HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

DOCKET NO. RP06-___

STATEMENT P
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HIGH ISLAND OFFSHORE SYSTEM
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Exhibit No. HIO-65

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, L.L.C.) **Docket No. RP06-**

Prepared Direct Testimony
of
Richard W. Porter

Q. Please state your name and business address.

A. My name is Richard W. Porter. My business address is 1100 Louisiana Street, Houston, Texas 77002.

Q. By whom are you employed and what are your responsibilities?

A. I am employed by Enterprise Products Partners ("Enterprise"), as Director of Rates and Regulatory Affairs. My responsibilities for High Island Offshore System, L.L.C. and other natural gas pipelines owned by Enterprise, include the oversight of the preparation of rate cases, including computation of the cost of service and rates associated with proceedings before the Federal Energy Regulatory Commission ("FERC").

Q. Please describe your educational background and work experience.

A. I graduated from Louisiana State University in 1976 and was awarded a Bachelor of Science degree with a major in Economics. From 1976 to 1979, I was employed by Allied Bank of Texas in the Trust Department. Since 1979, I have been employed in turn by Panhandle Eastern Pipeline Company, Arkla Energy Resources, Inc and ANR Pipeline Company ("ANR") in their rates and regulatory departments. During these years, my responsibilities included, a) the preparation of rate cases, including cost of service and rate design analyses, b) the preparation of certificate applications, and c) the intervention in and analysis of certificate applications and general rate filings of other interstate pipelines.

Q. What responsibilities have you had in connection with HIOS?

A. In 1992, when HIOS was affiliated with ANR, I was appointed head of the HIOS Rate Committee, a position I held until the abolition of the committee in 2001. In that capacity I prepared and oversaw the preparation of all HIOS rate cases since 1992, various tariff and tracker filings, as well as restructuring under Order Nos. 636 and 637. Since elimination of the committee, I have continued to manage the regulatory matters of HIOS. Currently I am responsible for coordinating and directing all rate and regulatory matters and also charged with making regulatory recommendations to HIOS management.

Q. Have you previously provided testimony in proceedings before the FERC?

A. Yes, I have sponsored testimony on behalf of various interstate pipelines before this Commission on several occasions.

Q. What is the purpose of your testimony in this proceeding?

A. First, I will identify the various HIOS witnesses and describe the issues included in their individual testimonies. Second, I will describe the reasons that HIOS is filing for a rate increase at this time, and why the amount of the increase is necessary. Then I will explain the basis for the proposed treatment of the annual expense incurred pursuant to the 36 month maintenance plan that has been established under the operating agreement that HIOS has in place. Next I will explain the basis for the economic life which is used to calculate the annual depreciation and negative salvage expense. I will also explain the basis for the capital structure that is used to calculate the overall rate of return, which is in turn used to calculate the management fee. Then I will explain why the return on equity proposed by HIOS is appropriate. After that, I will explain the purpose, justification and derivation of the management fee that HIOS is proposing. Finally, I will explain the need for enhancements to HIOS's transportation services to encourage efficient contracting by future shippers, and to promote revenue stability. In that regard, I am sponsoring the tariff sheets filed with this case that propose changes to the Rate Schedules and General Terms and Conditions under HIOS's FERC Gas Tariff.

Q. Who are the HIOS witnesses and what parts of the rate case are they supporting?

A. The table below is a list of the HIOS witnesses and a general description of their areas of testimony.

Witness	Description of Testimony
Richard W. Porter	Purpose of Filing, Treatment of Annual Expense From 36 Month Maintenance Plan, HIOS Economic Life, Rate of Return on Equity, Calculation of Management Fee, Service Agreement Enhancements and Proposed Tariff Changes
Leslie V. Pagels	Business Risk, Operating Agreement
Deborah E. Kwan	Total Cost of Service, Rate Base, Gas Plant, Depreciation Expense
Joan F. Collins	O&M Expenses, Income Taxes, Taxes Other Than Income Taxes
J. Scott Jenkins	Remaining Reserves Life
Robert C. Byrd	Negative Salvage

Steven J. Gaske	Rate of Return, Management Fee
Ronald A. Fulcher	Test Period System Throughput
Jeffrey M. Molinaro	Gas Balance, Cost Allocation and Rate Design, Base and Test Period Revenues, Other Revenues

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. I am sponsoring the following exhibits in support of my testimony:

Exhibit No.	Description of Exhibits
HIO-66	HIOS Economic Life
HIO-67	Calculation of Management Fee Using Modified Tarpon Method
HIO-68	Billing Examples for Proposed Revisions to Rate Schedule FT-1
HIO-69	Billing Examples for Proposed Revisions to Rate Schedule FT-2
HIO-70	Billing Examples for Proposed Rate Schedule FT-3
HIO-71	List and Description of Revised Tariff Sheets

Purpose of the Filing

Q. Please explain the purpose of the filing.

A. HIOS is filing this rate increase because of the dramatic cost increases and throughput decreases that have occurred on the pipeline since implementation of the rates from the last rate case in Docket No. RP03-221. During the base period HIOS's transportation revenues totaled $3.0 million less than the authorized revenue requirement. Furthermore, HIOS projects that its annual operating expenses will increase to $31.7 million, or $12 million more than the $19.7 million of operating expenses accepted by the Commission in the previous rate case. In addition, total cost of service is expected to increase to $42.5 million, or $18.9 million more than the $23.6 million in total cost of service authorized in the last rate case. Finally, HIOS projects that throughput will fall to 408 MMDth per day, or more than 301 MMDth below the 709 MMDth per day used to design rates in the previous case. If HIOS does not increase its rates, by the end of the test period, annual revenues will be approximately $13.7 million, or only 43% of fixed operating expenses. HIOS cannot continue to operate when it fails to recover nearly 60% of fixed operating expenses. In addition, through its proposed Management Fee, HIOS seeks to obtain a sufficient economic cushion to manage future disruptions to its revenue stream, and to be able to continue operating its pipeline system as a viable business entity. At the present time, under currently effective rates, HIOS's revenues are less than its operating expenses, and the operation of the pipeline fails to generate any income for the owners.

Q. Why do HIOS's current rates not provide the cost coverage and investor return that it requires?

A. In December 2002, HIOS filed a rate case, in Docket No. RP03-221, in accordance with the terms of the settlement from the previous rate case, and proposed to increase its transportation rates from the then-effective 12.44¢ per Dth, to 17.59¢ per Dth. As part of that filing HIOS proposed to include, as part of a total cost of service of $35.6 million, a management fee of $9.6 million. This management fee was intended in part to provide an economic cushion that would protect HIOS in the event of unexpected increases in costs or decreases in throughput. In my testimony filed in that proceeding, I explained the significant risks that HIOS faced, and why such an economic cushion was necessary. However, following a hearing, the Initial Decision recommended that HIOS should be granted a management fee of only $0.7 million, and that rates should be designed on a total cost of service of approximately $22.2 million (versus the as-filed amount of $35.6 million), and on average daily throughput of 709,000 Dth per day (versus the filed amount of 561,000 Dth per day). This combination produced a transportation rate of only 8.56¢ per Dth.

Q. Did that rate go into effect?

A. No. Subsequent to the hearing, HIOS filed a settlement of all issues in the rate case with the Commission. A key feature of the settlement was the retention of the previously effective transportation rate of 12.44¢. Such a rate would have provided HIOS with a larger revenue cushion to absorb fluctuations in cost and throughput. For example, even though HIOS's actual volumes during the base period in this case were 168,000 Dth per day lower than the design volumes in the last case, HIOS would have received $6.4 million per year in additional revenues if the higher settlement rates had been implemented. As demonstrated by this new rate case application, even that incremental revenue would not have been adequate given the dramatic increases in costs and the decreases in throughput that HIOS has subsequently experienced, although it would have mitigated the increase which HIOS is now forced to seek.

Q. Was the settlement approved?

A. No. The Commission rejected the settlement. As part of the order rejecting the settlement, the Commission largely approved the Initial Decision. However, the Commission did increase the Management Fee by $1 million to $1.7 million, and consequently the rate from 8.56¢ to 9.18¢. Still, this minor adjustment did not provide the cost coverage or economic cushion that HIOS needed, as subsequent events have proven.

Q. What has happened on HIOS since the implementation of the Commission's order?

A. HIOS has experienced an unprecedented increase in costs and an equally significant decrease in throughput, even beyond those levels it projected in the last rate case. For example, total annual transportation revenues during the base period were only $20.6 million or approximately $3.0 million less than the $23.6 million revenue requirement, i.e., cost of service, established by the Commission in Docket No. RP03-221. Furthermore, non-controllable costs have increased in 2006, and in particular HIOS received notice that effective May 1, 2006, its insurance premiums would increase by more than $6.0 million per year, or over 500%. This increase was a result of the 2005 hurricane season when Hurricanes Katrina and Rita devastated offshore facilities in areas where HIOS is located.

Q. Please describe the throughput decrease.

A. HIOS never came close to achieving the design throughput of 709,000 Dth per day utilized by the Commission in the last rate case. In fact, HIOS did not even achieve the average daily throughput of 561,000 Dth per day that it supported in its as-filed case. Rather, as the base period data shows, during the period of time that the previously ordered rates have been in effect, HIOS' average daily throughput has been approximately 541,000 Dth per day.

Q. Specifically, what is HIOS seeking in this filing?

A. HIOS is proposing a total cost of service of approximately $42.5 million, and a basic, firm service transportation rate of 29.28¢ per Dth. HIOS believes that this rate appropriately accounts for the two main issues that it seeks to address in this case. First, HIOS must have a cost of service that permits it to fully recover the operating costs of the system. Second, the cost of service must be adjusted to provide a management fee that is high enough to compensate the owners sufficiently for the ongoing risk of continuing to operate the system, and to provide an adequate economic cushion to manage future fluctuations in cost and throughput.

Treatment of Annual Expense
From
The 36 Month Maintenance Plan

Q. How does HIOS propose to treat the expense associated with the 36 month maintenance plan?

A. As explained by HIOS Witness Leslie V. Pagels, every 3 years, the Operator of the HIOS system provides HIOS with a 36 month maintenance plan, which includes the cost of implementing that plan. This is in addition to an annual operations and maintenance program as well as unplanned non-routine operations and maintenance activities. Upon approval and implementation of the most recently approved plan, HIOS will pay a fixed monthly fee equal to 1/36th of the plan cost. In January of 2007, when the plan becomes effective for the years 2007 through 2009, HIOS will pay the first of 36 monthly payments. Thus, each year HIOS will incur an annual expense equal to 1/3 of the total cost of the plan. I, therefore, have instructed HIOS witness Collins to include a full year of expense in Account 923, which she explains in her adjustment number 5 to operating expenses. HIOS will actually be incurring these monthly expenses by the close of the test period, and the ongoing incurrence of these expenses is both known and measurable, as HIOS is contractually obligated to make these ongoing monthly payments.

Q. What is the justification for the proposed treatment of this expense?

A. HIOS Witness Pagels explains that the goals of adopting a longer planning horizon with the Operator are to ensure the integrity of the pipeline and to enhance HIOS's ability to control costs over the long run. HIOS is at a stage in its existence where there are a number of long-term operations and maintenance expenditures that are required. Accordingly, HIOS and the operator agreed that it would be prudent to plan and budget for those expenditures required on a longer-term horizon. This provides cost stability to HIOS and a long-term plan to manage foreseeable, but non-routine, maintenance expenses. While HIOS and the operator have amended the operating agreement consistent with these goals, unless HIOS receives full cost of service and rate treatment of this known and measurable expense, its options will be limited. Absent full recovery of the cost included in the budget, HIOS will be forced to decide between a minimum of ongoing maintenance and the continued operation of the system at a loss. It is imperative that the annual cost of the 36 month maintenance plan be included in HIOS's cost of service, to allow this necessary work to be done on the HIOS system.

Economic Life Used to Calculate
<u>Annual Depreciation and Negative Salvage Expense</u>

Q. Do you believe that the reserves life estimate provided by HIOS Witness Jenkins is representative of the economic life of this asset?

A. No, I do not. Like any prudent business operator, HIOS cannot continue to operate the system beyond a time when revenues are no longer sufficient to cover the ongoing costs of operation and to provide a return on investors' equity interest in the asset. Given the projections of declining throughput, and therefore the anticipated declining revenues, this means that there is an economic life to the operation of HIOS. As a result, the management of HIOS needs to make a reasonable assessment of when this "cross-over" point will occur. For this purpose, I believe that the appropriate analytical approach is to examine the future throughput projections taking into consideration proven and probable reserves attached, or that might be attached in the future, to the system. For example, I am aware that under SEC reporting requirements, offshore producers are required to disclose the level of their proven reserves as a reasonable benchmark for investors to make an informed decision on the level of their investment risk. By applying an analogous approach, I have attempted to assess the economic life of the HIOS system, taking into consideration the declining throughput from proven and probable reserves attached, and new speculative supplies that might be attached to the system in the future.

Q. What were the factors that you applied to determine this estimated economic life of HIOS?

A. The estimated economic limit on the operation of HIOS was calculated to be a minimum necessary flow of 279 MMcf/d based on annual operating expenses of $31.7million, a recourse rate of 29.00¢ per dekatherm, and an average Btu content of 1075 Btu/Mcf, and which can be calculated as ($31.7/29.00¢/365 days/1.075Btu)*1000 = 279 MMcf/d). In other words, 279 MMcf/d is the average volume which must be transported by HIOS, at a 29.00¢ average transportation rate, to recover HIOS's filed annual operating costs and provide a return through the management fee.

Q. What did you determine to be the economic life of HIOS based on these parameters?

A. Exhibit No. HIO-66 identifies the estimated decline in throughput from the proven and probable reserves attached to HIOS, and new, speculative supplies that could be attached in the future. This information was provided to me by HIOS Witness Jenkins. I then plotted the time when production volumes would decline below the required minimum level of 279 MMcf of daily throughput described above. This shows that the estimated production of those volumes will decline to the economic limit of 279 MMcf/d by the end of 2012, representing a 6-year economic life for HIOS. I would note that this estimate may even be optimistic, since it includes deepwater reserves that may be potentially connected to HIOS, and thus are highly speculative. HIOS Witness Jenkins provides studies that demonstrate that some quantities of natural gas will be available for transportation on HIOS for a period ranging from 8 to 19 years. Since my calculation of the economic life supports a 6 year remaining life, HIOS could justifiably support a 6 year remaining life. However, as the Commission has a preference for supporting remaining life with a reserve life study, for purposes of this filing I have instructed HIOS Witness Kwan to use the low end of Witness Jenkins' range, or 8 years, for purposes of calculating annual depreciation and negative salvage expense.

Rate of Return on Equity

Q. Why has HIOS chosen a 14.04% return on equity in this case?

A. HIOS Witness Gaske has shown that the range of return on equity applicable to the proxy group of companies is 11.97% to 16.24%, with a median of 14.04%. Based on the significant business risks faced by HIOS, as outlined by HIOS Witness Pagels, including the high probability of continued steep declines in throughput and the remote possibility of attaching new deepwater reserves, an appropriate return on equity for HIOS could be set at the higher level of the return range. Indeed, given the fact that HIOS is not even able to recover its current operating expenses, and given the fact that HIOS has virtually no firm capacity subscriptions and therefore almost totally at risk of achieving a substantial portion of its design throughput in order to recover its ongoing cost of operation, HIOS would justify a rate of return that even exceeds the range of returns developed by Mr. Gaske. As I have noted above, I have been involved in reviewing the HIOS pipeline system for over 15 years now, and its financial situation is more precarious than it has ever been, and a return on equity in the high end of the range is clearly justified. However, as the Commission has a historical preference for establishing the return on equity at the midpoint of the proxy group range, in the interest of obtaining an expeditious resolution of this application given HIOS's financial situation, I have instructed HIOS Witness Kwan to calculate the overall rate of return using the median return on equity of 14.04%.

Q. Does your recommended rate of return depend upon the level of the management fee base that is established?

A. Absolutely. As I explain below, a management fee must be high enough to provide an opportunity to collect adequate revenue to provide sufficient cash flow to deal with extraordinary items, and to provide a financial incentive for the equity owners to continue operating the system. To accomplish this critical goal, the rate of return and the level of the management fee are inextricably linked to each other. If the Commission reduces the management fee base I am proposing, then my recommended rate of return needs to be increased by a commensurate amount to ensure that the management fee achieves its fundamental purpose.

Calculation of the Management Fee

Q. Is HIOS proposing a return on rate base in this case?

A. The HIOS system is fully depreciated and therefore for purposes of setting rates in this case, HIOS's rate base is zero. Since a pipeline's return and associated income taxes are directly related to its remaining rate base under the Commission's traditional ratemaking methodology, this zero rate base produces neither a return allowance nor a related income tax allowance for the cost of service.

Q. Why does HIOS project a rate base of zero as of the end of the test period?

A. Various factors produce this outcome on HIOS's projected rate base. First, the original HIOS certificate of public convenience and necessity reflected a depreciable life of only 12 years, and established a depreciation rate of 8.33 percent. Second, in the early years of operation, HIOS credited approximately $65.3 million of revenues as "Supplemental Depreciation" to its balance sheet, rather than to income, which had the effect of reducing rate base. Third, when the impact of approximately $15.4 million of negative salvage is also included, the result is negative net plant of approximately $5.7 million. Thus, the combination of the initial high depreciation rate, the supplemental depreciation, and the negative salvage in the accumulated depreciation account, has contributed to the elimination of rate base. When coupled with the fact that HIOS has been in service for over twenty-seven years, or more than twice as long as the original twelve-year estimated life, it is not unexpected that the rate base would be zero or even negative as it is.

Q. How does the Commission modify its cost of service model for a pipeline like HIOS with no rate base?

A. As it did in HIOS’s last rate case, in Docket No.RP03-221, HIOS anticipates that the Commission would allow HIOS to establish a management fee in lieu of the traditional return on rate base. HIOS is therefore again proposing a management fee that is intended to allow it to continue operating as a viable economic entity by providing it with an opportunity to collect sufficient revenue to provide sufficient cash flow to deal with extraordinary items, and to provide a financial incentive for the equity owners to continue operating the system. Without such a fee to replace the traditional return allowance, the owners of HIOS have no incentive to continue to maintain and operate the system. Indeed, no prudent investor maintains any investment without the prospect of either regular earnings or capital appreciation, or both.

Q. What method did the Commission use to calculate the management fee in the last case?

A. The Commission used its "Tarpon method" for purposes of calculating a management fee, with one adjustment. Under the Tarpon method, the Commission first determines the average annual rate base over the life of the facility, multiplies that average by a factor of 10%, and then multiplies that result by the allowed rate of return. The result is the management fee. The one adjustment to the traditional Tarpon method was associated with the elimination of HIOS' supplemental depreciation when computing the average rate base in the first step of the calculation. The Commission determined that the supplemental depreciation distorted the calculation of the average rate base, and consequently the level of the calculated management fee.

Q. Is HIOS proposing to utilize the same methodology used by the Commission in Docket No.RP03-221 for determining a management fee?

A. For the most part, yes, although HIOS is proposing one slight refinement in the methodology that the Commission used in order to address what I believe is a key weakness in that methodology.

Q. Please explain.

A. I do not believe that multiplying a current rate of return by 10% of the pipeline's average annual rate base is an appropriate methodology for determining a management fee. I agree that a rate of return can appropriately be applied to some base of investment to calculate a return allowance in the form of a management fee. I also agree with the proposition that, in the case of a pipeline such as HIOS, a surrogate rate base for purposes of calculating that return allowance needs to be developed, and that using the average rate base, halfway through the life of the pipeline, has a rational basis in the development of that surrogate. However, it is the second step - multiplying that average rate base by 10% - that I believe is totally arbitrary and without any rational basis. I am not aware of any basis for the 10% multiplier, and the result, at least in the case of HIOS, is an inadequate level of return. As the average rate base is roughly equal to 50% of the original gross plant investment, it is equivalent to calculating a return on roughly 5% of the original gross plant investment (calculated as plant investment * 50% * 10% * ROR = Management Fee), which I believe is an inadequate result for HIOS. Experience during the base period for this case demonstrates that HIOS needs a higher management fee to maintain its operations.

Q. What is the refinement to the Tarpon method that you have used to eliminate this 10% factor?

A. I have calculated a management fee for HIOS using what I refer to as the <u>Modified Tarpon</u> methodology. As shown on page 1 of Exhibit No. HIO-67, starting with the same <u>Tarpon</u> methodology, I first calculated the average cost of the facilities excluding the supplemental depreciation, and from that result, calculated the average rate base as was done by the Commission in the last rate case (See page 1 of 2, lines 1 through 4 of Exhibit No. HIO-67). However, as shown on line 5 of the exhibit, instead of using an arbitrary factor of 10% to calculate the management fee base, I applied a factor of 19.45% to compute a management fee base of approximately $35.5 million on line 6. This base is then multiplied by the overall rate of return of 12.96% proposed in this case, to derive the proposed management fee of approximately $4.6 million. I believe that the use of this derived multiplier of 19.45%, based on objective factors, is a much more rational approach to calculating a management fee base than simply selecting an arbitrary multiplier such as 10%.

Q. Please describe further how you derived this 19.45% multiplier that you used to derive the Modified Tarpon management fee base?

A. Page 2 of Exhibit No.HIO-67 includes data for 7 similar offshore pipelines. From Form 2 I determined for each pipeline the historical cost of facilities and the current cost of facilities (lines 1 and 2), and then I computed the average cost of facilities for each pipeline (line 3). The average cost of the facilities was then divided by 2 to calculate the average rate base for each pipeline (line 4). This is the same method that the Commission used to determine HIOS's average rate base in Docket No. RP03-221. On lines 5 through 6, I then calculated the imputed management fee base for the pipelines. To compute the management fee base I divided each pipeline's reported net income taken from Form 2 (line 5) by each pipeline's allowed return on rate base, from each pipeline's most recent rate case (line 6). I then calculated the management fee factor (line 7) for the 7 pipelines by dividing the management fee base by the average rate base. I eliminated the management fee factor outliers and used the management fee factor for the remaining five pipelines to compute the average management fee factor of 19.45%, which HIOS is proposing to use as the multiplier instead of the arbitrary and unsupported factor of 10%.

Q. Why is it more appropriate to use 19.45% to calculate the management fee base rather than the 10% used under the <u>Tarpon</u> method?

A. First, the 19.45% is a number derived from application of the same <u>Tarpon</u> methodology to other pipelines operating in the same industry environment, versus a completely arbitrary number. Ten percent is not necessarily the correct percentage to utilize to calculate the fee on the <u>Tarpon</u> base, much less the correct percentage in every case. The Commission itself stated in <u>Tarpon</u> that the management fee should be high enough to encourage the pipeline to aggressively market its services, increase its throughput and minimize costs, but not so high that it would be equivalent to a monopoly return unavailable to a firm operating under competitive conditions. An arbitrary ten percent level does not properly reflect those principles in all cases, especially in the case of HIOS. The appropriate percentage to use should be based on the specific circumstances applicable to the pipeline, including for example, the business and financial risks facing the pipeline. My method does this.

Moreover, reflective of the Commission's traditional methodology for determining a reasonable level of return dollars, my calculation defines the current relationship that exists between return and an average rate base for similar pipelines, and recognizes that the management fee should be structured to provide a return at a comparable level. Second, it provides a unique result for each pipeline. Based upon the universe of similar pipelines, the percentage calculated will be a unique reflection of the return provided to that group of pipelines. For example, since the peer groups will differ, the percentage used to calculate the management fee base for an offshore pipeline would be quite different from that used to calculate a long haul onshore pipeline. Finally, the percentage is dynamic. Calculating the percentage based upon recent data from peer group pipelines will always result in a calculation that properly reflects the current business environment for similar pipelines.

Q. Please summarize your recommendation for a management fee.

A. It is imperative that HIOS be provided with a recourse rate that offers the opportunity to collect revenues sufficient to (1) cover day-to-day operating expenses, (2) provide a cushion for unexpected increases in expenses or decreases in revenues and (3) offer an incentive for the equity owners to continue operating the system. Any proposal must meet all of these goals. Furthermore, a review of the revenue reconciliation in Statement J demonstrates that the need for an adequate management fee is particularly critical in this case given that, even under the proposed rates HIOS will recover only 88% of the cost of service. The calculation of a management fee using the same Tarpon method as in the last case would once again be insufficient to accomplish these goals, whereas my proposed refinement of the Tarpon method will accomplish them.

Implementation of Service Enhancements

Q. Is HIOS proposing any changes to its services in this proceeding?

A. Yes, there are a number of changes being proposed. HIOS is proposing to provide new flexibility for shippers under Rate Schedule FT, which it is proposing to re-name as Rate Schedule FT-1 for purposes of numbering consistency. HIOS is also proposing modifications to Rate Schedule FT-2 that will make it more consistent with similar services offered by nearby offshore pipelines. HIOS is also proposing a new default firm service, Rate Schedule FT-3, that will be priced using term-differentiated rates and that will permit shippers to structure their contract deliverability to reflect their individual commercial needs. Finally, as the proposed Rate Schedule FT-3 will become the default firm service, the rate for interruptible service under Rate Schedule IT is proposed in this case to be the 100% load factor equivalent of the proposed rate under Rate Schedule FT-3.

Q. Please describe the services that HIOS currently offers under its various rate schedules.

A. HIOS offers two firm services under Rate Schedules FT and FT-2. Rate Schedule FT is the basic firm transportation service that has been offered by HIOS since restructuring under Order No. 636. In 1999, HIOS designed Rate Schedule FT-2 to meet the demands of offshore producers for a more flexible firm service that met their specific needs. This service was designed to secure significant quantities of long-term firm gas transportation on the system. To qualify for service under this rate schedule, the shipper must dedicate a gas supply of at least 40 Bcf for the life of the reserves. In return for this reserve commitment, shippers are charged a volumetric rate, conditioned on the requirement that production from the committed lease be maintained at a throughput level of 80 percent of the shipper's maximum daily quantity over a rolling three month period. HIOS also offers an interruptible transportation service under Rate Schedule IT.

Rate Schedule FT-1

Q. How does HIOS propose to enhance the firm service provided under the re-named Rate Schedule FT-1?

A. HIOS is proposing to modify the billing of this service by a) establishing a 10% "billing ratchet"; b) establishing a minimum term of service of 1 year; and c) including a penalty for unauthorized overrun on critical days. I have prepared Exhibit No. HIO-71 which is a listing of the revised tariff sheets included in this filing. The revisions to Rate Schedule FT-1 are set forth on revised sheets numbers 14 through 25.

Q. Will you please explain the proposed 10% billing ratchet?

A. Under this proposal, the shipper's monthly bill would be based on a Maximum Billing Quantity, or MBQ, rather than the traditional method of billing based on Maximum Daily Quantity, or MDQ. For FT-1 service, the MBQ would be equal to the highest quantity tendered to HIOS by the shipper during any day of the applicable billing month, but could be no less than 90% of MDQ nor more than 100% of MDQ. In my Exhibit No. HIO-68 I have prepared a billing example using currently effective rates, which compares the billing of a Rate Schedule FT-1 shipper at various load factors under the current and proposed service. As shown in columns 2 and 4, under the current billing method this shipper's monthly bill would be equal to the total reservation charge calculated using the full MDQ of 100,000 Dth per day, regardless of the quantities shipped. Under the new billing ratchet proposal, however, if this shipper is not able to fully utilize its contract entitlement, there would be mitigation of the reservation charge. As shown on lines 7, 8 and 9 of columns

3 and 5, this shipper would be billed at an MBQ equal to 90% of MDQ if the peak day deliveries are less than the 10% ratchet (line 8, column 3), and will be billed at an MBQ equal to the actual peak day deliveries during the month if those deliveries fall within the 10% ratchet (line 8, column 5). In each of these instances, the effective unit rate of transportation shown on line 5 is always less than under the current method; as the shipper approaches full utilization of the contract, the effective unit rates are equal. This proposal provides firm service with some rate flexibility based on the level of actual flow, while at the same time allowing a shipper to reserve a full MDQ entitlement on the system in case that total entitlement is needed.

Q. Why are you proposing this service enhancement?

A. In addition to providing the flexibility to shippers I described above, the proposal is intended to encourage shippers to subscribe for firm service. Currently, throughput on the HIOS system is virtually 100% interruptible. In fact, less than 20% of the throughput in the test period is projected to be firm. If it is to continue as a viable economic entity, HIOS must take every opportunity to stabilize its revenue stream. Encouraging shippers to contract for firm transportation is one thing HIOS can do to promote revenue stability.

Q. Why did you choose a ratchet level of 10%?

A. I reviewed all firm services that were provided during the base period and analyzed their load factors. One of the shippers had an extremely low and another had an extremely high load factor, so I discarded these 2 “outliers”. I calculated the average load factor for the remaining load factors to be approximately 93%. Therefore, I determined that a 10% ratchet has a reasonable relationship to existing load factors, and should be adequate to allow a firm shipper operating at the average load factor to receive a benefit from this service.

Q. How would you account for these services when designing rates?

A. Since I am assuming that these shippers will operate at an average of 93% of their MDQ, in order to assure the best opportunity for cost recovery, their reservation charge design units would necessarily be included at 93% of MDQ. Or, alternatively, if there were actual contracts currently flowing under this service, the shipper's monthly MBQ could be used for purposes of rate design. However, since there are currently no FT-1 service agreements, I instructed HIOS Witness Jeff Molinaro to calculate the FT-1 rate as 93% of the FT-3 rate to properly allocate costs.

Q. What is the purpose of establishing a 1 year minimum term for Rate Schedule FT-1 service?

A. First, since HIOS is willing to encourage firm contracting by providing pricing flexibility, it is equitable to require shippers to commit to the system for a reasonable term for that service. Second, HIOS is also proposing to implement a new firm service priced using term differentiated rates under Rate Schedule FT-3, which will permit a shipper to buy firm service for 1 year or less. For the term-differentiated rates proposed under Rate Schedule FT-3 to have a chance to allocate capacity efficiently to those who value it most while also permitting HIOS a reasonable opportunity to recover its annual cost of service, consistent with the Commission's policies with respect to term-differentiated rates, a shipper seeking shorter term capacity, i.e., less than a year, cannot have the option of defaulting to the FT-1 rate. If a shipper can pay only the unit equivalent of the annualized FT-1 rate for capacity with a term of less than a year, then HIOS would not have any realistic opportunity to recover its annual cost of service.

Q. What is the purpose of including a penalty provision for unauthorized overrun on a critical day?

A. This type of penalty is widely used by interstate pipelines, and the lack of such a provision in the HIOS tariff is an administrative oversight. Although HIOS has ample capacity and should never have to refuse to schedule overrun, it is imperative that, in the event of a critical day, HIOS should at least have the ability to discourage unauthorized use of the system in order to protect its operational integrity. Furthermore, HIOS currently has a penalty crediting provision as Section 27 of its General Terms and Conditions, so HIOS will not retain any of these penalties.

Q. Will your proposed revisions have any negative impacts on existing shippers?

A. No, these proposed revisions will not impact any existing shipper on this HIOS system. First, the revisions are to be effective for contracts executed on or after October 1, 2006, the proposed effective date of these new tariff revisions. Second, there currently are no FT (now FT-1) shippers on the system. Third, since there are no FT-1 services, the design of the FT-1 rates at 93% of the FT-3 rates does not alter design units in this case. Consequently, it has no impact on the FT-2 or the FT-3 rates. Nor does it impact the IT rates which will be derived as the 100% load factor rate of the FT-3 default rate for a one year term.

Rate Schedule FT-2

Q. What modifications is HIOS proposing to Rate Schedule FT-2 in this case?

A. HIOS is proposing three changes to Rate Schedule FT-2 to make it more compatible with other HIOS firm services and to similar services offered by other offshore pipelines. First, HIOS proposes to change the billing of this service from commodity billing to a reservation and commodity charge structure. Second, HIOS proposes to add the same penalty provision for unauthorized overrun on critical days, as is proposed for Rate Schedule FT-1. Third, HIOS proposes to add a new provision that will match a shipper's future contract reduction rights more closely to the declining production. The revisions are set forth on revised sheet numbers 28, 30, 31, 32 and 36 of the HIOS tariff.

Q. How do you propose to change the billing to a two part rate?

A. I have designed this change so that no current shipper will be impacted by the change in billing, and so that current and future shippers can still effectively enjoy the benefits of commodity pricing, despite the change to a two-part rate structure reflective of the firm nature of this service. Exhibit No. HIO-69 is a monthly billing example that compares the proposed billing revisions to the current billing method for FT-2 services, using currently effective rates. For purposes of this Rate Schedule, the MBQ will be equal to the average daily throughput within MDQ during the applicable billing period. The example in my exhibit computes the monthly bills for a shipper operating at a 75% load factor (columns 2 and 3), an 85% load factor (columns 4 and 5), and a 100% load factor (columns 6 and 7). Because a Rate Schedule FT-2 shipper has a

80% minimum throughput requirement, when the shipper operates at 75% load factor, the current and proposed calculation of the monthly bill is the same, as is the effective unit rate as shown on line 15 of columns 2 and 3. However, as shown in the example in columns 4 and 5, when a shipper satisfies the minimum throughput commitment the current and proposed calculations of the monthly bill are different. Under the current method, the bill is calculated as the product of the commodity volumes and the 100% load factor rate (lines 11 through 13, column 4). Under the proposed method, the monthly bill is calculated as the product of the MBQ (in this case the average daily throughput) and the reservation rate, plus the product of the commodity volumes and rate (lines 5 through 10, column 5). The calculation methodology is the same for the shipper operating at a 100% load factor in columns 6 and 7 as it is for the shipper operating at an 85% load factor.

Q. Why are you adding the penalty provision for unauthorized overrun on critical days?

A. This is added for the same reasons I explained earlier when discussing the revisions to Rate Schedule FT-1.

Q. Will you please explain your final revision to this Rate Schedule?

A. Under the terms of Rate Schedule FT-2, a shipper has a unilateral right to make periodic contract reductions. The intent of this existing firm entitlement reduction right under FT-2 is to permit the shipper to match the firm entitlements to the unique declining production characteristics of the deepwater production. If a shipper has perfect information, then the contract reductions should establish the MDQ at a level that permits delivery of that shipper's production within contract levels. Of course, the estimating of future production is not an exact science and some variance between the firm contract entitlement and actual deliveries is expected. However, if HIOS is to efficiently schedule and market its system, it must have a reasonable expectation that the quantities that will flow under services provided pursuant to Rate Schedule FT-2 will match the contract entitlements.

Q. How does HIOS propose to achieve this goal?

A. HIOS is proposing to add a new Section 6.4 to Rate Schedule FT-2. This section provides that if a shipper exceeds the MDQ by more than 120% for 3 consecutive months, then HIOS would have the right to require the shipper to increase its MDQ for the next 12 months to more closely approximate the shipper's actual firm requirements. This section also provides that the shipper can elect to establish the increased MDQ either by a) the percentage relationship of actual overrun to MDQ during the previous 3 months, or b) by a quantity equal to the average daily overrun quantity during the previous 3 months. If the shipper fails to make an election, then the MDQ will be established using the percentage relationship of actual overrun to MDQ during the previous 3 months. This provision is similar to that included in this type of rate schedule by other offshore pipelines. The purpose of this provision is to provide HIOS with operational and scheduling control over the system and to encourage shippers to efficiently contract for firm capacity. A 20% margin over 3 consecutive months should be adequate to cover normal variations in production.

Q. Will these proposed revisions to Rate Schedule FT-2 impact current shippers?

A. No, they will not impact any current FT-2 shipper. The implementation of the new Section 6.4 provides that it will only impact services entered into on or after October 1, 2006, so existing services are not affected. In any event, the FT-2 service is designed to produce a billing at an effective unit rate that is equal to the 100% load factor rate if the shipper satisfies the minimum bill provisions of the service. This method preserves that billing result.

Rate Schedule FT-3

Q. Will you please describe your proposed Rate Schedule FT-3?

A. This service provides for a firm service priced at term-differentiated rates, and is proposed in light of the Commission's recognition in Order No. 637 that forms of term-differentiated rates may be a method to price capacity more efficiently. The term-differentiated rate design HIOS is proposing is similar to the pricing of storage service, where a shipper can purchase firm storage of shorter or longer duration. Under the design method for these storage service rates using the Equitable method, for example, a 10 day storage service is priced higher on a per Dekatherm basis than 150 day service. My FT-3 rate design proposal is also similar to the rate design for services offered by other interstate pipelines for power generators that may need a higher rate of delivery than a normal shipper, and thus may contract for service over less than a 24-hour gas day rather than the traditional gas day.

Q. Has your proposed rate design been utilized by other pipelines?

A. The design of rates for Gulfstream Pipeline Company's Rate Schedule FTS, and for ANR's Rate Schedule FTS-3, employs a design similar to the Equitable method to recognize the cost of providing these shorter term services. In the design of Rate Schedule FT-3, I have utilized the concepts established by the Equitable method to design a rate that prices out the annual service while providing for a term weighting factor to be applied to terms of shorter than 1 year. I have prepared Exhibit No. HIO-70 which demonstrates the pricing of this service. Finally, the terms and conditions of this proposed service, which are essentially the same as the terms and conditions of service for Rate Schedule FT-1, are set forth on original sheet numbers 44 through 52 of the HIOS tariff.

Q. Please explain your Exhibit No. HIO-70

A. Exhibit No. HIO-70 prices out this service for 1 month, 3 months, 6 months, 9 months, and 1 year. The examples assume that the various shippers have each contracted for an MDQ of 100,000 Dth per day for these varying terms of service, and that each shipper is operating at 100% load factor. On lines 1 and 4, the total reservation charge has been allocated 50% to the capacity calculation (lines 1 though 3), and 50% to the deliverability calculation (lines 4 through 7). The capacity charge is calculated in the traditional manner as the product of the capacity rate and the MDQ. The deliverability charge is calculated by converting 50% of the reservation charge to a unit rate (line 4), and weighting that unit rate by a factor to calculate the Monthly Deliverability Rate ("MDR"). The factor used for this conversion is calculated as the deliverability rate divided by the quotient of the number of days in the term of the contract and the number of days in the year. Thus, in column 4, the MDR for a 6 month service is calculated as ($0.0452 / (182.4 days / 365 days in the year)) = $0.0904. The MDR is then multiplied by the Maximum Billing

Quantity ("MBQ") to calculate the deliverability charge. Once the commodity charge is calculated the effective unit rate is then calculated and shown on line 12. The effective unit rate demonstrates that, as the term of the service approaches the 1 year default service, the spread between the unit rate and the 100% load factor rate narrows until the rates are equal. This pricing model parallels the pricing of the power generation services where, as shippers approach a full 24 hours under a 1/24 rate of delivery, or a normal gas day, the unit rates for service become equal.

Q. Why does HIOS need to be able to offer this service for less than a year?

A. For the same reason that a storage provider or a pipeline provides a rate that recognizes the term of service, HIOS needs to promote efficient pricing of its services and, as a result, likewise encourage efficient contracting of capacity on its system. Although HIOS currently has adequate capacity available to serve potential shippers, HIOS does have other capacity-related issues that set it apart from other interstate pipelines. Because HIOS is a feeder pipe to downstream, long line interstate pipelines, the available capacity on HIOS may not be the only controlling factor when evaluating the need for firm service. Recent history demonstrated that when downstream pipes experienced capacity constraints those problems rolled back up the HIOS system. This makes the decision to hold firm capacity on HIOS different that that on other pipelines. On HIOS, a shipper must not only consider capacity availability on HIOS, it must also consider how HIOS will be impacted by capacity and contractual considerations downstream. When making these decisions, especially in periods of short term capacity constraints, the pricing of service should efficiently allocate scarce capacity.

Q. What are the benefits for shippers of your proposed Rate Schedule FT-3?

A. This service will encourage shippers to purchase service of varying terms at prices that reflect the cost of the service, which will allow more efficient pricing of services to the benefit all shippers in the long run. In combination with the limitation on Rate Schedule FT-1 to a minimum term of service of one year, it discourages uneconomic cherry picking of firm capacity during periods of scarcity by new shippers in an effort to jump ahead of existing interruptible shippers in the scheduling queue, as a shipper will have to consider the true price of that capacity. Since in future rate cases the rate design units will be weighted to reflect the pricing structure of these services, the long run benefits will be reflected in lower rates for all other shippers.

Q. Is HIOS proposing any changes to service under Rate Schedule IT?

A. HIOS is not proposing to revise the terms and conditions of service under Rate Schedule IT. Since FT-3 will be the default service, however, I am proposing to design the IT rate as the 100% load factor rate of the FT-3 annual rate.

Q. Please summarize your adjustments to the current design of rates.

A. The modifications that I propose in this rate case will not have any impact on existing shippers on the system. I propose that the rate for service under FT-3 be used as the default rate for purposes of calculating a system wide rate. The rate for service under FT-1 and FT-2 therefore would be derived from the annual FT-3 rate. The FT-2 rate will be equal to 100% of the FT-3 annual rate, and the FT-1 rate will be equal to 93% of the FT-3 annual rate. Finally, the rate for service under Rate Schedule IT would be equal to the 100% load factor rate for service under FT-3. I have instructed HIOS Witness Molinaro to implement these changes in the design of rates.

Q. Are you proposing any other tariff changes?

A. Yes. I am proposing conforming changes to the General Terms and Conditions to implement the service revisions I have described above. The revised sheets reflecting these changes are listed in Exhibit No. HIO-70.

Q. Are there any other tariff revisions that you propose?

A. Yes. I propose to add a new section to the General Terms and Conditions, Section 29, which is reflected on revised sheet number 173B. This section, which is entitled "Third Party Charges," provides that if a shipper so desires, HIOS can contract with third party pipelines for capacity to provide "through haul" service and pass through the cost of that capacity. This section, which is similar to one included in the tariff of ANR, will permit HIOS and its shippers to provide seamless transportation services using third party pipelines. I am also proposing a new Section 30. This Section 30 is reflected on revised sheet numbers 173B and 173C and is entitled "Off – System Capacity". This section permits HIOS to contract for space on third party pipelines and operate that capacity pursuant to the terms and conditions of service in HIOS's tariff. This section is identical to those previously approved by the Commission for other pipelines. Both of these proposed sections are intended to enhance HIOS' ability to attract new transportation services.

Q. Does this complete your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of) Docket No. RP06-
High Island Offshore System, L.L.C.)

Affidavit of Richard W. Porter

Richard W. Porter, being first duly sworn according to law, on oath deposes and says that he is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, direct testimony in these proceedings.

Richard W. Porter

Richard W. Porter

Subscribed and sworn to before me this 29th day of August, 2006.

FRONELL SINGLETERRY
Notary Public, State of Texas
My Commission Expires
November 12, 2006

Fronell Singleterry

Notary Public

HIOS ECONOMIC LIFE

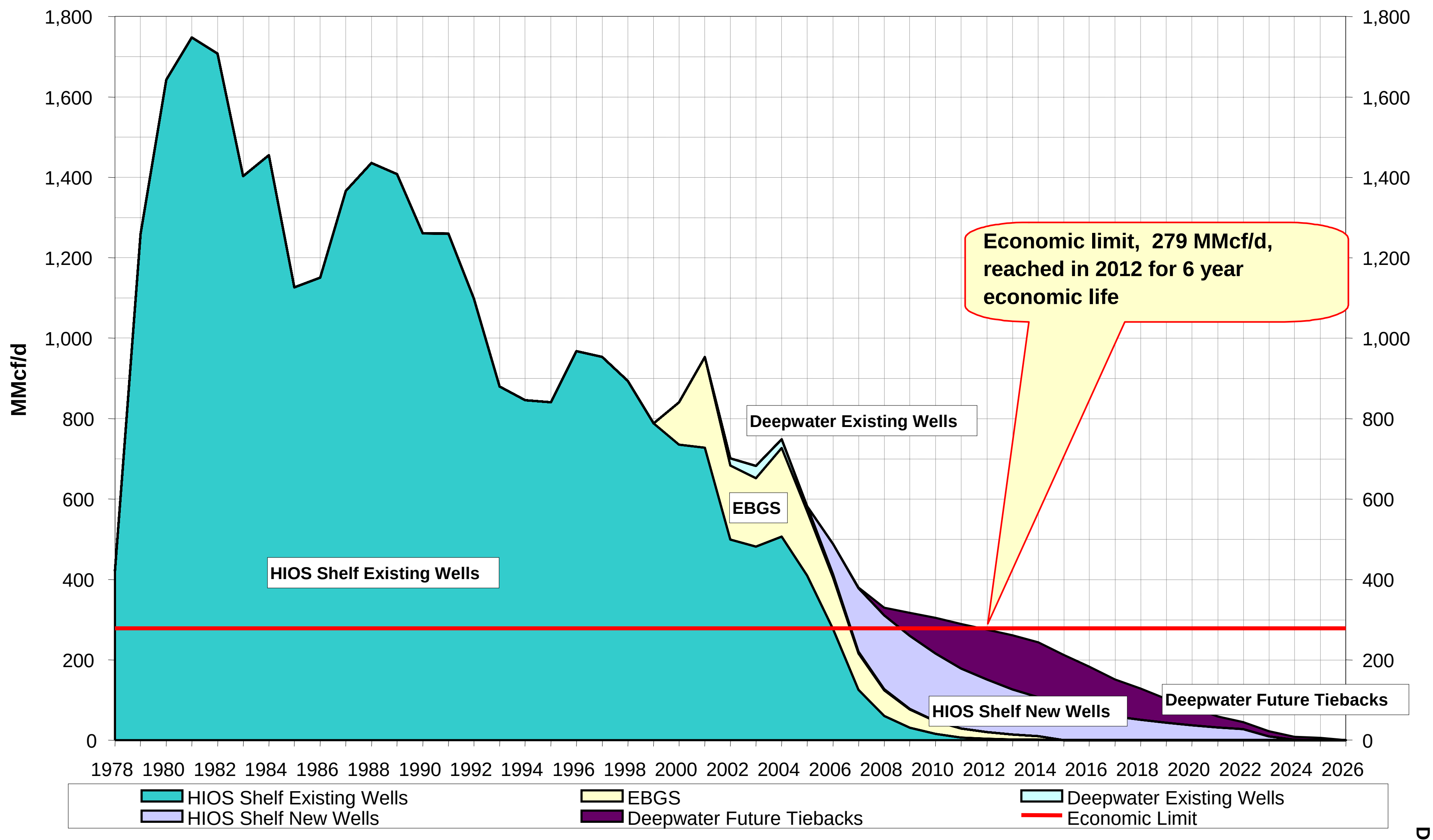

Exhibit No. HIO-66
Docket No. RP06-__

Docket No. RP06-____

High Island Offshore System, L.L.C.
Calculation of Management Fee
***Modified* Tarpon Method**

Line No.	Description (1)	Reference (2)	Amount (3)
1	Original Cost of Facilities	1979 Form 2	$ 337,310,982
2	Current Cost of Facilities at March 31, 2007	Schedule C-1	392,300,536
3	Average Cost of Facilities Over Useful Life	(Lines 1 + 2) / 2	$ 364,805,759
4	Average Rate Base	Line 3 / 2	$ 182,402,880
5	Management Fee Factor	Exhibit No. HIO-X2	19.45%
6	Management Fee Base	Line 4 * Line 5	$ 35,477,360
7	As Filed Return	Statement F-2	11.76%
8	Management Fee	Line 6 * Line 7	$ 4,172,138

High Island Offshore System, L.L.C.
Calculation of Management Fee Factor
***Modified* Tarpon Method**

Line No.	Description	Reference	Stingray	U-TOS	Sea Robin	Chandeleur	Sabine	Garden Banks	Nautilus	Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Calculation of Average Rate Base:									
1	Original Cost of Facilities 1/	Form 2	$ 248.30	$ 63.30	$ 253.40	$ 23.40	$ 57.60	$ 94.10	$ 119.40	
2	Current Cost of Facilities at December 31, 2005	Form 2 - Year 2005	$ 315.50	$ 52.40	$ 293.60	$ 41.20	$ 53.30	$ 100.50	$ 120.50	
3	Average Cost of Facilities Over Useful Life	(Lines 1 + 2) ÷ 2	$ 281.90	$ 57.90	$ 273.50	$ 32.30	$ 55.50	$ 97.30	$ 120.00	
4	Average Rate Base	Line 3 ÷ 2	$ 141.00	$ 29.00	$ 136.80	$ 16.20	$ 27.80	$ 48.70	$ 60.00	
	Calculation of Management Fee Base:									
5	Average Annual Net Income ("Management Fee")	Form 2 - Years '01 - '05	$ 2.18	$ 0.04	$ (1.25)	$ 1.60	$ 1.51	$ 2.07	$ 0.05	
6	Allowed Return on Rate Base		10.55%	12.75%	15.23%	10.14%	11.75%	12.42%	10.38%	
7	Calculated Management Fee Base	Line 5 ÷ Line 6	$ 20.7	$ 0.3	$ (8.2)	$ 15.8	$ 12.9	$ 16.7	$ 0.5	
	Calculation of Management Fee Factor:									
8	Calculated Management Fee Factor		**14.68%**	**1.03%**	**-5.99%**	**97.53%**	**46.40%**	**34.29%**	**0.83%**	**19.45%**

Footnotes:
1/ From 1990 Form 2 for Stingray, U-TOS and Sea Robin. From Form 2 in first year of operation for all others.

High Island Offshore System, L.L.C.
Proposed Revised Rate Schedule FT- 1 Billing Example

Line No	Description (Col. 1)	Shipper Peak Day At Less Than Ratchet At 85% Load Factor — Current Method (Col. 2)	Proposed Method (Col. 3)	Shipper Peak Day Within Ratchet At 92% Load Factor — Current Method (Col. 4)	Proposed Method (Col. 5)	Shipper Peak Day Within Ratchet At 100% Load Factor — Current Method (Col. 6)	Proposed Method (Col. 7)
	Assumptions:						
1	MDQ (Maximum Daily Quantity Or Maximum Quantitiy HIOS Is Obligated to Deliver On A Firm Basis On Any Day	100,000	100,000	100,000	100,000	100,000	100,000
2	Actual Quantities Delivered	2,280,000	2,280,000	2,432,000	2,432,000	3,040,000	3,040,000
3	Average Number of Days In The Billing Month	30.4	30.4	30.4	30.4	30.4	30.4
4	Average Daily Deliveries During The Month	75,000	75,000	80,000	80,000	100,000	100,000
5	Peak Day Deliveries During The Month	85,000	85,000	92,000	92,000	100,000	100,000
6	MBQ (Monthly Billing Quantity Is Peak Day Quantitiy Delivered Within Contract During The Month, But Never Less Than 90% Of MDQ)	-	90000	-	92000	-	100000
	FT-1 Monthly Billing Example						
	Reservation Charge						
7	Reservation Rate	$2.7507	$2.7507	$2.7507	$2.7507	$2.7507	$2.7507
8	MBQ	100,000	90,000	100,000	92,000	100,000	100,000
9	Reservation Charge (Line 7 * Line 8)	$275,070	$247,563	$275,070	$253,064	$275,070	$275,070
	Commodity Charge						
10	Commodity Rate	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
11	Commodity Volumes (MDQ * 365/12)	2,280,000	2,280,000	2,432,000	2,432,000	3,040,000	3,040,000
12	Commodity Charge (Line 10 * Line 11)	$2,964	$2,964	$3,162	$3,162	$3,952	$3,952
13	Total Monthly Bill (Line 9 + 12)	$278,034	$250,527	$278,232	$256,226	$279,022	$279,022
14	Effective Unit Rate	**$0.1219**	**$0.1099**	**$0.1144**	**$0.1054**	**$0.0918**	**$0.0918**

High Island Offshore System, L.L.C.
Proposed Revised Rate Schedule FT-2 Billing Example

Line No	Description	Shipper @ 75% Load Factor – Current Method	Shipper @ 75% Load Factor – Proposed Method	Shipper @ 85% Load Factor – Current Method	Shipper @ 85% Load Factor – Proposed Method	Shipper @ 100% Load Factor – Current Method	Shipper @ 100% Load Factor – Proposed Method
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)
	Assumptions:						
1	MDQ (Maximum Daily Quantity Or Maximum Quantitiy HIOS Is Obligated to Deliver On A Firm Basis On Any Day	100,000	100,000	100,000	100,000	100,000	100,000
2	Actual Quantities Delivered	2,280,000	2,280,000	2,584,000	2,584,000	3,040,000	3,040,000
3	Average Number of Days in the Billing Month	30.4	30.4	30.4	30.4	30.4	30.4
4	MBQ (Monthly Billing Quantity Or Average Daily Quantitiy Delivered Within Contract In The Month)	75,000	75,000	85,000	85,000	100,000	100,000
	FT-2 Monthly Billing Example						
	Reservation Charge						
5	Reservation Rate	$2.7507	$2.7507		$2.7507		$2.7507
6	MBQ	100,000	100,000		85,000		100,000
7	Reservation Charge (Line 5 * Line 6)	$275,070	$275,070		$233,810		$275,070
	Commodity Charge						
8	Commodity Rate	$0.0013	$0.0013		$0.0013		$0.0013
9	Commodity Volumes (MDQ * 365/12)	2,280,000	2,280,000		2,584,000		3,040,000
10	Commodity Charge (Line 8 * Line 9)	$2,964	$2,964		$3,359		$3,952
	Commodity Pricing						
11	100% Load Factor Rate			$0.0918		$0.0918	
12	Commodity Volumes (MDQ * 365/12)			2,584,000		3,040,000	
13	Commodity Charge (Line 11 * Line 12)			$237,211		$279,072	
14	Total Monthly Bill (Line 7 + 10 or Line 13)	$278,034	$278,034	$237,211	$237,169	$279,072	$279,022
15	Effective Unit Rate	**$0.1219**	**$0.1219**	**$0.0918**	**$0.0918**	**$0.0918**	**$0.0918**

Exhibit No. HIO-69
Docket No.RP06-___

High Island Offshore System, L.L.C.
Proposed Rate Schedule FT-3 Billing Example

Line No	Description	FT-3 1 Month Term	3 Month Term	6 Month Term	9 Month Term	1 Year Term
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)
	FT-3 Monthly Billing Example					
	Reservation Charge					
1	Capacity Rate	$1.3762	$1.3762	$1.3762	$1.3762	$1.3762
2	MDQ (Maximum Daily Quantity Or Maximum Quantitiy HIOS Is Obligated to Deliver On A Firm Basis On Any Day	100,000	100,000	100,000	100,000	100,000
3	Capacity Charge (Line 1 * Line 2)	$137,620	$137,620	$137,620	$137,620	$137,620
4	Deliverability Rate	$0.0452	$0.0452	$0.0452	$0.0452	$0.0452
5	MDR (Monthly Deliverabilty Rate = Deliverability Rate / (The Number of Days In The Term Of The Contract / The Number Of Days In A Year))	0.5426	0.1808	0.0904	0.0603	0.0452
6	MBQ (Monthly Billing Quantity = (MDQ * Number Of Days In The Contract Term) / Number of Billing Periods In The Contract Term	3,040,000	3,040,000	3,040,000	3,040,000	3,040,000
7	Deliverabilty Charge (Line 5 * Line 6)	$1,649,504	$549,632	$274,816	$183,312	$137,408
	Commodity Charge					
8	Commodity Rate	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
9	Commodity Volumes (MDQ * 365/12)	3,040,000	3,040,000	3,040,000	3,040,000	3,040,000
10	Commodity Charge (Line 8 * Line 9)	$3,952	$3,952	$3,952	$3,952	$3,952
11	Total Monthly Bill (Line 3 + 7 + 10)	$1,791,076	$691,204	$416,388	$324,884	$278,980
12	Effective Unit Rate	$0.5892	$0.2274	$0.1370	$0.1069	$0.0918

Exhibit No. HIO-70
Docket No.RP06-___

High Island Offshore System, L.L.C.
Proposed Tariff Sheets

<u>Revisions to Rate Schedule FT-1</u>
Second Revised Sheet No. 14
Third Revised Sheet No. 15
Fourth Revised Sheet No. 16
First Revised Sheet No. 17
First Revised Sheet No. 18
Second Revised Sheet No. 19
First Revised Sheet No. 20
Third Revised Sheet No. 21
First Revised Sheet No. 22
Second Revised Sheet No. 23
First Revised Sheet No. 24
First Revised Sheet No. 25

<u>Revisions to Rate Schedule FT-2</u>
Third Revised Sheet No. 28
Second Revised Sheet No. 29
Third Revised Sheet No. 30
Fourth Revised Sheet No. 31
Fourth Revised Sheet No. 32
Second Revised Sheet No. 36
Original Sheet No. 36A

<u>Revisions to Rate Schedule FT-3</u>
Second Revised Sheet No. 44
Original Sheet No. 45
Original Sheet No. 46
Original Sheet No. 47
Original Sheet No. 48
Original Sheet No. 49
Original Sheet No. 50
Original Sheet No. 51
Original Sheet No. 52

Third Party Charges
Second Revised Sheet No. 173B

Off-System Capacity
Second Revised Sheet No. 173B
Original Sheet No. 173C

Other Conforming Changes
Third Revised Sheet No. 1
Ninth Revised Sheet No. 2
Third Revised Sheet No. 4
Third Revised Sheet No. 5
Fifth Revised Sheet No. 10
Fourth Revised Sheet No. 64
Fifth Revised Sheet No. 69
Fourth Revised Sheet No. 70
Second Revised Sheet No. 72
First Revised Sheet No. 76
Second Revised Sheet No. 79
Fourth Revised Sheet No. 88
Second Revised Sheet No. 89
Third Revised Sheet No. 100
Third Revised Sheet No. 101
Third Revised Sheet No. 103
Third Revised Sheet No. 114
Second Revised Sheet No. 117
First Revised Sheet No. 122
Second Revised Sheet No. 123
Third Revised Sheet No. 123A
Fourth Revised Sheet No. 134
Fourth Revised Sheet No. 139
Second Revised Sheet No. 143
First Revised Sheet No. 144
Second Revised Sheet No. 150
Sixth Revised Sheet No. 173
Fifth Revised Sheet No. 174
Second Revised Sheet No. 177
Third Revised Sheet No. 178
First Revised Sheet No. 202

Exhibit No. HIO-72

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, L.L.C.) Docket No. RP06-

Prepared Direct Testimony
Of
Deborah E. Kwan

Q. Please state your name and address.

A. My name is Deborah Kwan. My business address is 1100 Louisiana Street, Houston, Texas, 77002.

Q. By whom are you employed and what are your responsibilities?

A. I am employed by Enterprise Products Partners L. P. Company ("Enterprise"), which owns High Island Offshore System, L.L.C. ("HIOS"), as a Senior Analyst in the Rates and Regulatory Affairs Department. My responsibilities consists of filing various annual and semi-annual Federal Energy Regulatory Commission ("Commission") reports and submitting certificate application related information to the Commission.

Q. Please describe your educational background and work experience.

A. I graduated from the University of Houston in 1990 with a Bachelor of Business Administration in Accounting. From 1991 to 1997, I was employed by Centerpoint Energy Entex and worked in the General Ledger Department, Gas Accounting Department and the Rate Department. In October 1997, I began working for The Williams Companies, Inc. as a Rate Analyst in the Regulatory Affairs group within Transcontinental Gas Pipeline's Rate Department. From 2001 to 2003, I worked for El Paso Corporation as a Rate Analyst within the Rate Department for Tennessee Gas

Pipeline; however in July 2003, I was transferred to the Rate Department in El Paso Field Services to work on the assets of GulfTerra Energy Partners, L.P. ("GulfTerra"). Due to the merger of Enterprise and Gulfterra, I accepted my current position within Enterprise in October 2004.

Q. Have you previously provided testimony in any proceedings before the Commission?

A. Yes.

Q. What is the purpose and scope of your testimony in this proceeding?

A. The purpose of my testimony is to present HIOS' overall cost of service, rate base, gas plant, depreciation of plant, and rate of return.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits, which were included in HIOS' filing:

Hearing Exhibit No.	**Schedule Reference**	**Description**
HIO-1	Statement A	Cost of Service Summary
HIO-2	Statement B	Rate Base & Return Summary
HIO-3	Schedule B-1	Accumulated Deferred Income Taxes
HIO-4	Schedule B-2	Regulatory Asset and Liability
HIO-5	Statement C	Cost of Plant Summary
HIO-6	Schedule C-1	End of Base and Test Period Plant Functionalized
HIO-7	Schedule C-1.1	Cost of Plant - Adjustments
HIO-8	Schedule C-2	Accts. 106 & 107-Major Plant Additions & Retirements Accts.
HIO-9	Schedule C-2.1	Uncompleted Work Orders
HIO-10	Schedule C-3	Storage
HIO-11	Schedule C-4	Methods in Capitalizing Allowance for Funds Used During Construction
HIO-12	Schedule C-5	Cost of Gas Plant in Service Not Used In Rendering Gas Service
HIO-13	Statement D	Accumulated Provision for Depreciation, Depletion, and Amortization
HIO-14	Schedule D-1	Depreciation Reserve Applicable to

		Portion of Depreciation Rates Not Yet Approved
HIO-15	Schedule D-2	Methods In Depreciating, Depleting and Amortizing Plant & Abandonments
HIO-16	Statement E	Working Capital
HIO-17	Schedule E-1	Cash Working Capital
HIO-18	Schedule E-2	Monthly Balances for Materials, Supplies, and Prepayments
HIO-19	Schedule E-3	Quantities & Cost of Gas Storage
HIO-20	Statement F-1	Rate of Return Claimed
HIO-21	Statement F-2	Capitalization, Capital Structure, & Return on Equity
HIO-22	Statement F-3	Debt Capital
HIO-23	Statement F-4	Preferred Stock Capital
HIO-47	Statement H-2	Depreciation, Depletion, Amortization and Negative Salvage Expenses
HIO-48	Schedule H-2.1	Transmission Plant Depreciation Rate
HIO-49	Schedule H-2(1)	Reconciliation of Depreciable Plant

Q. What is the basis for HIOS' cost of service?

A. HIOS' cost of service is derived from HIOS' annual cost of doing business during a test period specified by the Commission's regulations. The test period is comprised of a base period, consisting of twelve consecutive months of recently available actual experience, which the pipeline adjusts for known and measurable changes that will occur on or before nine months after the end of the base period. The base period in this docket is the twelve months ending June 30, 2006. The test period will end March 31, 2007.

Q. Please briefly describe the components of HIOS' $42,490,584 cost of service as set forth in Statement A (Exhibit No. HIO-1).

A. Statement A (Exhibit No. HIO-1) presents in summary form the major components of HIOS' overall cost of service for the twelve months ended June 30, 2006 (the base period), as adjusted for known and measurable changes occurring on or before the end of the test period on March 31, 2007. The first item on Statement A is the operating expense component of HIOS' cost of service. This component reflects the operation and maintenance expenses and the administrative and general expenses of HIOS. As shown on line 1 of Statement A, HIOS' operating expenses are $31,569,005.

The depreciation expense component in the cost of service formula is the loss in value of HIOS' assets and provides for the return of capital investment. As shown on line 2 of Statement A, HIOS' depreciation expense is $1,495,902. The next component of cost of service, the offshore negative salvage component, is the annual amortization of the estimated future cost of removal, less any salvage value, of HIOS' offshore facilities. The cost of service on Statement A, line 3, reflects HIOS' offshore negative salvage component of $3,701,210.

The cost of service also includes other tax expenses. HIOS' total other tax expense of $167,754 is set forth on line 8 of Statement A.

Finally, as explained in greater detail in the testimonies of HIOS Witness Richard W. Porter and HIOS Witness Steven J. Gaske, HIOS should be given an opportunity to recover a reasonable amount over and above operating and maintenance expenses, depreciation and taxes as an incentive for managing and operating the HIOS system efficiently. This is normally accomplished by the allowance of an overall rate of return applied to rate base. As shown on line 9 of Statement B (Exhibit No. HIO-2), HIOS' rate base currently reflects a negative balance and therefore a calculation of an overall rate of return on rate base would be zero. As an alternative to an allowed return on rate base, HIOS is proposing a management fee. HIOS' management fee of $4,172,138, as set forth on line 5 of Statement A, is supported by HIOS Witness Porter and HIOS Witness Gaske.

The total federal income tax expense of $1,649,992 reflected on line 6 of Statement A is entirely related to the HIOS management fee. HIOS' cost of service does not reflect any state income taxes.

Q. What is HIOS' overall cost of service?

A. As shown on line 11 of Statement A (Exhibit No. HIO-1), HIOS' net cost of service is $42,490,584, after HIOS' gross cost of service has been reduced by certain revenue credits, which are supported on Schedule G-5.

Q. What is shown on Statement B (Exhibit No. HIO-2)?

A. Statement B (Exhibit No. HIO-2) details the major components of HIOS' rate base in this proceeding and would normally show the amount for return on rate base. HIOS' rate base includes Net Utility Plant of $(5,650,238), as shown on line 6 of Statement B, which is derived by deducting the accumulated reserve for depreciation, supplemental depreciation and negative salvage, as shown on Statement D (Exhibit No. HIO-13), from the total gross plant identified on Statement C (Exhibit No. HIO-5). As shown on line 2 of Statement B, HIOS' current accumulated reserve for depreciation balance is $317,229,135. HIOS has $65,358,548 of supplemental depreciation as reflected on line 3 of Statement B (Exhibit No. HIO-2). The negative salvage portion of the accumulated reserve for depreciation balance of $15,363,091 is reflected on line 4. The total plant, as shown on Statement C (Exhibit No. HIO-5), excludes amounts related to construction work in progress and reflects the addition of capital projects expected to be in service by March 31, 2007, the end of the test period. If the balance related to HIOS' negative salvage collections is excluded from the calculation of net plant, the amount of net plant to be recovered through depreciation expense would be $9,712,853. HIOS' rate base does not reflect any components for working capital.

In addition, to reducing total plant by $397,950,774 for accumulated provisions for depreciation, supplemental depreciation and negative salvage related to gas utility plant, as shown on line 5 of Statement B, I have also deducted $546,436 for the reserve for deferred income taxes as shown on line 8. Schedule B-1, Pages 1 through 3 (Exhibit No. HIO-3) provides support for the determination of the reserve for deferred income taxes reflected in rate base. Schedule B-1, Page 3 of 3, itemizes HIOS' deferred tax activity and balances reflected in FERC Account Nos. 190, 282 and 283 for the twelve months ended June 30, 2006. Schedule B-1, Page 2 of 3, reflects a reconciliation of book and tax net plant balances. It also provides a calculation of deferred income taxes using current income tax rates and a comparison to HIOS' per book deferred tax balances. Schedule B-1, Page 1 of 3, reflects the balances in HIOS' deferred tax accounts as of the end of the base period, June 30, 2006. It also shows monthly adjustments to reflect additional projected accumulations of deferred taxes through March 31, 2007. In addition, this schedule reflects the adjustments that HIOS has made to remove deferred taxes reflected in FERC Accounts Nos. 190 and 283. HIOS has deducted from its rate base only the $546,436 of deferred income taxes related to the differences between book and tax depreciation as reflected in FERC Account No. 282.

As shown on line 9 of Statement B (Exhibit No. HIO-2), the total net rate base used to calculate an allowed overall return component is negative ($6,196,674). Therefore, HIOS' return component in the cost of service reflected on Statement A, line 4 (Exhibit No. HIO-1) is zero.

Q. Please describe Statement C (Exhibit No. HIO-5) and the related schedules.

A. Statement C and the related schedules depict HIOS' cost of plant for the base period and test period. As shown on line 3, column 6 of Statement C, the cost of plant at the end of the base period was $389,180,780. The test period adjustments to plant reflect a net increase of $3,119,756, resulting in a total cost of plant of $392,300,536 at the end of the test period. The detailed support for base period and test period plant by FERC Account is set forth on Schedule C-1 (Exhibit No. HIO-6).

Schedule C-1.1 (Exhibit No. HIO-7) summarizes the test period plant adjustments by function and by FERC Account. Schedule C-2 (Exhibit No. HIO-8) itemizes the major additions and retirements to plant that is expected to occur by the end of the test period, and shows the dollar amounts for each major item. HIOS does not project any major retirements to plant during the test period. Workpaper C-2.1 (Exhibit No. HIO-9) provides data relating to the uncompleted work orders reflected in FERC Account No.107, Construction Work in Progress.

Q. Please explain the test period plant adjustments in Schedule C-1.1 (Exhibit No. HIO-7).

A. Adjustment No. 1, consists of a positive adjustment of $3,197,800 to reflect the cost of transmission facilities that will be placed in service by the end of the test period. These facilities will be constructed pursuant to HIOS' blanket certificate authorization.

Adjustment No. 2 consists of General Plant expenditures projected during the test period related to furniture and fixtures (FERC Account No. 391). The total cost of these expenditures to General Plant is $10,000**.**

Adjustment No. 3 reflects an adjustment to the Construction Work in Progress ("CWIP") balance in FERC Account No. 107 to eliminate the $88,044 of CWIP at the end of the base period that will be placed in service during the test period. A detailed description of projects reflected in the CWIP account is provided on Workpaper C-2.1 (Exhibit No. HIO-9).

Q. Please explain Statement D (Exhibit No. HIO-13).

A. Statement D provides the details for the $397,950,774 of accumulated provisions for depreciation, depletion, amortization and negative salvage reflected in HIOS' rate base. Page 1 of Statement D presents a summary of the actual entries and balances in FERC Account Nos. 108 and 111 from July 1, 2005 through June 30, 2006, and anticipated entries and balances through the end of the test period on March 31, 2007. Statement D, Page 2 of 2, provides support for the test period adjustment that was made to the provisions for depreciation, depletion, and amortization for the additional expense expected to occur during the nine months of the test period.

Q. What depreciation rates did you use on Statement D, Page 2 of 2, to determine additional depreciation, depletion and amortization expense?

A. I have used the depreciation rates last approved by the Commission in its Order on Initial Decision and Settlement Offer (Order), issued on January 24, 2005, relating to HIOS' last rate case in Docket No. RP03-221-000. HIOS' currently effective depreciation rates are 1.85 percent for onshore transmission, 0.10 percent for offshore transmission, 5.70 percent for other equipment, and the currently effective negative salvage rate is 0.20 percent. Specifically, an annual transmission depreciation accrual rate of 1.85 percent for onshore transmission and 0.10 percent for offshore transmission, plus the 0.20 percent negative salvage rate applied to the appropriate plant balances, was used to calculate the test period adjustment listed on Statement D, Page 2 of 2. This statement delineates all of

HIOS’ existing approved depreciation rates, including its rates for intangible plant, communication equipment, and several categories of General Plant. As I discuss in more detail later in this testimony, and as reflected in Schedule H-2, HIOS proposes to change these existing rates to reflect HIOS' current estimate of the economic life of its assets.

Q. Please explain the adjustments reflected on Statement D to the provisions for depreciation, depletion, and amortization as of the end of the test period.

A. The adjustments identified on Statement D, Page 1 of 2, column 6, reflect adjustments to the accumulated provision for depreciation, depletion and amortization to recognize additional accumulated depreciation expense through the end of the test period. These adjustments, as reflected on Statement D, Page 2 of 2, column 7, use HIOS’ projected plant balances and currently effective depreciation rates to calculate the amount of additional accumulated depreciation that will occur between June 30, 2006 and March 31, 2007.

Q. Will you please explain Statement E (Exhibit No. HIO-16)?

A. Statement E normally reflects the details of various components of working capital included in rate base as shown on Statement B. The Statement E in HIOS' current docket explains that HIOS does not claim any working capital allowance in its rate base reflected on Statement B. Also, HIOS is not claiming any cash working capital and it does not have any gas storage facilities.

Q. Please explain Statement F-2 (Exhibit No. HIO-21).

A. Statement F-2 reflects HIOS’ claimed rate of return based on a capital structure of 40 percent debt and 60 percent equity, which is projected to be HIOS' parent's capital structure at the end of the test period. It reflects an 8.34% cost of debt which is the projected cost of debt as of the end of the test period. It also reflects a 14.04% return on equity which was provided to me by HIOS Witness Porter.

Q. Please explain Statement H-2 (Exhibit No. HIO-47) and Schedules H-2.1 and H-2(1) (Exhibit Nos. HIO-48 and HIO-49).

A. These schedules set forth the details related to depreciation, depletion and amortization expenses included in the cost of service. HIOS is proposing changes to its current 1.85 percent onshore transmission depreciation rate, 0.10 percent offshore transmission depreciation rate, 5.70 percent other equipment depreciation rate and its current 0.20 percent negative salvage allowance. All other depreciation rates reflected on Schedule H-2 (Exhibit No. HIO-47) are depreciation rates previously approved the Commission in its Order. HIOS' adjustments to base period depreciation expense reflect the annual effect of depreciation accruals using HIOS' current and proposed depreciation rates. As shown on Schedule H-2, column 5, HIOS' proposed new depreciation rates are 0.19 percent for onshore transmission plant, offshore transmission plant, and other equipment, and 1.00 percent for offshore transmission negative salvage rate. The following depreciation rates did not change, a 1 percent intangible plant depreciation rate, a 3.5 percent communications plant depreciation rate; a 6.67 percent depreciation rate for office furniture and equipment; a 10 percent depreciation rate for transportation equipment; a 5.71 percent depreciation rate for tools, shop and garage equipment; and a 20 percent depreciation rate for computer equipment. The proposed changes to the onshore transmission, offshore transmission, other equipment depreciation rates and the negative salvage depreciation rate are described in more detail below.

Q. What change has HIOS proposed to its current transmission depreciation rate?

A. Based on the testimonies of HIOS Witness Porter and HIOS Witness J. Scott Jenkins, HIOS' estimate of its remaining economic depreciable life is eight (8) years. Using this estimate of remaining life and the balance of net transmission plant, HIOS has calculated a new transmission plant depreciation rate of 0.19 percent. This replaces HIOS' previously approved onshore transmission depreciation rate of 1.85 percent, offshore transmission depreciation rate of 0.10 percent, and other equipment depreciation rate of 5.71 percent.

Q. Can you explain in more detail your calculations?

A. Yes. As shown on Schedule H-2.1, Page 1 of 2 (Exhibit No. HIO-48), HIOS has a remaining balance in transmission plant at March 31, 2007 of $5,788,482 (See line 7). Using HIOS Witness Jenkins' estimated remaining life of eight (8) years, I have calculated that HIOS' annual transmission depreciation expense is $723,560 ($5,788,482 /8) stated on line 9. This amount is then translated into a new transmission depreciation rate of 0.19 percent by dividing the $723,560 by the total transmission gross plant amount of $377,534,923 reflected on Line 3. When the 0.19 percent transmission depreciation rate is applied to the plant balances on Statement H-2, Lines 2, 3 and 6, it yields a transmission depreciation expense of $717,316.

Q. What is offshore negative salvage?

A. Offshore negative salvage is the cost to HIOS of removing retired offshore facilities after accounting for the salvage value of the facilities. As explained by HIOS' negative salvage Witness Robert C. Byrd, the salvage value of HIOS' offshore plant, taken as a whole, is negative. He projects that HIOS will incur $44,995,040 to provide for final abandonment of its offshore facilities.

Q. How does HIOS propose to recover its offshore negative salvage costs in rates?

A. First, as shown on Statement D (Exhibit No. HIO-13), HIOS' current offshore negative salvage rate of 0.20 percent is projected to recover $15,363,091 of negative salvage costs by the end of the test period or March 31, 2007. This means that HIOS must collect the net remaining projection of outstanding costs of $29,631,949 ($44,995,040 – 15,363,091) over the remaining life of HIOS' offshore transmission facilities. HIOS' remaining life, as supported by HIOS depreciation Witness Porter, is eight (8) years. Therefore, HIOS proposes to amortize its remaining negative salvage costs of $29,631,949 over the same period of eight (8) years. Based on the above determination, HIOS' annual negative salvage amortization is $3,703,994. When translated into a negative salvage amortization rate, HIOS is requesting approval to increase its current offshore negative salvage rate from 0.20 percent to 1.00 percent. Schedule H-2.1, Page 2 of 2 (Exhibit No. HIO-48) reflects the calculation of the new offshore negative salvage rate. When the 1.00 percent is applied to HIOS' offshore transmission plant balance on Statement H-2, it yields an annual negative salvage amortization of $3,701,210.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of	)	Docket No. RP06-
High Island Offshore System	)	

Affidavit of Deborah E. Kwan

Deborah E. Kwan, being first duly sworn according to law, on oath deposes and says that he is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, direct testimony in these proceedings.

Deborah E. Kwan

Deborah E. Kwan

Subscribed and sworn to before me this 29th day of August, 2006.

FRONELL SINGLETERRY
Notary Public, State of Texas
My Commission Expires
November 12, 2006

Fronell Singleterry

Notary Public

Exhibit No. HIO-73

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, L.L.C.	)))	Docket No. RP06-_____-000

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

Q. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7514 Wisconsin Avenue, Suite 550, Bethesda, MD 20814.

Q. Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also received a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

During the past 29 years I have been employed continuously as a teacher or consultant on matters related to finance, economics and regulation. From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. In 1980 and 1981, I was employed by Olson and Company where my primary duties were to assist in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for the Electric Rate Fundamentals course of the Edison Electric Institute. In 1986 I accepted an appointment as assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988 I returned to H. Zinder & Associates as a consultant. I have testified or filed testimony or affidavits before the Federal Energy Regulatory Commission on more than twenty occasions. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements and market power. I also have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil and gas pipeline operations before state regulatory bodies in Alaska, New York, North Dakota, Minnesota, Montana, South Dakota, and Wyoming, and the Comision Reguladora de Energia de México ("CRE"). In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing and utility economics before the U.S. Postal Rate Commission, the Alberta Energy and Utilities Board, the Ontario Energy Board, and state public utility Commissions in Iowa, Maine, Montana, North Dakota, Texas and Wisconsin. During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive, rate and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute. Finally, I am a member of the American Finance Association, the Financial Management Association and the American Economic Association.

I. INTRODUCTION

Scope and Overview

Q. What is the scope of your testimony in this proceeding?

A. I have been asked by High Island Offshore System ("HIOS") to evaluate the appropriate level of investor return that should be included in rates established for HIOS. Because HIOS does not have a significant rate base, a traditional rate calculation would yield zero return, and would be inadequate to compensate the owners for the use of the pipeline and its continued operation. Consequently, HIOS is proposing in this case to develop a level of return based on a management fee base, as more fully explained by HIOS witness Mr. Richard W. Porter. That method involves calculating the required rate of return for a company such as HIOS and multiplying that return times a management fee base that reasonably reflects the value of the property dedicated to public use. Taken together, this method assures that the owners will have an opportunity to earn a reasonable margin on the operating costs of the pipeline. As part of this testimony, I calculate the cost of common equity capital for HIOS's pipeline operations based on a Discounted Cash Flow ("DCF") analysis of natural gas pipeline proxy companies that have risks somewhat similar to those of HIOS's pipeline operations. The results of this DCF study are supported by various benchmark criteria that I have used to test the reasonableness of the DCF study results.

Q. Have you determined an appropriate rate of return to be applied in setting rates for HIOS in this proceeding?

A. Based on my analyses, I have determined that returns for a proxy group of peer pipeline entities would range from 11.97% to 16.24%. In addition, I have reviewed the testimony of HIOS witness Leslie J. Pagels, where she describes the extraordinary business risks that HIOS is presently facing. In light of her testimony, it is clear that none of the proxy companies faces risks as great as those of HIOS. Moreover, given its small size and relatively undiversified business and customer base, as well as the failure to recover operating and maintenance expenses during the past year, its declining throughput and relative lack of long-term firm contracts, the fact that it operates in off-shore areas that are difficult to operate and maintain, and that it has an unusually high exposure to the vicissitudes of weather, it is clear that HIOS could justify a rate of return that is at the high end of the range of reasonableness indicated by this group of proxy companies. For the reasons that he explains, HIOS witness Richard W. Porter is proposing to apply a rate of return of 14.04%, which is the median of my range of reasonableness, to calculate a management fee on the rate base that he has calculated. My analysis indicates that Mr. Porter's request is fully supportable. . Further, in order to provide an opportunity for HIOS to earn a reasonable return it is essential that both the rate of return and the rate base be set at levels that produce an end result that compensates investors for the use of their property, and assures that this pipeline is economically viable as an ongoing business.

Q. Please describe the revenue profile of HIOS.

A. HIOS currently provides three transportation services to shippers:

(1) firm, long haul service under Rate Schedule FT-2;

(2) an interruptible long haul service under Rate Schedule IT; and

(3) an interruptible short haul service also under Rate Schedule IT.

HIOS also has a Rate Schedule FT in its tariff that provides for a traditional firm transportation service, with long and short haul rates, but currently has no customers for this service. Notably, HIOS has only two firm customers under Rate Schedule FT-2, BP Energy and Exxon-Mobil, which account for approximately 30 percent of its volumes. The other 70 percent of HIOS's revenues come from unpredictable interruptible volumes that are recovered in a wholly volumetric interruptible rate. During 2005, HIOS derived revenues of $8.3 million from firm service and $18.0 million from interruptible service. In contrast, its revenue from firm service was $13.3 million in 2004 and from interruptible service it was $32.2 million. What this means is that 70 percent of revenues come from interruptible services, and that FT and IT revenues declined in 2005 by 38 percent and 44 percent, respectively. This degree of revenue uncertainty is exceptional for major interstate pipelines.

II. RETURN FOR A REGULATED COMPANY

Q. Does HIOS present any unusual circumstances for regulated ratemaking?

A. Yes. The cost of service formula typically used by the Commission for ratemaking is designed to set rates that will recover a pipeline's operating expenses, including depreciation, and a reasonable return on the capital invested in the company. However, because its plant is substantially depreciated for accounting purposes, HIOS does not have a positive rate base on which a return could be calculated. Consequently, if the Commission were to rely on its usual ratemaking formula HIOS would not be expected to earn a return on its pipeline business. In its latest rate proceeding, the Commission calculated rates for HIOS by including a return using the *Tarpon* method, which involves developing a management fee based on 10 percent of the company's average historical net plant in service. As HIOS witness Porter explains, experience during the past year has demonstrated that this method produced a management fee base that, when the rate of return was applied, produced an end result that is inadequate to sustain or justify operation of the pipeline.

Q. Are there any alternative methods of calculating a reasonable return for HIOS?

A. Yes. In addition to the management fee methodology, various regulatory bodies, including this Commission, have used several methods for calculating a reasonable profit for ratemaking purposes. For example, numerous regulatory bodies throughout history have used a "valuation" rate base, which reflects the current market or replacement value of the regulated assets. In addition, the Interstate Commerce Commission relied on profit margins (i.e., a markup over operating costs) to establish return levels for motor carriers, in part because their cost structure, being heavily weighted toward fuel and labor costs, did not have a predominance of capital costs.

Q. How should a reasonable return level be calculated in setting rates for HIOS?

A. Rate regulation generally is intended to protect customers from prices set at a profit-maximizing level that a company with unconstrained market power might charge. Traditionally, the Commission has relied on cost-based rates, with a rate of return on rate base, to ensure that rates are not excessive for customers while also attempting to ensure that the company has sufficient revenues to pay for operations and to generate a return for owners. However, when the rate base is substantially depreciated to a point that is far below replacement cost, rates calculated using a traditional cost formula will generally be far below an equilibrium competitive level, and even further below an unconstrained market power level. In these circumstances, rates that include a sufficient management fee that is based on a rate base that is considerably more than 10 percent of the historical average rate base, but less than the historical average rate base, are not excessive and should not be considered to be unreasonable. In contrast, the management fee calculated in the last HIOS rate proceeding was a nominal amount that provided an insufficient margin and return for the pipeline's owners.

A reasonable level of return should be sufficient to give the owners a sufficient economic justification for remaining in business and an incentive to continue investing in plant and maintenance. Moreover, it should recognize that as long as the facilities continue to be operated they have an economic value that may bear little or no relation to the depreciated original cost of assets on the balance sheet. Financially, it does not matter which method is used so long as the total amount of the allowed return is economically reasonable for both the owners and the customers. A reasonable level of return should be sufficient to give the company a comfortable assurance that revenues will be more than adequate to recover costs. In addition, it should be adequate to compensate for the risks of continuing to operate the pipeline. Finally, there should be enough return such that the company is justified in continuing to devote the time and expertise of its managers and employees to this project rather than shifting those resources to other projects that are more likely to earn a reasonable profit. The management fee rate base calculated by Mr. Porter, combined with a 14.04 percent rate of return on common equity and the company's proposed capital structure, would meet these standards.

III. FINANCIAL MARKET STUDIES

Criteria for a Fair Rate of Return

Q. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company?

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Electric Company (320 U.S. 591, 603 (1944)).* There the Court described the relevant criteria as follows:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;

2. sufficient to maintain the financial integrity of the regulated company; and,

3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is adequate for the risks involved. Thus, for any given level of risk there is a return that investors must expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards should apply. When a regulated entity faces competition, consumers will implicitly determine the fair rate of return by their consumption decisions. When regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, the consumer and public interest also lies in establishing a return that will readily attract capital without being excessive.

Q. How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest or dividends is relatively easy to determine. For example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This high degree of uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on several DCF analyses. In addition, I have conducted Risk Premium and Alternative Equity Investment analyses as comparison benchmarks to test the reasonableness of the rate of return determined by my analysis. Each of these approaches is described later in this testimony.

Interest Rates and the Economy

Q. What are the general economic factors that affect the cost of capital?

A. Investors are often influenced by their perceptions of the economy and both short- and long-term trends. Page 1 of Exhibit No. HIO-74 shows various general economic statistics. The economy has had a record of persistent growth during the past thirty years, with only temporary recessionary periods. Real growth in the Gross Domestic Product ("GDP") has averaged 3.1 percent annually during the past 30 years, 3.2 percent for the past 20 years and 3.3 percent for the past ten years. Industrial production and employment in the U.S. economy have risen rapidly during the past several years.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index has increased at an average annual rate of 2.6 percent, and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 2.0 percent.

Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates provide a standard measure of returns currently available on less risky securities. As Page 2 of Exhibit No. HIO-74 shows, long-term interest rates declined from mid-2004 to mid-2005. However, interest rates have been increasing significantly in recent months. In mid-2004 the Federal Reserve Board began to increase interest rates on federal funds in response to indications of potential inflation. The Federal Reserve Board and has continually increased this interest rate almost every month for the past two years so that the total increase in interest rates has been approximately 400 basis points. In contrast, long-term interest rates declined during the first half of that period and have generally risen slowly during the past year. Although long-term interest rates have lagged behind the large increase in the federal funds rate, and are no higher than they were before the Federal reserve began to tighten the money supply, long-term rates have begun to increase significantly in recent months. The recent yields on A-rated public utility bonds have been approximately 6.4 percent and the yields on Baa-rated public utility bonds have been approximately 6.6 percent.

Discounted Cash Flow Method

Q. Please describe the DCF method of estimating the cost of common equity capital.

A. The DCF method reflects the assumption that the market price of a share of stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method therefore is a matter of calculating the current dividend yield and estimating the long-term future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the DCF method utilizes readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

Q. What is the appropriate DCF formula to use in this proceeding?

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend payment is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + .75 g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + .5 g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D\,(1 + .625g)}{P} + g \qquad (1)$$

where:

K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

Flotation Cost Adjustment

Q. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. This is particularly true when the cost of common equity is estimated by conducting a DCF analysis that is based on the prices of common stocks traded in the "secondary" markets on stock exchanges. Because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital that the regulated company would incur to raise money in the "primary" markets, a DCF estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost-of-capital that the regulated company requires in order to raise capital on reasonable terms in the "primary" markets.

Q. Please describe the difference between "primary" and "secondary" markets for common equity.

A. When a company issues new common equity in order to raise cash for investment in plant, or otherwise to run its operations, it does so in the "primary" market. The "primary" market is defined very simply as the market in which the stock is first sold in order to raise cash funds to be used by the issuer. In this "primary" market, the company generally hires an investment banker, or a syndicate of bankers and brokers, to float its stock issue to the public. Associated with a company raising cash funds through a "primary" market sale of common stock there are significant costs of preparing and filing documents with the Securities and Exchange Commission ("SEC"), as well as other regulatory agencies, and issuing prospectuses. In addition, in the "primary" market the issuing company generally must pay a significant percentage of the proceeds from the stock issuance to the investment banker, or the syndicate of bankers and brokers, who undertakes to find investors who will provide cash to the issuing company.

Once stock has been issued to investors in the "primary market," those investors who initially provided cash to the issuing company may re-sell or "trade" the stock with other investors in the "secondary" market. Much of the trading in the "secondary" market occurs on stock exchanges and buyers and sellers are not required to file prospectuses with the SEC. The crucial difference between stock issued in the "primary" market and stock traded in the "secondary" market is that the issuing company does not receive any additional funds when its stock trades in the "secondary" market. Instead, the ownership of the stock merely changes hands between various investors. In addition, the brokerage fees associated with buying and selling stock in the "secondary" market generally are incurred by both the buyer and the seller, and are a small fraction of the level of the flotation costs incurred by a company that attempts to raise cash by issuing stock in the "primary" market.

Q. Why should the Commission set the allowed rate of return at a level that will attract capital in the "primary" markets for capital?

A. A focus on primary markets is inherent in the "Capital Attraction" standard established by the United States Supreme Court to determine whether an allowed rate of return meets a minimum standard of reasonableness. "Capital attraction" for a company means raising funds in the *primary* markets for financial capital. However, most analyses used to establish the allowed rate of return for regulated companies are based on studies of the returns required by investors that trade in the *secondary* financial markets. A secondary market focus is especially present in DCF analyses that are based on the publicly-traded stock prices of companies. Rates of return required for public utilities to attract capital in the primary financial markets can be calculated by applying a flotation cost adjustment to the rates of return that investors require when they trade common stocks in the secondary market.

Q. Would you elaborate on the "capital attraction" standard?

A. The Supreme Court established the "Capital Attraction" standard as one test of a reasonable allowed rate of return. For example, in *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and **enable** it to raise the money necessary for the proper discharge of its public duties. (Emphasis added).

The Court's requirement that the allowed return must be sufficient to "enable" a company to raise capital on reasonable terms does not mean that the company must raise capital within some specified time period. Instead, it means that the company must have in place the ability to attract capital so that it can exercise that ability if and when required.

Regulatory treatment of insurance premiums provides an apt analogy for the flotation cost requirement. In order to justify inclusion of insurance premiums in the regulated revenue requirement, utilities are not required to prove that they had a major accident during the test period, or that they will have a major accident during the upcoming year. Instead, insurance premiums are a necessary business expense for dealing with unpredictable events that may or may not actually occur. Similarly, a flotation cost adjustment is required for the return to be sufficient to enable the utility to issue common stock on reasonable terms, regardless of whether the company issued common stock during the test period or whether it can predict that it will issue stock during the upcoming year.

Similarly, in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944))* the Court described the relevant criteria for a reasonable return as follows:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... That return, **moreover**, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (Emphasis added).

By its use of the word "moreover" the Court made it clear that an allowed return is not sufficient if it merely allows the company to meet its current financial obligations. Instead, an additional and overriding requirement is that the return also must be sufficient to assure that the company can maintain its financial integrity so as to attract capital. Financial integrity is not a quality that a company dispenses with when it does not need to raise capital and then somehow reacquires when it does need to raise capital. Thus, regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. Because flotation costs are the additional component of capital costs that apply above and beyond the return required to service current capital needs, an allowance for flotation costs is required in order to meet the "capital attraction" standard.

Q. **Are you aware that Financial Management textbooks often recommend applying the required flotation cost adjustment only to the dividend yield portion of the required rate of return?**

A. Yes. However, it is important to distinguish between (i) the flotation cost adjustment that is applied in capital budgeting and (ii) the flotation cost adjustment that is required for setting the allowed rate of return.

For example, in capital budgeting the flotation cost adjustment is used to determine the minimum rate of return, or discount rate that must be earned on a particular project if the company is going to issue common stock to finance the project. The price of the common stock to which the capital budgeting flotation cost adjustment is applied is an exogenous variable that is treated as a "given" price in the capital budgeting analysis. In addition, the rate of return earned by the company's existing investments is of no consequence or interest in the capital budgeting analysis. Regardless of the return earned by the existing investments, the capital budgeting analysis assumes that, because of flotation costs, the new project requires a rate of return that is greater than the return required by the existing investments.

In contrast, the flotation cost adjustment required in setting a regulated rate of return is explicitly designed to increase the stock price by an amount sufficient to allow the regulated utility to issue common stock without diluting the value of the existing investment. Thus, unlike capital budgeting, the flotation cost adjustment used to calculate the regulated rate does not treat the stock price as a given, exogenous, factor. In addition, because a single allowed rate of return applies to all of the regulated assets of a utility, and is not different as between new investments and existing investments, the flotation cost adjustment needs to be applied to the entire rate of return.

Q. **Can you provide an example of the anomalies that can result from applying a flotation cost adjustment for a regulated utility by applying the capital budgeting method for determining a discount rate for a single project?**

A. The capital budgeting flotation cost adjustment recommended in financial management textbooks produces widely different results for companies with different dividend yields and payout ratios. For example, suppose there are two companies that have identical risks and required rates of return on common equity, but they have different dividend yields and expected future growth rates. In these circumstances, if the flotation costs are 5 percent of the gross price, the required rate of return in the secondary market and the primary market for these two companies might be as follows:

	Secondary Market	Primary Market
	$D_1/P_0 + g = k$	$D_1/(P_0 – f) + g = k$
Company A:	\$0.80/\$10 + 4% = 12%	\$0.80/(\$10 - \$0.50) + 4% = **12.42%**
Company B:	\$0.20/\$10 + 10% = 12%	\$0.20/(\$10 - \$0.50) + 10% = **12.11%**
Difference		**0.33%**

As this comparison demonstrates, the flotation cost adjustment is significantly higher for the company with a high dividend yield, even though each company has the same risks and required rate of return in the secondary market. In these circumstances, both companies should have the same flotation cost adjustment and the adjustment should be applied to the entire DCF rate of return estimate, which is 12 percent for both companies. Conversely, in capital budgeting the flotation cost adjustment is made to the dividend yield component of a rate of return estimate that uses only the specific company that is contemplating the investment. In addition, capital budgeting assumes that the individual project will pay out the same dividends as a percent of the value of the single project investment as the entire company, and that future growth for the company will occur at the same rate with or without the investment in the project. Moreover, the flotation cost adjustment is applied to the proxy companies, which will not have the same "dividend yield" component as the regulated company. Thus, the capital budgeting flotation cost adjustment is not appropriate for setting an allowed rate of return for regulatory purposes, and it may not be accurate even for setting a capital budgeting discount rate.

Q. Is the need for a flotation cost adjustment to the entire rate of return widely recognized among economists as a required part of an allowed rate of return that will attract capital without diluting the value of existing investors' equity?

A. Yes. In commenting on the fair rate of return in his classic treatise on public utility ratemaking, Professor Bonbright stated that:

> *"…book values (with allowances for the probable need to underprice new common-stock offering) should set a floor to the market values…"*

James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 249. Similarly, Myron Gordon, the man who is credited with having developed the DCF model for estimating rate of return, has stated that a regulatory agency should set the allowed rate of return greater than the investor return requirement so as to allow the firm to issue stock at a price that will yield net proceeds equal to book value. Professor Gordon advocates the following adjustment:

> *"The agency need only estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value."*

Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, 1974, pages 165-166. In order to meet this requirement, the flotation cost adjustment must be applied to the entire rate of return. The flotation cost adjustment that I propose attempts to meet the same standards advocated by these other economists.

Q. Have you quantified the cost of raising capital by issuing stock in the "primary" market?

A. Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital. Exhibit No. HIO-75 shows a representative sample of flotation costs incurred with 44 new common stock issues by natural gas pipeline and distribution companies between 1995 and 2005. Flotation costs associated with these new issues averaged 4.35 percent. This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, HIOS must have an expected return that places a value on its equity that is approximately 4.35 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.0435.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to <u>enable</u> a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

In summary, when a DCF analysis is based on stock prices and dividend yields in the "secondary" market, and the results are used to estimate the cost of capital and a reasonable allowed rate of return for a regulated company, a flotation cost adjustment is essential in order to account for the difference between (i) stocks traded between investors in the secondary markets and (ii) stock issued in the primary market to raise capital for plant construction and utility operations.

DCF Study of HIOS's Cost of Equity Capital in Primary Financial Markets

Q. Would you please describe the overall approach used in your DCF analysis of the cost that HIOS would incur if it needed raise common equity capital in the primary financial market?

A. It is essential that HIOS have an allowed return that matches returns potentially available from other similarly risky investments. In recent years, the Commission has stated a preference for using the DCF method for estimating the required return for interstate gas pipelines. However, the DCF method utilizes a price of common stock that is observed in the secondary-market in order to compute the dividend yield component of the DCF analysis. Since all interstate gas pipelines, including HIOS, are subsidiaries of larger corporate or partnership ownership structures, the operating pipeline companies for which the Commission sets rates generally do not have publicly-traded common stock that would produce a secondary-market price that is required for a DCF analysis. A direct, secondary-market-based DCF analysis of HIOS as a stand-alone company is not possible since it is owned by Enterprise Products Partners, L.P.. To get around this problem, I have used a proxy group of pipeline entities that have operations similar to HIOS's regulated interstate natural gas pipeline operations. Consequently, my estimate of the rate of return which investors require for HIOS is primarily determined by conducting a market-based DCF analysis of eight publicly-traded companies that have substantial natural gas pipeline operations. This analysis of generally comparable proxy companies suggests the range of returns that could be appropriate for HIOS.

<u>Analysis of Pipeline Proxy Companies</u>

Q. How did you select your group of proxy companies?

A. I primarily used the standard prescribed by the Commission:

> *In <u>Equitrans</u>, the Commission set forth the appropriate standards for proxy companies. Those requirements are: (1) The company's stock is publicly traded; (2) the company is recognized as a natural gas pipeline company and its stock is recognized and tracked by investment information service; and (3) pipeline operations constitute a high proportion of the company's business.*[1]

Based on these criteria, I selected a group of eight publicly-traded companies that have substantial natural gas pipeline operations. This proxy group (referred to as the Pipeline Proxy Group) consists of the group of companies that most closely match the risks of HIOS. In addition, purely for demonstration purposes, I have calculated required rates of return for three gas distribution companies – Equitable, National Fuel and Questar – that

[1] *Transcontinental Gas Pipeline Co.*, 90 FERC ¶ 61, 279 at 61,933.

have been used in some Commission decisions in recent years despite the fact that they generally have lower risks than a typical natural gas pipeline company, and especially lower risks than a high-risk pipeline such as HIOS. Although required rates of return for the distribution companies are computed for demonstration purposes herein, my recommendation is based on analysis of the eight non-distribution companies. The entities in the Pipeline Proxy Group and the illustrative gas distribution companies include:

Pipeline Companies

El Paso Corporation
Enbridge Energy Partners, L.P.
Enterprise Product Partners, L.P.
Kinder Morgan Energy Partners, L.P.
Kinder Morgan Inc.
ONEOK Partners, L.P.
TC Pipelines, L.P.
Williams Companies, Inc.

Gas Distribution Companies

Equitable Resources, Inc.
National Fuel Gas Co.
Questar Corp.

Comparability of Pipeline MLP's

Q. Are you aware that in the past the Commission has rejected the use of Master Limited Partnerships "MLP's" in proxy groups used to estimate the cost of capital for corporations?

A. Yes, I am aware that the use of MLP's is an unsettled issue. However, I have reviewed several decisions by the Commission and ALJ's on this topic and in my opinion each reason that has been cited for excluding MLP's from the proxy group is not supportable from the standpoint of economic and financial theory.

Q. What reasons has the Commission cited for excluding MLP's from the analysis?

A. In January 2005, the Commission's decision in *HIOS* observed, first, that "… the claimed dividend yields for the MLPs are twice the yields of natural gas companies …"[2] and then rejected the use of MLP's because the record did not distinguish between cash flows to partners that were a return of capital and those cash flows that were a payout of current earnings. The decision indicated that:

> However, it is not clear from the evidence presented by HIOS that the "dividend" figures supplied by HIOS for the MLPs it proposes to include in the proxy group are comparable to the corporate dividends the Commission uses in its DCF analysis. Partnerships make distributions to their partners, rather than pay dividends to stockholders. Those **distributions may include payment to the partners of a share of the partnership's earnings; to that extent the distribution is comparable to corporate dividend payments**. However, the distributions may also include a return of a portion of the partners' original investment, unlike a corporate dividend.[111] Use of a distribution payment that includes both earnings and a return of investment as an MLP's "dividend" for purposes of a DCF analysis would skew the DCF results, **since the dividend yield would appear higher than it actually was**.[112] Thus, the Commission will not consider including an MLP in the proxy group, unless the record demonstrates that the distribution used as the "dividend" includes only a payment of earnings and not a return of investment.[3]

This rationale does not correctly take into consideration the components of a DCF analysis. A DCF analysis consists of a current dividend yield, plus a forecast of the future growth rate of a company. However, the *HIOS* decision discusses the higher

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[2] High Island Offshore System, L.L.C., Docket Nos. RP03-221-000 and RP03-221-002, Order on Initial Decision and Settlement Offer, 110 FERC ¶61,043 (2005), paragraph 127, emphasis added.

[3] *High Island Offshore System, L.L.C.*, Docket Nos. RP03-221-000 and RP03-221-002, Order on Initial Decision and Settlement Offer, 110 FERC ¶61,043 (2005), paragraph 126, emphasis added.

dividend yields of MLP's without any recognition that there generally is an inverse relationship *between* the dividend yield and the growth rate. For example, other things being equal, a company that is expected to pay dividends that exceed its earnings (i.e., to have a negative earnings retention rate) in some years in the future generally would have a lower expected growth rate than a company that retains and reinvests all of its earnings. Thus, if a dividend yield consists of a return of capital, the estimated growth rate should fully reflect that fact so that the total DCF rate of return estimate is commensurate with the risks and required return for the company.

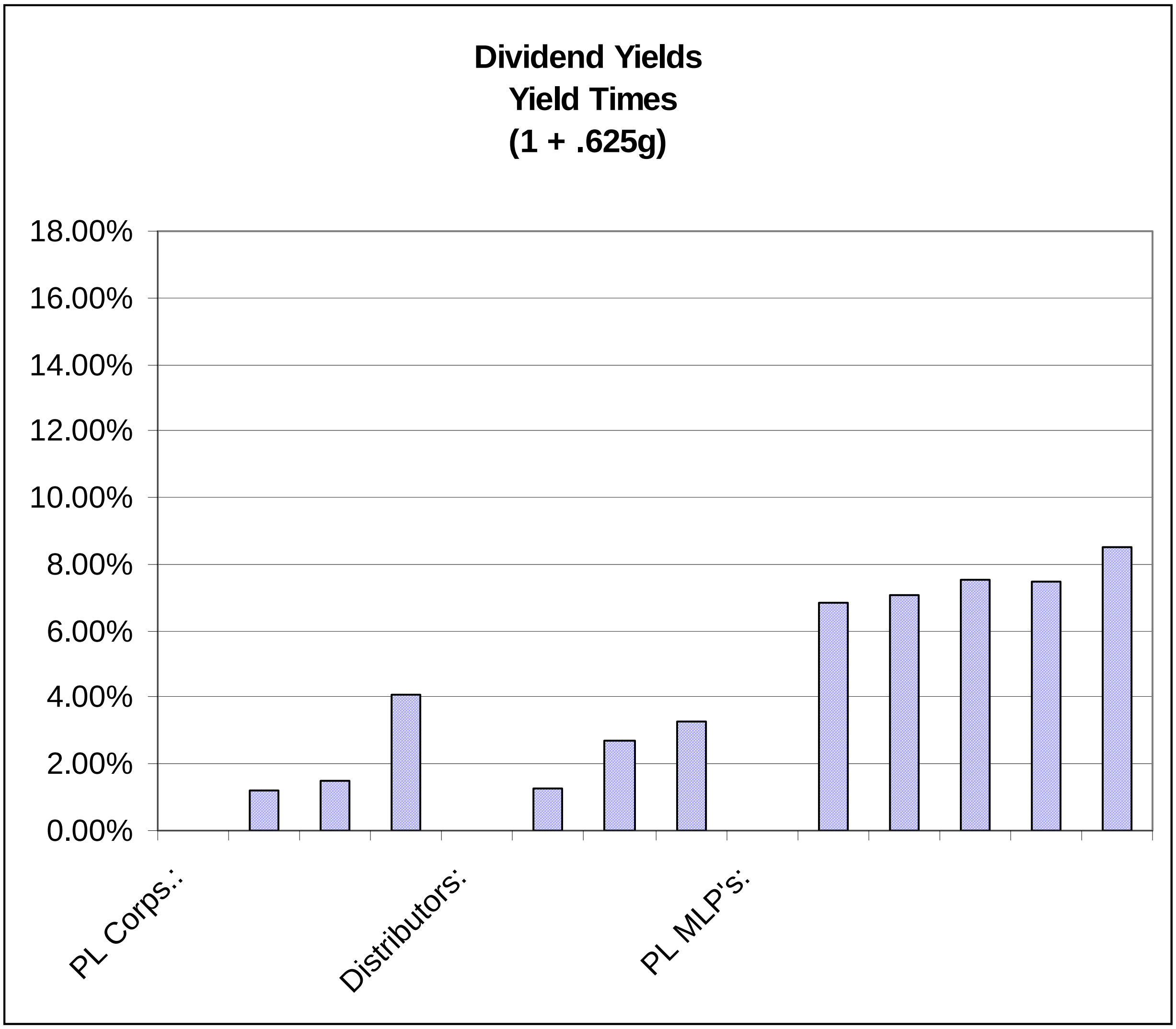
The deficiency in the *HIOS* decision's reasoning is illustrated by a situation in which a man walks from the back of a boat to the front of a boat. Although the boat becomes lighter in the back and heavier in the front, the total weight of the boat is unchanged. However, the reasoning of the *HIOS* decision would suggest that the total weight of the boat can be measured accurately when the man stands in the back, but that the boat's weight cannot be accurately measured when the man stands in the front of the boat. Because the *HIOS* decision never considered the obvious likelihood that higher dividend yields of MLP's are offset by lower growth rate estimates – i.e., merely shifting weight from the back end (growth rate component) of the total return, to the front end (dividend yield component) of the total return – the *HIOS* decision had no logical basis for concluding that the total DCF results for the MLP's were inaccurate. It is always the case that the components of a DCF analysis might occur in different proportions for different companies. However, the relevant consideration is whether the total return indicated by the components is accurate. The *HIOS* decision never addressed this consideration.

Q. Is the tradeoff between dividend yields and growth rates evident in your DCF analysis?

A. Yes. For example, it is useful to compare the dividend yields of the five MLP's in the proxy group with the dividend yields of the three pipeline companies and also, for demonstration purposes, with the dividend yields of the three pipeline companies combined with the three gas distribution companies. The average dividend yields of these three groups are as follows:

	Average Adjusted Dividend Yields
Gas Pipeline Corporations	2.25%
Gas Pipeline Corporations and Gas Distribution Cos.	2.35%
Gas Pipeline Master Limited Partnerships	**7.49%**

In addition, the dividend yields of each of the eleven companies are as follows:



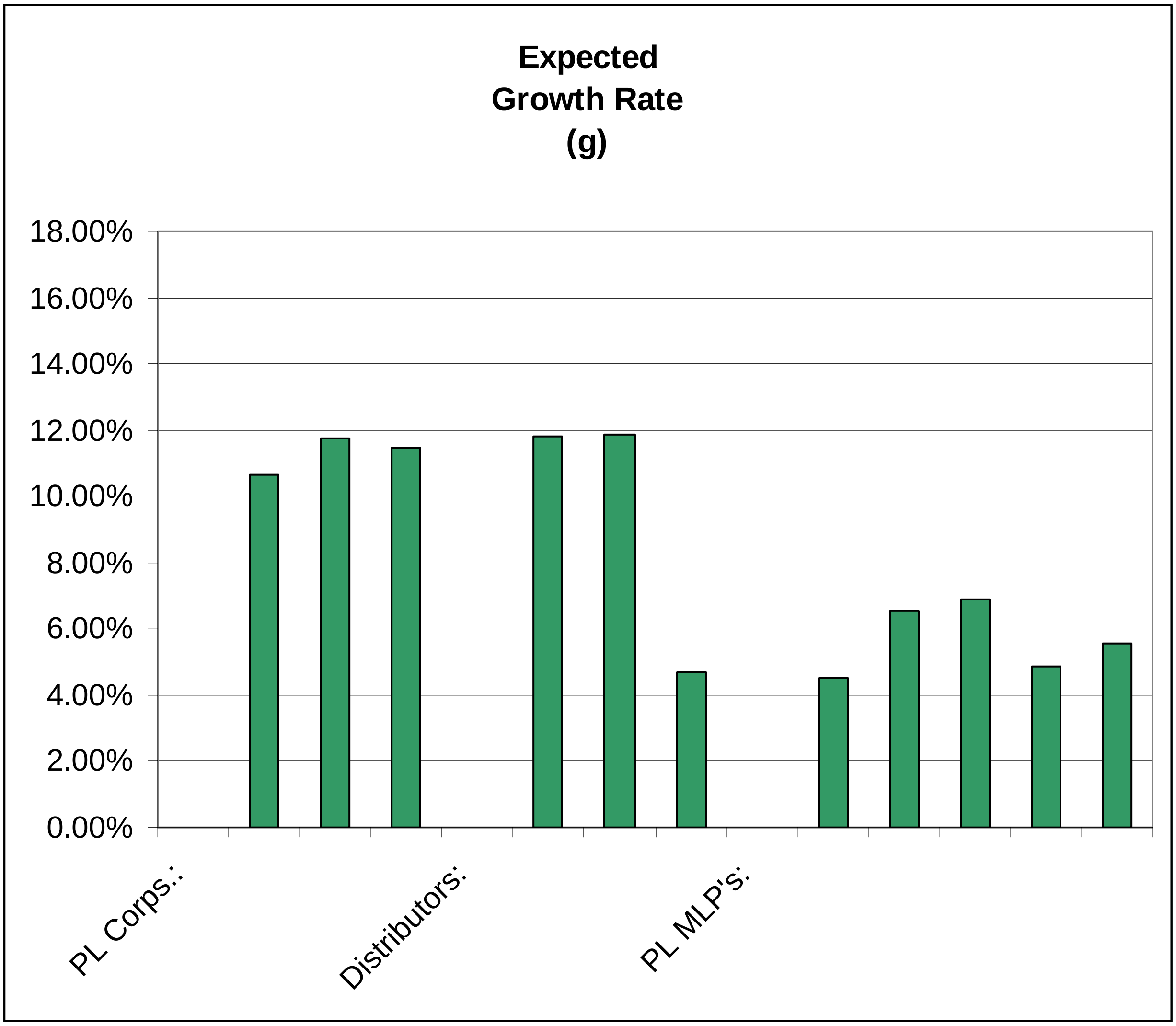
Obviously the dividend yields of the gas pipeline MLP's (shown on the right) are considerably higher than the dividend yields of either the gas pipeline corporations or the gas distribution companies. However, the reasoning in *HIOS* suggests that high distributions by MLP's result in inaccurate, or skewed, results *for the DCF analyses*, not just for the dividend yield component of the DCF analysis. In particular, the observation that "…**the dividend yield would appear higher than it actually was**" suggests that a DCF analysis of MLP's would skew the DCF analysis toward providing excessively high estimates for the cost of capital. However, investors are sufficiently rational to understand the nature and sources of the distributions paid by the MLP's. As a result, investor expectations of future growth for the MLP's should reflect this information in such a way that higher dividend payouts and higher dividend yields generally would be offset by lower expected growth rates for the gas pipeline MLP's. To the extent that lower expected growth rates offset high dividend yields, the reasoning in *HIOS*, which considered only the dividend yield component of the return, is inadequate to justify a conclusion that the overall DCF results are skewed or inadequate.

Q. Is it apparent that the higher dividend yields of MLP's are offset by lower expected growth rates?

A. Yes. The average growth rate estimates for the three groups of companies are:

	Average Expected Growth Rates
Gas Pipeline Corporations	11.29%
Gas Pipeline Corporations and Gas Distribution Cos.	10.37%
Gas Pipeline Master Limited Partnerships	**5.75%**

Moreover, the estimated growth rates for each of the eleven companies is as follows:



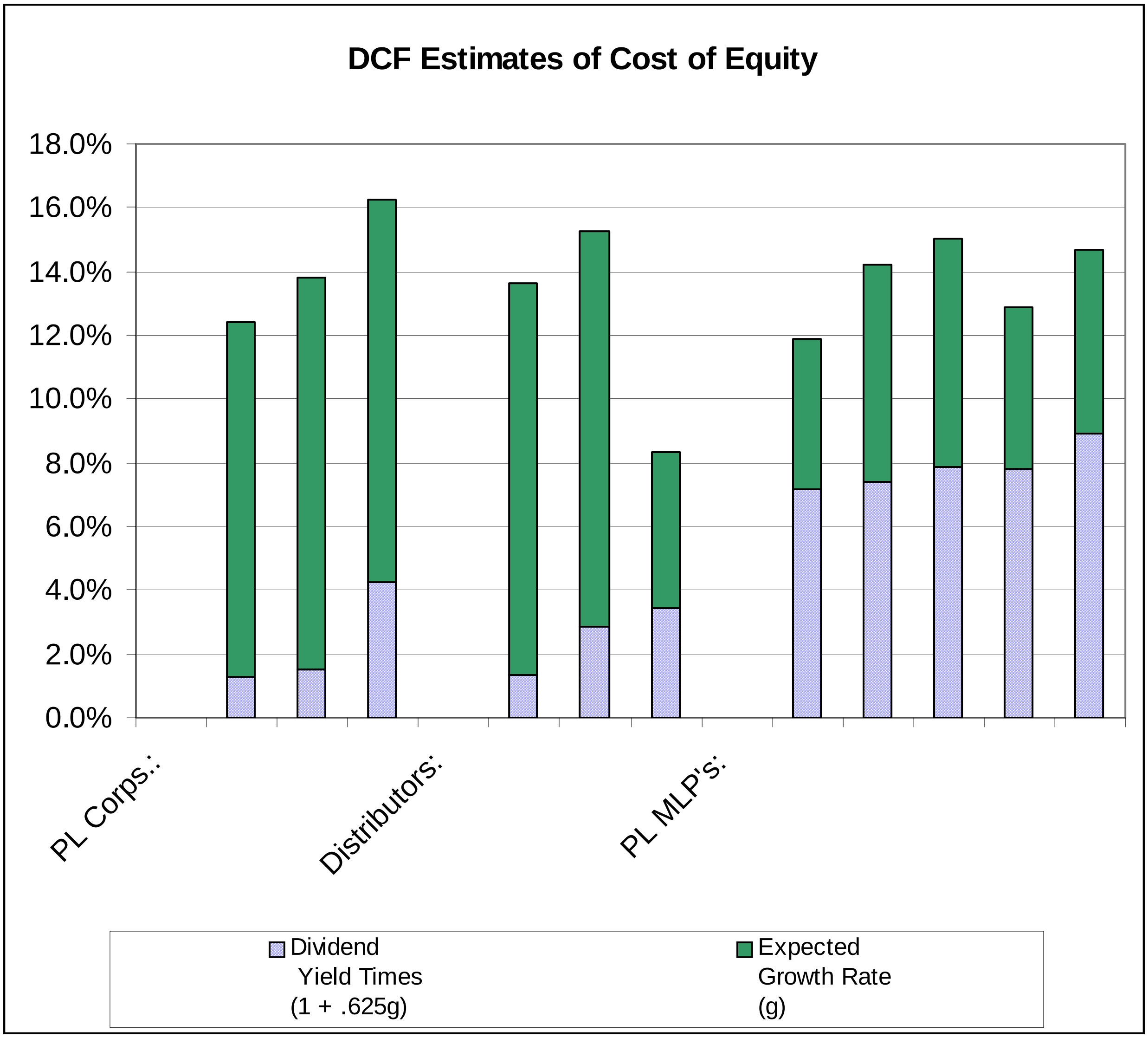
Clearly, the MLP's (shown on the right) generally have much *lower* expected growth rates than the other companies, which strongly suggests that investors are fully aware of the nature and source of MLP dividends, and are also aware that higher dividend yields are offset by lower expected growth rates.

Q. **Does your analysis indicate that dividend yields and growth rates interact so as to produce an overall estimate of the required rate of return that reflects the risks of a natural gas pipeline?**

A. Yes. The interaction between lower expected growth and higher dividend yields produces overall results that are neither skewed nor necessarily inaccurate. For example, examination of the three groups of companies indicates no evidence whatsoever that the required rates of return estimated for the MLP's are somehow skewed or, in particular, higher than they actually would be.:

	Average DCF Estimates
Gas Pipeline Corporations	14.13%
Gas Pipeline Corporations and Gas Distribution Cos.	13.27%
Gas Pipeline Master Limited Partnerships	**13.82%**

Moreover, the lack of any apparent skewness in the DCF results for the MLP's is illustrated in the following primary-market results:



Q. What do you conclude from this analysis?

A. The inclusion of MLP's in my DCF analysis produces results that are neither skewed nor overstated. Instead, the total cost of common equity that I have estimated for the MLP's (shown on the right) is substantially similar to the cost of common equity estimated for the corporations (shown on the left). In addition, these data demonstrate why the reasoning in the *HIOS* decision – which never addressed the fact that higher dividend payouts and higher dividend yields generally would be offset by lower expected growth rates for the gas pipeline MLP's – was not supported.

Q. Did the *HIOS* decision suggest any other reasons for rejecting the use of MLP's in the proxy group?

A. The decision also mentioned that "[t]he ALJ was concerned that, because MLPs do not pay corporate taxes," but there was no further discussion or recognition of the tax question in the *HIOS* decision.

<u>Theoretical Comparison of Corporations and MLP's</u>

Q. Have you prepared examples to respond to these claimed differences between Corporations and MLP's?

A. Yes. The prior decisions have suggested or stated explicitly that pipeline MLP's are not sufficiently comparable to a pipeline corporation to use MLP's in a DCF analysis of the rate of return required by pipeline corporations, even when those corporations are subsidiaries of MLP's. Only two reasons have been cited for the theory that a DCF analysis of MLP's will not produce results that are relevant for corporations.

One theory claims that the distribution yield of an MLP will appear to be higher than it would be otherwise if a portion of the distribution is a return of capital for tax and financial accounting purposes. As I discussed above, a high distribution yield does not mean that the DCF results are wrong if the high yield is offset by a lower expected growth rate. The results of my DCF analysis reflect the inverse relationship between yields and expected growth rates. Moreover, the different treatment of personal taxes does not necessarily overstate the expected return for an MLP when there is a return of capital. The first example below will show that an MLP and a corporation that have the same net cash flow after corporate taxes, will both require a given investor to pay essentially the same personal taxes, and leave that investor with essentially the same after-tax income during a one-year holding period. This result occurs even when the MLP pays out cash flow that technically is a "return of capital," while the corporation would retain and reinvest those funds so as to maintain, or increase, the company's future income. In addition, the personal tax effects of a return of capital should be greatly mitigated by the tendency for various types of investors to be attracted to investments that have tax characteristics that are advantageous for their circumstances. Finally, any remaining effects of personal taxes should be eliminated when the stock price, or the unit price, adjusts so as to arbitrage away any differences in the after-tax expected rate of return.

Q. What is the second theory with respect to the use of MLP results to set the rate of return for a corporation?

A. The other theory advanced is that a DCF analysis of MLP's is somehow invalid for setting corporate rates of return because MLP's do not pay corporate income taxes. However, the essence of a DCF analysis is the recognition that investors will adjust the stock price to reflect differences in the cash flows of companies that have equal risks. Consequently, the example below demonstrates that the same DCF return results will be obtained for an MLP and a corporation, despite the differences in their corporate tax liabilities, because investors will adjust the stock prices so as to account for the different tax treatment.

A “Return of Capital” is Not a Significant Difference

Q. Would a DCF analysis of MLP’s be overstated if a part of the distribution consists of a non-taxable return of capital to the owners?

A. No. It should be stressed that the investor pays income taxes each year on the earnings of the MLP regardless of whether the investor receives any distributions. Consequently, a distribution is largely a method of giving the partners their own money on which they have already paid income taxes. A somewhat analogous transaction for a corporation would occur if (i) the corporation paid dividends, (ii) stockholders paid personal taxes on their dividends, (iii) stockholders then gave the corporation an amount equal to the dividends on which they paid tax, and (iv) the corporation simply returned to each stockholder the money that the stockholder had given in the prior step. The point is that a “return of capital” has a different meaning for a partnership than it does for a corporation and the significance of a “return of capital” for a partnership will be misinterpreted if the corporation definition is applied to a partnership.

When a portion of an MLP’s distribution is a return of capital, the actual impact is to *defer* the payment of a capital gains tax on the returned capital until the shareholder sells its ownership interest. This tax effect is similar to the tax effect that would occur if a corporation were to retain and reinvest the cash flow that exceeds earnings. For example, when a corporation retains and reinvests cash flow, the value of the company is expected to increase so that, when the investor later sells its stock, the increase in value is subject to capital gains taxes that are *deferred* until the time of the stock sale. In other words, both forms of business structure create a combination of immediate personal taxes and deferred capital gains taxes, when an MLP pays distributions that are, in part, a return of capital, the overall personal-tax impact is expected to be more like the personal-tax impact experienced by a corporation that pays dividends that are not a return of capital in the context of a corporation. This similarity of overall impact is contrary to the assumption underlying the *HIOS* decision.

Q. **Are there other reasons why the results of a DCF analysis are likely to be unaffected by a return of capital in the distribution?**

A. Yes. Another reason for discounting the effects of a return of capital is the fact that some investors in high tax brackets will bid up the price of MLP's that have tax benefits associated with the return of capital. To understand why distributions that represent a return of capital are unlikely to overstate the cost of capital indicated by a DCF analysis, it is useful to compare how taxable distributions and non-taxable distributions affect the market for each type of investment. Two concepts are relevant for this analysis. First, in an efficient market stock prices will adjust to account for differences in the after-tax values of cash distributions. For example, consider two companies that both pay a distribution of $1 per share, and that both have a projected distribution growth rate of five percent.

Suppose that the stock price for Company A is $10 per share and that distributions from Company A are taxed at a marginal *personal* tax rate of 30 percent. A DCF analysis will indicate that investors require the following rate of return to invest in Company A:

Company A, DCF Required Return: $1/$10 + 5% = **15%**

However, when investors receive their distribution they must pay 30% in taxes, so the after-personal-tax return required by investors is actually:

Company A, After-Personal-Tax Req. Return: ($1*(1-.30))/$10 + 5% = 12%

In other words, when investors require an after-personal-tax return of 12%, they will pay a price for the stock ($10 per share) that provides a return of 15% based on the cash flows expected from the company.

In contrast, suppose that Company B is an MLP that pays distributions that are a return of capital and, therefore, <u>not</u> immediately subject to personal income taxes. In this case investors will compare Company A to Company B and realize that, at a price of $10 per share for both companies, they would get an after-personal-tax rate of return of 12% by investing in Company A, but an investment in Company B would yield a better after-personal-tax return of 15%. However, if these companies have equivalent risks, a difference in expected returns from the two companies will not persist. Instead, an efficient market will bid up the price of Company B (or bid down the price of A) until the expected after-personal-tax return that is approximately equal for the two investments. In this example, investors might pay $14.286 per share for stock in B, and the resulting returns would be:

Company B, DCF Required Return: $1/$14.286 + 5% = 12%

and the resulting after-personal-tax return also would be 12%, as follows:

Company B, After-Personal-Tax Req. Ret.: ($1*(1-.00))/$14.286 + 5% = 12%

In other words, when the distributions from a company, such as Company B, are not subject to personal income taxes, the logical result in an efficient market is a *reduction* in the rate of return indicated by a DCF analysis of the company. In this example, distributions from Company B are not subject to personal taxes and the Commission decisions are correct in suggesting that this makes distributions from

Company B more valuable than those from Company A. However, an efficient market will tend to equalize the after-personal-tax rate of return expected from both companies by increasing the stock price for Company B so that the DCF required rate of return for Company B is only 12% instead of the 15% required rate of return indicated by a DCF analysis of Company A. In fact, the popularity of the MLP structure for pipelines can be attributed to the fact that it tends to reduce the cost of common equity capital.

Q. Are there other reasons to expect that a return of capital in MLP distributions would have little or no effect on the results of a DCF analysis?

A. Yes. Financial and economic theory recognizes that tax considerations cause investors to prefer investments that favor their particular tax status. For example, investors who are in high tax brackets will tend to favor investment in MLP's because the tax advantages of a return of capital produce higher after-tax rates of return than they might achieve from corporations. This phenomenon of certain types of investors concentrating on certain types of investments is referred to as a "clientele" effect, and it is relevant for the MLP issue because it can greatly reduce the effect that tax advantages from an MLP's return of capital might have on the required rate of return produced by a DCF analysis.

An example similar to the one used to demonstrate the effects of MLP's on after-tax returns is useful for understanding why the "clientele effect" may eliminate the effects of distributions that include non-taxable returns of capital. Suppose that people and institutions that do not immediately pay personal income taxes (e.g., foundations, Universities, retirement plans, etc.) concentrate their investments in corporations that pay "taxable" distributions, the after-personal-tax returns for these investors will be identical to the DCF required rate of return from these companies. This result occurs when the distributions from Company A are taxed at a marginal *personal* tax rate of zero (0.0) percent. A DCF analysis will indicate that investors require the following rate of return to invest in Company A:

Company A, DCF Required Return: $1/$10 + 5% = 15%

However, if the investment is held by investors who do not pay personal income taxes, the required return after tax is not affected by taxes, as can be seen in this calculation of the after-tax required return:

Company A, After-Personal-Tax Required Return: ($1*(1-.00))/$10 + 5% = 15%

In other words, when a company that pays taxable distributions has an investor clientele that does <u>not</u> pay personal taxes, the effect on the required rate of return is identical to the effect that would occur if the distributions were tax free.

On the other hand, if investors who are in high tax brackets concentrate on investments that pay non-taxable, or tax-deferred, distributions, such as MLP's that include a return of capital in their distributions, those investors might achieve returns from Company B that are nearly the same as the returns to be derived from investments in Company A. With a clientele effect, a likely rate of return analysis would indicate the following returns:

Company B, DCF Required Return: $1/$10 + 5% = 15%

and, if 100 percent of the distribution is a return of capital that is tax free, or tax deferred, the resulting after-personal-tax return also would be 15%, as follows:

Company B, After-Personal-Tax Required Return: ($1*(1-.00))/$10 + 5% = 15%

In other words, a "clientele effect" reduces any personal tax effects that might be associated with a return of capital by an MLP. Corporations and MLP's generally would be held by different clienteles that are distinguished with respect to their personal tax status.

Q. **Is there any reason to believe that the yield calculated for the MLP's is understated?**

A. Yes. The distributions used in the calculation are those received by the limited partners which typically own 98 percent of the partnership. However, if the MLP is steadily increasing its payout, the General Partner usually receives very large bonus distributions that are disproportionate to its ownership interest. Consequently, the yield for limited partners that is calculated in the DCF analysis is understated to the extent that the General Partners are receiving significantly disproportionate distributions that are not part of the DCF calculation.

<u>Corporate Taxes Do Not Change the DCF Results</u>

Q. If an MLP does not pay corporate taxes, would a DCF analysis be expected to produce results that are different from those of a corporation?

A. No. The fundamental theory of the DCF analysis is that the stock price should adjust to reflect the risk and expected cash flows from an investment. For a given level of risk, an MLP that is expected to generate 50 percent higher cash flow than the same company organized as a corporation should have a unit price that is greater than the stock price of the same company organized as a corporation. Thus, the exemption from corporate taxes would generate higher cash flows, but the stock price should adjust so that the required rate of return produced by a DCF analysis reflects the risk of the entity and is essentially the same regardless of whether the company is a corporation or an MLP.

Q. Would you provide an example of how the price of equity units would change if a company switched from being a corporation and became an MLP that is not subject to corporate taxes?

A. Suppose a corporation faces a corporate income tax rate of 33.33% and it has gross income of \$22.50 per share, and that it is able to grow by 5 percent per year without retaining any earnings, but that retained earnings will increase its growth rate. This corporation has a book value of \$100 and is expected to have net income of \$15 after paying corporate taxes. Assume also that the cost of common equity is 15%, and that the corporation is expected to pay a dividend of \$10 in the upcoming year, and retain earnings of \$5, an amount equal to 5 percent of book value. Between retention growth of 5 percent and an additional growth of 5 percent from other sources, the corporation's income and dividends are expected to grow at a rate of 10 percent per year. The stock price in this case would be **\$200**, derived from the following standard formula:

$$P_{Corp} = D_1/(k - g) = \$10/(15\% - 10\%) = \mathbf{\$200}$$

Where:

P_{Corp} = the price per share of corporate stock
D_1 = The expected dividend next year
k = the cost of capital
g = the expected growth rate of future cash flows

On the other hand, an MLP would not pay corporate income taxes and it would have income available to stockholders of \$22.50. If the MLP is expected to pay the whole \$22.50 as a distribution, its growth rate would be 5 percent from miscellaneous sources, but zero growth would come from earnings retention. The stock price for this MLP would therefore be **\$225**, calculated as follows:

$$P_{MLP} = D_1/(k - g) = \$22.50/(15\% - 5\%) = \mathbf{\$225}$$

Where:

P_{MLP} = the price per unit for partnership units

A DCF calculation of the cost of common equity for these two companies would be:

	Corporation	MLP
Dividend/Distribution	$10.00	$22.50
Price per Share/Unit	$200.00	$225.00
Yield	5%	10%
Expected Growth	10%	5%
DCF Estimate of Return	**15%**	**15%**

As this example demonstrates, the fact that an MLP does not pay corporate taxes should not affect the results of the DCF analysis because the price of partnership units would be expected to adjust to the greater cash flows available in the absence of corporate income taxes. For both a corporation and an MLP, the DCF estimate would be expected to be 15 percent.

Q. What do you conclude with respect to the effects of MLP status on the cost of capital estimated by a DCF analysis?

A. The concepts of efficient markets and clientele effects in financial economics suggest that MLP status and a return of capital should have little or no effect on the required rate of return indicated by a DCF analysis. As this analysis demonstrates, it is incorrect to suggest that distributions that include a tax-free return of capital cause the expected rate of return produced by a DCF analysis to be overstated. Instead, it is more likely that a DCF analysis of MLP's that pay a return of capital might *understate* the rate of return required by a corporation with equivalent risks. Consequently, there is no theory under which the tax status of the MLP business structure would cause a DCF analysis of natural gas pipeline MLP's to overstate the cost of capital for a natural gas pipeline that is organized as a corporation. Because it is important to use a proxy group that has risks that are as similar as possible to those of the regulated entity, the natural gas pipelines that are structured as MLP's should be included in the proxy group when data are available to estimate their growth rates .

Q. Have any other decisions adopted the HIOS approach?

A. Yes. The *HIOS* approach subsequently was applied in cases involving Bay State Gas Storage Company and Cranberry Pipeline Corporation.[4] In addition, in March 2006 an Initial Decision was issued by an ALJ in a case involving Kern River Gas Transmission Company.[5] That decision simply cited to the *HIOS* decision and rejected the use of MLP's in the proxy group because there had not been a showing that the dividend yield of these companies, and the partnership distributions in particular, were not a return of capital for tax purposes.[6] Thus, the Judge treated the *HIOS* decision as a precedent without further analysis. However, the reasoning of the *HIOS* decision did not reflect the economic fundamentals of a DCF analysis and, notably, Commissioner Brownell dissented from the portion of the *HIOS* decision concerning MLP's because she believed that MLP's should properly be included in the proxy group. For example, in dissents in *HIOS* and *Bay Gas Storage Company*, Commissioner Brownell stated:

> HIOS argues that Commission precedent has uniformly rejected use of distribution companies as proxies for gas pipelines because distributors have franchised service territories and, therefore, significantly lower risks.

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[4] *Bay Gas Storage Company, Ltd.*, 111 FERC ¶61,345 (2005); and *Cranberry Pipeline Corporation*, 112 FERC ¶61,268 (2005).

[5] *Kern River Gas Transmission Company*, Initial Decision, Docket No. RP04-274-000, 114 FERC ¶ 63,031 (March 2, 2006).

[6] *Id.*, at para. 270 – 275.

> HIOS offered the alternative to include four pipeline master limited partnerships (MLPs) in the proxy group. The Commission has permitted use of MLPs in the proxy group in SFPP, L.P. The majority acknowledges that, in theory, it might be appropriate to compare HIOS, an L.L.C. owned by an MLP, to other MLPs whose business is made up primarily of pipeline operation. Consequently, I believe the proxy group used by the majority is unrepresentative.[7]

DCF Analysis of Proxy Companies

Q. How did you calculate the dividend yields for the companies in your comparison group?

A. These calculations are shown on page 3 of Exhibit No. HIO-76. For the price component of the calculation I used the average of the high and low stock prices experienced by each company during the six month period from February 2006 to July 2006. The dividend yields were calculated for each company by dividing the indicated annual dividend by the average of the stock prices for each company. These dividend yields are then multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the dividend yield component of the secondary-market DCF model.

Q. Please describe the method you used in estimating the future growth rate that investors expect from this group of companies.

A. I developed a "two-stage" growth rate analysis using publicly-available forecasts that marginal investors reasonably rely upon when they buy and sell each of the proxy companies at a specific stock price in the secondary market. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must

[7] High Island Offshore System, L.L.C., 110 FERC ¶61,043 (2005) at 61,173, footnote omitted; also dissenting in HIOS Order on Rehearing 112 FERC ¶61,050 (2005); and Bay Gas Storage Company, Ltd., 111 FERC ¶61,345 (2005) at 62,532 referencing HIOS; and Cranberry Pipeline Corporation, 112 FERC ¶61,268 (2005) at 62,249.

attempt to ensure that the end result is an estimate that reasonably reflects the forward-looking growth rate that investors expect. Investment analysts and information services provide company-specific forecasts of growth for each of the proxy companies. In my analysis of the proxy group, I have used a combination of: (i) the consensus of investment analysts' forecasts of long-term earnings growth rates that are published for each proxy company; and (ii) when available and meaningful, the Value Line retention growth rate forecasts that are developed specifically for each proxy company, or (iii) the Commission Staff's approach of using a forecast of the U.S. GDP growth rate when Value Line retention growth forecasts are not available or meaningful. In effect, the analysts' long-term earnings growth rate forecasts represent a first-stage growth rate that is expected to be maintained for a number of years in the future, and the forecast of earnings retention growth rates represent an estimate of a primary underlying determinant of second-stage growth that can be expected to begin occurring 3-5 years in the future, and that can be sustained by each company indefinitely thereafter. Unfortunately, Value Line does not publish retention growth rate forecasts for every company in the proxy group and two of the companies, Enterprise Products and Kinder Morgan Energy, did not have meaningful Value Line forecasts. Consequently, I have utilized the U.S. GDP growth rate forecast for those companies.

Q. What is the source of investment analysts' earnings growth rate forecasts that you used as a first stage expected growth rate?

A. Thomson First Call (formerly IBES) is a service that collects estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the

Thomson First Call consensus forecasts as the source for analysts' forecasts in my calculations as shown on page 5 of Exhibit No. HIO-76.

Q. Would you please describe the second stage, retention growth rate component of your analysis?

A. In addition to analysts' growth rate forecasts, where available, I have relied upon Value Line projections of the retention growth rates that the proxy companies are expected to begin maintaining three to five years in the future. Although companies may experience extended periods of growth for other reasons, in the long run, growth in earnings and dividends per share depend in part on the amount of earnings that are being retained and reinvested in a company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and, (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii).

Q. How can a company's earnings retention rate affect its future growth?

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that are generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (b) times the rate of return on common equity (r) that a company is expected to earn in the future. For example, a company that is expected to earn a return of 15 percent and retain 80 percent of its earnings might be expected to have a growth rate of 12 percent, computed as follows:

$$.80 \times 15\% = 12\%$$

On the other hand, another company that is also expected to earn 15 percent but only retains 20 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$.20 \times 15\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

Q. How did you calculate the expected future retention growth rates of the proxy companies?

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected to occur several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a *minimum* "cruising speed" that companies can be expected to maintain indefinitely. However, it should be noted that companies also tend to grow in a variety of ways in addition to retention of earnings. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies with available information is shown on page 4 of Exhibit No. HIO-76. The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that are being retained and reinvested in the company. This earnings retention rate is multiplied times the projected return on common equity to arrive at the projected retention growth rate that is expected for each specific company.

Q. How did you estimate the second-stage growth rate for those companies that lack Value Line forecasts that can be used to estimate future retention growth rates?

A. I have utilized the U.S. GDP growth rate forecast for those companies that do not have Value Line forecasts that can be used to estimate future expected retention growth rates. In reviewing the companies for which meaningful Value Line retention growth forecasts are not available it appears that the GDP growth rate forecast is remarkably close to the analysts' forecasts for those particular proxy companies. Thus, although the GDP growth rate forecast generally bears no relation to investors' realistic expectations for a second-stage growth rate, it is reasonable to use GDP growth when better data are not available and when the GDP growth rates are reasonably consistent with analysts' growth rate forecasts. Those conditions exist in this proceeding for the companies that do not have Value Line growth rate forecasts.

Q. How did you utilize the projected first- and second-stage growth rates in estimating expected growth for the proxy companies?

A. As shown on page 5 of Exhibit No. HIO-76, I calculated a weighted average of the analysts' projected growth rates and the projected second-stage growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave a two-thirds weighting to the analysts' growth rate projections to reflect the fact that analysts are attempting to evaluate all sources of growth and not just growth that is expected to result from retained earnings. This weighting also reflects the fact that the analysts' long-term growth forecasts can be expected to prevail for a relatively long period of time in the future.

This two-thirds weighting for analysts' forecasts is the same weighting that the FERC used in Opinion No. 414-A for setting the allowed return on equity for gas pipeline companies. *Transcontinental Gas Pipeline Co.*, 80 FERC ¶ 61,084 (1998).

Q. How did you utilize these weighted-average growth rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A. The dividend yield for each company shown on page 3 of Exhibit No. HIO-76 is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is then added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.0435 to arrive at the cost of common equity capital for the proxy companies. These calculations are shown on page 6 of Exhibit No. HIO-76.

Q. Would you please summarize the results of your DCF analysis of natural gas pipeline proxy companies?

A. The DCF analysis of pipeline proxy companies indicates the following distribution of results for the proxy companies, ranked in order:

16.24%
15.13%
14.77%
14.29%
13.79%
12.95%
12.38%
11.97%

It can be seen that the cost of common equity capital for the corporate proxy companies is in a range between 12.0 percent and 16.2 percent, and the median for the group is 14.0 percent.

Risk Premium Analyses

Q. Have you conducted additional analyses in determining the cost of capital to HIOS?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual returns on large company common stocks have exceeded the returns on Long-Term U.S. Government Bonds by an average of 660 basis points (6.60 percent). However, the returns on relatively small company stocks in the size range of HIOS's natural gas pipeline operations have been 1,560 basis points (15.6 percent) above the yields on long-term government bonds. As shown on page 1 of Exhibit No. HIO-76, HIOS is a fraction of the size of any of the proxy companies. In recent months, the yield on long-term U.S. Government bonds has been approximately 5.0 percent. Adding a 6.6 percent premium to a yield of 5.0 percent indicates that investors in large company common stocks expect a return of at least 11.6 percent. Adding the 15.6 percent premium for companies in HIOS's size range suggests a required return of 20.6 percent.

Another risk premium approach is to examine the long-term premium of large company common stock returns as compared with returns on corporate bonds. This premium has averaged 610 basis points (6.1 percent) annually over a long period of time in the past. When this premium is added to the 6.35 percent yield on Moody's corporate bonds that has prevailed in recent months, the result is an investor return requirement for large company stocks of 12.5 percent. However, over the long term companies in HIOS's size range have had a premium of 1,540 basis points (15.4 percent) over the average returns on long-term corporate bonds. When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 21.8 percent.

When compared with the returns of 20 percent or more that are indicated by the risk premium analyses of companies in the same size range, it is not unreasonable to use a rate of return of 14.04 percent, or higher, to set regulated rates for HIOS.

Alternative Equity Investment Analysis

Q. Have you analyzed the returns available on common equity investments in other industries?

A. Yes. When investors consider whether to invest their funds in a particular company or line of business, they evaluate the returns potentially available from other companies. This process whereby projects and companies compete for scarce equity capital ensures that capital resources are deployed efficiently. As a result, regulated natural gas pipeline operations must bid against other companies and other possible projects within the same company for equity capital by offering potential returns that investors find attractive relative to the risks involved.

Q. What level of returns are potentially available to unregulated companies?

A. The potential returns are often considerably above 20 percent and the average returns for broad-based, diversified portfolios have averaged 20.0 percent or more in recent years. For purposes of comparison with allowed returns for regulated natural gas pipeline operations, a good indicator of earnings on alternative equity investments is provided by data on 746 industrial, retail and transportation companies published by *The Value Line Investment Survey*. Excluding extraordinary and non-recurring items, the average returns on the original cost book value of common equity for these companies in recent years has been:

2000	32.44
2001	24.42
2002	26.18
2003	28.70
2004	31.91
5-year Average	**28.73%**

Q. Is it appropriate to set the allowed rate of return for a natural gas pipeline company equal to the average return available to industrial companies?

A. The average return for industrials serves as a useful indicator of the cost of capital because natural gas pipeline companies must offer potential returns that are competitive with other investments in order to attract capital. It is important to remember that an industrial company has an opportunity to earn returns far in excess of 20 percent. In fact, the average company has earned normal returns on the book value of equity well in excess of 20 percent in recent years. This average reflects many companies that experienced enormous losses as well as those with large returns.

Similarly, when a regulator sets an allowed return it is providing only an *opportunity* to earn that return. In exceptionally good times a regulated company might earn slightly more than this amount, but it might earn substantially less than the allowed return and, in fact, often does earn less than that amount. Natural gas pipeline companies generally have risks that are less than those of the average large industrial company. Consequently, it would be appropriate to view average returns earned by a broad cross-section of industry as being only a general indicator for reasonable allowed returns.

As a benchmark, allowed returns for natural gas pipeline companies can be compared to returns on book value for large companies. Normal returns have averaged 28.7 percent during the past five years. As this comparison also indicates, an allowed return of

14.04 percent for HIOS would be low in comparison with the returns earned by large companies.

IV. SUMMARY AND CONCLUSIONS

Q. Would you please summarize the results of your cost of capital study?

A. My DCF analysis of the eight pipeline proxy companies indicates that the cost of common equity faced by this comparable group of natural gas pipeline companies in the primary capital markets is in a range between 11.97% and 16.24%. For the reasons I have discussed, and in light of the risks faced by HIOS, I believe that a rate of return for HIOS that is at the median of my range is fully supportable, and therefore a rate of return of 14.04 percent for HIOS is justified. It is important to note, however, that this 14.04 percent median rate of return will not be adequate if the Commission adopts a management fee base that is lower than that supported by HIOS witness Porter, because application of the 14.04 percent rate of return to a lower management fee base will produce an inadequate margin on the operating costs of this pipeline.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of	)	
High Island Offshore System, L.P.	)	**Docket No. RP06-___-000**
	)	

Affidavit for Prepared Direct Testimony of J. Stephen Gaske

J. Stephen Gaske, being first duly sworn, states that he is the J. Stephen Gaske whose Prepared Direct Testimony accompanies this affidavit; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he adopts said testimony as his sworn testimony in this proceeding.

J. Stephen Gaske

J. Stephen Gaske

Subscribed and sworn to before me, a Notary Public in and for THE STATE OF MARYLAND this 25th day of August 2006.

Ryan M. Harper

Notary Public

RYAN M. HARPER
NOTARY PUBLIC
MONTGOMERY COUNTY
MARYLAND
MY COMMISSION EXPIRES OCT. 5, 2009

High Island Offshore System, L.P.

General Economic Statistics

1975-2005

	Percentage Price Changes			
Year	Consumer Price Index	GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP (Billions)
1975	9.1%	9.4%	-0.2%	1,638.3
1976	5.8%	5.8%	5.3%	1,825.3
1977	6.5%	6.4%	4.6%	2,030.9
1978	7.6%	7.0%	5.6%	2,294.7
1979	11.3%	8.3%	3.2%	2,563.3
1980	13.5%	9.1%	-0.2%	2,789.5
1981	10.3%	9.4%	2.5%	3,128.4
1982	6.2%	6.1%	-1.9%	3,255.0
1983	3.2%	4.0%	4.5%	3,536.7
1984	4.3%	3.8%	7.2%	3,933.2
1985	3.6%	3.0%	4.1%	4,220.3
1986	1.9%	2.2%	3.5%	4,462.8
1987	3.6%	2.7%	3.4%	4,739.5
1988	4.1%	3.4%	4.1%	5,103.8
1989	4.8%	3.8%	3.5%	5,484.4
1990	5.4%	3.9%	1.9%	5,803.1
1991	4.2%	3.5%	-0.2%	5,995.9
1992	3.0%	2.3%	3.3%	6,337.7
1993	3.0%	2.3%	2.7%	6,657.4
1994	2.6%	2.1%	4.0%	7,072.2
1995	2.8%	2.0%	2.5%	7,397.7
1996	3.0%	1.9%	3.7%	7,816.9
1997	2.3%	1.7%	4.5%	8,304.3
1998	1.6%	1.1%	4.2%	8,747.0
1999	2.2%	1.4%	4.5%	9,268.4
2000	3.4%	2.2%	3.7%	9,817.0
2001	2.8%	2.4%	0.8%	10,128.0
2002	1.6%	1.7%	1.6%	10,487.0
2003	2.3%	2.0%	2.7%	11,004.0
2004	2.7%	2.6%	4.2%	11,734.3
2005	3.4%	2.8%	3.5%	12,487.1
Average Rate of Change: 1/				
1975-2005	4.6%	3.9%	3.1%	7.0%
1985-2005	3.1%	2.4%	3.2%	5.6%
1995-2005	2.6%	2.0%	3.3%	5.4%

1/ Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

Sources: *Economic Report of the President* , February 2006 and *Economic Indicators* , April 2006.

High Island Offshore System, L.P.

Mergent Bond Yield Averages
August 2004 - July 2006

		Average	Public Utility Bonds	
		Corporate	A-Rated	Baa-Rated
2004	AUG	6.08	6.14	6.45
	SEP	5.91	5.98	6.27
	OCT	5.87	5.94	6.17
	NOV	5.89	5.97	6.16
	DEC	5.84	5.92	6.10
2005	JAN	5.72	5.78	5.95
	FEB	5.55	5.61	5.76
	MAR	5.77	5.83	6.01
	APR	5.65	5.64	5.95
	MAY	5.54	5.53	5.88
	JUN	5.35	5.40	5.70
	JUL	5.46	5.51	5.81
	AUG	5.49	5.50	5.80
	SEP	5.53	5.52	5.83
	OCT	5.77	5.79	6.08
	NOV	5.86	5.88	6.19
	DEC	5.81	5.80	6.14
2006	JAN	5.75	5.75	6.06
	FEB	5.80	5.82	6.11
	MAR	5.95	5.98	6.26
	APR	6.26	6.29	6.54
	MAY	6.36	6.42	6.59
	JUN	6.35	6.40	6.61
	JUL	6.33	6.37	6.61

Source: Mergent Bond Record.

High Island Offshore System, L.P.

Common Equity Flotation Costs of
Natural Gas Distribution/Transmission Companies
1995-2005

Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Northwest Natural Gas	2/15/1995	1,000,000	$29.750	$28.590	4.06%
MCN Corp.	3/14/1995	5,000,000	$17.875	$17.210	3.86%
Piedmont Natural Gas	3/20/1995	1,500,000	$20.000	$19.140	4.49%
Laclede Gas	5/15/1995	1,550,000	$19.000	$18.120	4.86%
United Cities	6/8/1995	1,200,000	$14.500	$13.880	4.47%
Atlanta Gas Light	6/12/1995	1,300,000	$33.625	$32.510	3.43%
WICOR, INC.	12/5/1995	1,100,000	$31.875	$30.630	4.06%
Connecticut Natural Gas	6/5/1996	640,000	$23.250	$22.190	4.78%
Delta Natural Gas	7/15/1996	350,000	$16.000	$15.070	6.17%
Tejas Gas	7/22/1996	3,075,000	$35.000	$33.420	4.73%
KN Energy	7/31/1996	3,100,000	$32.250	$31.010	4.00%
Cascade Natural Gas	8/13/1996	1,350,000	$15.250	$14.450	5.54%
Energen	1/17/1997	1,500,000	$29.500	$28.390	3.91%
KCS Energy	1/29/1997	3,000,000	$39.000	$36.910	5.66%
Energen	9/18/1997	1,200,000	$35.500	$34.160	3.92%
COHO Energy, Inc.,	9/29/1997	8,585,000	$10.500	$9.870	6.38%
Fall River Gas Co.	10/30/1997	340,000	$13.250	$12.060	9.87%
Connecticut Energy Corp.	11/12/1997	900,000	$24.250	$23.170	4.66%
Roanoke Gas Co.	2/22/1998	166,000	$20.000	$18.668	7.13%
KN Energy	3/4/1998	11,000,000	$52.000	$49.902	4.20%
Enron Corp.	5/5/1998	15,000,000	$50.000	$48.466	3.17%
Washington Gas Light	12/12/1998	2,000,000	$25.063	$24.089	4.04%
Laclede Gas	5/5/1999	1,100,000	$20.188	$19.252	4.86%
Semco	6/12/2000	9,000,000	$10.000	$9.600	4.17%
WGL Holdings	6/26/2001	1,790,000	$26.730	$25.804	3.59%
Utilicorp	1/25/2002	11,000,000	$23.000	$22.252	3.36%
MDU Resources Group	11/29/2002	2,100,000	$24.000	$23.188	3.50%
AGL Resources, Inc	2/11/2003	5,600,000	$22.000	$21.185	3.85%
Southern Union Co.	6/5/2003	9,500,000	$16.000	$15.351	4.23%
Atmos Energy Corp.	6/18/2003	4,000,000	$25.310	$24.202	4.58%
Vectren Corporation	8/7/2003	6,500,000	$22.810	$21.966	3.84%
Sempra Energy	10/8/2003	15,000,000	$28.000	$27.127	3.22%
Piedmont Natural Gas	1/20/2004	4,250,000	$42.500	$41.010	3.63%
UGI Corp.	3/18/2004	7,500,000	$32.100	$30.696	4.57%
Northwest Natural Gas	3/30/2004	1,200,000	$31.000	$29.844	3.87%
The Laclede Group	5/6/2004	1,500,000	$26.800	$25.862	3.63%
Ameren	6/30/2004	10,000,000	$42.000	$40.700	3.19%
Southern Union Co.	7/26/2004	11,000,000	$18.750	$18.003	4.15%
Aquila(M)	8/18/2004	40,000,000	$2.550	$2.451	4.04%
Atmos Energy Corp.	10/21/2004	14,000,000	$24.750	$23.760	4.17%
AGL Resources, Inc	11/19/2004	9,600,000	$31.010	$30.038	3.23%
Cinergy	12/15/2004	6,100,000	$41.000	$40.477	1.29%
Southern Union Co.	2/7/2005	14,913,000	$23.000	$22.233	3.45%
SEMCO Energy	8/9/2005	4,300,000	$6.320	$5.997	5.38%
Average 1994-2004					**4.35%**
Selected Flotation Costs for Cost of Equity					**4.35%**

Sources: EBASCO, *Analysis of Public Utility Financing* and *Public Utility Financing Tracker*

High Island Offshore System, L.P.

Natural Gas Pipeline Proxy Group
December 31, 2005 Operating Data

	Assets ($000,000)	Operating Revenues	Operating Income
El Paso Corporation	$30,601	$4,017	$220
Enbridge Energy Partners, L.P.	4,428	6,477	174
Enterprise Product Partners, L.P.	12,591	12,257	648
Kinder Morgan Energy Partners, L.P.	11,923	9,787	1,008
Kinder Morgan Inc.	17,452	1,586	516
ONEOK Partners, L.P. *	2,527	679	257
TC Pipelines, L.P.	316	53	51
Williams Companies, Inc.	29,443	12,584	1,232
Mean	**$13,660**	**$5,930**	**$513**
Median	**$12,257**	**$5,247**	**$387**

	Assets	Revenues	Pro Forma Operating Income
High Island Offshore System	**$51**	**$25**	**$6**
HIOS as a % of Proxy Median	**0.4%**	**0.5%**	**1.6%**

* On May 19, 2006 Northern Border Partners, L.P. changed its name to ONEOK Partners, L.P.

+Fiscal year-end falls in the month of September. Revenues and Income are as of Sept. 30, 2005. Assets are as of December 31, 2005.

Source: Zacks.com

High Island Offshore System, L.P.

Bond Ratings of
Natural Gas Pipeline Proxy Group

		Standard & Poor's	Moody's
El Paso Corporation	EP	B	B1
Enbridge Energy Partners, L.P.	EEP	BBB	Baa2
Enterprise Product Partners, L.P.	EPD	BB+	Baa3
Kinder Morgan Energy Partners, L.P.	KMP		
Kinder Morgan Inc.	KMI	BBB	Baa2
ONEOK Partners, L.P. *	OKS		
TC Pipelines, L.P.	TCLP		
Williams Companies, Inc.	WMB	BB-	Ba1
Gas Distribution Companies			
Equitable Resources, Inc.	EQT	A-	A2
National Fuel Gas Co.	NFG	BBB+	Baa1
Questar Corp.	STR	A-	A2

Source: C.A. Turner, *Utility Reports* , August 2006

High Island Offshore System, L.P.

Natural Gas Pipeline Proxy Group
Dividend Yields
February 2006 - July 2006

		Stock Price February '06 - July '06				
		High	Low	Average	Dividend	Yield
El Paso Corporation	EP	$ 16.12	$ 11.80	$ 13.96	$ 0.16	1.15%
Enbridge Energy Partners, L.P.	EEP	$ 47.80	$ 42.00	$ 44.90	$ 3.70	8.24%
Enterprise Product Partners, L.P.	EPD	$ 26.00	$ 23.38	$ 24.69	$ 1.78	7.21%
Kinder Morgan Energy Partners, L.P.	KMP	$ 51.39	$ 43.71	$ 47.55	$ 3.24	6.81%
Kinder Morgan Inc.	KMI	$ 103.19	$ 81.00	$ 92.10	$ 3.50	3.80%
ONEOK Partners, L.P. *	OKS	$ 50.10	$ 47.00	$ 48.55	$ 3.52	7.25%
TC Pipelines, L.P.	TCLP	$ 38.13	$ 31.04	$ 34.59	$ 2.30	6.65%
Williams Companies, Inc.	WMB	$ 24.56	$ 19.35	$ 21.96	$ 0.30	1.37%
Average						5.09%
Median						6.65%
Gas Distribution Companies						
Equitable Resources, Inc.	EQT	$ 37.87	$ 31.59	$ 34.73	$ 0.88	2.53%
National Fuel Gas Co.	NFG	$ 37.43	$ 34.95	$ 36.19	$ 1.16	3.21%
Questar Corp.	STR	$ 89.00	$ 67.37	$ 78.19	$ 0.94	1.20%

* On May 19, 2006 Northern Border Partners, L.P. changed its name to ONEOK Partners, L.P.

Source: America Online and Zacks.com, August 2006

High Island Offshore System, L.P.

Projected Earnings Retention Growth Rates
for Natural Gas Pipeline Proxy Group

	Value Line Forecast 2009-2011						
		EPS		DPS	ROE	Retention Rate	Retention Growth
El Paso Corporation	$	1.30	$	0.16	11.50%	87.69%	10.1%
Enbridge Energy Partners, L.P.							N.A.
Enterprise Product Partners, L.P.							N.M.
Kinder Morgan Energy Partners, L.P.							N.M.
Kinder Morgan Inc.	$	7.75	$	4.30	19.00%	44.52%	8.5%
ONEOK Partners, L.P. *							N.A.
TC Pipelines, L.P.							N.A.
Williams Companies, Inc.	$	1.85	$	0.55	12.00%	70.27%	8.4%
Gas Distribution Companies							
Equitable Resources, Inc.	$	2.50	$	1.03	27.50%	58.80%	16.2%
National Fuel Gas Co.	$	2.05	$	1.26	10.50%	38.54%	4.0%
Questar Corp.	$	4.10	$	0.94	11.50%	77.07%	8.9%

Source: Value Line, June 16, 2006

High Island Offshore System, L.P.

Growth Rate Estimates for
Natural Gas Pipeline Proxy Group

	2/3 Thomson (IBES)	1/3 2nd Stage Growth	**Weighted Average**
El Paso Corporation	10.92%	10.1%	10.64%
Enbridge Energy Partners, L.P.	5.83%	5.22%	5.63%
Enterprise Product Partners, L.P.	7.86%	5.22%	6.98%
Kinder Morgan Energy Partners, L.P.	7.29%	5.22%	6.60%
Kinder Morgan Inc.	13.00%	8.5%	11.49%
ONEOK Partners, L.P. *	4.80%	5.22%	4.94%
TC Pipelines, L.P.	4.33%	5.22%	4.63%
Williams Companies, Inc.	13.40%	8.43%	11.74%
Average	8.43%	6.63%	7.83%
<u>Gas Distribution Companies</u>			
Equitable Resources, Inc.	9.75%	16.2%	11.89%
National Fuel Gas Co.	5.00%	4.0%	4.68%
Questar Corp.	13.26%	8.9%	11.79%

High Island Offshore System, L.P.

DCF Calculation
for Natural Gas Pipeline Proxy Group

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Secondary Markets: Investor Required Return	Flotation Cost Adjustment	Primary Markets: Cost of Capital
El Paso Corporation	1.15%	1.22%	10.64%	11.86%	1.0435	12.38%
Enbridge Energy Partners, L.P.	8.24%	8.53%	5.63%	14.16%	1.0435	14.77%
Enterprise Product Partners, L.P.	7.21%	7.52%	6.98%	14.50%	1.0435	15.13%
Kinder Morgan Energy Partners, L.P.	6.81%	7.09%	6.60%	13.69%	1.0435	14.29%
Kinder Morgan Inc.	3.80%	4.07%	11.49%	15.56%	1.0435	16.24%
ONEOK Partners, L.P. *	7.25%	7.47%	4.94%	12.41%	1.0435	12.95%
TC Pipelines, L.P.	6.65%	6.84%	4.63%	11.47%	1.0435	11.97%
Williams Companies, Inc.	1.37%	1.47%	11.74%	13.21%	1.0435	13.79%
High				15.56%	1.0435	16.24%
Median				13.45%	1.0435	**14.04%**
Low				11.47%	1.0435	11.97%
Gas Distribution Companies						
Equitable Resources, Inc.	2.53%	2.72%	11.89%	14.61%	1.0435	*15.25%*
National Fuel Gas Co.	3.21%	3.30%	4.68%	7.98%	1.0435	*8.33%*
Questar Corp.	1.20%	1.29%	11.79%	13.09%	1.0435	*13.65%*

High Island Offshore System, L.P.

Natural Gas Pipeline Proxy Group
Capital Structures as of December 31, 2005

	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
El Paso Corporation	$ 16,232.0	80.57%	$ 750.0	3.72%	$ 3,164.0	15.71%	$ 20,146.0
Enbridge Energy Partners, L.P.	$ 1,713.9	55.69%	$ -	0.00%	$ 1,363.8	44.31%	$ 3,077.7
Enterprise Product Partners, L.P.	$ 4,833.8	45.98%	$ -	0.00%	$ 5,679.3	54.02%	$ 10,513.1
Kinder Morgan Energy Partners, L.P.	$ 5,319.4	59.27%	$ -	0.00%	$ 3,656.1	40.73%	$ 8,975.4
Kinder Morgan Inc.	$ 6,634.2	56.19%	$ -	0.00%	$ 5,171.7	43.81%	$ 11,805.9
ONEOK Partners, L.P. *	$ 1,355.0	56.57%	$ -	0.00%	$ 1,040.1	43.43%	$ 2,395.1
TC Pipelines, L.P.	$ 13.5	4.28%	$ -	0.00%	$ 301.6	95.72%	$ 315.1
Williams Companies, Inc.	$ 7,713.1	57.76%	$ -	0.00%	$ 5,641.6	42.24%	$ 13,354.7
Average		**52.04%**		**0.47%**		**47.50%**	
Median		**56.38%**		**0.00%**		**43.62%**	
Equitable Resources, Inc.	$ 766.4	55.45%	$ -	0.00%	$ 615.7	44.55%	$ 1,382.2
National Fuel Gas Co.	$ 1,126.3	46.02%	$ -	0.00%	$ 1,321.3	53.98%	$ 2,447.6
Questar Corp.	$ 983.2	35.07%	$ -	0.00%	$ 1,820.3	64.93%	$ 2,803.5

* On May 19, 2006 Northern Border Partners, L.P. changed its name to ONEOK Partners, L.P.

Source: Zacks.com

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, L.L.C.) Docket No. RP06-__-000

Prepared Direct Testimony
of
Leslie V. Pagels

Q. Please state your name and business address.

A. My name is Leslie V. Pagels. My business address is 1100 Louisiana Street, Houston, Texas 77002.

Q. By whom are you employed and what are your responsibilities?

A. I am employed by Enterprise Products Partners, L.P. ("Enterprise"), as Director of Offshore Natural Gas Pipelines. In such position, my responsibilities include the overall management of the offshore pipelines and associated facilities owned by High Island Offshore System, L.L.C. ("HIOS").

Q. Please describe your educational background and work experience.

A. I graduated from the Colorado School of Mines in 1979 with a Bachelor of Science in Mining Engineering. From 1979 to 1983 I was employed by Shell Oil Company as a production engineer assigned to the San Joaquin Valley of California and later to the Gulf of Mexico. From 1983 to 1991 I was employed by Transco Energy (now Williams Companies) as a petroleum engineer for the Gulf of Mexico, and as a manager of strategic planning in Transco's gas pipeline business segment. Since 1991, I have been employed by Enterprise or a predecessor company in the offshore commercial business segment, with commercial responsibilities for all of Enterprise's Gulf of Mexico gas pipelines and its Poseidon Oil Pipeline.

Q. Please describe in detail your responsibilities for HIOS.

A. I am responsible for overseeing the day-to-day commercial management of this asset. In this role I have supervisory responsibility over certain employees responsible for HIOS matters, and I am responsible for approval of matters arising with the third party operator who provides operational and maintenance services for HIOS. In particular, as part of this management role, I am directly responsible for pursuing the potential attachment of new gas supply reserves to HIOS.

Q. Have you previously provided testimony in proceedings before the Federal Energy Regulatory Commission?

A. No, I have not.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is two-fold. First, I will describe the current and long-term business risk that HIOS is facing in the offshore Gulf of Mexico gas supply transportation environment. Second, I will describe and support the reasons for the recent changes that HIOS made to its operating agreement for the system.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. I am sponsoring the following exhibits in support of my testimony:

Exhibit No.	Description of Exhibits
HIO-78	HIOS Throughput Decline

HIO-79	Firm Volumes as a Percent of Pipeline Capacity & Throughput
HIO-80	Diana Hoover Field – Decline in Throughput Volumes
HIO-81	HIOS System Map
HIO-82	Operating Services Agreement (OSA)
HIO-83	OSA, Amendment No. 1

The HIOS System

Q. Can you briefly describe the HIOS system?

A. Yes. The HIOS system is shaped like a three-pronged fork, with the three upstream lateral prongs delivering gas from production areas in the Western Gulf of Mexico to a point where the three prongs converge at High Island Block A-264. In addition, upstream of the center prong, there is an 85-mile, non-jurisdictional gathering system that is operated by a HIOS affiliate, Enterprise Field Services, LLC, and is known as the East Breaks Gathering System ("East Breaks"). East Breaks connects HIOS to a production platform located in 4,800 feet of water approximately 140 miles offshore in the Alaminos Canyon area. From the downstream point of convergence at High Island Block A-264, HIOS operates a 42-inch diameter mainline that extends northward for 66 miles, where it interconnects with the interstate pipeline systems of three companies: ANR Pipeline Company; U-T Offshore System, L.L.C; and Tennessee Gas Pipeline Company. My Exhibit No. HIO-81 is a map of the HIOS system that shows the interconnections with these downstream pipelines and the upstream interconnection with East Breaks.

Q. Please describe the nature of HIOS's operations.

A. HIOS was constructed over twenty-five years ago by a gas pipeline consortium for the purpose of moving gas from what was then a new production area in offshore Texas, to interconnections with other pipelines, for further downstream delivery to onshore markets. When HIOS was first placed in service in 1978, it was supported by long-term firm transportation contracts, of 15 years in duration. During its initial years of operation, throughput on HIOS steadily increased. These initial contracts have since expired, and HIOS has been competing to attach new supplies since that time.

In 1999, in conjunction with its connection to East Breaks, HIOS implemented a new firm transportation service under Rate Schedule FT-2 to address offshore producers' desire for a more flexible service that was suited to their particular needs. Although nominally a firm service, the shippers have the unilateral right under the Rate Schedule to reduce their firm service entitlements annually, based on an updated production profile. While this service was initially successful in attracting new "firm" throughput to the system, today HIOS provides mostly interruptible transportation service. Specifically, as of the end of the test period, out of a total physical capacity of 1.8 Bcf per day, HIOS will have under firm subscription only 76 MDth/d (71 MMcf per day), or 3.94% of its physical capacity, and average daily throughput of 408 MDth/d (380 MMcf per day), or 21.1% of capacity.

Business Risk

Q. Please describe the business risks that HIOS is facing today and into the future.

A. HIOS operates today in what can only be described as an extremely difficult business environment. On the one hand, HIOS has experienced in recent years a precipitous decline in its throughput, which decline is expected to continue without any real prospects of reversal. This has resulted in a significant decline in the revenues that were forecast in its last rate case. Compounding this drop in throughput and revenues, HIOS has been subjected to significant cost increases, most noticeably an increase of over five hundred percent (500%) in its insurance costs as a result of the aftermath of hurricanes Rita and Katrina in the GOM. In addition, after operating approximately fifteen years beyond its originally expected life, HIOS now faces the need to undertake a significant amount of expenditure on certain non-routine maintenance and upgrade projects, to ensure that the pipeline and associated facilities can continue to operate in a safe and reliable manner. In order to describe HIOS's business risks in greater detail, I believe they can be divided into three categories.

Q. What is the first category?

A. The first category I would describe as the "competitive risk," that is, the risk of competition from other pipeline service providers for the attachment of any new, deepwater gas production south of HIOS. As I discuss below, and as explained by HIOS witness J. Scott Jenkins, the only reasonably foreseeable, potential new gas supply reserves of any significance are located in the deepwater area south of HIOS. HIOS has experienced mixed results in attaching those new reserves, which can only be attached at significant expense. For example, in June, 2000, as a result of the construction of East Breaks by a HIOS affiliate at a cost of over $85 million, HIOS was able to attach new production from the "Diana Hoover" fields located in East Breaks Block 945 and Alaminos Canyon Block 25, respectively, and operated by ExxonMobil U.S. Production Company ("ExxonMobil"). Since that time, however, HIOS has not been able to attract any other significant new deepwater gas reserves to its system.

Q. Why has HIOS not been able to attach any new reserves to its system since 2000?

A. There are primarily two reasons. First, the optimistic projections prior to 2000 of the potential for significant new deepwater reserves south of HIOS simply have not materialized. That area was originally considered to hold potential for the discovery of significant new deepwater gas reserves, which was a major reason why the substantial sum of $85 million was invested by HIOS's affiliate to attach these potential reserves. However, as confirmed by HIOS witness Jenkins, results of exploration efforts in the deepwater south of HIOS have been extremely disappointing. Only 1.5 Tcf, or 11%, of the 13.6 Tcf total deepwater Gulf of Mexico production to date, has come from the area south of HIOS. Further, only 35 (or 25%) of the 138 leases drilled in the deepwater south of HIOS since 1985 have resulted in commercial production, and only 58% of that production has been gas, with the remainder being oil.

The second reason why HIOS has been unsuccessful in attaching new reserves is that, despite its aggressive attempts to compete with other pipelines, HIOS has not been able to negotiate acceptable agreements with the producers for the limited new reserves that have become available. Only 13 of those 35 deepwater leases that have commenced production south of HIOS were connected to HIOS or East Breaks. Cumulative production-to-date from those 13 blocks is 498 Bcf, which is approximately 32% of the 1,535 Bcf produced to date from all 35 blocks. In 2000, HIOS entered into extensive negotiations with Kerr McGee Oil & Gas Corporation ("Kerr McGee") for the potential connection of the "Boomvang/Nansen" development located in the East Breaks Block 643/602 area. After months of negotiations, Kerr McGee elected to contract with the Williams Companies' Transcontinental Gas Pipe Line Corporation, which connected a new 105-mile gathering lateral from its existing Central Texas Gathering System to this new development. The Boomvang/Nansen complex has produced 428 Bcf since commencing deliveries in July 2001, and is still producing about 200 MMcf/d.

In 2001, HIOS entered into extensive negotiations with Kerr McGee for potential connection of its Gunnison development located in Garden Banks Block 668. After months of negotiations, Kerr McGee elected to contract with Enbridge Pipelines, which connected a new 45-mile gathering lateral from its existing Stingray pipeline to this new development. Gunnison has produced 94 Bcf since commencing deliveries in 2003, and is still producing approximately 125 MMcf/d.

The only other significant new reserves discovered since 2000 comprise the proposed “Great White” development by Shell Offshore, Inc. in the southern portion of Alaminos Canyon, 50 miles south of the terminus of East Breaks, in 7,500 feet of water. Once again, we competed extremely aggressively with Williams for this new business, which would have required the investment by an affiliate of an estimated $200 million in a new pipeline and associated facilities. Williams was ultimately the successful bidder because, as we understand it, Williams was able to tie the gas transportation services to other ancillary services, such as gas processing, that HIOS could not provide. Publicly available well logs from this area show it to be oil prone, such that the gas will be primarily casinghead gas associated with production from oil wells. In addition, as discussed by HIOS witness Jenkins, recent leasing activity surrounding Great White has resulted in over 50 leases being relinquished, and none of these leases received bids in the August, 2006 lease sale.

Q. Are you anticipating any other deepwater reserve connections to HIOS?

A. As noted above, there really are no reasonably feasible prospects of significant future reserves that could be attached to HIOS. Even if there were, due to the typical five year lag time from discovery to first production, and given that witness Jenkins’ testimony shows no large discoveries have been made in this area, it is obvious that HIOS’s volumes will continue to decline, at least for the next five years. The low discovery rate, combined with the oil prone nature of deepwater prospects and the fierce competition for connections, greatly reduce the chances of finding and connecting any significant gas supplies in the prospects that remain un-drilled. It is also important to recognize that - in addition to the competition to obtain the producer commitment - it is extremely expensive (and risky) to connect to these supply reserves. Essentially, the producers shift the reserve risk of these new fields onto the pipelines, by insisting upon contract provisions that allow them to tie the level of their firm entitlements (and firm payment obligations) to the level of their actual production. HIOS's Rate Schedule FT-2 is a case in point: as noted above, under that Rate Schedule, shippers have the unilateral right at least once annually to reduce their firm service entitlements and their payment obligations. These types of contract provisions essentially place pipelines in a risk profile position of having to "build it and they will come." In the case of East Breaks, the risks taken have far exceeded the expected, commensurate return on investment.

Q. You have focused on the risk of building new pipeline in deepwater to attach deepwater reserves at the southern end of the system. Why doesn't HIOS compete for the attachment of new supplies along its existing system?

A. HIOS certainly does compete aggressively for transportation of production along its system. However, near-shore production in the Western Gulf of Mexico is declining rapidly, as HIOS witness Jenkins shows. There is also competition from other pipeline transporters in the vicinity of HIOS. Based on my experience in negotiations for this supply, it simply is not realistic for

HIOS to count on any significant new sources of revenue from this part of its system.

Q. Please turn to the second category of business risk that you mentioned earlier.

A. Somewhat related to the risk of competition for new reserves is what I would describe as the "throughput/revenue risk," that is, the risk of production decline in reserves already attached to the system, and the resulting reduction in revenues. HIOS continues to experience a significant decline in throughput. As shown in Exhibit No. HIO-78, from 2000 through the end of the test period, total throughput has declined by 128.4 MMDth, from 326.0 MMDth per year to 197.6 MMDth per year. As shown on Schedule G-3, Exhibit No. HIO-27 and explained in the testimony of HIOS Witness Ronald Fulcher, HIOS anticipates that base period total throughput will continue to decline by a factor of 24.6% next year, to an annualized level of approximately 148.9 MMDth by the end of the test period. The expectation of a continuing significant decline in throughput is also supported in the testimony of HIOS Witness Jenkins. Exhibit No. HIO-85, prepared by Mr. Jenkins, shows that based on the remaining life of proved and probable reserves that are located on the continental shelf and attached to HIOS, throughput on the system, assuming it were economic to operate the system, is expected to become negligible by 2014.

Q. How has this decline in throughput affected revenue recovery?

A. It has virtually eliminated HIOS's ability to obtain the assurance of a minimum level of revenue recovery under firm contracts. As shown on my

Exhibit No. HIO-79, as of the end of the base period, 9.1% of pipeline capacity and 30.1% of contracted capacity on HIOS was subscribed under firm contracts. These are further declines from the end of the test period in HIOS's last case in 2002, when firm service had already declined to 9.5% of pipeline capacity and 24.0% of contracted capacity.

Q. What is the reason for this decline in firm contracting?

A. The most recent, significant reductions in firm service commitments have resulted from the unexpected and extremely disappointing decline in the level of production from the Diana Hoover field. After ramping up to an average of 225 MMcf/d in 2001, and producing between 170 and 225 MMcf/d through 2004, East Breaks volumes have declined to approximately 100 MMcf/d. This has resulted in a significant reduction in the level of firm service entitlements under the contracts for the two primary producers from that field, pursuant to their unilateral MDQ reduction rights under Rate Schedule FT-2. Set forth below are the levels of entitlements that those two producers, ExxonMobil and BP Exploration & Production Inc. ("BP"), estimated in 2000 would be their firm service entitlements for the first quarter of 2007, contrasted with the actual firm entitlements that are now currently in effect following the recent exercise of their contract reduction rights:

MDQ in 1Q, 2007		
	2000 Estimate	June, 2006 Actual
ExxonMobil	169,300 Dth/d	71,000 Dth/d
BP	130,000 Dth/d	5,000 Dth/d

These reduced MDQs are the direct result of the lower-than-expected production. Actual average daily production by ExxonMobil in June, 2006, was 87,680 Dth, and estimated at 83,942 Dth in July 2006 (49% of its original MDQ). Average daily production by BP during June 2006 was 32,265 Dth, and is estimated at 30,525 Dth in July 2006 (23% of its original entitlement). Actual throughput from the Diana Hoover field continues to decline, as shown by my Exhibit No. HIO-80. In other words, in June, 2006, combined average daily production by ExxonMobil and BP totaled 119,945 Dth/d; in July, 2006, that production declined to an estimated 114,467 Dth/d, and further declines are anticipated.

Q. Couldn't the production decline reversal, as occurred during the test period in the last rate proceeding, occur again?

A. A very short-term reversal in the overall trend of production decline did occur during the test period in the last case, but since that time the steep decline has resumed. A misleading impression of a reversal of the production decline could be gained by taking a brief snapshot of a few months during that period. However, as can be seen clearly from Witness Jenkins' Exhibit No. HIO-85, that brief, slight "spike" in production was a clear anomaly, and the trend of a precipitous decline in production continues.

Q. How do these reductions in firm throughput and revenues affect HIOS?

A. First, HIOS has no assurance of a level of firm revenue stream that could be used to support continued operation of the system. Second, in conjunction with declining throughput, the lack of firm contracts contributes to inefficiencies when shippers contract for capacity on HIOS. Since approximately 96% of the HIOS capacity will not be contracted on a firm basis as of the end of the test period in this case, since total throughput is significantly below capacity this means that interruptible service is virtually firm and there is no incentive for a shipper to purchase firm service.

Q. What steps has HIOS taken to increase throughput on the system?

A. As explained by HIOS witness Mr. Richard W. Porter, HIOS is proposing to implement in this case creative refinements to the firm services that it currently offers, and to implement a new, innovative firm service for terms of less than one year. By providing additional, flexible service opportunities, HIOS is seeking to attract additional firm service commitments to its system.

Q. What is the third business risk that HIOS faces?

A. I characterize this business risk as the “operational” risk. HIOS was one of the earliest pipelines constructed out into the western Gulf of Mexico. The system is now over twenty-seven years old. Unlike pipelines that are constructed onshore, offshore pipelines not only require the typical level of routine maintenance, but because of the harsh salt-water environment in which they operate they are subjected to a greater need for significant, non-routine maintenance over and above that typically required. Because of its age, HIOS is at a stage where a substantial level of this additional maintenance is now required. I describe below in greater detail the types of non-routine maintenance that are now required for the HIOS system when I discuss the operating agreement that is in place for the system.

Q. Please summarize the business risks facing HIOS.

A. HIOS projects that in the future the system will continue to experience declines in both firm contracts and total throughput. Reversing these declines is an extremely difficult challenge given the unexpected and disappointing future of new sources of supply. Coupled with the competition to attach these supplies, these declines, together with escalating costs, produce significant business uncertainty for HIOS. This uncertainty inhibits the ability to compete for new deepwater supplies because of the capital investments required to connect them.

Operating Agreement

Q. Please describe the Operating Agreement that is currently in effect for the HIOS system.

A. On September 30, 1999, HIOS and an affiliate of one of the then-owners, Leviathan Operating Company, L.L.C., entered into an "Operating Services Agreement," or "OSA", a copy of which is attached to my testimony as Exhibit No. HIO-82. Under that OSA, the operator is responsible for performing all administrative, physical and operational functions for the HIOS system. Specifically, pursuant to the OSA, the operator provides a comprehensive array of "Routine Operation Services," which are set forth in Section 2.2 of the OSA. The operator also provides certain "Non-Routine Operation Services", as provided for in Section 2.3 of the OSA. As compensation for the Routine Operation Services, HIOS pays a fixed monthly "Turnkey Fee," which is subject to annual adjustment under an indexing mechanism. The adjustment to reflect the current level of this fee is shown on

Schedule H-1.1, Adjustment No. 4 (Exhibit No. HIO-32), which is supported by HIOS witness Joan F. Collins. As compensation for the Non-Routine Services, HIOS makes a separate payment on an as-performed basis.

Q. Is that original OSA currently in effect?

A. Yes, it is, however as a result of intervening changes in ownership, the operator under the OSA is now a 100% affiliate of HIOS, Enterprise GTM Offshore Operating Company, LLC ("EGOOC"). Further, effective August 1, 2006, at the request of HIOS, the parties entered into an Amendment No. 1 that modified the OSA in two major respects. I have attached a copy of this Amendment to my testimony as Exhibit No. HIO-83.

Q. Please describe the changes made by this Amendment No. 1.

A. HIOS and EGOOC agreed to two substantive changes to the OSA. First, the parties agreed to add a new, substitute index for purposes of calculating the annual increase or decrease of the Turnkey Fee. The addition of the new index, which uses the "Wage Index Adjustment Factor" published by the Council of Petroleum Accountant Societies, became necessary because the existing index has ceased being published. The annual adjustment under this new revised index that occurs during the test period (that is, effective January 1, 2007) is reflected as Adjustment No. 5 on Schedule H-1.1 (Exhibit No. HIO-32), and is supported by HIOS Witness Collins.

Q. What was the other amendment that was made to the OSA?

A. Because, based on its age, the HIOS system will require some significant, non-routine expenditures to ensure its continued safe and efficient operation, I requested EGOOC to agree to establish a longer term budgeting process to manage more effectively the level and timing of the Non-Routine Operation Services provided for under the OSA. Under the newly agreed, three-year budget process, EGOOC is required to submit to HIOS, by August 1 of every third year, a proposed budget of these expenditures, together with “sufficient support for the proposed budget for HIOS to make a reasonable determination as to the appropriateness of the proposed budget amount.” EGOOC submitted its proposed budget for the next three years to HIOS on August 7, 2006. I reviewed that budget with Enterprise management, and it was found to be acceptable. The first monthly installment payable by HIOS pursuant to this provision, effective January 1, 2007, is shown as Adjustment No. 5 on Statement H-1, and is supported by HIOS witness Collins.

Q. Should HIOS be permitted to include these monthly installments in its cost of service?

A. Absolutely. These monthly payments will be recurring obligations on HIOS’s part as of the end of the test period in this case, and they are expenditures necessary for the continued, safe operation of HIOS. When HIOS was designed and constructed during the late 1970's, the design life was anticipated to be approximately twelve years. After nearly thirty years of service, HIOS is routinely contending with mounting mechanical and operational challenges. These challenges include: platform infrastructure upgrades, maintenance support issues, compatibility of the obsolete technology associated with HIOS's voice and data communication equipment network, platform control automation upgrades, environmental containment design modifications, and plant changes needed to assure that the pipeline/platform safety monitoring systems remain effective and in compliance with applicable regulations. To implement the majority of these required modifications, HIOS is required to invest in new technology, component upgrades, and infrastructure construction activities. Commitment to these investments is required now in order to maintain the daily operational status of the system. Additionally, the HIOS system has been exposed to the corrosive elements of the offshore environment, and has been subjected to the stresses of constant and sometimes severe wave action. All of these factors contribute to a significant impact on an offshore pipeline system that is operating well beyond its originally engineered service life.

Q. Does this complete your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of	)	Docket No. RP06-
High Island Offshore System	)	

Affidavit of Leslie V. Pagels

Leslie V. Pagels, being first duly sworn according to law, on oath deposes and says that she is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as her sworn, direct testimony in these proceedings.

Leslie V. Pagels

Leslie V. Pagels

Subscribed and sworn to before me this 23rd day of August, 2006.

FRONELL SINGLETERRY
Notary Public, State of Texas
My Commission Expires
November 12, 2006

Notary Public

Exhibit No. HIO-78

Docket No. RP06-___

High Island Offshore System, L.L.C.

HIOS Throughput Decline
Annual Percent Change

Line No	Year		Annual Throughput (MMDth)	Percent Change
	Col (1)		(2)	(3)
1	2000		326.0	
2	2001		367.3	12.7%
3	2002		268.2	-27.0%
4	2003		259.7	-3.2%
5	2004		282.7	8.9%
6	2005		232.1	-17.9%
7	July 2005 - June 2006	1/	197.6	-14.9%
8	Cumulative % Change	2/	-128.4	-39.4%

Note 1: July 2005 thorugh June 2006 represents the Base Period.

Note 2: Cumulative change from January 2000 through June, 2006
(Col. 2 - line 7, 197.6 less Col. 2 - line 1, 326.0).

Exhibit No. HIO-79

Docket No. RP06-___

High Island Offshore System, L.L.C.

Firm Volumes
As a Percent of Capacity and Total Throughput

Line No	Year	Firm Volume - Percent of Capacity 1/	Firm Volume - Percent of Throughput
	Col (1)	(2)	(3)
1	2000	6.2%	12.5%
2	2001	13.5%	24.2%
3	2002	10.0%	24.5%
4	2003	10.2%	25.8%
5	2004	13.5%	31.3%
6	2005	10.3%	29.1%
7	Base Period	9.1%	30.1%
8	Test Period	4.2%	18.6%

Note 1: Total HIOS Pipeline Capacity of 1.8 Bcf per day, 657 Bcf per year.

Exhibit No. HIO-80

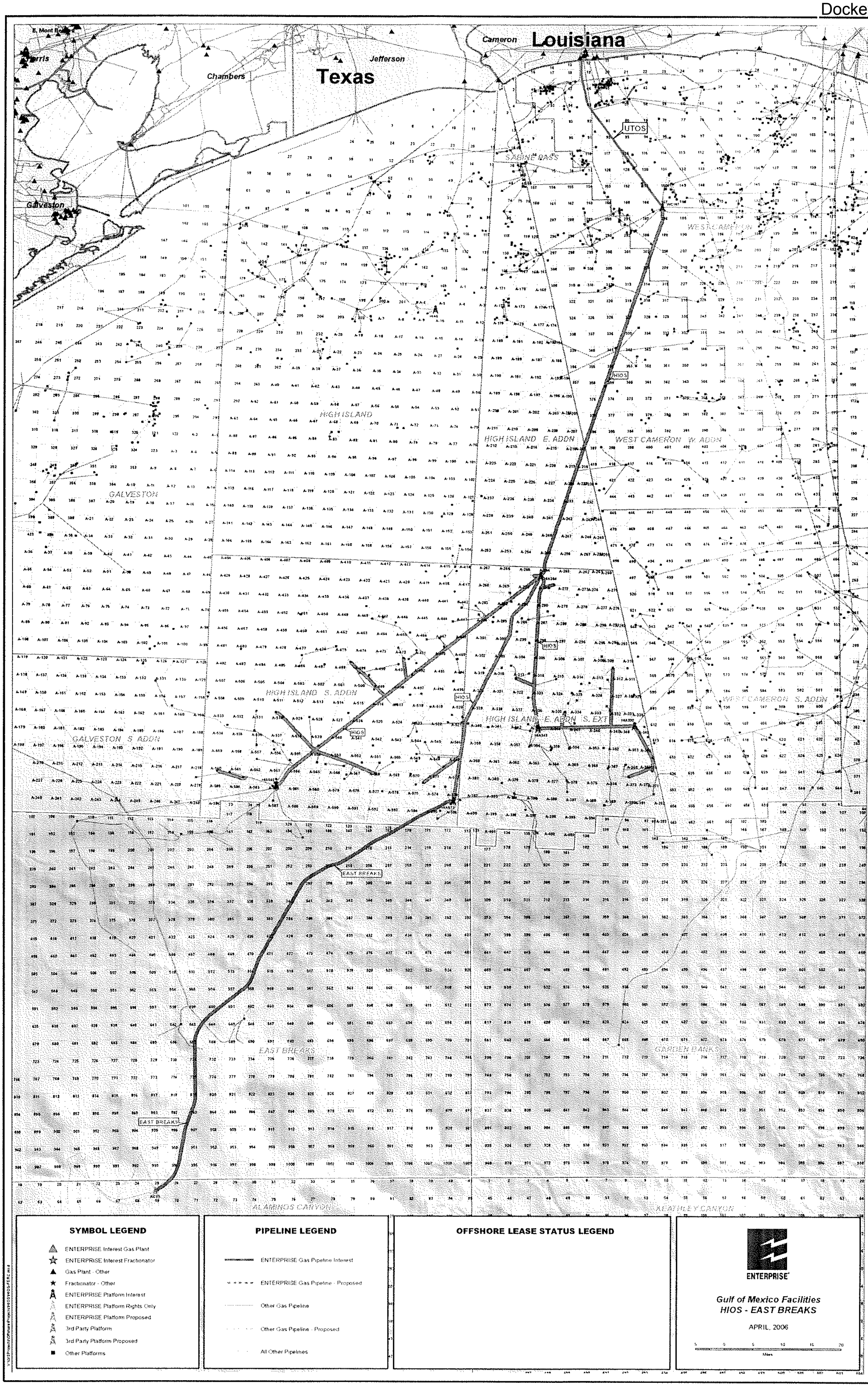
Docket No. RP06-___

High Island Offshore System, L.L.C.

Diana Hoover Field
Decline in Throughput Volumes

Line No	Year	Diana Hoover Volume	Percent Decline
	Col (1)	(2)	(3)
1	2000	40.7	
2	2001	88.8	118.3%
3	2002	65.7	-26.0%
4	2003	66.9	1.7%
5	2004	88.5	32.3%
6	2005	63.1	-28.7%
7	Base Period	52.7	-16.5%

Exhibit No. HIO-81
Docket No. RP06-



OPERATING SERVICES AGREEMENT

BETWEEN

HIGH ISLAND OFFSHORE SYSTEM, L.L.C., as Owner

AND

LEVIATHAN OPERATING COMPANY, L.L.C., as Operator

Dated: September 30, 1999

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OPERATING SERVICES AGREEMENT

THIS OPERATING SERVICES AGREEMENT is made and entered into as of September 30, 1999, but effective on the Operator Transition Date (herein defined), by and between High Island Offshore System, L.L.C., a Delaware limited liability company ("Owner"), and Leviathan Operating Company, L.L.C., a Delaware limited liability company ("Operator").

WITNESSETH:

WHEREAS, Owner is the owner of the System (as hereinafter defined) and the operator of the Operated Assets (as hereinafter defined); and

WHEREAS, Owner and Operator desire to define the terms and conditions under which Operator will operate the Operated Assets.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein contained, the parties hereto hereby agree as follows:

ARTICLE I
DEFINITIONS

1.1 Definitions. The terms set forth below shall have the meanings ascribed to them in this Article I or in the part of this Agreement referred to below:

"AAA" shall mean the American Arbitration Association.

"Affiliate" shall mean, with respect to any relevant Person, any other Person that directly, or indirectly through one or more intermediaries, Controls, is Controlled by, or is under common Control with such relevant Person in question; provided, that Operator and its Affiliates shall be deemed not to be Affiliates of Owner, the Parent, the members of the Parent (other than Operator's Affiliates), and their respective Affiliates, and vice versa.

"Agreement" shall mean this Operating Services Agreement, as amended, restated, supplemented, or otherwise modified from time to time.

"Calendar Year" shall mean a period of 365 consecutive days, 366 consecutive days when such period includes a February 29, beginning at 8:00 a.m. Central Time on January 1 and ending at 8:00 a.m. Central Time on the following January 1.

"Control" (including its derivatives) shall mean the power to direct or cause the direction of the management or policies of the relevant Person, whether pursuant to the ownership of voting interest, by contract or otherwise.

"Default Rate" shall mean a rate per annum equal to the lesser of (a) a varying rate per annum that is equal to the interest rate publicly quoted by The Chase Manhattan Bank, New York, New York from time to time as its prime commercial or similar reference interest rate, with adjustments in that varying rate to be made on the same date as any change in that rate, plus two percent (2%) or (b) the maximum rate permitted by applicable law; provided, that the

Default Rate shall never be less than two percent (2%) greater than the London Inter Bank Offer Rate.

"Direct Costs" shall mean all direct costs of services, materials and equipment, including transportation thereof, paid to nonAffiliated third parties or any Affiliated parties approved by Owner, but excluding (i) the costs of Operator's and its Affiliates' personnel and (ii) the costs of any material that would otherwise be provided as a Routine Operation Service.

"LLC Agreement" shall mean the Limited Liability Company Agreement of Owner, as amended, restated, supplemented, or otherwise modified from time to time.

"Management Committee" shall have the meaning set forth in the LLC Agreement

"Non-Routine Operation Services" shall have the meaning set forth in Section 2.3.

"Operated Assets" shall mean the System.

"Operation Services" shall have the meaning set forth in Section 2.1.

"Operator" shall have the meaning set forth in the preamble.

"Operator Transition Date" shall mean the date upon which Operator becomes the operator of the Operated Assets and of the pipelines or other assets owned by Stingray Pipeline Company, L.L.C., U-T Offshore System, L.L.C., and East Breaks Gathering Company, L.L.C.

"Owner" shall have the meaning set forth in the preamble.

"Parent" shall mean Deepwater Holdings, L.L.C.

"Parent Members" shall mean the members of the Parent and such members' respective permitted successors and assigns, and "Parent Member" means any one of them.

"Party" shall mean Owner or Operator, and "Parties" shall mean both Owner and Operator.

"Person" shall mean an individual, corporation, voluntary association, joint stock company, business trust, partnership, limited liability company or other entity.

"Routine Operation Services" shall have the meaning set forth in Section 2.2.

"System" shall mean (i) the gas pipeline and related facilities owned by Owner as of the Operator Transition Date, including without limitation, those described in Exhibit A, and (ii) any extension, expansion, addition or enhancement thereto hereafter acquired, but shall not include any of the property described in (i) or (ii) after it is sold or abandoned by Owner or otherwise no longer the responsibility of Owner.

"Tariff" shall mean the terms and conditions, including without limitation, rate schedules, approved by the Federal Energy Regulatory Commission or any successor governmental authority, under which Owner is authorized from time to time to provide transportation and other services on the System.

"TMM" shall have the meaning set forth in the Limited Liability Company Agreement of the Parent.

"Turnkey Fee" shall mean $806,382.00, as adjusted from time to time pursuant to Section 3.3.

1.2 Terminology. All article, section, subsection, schedule and exhibit references used in this Agreement are to this Agreement unless otherwise specified. All schedules and exhibits attached to this Agreement constitute a part of this Agreement and are incorporated herein. Unless the context of this Agreement clearly requires otherwise (a) the singular shall include the plural and the plural shall include the singular wherever and as often as may be appropriate, (b) the words "includes" or "including" shall mean "including without limitation," and (c) the words "hereof," "herein," "hereunder," and similar terms in this Agreement shall refer to this Agreement as a whole and not any particular section or article in which such words appear. Currency amounts referenced herein are in United States Dollars. References to "generally accepted accounting principles" herein shall refer to such principles in effect in the United States of America as of the date of the statement to which such phrase refers.

ARTICLE II
GENERAL RESPONSIBILITIES OF OPERATOR

2.1 Operation Services. Subject to the terms and conditions of this Agreement, Operator shall, as may be directed by Owner from time to time, perform all Routine Operation Services and Non-Routine Operation Services (collectively, the "Operation Services") for the Operated Assets in accordance with the terms and conditions contained herein.

2.2 Routine Operation Services. Operator shall provide or acquire all supervisory, administrative, technical and other services as may be required to provide all routine operation and maintenance of the Operated Assets (the "Routine Operation Services") under this Agreement. The Routine Operation Services shall include:

(a) Operating and maintaining (including minor repairs associated with routine maintenance) the Operated Assets and procure and furnish all materials (e.g. consumables, including bolts, gaskets and fluids), equipment, tools, services, supplies, supervision and labor necessary to carry out Operator's responsibilities under this Agreement;

(b) Performing the administrative functions of Owner, including legal, accounting, engineering, planning, budgeting, reporting and other technical services, and maintaining the books of account and records of Owner;

(c) Supervising the construction of any expansion to the System;

(d) Having custody of the funds, notes, drafts, acceptances, commercial paper and other securities belonging to Owner; keeping the funds belonging to

Owner on deposit in one or more banking institutions in accounts in the name of Owner and bearing interest to the extent appropriate; invest available funds in United States government securities, certificates of deposit, commercial paper or other marketable securities; and disbursing such funds;

(e) Preparing preliminary engineering plans and outlines of proposed construction for any modification, improvement, extension, expansion or replacement of the System;

(f) Maintaining in force and effect and requiring all contractors (and their subcontractors) of Operator performing services for the benefit of Owner to maintain in force and effect insurance of the types and in the amounts specified by Owner;

(g) Keeping an accurate account of all transactions in the funds and securities of Owner for which Operator is responsible under (d) above and, whenever requested by Owner or any Member, promptly preparing and submitting to Owner, or to such Member, reports and other information in such form and detail as Owner or such Member may reasonably request;

(h) Preparing and making all filings, notifications and reports required to be made or filed by Owner with governmental authorities under applicable laws, orders, rules and regulations; and operating and maintaining the Operated Assets in accordance with all applicable laws, orders, rules and regulations, including but not limited to safety regulations and cathodic protection regulations;

(i) Providing for proper communications, inspections, surveillance, flow control, corrosion control, cathodic protection, and monitoring of the Operated Assets;

(j) Marketing the System transportation services to shippers and other potential customers in accordance with the marketing and business development plans for the System prepared by the Management Committee of the Parent, and maintain customer relationships;

(k) Operating and maintaining a SCADA system for collecting System operating data and providing electronic access to such system by the Members;

(l) Performing all nomination, confirmation, scheduling and dispatching functions required in providing transportation services and operating the System and the Laterals;

(m) Providing written notification (which may be in the form of the service request) to each Member of each request for transportation service on the System within five (5) business days after receipt of such request;

(n) Promptly paying and discharging all costs and expenses properly incurred by Operator pursuant to this Agreement;

(o) Collecting all amounts due to Owner in connection with all transportation services and all other amounts owed to Owner, and depositing all amounts collected into Owner's account as received; and

(p) Doing such other acts and things (other than Non-Routine Operation Services) as are necessary for the operation of the Operated Assets.

2.3 Non-Routine Operation Services. Operator shall provide or acquire all supervisory, administrative, technical and other services as may be required to provide all of the following services (such services, including emergency operations, being the "Non-Routine Operation Services"):

(a) Construction of any expansion or extension to the Operated Assets, e.g. construction of new pipeline(s), riser(s), facilities;

(b) Major maintenance, major equipment overhaul or repairs, modification of the Operated Assets or alteration of equipment/facilities, e.g. overhaul of compressors or turbines, replacement of valves, piping or other facilities, or painting of platforms, risers or other facilities, restaging of compressors, major piping reconfigurations;

(c) Subsea repairs, replacements and inspections;

(d) Filing and prosecuting with appropriate governmental authorities any change, including, without limitation any rate change, in Owner's Tariff; and

(e) Any other service of a nonrecurring and major nature that is approved in writing by Owner as a Non-Routine Operation Service.

Non-Routine Operation Services shall not be performed until written consent has been received from the Owner, except for such emergency operations as Operator is authorized to conduct prior to receiving Owner's authorization under the terms of Section 2.4.

2.4 Emergency Operations. Notwithstanding any other provision of this Agreement, in case of explosion, fire, extreme cold, freezing, spills, leaks or other environmental occurrences, or other sudden emergency, or any major interruption of the operation of the Operated Assets, or any part thereof, the prior approval of the Owner shall not be a prerequisite to Operator's taking such steps and incurring such costs as, in Operator's opinion, are required to deal with such emergency or interruption or to safeguard life and/or property in such event if, in Operator's good faith opinion, any potential delay incurred by securing such approval would possibly jeopardize the interests of Owner; provided, however, that Operator shall, as promptly as may be reasonably practicable, report such emergency or interruption to Owner and the Members and endeavor to secure therefrom any authorization that might be required for any further action or expenditure. Operator shall also, as promptly as may be reasonably practicable, make any required reports of such emergency or interruption to federal, state or local regulatory authorities having jurisdiction.

2.5 Reports. Operator shall report on a monthly basis in reasonable detail to Owner and each Member on the operation of the System and shall timely prepare and deliver for Owner and each Member the statements and other information referred to in Article IX of the LLC Agreement. Operator shall also furnish to Owner and each Member annual budgets for Owner and such additional information, reports, records and projections as may be reasonably requested by Owner or any Member. Additionally, Operator shall be required to meet with the Members on a quarterly basis, at Operator's corporate offices or such other location as designated by Owner, to report on all operational, maintenance and other aspects of its operatorship.

2.6 Personnel. Operator shall employ and have supervision over the persons (including consultants and professional, service or other organizations) required by Operator to perform its duties and responsibilities hereunder in an efficient and economically prudent manner. Operator shall pay all expenses in connection therewith, including compensation, salaries, wages, expenses, social security taxes, workman's compensation insurance, retirement and insurance benefits and other such expenses. All such expenses shall be covered under the Turnkey Fee.

2.7 Business Development. Operator shall handle all day-to-day marketing and business development activities (including solicitation, negotiation, and documentation of all business arrangements) with respect to the System and any other Operated Assets owned by Owner in accordance with the marketing and business development plans prepared by the Management Committee of the Parent from time to time; provided, that Operator must receive approval from Owner before negotiating arrangements which would (i) in the reasonable opinion of Operator, require Owner to request a contribution of capital from Owner's parent or (ii) require a discounted fee on any asset owned by Owner or any Affiliate of Owner. Operator will provide Owner with quarterly status reports with respect to its marketing and business development activities on behalf of Owner.

2.8 Restricted Activities. Operator shall not take any of the following actions without first procuring the prior written approval of the Owner:

(a) expansion or extension of the System;

(b) interconnection of the System with any other facilities (other than any interconnection that Owner is required to make under the terms of its Tariff or pursuant to a valid order issued by the appropriate governmental authority requiring the installation of an interconnection, the cost of which is borne by the connecting party);

(c) discounting of transportation services from the rates established in the applicable Tariff;

(d) requesting from the Federal Energy Regulatory Commission any changes in Owner's Tariff; and

(e) any action to decommission, idle, or retire any major item of equipment.

ARTICLE III
ACCOUNTING AND COMPENSATION

3.1 Accounting Records. The Operator shall, and shall cause its contractors, subcontractors, agents, vendors and other representatives to keep complete and accurate books and records of Owner in accordance with generally accepted accounting principles and the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B natural gas companies.

3.2 Compensation. The Operator shall be compensated for the Operation Services as follows:

3.2.1 Routine Operation Services. For the performance of Routine Operation Services for all Operated Assets, Owner shall pay monthly to Operator the Turnkey Fee.

3.2.2 Non-Routine Operation Services. For the performance of Non-Routine Operation Services with respect to all Operated Assets, Owner shall pay Operator the Direct Costs incurred by the Operator in performing such Non-Routine Operation Services, plus ten percent (10%) of such Direct Costs.

3.2.3 Direct Flowthrough Costs. Other than costs paid pursuant to Sections 3.2.1 and 3.2.2, Operator shall pay (i) Owner's costs incurred under any contractual obligations of Owner (including Owner's share of costs for separation, dehydration and measurement services at the Grand Chenier facility) and (ii) Owner's costs imposed by governmental or similar authorities (including taxes and FERC related costs). Such costs shall be billed to Owner as a direct charge, separate from the Turnkey Fee, and no overhead fees or other charge shall be applicable thereto.

3.3 Adjustments.

3.3.1 Changes in Operated Assets. A significant change in the Operated Assets, e.g. expansion, extension, addition, enhancement, disposition or abandonment, will result in an increase or decrease in the Turnkey Fee. This increase or decrease will be presented to the Owner for approval at the same time that such significant change is approved by Owner.

3.3.2 Annual Adjustment. The Turnkey Fee shall be subject to annual adjustment effective January 1 of each year beginning with January 1, 2002. The adjustment shall be computed by multiplying the current Turnkey Fee by the percentage increase or decrease in the average weekly earnings of Crude Petroleum and Gas Production Workers for the last calendar year compared to the calendar year preceding as shown by the index of average weekly earnings of Crude Petroleum and Gas Production Workers as published by the United States Department of Labor, Bureau of Labor Statistics. Such adjustment shall not exceed five percent (5%) in any given year.

3.4 Statement and Billings. Operator shall bill Owner each month : (i) the Turnkey Fee; (ii) in accordance with Section 3.2.2, the Direct Costs incurred by the Operator in performing Non-Routine Operation Services, plus ten percent (10%) of such Direct Costs; (iii) direct flowthrough costs in accordance with Section 3.2.7, and (iv) any adjustment which may be necessary to correct prior billings. Such bills will be summarized by appropriate classifications indicative of the nature thereof.

3.5 Payments. Owner shall pay to Operator the full amount of each invoice within fifteen (15) days of receipt of each such invoice. If Owner fails to make timely payments of any invoice, then Operator shall be entitled to collect the amount of such invoice together with the interest at the Default Rate on any unpaid undisputed amount; provided that if Owner has sufficient funds to make payment and the failure to make timely payment is due to delay by Operator in making such payment from Owner's account, no interest charge shall be imposed for late payment. If Owner's failure to pay is a result of a good faith dispute of any such charges, then interest will be payable only on the disputed portion that is found to be ultimately due. Interest shall accrue on unpaid amounts beginning on the payment due date of the Operator's invoice to Owner and shall terminate upon payment of such invoice. Payment shall not be construed as an acceptance of defective work or improper materials or a waiver of any right under this Agreement by Owner.

3.6 Budgets. As soon as practical after the Operator Transition Date, Operator shall prepare and submit for approval by Owner an estimate of expenditures which Operator anticipates will be incurred during the remainder of the Calendar Year. On or before October 1 of each Calendar Year, Operator shall prepare and submit for approval by Owner an estimate of operating income, expenses, capital expenditures, operating cash flow, and distributions which Operator anticipates for the twelve month period commencing on the following January 1. Except as Owner may otherwise direct, the budget approved by Owner and then in effect shall constitute authorization to Operator to incur the expenditures contained in such budget. If it subsequently appears that the budgeted amount for any Non-Routine Operation Service will be exceeded by the lesser of (i) 10% of such budgeted amount or (ii) $100,000, Operator shall submit a revised budget request, which shall include an explanation of the reason for the anticipated budget overrun, to Owner for approval.

3.7 Capital Items and Construction Costs. Prior to the acquisition of any property in the name of or on behalf of Owner which might be capitalized under the accounting rules and regulations, if any, at the time prescribed by the regulatory body or bodies under the jurisdiction of which the Owner is at the time operating, Operator shall prepare and submit to Owner a forecast of the cost of all such property. Upon approval of such forecast by Owner, Operator shall have authority to purchase such property in Owner's name or in Operator's name for the benefit of Owner without further approval or action by Owner. To the extent Operator owns property necessary or desirable for the construction, operation, and maintenance of the System which (i) under the accounting rules and regulations, if any, at the time prescribed by the regulatory body or bodies under the jurisdiction of which the Owner is at the time operating, might be capitalized, (ii) Operator is willing to transfer to Owner and Owner is willing to have transferred to it, and (iii) can be transferred by Operator to Owner free and clear of all prior liens and encumbrances, Operator may so transfer such property to Owner and charge Owner the lesser of the net book or fair market value thereof as of the date of transfer.

3.8 Rate Reviews. Operator shall review from time to time the rates and fees charged for transportation services and recommend to Owner revision in such rates and fees as necessary to reflect increased or decreased costs or other changes in the conditions of service.

3.9 Inspection. Owner and each Parent Member shall have the right at all reasonable times during usual business hours to inspect the facilities of Owner and to examine and make copies of the books of account, excluding any books of accounts associated with Routine Operation Services. Owner and each Parent Member may inspect the records of Operator directly related to Operation Services in order to verify compliance with proper operating procedures, but not to verify or inspect Operator's costs or other such financial information related to Routine Operation Services. Such right may be exercised through any agent or employee of Owner or such Parent Member designated in writing by it or by an independent accountant or attorney so designated. The person making the request shall bear all expenses incurred in any inspection or examination made at its behest. Nothing contained herein shall restrict the right of Owner or any Parent Member to inspect the records of Operator related to compliance with operating and maintenance requirements hereunder.

3.10 Audit. Owner or any Parent Member, after 15 days notice in writing to Operator, shall have the right during normal business hours to audit, at its own expense, all books and records of Operator relating to the operation of the System, excluding all books of account of Operator associated with Routine Operation Services. Any such audit may encompass the records of Operator directly related to Operation Services in order to verify compliance with proper operating procedures, but not to verify or inspect Operator's costs or other such financial information related to Routine Operation Services. Such audits shall not be made more often than twice each Calendar Year. Owner and each Parent Member shall have two years after the close of a Calendar Year in which to make an audit of Operator's records for such Calendar Year. Operator shall neither be required nor permitted to adjust any item unless a claim therefor is presented or adjustment is initiated within two years after the close of the Calendar Year in which the statement therefor is rendered, and in the absence of such timely claims or adjustments, the bills and statements rendered shall be conclusively established as correct.

ARTICLE IV
PERFORMANCE OF OPERATOR'S OBLIGATIONS

Operator shall perform its services hereunder in accordance with the requirements of all applicable laws, rules, orders and regulations of governmental authorities having jurisdiction, including, without limitation, 49 Code of Federal Regulations Parts 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) and 199 (Drug Testing), and any successor laws, rules, orders and regulations, and in accordance with sound, efficient, workmanlike and economically prudent natural gas pipeline industry practices and Operator's standard engineering and/or construction practices. Owner, through its management committee and/or subcommittees of such management committee, shall have the right to observe, and to consult with Operator in connection with, Operator's performance of its obligations under this Agreement, but Owner shall not have the right to supervise, direct or control Operator's performance of such obligations. In the performance of such obligations, Operator shall be an independent contractor and not an employee or agent of Owner and shall comply with all of the applicable laws, rules, orders and regulations of governmental authorities having jurisdiction.

Operator may, but shall not be obligated to, use the services of Operator's or its Affiliates' legal, accounting, engineering, planning, budgeting, operating, rates and economics, land, purchasing and other departments. All measurement and measurement equipment shall comply with the applicable provisions of Owner's Rate Schedules FTS and ITS and the General Terms and Conditions applicable thereto as such may be amended from time to time. Operator shall perform its duties hereunder in a manner consistent with the standards of the Gas Industry Standards Board and applicable rules and regulations of the Federal Energy Regulatory Commission. Operator shall perform custody transfer measurement in a manner that meets or exceeds Owner's specifications as defined in its current Tariff and applicable regulatory requirements. Owner's sole recourse with respect to a breach by Operator of any standard of performance established by this Article are set forth in Section 9.2(a)(vi).

ARTICLE V
INDEMNITY, LITIGATION AND INSURANCE

5.1 Indemnity and Litigation.

5.1.1 Owner's Indemnity. Inasmuch as the services to be performed by Operator are to be furnished and performed for only the reimbursements provided in Article III, Owner hereby agrees to **RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS** Operator, its Affiliates and their respective officers, agents and employees, when acting as Operator, against any and all claims, damages and causes of action (to the extent only that such claims, damages and causes of action are not satisfied by insurance carried pursuant to Section 5.2.1 or otherwise carried by Operator) arising out of, in connection with, or as an incident to any act or omission in connection with the performance of Operator's obligations hereunder, **INCLUDING NEGLIGENCE (BUT NOT GROSS NEGLIGENCE OR WILLFUL MISCONDUCT) OF OPERATOR, ITS MEMBERS, AFFILIATES, OR THEIR RESPECTIVE OFFICERS, AGENTS OR EMPLOYEES**.

5.1.2 Litigation. Any and all claims, damages or causes of action in favor of any one other than Owner hereto arising out of the performance of Operator's obligations hereunder which are not covered by insurance shall be settled or litigated and defended by Operator in accordance with its best judgment and discretion when (i) the amount involved is $25,000 or less, (ii) no injunctive or similar relief is sought and (iii) no criminal sanction is sought; otherwise, such decision shall be made by Owner, and any settlement or defense thereof shall be controlled by Owner.

5.1.3 Transportation Agreements. Owner will include in each agreement for the transportation of gas and associated liquids in the System a provision indemnifying and saving harmless Operator, its officers, agents and employees from any claim, demand or expense for loss, damage or injury arising out of or in any way connected with the quality, use or condition of the gas and associated liquids after delivery from the System for the account of the shipper and further providing that Operator shall not be responsible for any losses or shrinkage of gas and associated liquids during transportation in the System, except in the case of willful misconduct or gross negligence on the part of Operator, its Affiliates or their respective officers, agents or employees.

5.2 Insurance.

5.2.1 Coverage. Operator shall, at Owner's expense, carry and maintain in force for the benefit of Operator and Owner insurance of the type and in the amounts specified by Owner.

5.2.2 Waiver of Rights of Recovery. With respect to claims and losses for damage, injury or destruction of property which is a part of the System, which property is covered by insurance actually collected, other than insurance provided for in Section 5.2.1, it is agreed that neither Operator nor Owner or any of its Members shall have any rights of recovery against one another, nor against the Affiliates of each, nor the insurers of any of them, and their rights of recovery are mutually waived. All such policies of insurance purchased to cover the System or any part thereof, or the operation (in any respect) of the System or any part thereof, or any gas transported or handled therein, shall be endorsed properly to effectuate this waiver of recovery.

ARTICLE VI
TAXES

Unless otherwise instructed by Owner, Operator, on behalf of Owner and subject to the direction of the TMM, shall file all returns and render and pay (prior to delinquency) all taxes presently and hereinafter enacted attributable to or arising from the construction, ownership, operation, repair and maintenance of the System or the transportation of gas and associated liquids through the System. The taxes so paid by Operator on Owner's behalf shall be reimbursed to Operator in accordance with Section 3.2.7.

ARTICLE VII
ASSIGNMENT

7.1 Assignment. Owner may assign this Agreement or any interest herein only in connection with an assignment of Owner's interest in the System. Operator may not assign this Agreement or any interest herein or any property, real or personal, acquired in connection therewith, without the prior written consent of Owner, except that Operator may assign any of its right, title and interest in this Agreement if such right, title and interest is transferred to another Person (which Person is Controlled by Leviathan Gas Pipeline Partners, L.P., a Delaware limited partnership) pursuant to (i) a statutory merger or consolidation or (i) a sale of all or substantially all of the assets of Operator provided that such Person assumes by operation of law or express agreement with Owner (in form and substance satisfactory to the Management Committee) all of the obligations of Operator under this Agreement and that no such transfer (other than pursuant to a statutory merger or consolidation wherein all obligations and liabilities of Operator are assumed by the successor Person by operation of law) shall relieve Operator of its obligations under this Agreement without the unanimous approval of the Management Committee.

7.2 Mortgage. Both Parties may mortgage, pledge, and hypothecate this Agreement to any financial institution or lender as security for bonds, mortgages or indentures of such Party or such Party's Affiliates, or other obligations or securities of such Party or such Party's

Affiliates, provided, no such mortgage, pledge, or hypothecation shall relieve such Party of its obligations under this Agreement.

ARTICLE VIII
FORCE MAJEURE

8.1 Force Majeure. If by reason of force majeure either Party is rendered unable, wholly or in part, to carry out its obligations under this Agreement, and if such Party gives notice and reasonably full particulars of such force majeure in writing or by facsimile to the other within a reasonable time after the occurrence of the cause relied on, the Party giving such notice, so far as and to the extent that it is affected by such force majeure, shall not be liable in damages during the continuance of any inability so caused; provided, such cause shall be remedied with all reasonable dispatch.

8.2 Force Majeure Defined. As used herein, force majeure shall mean acts of God, strikes, lockouts, or other industrial disturbances; acts of a public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms (including but not limited to hurricanes or hurricane warnings), crevasses, arrests and restraints of the government, either federal or state, civil or military, civil disturbances; shutdowns for purposes of necessary repairs, relocation, or construction of facilities; breakage or accident to machinery or lines of pipe; the necessity for testing (as required by governmental authority or as deemed necessary by Operator for the safe operation thereof), the necessity of making repairs or alterations to machinery or lines of pipe; failure of surface equipment or pipelines; accidents, breakdowns, inability of either Party hereto to obtain necessary material, supplies, or permits, or labor to perform or comply with any obligation or condition of this Agreement, rights of way; and any other causes, whether of the kind herein enumerated or otherwise, which are not reasonably in the control of the Party claiming suspension. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the Party having the difficulty and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of an opposing party when such course is inadvisable in the discretion of the Party having the difficulty.

8.3 Limitations. Such force majeure affecting the performance hereunder by either Party, however, shall not relieve such Party of liability in the event of concurring negligence or in the event of failure to use due diligence to remedy the situation and to remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting such performance relieve either Party from its obligations to make payments as determined hereunder.

ARTICLE IX
TERMINATION

9.1 Term. This Agreement shall become effective on the Operator Transition Date. Thereafter, this Agreement shall continue in force and effect for a primary term of twenty (20) years unless terminated pursuant to Section 9.2.

9.2 Termination.

(a) Owner may terminate this Agreement by not less than 120 days prior written notice to Operator if any of the following shall occur:

(i) Operator is in default in the performance of any of its obligations hereunder (other than the standard of performance set forth in Article IV except as provided in Section 9.2(a)(vi)) and Operator has failed to cure such default within 30 days after notice in writing thereof by Owner specifying such default, or if such cure cannot be completed within the 30 day period, Operator fails to promptly upon receipt of such notice commence such cure and dilig tly proceeds thereafter to cure such default;

(ii) Operator dissolves, liquidates or terminates its separate corporate existence, other than pursuant to a merger, share exchange or consolidation with an Affiliate;

(iii) Proceedings shall be commenced by or against Operator for any relief under any bankruptcy or insolvency law, or any law relating to the relief of debtors, readjustment of indebtedness, reorganization, arrangement, composition or extension, and, if such proceedings have been commenced against Operator, such proceedings shall not have been dismissed, nullified, stayed or otherwise rendered ineffective (but then only so long as such stay shall continue in force or such ineffectiveness shall continue) within 90 days after such proceedings shall have been commenced;

(iv) A decree or order of a court having jurisdiction in the premises for the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of Operator or of a substantial part of its property, or for the winding up or liquidation of its affairs, shall have been entered, and such decree or order shall have remained in force undischarged and unstayed for a period of 90 days, or any substantial part of the property of Operator shall be sequestered or attached and shall not be returned to the possession of Operator or released from such attachment within 90 days thereafter;

(v) Operator shall make a general assignment for the benefit of creditors or shall admit in writing its inability to pay its debts generally as they become due;

(vi) Operator is negligent or imprudent in carrying out its duties hereunder, unless (i) such negligence or imprudence is caused by the failure of Owner to approve any Non-Routine Operation Service that is necessary in order to enable Operator to carry out its duties hereunder in a nonnegligent or prudent manner, that Operator has requested Owner to approve and that each Affiliate of Operator owning an interest in Owner (and Operator if it owns an interest in Owner) has voted its interest under the LLC Agreement to approve or (ii) such negligent or imprudent acts or omissions (x) could not reasonably be expected to have a material adverse effect on Owner, (y) result from a course or pattern of negligent or imprudent acts or omissions about which Company (1) has not notified Operator or (2) has notified Operator and which Operator has corrected promptly after receipt of such notice, or (z) are one-time or non-recurring acts or omissions that Operator does not have the opportunity to cure, such as the act of a "rogue" employee;

(vii) Owner sells or leases the entire System to a Person not Affiliated with Owner or any Parent Member; or

(viii) Operator and its Affiliates fail for any reason to collectively maintain direct ownership and control of at least 33-1/3% of the membership interests in the Parent.

(b) Operator may terminate this Agreement by not less than 120 days prior written notice given by Operator to Owner if any of the following shall occur:

(i) Owner is in default in the performance of any of its obligations hereunder and Owner has failed to cure such default within 30 days after notice in writing thereof by Operator specifying such default, or if such cure cannot be completed within the 30 day period, Owner fails to promptly upon receipt of such notice commence such cure and diligently proceeds thereafter to cure such default;

(ii) The dissolution and completion of winding up of the business of Owner;

(iii) Proceedings shall be commenced by or against Owner for any relief under any bankruptcy or insolvency law, or any law relating to the relief of debtors, readjustment of indebtedness, reorganization, arrangement, composition or extension, and, if such proceedings have been commenced against Owner, such proceedings shall not have been dismissed, nullified, stayed or otherwise rendered ineffective (but then only so long as such stay shall continue in force or such ineffectiveness shall continue) within 90 days after such proceedings shall have been commenced;

(iv) A decree or order of a court having jurisdiction in the premises for the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of Owner or of a substantial part of its property, or for the winding up or liquidation of its affairs, shall have been entered, and such decree or order shall have remained in force undischarged and unstayed for a period of 90 days, or any substantial part of the property of Owner shall be sequestered or attached and shall not be returned to the possession of Owner or released from such attachment within 90 days thereafter;

(v) Owner shall make a general assignment for the benefit of creditors or shall admit in writing its inability to pay its debts generally as they become due;

(vi) Owner sells or leases the entire System to a third party; or

(vii) Any Non-Routine Operation Service which is necessary in order to maintain the safety of the Operated Assets in accordance with applicable regulatory requirements and prudent operating practices is not approved by Owner within 30 days following a request for such approval from Operator, there is no reasonable alternative method of operating the applicable Operated Assets in a safe manner without conducting such Non-Routine Operation Service, Operator has provided Owner all information concerning the proposed Non-Routine Operation Service reasonably requested by Owner, and each Affiliate of Operator owning an interest in Owner (and Operator if it owns an interest in Owner) has voted its interest under the LLC Agreement in favor of conducting such proposed Non-Routine Operation Service.

9.3 Effect. Termination of this Agreement shall not relieve either Party from any obligation accruing or accrued to the date of such termination or deprive the Party not in default of any remedy otherwise available to it.

9.4 Transfer. In the event of termination of this Agreement, Operator will submit to Owner a final accounting of its operations hereunder and deliver to the successor operator designated by Owner all records, reports, and data that are in its possession as the Operator hereunder as promptly as possible. Operator may retain copies of all of said records, reports and data, which copies will be prepared at the expense of Owner. Operator will cooperate with Owner and any successor operator to cause an orderly transition of operations to the successor operator, including the execution by Operator of all documents, instruments and regulatory filings reasonably requested by Owner in connection with such transition.

ARTICLE X
NOTICES

Any notice, request, statement or other communication provided for in this Agreement shall be in writing and shall be given by personal delivery, United States mail, postage prepaid, or telecopy and addressed as follows:

If to Owner:

High Island Offshore System, L.L.C.
El Paso Energy Building
1001 Louisiana
Houston, Texas 77002
Attn:
Telecopy: 713-420-5477

If to Operator:

Leviathan Operating Company, L.L.C.
El Paso Energy Building
1001 Louisiana
Houston, Texas 77002
Attn:
Telecopy: 713-420-5477

For purposes of this Agreement, the date on which any notice, request, statement, payment or other communication shall be deemed to have been given shall be the date on which it is received by the recipient, provided any such notice, request, statement, payment or other communication transmitted by registered or certified mail, return receipt requested, postage prepaid, shall be deemed to have been given on the third day following the date on which same was deposited in the United States mail, addressed in accordance with this Article X. Either Party may designate a further or different address to which subsequent notices, requests, statements, payments or other communications shall be sent. Copies of all such notices, requests, statements or other communications shall be sent to each Member at the address designated by it.

ARTICLE XI
MISCELLANEOUS

11.1 Applicable Law. THIS AGREEMENT SHALL BE GOVERNED BY AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, WITHOUT REGARD TO ANY CONFLICTS OF LAWS PRINCIPLES WHICH, IF APPLIED, MIGHT PERMIT OR REQUIRE THE APPLICATION OF THE LAWS OF ANOTHER JURISDICTION.

11.2 Laws and Regulatory Bodies. This Agreement, the operation of the Operated Assets and the rights and obligations of Owner and Operator hereunder shall be subject to all valid and applicable laws, orders, directives, rules and regulations of any duly constituted governmental body or official having jurisdiction.

11.3 Waiver. No waiver by either Party of any default by the other Party in the performance of any provision, condition or requirement herein shall be deemed to be a waiver of, or in any manner release the other Party from, performance of any other provision, condition or requirement herein, nor deemed to be a waiver of, or in any manner release the other Party from, future performance of the same provision, condition or requirement; nor shall any delay or omission of either Party to exercise any right hereunder in any manner impair the exercise of any such right or any like right accruing to it thereafter.

11.4 Modification. This Agreement may not be modified, varied or amended except by an instrument in writing signed by the Parties.

11.5 Captions. The titles to each of the various Articles and Sections in this Agreement are included for convenience or reference only and shall have no effect on, or be deemed as part of the text of, this Agreement.

11.6 Multiple Counterparts. This Agreement may be executed in several counterparts, each of which shall be an original, and all of which, when taken together, shall constitute but one and the same Agreement.

11.7 Claims of Operator. All claims hereunder of Operator shall be limited to the assets of Owner, and Operator hereby waives any and all rights to proceed against the Members individually.

11.8 Equal Employment Opportunity. Operator agrees to be bound by, and fully comply with, the provisions of Section 202 of Executive Order 11246 and the other provisions set forth in Exhibit B attached hereto.

11.9 Operating and Maintenance Plan. Operator shall submit to Owner for approval an operating and maintenance plan for the System, as required by the Minimum Federal Safety Standards, Part 192, of the Department of Transportation. The operating and maintenance plan shall include a section specifically outlining in detail the Operator's Corrosion Program. It shall address mitigation plans for both external and internal corrosion. The Operator shall have an effective internal corrosion mitigation program that considers factors such as CO_2, H_2S, water ph, flow velocities, piggability of lines, presence of free water and vapor phase water. This program shall be designed and monitored in a manner to insure corrosion rates in the System do not exceed 1 mil per year. The Operator shall also have an effective bacteria monitoring program designed to monitor SRB's (sulfate reducing bacteria) and APB's (acid producing bacteria) that includes testing and monitoring of all receipt points (at least quarterly) on the System to maintain colony counts at or below 100 colonies per milliliter. Corrosion inhibitor programs shall include documentation of all injection rates (recommended and actual), injection points, testing, test results, and action plans for correcting any locations not meeting desired results.

11.10 Operator's Office. Operator may select the location of its office or offices to perform its obligations hereunder. However, Operator shall maintain an office in Houston, Texas, which will be staffed by a person or persons who will be familiar with the daily operations of the System.

11.11 Conflict or Inconsistencies with LLC Agreement. In the event of any conflict or inconsistency between the LLC Agreement and this Agreement, the LLC Agreement shall control.

11.12 Arbitration. (a) Any and all claims, counterclaims, demands, cause of action, disputes, controversies, and other matters in question arising out of or relating to this Agreement, any provision hereof, the alleged breach of any such provision, or in any way relating to the subject matter of this Agreement or the relationship between the Parties created by this Agreement, involving the Parties and/or their respective representatives (all of which are referred to herein as "Claims"), even though some or all of such Claims allegedly are extra-contractual in nature, whether such Claims sound in contract, tort, or otherwise, at law or in equity, under State or federal law, whether provided by statute or the common law, for damages or any other relief, shall be resolved by binding arbitration in accordance with this Section 11.11.

(b) It is the intention of the parties that the arbitration shall be conducted pursuant to the Federal Arbitration Act, as such Act is modified by this Agreement. The validity, construction, and interpretation of this Section 11.11, and all procedural aspects of the arbitration conducted pursuant to this Section 11.11, including but not limited to, the determination of the issues that are subject to arbitration (i.e., arbitrability), the scope of the arbitrable issues, allegations of "fraud in the inducement" to enter into this Agreement, or this arbitration provision, allegations of waiver, laches, delay or other defenses to arbitrability, and the rules governing the conduct of the arbitration (including the time for filing an answer, the time for the filing of counterclaims, the times for amending the pleadings, the specificity of the pleadings, the extent and scope of discovery, the issuance of subpoenas, the times for the designation of experts, whether the arbitration is to be stayed pending resolution of related litigation involving third parties not bound by this Agreement, the receipt of evidence, and the like), shall be decided by the arbitrators. The arbitration shall be administered by the AAA and shall be conducted pursuant to the Commercial Arbitration Rules of the AAA, as modified by this Agreement. In deciding the substance of the parties' Claims, the arbitrators shall refer to the substantive laws of the State of Texas for guidance (excluding Texas choice-of-law principles that might call for the application of some other State's law). Notwithstanding any other provision in this Section 11.11 to the contrary, the Parties expressly agree that the arbitrators shall have absolutely no authority to award incidental, special, treble, exemplary or punitive damages of any type under any circumstances regardless of whether such damages may be available under Texas law, the law of any other State, or federal law, or under the Federal Arbitration Act, or under the Commercial Arbitration Rules of the AAA, the parties hereby waiving their right, if any, to recover incidental, special, treble, exemplary or punitive damages in connection with any such Claims.

(c) The arbitration proceeding shall be conducted in Houston, Texas before a panel of three arbitrators appointed in accordance with the Commercial Arbitration Rules of the AAA consisting of persons from any of the following categories: (i) attorneys having practiced in the area of natural gas transportation law for at least ten (10) years, (ii) engineers with at least ten (10) years of experience in the natural gas transportation industry, or (iii) accountants with at least ten (10) years of experience in the natural gas transportation industry. The arbitrators shall conduct a hearing as soon as reasonably practicable after appointment of the third arbitrator, and a final decision completely disposing of all Claims that are the subject of the arbitration proceedings shall be rendered by the arbitrators within thirty (30) days after the hearing. There shall be no transcript of the hearing before the arbitrators. The arbitrators' ultimate decision after final hearing shall be in writing, but shall be as brief as possible, and the arbitrators shall not assign reasons for their ultimate decision. In case the arbitrators award monetary damages to either Party, the arbitrators shall certify in their award that they have not included any incidental, special, treble, exemplary or punitive damages.

(d) The fees and expenses of the arbitrators shall be borne equally by the Parties, but the decision of the arbitrators may include such award of the arbitrators' fees and expenses and of other costs and attorneys' fees as the arbitrators determine appropriate.

(e) To the fullest extent permitted by law, the arbitration proceeding and the arbitrators' award shall be maintained in confidence by the Parties.

(f) The award of the arbitrators shall be binding upon the parties and final and nonappealable to the maximum extent permitted by law, and judgement thereon may be entered in a court of competent jurisdiction and enforced by any Party as a final judgment of such court.

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IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first set forth above.

OWNER:

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.,

By: ______________________________
Name: William L. Johnson
Title: Vice Chairman

OPERATOR:

LEVIATHAN OPERATING COMPANY, L.L.C.

By: ______________________________
Name: T. Darty Smith
Title: Vice President

Exhibit A: The System
Exhibit B: Equal Employment Opportunity Provisions

EXHIBIT A

THE SYSTEM

[Attached.]

EXHIBIT B

TO

OPERATING SERVICES AGREEMENT

EQUAL EMPLOYMENT OPPORTUNITY PROVISIONS

A. Equal Opportunity Clause (41 CFR 60-1.4)

During the performance of this contract, Operator agrees as follows:

(1) Operator will not discriminate against any employee or applicant for employment because of race, color, religion, sex, age or national origin. Operator will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, age or national origin. Such action shall include, but not be limited to the following: Employment, upgrading, demotion, or transfer, recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. Operator agrees to post in conspicuous places, available to employees and applicants for employment, notices setting forth the provisions of this nondiscrimination clause.

(2) Operator will, in all solicitations or advertisements for employees placed by or on behalf of Operator, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(3) Operator will send to each labor union or representative of workers with which Operator has a collective bargaining agreement or other contract or understanding, a notice advising the labor union or worker's representative of Operator's commitments under section 202 of Executive Order 11246 of September 1965, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) Operator will comply with all provisions of Executive Order 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(5) Operator will furnish all information and reports required by Executive Order 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Secretary of Labor and his representatives for purposes of investigation to ascertain compliance with such rules, regulations and orders.

(6) In the event of Operator's noncompliance with the nondiscrimination clauses of this contract or with any of such rules, regulations, or orders, this contract may be canceled, terminated or suspended in whole or in part and Operator may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order 11246 or

September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(7) Operator will include the provisions of paragraphs (1) through (7) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to section 204 of Executive Order 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. Operator will take such action with respect to any subcontract or purchase order as the contracting agency may direct as a means of enforcing such provisions including sanctions for noncompliance; provided, however, that in the event Operator becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the contracting agency, Operator may request the United States to enter into such litigation to protect the interests of the United States.

B. Employee Information Report (41 CFR 601.7)

Operator acknowledges that it may be required to file Standard Form 100 (EEO-1) promulgated jointly by the Office of Federal Contract Compliance, the Equal Employment Opportunity Commission and Plans for Progress with Joint Reporting Committee, Federal Depot, Jeffersonville, Indiana, within thirty (30) days of the date of contract award if such report has not been filed for the current year and otherwise comply with or file such other compliance reports as may be required under Executive Order 1 1246, as amended and Rules and Regulations adopted thereunder.

C. Affirmative Action Programs (41 CFR 60-1.40)

Operator further acknowledges that it may be required to develop a written affirmative action compliance program as required by the Rules and Regulations approved by the Secretary of Labor under authority of Executive Order 11246 and supply Owner with a copy of such program if they so request.

D. Certification of Nonsegregated Facilities (41 CFR 60-1.8)

Operator certifies that it does not maintain or provide for its employees any segregated facilities at any of its establishments, and that it does not permit its employees to perform their services at any location under its control, where segregated facilities are maintained. It certifies further that it will not maintain or provide for its employees any segregated facilities at any of its establishments, and that it will not permit its employees to perform their services at any location, under its control where segregated facilities are maintained. Operator agrees that a breach of this certification is a violation of the Equal Employment Opportunity Clause in this contract. As used in this certification, the term "segregated facilities" means any waiting rooms, work areas, rest rooms and wash rooms, restaurants and other eating areas, time clocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation, and housing facilities provided for employees which are segregated by explicit directive or are in fact segregated on the basis of race, creed, color, or national origin, because of habit, local custom or otherwise. It further agrees that (except where it has obtained identical certifications from proposed subcontractors for specific time periods) it will obtain identical certifications from proposed subcontractors prior to the award of subcontractors exceeding $10,000 which are not exempt from the provisions of Equal Employment Opportunity Clause; that it will retain such certification in its files; and that it will forward the following notice to such proposed subcontractors (except where the proposed subcontractors have submitted identical certifications for specific time periods): NOTICE TO PROSPECTIVE SUBCONTRACTORS OF REQUIREMENT FOR CERTIFICATIONS OF NONSEGREGATED FACILITIES. A Certificate of Nonsegregated Facilities, as required by the May 9, 1967, order on Elimination of Segregated Facilities, by the Secretary of Labor (32 Fed. Reg. 7439, May 19, 1967) must be submitted prior to the award of subcontract exceeding $10,000 which is not exempt from the provisions of the Equal Employment Opportunity Clause. The certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually, or annually). (Note: The penalty for making false statements in offers is prescribed in 18 U.S.C. 1001.)

E. <u>Listing of Employment Openings (41 CFR 50-250)</u>

Operator agrees to comply with the rules and regulations of the Department of Labor concerning the listing of employment openings, including the contract clause set forth in 41 CFR 50-250.2, which clause is incorporated herein by reference. Operator also agrees to place the foregoing provision in any subcontract directly under this contract.

F. <u>Employment of Handicapped Individuals</u>

In employing persons to carry out this Agreement, Operator will take affirmative action to employ and advance in employment qualified handicapped individuals as defined in Section 7(6) of the Federal Rehabilitation Act of 1973.

Amendment No. 1 to Operating Services Agreement

This **AMENDMENT TO OPERATING SERVICES AGREEMENT** ("Amendment") is entered into effective as of August 1, 2006, ("Effective Date") between **HIGH ISLAND OFFSHORE SYSTEM, L.L.C.**, a Delaware corporation ("Owner") and **ENTERPRISE GTM OFFSHORE OPERATING COMPANY, LLC**, a Delaware limited liability company ("Operator").

W I T N E S S E T H

WHEREAS, Owner and Leviathan Operating Company, L.L.C. entered into that certain Operating Services Agreement dated September 30, 1999 ("Agreement");

WHEREAS, Operator is the successor in interest to Leviathan Operating Company, L.L.C. under the Agreement; and

WHEREAS, Owner and Operator desire to revise the Agreement to reflect a mutually agreed replacement index for calculating the annual adjustment of the Turnkey Fee; and

WHEREAS, the Parties desire to amend the Agreement to modify the budgeting process for Non-Routine Operation Services.

NOW, THEREFORE, in consideration of the mutual promises made herein, and intending to be legally bound by the provisions hereinafter set forth, Owner and Operator agree to amend the Agreement effective as of the Effective Date as follows:

1. The Agreement is amended by deleting Section 3.3.2 in its entirety and replacing it with the following new Section 3.3.2:

   "3.3.2 Annual Adjustment. The Turnkey Fee shall be subject to annual adjustment effective January 1 of each year beginning with January 1, 2002. The adjustment shall be computed by multiplying the Turnkey Fee by the percentage increase or decrease in the average weekly earnings of Crude Petroleum and Gas Production Workers for the last calendar year compared to the calendar year preceding, as shown by the index of average weekly earnings of Crude Petroleum and Gas Production Workers as published by the United States Department of Labor, Bureau of Labor statistics. Should such index cease being published, then the annual adjustment shall be made using the Wage Index Adjustment Factor published by the Council of Petroleum Accountants Societies (COPAS) in April of each year to adjust the Turnkey Fee beginning the following

January 1. In any case, such adjustment shall not exceed five percent (5%) in any given year."

2. The Agreement is amended by deleting Section 3.2.2 in its entirety and replacing it with the following new Section 3.2.2:

"3.2.2 Non-Routine Operation Services. For the performance of Non-Routine Operation Services with respect to all Operated Assets, Owner shall pay Operator (i) the monthly fee resulting from the 36-Month Non-Routine Operation Services Budget process described in Section 3.6 ("36-Month Non-Routine Expense Payment") and (ii) one hundred and ten percent (110%) of any additional Direct Costs that are not budgeted pursuant to Section 3.6 incurred by Operator in performing Non-Routine Operation Services (hereafter "Other Non-Routine Expense Payment")."

3. The Agreement is amended by deleting subsection (ii) of Section 3.4 in its entirety and replacing it with the following new subsection (ii):

"(ii) in accordance with Section 3.2.2, the 36-Month Non-Routine Expense Payment and the Other Non-Routine Expense Payment;"

4. The Agreement is amended by deleting Section 3.6 in its entirety and replacing it with the following new Section 3.6:

"3.6 Budgets. As soon as practical after the Operator Transition Date, Operator shall prepare and submit for approval by Owner an estimate of expenditures which Operator anticipates will be incurred during the remainder of the Calendar Year.

(i) Beginning on August 1, 2006, and on August 1 every three (3) years thereafter, Operator will submit to Owner a budget of the costs that it anticipates incurring to provide Non-Routine Operation Services for the 36 months beginning on the first day of the next Calendar Year ("36-Month Non-Routine Operation Services Budget"). Such 36-Month Non-Routine Operation Services Budget shall identify the particular Non-Routine Operation Services that Operator recommends be undertaken during the succeeding 36-Month period and the budget that Operator proposes to charge Owner for such services, with sufficient support for the proposed budget for Owner to make a reasonable determination as to the appropriateness of the proposed budget amount. Owner shall approve or modify the submitted 36-Month Non-Routine Operation Services Budget by August 31 of the year in which Operator submitted the subject 36-Month Non-Routine Operation Services Budget. If Owner makes modifications to the 36-Month Non-Routine Operation Services Budget and Operator disagrees with such modifications, the Parties shall meet and agree on a 36-Month Non-Routine Operation Services Budget by

September 30 of the same calendar year. After the 36-Month Non-Routine Operation Services Budget has been approved by Owner, Owner shall be obligated to pay to Operator in 36 equal monthly installments over the subject 36-Month period the amount of the approved 36-Month Non-Routine Operation Services Budget, and Operator shall be obligated to perform during such 36-Month period the Non-Routine Operation Services approved in such budget. Either Owner or Operator may notify the other during a 36-Month period that it wishes to consider modifications to the then in effect 36-Month Non-Routine Operation Services Budget, and in such event, the Parties shall meet to consider such modifications. If any such modifications are agreed, the monthly payments and the services to be performed shall be modified accordingly through a revised 36-Month Non-Routine Operation Services Budget for the remainder of the then current 36-Month period.

(ii) On or before October 1 of each Calendar Year, Operator shall prepare and submit for approval by Owner an estimate of operating income, expenses, capital expenditures, operating cash flow, and distributions which Operator anticipates for the twelve month period commencing on the following January 1, provided that such submission shall not include items subject to the then in effect 36-Month Non-Routine Operation Services Budget. Except as Owner may otherwise direct, the annual budget approved by Owner and then in effect shall constitute authorization to Operator to incur the expenditures contained in such budget. If it subsequently appears that the budgeted amount for any Non-Routine Operation Service, other than such Non-Routine Operation Services subject to the then in effect 36-Month Non-Routine Operation Services Budget, will be exceeded by the lesser of (i) 10% of such budgeted amount or (ii) $100,000, Operator shall submit a revised budget request, which shall include an explanation of the reason for the anticipated budget overrun, to Owner for approval."

5. The Agreement is amended by deleting the reference to "Leviathan Gas Pipeline Partners, L.P." in Section 7.1 and replacing it with "Enterprise GTM Holdings L.P."

Except as expressly amended hereby, the terms, conditions and provisions of the Agreement shall continue in full force and effect.

IN WITNESS WHEREOF, Owner and Operator have executed this Amendment effective as of the Effective Date.

OWNER:

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

By: ____________________

Name: MICHAEL A. CREEL
Executive Vice President and CFO

Title: ____________________

Approved as to form: KLM

OPERATOR:

ENTERPRISE GTM OFFSHORE OPERATING COMPANY, LLC

By: ____________________

Name: ROBERT G. PHILLIPS

Title: President and CEO

Approved as to form: KLM

Exhibit No. HIO-84

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System L.L.C.) Docket No. RP06-

Prepared Direct Testimony
Of
J. Scott Jenkins

Q. Please state your name and address.

A. My name is J. Scott Jenkins. My business address is 1100 Louisiana Street, Houston, TX 77002.

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

A. I am Manager of Supply Appraisal for Enterprise Products Partners L.P. ("Enterprise").

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Geology from the University of Houston in 1974. In 1981, I received a Master of Business Administration from the same institution with a concentration in Finance.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring testimony with regard to the reserve life of the gas supplies connected to HIOS.

Q. Have you previously provided testimony before the FERC related to HIOS?

A. Yes, I provided testimony in Docket No. RP03-221-000.

Q. Please describe your duties at Enterprise.

A. My primary duties are directly related to my testimony in this case and pertain to the development of gas production forecasts for pipeline assets.

Q. What experience do you have on these issues?

A. Since the time of first being employed by ANR Pipeline Company ("ANR") (the original operator of HIOS) in 1974, my primary job has been to estimate gas reserves and forecast gas production. I held several positions within the Reserves and Availability Department of ANR and was named Director of that group in November 1986. In that position, I was responsible for overseeing all reservoir engineering and geological studies with respect to ANR gas supply, including HIOS. In February 2001, ANR was merged into El Paso. At that time, I was named Manager of Supply Appraisal for the Eastern Pipeline Group of El Paso, supervising a group of professionals charged with scouting for and forecasting gas supplies for ANR, Tennessee Gas Pipeline and Southern Natural Gas Company. In May of the same year, I was also named Manager of Reservoir Engineering for El Paso Field Services ("EPFS"), supervising a group of professionals charged with scouting for and forecasting gas and oil supplies for all of the assets operated and managed by EPFS. My EPFS responsibilities included assets such as HIOS which became part of El Paso's GulfTerra Energy Partners, L.P. In 2004 El Paso sold GulfTerra Energy Partners, L.P. to Enterprise, including HIOS. My staff and I transferred to Enterprise with the assets.

Q. Do you have any other experience pertinent to this testimony?

A. Yes, I have served on the Potential Gas Committee ("PGC") since 1983 in various positions including President of the PGC, and Chairman of the Board, as well as Chairman of the Gulf Coast Area work committee. The PGC is a voluntary organization that publishes biennial estimates of potential gas resources (as opposed to proved reserves) for the United States. I am also a Certified Petroleum Geologist of the American Association of Petroleum Geologists, and a registered Professional Geoscientist with the state of Texas.

Q. What is the purpose of your testimony in this case?

A. My testimony will speak to the expected life of gas production from supply sources attached to HIOS in the absence of economic criteria, or to the "reserve life" of HIOS. HIOS witness Richard W. Porter has determined the economic life based on the economics of operating HIOS, taking into consideration my supply forecast. Based on the gas supply studies conducted by me or under my supervision, which are summarized in my attached exhibits, I recommend a reserve life of 19 years for HIOS, though a reserves life as low as 8 years could be supported.

Q. What exhibits are you sponsoring in support of this recommendation?

A I am sponsoring the following exhibits:

Exhibit No.	HIO-85	HIOS gas forecast of proved and probable reserves
Exhibit No.	HIO-86	HIOS shelf gas production from existing wells
Exhibit No.	HIO-87	HIOS well statistics
Exhibit No.	HIO-88	HIOS reserve statistics
Exhibit No.	HIO-89	HIOS shelf forecast parameters
Exhibit No.	HIO-90	HIOS shelf gas production from existing and new wells
Exhibit No.	HIO-91	HIOS gas forecast

Q. Please explain.

A. The gas supply studies conducted under my supervision were designed to project the level of likely gas volumes adjacent to HIOS, which HIOS could reasonably be expected to transport in the future, if no economic limits on the ability to produce and transport those supplies are taken into consideration. My studies are summarized in Exhibit No. HIO-85, which is a chart that compiles different sources of likely gas supply, including my forecast of production from existing wells connected to HIOS on the Outer Continental Shelf ("Shelf"). These existing Shelf wells connected to HIOS are described in my testimony and exhibits as "HIOS Shelf Existing Wells". I have also included in the graph shown on Exhibit No**.** HIO-85**,** certain data for existing deepwater wells connected directly to HIOS ("HIOS Deepwater Existing Wells"), or via the East Breaks Gathering System ("EBGS"). The summation of my forecasts for these three groups of wells constitutes the proved and probable reserves attached to HIOS except that no economic limit has been applied to the forecasts as required for producing companies' annual reports of proved reserves to the Securities and Exchange Commission ("SEC"). Specifically, it is my understanding that producers are required to identify their proved reserves in their annual reports pursuant to SEC definitions, so that investors may make financial decisions. Exhibit No. HIO–85 shows that the proved and probable reserves attached to HIOS will be depleted by the end of 2014, or in 8 years, assuming that no economic limit is applied to the costs of producing and transporting the gas.

Q. What are the historical production trends for sources connected to HIOS, and how do those trends relate to the reserve life you are projecting for HIOS?

A. For HIOS, historical production volumes peaked at over 1,750 MMcf/d in 1981, declined to an average of 956 MMcf/d in 2001, and have continued to decline to below 400 MMcf/d in August, 2006. My studies forecast continuation of this decline.

Q. Please describe the methodology you used to forecast the production from HIOS Shelf Existing Wells.

A. Exhibit Nos. HIO-86 through HIO-88 provide backup for my forecast of existing Shelf wells which should be considered in this case. My staff performed a "vintaging" study on all Shelf wells currently connected to HIOS to establish trends for the number of wells added per year, reserves per well, start rate per well, and the associated decline factors for each well. The wells completed in each year from 1978 through 2005 were accumulated into "vintages". Production from each vintage was plotted and forecasted using exponential declines (Exhibit No. HIO-86). The composite of all vintage forecasts for 1978 through 2005 represents the amount of gas expected to be produced in the future from HIOS Shelf Existing Wells, again assuming that no economic limits on the ability to produce and transport those supplies are taken into consideration.

Average well information was determined by dividing each vintage by the number of wells completed that year. The forecasts were divided by the number of wells to determine average reserves and initial (maximum) flow rate per well (Exhibit No. HIO-87). These statistics show that the ultimate reserves per well have declined an average of about 6% per year over the last ten years, starting at over three billion cubic feet, and declining to one and one-half billion cubic feet at present. Note that the maximum flow rate per well has declined an average of 3% over the last ten years.

Statistics were also developed on the number of wells added each year (Exhibit No. HIO-88). These data show the number of wells added each year has been declining an average of 8% per year over the last ten years, from 100 wells in 1996 to 53 wells in 2005. This decline in activity, coupled with the decline in reserves per well, has caused the ultimate reserves added from Shelf drilling to decline an average of 13% per year.

Q. How did you forecast the existing deepwater volumes producing directly into HIOS and via EBGS?

A. Only one deepwater field currently produces directly into HIOS, East Breaks Block 421, also known as Lost Ark. EBGS gathers deepwater gas and transports such gas from the Diana/Hoover platform located in 4,500 feet of water 80 miles northeast to a connection with HIOS in 350 feet of water. I have considered gas volumes expected to be produced into EBGS, including the Diana, South Diana, Hoover, Madison and Marshall fields. My staff prepared forecasts for Lost Ark and the fields connected to EBGS using decline analysis methodology based on publicly available data on reserves, production, geology, reservoir characteristics, and analogous fields. The HIOS Deepwater Existing Wells and EBGS forecasts are the result of that analysis, again without taking into consideration any economic limits on the ability to produce and transport those supplies.

Q. Are there any additional volumes of gas which should be considered to estimate reserve life for HIOS?

A. Perhaps. In order to represent the total potential picture, volumes from Shelf wells that are expected to be completed in the future and which would likely be connected to HIOS, should be included. I refer to these wells as HIOS Shelf New Wells

Q. Please describe the methodology you used to forecast the production from HIOS Shelf New Wells.

A. The statistics subsequently derived from the historical vintage data for the HIOS Shelf Existing Wells were used to forecast future vintages of HIOS Shelf New Wells. Exhibit No. HIO-89 shows the parameters used. Exhibit No. HIO-90 shows the summation of the vintage forecasts for HIOS Shelf Existing Wells and HIOS Shelf New Wells, again with no economic limits applied for production and transportation. HIOS Shelf New Wells are wells which have yet to be drilled on the Shelf in this mature producing province, but can be forecast in aggregate with some degree of certainty through "vintaging" analysis of historical trends. My understanding is that HIOS Shelf New Wells would not meet SEC criteria for proven reserves.

Q. Is "vintaging" a concept that is used in the industry to forecast gas resources?

A. Yes. Vintaging is used by several organizations within the industry, including the PGC, to analyze historical production trends. Enterprise's Supply Appraisal has successfully applied these techniques in many "mature" producing areas to forecast future production. My assumption is that HIOS will have access to new Shelf supplies represented by this vintaging approach, although there is no guarantee that such production will occur or be connected to HIOS.

Q. What reserve life is possible for HIOS if the resources from HIOS Shelf New Wells are considered?

A. Exhibit No. HIO-91 shows the total of existing supply sources and HIOS Shelf New Wells essentially depletes in 2025. If no economic limits on production and transportation are applied, a reserves life of 19 years is possible under those assumptions.

Q. Are there additional volumes of gas that could possibly be considered to estimate reserve life for HIOS?

A. Additional speculative volumes from undrilled deepwater prospects which may produce gas in the future ("Deepwater Future Tiebacks") could also possibly be considered, but it is my opinion that they are too speculative to be included in my recommendation.

Q. How did you forecast Deepwater Future Tiebacks volumes?

A. There can be no assurance that additional future deepwater prospects will be drilled and connected to HIOS. Geology, geophysics, and economics drive deepwater exploration and development decisions for the companies that drill and produce gas in the deepwater area. For these producers, individual wells cost between 25 and 150 million dollars, and production systems range from subsea wellheads to floating platforms and cost from 50 million to over 1 billion dollars. Pipelines in the deepwater area typically cost over one million dollars per mile to construct, which must be factored into production decisions. Further, the geology of the deepwater area is complex including structural, stratigraphic and combination traps influenced by salt movements and faulting. Even though improved seismic technology has helped to image these potential traps prior to drilling, such technology still lacks much of the detail that would reduce the risk of drilling in the deepwater area, especially near salt bodies typically associated with the larger prospects. The high risk of commercial failure and high exploration costs dictate that only prospects with large potential will be drilled. Once a commercial discovery is made it takes 2 to 10 years to develop. Commercial development of gas supplies is very difficult to achieve in deepwater due to the complex geology and geophysics, and the enormous cost of drilling and development. For example, in the vicinity of the Alaminos Canyon Block 857 “Great White” discovery BP and Shell recently relinquished 35 contiguous leases surrounding their Diamondback prospect in 7,000 feet of water, after conducting exploratory drilling and apparently finding only non-commercial hydrocarbons. An additional 30 leases in the area were also relinquished. Those same 65 blocks were made available for leasing at the August, 2006 federal lease sale, and received no bids.

Finally, deepwater developments tend to be oil prone with gas as a by-product. Associated gas produced with the oil may be re-injected into the reservoir to improve oil recovery. Technology is also being developed to convert the gas to liquids. Thus, under these scenarios, the gas in a deepwater project might never be produced into a gas pipeline such as HIOS. In short, there is no guarantee that any of this additional deepwater gas will be produced or transported on HIOS.

Q. How have you determined these deepwater volumes that could possibly be considered to estimate reserves life for HIOS?

A. The Deepwater Future Tiebacks volumes that I have included in my study are derived from Enterprise’s proprietary database which has estimates on all active deepwater prospects in the Gulf of Mexico. The database estimates start with resource potential for each active prospect. This potential is then reduced for various elements of risk related to geology, commercial considerations, and the competition by pipelines for connection of such future supplies. Production profiles based on existing fields were applied to each prospect to generate a forecast of future production. Such individual prospect forecasts were added together to generate a “risked” portfolio, or one which has been adjusted for the various risk elements I have just described. I am then forecasting that this “risked” portfolio may be accessible to HIOS in the future, although there is no realistic guarantee that any such future volumes will be produced or, even if produced, connected to HIOS. The portfolio of deepwater prospects potentially accessible to HIOS or EBGS in the future contains no large discoveries with reserves sufficient to justify a new platform. Instead it contains numerous undrilled prospects, which, even if they are proved commercial by future drilling, are likely to be small fields developed as tiebacks from subsea wellheads to existing platforms.

Q. Is such forecasting of future production valid?

A. While the individual estimates of prospects can be inaccurate, experience has demonstrated that a portfolio estimate of the type I have formulated can give an approximation of total future supplies, assuming HIOS is able to successfully compete for the connection of new deepwater supplies. However, as HIOS witness Pagels explains, HIOS has been unsuccessful in attempts to secure connection of any sizeable deepwater projects in the last 5 years. Assuming the addition of the speculative Deepwater Future Tiebacks layer to the total HIOS forecast, the projected HIOS gas supply depletes in 2025 for a reserve life of 19 years, again, assuming that no economic limits on the ability to produce and transport those supplies are considered. (Exhibit No. HIO-91)

Q. How does your gas supply forecast in this case compare with the forecast that you provided in HIOS's last rate case?

A. The current forecast is lower until 2013, and slightly higher in subsequent years. This is primarily due to poorer than expected performance of the fields connected to EBGS, and lower volumes and delayed first production from Deepwater Future Tiebacks. The speculative Deepwater Future Tieback volumes are now known to be more oil prone with higher commercial risks, and it has become apparent that there are reduced chances of connection to HIOS due to increased competition.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of	)	Docket No. RP06-
High Island Offshore System	)	

Affidavit of James Scott Jenkins

James Scott Jenkins, being first duly sworn according to law, on oath deposes and says that he is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, direct testimony in these proceedings.

James Scott Jenkins

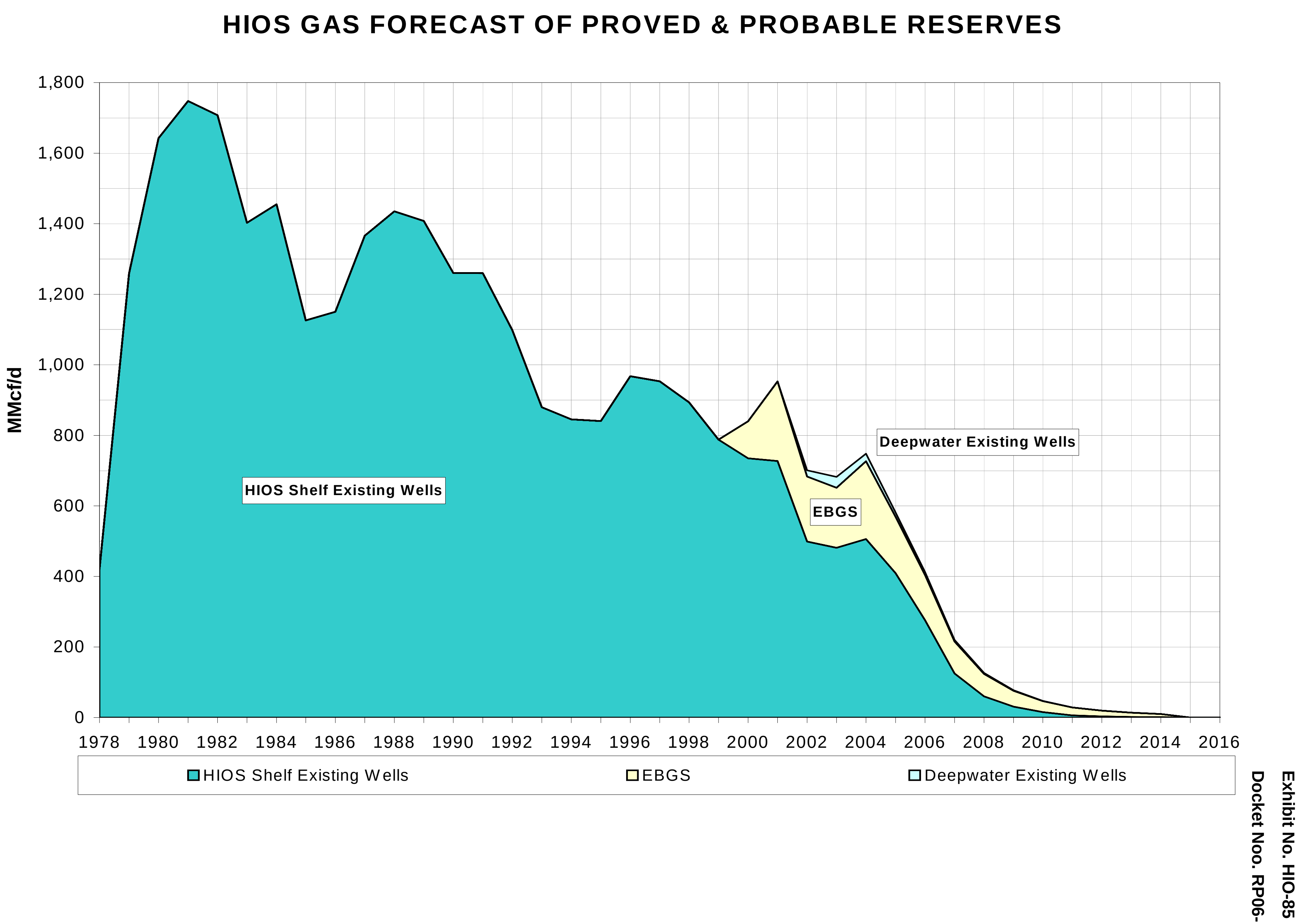
James Scott Jenkins

Subscribed and sworn to before me this 24th day of August, 2006.

NOTARY PUBLIC STATE OF TEXAS
FRONELL SINGLETERRY
Notary Public, State of Texas
My Commission Expires
November 12, 2006

Fronell Singleterry

Notary Public


HIOS GAS FORECAST OF PROVED & PROBABLE RESERVES
MMcf/d
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
HIOS Shelf Existing Wells
EBGS
Deepwater Existing Wells
Exhibit No. HIO-85
Docket Noo. RP06-

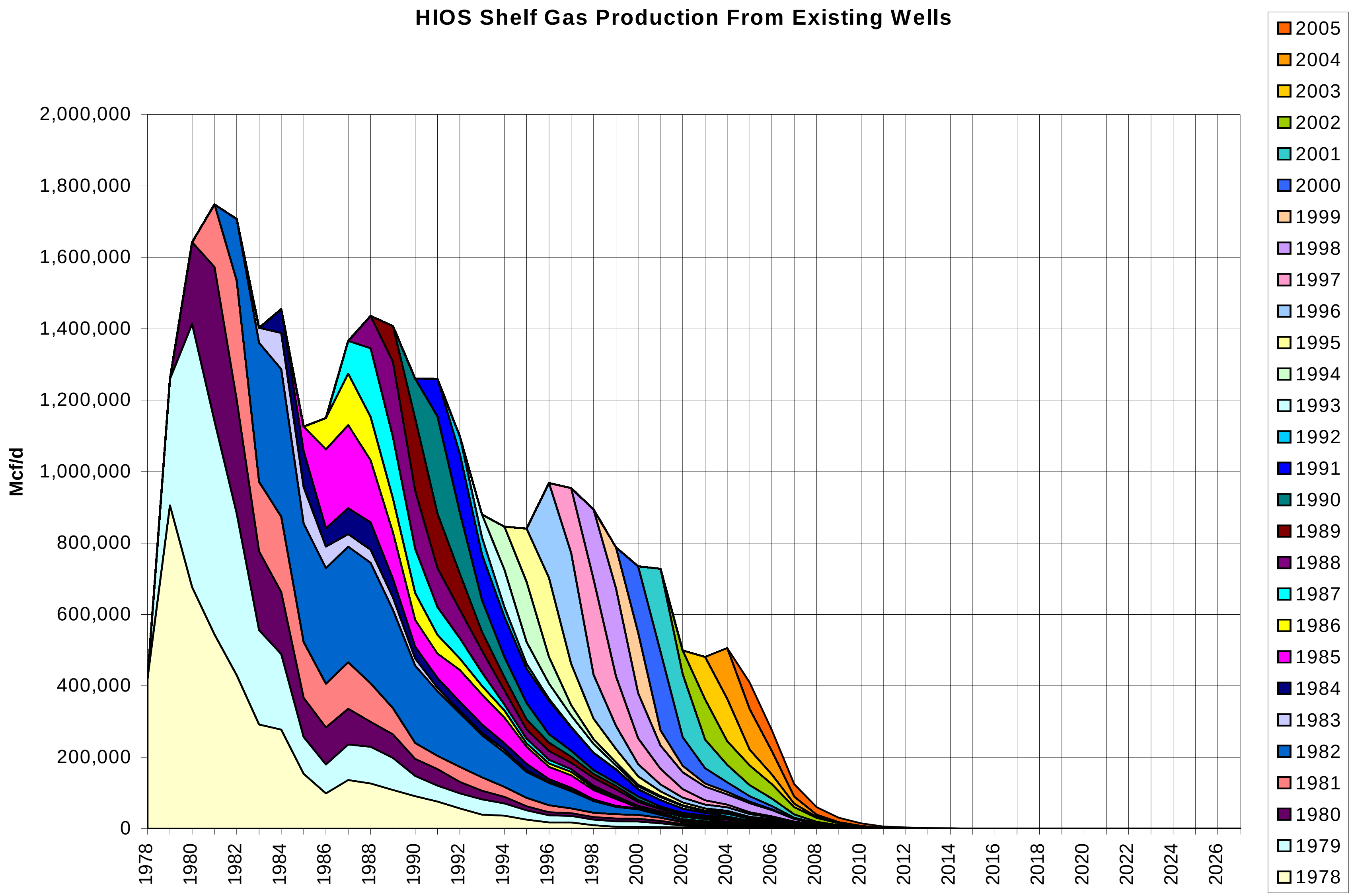


Exhibit No. HIO-86
Docket No. RP06-

HIOS Well Statistics

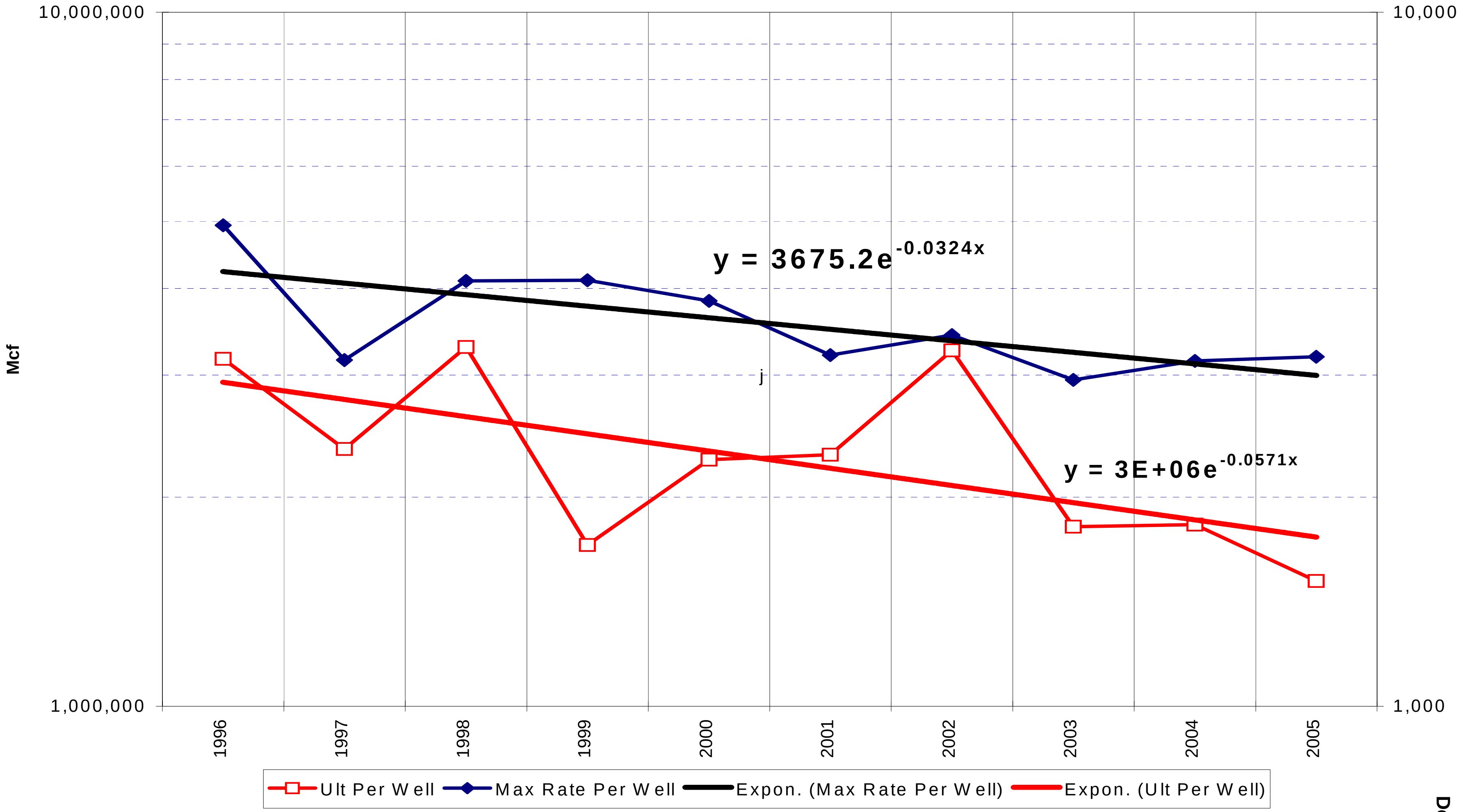


Exhibit No. HIO-87
Docket No. RP06-

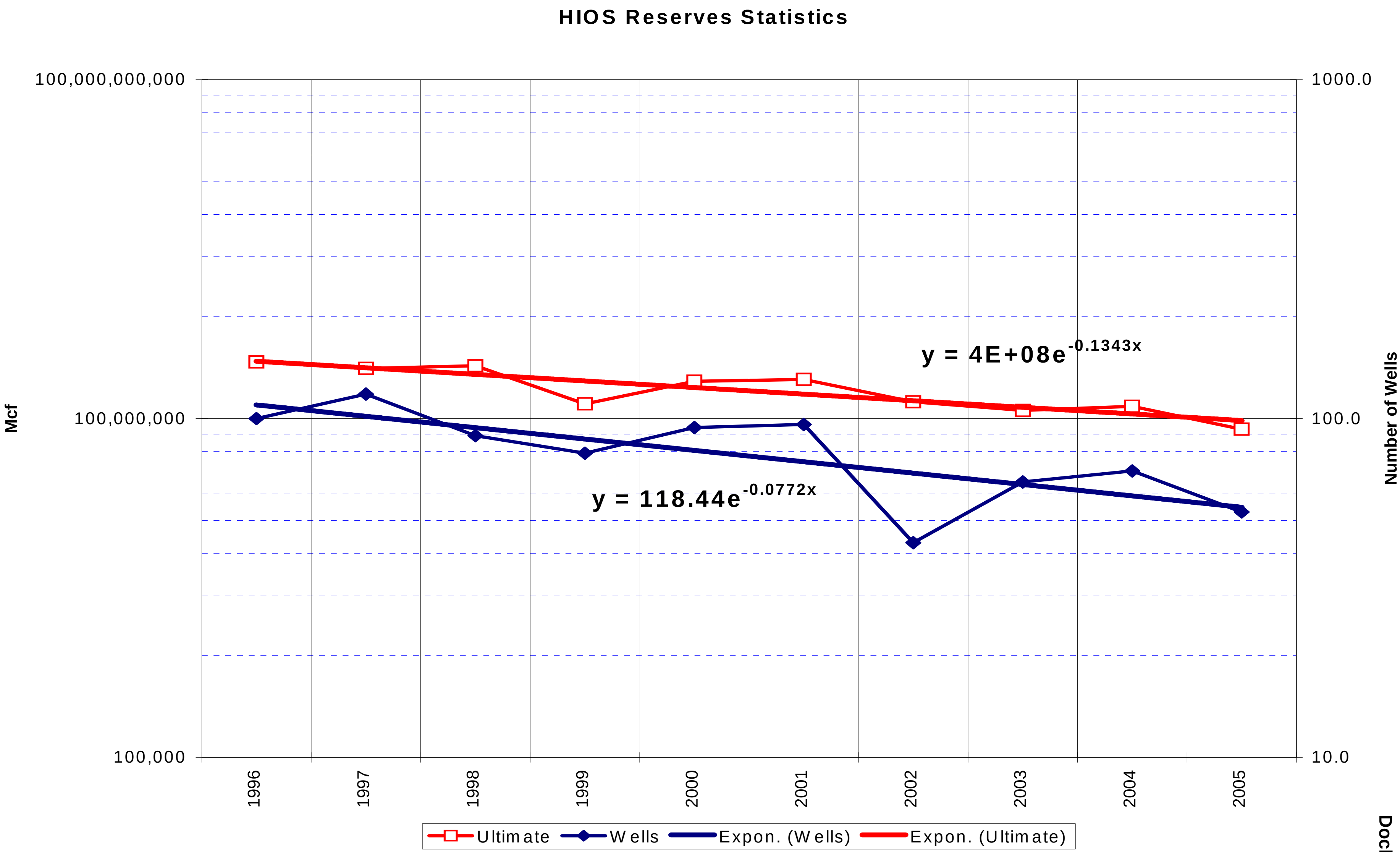


Exhibit No. HIO-88
Docket No. RP06-

HIOS SHELF FORECAST PARAMETERS	Variables in Red				
Start Date	1/1/2006				
Starting Number of Wells Completed Per Year	60				
Annual Decline in Number of Wells Added	8.00%				
Starting Ultimate Reserves Per Well	1,500,000	Mcf			
Annual Decline in Reserves Added Per Well	6.00%				
Starting Ultimate Reserves	90,000,000	Mcf			
Annual Decline in Reserves Added	13.52%				
Start Rate Per Well	1,100,000	Mcf/Yr	Or	3,014	Mcf/d
Annual Decline in Start Rate Per Well	0.00%				
Start Rate	66,000,000	Mcf/Yr	Or	180,822	Mcf/d
Annual Decline in Start Rate	8.00%				
End Rate Per Well	400,000	Mcf/Yr	Or	1,096	Mcf/d
Production Profile of Each Vintage Year	Exponential				
For each vintage year the number of wells and the per well start rate and recoverable reserves may be modified by a constant percentage each year.					

Exhibit No. HIO-89
Docket No. RP06-

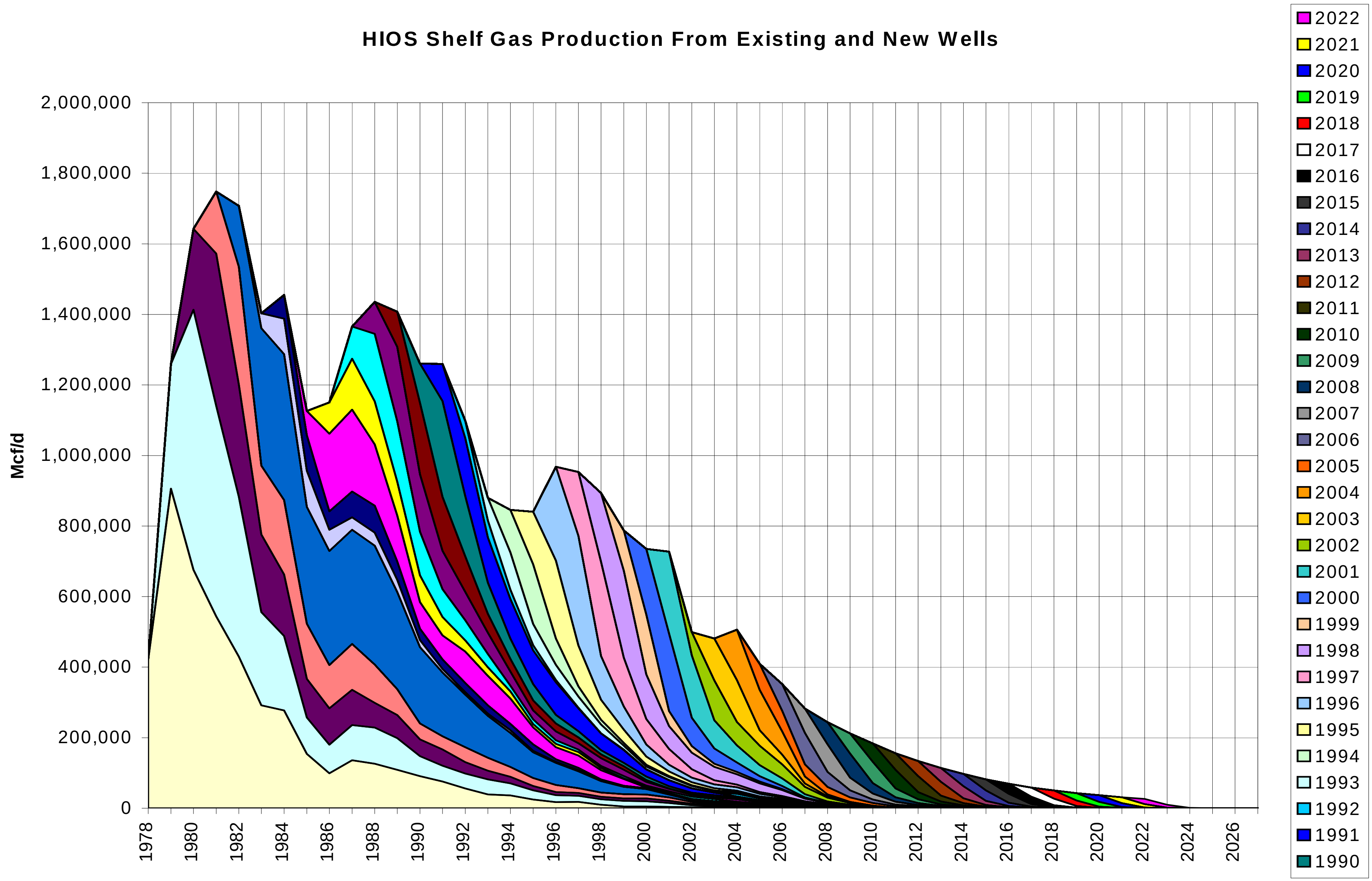


Exhibit No. HIO-90
Docket No. RP06-

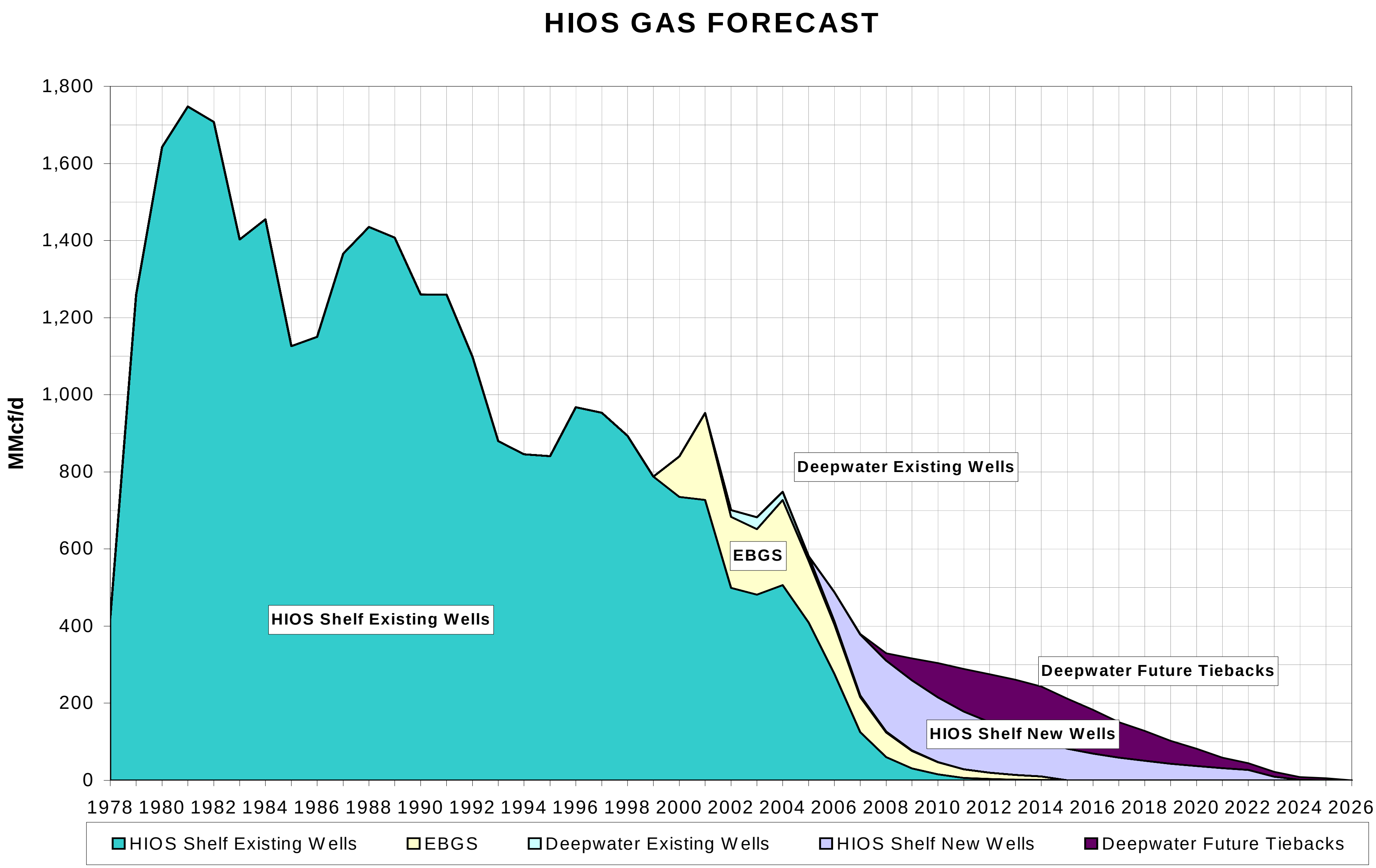


Exhibit No. HIO-91
Docket No. RP06-

Exhibit No. HIO-92

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, L.L.C.) Docket No. RP06-___-000

Prepared Direct Testimony
Of
Robert C. Byrd, Ph.D., P.E.

Q. Please state your name and business address.

A. My name is Robert C. Byrd. My business address is 13105 Northwest Freeway, Suite 800, Houston, Texas, 77040.

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

A. I am employed by Twachtman Snyder & Byrd, Inc. ("TSB") as Senior Vice President.

Q. Please describe your education and business experience.

A. I attended the U.S. Coast Guard Academy and received a Bachelor of Science in Marine Engineering in 1966. I also attended graduate schools at the University of Alaska, receiving a Master of Science in Ocean Engineering in 1972, and at the University of California at Berkeley where I received a Master of Science in Structural Engineering in 1977 and a Ph. D. in Engineering in 1978. I am a licensed Professional Engineer in Texas (No. 47767). I am a licensed Contractor for Oil and Gas Field Construction in Louisiana (No. 37462) and I have been certified as a Project Management Professional (Certificate No. 01577). I served as a Coast Guard officer for four years from 1966 to 1970 as an engineering officer on two different ships. Between graduate schools I worked in Norway as a research engineer on North Sea offshore platform designs. Following graduation from UC Berkeley in June 1978, I joined a small engineering company in Houston named Brian Watt Associates, Inc. (BWA). I worked on a wide variety of offshore field developments, initially as a structural engineer and later as a project manager. I reached the level of Vice President and Head of the Marine Engineering Department. I was also a Director of the company. I left BWA in August 1984 to become President and Chief Operating Officer for an international marine construction contractor named IMODCO, Inc., based in Los Angeles, California. From the beginning of 1986 through 1987, I served concurrently as the company's Chief Engineer. Our business was turn-key design and construction of marine terminals for tankers and floating production, storage, and offloading systems (FPSO's). We sold the company and I returned to Houston in August 1993 to join the predecessor company which is now TSB. Founded in 1987, TSB is a contracting and consulting engineering firm focused on providing the offshore oil and gas industry with contracting services and technical support for all aspects of offshore facility construction and removal. TSB specializes in platform and pipeline decommissioning, and the removal and reuse of offshore facilities and associated major components such as jackets and decks.

Q. What is the purpose and scope of your testimony in this proceeding?

A. I was requested by High Island Offshore System (HIOS) to verify the level of the negative salvage value of the HIOS system that I prepared in 2002. At that time, my study had indicated that the cost to decommission the HIOS system was approximately $27.5 million. In performing this review for HIOS, I determined that the estimated cost, while accurate at the time, has now increased by a significant amount. This increase is primarily as a result of the significant upturn in salvage activity in the area, and the substantial cost increases that are the inevitable result of increased demands for equipment and qualified operators. In light of this, I recommended to HIOS that it update the study to reflect more recent costs. I am therefore providing direct testimony in support of the updated study that I prepared, which indicates a current $44,995,040 net negative salvage value. The study, which was prepared under my supervision and direction, developed decommissioning liability cost estimates for the entire HIOS system. As described below, decommissioning liability costs are those required in connection with the abandonment and removal of offshore facilities and pipelines.

Q. Why will HIOS incur costs in connection with the removal and abandonment of offshore facilities and pipelines?

A. When offshore facilities and the associated pipelines have served their useful purpose, government regulations require the removal of facilities, the abandonment of pipelines, and the return of the sea floor to its natural state in so much as is possible. The Minerals Management Service (MMS) requires the removal of all facilities rising above the sea floor, such as platforms, flare piles and risers (30 C.F.R. § 250.143). The Department of Transportation requires either abandonment "in-place" or complete removal of pipelines not in service (49 C.F.R. § 192.727). Abandonment "in-place" requires that pipelines be purged of all hydro-carbons, filled with seawater, disconnected from all sources and supplies of oil or gas, sealed on each end, buried a minimum of 3ft. below the mudline, and the ends covered with sandbags. Complete removal, if required, involves purging, filling with seawater, disconnecting, excavating, recovering and disposal of pipeline sections and components. As a result of complete compliance with these regulations, there are significant costs, well above any salvage value, associated with removal and abandonment of offshore facilities and pipelines.

These are referred to broadly as decommissioning liability costs. When the facilities reach the end of their service life they have no value other than as scrap.

Q. What are the basic principles that underlie the offshore negative salvage study in this case?

A. The basic principles that underlie our study are as follows:

1) All costs are stated in 2006 dollars. The study does not reflect any increase in costs due to inflation from 2006 to a future year in which the costs would actually be incurred.

2) All cost estimates were based on information supplied by HIOS, and relate to properties and equipment either wholly owned or held in partnership by HIOS.

3) All costs were based on current regulations of state and federal regulatory authorities. No allowance was made for the potential of increased costs due to more stringent regulations being enacted in the future.

4) All costs were estimated with a 6% allowance for delays due to weather and a 15% allowance for miscellaneous work, based on spring/summer work seasons in the Gulf of Mexico. No provisions were made for HIOS overhead, insurance, omissions, or unusual environmental conditions.

5) All costs were estimated with an 8% allowance for engineering, project management/supervision and inspection services. Allowance percentages for weather, miscellaneous work and project management were developed from years of actual experience with decommissioning projects in the Gulf of Mexico.

Q. Please explain how your company arrived at the estimated decommissioning liability costs reflected in the offshore negative salvage study.

A. To develop cost estimates of this type, some assumptions are used as a matter of standard practice. The following assumptions, are reflected in the final results of the study:

1) All decks and jackets are taken to shore and scrapped.

2) Removal contractor is responsible for transport and disposal of decks, jackets and associated additional equipment.

3) No salvage or resale value is included for the structures or equipment, and no additional cost is included for disposal of material.

4) One spread mobilization/demobilization cost is included for each location block, i.e., all facilities at one location are removed at the same time.

5) All mobilization times are estimated from a location known as the Eugene Island Sea Buoy. This is consistent with general offshore construction and salvage practice in the Gulf of Mexico.

6) No dockside mobilization or demobilization is required. Construction barge spreads are assumed to be readily available in the Gulf of Mexico.

7) All work is performed during the spring/summer optimal work season, which is May 15th to September 30th.

8) No allowances are made for unusual downtime due to named tropical storms or hurricanes, such as experienced in 2005. The 6% provision is derived from project experience in the period from 1988 to 1998.

9) Current approved guidelines for the use of explosives are assumed.

10) No allowances are made for the presence of marine mammals or sea turtles, which can cause project delays.

11) Normally Occurring Radioactive Material ("NORM") is not encountered in the facility. The presence of NORM can increase platform preparation and disposal cost significantly.

12) All pipelines are abandoned "in-place". Riser bends and 100' of pipeline are removed at each end of a pipeline segment.

13) Pipeline ends are buried to a minimum of 5ft. below the mudline.

14) The ends of all pipelines are sealed using simple mechanical-type plugs (i.e. a "plumber's plug").

15) Site Clearance and Site Clearance Verification are performed in accordance with MMS NTL 98-26[1].

16) Hourly rates for construction and diving spreads are based on rates provided by offshore contractors in bids for recent projects.

17) Data related to the individual HIOS facilities, such as deck and equipment weights, jacket weights, etc., if not provided by HIOS, are based on previously developed estimates and models, and the on-site work experience of TSB personnel.

Q. What method did you use to prepare your negative salvage study?

A. Estimating decommissioning liabilities requires an understanding of the facilities and pipelines, the decommissioning process, and the proper application of past experience. Over the past nineteen years we have been able to assist our clients with regular and accurate estimates of current liabilities and planning to reduce liabilities wherever possible. We structure the information in ways that lead to greater efficiency of use and provide reports that facilitate sound decision making. We also track changes in

[1] MMS Notice to Lessees (NTL) regarding Minimum Interim Requirements for Site Clearance (and Verification) of Abandoned Oil and Gas Structures in the Gulf of Mexico dated November 30, 1998.

liabilities over time. We have accomplished all of this by developing proprietary cost estimating software known as "Platform Abandonment Estimating System" (“PAES”).

PAES was developed by the compilation of real cost data generated through actual decommissioning projects and experience, and by combining that data with the actual methodology used and the required tasks to execute the work. Once developed, the estimates are stored in a database where they can be updated and compared over time. PAES contains specific estimates for over 2,000 domestic and international platforms and pipelines. Decommissioning efforts are based on the assumption that a knowledgeable contractor will use the most efficient technology and equipment available at any given time to accomplish the task. New cost estimates are presented in current dollars. Decommissioning costs for each task are determined from actual cost data obtained from TSB work experience, and rate schedules provided by the various contractors engaged in this type of work.

Based on the information obtained from the client, other operators and TSB's knowledge and experience in the construction and decommissioning of offshore structures, the tasks and the time and the resources required to accomplish those tasks are identified. Assumptions, work variables, and cost data are entered by task, and the final report, tailored to the specific needs of the client, is generated.

Q. Please describe Exhibit No. HIO-93 in more detail.

A. Exhibit No. HIO-93 sets forth the estimated cost of the abandonment and removal of the offshore facilities owned by HIOS as of June 30, 2006, based on the principles I discussed previously. The final report, as shown in Exhibit No. HIO-93, consists of the following sections:

Section 1: Executive Summary

Section 2: Summary Report

Section 3: General Methodology & Assumptions

Section 4: PAES

Section 5: Detailed estimates

The "Executive Summary" briefly states the parameters within which, and for whom, the report was generated. It also illustrates the total costs of decommissioning all facilities, pipelines and wells, and the basic assumptions made in determining those costs.

The "Summary Report" provides cost summaries for individual platforms, pipelines and wells according to field location. Each platform owned by HIOS is summarized by platform location and function. The total gross cost of removal, including the cost to remove the platform and the cost to remove associated pipeline facilities, is identified. The net cost of removal, or the cost associated with HIOS' ownership share of the abandonment, is reflected in the last column for each platform identified. As summarized on the page 3 of the summary report, TSB estimates that it will cost HIOS $44,995,040 to retire its offshore facilities.

The rest of the report provides detailed work-papers supporting each platform abandonment estimate. Behind each individual platform tab is a "General Methodology & Assumptions" section and a "PAES" section. The "General Methodology & Assumptions" section provides a description of the methods used to develop costs, and the assumptions made in defining the various tasks. The "PAES" section consists of the detailed costing of each facility, and is divided into five (5) sections:

Section 1: Provides summary information related to the scope of work, disposal method, onsite conditions, operating assumptions, and total estimated cost. The "scope of work" outlines how the work is to be accomplished. Disposal methods can vary from disposal onshore to disposal at sea, to partial reefing or full reefing; the most cost efficient method must be determined on an individual basis. Onsite conditions can be a factor that may limit available options. Operating assumptions help define the work, particularly when information is lacking or unavailable.

Section 2: Provides basic information such as general facility data and ownership data. General facility data would include platform name, co-ordinates, water depth, function, installation year, and lease number. Partnership data would include name and number of partners, and percent of ownership.

Section 3: Provides information related to platform removal including general data on piles, decks, conductors, jackets, tasks, equipment and resources required, and associated costs. General data would also include number, size and specifications for piles, decks, conductors and jackets. The listed tasks would include mobilization/de-mobilization of personnel and equipment, platform removal preparation, removal and disposal of major equipment packages, removal and disposal of decks, removal and disposal of jackets, site clearance and site clearance verification. The equipment and resources required to accomplish those tasks are also identified.

Section 4: Provides specific information on pipeline abandonment, including general data on facility location, pipeline specifications, tasks required, equipment and resources required, and associated costs to abandon. General data would include water depth, origin and terminus of pipeline, and operator. Pipeline data would include outside diameter and wall thickness, coatings, depth of bury, length and product transported. Listed pipeline abandonment tasks would include mobilization/demobilization of personnel and equipment, pigging and flushing, excavating, cutting, removal and disposal of riser bends and other removed pipe sections, plugging and burying ends of pipeline, and the equipment and resources required to accomplish those tasks.

Q. Please summarize your findings in HIOS' negative salvage study.

A. TSB estimated the present net cost that would be incurred for the decommissioning of the HIOS system, including the cost of removal of the HIOS platforms and associated piping and the abandonment "in-place" of HIOS pipelines, to be $44,995,040. This is an increase of approximately $17.5 million, or about 64%, since the last assessment of liability in 2002. This cost increase represents an annual inflation rate of about 13% and, as I noted above, results primarily from a sharp increase in the cost of all offshore construction services, due to increased activity.

Q. Does this complete your direct testimony in this proceeding?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of	)	Docket No. RP06-
High Island Offshore System	)	

Affidavit of Robert C. Byrd

Robert C. Byrd, being first duly sworn according to law, on oath deposes and says that he is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit: that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, direct testimony in these proceedings.

Robert C Byrd

Robert C. Byrd

Subscribed and sworn to before me this 25th day of August, 2006.

CANDICE GANTZ
MY COMMISSION EXPIRES
FEBRUARY 24, 2009

Candice Gantz

Candice Gantz
Notary Public State of Texas
My Commission Expires:
February 24, 2009

Exhibit No. HIO-93

Docket No. RP06-

HIGH ISLAND OFFSHORE SYSTEM, L.L.C.

ROBERT C. BYRD
OFFSHORE NEGATIVE SALVAGE STUDY

(Included in Volume 3 of 3)

Exhibit No. HIO-94

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System) Docket No. RP06-

Prepared Direct Testimony
of
Joan F. Collins

Q. Please state your name and business address.

A. My name is Joan F. Collins. My business address is 1100 Louisiana Street, Houston, Texas 77002.

Q. By whom are you employed and what are your job responsibilities?

A. I am employed by Enterprise Products Partners, L.P. ("Enterprise"), as a Senior Rate Analyst. My responsibilities include rate analyses and studies pertaining to regulatory filings for High Island Offshore System, L.L.C. ("HIOS").

Q. Please describe your educational background and work experience.

A. I graduated from Midland Lutheran College in 1977 and was awarded a Bachelor of Arts degree with a major in Accounting. From 1977 to 1979, I was employed by Arthur Anderson as an auditor in the Regulated Division. In 1979, I accepted a position as staff accountant at Creighton University. In 1980, I accepted a position with Northern Natural Gas Company ("Northern") in the Gas Accounting Department. While at Northern, I held increasing levels of responsibility in various parts of the company including Gas Accounting, Financial Accounting, Regulatory Affairs and Transportation Marketing. In June of 2000, I accepted a position with Enron Energy Services in the Risk Management division where I was responsible for analysis of both natural gas and electric utilities tariff structures for purposes of hedging risk. In May, 2002, I accepted a position with El Paso Corp, working as a Principal Rate Analyst in the Rates and Regulatory department of ANR Pipeline Co. In December, 2004, I accepted my current position with Enterprise Products Partners L.P. in the Rates and Regulatory Affairs Department.

Q. Have you previously provided testimony before a regulatory commission?

A. Yes, I have prepared and filed written testimony before this Commission in other proceedings.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits, which were included in HIOS' filing:

Hearing <u>Exhibit No.</u>	**Schedule <u>Reference</u>**	**<u>Description</u>**.
HIO-31	Statement H-1	O&M Expenses
HIO-32	Schedule H-1.1	O&M Adjustments
HIO-33	Schedule H-1(1)(a)	O&M - Labor
HIO-34	Schedule H-1(1)(b)	O&M - Materials & Other
HIO-35	Schedule H-1(1)(c)	Quantities App. to Accts. 810-812
HIO-36	Schedule H-1(2)(a)	Fuel Used & Gas Losses
HIO-37	Schedule H-1(2)(b)	Advertising Expense
HIO-38	Schedule H-1(2)(c)	Office Supplies & Expenses
HIO-39	Schedule H-1(2)(d)	A&G Expenses Transferred
HIO-40	Schedule H-1(2)(e)	Outside Services Employed
HIO-41	Schedule H-1(2)(f)	Employee Pension & Benefits
HIO-42	Schedule H-1(2)(g)	Regulatory Commission Expense
HIO-43	Schedule H-1(2)(h)	Duplicate Charges - Credit
HIO-44	Schedule H-1(2)(i)	Miscellaneous General Expenses
HIO-45	Schedule H-1(2)(j)	Interco. & Interdep. Transaction
HIO-46	Schedule H-1(2)(k)	Lease Payments
HIO-50	Statement H-3	Income Taxes
HIO-51	Schedule H-3(1)	Income Tax Paid State Government
HIO-52	Schedule H-3(2)	Tax Reconciliation
HIO-53	Statement H-4	Other Taxes

Q. Please explain Statement H-1 (Exhibit No. HIO-31).

A. Statement H-1 sets forth in detail the monthly operation and maintenance expenses ("O&M") for HIOS, as adjusted for known and measurable changes which have occurred during the base period ending June 30, 2006, or are expected to occur on or before March 31, 2007, the end of the test period. The base period expenses shown on Statement H-1 primarily reflect the amount of expenditures charged to HIOS from its operating company, Enterprise GTM Offshore Operating Company, LLC ("EGOOC"), as obtained from the company's books. Additionally, expenses not covered by the Operating Services Agreement ("OSA") and directly charged to HIOS are also reflected on Statement H-1. Also shown on Statement H-1 are the total test period adjustments to these base period expenses (Col. 16), and the total test period O&M expenses by FERC Account (Col. 17).

Q. Please provide an overview of the adjusted O&M expenses compared to the base period.

A. Non-gas O&M expenses as adjusted total $31,569,005 (Col. 17, line 31) as compared to base period non-gas O&M of $19,066,511 (Calculation: $30,875,399 - Col. 15, line 31 less $11,808,888 – Col. 15, line 5). This represents an overall O&M increase of $12,502,494 (Calculation: $693,606 – Col. 16, line 31 less $(11,808,888) - Col. 16, line 5). Total O&M as adjusted is carried forward and reflected on Statement A (Exhibit No. HIO-1).

Q. In general, what is the functionality of the costs included on H-1?

A. HIOS provides transmission services only. Therefore, the expenses reflected on Statement H-1 are transmission only and require no further allocation of costs among other services such as storage.

Q. What is the purpose of the schedules which support H-1?

A. Schedule H-1.1, Page 1 of 6 (Exhibit No. HIO-32), summarizes the test period adjustments made to O&M expense by HIOS. Schedule H-1.1, Pages 2 though 6 provide detailed support for each of the test period O&M adjustments according to FERC account and type of adjustment. These adjustments are discussed in further detail below.

Schedule H-1(1)(a) (Exhibit No. HIO-33) and H-1(1)(b) (Exhibit No. HIO-34) support total O&M reported on Statement H-1, with H-1(1)(a) detailing monthly labor expense by FERC account for the base period and test period, as adjusted. H-1(1)(b) details monthly materials and other expenses by FERC account for the base and test period, as adjusted. The additive of the amounts stated on the two schedules equals the amount stated on Statement H-1 for the base and test periods, as adjusted.

H-1(1)(c) (Exhibit No. HIO-35) details by month the quantities of gas, stated in Dth, associated with company-use fuel reflected in Acct. 854-Compressor Station Fuel for the base period and as adjusted. HIOS company-use fuel is recovered by a fuel tracker mechanism established by FERC Order dated January 24, 2005. Therefore, an adjustment is made to eliminate the Dth quantities in the test period.

Schedules H-1(2)(a) through H-1(2)(k) (Exhibit Nos. HIO-36 through HIO-46) provide a description of HIOS' base and test period O&M for specific FERC Accounts.

Q. Please explain the adjustments to O&M expense summarized on Page 1 of 6, Schedule H-1.1 (Exhibit No. HIO-32).

A. Adjustment No. 1, as shown on Schedule H-1.1, Page 2 of 6 (Exhibit No. HIO-32) reflects the increase in property insurance costs due to Hurricanes Katrina and Rita. In May of 2006, insurance premiums were increased by HIOS' insurance carrier from $100,700 to $614,400 per month, a monthly increase of $513,700. Based on this increase, test period insurance costs are projected at $7,372,800 (Col. 3, line 4) on an annualized basis as compared to $2,800,885 (Col. 3, line 5) in the base period, resulting in a test period adjustment of $4,571,915 (Col. 4, line 7) to Account 924 – Property Insurance.

Q. Are these insurance costs billed to HIOS by the operating company, EGOOC?

A. Yes, the insurance premiums are paid for by EGOOG and then passed directly on to HIOS. Such costs are defined as "Direct Flowthrough Costs" in Section 3.2.3 of the OSA.

Q. Please describe the purpose Adjustment No. 2 as shown on H-1.1, Page 2 of 6 (Exhibit No. HIO-32).

A. Adjustment No. 2 reflects the consolidation of the HIOS OSA "Turnkey Fee", currently allocated among various FERC accounts, into FERC Account 923 – Outside Services. As described by HIOS Witness Leslie V. Pagels, the Turnkey Fee is a fixed monthly fee currently totaling $813,792 paid by HIOS to EGOOC per OSA, Section 2.2, and covers a comprehensive list of routine operating services. The purpose of this adjustment is to allow accounting to more closely track the actual billing and to simplify the accounting process. The fee is currently allocated by HIOS among various FERC labor, non-labor and tax accounts based on historic detail. As the fixed fee includes those monthly routine operating services provided by EGOOC, it is more appropriately charged to Account 923 – Outside Services Employed.

Q. Please describe the adjustment in more detail.

A. Adjustment No. 2 transfers the Turnkey Fee allocated to the various FERC accounts during the base period, including allocations to O&M accounts totaling $(9,513,208) as shown in Col. 3, line 28, and to Account 408 - Other Taxes totaling $(252,296) as shown in Col. 3, line 10. The total of the O&M Accounts and Other Taxes is then transferred to Account 923 – Outside Services Employed, totaling $9,765,504 (Col. 3, line 29). As the transfer to Account 923 includes Other Taxes, not part of O&M, the result is a net positive O&M adjustment of $252,296 (Col. 4, line 30). An equal, offsetting negative adjustment of $(252,296) is included in Other Taxes on Statement H-4, Col. 3, line 2 (Exhibit No. HIO-53).

Q. Does this adjustment have any rate impact?

A. No. As HIOS provides only transmission services, O&M is classified in total to the transmission function, requiring no allocation to other services such as storage. As such, this adjustment creates no rate impact.

Q. Are any other adjustments made to the Turnkey Fee?

A. Yes. Adjustment No. 3, shown on H-1.1, Page 3 of 6 (Exhibit No. HIO-32), reflects an annualized adjustment of the Turnkey Fee. As HIOS Witness Pagels explains in her testimony, the Turnkey Fee is subject to an annual adjustment under an index mechanism as provided by the amended OSA, Section 3.2.2. The "Wage Index Adjustment Factor" published by the Council of Petroleum Accountant Societies ("COPAS Index") is utilized to make the annual adjustment. HIOS has been notified by EGOOC that effective January 1, 2007 the monthly Turnkey Fee will be adjusted based on the COPAS Index from $813,792 (Col. 3, line 3) to $870,117 (Col. 3, line 2). This will result in an annualized increase in the Turnkey Fee of $675,900 (Col. 4, line 7) reflected as an adjustment to Account 923 – Outside Services Employed.

Q. Please explain Adjustment No. 4 – Account 923, Outside Services Employed as shown on H-1.1, Page 4 of 6 (Exhibit No. HIO-32).

A. Adjustment No. 4 reflects an adjustment to the EGOOC OSA non-routine expenses and is actually composed of two separate adjustments shown here as Adjustment No. 4(A) and 4(B). Adjustment No. 4(A) eliminates the non-routine expenses charged to HIOS pursuant to the Section 3.2.2 of the OSA during the base period. Adjustment No. 4(B) reflects the annualized monthly fixed fee for a 36 month, budgeted non-routine operating plan, covering calendar years 2007, 2008 and 2009, effective January 1, 2007, pursuant to the amended OSA, Section 3.2.2.

Q. Please describe Adjustment No. 4(A) in further detail.

A. Pursuant to the OSA, Sections 3.2.2, HIOS was billed for various non-routine operations services during the base period. As explained in greater detail by HIOS Witnesses Pagels and Porter, this section of the OSA has been amended to include a 36-month non routine operating budget effective January 1, 2007. Therefore, all non-routine charges booked during the base period to various O&M labor and non-labor accounts totaling $(3,062,551), as reflected in Col. 3, line 21, are being eliminated in this adjustment. The elimination of non-routine charges to Account 408 - Other Taxes, is reflected on Statement H-4, Col. 3, line 2 (Exhibit No. HIO-53).

Q. Please describe Adjustment No. 4(B) in further detail.

A. Section 3.2.2 of the OSA has been amended to include the implementation of a 36-month, budgeted operating plan to be effective January 1, 2007. As explained by HIOS Witness Pagels, this budget period encompasses calendar years 2007 through 2009, and includes significant non-routine expenditures necessary to ensure safe and efficient pipeline operation. I have been instructed by HIOS Witness Porter to include a full year of expense in Account 923 – Outside Services Employed. To calculate this adjustment, the budgeted expenses for the each of the 3 years (2007-\$10,620,000 + 2008-\$9,550,000 + 2009-\$10,480,000) are added together. The sum of the 3 years, \$30,650,000 (Col. 3, line 27), is then divided by 3 to arrive at the test period expenses of \$10,216,667 (Col. 3, line 28).

Q. What is the net impact of the non-routine expense adjustments 4(A) and 4(B)?

A. The net impact is determined by adding together Adjustment No. 4(A) – elimination of non-routine base period expenses totaling \$(3,062,551) in Col. 3, line 21 and Adjustment No. 4(B) – 36-month non-routine budgeted expenses totaling \$10,216,667 in Col. 3, line 28, which results in a test period adjustment of \$7,154,116 (Col. 4, line 29).

Q. Please describe Adjustment No. 5 – Account 854, Gas for Compressor Station Fuel as shown on H-1.1, Page 5 of 6 (Exhibit No. HIO-32).

A. This adjustment eliminates company use fuel expense booked to Account 854 totaling \$(11,808,888) as shown in Col. 4, line 3. Such costs are recovered by a separate fuel tracker mechanism established by FERC Order dated January 24, 2005 as defined in the HIOS Tariff and therefore, are not included in the cost of service.

Q. Please explain Adjustment No. 6 – Account 928, Regulatory Commission Expenses as shown on H-1.1, Page 5 of 6 (Exhibit No. HIO-32).

A. The adjustment to Account 928 is made to reflect the latest FERC 2006 Annual Charge Billing of $394,190 (Col. 3, line 6). This amount, when compared to the base period balance of $595,756 (Col. 3, line 7) results in an adjustment of $(200,865) as shown in Col. 4, line 9.

Q. Please explain Adjustment No. 7 – Account 923, Outside Services Employed as shown on H-1.1, Page 6 of 6 (Exhibit No. HIO-32).

A. This purpose of this adjustment is to eliminate certain out-of-period costs and non-recurring costs booked directly by HIOS in Account 923 in the base period. These costs were not charged through the OSA. The base period balance, $220,604 - Col. 3, line 3, is adjusted for the elimination of out of period costs, $(51,250) - Col. 3, line 4, and non-recurring costs, $(48,900) - Col. 3, line 5 resulting in a net adjustment of $(100,150) - Col. 4, line 10.

Q. Please explain Adjustment No. 8 – Account 930.2, Miscellaneous General Expenses as shown on H-1.1, Page 6 of 6 (Exhibit No. HIO-32).

A. This adjustment eliminates out-of-period costs included in Account 930.2. The base period balance, $(144,625) – Col. 3, line 13, is first adjusted to for the amount transferred to Account 923 in Adjustment No. 3, $4,657 (Col. 3, line 12). The remaining negative balance, $(149,282) - Col. 3, line 15, is then eliminated, resulting in a test period adjustment of $149,282 (Col. 4, line 18).

Q. What is the total of all test period adjustments?

A. Test period adjustments total $693,606 as shown on H-1.1, Page 1of 7, Col. 15, line 31 (Exhibit No. HIO-32). This amount is comprised of $12,502,494 in non-gas test period adjustments (Calculation: $693,606 – Col. 16, line 31 less $(11,808,888) – Col. 16, line 5) and $(11,808,888) in gas cost adjustments.

Q. Please describe Statement H-3 (Exhibit No. HIO-50).

A. Statement H-3 shows the calculation of the Federal and state income taxes included in the cost of service for the test period as reflected on Statement A (Exhibit No. HIO-1). Statement H-3 shows the computation of HIOS's federal income tax based on an income tax allowance of 28.34%, determined in compliance with the Commission's Policy Statement on Income Tax Allowances issued May 4, 2005 in Docket No. PL05-5. Since HIOS' traditional return allowance reflected on line 1, Statement H-3, is zero, HIOS reflects taxable income related to its requested management fee shown on line 2, Statement H-3. As a tax obligation is associated with the collection of a management fee, a tax allowance on this amount must be provided as part of HIOS' cost of service. As shown on Statement H-3, line 6, the Federal income tax allowance of $1,649,992 is based solely on HIOS's proposed management fee of $4,172,138. HIOS has not computed a state income tax allowance.

Q. Please explain the basis of the income tax allowance calculation.

A. HIOS is owned by Enterprise, a master limited partnership ("MLP"), and as such is a pass-through entity for income tax purposes. The taxable income of the partnership, including that of HIOS, is allocated to its partners who pay income taxes on their pro rata share of taxable income. In its policy statement on income tax allowances (Docket No. PL05-5), the Commission stated that any pass-through entity seeking an income tax allowance in a specific rate proceeding must establish the tax status of its owners.

To establish the tax status, Enterprise has categorized its investors into entity types - individuals, corporations, partnerships, estates, trusts, foreign citizen, other, exempt organization, IRA/SEP/KEOGH's and pension plans - utilizing the 2004 Federal Income Tax return and entity classification information provided by PricewaterhouseCoopers (PWC). Based on the PWC data provided, an ownership percentage was calculated for each category. An effective tax rate was calculated based on each categories ownership percentage and maximum federal tax rate. This calculation results in a proposed tax allowance of 28.34%.

Q. What is shown on Statement H-4 (Exhibit No. HIO-53)?

A. This schedule details the taxes, other than income taxes, which are included in the cost of service. Statement H-4 reflects HIOS' base period level of ad valorem taxes. HIOS is responsible for ad valorem (property) taxes in the states of Louisiana and Texas. These taxes are associated with HIOS plant, property and equipment subject to property taxation in those states. As shown on Statement H-4, Col. 4, line 1, ad valorem taxes for the test period are $167,754.

As part of the OSA, payroll taxes totaling $252,846 (Col. 2, line 2) are billed as part of the monthly routine and non-routine services fee. As such, this balance is transferred out of Account 408 into Account 923 in two test period adjustments included in Schedule H-1.1. First, other taxes included in the monthly Turnkey Fee totaling $252,296 have been transferred as part of Adjustment No. 2, detailed on H-1.1, Page 2 of 6 (Exhibit No. HIO-32). Secondly, taxes included in non-routine services totaling $550 has been transferred as part of Adjustment No. 4, detailed on H-1.1, Page 4 of 6.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of	)	Docket No. RP06-
High Island Offshore System	)	

Affidavit of Joan F. Collins

Joan F. Collins, being first duly sworn according to law, on oath deposes and says that she is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as her sworn, direct testimony in these proceedings.

Joan F. Collins

Joan F. Collins

Subscribed and sworn to before me this 29th day of August, 2006.

NOTARY PUBLIC STATE OF TEXAS
FRONELL SINGLETERRY
Notary Public, State of Texas
My Commission Expires
November 12, 2006

Notary Public

Exhibit No. HIO-95

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, L.L.C.) **Docket No. RP06-**

Prepared Direct Testimony
of
Ronald A. Fulcher

Q. Please state your name and business address.

A. My name is Ronald A. Fulcher. My business address is 1100 Louisiana Street, Houston, Texas 77002.

Q. By whom are you employed and what are your responsibilities?

A. I am employed by Enterprise Products Partners, L.P., ("Enterprise") as Offshore Commercial Development Manager. My responsibilities include negotiating new gas supply connections and transportation service agreements on the High Island Offshore System, L.L.C. ("HIOS") and various other offshore assets owned by Enterprise, and managing the gas scheduling and contract administration activities for HIOS.

Q. Please describe your educational background and work experience.

A. I graduated from the University of Arkansas in 1977 with a Bachelor of Science degree in Civil Engineering. From 1977 to 1982 I was employed by Mehlburger Engineers as a Project Engineer. From 1982 to 1999, I was employed by Natural Gas Pipeline Company of America. While there I spent 3 years as a field district engineer, then served as a Supply Operations Representative involved with gas purchase contracts. Later I had various other responsibilities in gas supply and transportation including management of a gas scheduling and allocations group, negotiating new supply connections onshore and offshore, handling transportation and capacity release activities on other pipelines and managing joint venture activities. Since 2000, I have been employed by Enterprise or a predecessor company in the offshore commercial group, with commercial responsibilities for HIOS and various other gas gathering and production handling assets.

Q. Have you previously provided testimony in proceedings before the FERC?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. I will describe the adjustments made to base period firm service entitlements (maximum daily quantities, or MDQs) and commodity throughput to calculate end of test period MDQs and throughput design determinants for all services. The exhibits which I am sponsoring are as follows:

Hearing Exhibit No.	**Description**
HIO-27	Schedule G-3 (Test Period Adjustments to Base Period Throughput)
HIO-96	Contract Reduction Notices
HIO-97	Net Rate of Interruptible Throughput Decline
HIO-98	Rate Schedule FT-2 Average Load Factor

Q. Please describe the adjustments you made to the MDQs and throughput volumes for Rate Schedule FT-1 services.

A. As a point of clarification, proposed Rate Schedule FT-1 will replace Rate

Schedule FT, which was in HIOS' Tariff during the base period. As a result, I use FT and FT-1 interchangeably in this discussion. As shown in column 3 of Exhibit No. HIO-27, the MDQ entitlements and commodity volumes for each FT-1 service were adjusted to reflect the expiration of all current FT contracts on the system. Three of the four FT contracts in effect during the base period expired prior to the end of the base period, and the fourth expired August 15, 2006. These firm services were entered into because these shippers were concerned about capacity restrictions in the aftermath of Hurricane Rita on both HIOS and downstream pipelines. There are no requests pending from these shippers for replacement FT-1 service, and I do not expect any such requests (or requests for any incremental firm service from any other shippers) prior to the end of the test period or in the foreseeable future. Consequently, the end of test period MDQs and throughput for FT-1 are both projected to be zero.

Q. What adjustments did you make to base period experience for services provided under Rate Schedule FT-2?

A. As shown in column 4 of Exhibit No. HIO-27, I adjusted the FT-2 firm service entitlements to 100% of the end of test period contractual MDQ, in accordance with the Rate Schedule FT-2 tariff provisions.

Q. Why did you make this adjustment to these firm service entitlements?

A. Pursuant to the terms of Rate Schedule FT-2, shippers are entitled to make periodic unilateral reductions to their firm service entitlements. In other words, they have the right to reduce their MDQ, at predefined periods, over the life of the contract. There are currently two shippers who have service pursuant to this

Rate Schedule. Each of these shippers has notified HIOS that it will exercise this right to reduce its MDQ, effective for the first calendar quarter of 2007. Consequently, as of March 31, 2007, the aggregate MDQ of these two shippers will be 76,000 Dth/day. This end of test period MDQ of 76,000 Dth/day represents the entire amount of FT-2 service entitlement on the HIOS system. I have included copies of their respective contract reduction notices as Exhibit No. HIO-96.

Q Have you made any end of test period adjustments to the commodity determinants under Rate Schedule FT-2?

A. Yes. To reflect the associated decline in Rate Schedule FT-2 commodity units, I annualized the test period MDQ of 76,000 Dth to derive an annual commodity throughput of 27,740,000 Dth (76,000 x 365 = 27,740,000), which I netted against actual base period throughput of 52,679,846 Dth, resulting in a net commodity adjustment of 24,939,846 Dth (Exhibit No. HIO-27, column 4, line 4).

Q. Have you made an allowance for any overrun volume for the FT-2 services?

A. To the extent overrun volumes are reasonably expected to occur, it is appropriate to treat them as interruptible throughput and include them in the test period volumes under Rate Schedule IT. In fact, overrun is separately nominated and scheduled as interruptible service, so it is appropriately considered with all other IT services. Because the data indicates that there will be some level of overrun associated with these two FT-2 services, I have included an appropriate adjustment in IT services which I discuss more fully below.

Q. What level of determinants are you proposing for interruptible services?

A. I am proposing total, end of test period interruptible throughput of 121,163,592 Dth per annum (Exhibit No. HIO-27, column 8, line 5).

Q. Please explain your adjustments to Rate Schedule IT base period commodity billing determinants.

A. The test period Rate Schedule IT commodity determinants were calculated by a) making normalizing adjustments to base period volumes that flowed under IT contracts, b) multiplying these adjusted base period volumes by the historical HIOS rate of throughput decline, and c) adding volumes for any new Rate Schedule IT services anticipated to come online during the test period.

Q. Please explain in more detail these adjustments.

A. First, I reviewed individual shipper activity on the system in the base period. Although non-operational events such as hurricanes caused disruption of deliveries for certain shippers, this was offset by the increase of throughput from non-traditional shippers when their services on other pipelines were disrupted. As a result, the overall volume for the base period was more or less at the expected level. However, I made an adjustment to one shipper's volumes. This shipper experienced operational issues on its production lateral that prohibited the delivery of its gas to HIOS, but that issue should be resolved during the test period and I expect flow to return to prior levels. Accordingly, I adjusted the base period volume for this shipper by 3,942,000 Dth (Exhibit No. HIO-27, column 5, line 5), which was the approximate volume that could not be delivered to HIOS during the base period, to reflect a normal year. Next, I adjusted all interruptible volumes to reflect the historical annual net rate of decline in IT throughput on HIOS. I have reviewed Exhibit No. HIO-97 which calculates this net rate of interruptible throughput decline on HIOS, from 2001 through the end of the base period. This schedule shows the net rate of decline because the calculated percentage reduction in throughput from year to year includes both declining production from existing shippers and the new production from new shippers. As shown in Exhibit No. HIO-97, the average annual rate of net decline during the 5 years from 2001 through 2005 is 10%. The net rate of decline from 2005 to 2006 (annualized) is 18%, and the net rate of decline for the twelve months ended June 2005, to the twelve months ended June 2006 is 26%. Thus, this exhibit demonstrates that the net rate of decline is accelerating as existing, attached production plays out, and, as shown by HIOS witness Ms. Leslie Pagels, very little significant new production has been or is anticipated to be attached to the pipeline. Therefore, I reduced the base period interruptible throughput by a total of 25,561,710 Dth (Exhibit No. HIO-27, column 6, line 5), or by 18%, which was the net rate of decline from 2005 to 2006 (annualized). This is a reasonable adjustment factor to use, as it is near the midpoint of the 5 year average (10%) and most recent year net rate of decline (26%).

Q. Is there any recognition of overrun volumes associated with FT-2 services included in the interruptible throughput?

A. Yes. In addition to the adjustments described above, I am including additional annual interruptible throughput of 4,715,800 Dth (Exhibit No. HIO-27, column

7, line 5). I have reviewed Exhibit No. HIO-98 which shows the historical use of overrun by the FT-2 services over the life of these service agreements. This exhibit demonstrates that while overrun usually occurs, the level is unpredictable. To provide some recognition of overrun, I have computed that, over the life of their contracts, these FT-2 shippers have operated at an average load factor of 117%. Therefore, I made an adjustment to recognize that the current FT-2 shippers are reasonably expected to continue to overrun their services and take 17% of their test period MDQ of 76,000 Dth per day as overrun. Applying this factor of 17%, I calculated and included an additional 4,715,800 Dth of interruptible throughput for FT-2 overrun.

Q. Did you make any other adjustments to the billing units?

A. No. I made the adjustments described above to reflect the billing activity projected as of the end of the test period, and provided them to HIOS witness Jeffrey M. Molinaro who made additional adjustments for purposes of designing the rates. He explains the design adjustments in his testimony.

Q. Does this conclude your testimony?

A. Yes it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of	)	Docket No. RP06-
High Island Offshore System	)	

Affidavit of Ronald A. Fulcher

Ronald A. Fulcher, being first duly sworn according to law, on oath deposes and says that he is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, direct testimony in these proceedings.

Ronald A. Fulcher

Ronald A. Fulcher

Subscribed and sworn to before me this 23rd day of August, 2006.

NOTARY PUBLIC STATE OF TEXAS
FRONELL SINGLETERRY
Notary Public, State of Texas
My Commission Expires
November 12, 2006

Fronell Singleterry

Notary Public

BP America Production Company
200 Westlake Park Boulevard
Houston, Texas 77253-3092

281-366-5220

June 30, 2006

Mr. Ronald A. Fulcher
HIGH ISLAND OFFSHORE SYSTEM, L.L.C.
c/o Enterprise Products Partners LP
2727 North Loop West, Suite 120
Houston, Texas 77008

RE: REQUEST FOR REVISION TO MAXIMUM DAILY QUANTITY (MDQ) FT-2 TRANSPORTATION AGREEMENT DATED SEPTEMBER 12, 2002 BETWEEN HIGH ISLAND OFFSHORE SYSTEM AND BP EXPLORATION & PRODUCTION INC. (AS SUCCESSOR TO AMOCO ENERGY TRADING CORPORATION)

Dear Ron:

Please refer to the above Agreement that covers transportation of gas production from the Diana/Hoover fields. In accordance with Section 6.3 of Rate Schedule FT-2, BP America Production Company (as successor to Amoco Energy Trading Corporation) hereby elects to reduce its Maximum Daily Quantity (MDQ) for the 3-month Delivery Period beginning January 1, 2007. The new MDQ is shown below:

3 Month Delivery Period		
Start	**End**	**MDQ (Dth per day)**
1/1/07	**3/31/07**	**5,000**

Please forward the amendments necessary to cover the changes requested herein. If you have any questions, please contact me at (281) 366-5220.

Sincerely,

Osvaldo Gotera

Cc: J. Harris, WL1 4.243E
K. Wu, WL4 1933
G. Arnold, WL4 1939
J. McCollum, WL1 4.245

ExxonMobil Gas & Power
Marketing Company
800 Bell Street
CORP-EMB-3573F
Houston, Texas 77002-2180
713-656-7304 (Telephone)
713-656-2388 (Facsimile)
chris.seal@exxonmobil.com

Christopher W. Seal
Offshore Region Transportation Manager
Americas, Transportation and Regulatory

ExxonMobil
Gas & Power
Marketing

June 20, 2006

VIA FACSIMILE (713) 803-7996

High Island Offshore System, L.L.C., Owner
GulfTerra Energy Partners, L.P.
2727 North Loop West, Suite 120
Houston, Texas 77008

Attention: Ron Fulcher

Re: Quarterly MDQ Update, Alaminos Canyon 25, ExxonMobil Gas & Power Marketing Company Contract No. A578NGD

Dear Mr. Fulcher:

ExxonMobil Gas & Power Marketing Company is submitting this update for ExxonMobil's share of production from Alaminos Canyon 25. Per our prior discussions the corrected MDQ for the 1st Quarter 2007 is 71,000 Dth/D.

Enclosed is the revised amendment showing the corrected MDQ that has been signed on behalf of ExxonMobil Gas & Power Marketing Company. Please ask an authorized representative of High Island Offshore System, LLC to sign the amendment and have one fully executed original returned to my attention at the letterhead address.

Sincerely,

Chris Seal

Exhibit No. HIO-97

Docket No. RP06-

High Island Offshore System, L.L.C.
Net Rate of Interruptible Throughput Decline
Over Various Periods

Line No.	Year	IT Throughput	% Decline
	(1)	(2)	(3)
	5 Year Rate of Decline		
1	**2001**	278,549,039	-
2	**2002**	202,444,384	-27%
3	**2003**	192,831,039	-5%
4	**2004**	194,274,407	1%
5	**2005**	164,602,954	-15%
6	**Total Decline (2001 - 2005)**		-41%
7	**Annual Average Decline (2001 - 2005)**		**-10%**
	Current Year Net Rate of Decline 2005 vs. 2006		
8	2005	164,602,954	
9	2006 (Jan - Jun 2006 Annualized)	135,552,096	**-18%**
	Base Period Decline		
10	12-months ended June 2005	187,523,357	
11	12-months ended June 2006	138,067,502	**-26%**

Exhibit No. HIO-98

Docket No. RP06-

High Island Offshore System, L.L.C.
Rate Schedule FT-2
Average Load Factor

Line No.	Year	BP	ExxonMobil	Total
	(1)	(2)	(3)	(4)
1	2000	52%	198%	95%
2	2001	74%	104%	91%
3	2002	72%	103%	90%
4	2003	117%	156%	141%
5	2004	155%	177%	170%
6	2005	174%	126%	136%
7	2006	340%	113%	141%
8	Average	97%	130%	117%

Exhibit No. HIO-99

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, L.L.C.) Docket No. RP06-

Prepared Direct Testimony
Of
Jeffrey M. Molinaro

Q. Please state your name and business address.

A. My name is Jeffrey M. Molinaro. My business address is 1100 Louisiana, Houston, Texas 77002.

Q. By whom are you employed and what are you job responsibilities?

A. I am employed by Enterprise Products Partners, L.P., as a Senior Rates and Regulatory Affairs Analyst. My responsibilities include rate analyses and studies pertaining to regulatory filings by High Island Offshore System, L.L.C. ("HIOS").

Q. Please describe your educational background and work experience.

A. I graduated from The University of Notre Dame in 1994 with a Bachelor of Business Administration degree, majoring in Finance. In 1998 I received a Master of Business Administration degree from The University of St. Thomas. From 1994 - 2001, I was employed as a Rate Analyst with Transcontinental Gas Pipeline Corporation and held positions of increasing responsibility within the Rates Department. In June 2001, I accepted a position as a Rates and Regulatory Affairs Analyst with Enron North America. In May 2002 I accepted a position as a Senior Rates Analyst with ANR Pipeline Company. In December 2004 I accepted my current position at Enterprise Products Partners, L.P.

Q. Have you previously provided testimony before this Commission?

A. Yes, I have prepared and filed written testimony in the Petal Gas Storage, L.L.C. Cost and Revenue Study, filed on July 1, 2005.

Q. Please provide an overview of your testimony in this proceeding and the related exhibits that you are sponsoring.

A. My testimony will cover Statements G, I and J and their supporting schedules. Specifically, my testimony will explain HIOS's transportation volumes and revenues under current and proposed rates as detailed in Statement G, describe the functionalization of and allocation of cost of service as detailed in Statement I, and explain the rates derivation and revenue reconciliation reflected in Statement J. I am sponsoring the following exhibits.

Hearing Exhibit No.	**Schedule Reference**	**Description**
HIO-24	Statement G	Revenues, Credits and Billing Determinants
HIO-25	Schedule G-1	Base Period Revenues and Volumes
HIO-26	Schedule G-2	As Adjusted Revenues and Volumes
HIO-28	Schedule G-4	At-Risk Revenue
HIO-29	Schedule G-5	Other Revenues
HIO-30	Schedule G-6	Miscellaneous Revenues
HIO-54	Schedule I-1(a)	Functionalization of Cost of Service
HIO-55	Schedule I-1(b)	Incremental v. Non-Incremental
HIO-56	Schedule I-1(c)	Cost of Service by Zone
HIO-57	Schedule I-1(d)	Allocation of Common and Joint Costs
HIO-58	Schedule I-2	Classification of Cost of Service
HIO-59	Schedule I-3	Allocation of Cost of Service

HIO-60	Schedule I-4	Transmission and Compression by Others
HIO-61	Schedule I-5	Gas Account - Natural Gas
HIO-62	Statement J	Reconciliation of Rev. with Cost of Service
HIO-63	Schedule J-1	Summary of Billing Determinants
HIO-64	Schedule J-2	Derivation of Rates

Q. Please summarize the revenues generated by HIOS during the base period.

A. Schedule G-1 (Exhibit No. HIO-25, pg 18, col. 14, line 28) shows that HIOS generated $20,313,574 of revenues, determined by actual invoiced amounts during the base period.

Q. Please summarize the billing determinants during the base period.

A. Statement G (Exhibit No. HIO-24) shows that HIOS's annual billing determinants during the base period, based on actual invoiced amounts, were 1,000,000 Dth on a reservation basis (col. 6, line 5), and 197,570,942 Dth on a commodity basis (col 7, line 5 plus col 8, line 5).

Q. Please summarize the annual revenues that HIOS expects to generate on an as-adjusted basis.

A. Schedule G-2 (Exhibit No. HIO-26, pg 18, col. 14, line 28) shows that HIOS expects to generate $37,354,458 of revenue per year on an as-adjusted basis.

Q. Please describe the annualized billing determinants on an as-adjusted basis.

A. As shown on Statement G (Exhibit No. HIO-24), HIOS expects to achieve total billing determinants on an as-adjusted basis of 148,903,592 Dth on an annual basis, comprised of 27,740,000 Dth of firm volumes (col. 6, line 10) and 121,163,592 Dth of interruptible throughput (col. 7, line 12 plus col. 8, line 12). This interruptible throughput includes 4,715,800 Dth of FT-2 overrun volumes.

Q. Please explain how these levels of test period volumes were determined.

A. I relied on the testimony of HIOS Witness Ronald A. Fulcher, and Schedule G-3 (Exhibit No. HIO-27), which details the adjustments made to base period volumes to arrive at the appropriate level of as-adjusted volumes.

Q. Please explain the remaining schedules contained in Statement G.

A. First, Schedule G-4 (Exhibit No. HIO-28) is not applicable in this proceeding as HIOS does not have any At-Risk Revenue. Next, Schedule G-5 (Exhibit No. HIO-29) contains revenue generated from the transportation of liquids for the base period and on an as-adjusted basis. Finally, Schedule G-6 (Exhibit No. HIO-30) shows cash out revenue, penalty revenue and exit fees collected for both the base and test periods.

Q. Please explain the information contained in Statement G (Exhibit No. HIO-24).

A. Statement G (Exhibit No. HIO-24) summarizes the information detailed in Schedule G-1 (Exhibit No. HIO-25), Schedule G-2 (Exhibit No. HIO-26) and Schedule G-5 (Exhibit No. HIO-29).

Q. Please describe Schedule I-1(a) (Exhibit No. HIO-54).

A. Schedule I-1(a) (Exhibit No. HIO-54) contains the cost of service separated by function. HIOS's only function is the transmission of natural gas, therefore HIOS's total cost of service in this filing of $42,490,584 from Statement A (Exhibit No. HIO-1) has been functionalized entirely as transmission.

Q. Please describe Schedules I-1(b), I-1(c) and I-1(d) (Exhibit Nos. HIO-55 through HIO-57).

A. None of the three schedules are applicable to this proceeding. Schedule I-1(b) (Exhibit No. HIO-55) is not applicable as HIOS does not bill on an incremental basis. Schedule I-1(c) (Exhibit No. HIO-56) is not applicable because HIOS does not utilize a zoned rate methodology and is not proposing a zoned rate methodology in this proceeding. Finally, HIOS does not have common or joint costs that require allocation, so Schedule I-1(d) (Exhibit No. HIO-57) is not applicable.

Q. Please explain Schedule I-2 (Exhibit No. HIO-58).

A. Schedule I-2 (Exhibit No. HIO-58) reflects the classification of costs, by cost of service element, between fixed and variable costs, and between reservation costs and usage costs. On the HIOS system, reservation costs equal fixed costs of $42,490,584 and usage costs equal variable costs of zero dollars, consistent with the Commission's strong preference for straight-fixed variable rate design. Historically, costs in FERC Account 853 - Compressor Station Labor and Expenses, and FERC Account 864 – Maintenance of Compressor Station Equipment, have been considered to include variable costs. However, I have examined the cost accounts and found that FERC Accounts 853 and 864 contain zero dollars on an as-adjusted basis. Therefore, I have classified all costs in this case as fixed.

Q. Please explain how the HIOS cost of service is allocated.

A. HIOS calculates a system-wide rate and does not allocate costs to rate schedules. As a result, Schedule I-3 (Exhibit No. HIO-59) is not applicable to this proceeding.

Q. Does HIOS have any FERC Account 858 costs?

A. No. HIOS does not have contracts with third parties for transportation and compression of gas by others (FERC Account No. 858). Therefore Schedule I-4 (Exhibit No. HIO-60) is not applicable.

Q. Please explain the information contained in Schedule I-5 (Exhibit No. HIO-61).

A. Schedule I-5 (Exhibit No. HIO-61) contains the HIOS gas balance by month during the base period, with applicable adjustments. It reflects the test period throughput as summarized on Statement G (Exhibit No. HIO-24).

Q. Please explain the schedules contained in Statement J (Exhibit No. HIO-62).

A. Statement J (Exhibit No. HIO-62) contains a comparison of the revenues expected to be generated to the overall cost of service. Schedule J-1 (Exhibit No. HIO-63) shows the calculation of rate design determinants and Schedule J-2 (Exhibit No. HIO-64) contains the derivation of rates.

Q. Please summarize the HIOS billing determinants used for rate design purposes.

A. Schedule J-1 (Exhibit No. HIO-63) contains the billing determinants by Rate Schedule as reported on Schedule G-2 (Exhibit No. HIO-26). Two adjustments are then made to the billing determinants to arrive at the rate design determinants, as shown on column 5 of Schedule J-1 (Exhibit No. HIO-63). First, based on the level of interruptible commodity billing determinants reported on an as-adjusted basis, a level of MDQ is imputed for interruptible services. Next, an adjustment is made to account for short haul transportation.

Q. Please explain how the imputed MDQ is calculated.

A. Consistent with HIOS' current rate design, I imputed reservation determinants for interruptible long haul and short haul services so that the rates for these services would share in fixed cost recovery. The imputed reservation determinants are calculated by dividing the test period billing determinants for interruptible transportation by 365 days. The result is reservation determinants for IT service, expressed on a daily basis.

Q. Please explain the adjustment made for short haul transportation.

A. Under HIOS's currently effective tariff, all volumes received downstream of High Island Block A-264 are billed at 40% of the long haul rate. Consequently, I reduced reservation and commodity billing determinants in this case by 60%, which leaves 40% of the imputed reservation determinants, and 40% of the test period commodity billing determinants, applicable to short haul IT for rate design purposes.

Q. Please explain HIOS's rate design.

A. HIOS's rate design calculations are contained on Schedule J-2 (Exhibit No. HIO-64). First, I designed a system-wide default rate applicable to Rate Schedule FT-3 and calculated the rate for Rate Schedule FT-1 as the product of 93% of the Rate Schedule FT-3 annual rate and the Rate Schedule FT-2 rate as 100% of the Rate Schedule FT-3 annual rate. The interruptible rate for long haul transportation was then calculated as the 100% load factor derivative of the Rate Schedule FT-3 rate, with the short haul interruptible rate calculated as 40% of the 100% load factor long haul rate.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of High Island Offshore System	))	Docket No. RP06-

Affidavit of Jeffrey M. Molinaro

Jeffrey M. Molinaro, being first duly sworn according to law, on oath deposes and says that he is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, direct testimony in these proceedings.

Jeffrey M. Molinaro

Jeffrey M. Molinaro

Subscribed and sworn to before me this 29th day of August, 2006.

FRONELL SINGLETERRY
Notary Public, State of Texas
My Commission Expires
November 12, 2006

NOTARY PUBLIC STATE OF TEXAS

Fronell Singleterry

Notary Public