0	0
Centennial 12"	0	0	2	0	0	0	0	0
Opal - 30"	1	1	1	0	0	0	2	0
Totals	28	27	202	189	9	8	126	123
Sub-Total by Types	55		391		17		249	
Common Facilities								
42" Uncased	4	3	52	25	0	0	0	0
42" Cased	3	3	19	9	2	2	4	1
30" East Lateral - Uncased	0	0	12	0	0	0	0	0
30" East Lateral - Cased	1	0	4	0	0	0	1	0
30" West Side - Uncased	0	0	0	0	0	0	0	0
30" West Side - Cased	0	0	45	0	0	0	0	0
Totals	8	6	132	34	2	2	5	1
Sub-Total by Types	14		166		4		6	

Nitrogen Purging Costs			
Northern System	**Miles**	**Cost Per Mile**	**Total**
36" Pipe	1318.9	$1,797	$2,370,063
30" Pipe	6.0	$1,247	$7,482
20" Pipe	13.0	$690	$8,970
12" Pipe 1)	2.0	$321	$4,680
Additional for Wasatch Mtns			$8,000
Additional Setups 2)			$338,400
Sub-Total			**$2,737,595**
Common Facilites			
42" Pipe	220.3	$2,358	$519,467
30" Pipe	70.5	$1,247	$87,914
16" Pipe 1)	6.4	$468	$4,680
12" Pipe 1)	4.1	$321	$4,680
Additional Setups 2)			$79,920
Sub-Total			**$696,661**
KRGT portion of Cost @ 68.448%			**$476,850**
	Total Nitrogen Purging Cost		**$3,214,446**

Note: 1) $4680 Minimum cost for any single segment.

2) Base cost assumed pipe segemnts to be purged would average 10 mi sections. Additional setup cost of 2 hours for equipment & crew is required for the higher sections because of the number of crossings to be isolated and filled with grout. The additional setups required for the northern system is 470 and 111 for the Common facilites @ $720 per setup.

3) Nitrogen purging costs were developed in consultation with UCISCO a subsidiary of Praxair who provides this service to pipeline companies on a regular basis.

Nitrogen Purging By Line Size Per Mile						
	42"	36"	30"	20"	16"	12"
Nitrogen	$1,463	$1,077	$740	$328	$206	$128
Pumper	$80	$63	$43	$29	$20	$14
Labor	$109	$85	$58	$40	$28	$19
Equipment Transport	$48	$38	$26	$18	$12	$9
Pumper Transport	$30	$30	$30	$30	$30	$30
Nitrogen Transport	$608	$486	$334	$230	$158	$108
Compliance Surcharge	$9	$6	$4	$3	$2	$1
Per Diem	$12	$12	$12	$12	$12	$12
Total	$2,358	$1,797	$1,247	$690	$468	$321

Remove and Cap Pipeline Taps			8/21/2003
	# of Taps	Cost/Tap	Total
Northern System	28	$13,000	**$364,000**
Jointly Owned	32	$13,000	$416,000
KRGT Portion @ 68.448%			**$284,744**
Total Tap Removal Cost			**$648,744**

Note: Cost based on a small tie-in crew removing a tap in three days.

		Remove Pig Launchers/Receivers		8/13/03
System	**Size**	**Quantity**	**Cost Each**	**Total**
KRGT 36"	36"	36	$48,600	$1,749,600
Opal Lateral	30"	2	$44,550	$89,100
Whitney Canyon	20"	2	$37,100	$74,200
High Desert	24"	2	$41,600	$83,200
Big Horn	12"	2	$29,700	$59,400
Moapa	16"	2	$33,400	$66,800
Sub-Totals		**46**		**$2,122,300**
Common System	42"	6	$52,700	$316,200
KRGT Portion @ 68.448%				$217,700
	Total Removal Cost			**$2,340,000**

Note: 1) Cost based on consultation with Gregory & Cook, a pipeline contractor very familiar with this work and one of the prime contractors on the KRGT 2002-03 expansion

Abandonment of Cathodic Protection Systems Surface Facilities						
Faciltiy		**Quantity**	**Unit Cost**	**Total**		
Test Sites		1340	$600	$804,000		
Ground Beds		31	$2,000	$62,000		
Sub-Total				**$866,000**		
Common Facilities						
Test Sites		301	$600	$180,600		
Ground Beds		4	$2,000	$8,000		
Sub-Total				**$188,600**		
KRGT Portion @ 68.448%				**$129,093**		
Total				**$995,093**		

Notes:

1) Unit cost estimates were based on two person crews removing 2 to 3 surface facility sites per day for test sites.
2) Unit cost estimates were based on two person crews removing 1 to 2 surface faciliity sites per day for ground beds.
3) There is a test site every mile on the pipeline. There are 19 Mainline Ground beds and 1 at every compr station except Muddy Creek and Fillmore where there are two. It is extimated that there are four ground beds on the common facilites.

Pipeline Inspection Costs - Based on Monthly Crew Costs			8/13/2003
Chief Inspector		$11,696	
Field Accountant/Materialman		$10,963	
(4) Inspectors		$43,852	
	Total	**$66,511**	
Equivalent Crew Months			**Cost**
	Pipeline Evacuation	1.5	$99,766.50
	Pipeline Cleaning	12.0	$798,132.00
	Nitrogen Purging &Crossings	24.0	$1,596,264.00
	Remove Aboveground Piping & Appurtenances	4.0	$266,044.00
	Sub-Total		**$2,760,207**
Common Facilities			
Equivalent Crew Months			
	Pipeline Evacuation	0.5	$33,256
	Pipeline Cleaning	3.0	$199,533
	Nitrogen Purging &Crossings	6.0	$399,066
	Remove Aboveground Piping & Appurtenances	1.0	$66,511
	Sub-Total		**$698,366**
KRGT Portion @ 68.448%			$478,017
Total Cost			**$3,238,224**

Note: 1) Inspection costs based on rates paid through Quality Inspection Service, the company used for the Kern River 2002-03 expansion.

Salvage Value		8/13/2003
	Quantity	**Total**
Scrap Pipe	270	$16,200
Valves	230	$57,500
Sub-Total		**$73,700**
Common Facilities		
Scrap Pipe	1469	$367,250
Valves	74	$18,500
Sub-Total		**$385,750**
KRGT Portion at 68.448%		$264,038
Total Pipe/Valve Salvage		**$337,738**

Notes: 1) The salvage value used for valves is $250 each.

2) The salvage value used for pipe is $60 per ton

Updated 8/6/03

Pipe Sizes	**Length Miles**	**Volume Cubic Feet**
36"		
Original	634.3	22,365,154
Expansion II	684.6	24,138,711
Total	1318.9	46,503,864
30"	6.0	147,756
20"	13.0	138,658
12"	2.0	8,290
Sub-Total KRGT	1339.9	
Common Facilities		
42"		
Original	137.9	6,669,842
Expansion II	82.4	3,986,906
Total	220.3	10,656,749
30"	70.5	1,736,621
16"	6.4	46,938
12"	4.1	16,869
Sub-Total Common	301.2	
Total Miles	1641.1	59,255,745

<u>Kern River Gas Transmission Net Salvage Value</u>
August 2003
Abandonment of Compression Facilities

Any materials that are salvaged will not be reconditioned before they are sold. The contractor disassembling the station facilities will lift, load and transport material from the station site. The estimate includes the cost of freight to an off site salvage dealer. All metal scrap will be valued at $60 per ton regardless of whether it is carbon steel, copper, stainless steel, etc. All equipment and materials, regardless of actual age, can no longer perform their intended functions without major refurbishment by the new user. This also applies to all new spare parts currently stored at the site. Station equipment will be valued at 3% of original value because of significant obsolescence and years of service. All salvage values will be based on a percent of the original plant value of the equipment at the time it was installed and not the current purchase price for new equipment of the same type. All tools, work equipment, furniture, communications will be considered "General Plant " and not be assigned a salvage value, nor a removal cost.

Demolition drawings will be prepared for use by the demolition contractors, by shading or cross hatching existing drawings, and adding minor bills of materials, where necessary.

The amount of line pack gas inside a station is minimal and will be given zero value since it will be blown to the atmosphere. On-site water wells will be capped at the surface but not plugged down hole. All pumps and derricks aboveground will be removed. None of the existing yard gravel will be picked up nor hauled off site. No reseeding of any of the ground surface is planned. Foundations extending over a foot above grade will be removed (i.e. pipe supports, yard equipment supports, etc.). The main compressor building and control building foundations will be left in place at floor level. Any pits will be filled with sand to eliminate a safety hazard.

All hazardous liquid wastes that must be disposed of off-site will be at a cost of $1.00 per gallon, no matter what the fluid is (i.e. oil, glycol, hydrocarbon condensate, etc). This includes both new and used fluids. An average quantity, for all fluids combined, is approximately 2,500 gallons per compressor unit.

A typical Kern River compressor station was analyzed to determine what and how the facilities would be abandoned or removed in relation to its original cost. Using this methodology the abandonment cost will be estimated to be 5.6% of the total plant cost. (See page 32.)

8/23/2003

Abandonment of Compressor Stations Summary			
Final Abandonment			
Removal Cost [1]			$4,746,816
Misc Sales & Use Taxes [2]			$15,664
Project Management [3]			$379,745
Engineering Design & Drafting [4]			$237,341
FERC 7B Filing & Permitting [5]			$94,936
Inspection [6]			$98,124
Overhead @ 8%			$379,745
ROW Cost for Sale of Property [7]			$0
TOTAL			$5,952,372
Credit for Scrap Material Revenue [8]			($82,222)
Credit for Sale of Land [9]			$0
Credit for Salvaged Equipment [10]			($1,440,998)
	Sub-Total		**($1,523,220)**
TOTAL Final Abandonment Costs			**$4,429,152**
Interim Abandonment			
Removal Cost [1]			$14,943,087
Misc Sales & Use Taxes [2]			$49,312
Project Management [3]			$1,195,447
Engineering Design & Drafting [4]			$747,154
FERC 7B Filing & Permitting [5]			$298,862
Inspection [6]			$970,920
Overhead @ 8%			$1,195,447
ROW Cost for Sale of Property [7]			$148,800
TOTAL			$19,549,029
Credit for Scrap Material Revenue [8]			($258,836)
Credit for Sale of Land [9]			($1,407,810)
Credit for Salvaged Equipment [10]			($4,536,294)
	Sub-Total		**($6,202,940)**
TOTAL Final Abandonment Costs			**$13,346,089**
TOTAL Abandonment Costs			**$17,775,241**

Notes: 1) See page 29 for removal costs.

2) Miscellaneous Sales & Use Tax of 6.6% represents an approximate average over the four state area of KRGT's facilites and was applied to 5% of the sub-total of direct costs that would be subject to this tax.

3) Project Management of 8% represents Nothwest Pipeline's past experience (per 1996 study) and was applied to the sub-total of direct costs.

4) Design and drafting for the preparation of abandonment drawings was calculated to be 5% of the sub-total direct costs which is half of the rate to complete a new design.

5) The portion of the FERC 7B filing and permitting cost allocated to compression was calculated at 3% of the sub-total direct costs.

6) See page 30 for inspection costs.

7) Right-of-way costs for the sale and relinquishments of sites that includes realtor fees, title work and legal fees.

8) See page 29 for scrap material revenue.

9) See page 31 for sale of land values.

10) See page 29 for salvaged equipment.

Itemized Compressor Station Removal Costs				
Station	Original Book Value	Scrap Revenue	Salvage Revenue	Removal Costs
Compressor Stations				
Final Abandonment				
Muddy Creek	$84,764,570	$82,222	$1,440,998	4,746,816
Interim Abandonment				
Painter	$16,368,726	$15,878	$278,268	916,649
Anschutz	$4,662,193	$4,522	$79,257	261,083
Coyote Creek	$22,359,752	$21,689	$380,116	1,252,146
Salt Lake City	$31,997,917	$31,038	$543,965	1,791,883
Elberta	$31,857,917	$30,902	$541,585	1,784,043
Fillmore	$42,234,878	$40,968	$717,993	2,365,153
Veyo	$20,272,860	$19,665	$344,639	1,135,280
Dry Lake	$26,542,529	$25,746	$451,223	1,486,382
Good Springs	$51,096,206	$49,563	$868,636	2,861,388
Daggett 1)	$19,447,853	$18,864	$330,614	1,089,080
Sub-Total	**$266,840,831**	**$258,836**	**$4,536,294**	**14,943,087**
Total	**$351,605,401**	**$341,057**	**$5,977,292**	**19,689,902**

Notes: 1) Property accounting records used represent KRGT portion of the Daggett Compressor Station

8/21/2003

Compressor Inspection Costs			
Lead Inspector		$	11,392
Field Accountant		$	10,658
Utility Inspector		$	10,658
Total Crew Cost Per Month		**$**	**32,708**
Final Abandonment		$	98,124
Interim Abandonment		$	981,240
Total Inspection Costs [2)]		**$**	**1,079,364**
Reduction for Mojave portion			
of Daggett		$	10,320
Net Interim Inspection Costs		**$**	**970,920**

Notes:

1) A total of 33 inspection crew months would be required to complete the abandonment.

2) Total inspection costs are calculated by multiplying the monthly cost by 33 crew months. The inspection rates are based on the rates paid through QIS for the KRGT 2002-03 expansion

8/23/2003

Compression Station Land Values		
Compression Station Facilities CS	**Size (acre)**	**Value ($)**
Fillmore	31	11,635
Elberta	125	20,835
Salt Lake City	30.45	1,202,081
Daggett	135	173,259
	321	**1,407,810**

Note: 1) Land values obtained from Kern River right-of-way staff were reduced by 25% because of the underground facilities that would be left in place encumbering the land

2) The value of Daggett represents KRGT 68.448% share.

Compressor Station Removal Cost Salt Lake Compressor Station			8/13/2003
Disassemble Buildings	$168,400	75% OF INSTALL	
Remove Turbine Equipment	$87,000	100% OF INSTALL	
Remove Other Station Equipment	$102,000	100% OF INSTALL	
Remove Above Ground Piping			
High Pressure Unit Piing	$243, 300	40% of INSTALL	
High Pressure Yard Piping	$336,500	20% of INSTALL	
Fill Underground Headers	$168,250	10% of INSTALL	
Remove Utility Piping	$129,500	40% of INSTALL	
Remove Electrical and Instrumentation	$218,600	20% of INSTALL	
Remove Above Grade Foundations	$203,700	40% of INSTALL	
Dust Control/soil & sed Control	$125,803	50% of INSTALL	
Fill Pits with Sand	$53,900	10% of INSTALL	
Dispose of Liquids	$5,000	2500 Gal per Unit @$1.00 per Gallon	
Sub-Total	$1,598,653		
10% Misc	$159,865		
Total	$1,758,518		
Removal as a % of Total Cost = 1,759,343/31,638,829 or		**5.6%**	
Revenue from Salvage as a % of Total = 3% of 17,492,501/31,638,829 or			**1.7%**
Revenue from scrap as a % of Total = 1.5% of 50% above grade 4,102,278 or			**0.097%**

Note: 1) An analysis of the abandonment of the recently installed Salt Lake Compressor Station was used to develop the percentages that would be applied to other station total costs for removal, salvage and scrap costs for all of the KRGT stations.

Kern River Gas Transmission Net Salvage Value
August 2003

Abandonment of Measurement Facilities

The costs for abandonment of measurement facilities are for the removal of the 72 receipt and delivery meters throughout the system. All surface facilities would be removed and the fee land would either be sold or returned to the surrounding landowners. A credit would apply for marketable land where it was required in the past to purchase a large piece of property for a much smaller meter station. At many locations, where the purchased property was only the small amount required for the station and the property is not marketable, the land would be returned to the surrounding landowner.

The majority of the equipment and material would only have scrap value due the time of service and obsolescence.

In order to estimate the removal costs, a 1996 Northwest Pipeline study was used that consulted with Snelson Companies, a contractor that has done this type of work for gas pipelines in the Northwest. The abandonment of each facility would meet the requirements of DOT CFR Part 192.727, Abandonment or Deactivation of Facilities.

Based on the age and size of the station, a credit was estimated for the salvage value of material removed from each site.

Abandonment of Meter Station Facilities Summary							
Retirement Costs						$5,625,520	
				Sub-Total of Direct Costs		**$5,625,520**	
Misc Sales & Use Tax 5)						$18,564	
Project Management 6)						$450,042	
Engr Design & Drafting 7)						$281,276	
Inspection 8)						$545,084	
FERC 7B Filing & Permitting 9)						$112,510	
Overhead @ 8% 10)						$450,042	
ROW Cost for Sale/Relinquishment of Property 11)						$62,219	
				Sub-Total		**$7,545,257**	
Credit for Salvaged Material 12)						$707,476	
Credit for Sale of Land 13)						$0	
				Sub-Total		**$707,476**	
Total Abandonment Costs						**$6,837,781**	

Notes:

1) The costs for abandonment of measurement facilities is for the removal of the 72 (41 KRGT and 31 common facilities) receipt and delivery meters throughout the system.
2) The demolition costs are based on a previous 1996 study by Northwest Pipeline that consulted with Snelson Companies, a contractor that has done this type of work before.
3) The abandonment of each facility would meet the requirements of DOT CFR Part 192.727, Abandonment or Deactivation of Facilities.
4) A credit was calculated for the salvage value of material removed from each site.
5) Miscellaneous Sales & Use tax of 6.6% represents an approximate average over the four state area of KRGT's facilities and was applied to 5% of the sub-total of direct costs that would be subject to this tax.
6) Project Management of 8% represents Northwest Pipeline's past experience (per 1996 study) and was applied to the sub-total of direct costs.
7) Design and drafting for the preparation of abandonment drawings and related documentation was calculated to be 5% of the sub-total direct cost which is half of the rate to complete a new design.
8) Inspection costs were based on one inspector at a site where the work would take up to 20 average days per site.
9) The portion of the FERC 7B filing and permitting cost allocated to measurement was calculated at 2% of the sub-total direct costs.
10) A coporate overhead rate of 8% is applied to the sub-total of direct costs.
11) Right-of-way costs for the relinquishments of sites that includes damages, title work and legal fees (Cost adjusted for Kern River's portion of common facilities).
12) See Schedule ___ for Salvage Material costs.
13) See Schedule ____ for Land Values.

Measurement Facility List of Costs			8/13/2003
Meter Station Name	Total Plant On Books	Salvage Value of Materials	Cost to Remove Above Ground Facilties
Round Mountain	$106,395	$1,064	$8,299
West Valley	$770,539	$7,705	$60,102
Daggett	$10,304,302	$103,043	$803,736
Opal	$6,199,725	$61,997	$483,579
NWPL/Muddy Crk	$1,814,472	$18,145	$141,529
Harry Allen	$1,328,576	$13,286	$103,629
Hunter Park	$861,848	$8,618	$67,224
PG&E - Daggett	$1,676,018	$16,760	$130,729
Questar - Roberson Creek	$866,141	$8,661	$67,559
Whitney Canyon	$1,264,185	$12,642	$98,606
Carter Creek	$1,269,645	$12,696	$99,032
Painter	$1,266,661	$12,667	$98,800
CIG Muddy Creek	$726,497	$7,265	$56,667
Union Pacific	$953,671	$9,537	$74,386
Anschutz	$1,171,631	$11,716	$91,387
Apex	$1,163,703	$11,637	$90,769
Lone Mountain	$1,183,143	$11,831	$92,285
Pecos	$521,331	$5,213	$40,664
Wecco	$501,684	$5,017	$39,131
Fillmore	$386,061	$3,861	$30,113
Milford	$361,829	$3,618	$28,223
Dog Valley	$504,769	$5,048	$39,372
New Castle	$284,558	$2,846	$22,196
Central	$402,237	$4,022	$31,374
Holden	$233,450	$2,335	$18,209
Scipio	$182,058	$1,821	$14,201
Blue Diamond	$1,443,495	$14,435	$112,593
Eagle Mountain	$6,291,625	$62,916	$490,747
Kramer Junction	$1,754,377	$17,544	$136,841
Arrolime	$1,126,628	$11,266	$87,877
Bighorn	$1,121,032	$11,210	$87,440
Centennial	$739,788	$7,398	$57,703
Clear Creek	$1,017,724	$10,177	$79,382
La Paloma - Cancelled	$0	$0	$0
Primm	$233,301	$2,333	$18,197
Sidewinder	$1,170,635	$11,706	$91,310
Riverton	$1,263,738	$12,637	$98,572
Coalville	$296,466	$2,965	$23,124
Chevron/ColumbiaTennT	$464,444	$4,644	$36,227
Goshen	$1,736,571	$17,366	$135,453
Roberson Creek	$1,850,000	$18,500	$144,300

Common Facilites			
Freemont Peaks	$1,855,066	$18,551	$144,695
Wheeler Ridge	$1,431,201	$14,312	$111,634
Tehachapi-Cummings	$426,368	$4,264	$33,257
Taft	$292,767	$2,928	$22,836
Texaco 17Z	$289,539	$2,895	$22,584
Sycamore	$247,980	$2,480	$19,342
South Midway	$289,933	$2,899	$22,615
Shell 17Z	$289,539	$2,895	$22,584
Kern Santa Fe	$215,768	$2,158	$16,830
SE Kern River	$216,302	$2,163	$16,872
Racetrack	$542,442	$5,424	$42,310
Oxford	$292,790	$2,928	$22,838
North Midway	$292,790	$2,928	$22,838
North Kern River	$216,302	$2,163	$16,872
Mt. Poso	$216,687	$2,167	$16,902
Mobile 17Z	$289,539	$2,895	$22,584
Midway Midset	$292,790	$2,928	$22,838
McKittrick	$289,539	$2,895	$22,584
Midway Santa Fe	$292,790	$2,928	$22,838
Kern River - Chevron	$216,837	$2,168	$16,913
Kern Front	$638,602	$6,386	$49,811
Granite	$3,277	$33	$256
Crocker Springs	$292,790	$2,928	$22,838
Coolwater	$456,693	$4,567	$35,622
Chevron 17Z	$289,539	$2,895	$22,584
China Grade	$216,302	$2,163	$16,872
Boron	$303,455	$3,035	$23,669
Bear Mountain	$477,298	$4,773	$37,229
Victorville	$3,628,169	$36,282	$282,997
Grapevine 6)	$215,000	$2,150	$16,770
Oxy 17Z 6)	$289,000	$2,890	$22,542
TOTALS	**$72,122,047**	**$721,220**	**$5,625,520**

Notes: 1) Reimbursed meters station facilties are included since it will be Kern River responsibility to abandon these facilties.

2) Based on previous studies by Northwest Pipeline in 1996 the cost to remove and abandon a meter site is approximately 7.8% of the total station cost. This cost was based on consultation with Snelson Companies, a contractor who had experience doing this work.

3) All of the material and equipment removed is expected to have junk or scrape value. This value is estimated to be 3% of the total material cost or 1% of the total plant cost since material represents approximately 33% of the total plant cost.

4) Property accounting records shows Kern River share of jointly owned facilites.

5) There were no meter stations sites greater than 1 acre owened in fee. The six fee sites that were identified would revert back to surrounding land owners and would have no sales revenue.

6) The cost for these meter stations was not broken out separately in the property records so the total plant cost was estimated based on similar facilies in the same area of the pipeline.

Meter Station Facility Values			8/13/03
Meter Station Facilities (MS)	**Size (acre)**	**Current Value($)**	**Original Cost ($)**
Fillmore MS	0.301	$0	$1,827
Holden MS	0.314	$0	$1,819
Scipio MS	0.329	$0	$1,569
Dog Valley MS	0.339	$0	$2,335
Newcastle MS	0.309	$0	$2,346
Goshen MS	0.57	$0	$10
		$0	$9,906

Note: 1) Land parcels under one acre would revert back original landowners at no cost because the land would be encumbered with the underground facilities.

Meter Station Abandonment Inspection						8/8/2003
Northern Facilities (41)			**Cost/Day**	**Days**	**Total**	
Utility Inspector			$350.43	615	$215,514	
Field Accountant/Material Handler			$350.43	410	$143,676	
Sub-Total					**$359,191**	
Common Facilities (31)						
Utility Inspector			$350.43	465	$162,950	
Field Accountant/Material Handler			$350.43	310	$108,633	
Sub-Total					$271,583	
KRGT Portion of Cost @ 68.448%					**$185,893**	
Total Meter Station Inspection Cost					**$545,084**	

Note: 1) One inspector at a site an average of 15 days per site and
Field Accountant/Material Handler at a site an average of 10 days per site

2) Inspection cost based on the rates paid through Quality Inspection Services, the company used during Kern River's 2002-03 expansion project.