UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Portland Natural Gas Transmission System **Docket No. RP08-___**

Prepared Direct Testimony
of
Barry E. Sullivan

Q1. Please state your name, occupation and business address.

A1. My name is Barry E. Sullivan and my business address is 1155 15th Street, N.W., Suite 400, Washington, D.C. 20005. I am President of Brown, Williams, Moorhead & Quinn, Inc., an energy consulting firm with offices in Washington, D.C. and Houston, Texas.

Q2. What is the nature of the work performed by your firm?

A2. We offer technical, economic and policy assistance to the various segments of the natural gas pipeline industry, oil pipeline industry and electric utility industry on business and regulatory matters.

Q3. Please briefly state your professional experience and qualifications.

A3. My personal vitae, which is attached as Appendix A (Exhibit No. PNG-13), details my experience since my employment at the Federal Energy Regulatory Commission ("FERC or Commission") in 1979. I was a Supervisor in the Office of Administrative Litigation at the time I left the FERC in September 2005. As a Supervisor in the Office of Administrative Litigation, I supervised and directed a significant number of the natural gas pipeline, oil pipeline, and electric utility proceedings that were set for formal hearing proceedings at the Commission. I also supervised and directed the preparation and presentation of the Commission technical Trial Staff's settlement and testimony positions on a wide range of issues in these formal proceedings. These issues included: the Enron and the Western Market investigation; formal market power studies; market-based rates; cost classification; cost allocation; rate design; seasonal rates; distance-based rates; separation of services (unbundling); discounting; capacity release; capacity assignments; interruptible transportation rates; storage rate design; refunctionalization studies; stranded costs; restructuring issues; incremental versus rolled-in rates; depreciation and negative salvage costs; cost-of-service and rate base issues; oil pipeline rates; tariffs and operational issues; and the resolution of contract disputes.

In addition, I have testified as an expert witness on depreciation, cost classification, cost allocation, rate design, billing determinants, market power and market-based rates, and other rate-related issues in numerous natural gas rate proceedings, oil pipeline proceedings, and electric proceedings. A list of the cases that I supervised while at the Commission is attached as Attachment A-1 (Exhibit No. PNG-13). A list of the cases in which I provided testimony and/or testified is attached as Appendix B (Exhibit No. PNG-13).

Q4. Would you briefly state your educational background?

A4. I graduated from the University of Massachusetts at Boston with a BA degree in economics. I also completed a one-year program in graduate economics at the University of York, England.

Purpose of Testimony

Q5. On whose behalf are you presenting testimony in this proceeding?

A5. I am presenting testimony at the request of Portland Natural Gas Transmission System ("PNGTS").

Q6. What is the purpose of your testimony in this proceeding?

A6. My testimony addresses depreciation and short-term transportation rates, and risks in the natural gas industry.

Q7. Please describe the PNGTS system.

A7. The PNGTS system was originally constructed during 1998 and 1999 and went into service on March 10, 1999. PNGTS consists of approximately 290 miles of pipeline, including a northern segment of about 190 miles of pipeline proceeding from an interconnect with TransQuebec & Maritimes Pipeline, Inc. ("TQM") at the Canadian border near East Hereford, Quebec southeast to Westbrook, Maine where it interconnects with the Maritimes & Northeast Pipeline, L.L.C. ("Maritimes"). The jointly owned (with Maritimes) southern segment is a 30-inch, approximately 102-mile pipeline that begins at Westbrook, Maine and proceeds in a southwesterly direction through southern Maine, the New Hampshire seacoast and terminates at an interconnection with Tennessee Gas Pipeline Company at Dracut, Massachusetts.

Depreciation

Q8. Please explain your depreciation recommendation.

A8. My testimony addresses the determination of the just and reasonable depreciation rates to be applied to PNGTS' depreciable transmission and general plant, as well as an appropriate allowance for negative salvage, as discussed by PNGTS witness Taylor. As part of the support for such determinations, I am presenting a detailed depreciation study, as well as an assessment of market demand and natural gas supplies as they relate to the useful life of PNGTS' pipeline facilities.

Q9. Please provide the calculated depreciation rates that you believe are justified for PNGTS' depreciable transmission and general plant.

A9. Based on my studies and determinations, I believe that the following depreciation rates would be fully justified on the PNGTS system:

TOTAL COMPOSITE RATE	3.59 percent
TRANSMISSION PLANT	3.53 percent
GENERAL PLANT	
Acct. 391 Office Furniture and Equipment	16.67 percent
Acct. 392 Transportation Equipment	25.00 percent
Acct. 393 Stores Equipment	8.33 percent
Acct. 394 Tools, Shop and Garage Equipment	16.67 percent
Acct. 397 Communication Equipment	10.00 percent
Acct. 398 Miscellaneous Equipment	16.67 percent
Acct. 399 Other Tangible Equipment	25.00 percent

Q10. Is it your understanding that the foregoing rates of depreciation will be incorporated into the derivation of PNGTS' rates filed as part of this case?

A10. The settlement resolving PNGTS' last rate case in Docket No. RP02-13 specified that PNGTS should recognize a 2% depreciation rate for mainline facilities as part of its filing. Consequently, PNGTS has complied with that obligation.

However, my depreciation analysis shows that PNGTS will be severely under-collecting its required annual depreciation expense by filing a 2% composite depreciation rate in this proceeding. My depreciation analysis demonstrates that a just and reasonable composite depreciation rate for the PNGTS system is 3.59%**.**

In addition, PNGTS' remaining economic life associated with a 2% depreciation rate is 39 years. The TransCanada pipeline facilities that transport Western Canadian Sedimentary Basin ("WCSB") gas for the transportation customers of PNGTS are currently utilizing depreciation rates based on an economic truncation date of 2027. PNGTS' calculated remaining economic life based on a 2% depreciation rate at the end of 2007 is 39 years or through the year 2046. The remaining service life implied by the 2% depreciation rate for the PNGTS facilities exceeds TransCanada's remaining economic life by almost 20 years. (National Energy Board, Reasons for Decision, TransCanada PipeLines Limited, RH-1-2002, Issued July 2003).

Q11. Have you provided the calculated depreciation rate of 3.59% to PNGTS witness Lovinger?

A11. Yes. If the Commission ultimately adopts all of the elements of PNGTS' filed case such as the requested rate of return and directs that PNGTS' composite rate of depreciation should be 3.59%, the transportation rates that result are contained in Pro Forma Tariff Sheet Nos. 100 - 102. These composite rates, and the individual rates listed above, are the lowest level of depreciation that allows for the systematic recovery of PNGTS' capital investment over the remaining useful life of the assets.

Overview

Q12. Please explain your depreciation analysis with respect to transmission plant.

A12. I analyzed PNGTS' system operations, along with its markets for transportation services and sources of gas supply. I determined an average remaining life of PNGTS' transmission plant based on the expected physical lives of its transmission facilities, as well as an economic life of its pipeline based upon projected WCSB, Mackenzie Delta gas, potential Alaska North Slope gas, and LNG. In addition, I have included an analysis of potential auxiliary gas supplies from Lower 48 supply areas that may become available for shipment to TransCanada at Dawn, Ontario as WCSB gas available for export declines in the future. Additionally, I considered the impact of LNG supplies on the PNGTS system. I also considered how demand for pipeline transportation capacity in PNGTS' geographic market affects the economic life of PNGTS' facilities. I applied the average remaining life to each of PNGTS' plant accounts to determine the composite depreciation rate for the transmission plant function.

I also determined the negative salvage rate by applying the total negative salvage calculation provided to me by PNGTS witness Taylor to the same physical lives and economic life used to determine the transmission plant depreciation rate. I independently reviewed witness Taylor's negative salvage analysis, and I determined that the calculation used by Mr. Taylor reflects conventional/standard industry practice. Mr. Taylor's analysis is found in Exhibit No. PNG-18. The methodology I employed for determining PNGTS' just and reasonable depreciation rates and negative salvage rates is fully consistent with methods that the Commission uses.

Depreciation Definition

Q13. What is depreciation and how is it used for rate purposes?

A13. Depreciation is the allocation of the original cost of tangible facilities in service over the useful lives of those facilities. For rate purposes, depreciation is treated as an operating expense. Depreciation is intended to systematically recover invested capital over the useful life of the depreciable asset. Depreciation is the expiration or consumption of the plant investment, and its recoupment over a reasonable and consistent manner, during the expected service life of the plant investment. Over the past 35 years, FERC has embraced the life span approach with an economic life as a key ingredient in the determination of depreciation for jurisdictional pipeline companies. It has authorized rates employing economic lives generally ranging from 20 to 35 years depending upon the circumstances of the individual pipeline company.

Q14. What method or approach did you use to determine a just and reasonable depreciation rate for PNGTS?

A14. I used the average service life approach for all classes of property.

Q15. Why did you choose the average service life method?

A15. The average service life method is the most widely used and Commission accepted method for developing depreciation rates. This method calculates the rates for groups of plant based upon average service lives for those groups, which are determined to be appropriate through studies of the forces affecting the lives of the pipeline's facilities.

Remaining Life Factors

Q16. What causes a plant unit to reach the end of its useful life and retirement?

A16. The measurement of depreciation recognizes that all plant will ultimately reach the end of its useful life based on one or more of the following factors:

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

Q17. Which of those are the most common causes of retirement?

A17. The physical causes, such as wear and tear and deterioration, are the most easily observed reason for retirements. However, functional causes, such as inadequacy, obsolescence, requirements of public authorities and particularly the inadequacy of supplies and markets, are probably the more prevalent causes of retirements in the pipeline industry.

Q18. Please further explain the "adequacy of supply or market" factor and its significance.

A18. The adequacy of supply or market is unrelated to the physical characteristics of the property or the action of public authorities. Determining the "adequacy of supply or market" involves assessments of whether there will be (i) sufficient natural gas supplies available to a pipeline, and (ii) sufficient demand, to economically justify the continued operation of the pipeline. Traditionally at the Commission, the adequacy of gas supply has been the most important element and determining factor in setting the useful life for natural gas pipeline facilities. In a depreciation study, the adequacy of supply and markets is referred to as the economic life.

The Depreciation Model

Q19. What model did you use for determining depreciation?

A19. I employed the straight-line average remaining life method as traditionally adopted by the Commission. It is described as follows:

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

Where,

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

Q20. What is a survivor curve and what is its purpose?

A20. A survivor curve, fitted to a particular type of plant, predicts the average remaining service life and normal retirement pattern of that plant. A survivor curve graphically reflects the percent of capital investment remaining at each age throughout the entire physical life of an original group of property. From the survivor curve, the average service life or average remaining life can be calculated. The survivor curves are referred to as Iowa type survivor curves.

Q21. How are survivor curves constructed?

A21. Survivor curves, as they are employed to determine the future interim retirements of plant groups, represent a forecast factor and are constructed based upon: a) a statistical assembly of historical retirements (where available), b) an analysis of the operation of the specific facility group, c) the typical lives of similar assets, and d) the experience and judgment of the analyst.

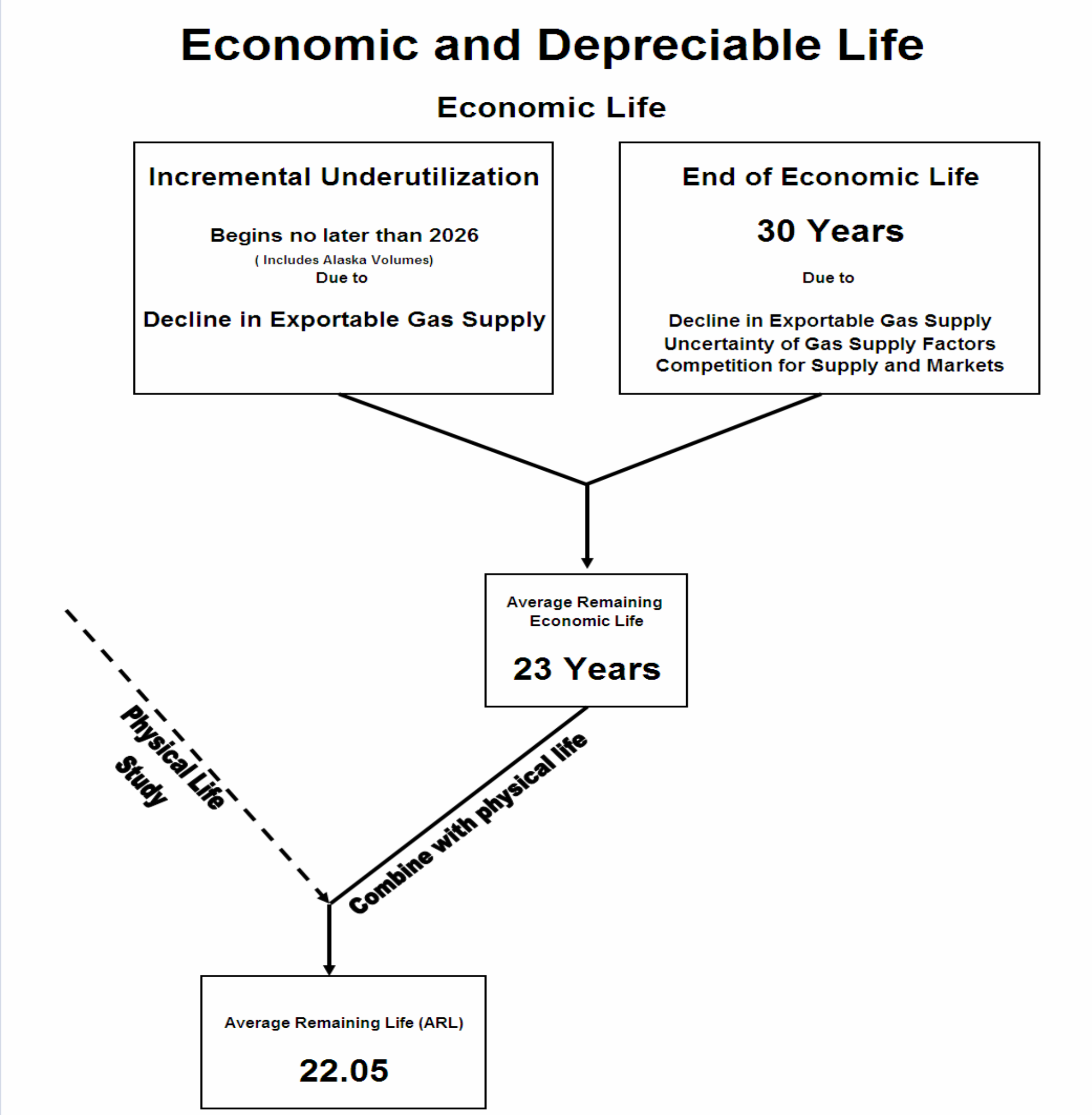
Economic Life of the System

Q22. Please describe the economic life of the PNGTS system.

A22. The economic life of the PNGTS system is dependent primarily upon the productive capability of the supply areas from which it receives gas for transmission. It also is dependent upon circumstances in the markets it serves. PNGTS’ markets are made up of a combination of local distribution companies serving residential, industrial and commercial end-users, an assortment of industrial concerns, natural gas-fired power generators, and interconnecting pipelines.

Adequate supply of gas for shipment is crucial to the remaining life of a pipeline system. Essentially, the current main source of gas for transportation in PNGTS' pipeline facilities is the gas supplies of the WCSB. I have employed a comprehensive gas supply study of the WCSB prepared under my supervision. The gas supply analysis and study forecasts the amount of gas supply that will be available from the WCSB in the future. This gas supply study is presented in Appendix C to my testimony, Exhibit No. PNG-14, and is referred to as the Assessment of the Availability of Natural Gas in the Western Canadian Sedimentary Basin (Assessment). I analyzed other Canadian and Northern sources, such as potential Alaskan and Mackenzie Delta pipeline gas as well as potential LNG sources. I also included volumes available from the Scotian Shelf. Additionally, I recognize that PNGTS could potentially receive and transport natural gas supplies from traditional natural gas supply basins in the Lower 48 states via the Dawn market center at Dawn, Ontario. The Dawn market hub is directly connected to TransCanada pipeline facilities that directly connect to PNGTS. The Dawn market hub accesses natural gas supplies from the WCSB, Gulf Coast, MidContinent and Rocky Mountain supply regions. Schedule No. 10 shows the average remaining economic life based on auxiliary supplies of future natural gas supply that may become available from these supply regions and that may be available to supplement the dwindling export supplies from the WCSB. I used all of these studies to determine PNGTS' probable economic life. The results of those studies, when directly related to PNGTS' existing facilities, indicates an economic end life of 30 years based on future natural gas supplies. As I will discuss in detail later in my testimony, I take into account the amount of gas available for shipment on PNGTS under different scenarios to determine the average remaining economic life of 23 years for PNGTS' mainline facilities. The next step is to determine the average remaining life (ARL). The ARL is determined from a combination of the physical life and average remaining economic life. A diagram describing the procedure for determining the ARL is shown in Figure 1, below. The ARL is calculated by selecting an Iowa survivor curve which represents physical life characteristics for each plant account in determining the area under the curve from today to the date of retirement or average remaining economic life. As an example of this process, Figure 1 shows that the ARL for PNGTS' transmission facilities is 22.05 years.

Figure 1



Q23. Has Alberta recently considered raising the royalty rate on natural gas production in the WCSB?

A23. Yes. On September 18, 2007 the Alberta Royalty Review Panel recommended that the Province of Alberta significantly increase the royalty rates on natural gas and oil production. These increased royalty payments by producers will lower producer netbacks and result in less profit per well, thereby reducing producer incentives to find and produce natural gas in the WCSB.

Q24. Does your analysis of the average remaining life include the impact of the increased royalty payments in Alberta?

A24. No. I have taken a conservative approach in determining PNGTS' remaining average life and did not attempt to reduce my assessment of WCSB supplies that will be available for export to reflect the impact of the increased royalty payments.

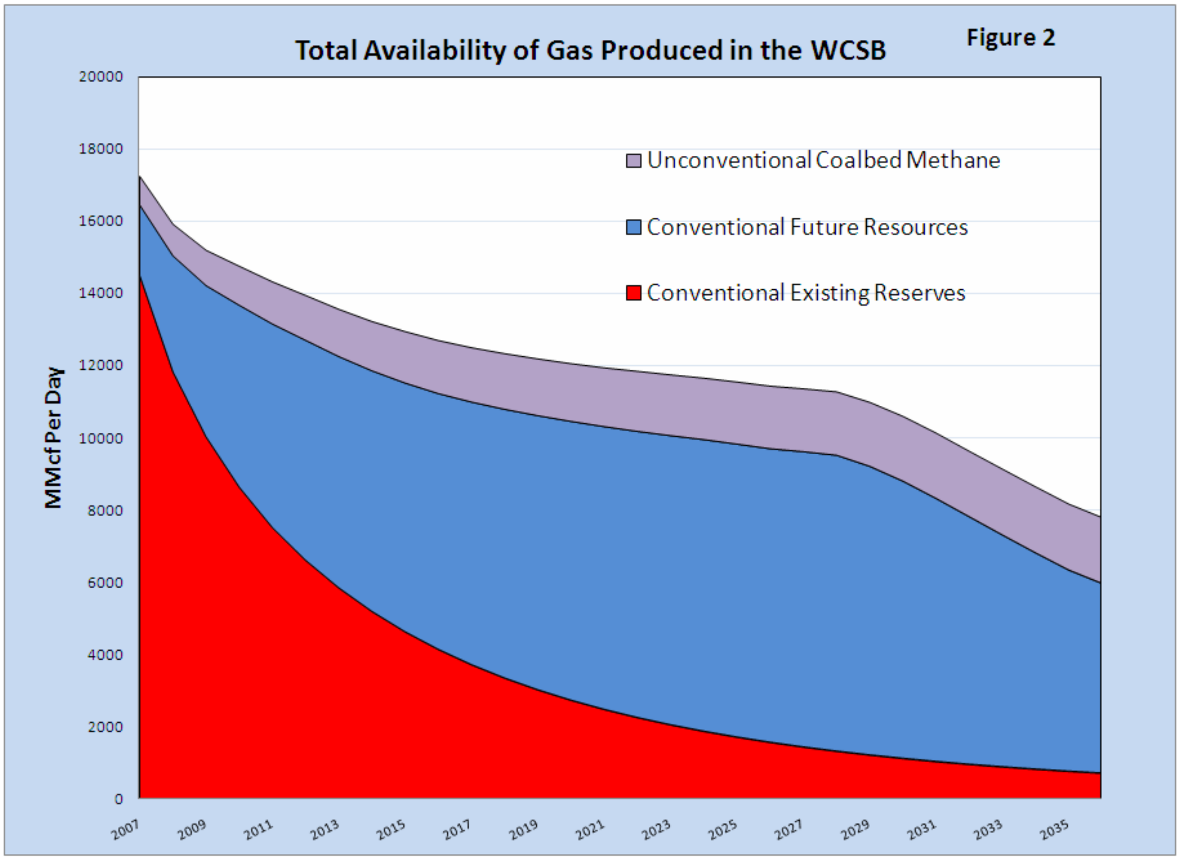
Gas Supply

Q25. Would you please describe the gas supply analysis that you used in your depreciation study?

A25. The gas supply analysis provides a detailed study of the existing proven reserves of natural gas in the WCSB, as well as estimates of potential natural gas resources in the WCSB areas. The availability of natural gas supplies from these existing and potential WCSB sources is forecasted over the next 30 years. Included in the forecast of Western Canadian natural gas supplies are estimated volumes of both conventional and unconventional gas. Conventional resources are located in distinct accumulations and generally have more favorable performance characteristics and are responsive to traditional exploratory techniques. Nonconventional resources, such as coal bed methane, are typically continuous accumulations that are much larger in aerial extent than conventional distinct accumulations. They are relatively more challenging and expensive to bring to commercial production.

Q26. What are the results of your gas supply analysis.

A26. The results of my gas supply analysis is found in the Assessment in Appendix C, Exhibit No. PNG-14. The profile of gas available from western Canada is shown below in Figure 2 and in Schedule No. 2 of Exhibit No. PNG-15.



Canada's domestic demand for natural gas according to the National Energy Board ("NEB") (Canada's Energy Future, An Energy Market Assessment November 2007) will be 11.5 Bcf per day in the year 2025. The NEB states that by 2028, Canadian domestic gas consumption is estimated to be equivalent to Canadian domestic gas production and Canada's role as a net gas exporter would come to an end in that case. My study indicates that even with greater supplies from unconventional gas sources and LNG, the

Canadian supply and demand crossover occurs by 2033. (See Schedule No. 3 of Exhibit No. PNG-15).

Q27. **Does your consideration of access to domestic US gas supplies extend the average remaining life of PNGTS?**

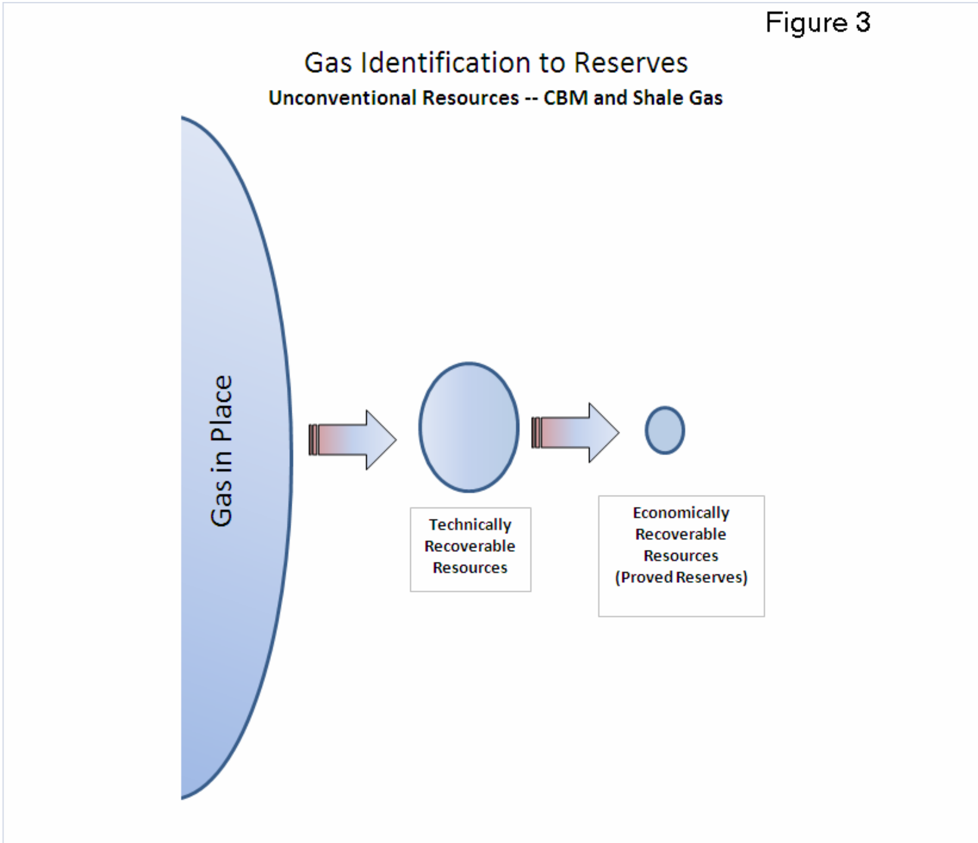
A27. Yes. As Schedule No. 20 indicates, the average remaining life of PNGTS is extended to 22.05 years, versus the 20.16 years shown in Schedule No. 16, an increase of approximately two years.

Q28. How did you use the results of the gas supply studies?

A28. I used the results of the gas supply study to determine the economic life of PNGTS' gas transportation system. The trend lines show annual WCSB production has peaked, and will experience declining annual production henceforth. The production profiles contained herein reveal that the WCSB cannot produce sufficient net exportable quantities to maintain even existing throughput levels on Alberta export pipelines. As can be observed from the availability profiles, supply/demand deficiencies begin to occur in the second decade of the 21^{st} century. Specifically, the WCSB forecasts (including North Slope Alaska, Mackenzie Delta and LNG), along with estimates of Canadian domestic demand, indicate major throughput deficiencies for export pipelines. The magnitude of the decline in the amount of Canadian gas available for export to the Lower 48 states under three scenarios is shown in Schedule Nos. 4, 5 and 6 of Exhibit No. PNG-15. A graph of these three availability scenarios is presented in Schedule Nos. 7, 8 and 9. Declining gas availability from western Canada creates situations where significant underutilization of present pipeline capacity may take place, resulting in potential major retirements of pipeline facilities.

Q29. Could you put into context the current status of conventional Canadian gas resources as it affects the economic life of PNGTS' system?

A29. The purpose of depreciation is to allow for the recovery of the investment in pipeline facilities over a reasonable estimated life. The economic life component is an integral part of a proper depreciation determination. The determination of the economic life must rely upon logical and reasoned gas supply forecasts as they affect the useful life of PNGTS' facilities. The gas supply life forecasts must meet a dual standard, they must be certain enough to assure investors that they will get a return of their investment dollar for dollar, while shippers are reasonably assured that the transportation rates that they pay reflect their fair generational share of the depreciation cost recovery, no more and no less. Western Canada began its production life history with exceedingly large quantities of hydrocarbon resources in-place. In-place gas resources are deposits that reside in the underground reservoirs. However, only a fraction of such resources are producible and marketable, and that fraction ranges from a high of 60 percent of conventional gas resources in Alberta to a very low (less than 10 percent) level for unconventional resources such as coalbed methane. Figure 3 below shows for unconventional resources, a diagram of the transition between gas in-place volumes and that which is marketable.



The reality for Western Canadian Sedimentary Basin natural gas supply is that the largest in place reserves have already been discovered and the remaining resource base is a fraction of what has been previously discovered. The majority of the WCSB conventional resources have been discovered as indicated in Table 1 of Exhibit No. PNG-13 below.

Table 1

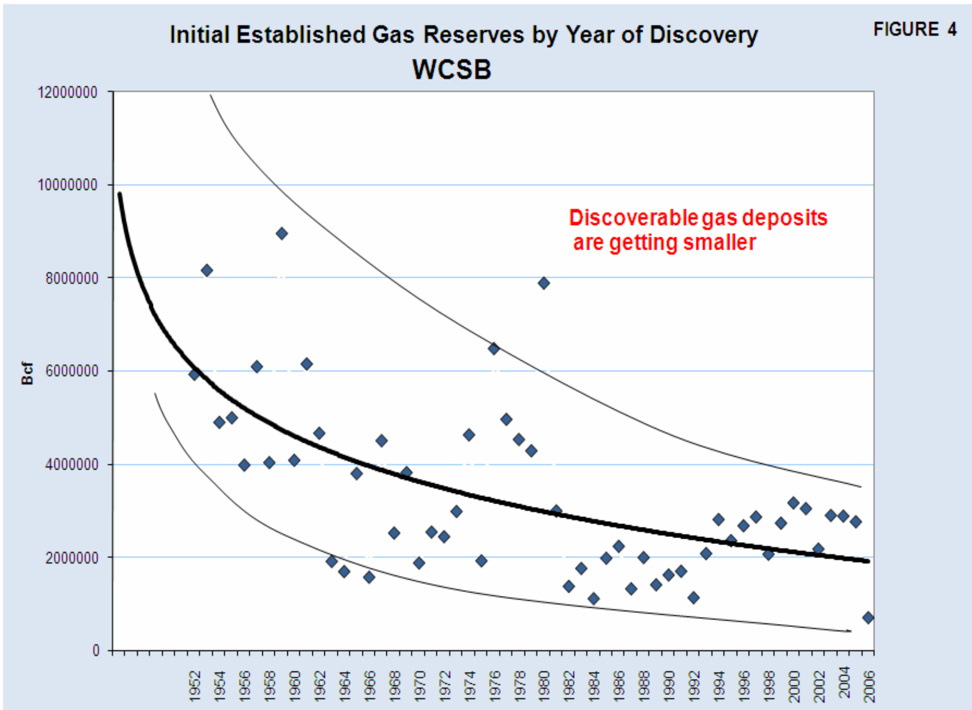
Relationship Between Discovered Resources and Ultimate Potential Gas Resources in the WCSB
Volumes in Bcf
Year-end 2003

	Discovered Marketable Resources	Undiscovered Resource	Ultimate Resource Potential
WCSB Conventional			
Alberta	161,241	61,557	222,798
British Columbia	24,531	26,448	50,978
Saskatchewan	8,591	462	9,053
Southern Territories	1,030	5,929	6,958
Total	195,392	94,395	289,787

Discovered Marketable Resources includes cumulative production and remaining proved reserves.

Source: AEUB, Alberta's Ultimate Potential for Conventional Natural Gas

The trend towards the discovery of smaller and smaller pools (gas reservoirs) is shown in Figure 4 of Exhibit No. PNG-13. The trend line summarizes a disturbing and important development; the largest pools have already been discovered and they are also the most depleted.



With the exception of 2004 and 2005, annually connected new reserve additions have not reached a level to replace the 2006 production level. In eight of the past ten years the new reserves were less than the 2006 production level. This is demonstrated in Figure 5 of Exhibit No. PNG-13.

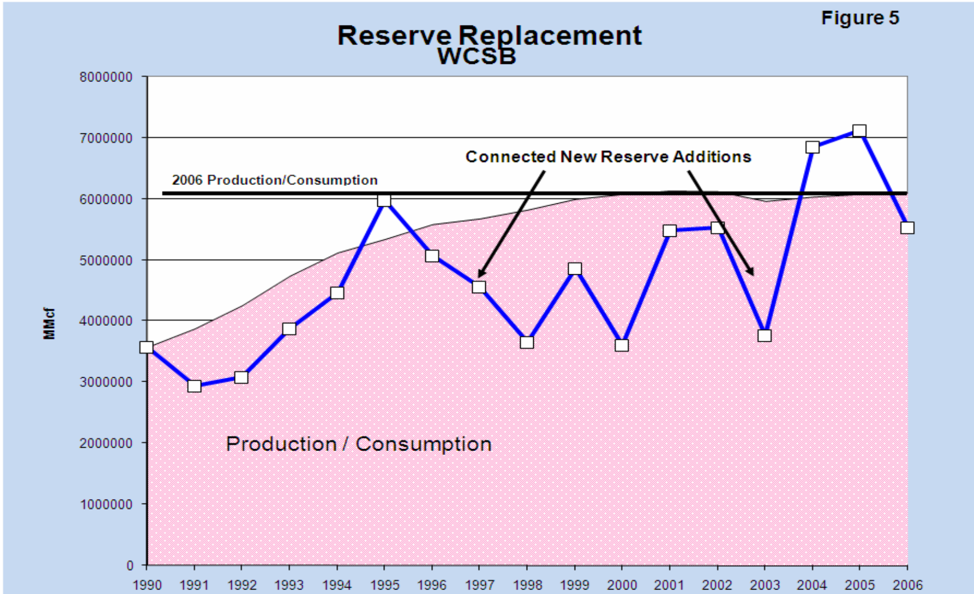


Figure 5

Reserve additions by year of discovery are progressively smaller as shown below in Figure 6 of Exhibit No. PNG-13. The production performance of successive years' new gas discoveries is decreasing and the first year production per new well has decreased by more than 50% in less than six years as shown in Figure 6.

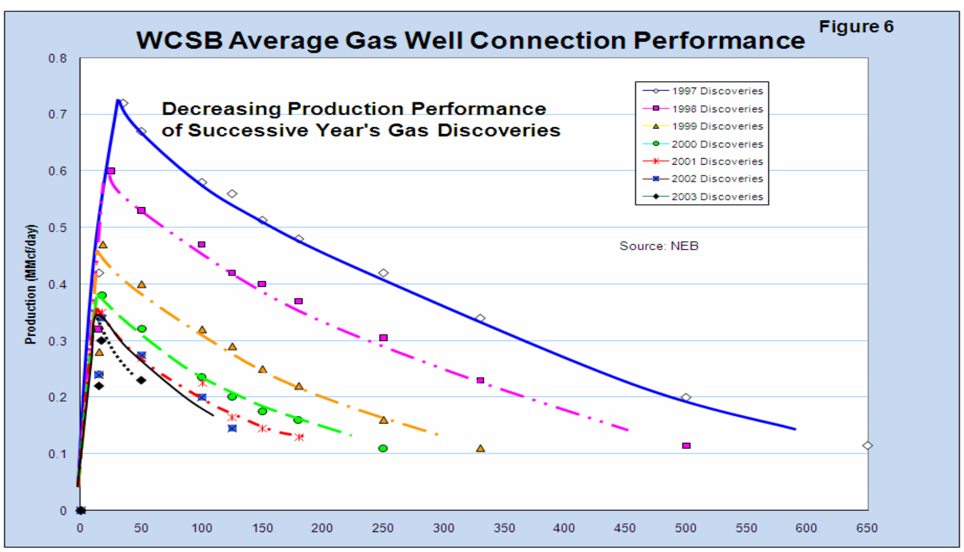
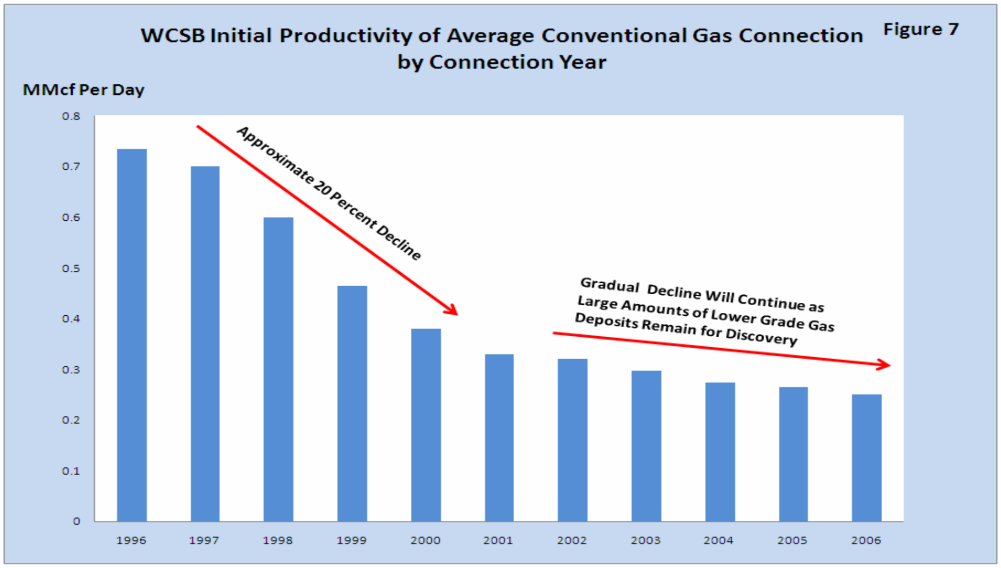
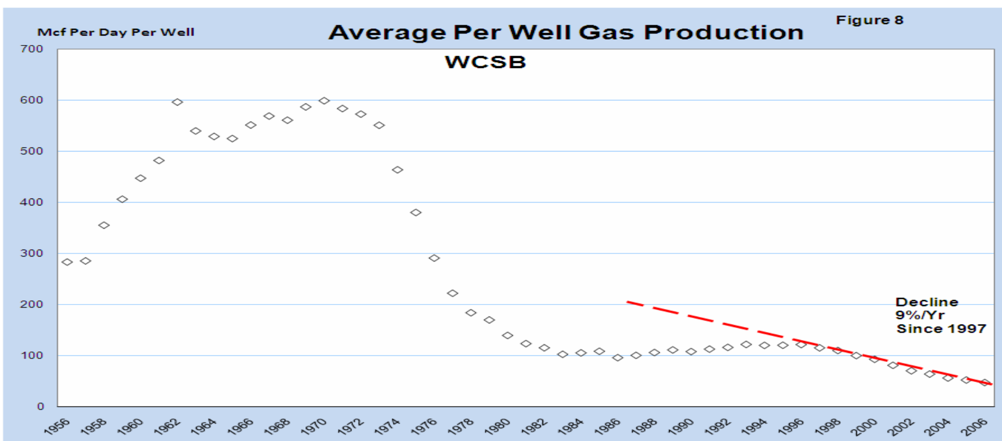


Figure 6

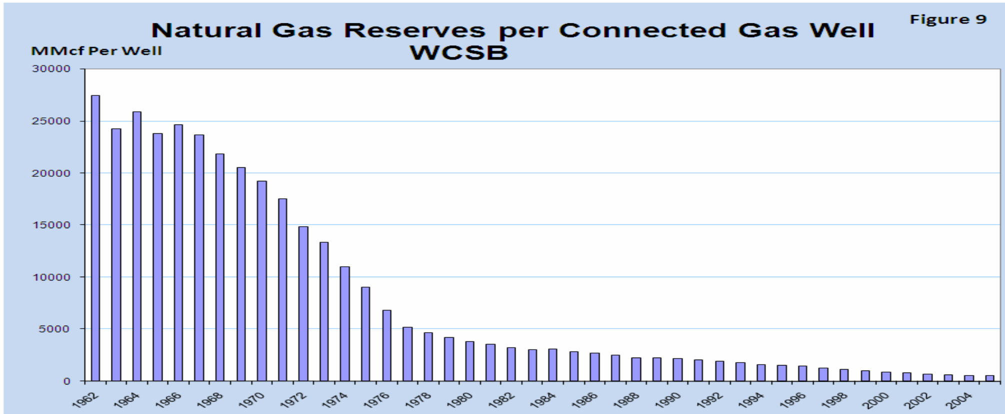
Figure 7 shows that initial gas well productivity over time has decreased substantially. See Figure 7 of Exhibit No. PNG-13.



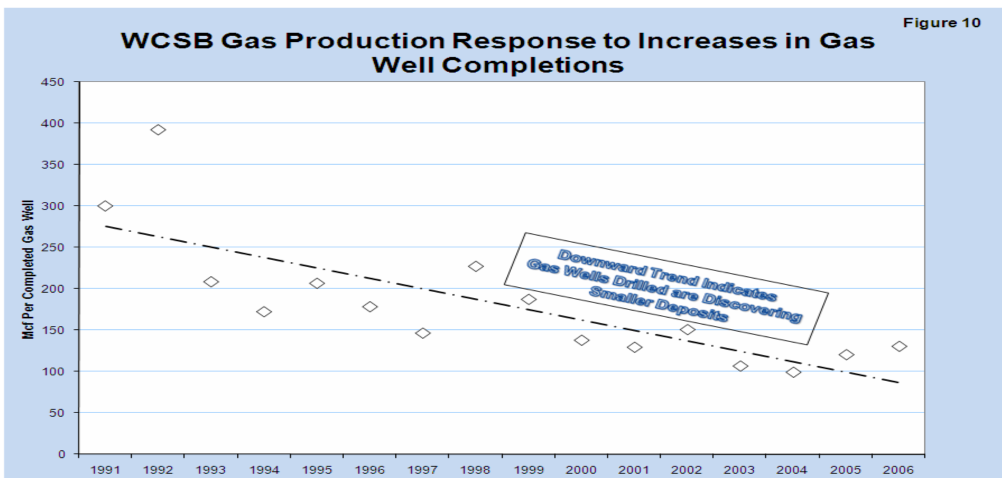
Per well production throughout the WCSB is decreasing as shown in Figure 8 of Exhibit No. PNG-13.



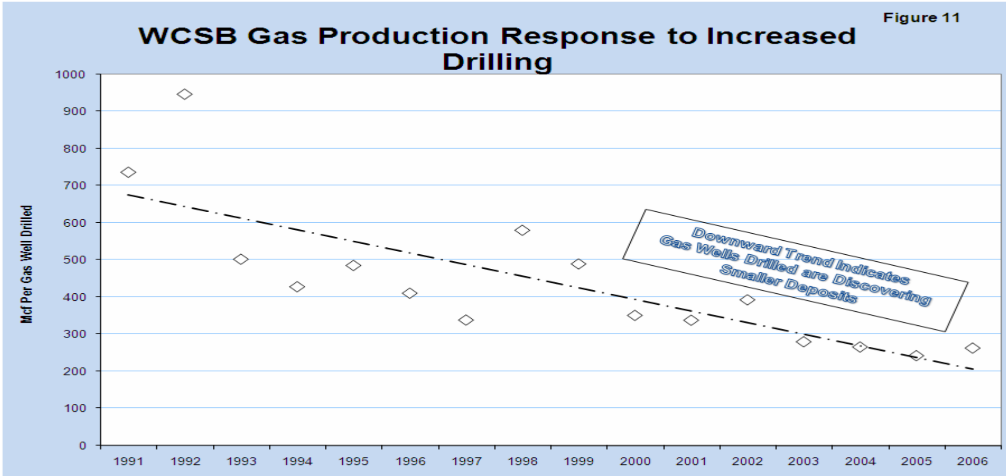
The level of per well reserves throughout the WCSB is decreasing as shown in Figure 9 of Exhibit No. PNG-13.



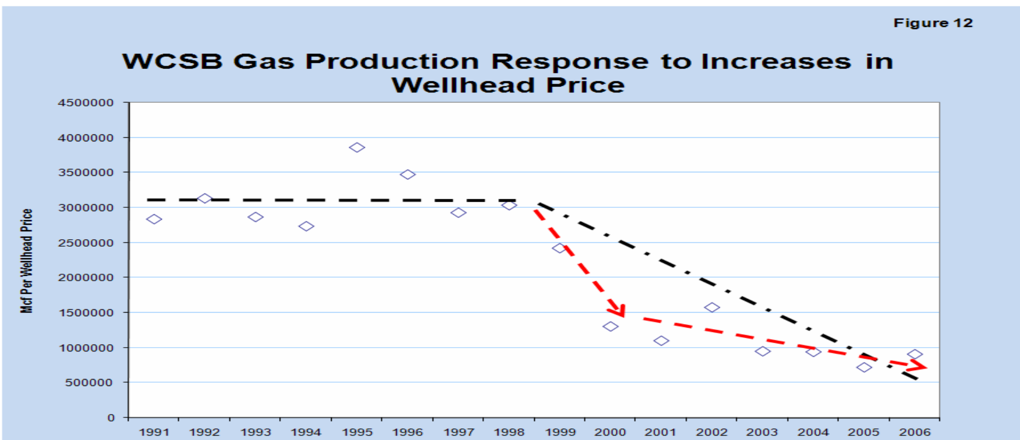
Gas production response to the increasing number of gas wells completed is in a clear decline as shown in Figure 10 of Exhibit No. PNG-13.



Gas production response to increased drilling is a clear decline as shown in Figure 11 of Exhibit No. PNG-13.



Gas production response, notwithstanding wellhead gas price increases, is in a clear decline as shown in Figure 12 of Exhibit No. PNG-13_.



The above facts indicate that the WCSB is entering the mature stage. Canada's NEB has recognized these facts and states: "recent drilling and production data suggests that the WCSB may be maturing; and changes in natural gas resource estimates may be warranted for some areas" (NEB 2007 Report).

With the declining status of future natural gas production in the WCSB, Canadian natural gas exporting pipelines from the WCSB and United States importing pipelines from the WCSB face shortfalls in natural gas available for export and potentially large amounts of excess pipeline capacity.

According to the Canadian Energy Research Institute (CERI), such unused capacity could amount to 42 percent by 2018 (Petroleum News, Volume 13, No. 3, Week of January 20, 2008). CERI states that unused takeaway capacity out of Western Canada is currently 2.5 Bcf per day, representing 17% of the available export capacity of 14.980 Bcf per day, and it is projected to further deteriorate, reaching 3.5 Bcf per day of un-utilized capacity, representing 23% of capacity, by 2012. In essence, the WCSB is in a declining treadmill status where the angle of the treadmill will be increasingly steep and the runner can only take smaller and smaller steps as time goes by. The current declining status of conventional Canadian natural gas resources will limit the supply of economically available gas to PNGTS as time goes on and therefore also limit the economic life of the PNGTS' pipeline facilities.

Q30. Are there other gas supplies that could mitigate the expected decline in WCSB natural gas production in the future?

A30. Yes. Imported LNG supplies from the Maritime provinces, the province of Quebec via the St. Laurence Seaway, and the Canadian West Coast via the province of British Columbia, have the potential to offset a portion of the decline in the WCSB. However, there are substantial risks associated with the reliance on potential imports of LNG supplies. This is especially true for projections of LNG supplies to be received by re-gasification facilities that have not been built or are not certificated or permitted. Authorized and constructed facilities are far less speculative than other proposed LNG projects. Sponsors of existing facilities have incurred significant debt to construct the project and will be seeking volumes to help recover those costs. Permitted and certificated LNG facilities have survived regulatory scrutiny, unlike more speculative proposed projects, and LNG facilities that have actually been constructed are even less speculative.

Q31. Can you describe some of the risks associated with LNG projects that have not been permitted or constructed?

A31. Obviously, facilities that have not been permitted must face the expense and delay inherent in the regulatory process. Construction entails the risk of cost overruns. These risks may arise both at points of re-gasification as well as liquification. Additionally, it is critical to recognize the risk of securing adequate and reliable supplies.

Q32. Are there other risks associated with unconstructed and unpermitted LNG facilities?

A32. Yes. Many of the competing LNG import facilities in foreign countries price LNG on a Btu equivalent/derivative basis with oil supplies. Oil prices are considerably higher on a Btu basis, than North American natural gas prices at the current time, and pricing LNG imports on a Btu equivalent basis may price these incremental gas supplies out of the North American market. In addition, there are a large number of currently planned import facilities that may or may not be built depending on a number of regulatory, economic and environmental factors. Currently planned and existing LNG regasification import facilities far outweigh the actual liquefaction facilities planned and in existence throughout the world. Large increases in future LNG imports will not occur unless significant new liquefaction facilities are constructed in exporting countries. Given world-wide demand for LNG shipments and higher prices in regions outside of North America, it may be nearly impossible to line up steady LNG landings every 3-5 days to ensure a close to 100% utilization rate for an increasing number of North American LNG facilities. LNG shipments can be diverted at any time to a new destination market that is willing to pay a higher rate while the tankers are in route. See PNGTS witness Reed's testimony for an explanation of the potential size and reward of the LNG market but also the business risk faced by planned and proposed LNG projects. As an example of the business risk of LNG projects, Russia has recently backed out of supplying the Gros Cacouna LNG project.

Q33. Please provide additional detail on planned and proposed Canadian LNG projects?

A33. The Canaport LNG project is expected to go online this November 2008, and it will supply PNGTS' direct pipeline competitor, Maritimes. Additional announced planned projects in Eastern Canada include a 1.0 Bcf/d Keltic project in Goldsboro, Nova Scotia, a 1.0 Bcf/d Gros Cacouna project in Riviere-du-Loup, Quebec, a .5 Bcf/d Rabaska project in Quebec City, Quebec, a .5 Bcf/d Statia project in Point Tupper, Nova Scotia, and a 1.0 Bcf/d Energie Grande Anse project in Saguenay, Quebec.

Q34. Do planned offshore and onshore LNG terminals in New England have the potential to lessen the future demand for transportation services on PNGTS?

A34. Yes. PNGTS faces significant risk that there will be significantly lower demand for transportation service on its system if the proposed offshore and onshore LNG projects in the New England market area are constructed. Neptune LNG/Suez LNG are proposing an offshore terminal connection that would have regasification capacity of 400 MMcf/d and the offshore Northeast Gateway/Excelerate Energy project has constructed peak day capacity of 800 MMcf/d. Both of these projects have received Coast Guard approval. The Weavers Cove project in Fall River, Massachusetts has received FERC approval for 800 MMcf/d of regasification capacity. The Broadwater project in Long Island sound between Connecticut and New York has received FERC certification for 1,000 MMcf/d of regasification capacity. There is an existing LNG terminal in Everett, Massachusetts with regasification capacity of 1,035 MMcf/d. Clearly, the PNGTS transportation capacity and the need for its transportation service could be completely replaced by any combination of these LNG projects.

Q35. Given the predicted decline in future natural gas production in the WCSB, did you consider a reversal of flow on the PNGTS pipeline that would allow Nova Scotia offshore gas supplies, Canaport LNG supplies, and other potential new LNG projects to transport gas to Quebec markets in your depreciation life analysis?

A35. Yes. I carefully considered that possibility. I consider the option to reverse flow on the PNGTS system, less than 10 years after its construction to supply New England markets, as an extremely unlikely outcome. Given the uncertainty surrounding the location of future LNG facilities in New England and Canada it is premature to determine at this time the impact on PNGTS' operations. In my judgment, a reversal of flow would be an extreme event that cannot be properly anticipated at this time and should not influence the depreciation life analysis at this time.

Q36. Could you put into context the current status of Western Canada non-conventional gas supplies versus conventional WCSB production?

A36. As the decline in significant new natural gas reserves in the WCSB production region continues, interest in non-conventional resources is increasing.

Q37. Please describe Canada's unconventional resources.

A37. Canada's unconventional resources fall into four categories: coalbed methane (CBM), tight gas, shale gas, and gas hydrates.

Q38. Please describe CBM and its relationship to Canada's resource base.

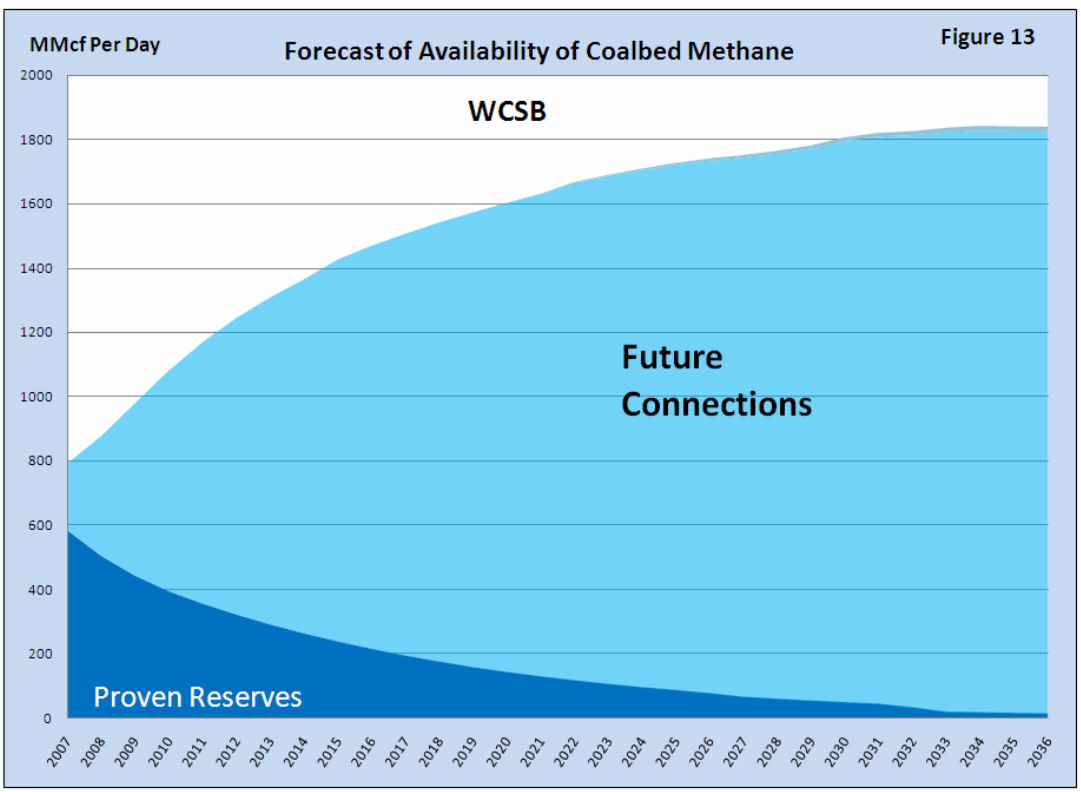
A38. Western Canada (Alberta) contains vast amounts of coal distributed throughout the southern Plains, Foothills and Mountains. However, there are a number of challenges to successfully develop Canadian CBM. They include: finding localized areas where the CBM has all the right characteristics; developing the correct technique for production; finding viable water disposal options; resolving legal issues over ownership; and overcoming the large cost of compressing produced gas to achieve pipeline pressures. Less than half of the CBM wells drilled had produced or were producing by year-end 2004. CBM production from such wells in 2004 was minimal (58 MMcf per day, or less than 0.5 percent of just Alberta's gas production). There is an important difference between CBM production and production from CBM wells. CBM wells are those wells that are drilled to produce CBM, while CBM may produce from conventional gas wells. Conventional gas wells in Alberta, in many instances, produce from a coal zone. As of the end of 2006, the Alberta Energy and Utility Board (EUB) estimates remaining established reserves of CBM to be 871.9 Bcf.

Q39. What is the relationship between CBM gas in place and marketable gas that could be produced?

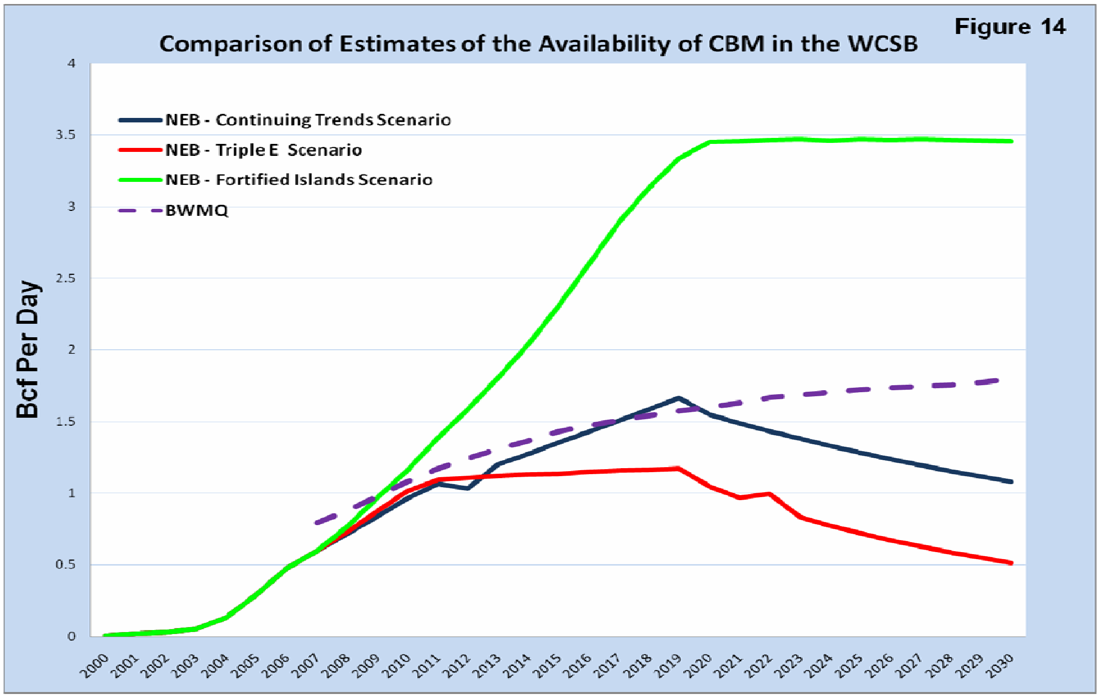
A39. Recall that gas in place (GIP) describes the *total* amount of gas that resides buried in the reservoir. Given technical and economic constraints, only a fraction of such gas can be recovered. In the case of CBM, according to estimates based on data published by the EUB in its Supply and Demand Outlook, Alberta Reserves 2006, (published in 2007), only an average of 6 to 9 percent of the GIP can be recovered once technically recoverable deposits are found and established. Table 2 of Exhibit PNGTS-14 shows that total estimated ultimate recovery is only 8.6%.

Q40. What amount of CBM supply do you believe is reasonable and prudent to employ in a determination of the amount of investment recovery via depreciation accruals?

A40. The long-term outlook of volumes of Canadian CBM is far more uncertain than conventional gas supply sources. The reason for such caution is that Canada has not established a track record of sustained production from stand-alone CBM projects. Further, while Canadian CBM is a reality and will supplement the fall-off in conventional supplies to some degree, current analysis indicates the level of volumes will be limited. The availability of Canadian CBM is included in the Assessment of the Availability of Gas from the WCSB. Figure 13 shows the results of that study. Volumes of CBM gas determined in the Assessment are similar to those determined by the NEB in their Energy Market Assessment of November 2007.



The comparison of the CBM availability forecasted in my Assessment and the latest NEB forecasts are shown in Figure 14. The NEB Fortified Islands scenario is extremely optimistic and includes natural gas supply from Newfoundland, Deep Nova Scotia, and unconventional sources.



Q41. Would you please describe another of the nonconventional gas supply sources in Canada -- gas shale?

A41. There are over 35,000 producing gas shale wells in the United States, from Texas to Ohio and West Virginia, with a current production of about 600 Bcf per year. There is little, if any indication that gas shales in Canada have similar producible characteristics to those in the U.S.

Technical and non-technical issues for assessing the resource potential are somewhat similar to that for CBM. These include a lack of production test data, need for natural fractures and less formation heterogenity. Only a very small percent of GIP resource could, in any event, be developed. Even within that developable area (natural fractures, etc) only a very low recovery factor would be appropriate.

Gas producing shale formations are not new to Canadian producers. Historically, many wells with deeper target formations penetrate the gas shale formations. Many gas producing wells also produce from the shale formations. Thus shale gas volumes are included in the forecast of the availability of gas from the WCSB found in the assessment.

Q42. Would you please describe another of the potential nonconventional supply source -- tight gas sands?

A42. The WCSB has many potential tight gas zones, especially on the western, deeply buried side of the basin. Gas pool areas with tight gas potential have already produced conventionally, however, the line separating conventional and nonconventional reserves and resources is not sharp. These fields or units have both a conventional and nonconventional component.

There is very little public data for assessing deep basin centered gas, such as detailed information on well fracture stimulation treatments. Further, Canada does not have a specific definition (for regulatory purposes) of tight gas. Because of the difficulty and potential confusion in terms associated with tight gas resources, efforts to separately quantify tight gas with WCSB runs the risk of double counting resources.

The Canada Gas Potential Committee (CGPC) assessment does not distinguish between conventional and tight gas. Its estimates include potential tight gas pools, as well as higher permeability pools. Therefore, tight gas potential in the WCSB may be largely captured in the conventional exploration plays assessed by the CGPC, EUB and NEB. For example, historically 50 percent of WCSB gas wells undergo fracture stimulation (frac job) indicating relatively low permeability. These wells account for 25 percent of new gas production. Thus, tight gas is included in the forecast of the availability of gas in the WCSB as shown in the Assessment.

Q43. Are there other methods you could have relied upon to determine the gas resources available, which would have produced better results?

A43. While other methodologies could have been used, in my opinion, the Assessment represents the most reasonable method of estimating the size and characteristics of the WCSB's gas resource base.

Q44. Why did you reject such other potential methodologies?

A44. Projections of gas production must consider only that portion of the ultimate resource that can reasonably be expected to be delivered to markets. Analyses that do not recognize constraints, such as: surface location restrictions, the fact that not all pools below the surface will be discovered, and the economic realities of small pools; will over estimate the future supply availability and hence future natural gas production projections.

The purpose of depreciation is to recover investment over a reasonable period of time. I do not believe that it would be in the public interest to set a depreciation rate for PNGTS based upon highly uncertain future sources of gas supply availability. Therefore, it would be unreasonable to include in the economic life evaluation uncertain and speculative gas resources.

Q45. How did you determine that the end of the economic life would be most reasonably represented by a 30-year period, from the beginning of 2008?

A45. The economic life analysis was conducted using three gas supply scenarios: Scenario A includes WCSB plus Mackenzie pipeline gas and 3 Canadian LNG projects; Scenario B includes WCSB plus Mackenzie pipeline gas and 6 Canadian LNG projects; and Scenario

C includes WCSB plus Mackenzie pipeline gas, 6 Canadian LNG projects and an Alaskan gas pipeline project. The end of the economic life of 30 years is based upon the following factors:

- My analysis of the amount of gas available from all Canadian sources- WCSB gas supply, Nova Scotia supply, Mackenzie Delta and LNG, combined with expected Canadian domestic demand, indicates very limited ability to export gas to the Lower 48 states as time progresses
- Under Scenarios A and B, the amount of exportable Canadian gas decreases to zero in 30 years
- Only in Scenario C, which includes the potential for the construction of an Alaskan natural gas pipeline that will connect to Canadian natural gas pipelines, is the major reduction in exportable gas mitigated, but only partially. Even in Scenario C the amount of gas being exported across the Canadian border in 30 years is 50 percent lower than today's volumes.
- A high degree of consensus that the WCSB will be a declining source of conventional natural gas supplies – *e.g.*, current declines in size and productive availability.
- No proven method of economically accessing the vast majority of WCSB unconventional gas supplies *e.g.*, CBM, tight gas and shale gas.
- Uncertainty concerning whether an Alaskan natural gas pipeline will be constructed given escalating pipeline construction costs, environmental concerns and costs, the resistance of North Slope producers to commit natural gas reserves to an open-access, independent natural gas pipeline supported by Governor Palin

of the State of Alaska, and the decades-long history of an inability to bring an Alaskan natural gas pipeline to fruition, despite the occurrence of at least 4 energy crises during the period (i.e., 1973-74, 1979-80, 1990-91 and the present).

Q46. What is the effect of declining natural gas supplies available for shipment on pipeline facilities?

A46. As future natural gas supply from the WCSB declines, significant amounts of pipeline facilities become underutilized and the pipeline's transportation rates increase as the cost of service is recovered over lower billing determinants. Specifically, the Assessment indicates gradual, yet steady and significant decreases in the supply of gas from the WCSB area over the period 2008 to 2037. This decline in production directly affects the utilization of PNGTS' mainline transmission facilities. My analysis of the Western Canadian natural gas supplies and Canadian natural gas demand indicates, under Scenarios A and B, that, by the year 2036, natural gas volumes available for export in the WCSB supply region, including Mackenzie Delta, as well as coalbed methane and LNG will have decreased to approximately zero. And, in 20 years, that supply region will not produce enough gas to satisfy Canadian domestic demand needs. Such fall-offs in the availability of natural gas from Canadian gas supplies will affect the utilization of PNGTS' mainline facilities. The forecasted level of exports as determined herein is shown on Schedule Nos. 7, 8, and 9 of Exhibit No. PNG-15.

Q47. What are the results of your analysis of the economic life of PNGTS' present facilities?

A47. As a result of my analysis of PNGTS' system operation, the nature of its markets, and the gas supply comprising its throughput, I determined the economic end life to be 30 years.

This conclusion is based upon underutilization of certain of its facilities (major retirements) due to depletion of its traditional gas supply sources. It is also due to the uncertainty of market retention due to competitive pressure from other sources.

Q48. What are major retirements, and how do you conceptualize them with respect to the economic life?

A48. Major retirements are severely underutilized facilities due to economic forces (rather than physical forces), such as gas supply depletion causing underutilization and changes in system operations.

Q49. How did you determine 23 years as the average remaining economic life for PNGTS' pipeline facilities?

A49. I determined major underutilization that would take place along PNGTS' system from the results of my gas supply study. The results are shown on Schedule Nos. 10, 11, 12, and 13 of Exhibit No. PNG-15. Basically, I established candidates for retirement in direct proportion to the decline in availability. I performed the calculations for each supply area and how they would affect the pipeline system.

Q50. How did you determine these major retirements caused by underutilization?

A50. I determined the effect that the combined supply areas would have on PNGTS' facilities by assuming that the percentage decline in supply would result in underutilization of PNGTS' facilities at the same extent as other pipelines exporting volumes from Western Canada. My analysis calculates retirements or candidates for major retirement from underutilization of pipeline facilities based upon the decline in gas availability. My analysis is very conservative given the unique risk of the PNGTS system, because in reality, supplies to PNGTS may decrease disproportionately to the availability of supplies to other pipelines that have closer direct access to the WCSB.

The projected economic life reflects the projected underutilization of PNGTS' facilities due to declines in throughput. It is not necessary that an actual physical retirement take place in order to qualify a facility as underutilized in the determination of the economic life of the PNGTS system. Fairness and intergenerational equity support the concept of projecting declines in throughput to establish permanent underutilization as a part of calculating economic life. Intergenerational equity is nothing more than directly relating cost responsibility to those shippers who will use the pipeline facility. For example, when a compressor unit or a loop line is no longer used on a regular basis, other than for repair or emergency purposes, it should be fully accrued (depreciated). However, such a facility may linger in service for a period of time as an emergency back up; it may be put in mothball status waiting for the appropriate time to physically retire the facility when abandonment is formally approved; or it may simply not be used because it is a component of a larger facility, a portion of which is still used and useful.

Referring to the cost responsibility concept, one objective in depreciation is that one generation of ratepayers should not pay an inequitable portion of depreciation with respect to another generation of ratepayers.

Q51. Does underutilization or major retirements actually take place in the gas pipeline industry?

A51. Yes. It is my experience, in analyzing the operation and actual retirements of pipeline properties that such situations have occurred. In market areas, loss of customer base causes underutilization and eventual retirement from such economic forces. In supply areas, depletion of gas reserves and competition are typical causes of underutilization and eventual retirement. For example, on March 9, 2000, Trunkline Gas Company, after exhibiting underutilization on its south Louisiana to Tuscola, Illinois mainline system, retired an entire 700-mile loop line. As another example, Trans-Northern Pipelines Inc. was granted abandonment authority by the NEB for its entire Don Valley Lateral to Toronto Harbour. That decision was made as the facility was in a “serious deficit position” due to reduced throughput. Further, offshore Gulf of Mexico facilities are constantly being retired.

Q52. Are there any other specific examples of major retirements related to supply or throughput deficiencies?

A52. There are other examples of major retirements. Due to decreasing gas availability, Florida Gas Transmission Company (Florida Gas) retired, and sold for a fraction of their original cost, major South Texas Gulf Coast production area pipeline and compressor facilities, including (1) pipeline facilities located south of its Compressor Station No. 2, and (2) pipeline facilities and Compressor Station No. 2, both located south of Station No. 3 and the Matagorda Offshore Pipeline System interconnect.

CenterPoint Energy – Mississippi River Transmission Corporation (MRT) (Docket No. CP04-334-000) abandoned 307 miles of 22-inch diameter mainline and other equipment such as compressor engines, including both old and more recent vintage facilities. This facility was underutilized.

Q53. How should we assess intergenerational fairness?

A53. Long-term fairness, specifically, minimizing or avoiding intergenerational inequities in the consumption of service value (depreciation), is important. Any unnecessary deferral of recovery of invested capital, unfairly burdens future shippers with the costs associated with this deferred recovery of depreciation. Therefore, as much as possible, the consumption of pipeline service value should be estimated over a reasonable service life. Thus, as facilities become underutilized due to declining throughput, a depreciation rate which does not take such declines into consideration would result in inequitable treatment of future ratepayers, as the unit cost of depreciation would be many times higher than that for current ratepayers. The Court of Appeals for the District of Columbia in the landmark Memphis decision on depreciation emphasized, "Even assuming continued serviceable life, declining use of pipeline facilities might conceivably lead in future years to depreciation dollars per unit of gas so high as to be unreasonable." Memphis Light, Gas and Water v. FPC, 504 F.2d 225, 234 (D.C. Cir. 1974). If PNGTS' primary depreciation rates remain approximately the same as its current rates, further deferral of the recovery of invested capital will either increase costs to future users of the system in contradiction of the teaching of Memphis, or expose PNGTS to potential under-recovery.

Q54. Do any other pipelines that rely upon WCSB gas supplies employ 25 to 30 years as the economic life to determine depreciation?

A54. Yes, as I have already discussed, in a 2003 decision the NEB set TransCanada's depreciation rates based on a 25-year remaining economic life. The NEB adopted TransCanada's analysis that determined that 2027 was the end of the planning horizon based on three factors: (1) the decline in throughput on the Mainline to 50% of system utilization; (2) the mid-point of the period during which the majority of the Mainline's facilities will be retired; and (3) industry practice. The NEB decision also stated:

> (T)he Board is of the view that a 25-year economic planning horizon is more in line with the planning horizons used by competing pipelines. To require the Mainline to operate under a proposed 30-year (CAPP) or 35-year (FSG) planning horizon could be unfair to the Mainline, as it may place it at a competitive disadvantage should competing pipelines be fully depreciated sooner than the Mainline. **(RH-1-2002, page 34, July 2003)**

The Straight Line Remaining Life Approach

Q55. How did you apply the 23-year economic life to the depreciation model?

A55. The 23-year economic life plays a key role in the determination of the average remaining life ("ARL"). It represents the average year of the final recoupment of PNGTS' investment in its facilities as an overall group. The best way to describe the relationship of the economic life to the ARL is to overlay it with the normal retirement survivor curve.

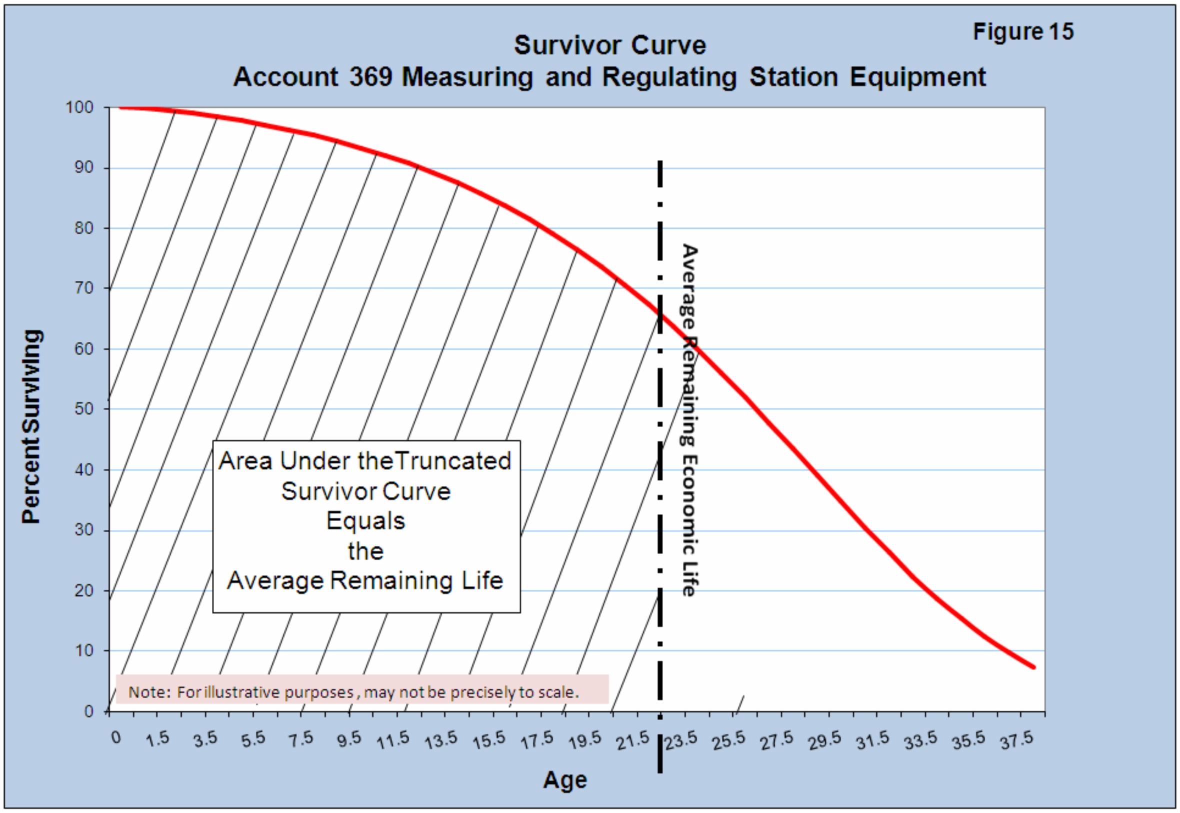
Q56. How did you determine the normal retirement survivor curve?

A56. The survivor curve represents the pattern of annual normal retirements that will occur over time for property of a certain character. I determined the normal retirement curve for each of PNGTS' transmission accounts. For example, I determined that Account 367 (Mains) has an average service life of 60 years, with an R_3 survival pattern. Mains make up about 85 percent of PNGTS' mainline transmission system. My analysis began with an Iowa-type survivor curve determination utilizing the Simulated Plant Record (SPR) method, which with adequate data allows derivation of a survivor curve based upon historical retirements. Another method of determining a survivor curve from historical plant data is the actuarial method, based upon the assembly of historical retirements categorized by the year in which facilities first went into service. The SPR method establishes a survivor curve based upon the curve which best compares to the actual plant retirements and surviving plant balances. A survivor curve developed from historical retirements is only as good as the underlying data. For example, heavy reliance on the shape and average service life of a "stub curve" would not be prudent. A "stub curve" may represent only 10 percent as the amount of plant retirement experience. This is not enough from which to conclude a specific curve. In such cases, I also rely upon an analysis of the type of equipment, its usage and condition, as well as its age and survivor curve retirement patterns that are typical in the industry of such facilities. For the Mains account, the 60 R_3 survivor curve is shown on Schedule No. 14 of Exhibit No. PNG-15. I determined the survivor curve and resulting average service life which best applies for each of the other accounts as follows:

Account No.	Description	Average Service Life	Survivor Pattern
365.2	Rights-of-way	60	R_5
366	Structures	45	R_5
369	Meas. & Reg. Sta. Equip.	21	S_5
370	Communication Equip.	15	S_5
371	Other Transmission Equip.	10	R_2

Q57. What is the next step in your analysis?

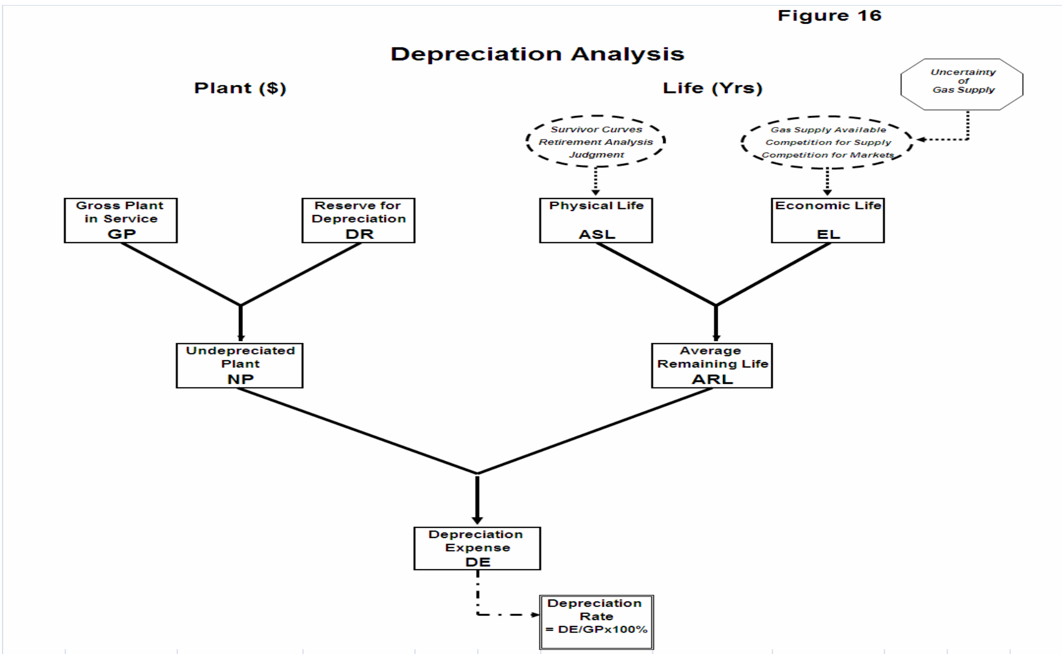
A57. When the economic life is applied to the survivor pattern, future normal retirements beyond 23 years are not relevant. The ARL is determined by integrating or calculating the area under the truncated survivor curve. This calculation is shown in conceptual form in Figure 15 below.



For the transmission mains, the ARL was determined to be 22.1 years. The ARL for all accounts is summarized on Schedule No. 15 of Exhibit No. PNG-15.

Q58. What is the next step in the process?

A58. After determining the individual ARLs for each account, one would then divide each ARL into the difference between the depreciable plant and the accumulated reserve for depreciation, thus arriving at the indicated depreciation expense. The indicated depreciation expense for each account would be totaled, producing the indicated depreciation expense. I performed this operation for 2008, as shown on Schedule Nos. 16 through 19 of Exhibit No. PNG-15, for the available Canadian export scenarios. Schedule No. 20 of Exhibit No. PNG-15 shows the depreciation rate when both Canadian volumes as well as Lower 48 volumes that may become available at Dawn, Ontario are used to determine the economic life. The indicated depreciation rate for PNGTS' transmission plant is 3.53 percent. It is based on the above combination of Canadian export scenarios and the forecasted volumes of Rocky Mountain, Midcontinent and Gulf Coast that may become available at Dawn, Ontario. The procedure in determining the depreciation rate is illustrated in the diagram shown below in Figure 16.



Depreciation Rate for General Plant

Q59. What accounts make up the general plant?

A59. The general plant is made up of the following accounts:

Account No.	Description
391	Office Furniture & Equip.
392	Transportation Equipment
393	Stores Equipment
394	Tools, Shop and Garage Equip.
397	Communication Equipment
398	Miscellaneous Equipment
399	Other Tangible Equipment

Q60. Please explain how you determined the average service life and why you made a separate determination for each individual account.

A60. I determined the appropriate average service life that best applies to each type of equipment in the individual accounts. These lives, along with their respective depreciation rates, are shown on Schedule No. 26 of Exhibit No. PNG-15. These average service lives were developed based upon analysis of the properties in each account. My analysis was also based on discussions with PNGTS personnel, as well as the experience of similar properties of other pipeline companies. The determination of the above depreciation rates differs from the mechanics employed for the transmission plant. Because of the high turnover rate of the facilities in the general plant, the whole life method was used to determine depreciation instead of the remaining life method.

Q61. Would you please summarize your depreciation testimony?

A61. I have calculated rates of depreciation for the depreciable facilities belonging to PNGTS, analyzing the tangible properties and operations of its pipeline system and estimating its average remaining life. I concluded that the economic end life of PNGTS' pipeline system is 30 years. I developed a depreciation rate of 3.53 percent for transmission plant and a total composite depreciation rate of 3.59 percent. Further, I determined a separate rate of 0.32 percent to cover the accrual for negative salvage expense.

Negative Salvage Rate

Q62. Please explain the term negative salvage.

A62. Negative salvage is the net amount of funds necessary to retire a specific facility or group of facilities. It is the difference between the gross salvage, if any, and the cost of removal. Gross salvage may be in the form of value of the facilities stored in a warehouse for reuse or the proceeds from a sale of such facilities.

Q63. What is a negative salvage rate?

A63. A negative salvage rate is the annual rate, as a percent of the gross plant subject to retirement that will accrue enough funds in an orderly and fair manner to cover the cost of retirement. I used the same straight line remaining life method that I employed to determine the depreciation rates to accrue negative salvage funds.

The negative salvage rate reflects the future obligation of decommissioning when the plant is retired. Like depreciation, the cost of retiring facilities is a legitimate cost of doing business. It is both reasonable and necessary for the ratepayers who are receiving service from these facilities to fund the costs of retirements through negative salvage depreciation rates. To ensure that an adequate reserve will be on hand to decommission the facilities when they are retired, and to restore the land to its original condition, PNGTS should collect such an amount in rates over the estimated remaining useful life of its plant. Failing to include such an expense in current rates will force a subsequent generation of ratepayers to subsidize service provided to current ratepayers.

Furthermore, a negative salvage allowance requires current ratepayers to pay the full cost of using these facilities by bearing their fair share of these costs.

Q64. In your view, will PNGTS' facilities eventually be decommissioned?

A64. PNGTS' pipeline facilities will have to be decommissioned. Pipeline facilities eventually wear out, become obsolete or uneconomic. Gas supply and facility utilization studies reflect retirements that occur due to specific pipeline facilities becoming obsolete, redundant or otherwise unnecessary. At some point, each pipeline reaches the end of its economic life. These facts are demonstrated by my plant retirement and survivor curve analysis, which reflects retirements due to physical causes, and by my earlier discussion that shows specific examples of retirements of facilities by other pipelines.

Q65. Did you build negative salvage allowance into your depreciation calculations?

A65. No, I did not. I treated negative salvage separate from the depreciation calculation.

Q66. Please explain how you calculated PNGTS' recommended negative salvage rate?

A66. The determination of net negative salvage for pipelines in general and PNGTS in particular is a two part study. There are two types of facility retirements for the purpose of this study: interim retirements and terminal retirements. The cost of removal and gross salvage value differ for each type.

A terminal negative salvage ("TNS") study encompassing PNGTS' pipeline system facilities was prepared by PNGTS witness Taylor. In addition to Mr. Taylor's study, a determination was made of the cost of removal of interim retirements that will take place during the service life of the pipeline system. The difference between the two studies is that Mr. Taylor's TNS study determines the decommissioning cost (in current dollars) of PNGTS' entire pipeline system, considering today's facilities in service; while the study of the cost of removal of interim retirements reflects the cost of retiring plant that will not be in service at the TNS point in time. Based on the analysis of interim retirements, and their related cost of removal, along with a TNS study performed by Mr. Taylor, a composite transmission plant net negative salvage rate was determined to be 0.32 percent. This rate is in the form of an annual percentage rate applied to the transmission plant in service.

Q67. Can you describe the mathematical calculations used to determine the negative salvage rate?

A67. Schedule No. 21 of Exhibit No. PNG-15 shows the summary of Mr. Taylor's TNS estimate. Schedule No. 22 of Exhibit No. PNG-15 shows the determination of the negative salvage for interim retirements along with its average remaining life. The negative salvage cost for interim retirements reduce Mr. Taylor's TNS estimate as these retirements will take place before the final closure (TNS). The reduction in the TNS estimate is shown in Schedule No. 23 of Exhibit No. PNG-15. The composite negative salvage cost and average accrual period – adjusted TNS and interim retirements is shown in Schedule No. 24 of Exhibit No. PNG-15. Finally, the composite negative salvage rate is calculated by dividing the estimated amount of negative salvage by the average remaining life of 22 years. I then divided that quotient by the transmission plant in service to arrive at 0.32 percent.

Q68. How do you recommend net salvage be reflected for accounting purposes?

A68. I recommend that PNGTS establish a sub-account for negative salvage in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant, which allows the negative salvage reserve to be reviewed periodically and separately with ease.

Q69. Based on your analysis, what did you determine PNGTS' net negative salvage for each dollar of plant retired to be?

A69. I expect that PNGTS' will average approximately 7 percent net negative salvage for each dollar of plant retired.

Short-term Services

Q70. Please describe PNGTS' proposal to implement rates for short-term services?

A70. PNGTS has asked me to review its proposal, as presented by PNGTS witness Haag, to implement rates for short-term services, capped at 250% of the long term firm recourse rate, for transportation customers contracting for service for less than one year, and to assess whether the proposal is consistent with the FERC's current regulatory goals and policies.

Q71. What did you conclude?

A71. I conclude that PNGTS' short-term rate proposal is fully consistent with the FERC's goals and policies and is in the public interest.

Q72. What Commission goals and policies have you analyzed in reviewing PNGTS' short-term rate proposal?

A72. I have reviewed the evolution of the Commission's policies regarding short-term, seasonal and peak/off-peak rates for interstate natural gas transportation services. Relevant Commission Orders include Order No. 637 and the Commission Policy Statement on Alternatives to Traditional Cost-of-Service Ratemaking (Policy Statement). *See*, Order No. 637, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 and Policy Statement and Request for Comments, Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation

Services of Natural Gas Pipelines, Docket Nos. RM95-6-000 and RM96-7-000, January 31, 1996, 74 FERC ¶ 61,076.

Q73. Please explain the evolution of the Commission's policies regarding alternatives to cost-based rates.

A73. Commission policy has promoted the evolution of competitive, efficient markets and market-based rate principles in natural gas markets over traditional regulation and strict adherence to cost-based rates. Over the past 20 years, the Commission has focused on increasing competition and creating viable competitive markets in the natural gas pipeline industry. The Commission issued a number of key orders: Order No. 436, Order No. 636, the Policy Statement, Order No. 637, and Order No. 678, Rate Regulation of Certain Natural Gas Storage Facilities in Docket Nos. RM05-23-000 and AD04-11-000. The latter order provides storage providers with increased opportunities to obtain market-based rate approval and broadens the Commission's definition of the relevant product market for storage. The Commission has approved market-based rates for a large number of natural gas storage companies and two natural gas transmission pipeline companies. Currently, the Commission is considering removal of the rate cap on short-term capacity release transactions in Docket Nos. RM06-21 and RM07-4. A number of natural gas pipeline industry participants have urged the Commission to consider removing the rate cap on all short-term transactions, including short-term firm pipeline capacity, interruptible capacity and short-term capacity release transactions.

Q74. Please provide a brief history of the Commission decisions that have implemented alternative pricing and market solutions in the natural gas pipeline industry.

A74. In 1985, the Commission laid the foundation for the open-access, competitive interstate natural gas pipeline transportation system that we have today by issuing Order No. 436. Order No. 436 encouraged natural gas pipelines to transport natural gas on behalf of entities that did not own the pipeline in a manner that was not unduly discriminatory. Local distribution companies were then allowed to contract and purchase their own natural gas supplies and transport those supplies on an open-access natural gas pipeline. Previously, a local distribution company was required to purchase its gas supply from an interstate pipeline company. The effect of Order No. 436 was to open up the interstate pipeline grid, providing competition among pipelines, developing market centers and gas trading hubs, and creating a more efficient and dynamic natural gas supply market. With regard to competition among alternative gas suppliers, producers and marketers almost immediately began to complain that the policies implemented by pipelines favored the transportation of pipeline-owned supplies over the transportation of third-party supplies. Interstate pipelines were still selling a bundled gas transportation and sales service that some customers believed favored the transportation of the pipelines' own gas supplies. Persistent concerns about whether consumers were able to access gas supplies on comparable terms eventually led to the issuance of Order No. 636 in 1992.

Q75. What was the goal of the Commission in issuing Order No. 636?

A75. The Commission stated that its goal in issuing Order No. 636 was to create a national gas market in which consumers and producers could meet anywhere on the pipeline grid to transact most efficiently. To that end, the Commission stated that, for an efficient national gas market to develop, transportation must be on comparable terms and the true cost of transportation must be reflected in the delivered cost of gas. To achieve its goal, the Commission, among other things, required pipelines to eliminate bundled sales service and to allow customers to convert their sales entitlements to transportation entitlements. Pipelines were also required to use the straight-fixed-variable method of designing rates. These elements were required, the Commission stated, to ensure that customers enjoyed equal access to natural gas supplies anywhere on the national pipeline grid.

Q76. When did the Commission issue its Policy Statement?

A76. The Commission issued its Request for Comments on Alternative Pricing Methods on February 8, 1995, and the actual Policy Statement on January 31, 1996. In the Policy Statement, the Commission stated that it would allow natural gas pipeline companies to charge market-based rates for transportation services if the pipeline could demonstrate that it did not have market power over transportation rates.

Q77. What was the next major step taken by the Commission to promote more efficient price signals for natural gas pipeline transportation markets?

A77. The Commission issued Order No. 637 in 2000. In Order No. 637, the Commission approved the concept of using peak/off-peak, or seasonal rates for pipeline services to improve efficiency in the marketplace by allowing regulation that (1) accounts for seasonal demand for capacity, while at the same time, (2) protecting and benefiting long-term captive customers (see, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,287). The Commission permitted pipelines to institute peak/off-peak rates for all short-term services (i.e., short-term firm and interruptible service and multi-year seasonal contracts) as one possible method of promoting allocative efficiency while still protecting customers from the possible exercise of market power.

Order No. 637 Addresses Potential Problems Associated with Short-Term Contracts, Decontracting and Discounting

Q78. What potential problems did the Commission attempt to address in Order No. 637?

A78. The Commission focused on two major issues. First, in 2000, the Commission was clearly concerned that some traditional LDCs and end users were decontracting with their natural gas pipeline transporters and moving to short-term firm contracts and interruptible contracts, thereby shifting the recovery of additional fixed pipeline costs onto the remaining long-term firm recourse rate customers. Second, shorter-term contracts were often discounted and the cost of the discounting was often passed on to the remaining long-term firm recourse rate customers. To address the problems the Commission identified, pipelines were allowed the opportunity to increase their revenue recovery from short-term services. The Commission in Order No. 637 stated at ¶ 31,091 at 31,288:

> Peak/off-peak rates could allow pipelines to increase revenue recovery from short-term peak period shippers. Increased cost recovery from peak short-term services lessens the level of costs that need to be recovered from long-term customers and minimizes the cost shifting that occurs with off-peak discounting. By reducing the rates in the off-peak periods, peak/off-peak rates could reduce the need for discounts and reliance on discount adjustments …. Peak/off-peak rates could better reflect the value of capacity during peak and off-peak periods, thereby reducing the need to make discount adjustments.

Q79. What is the Commission's current discount policy?

A79. The Commission recently reaffirmed its discount policy (See Order Reaffirming Discount Policy and Terminating Rulemaking Procedure in Docket No. RM05-2, issued May 5, 2005). The Commission stated that it would continue to allow a discount adjustment for pipelines in designing their maximum firm rates. However, the Commission has recognized that the discount adjustment reduces total firm billing determinants and shifts costs to captive customers. (I will discuss this issue later in my testimony).

Based on similar considerations, in Order No. 637, the Commission stated that peak/off-peak rates could allow pipelines to increase revenue recovery from peak period, short-term shippers. Such increased cost recovery from peak short-term services would lower the level of costs that need to be recovered from long-term customers and minimize the cost shifting that occurred with off-peak discounting. By reducing the rates in the off-peak periods, peak/off-peak rates could reduce discounting and reliance on discount adjustments. The Commission clearly recognized that peak/off-peak rates would better reflect the value of capacity during peak and off-peak periods, again reducing the need for discount adjustments. The Commission in Order No. 637 has stated at ¶ 31,091 at 31,287:

> Use of peak/off-peak, or seasonal, rates for pipeline services could improve efficiency in the market place by better accommodating regulation to seasonal demand for capacity, and at the same time could benefit long-term captive customers. Therefore, as discussed below, the Commission will permit pipelines to institute peak/off-peak rates for all short-term services, *i.e.*, short-term firm and interruptible service and multi-year seasonal contracts, [footnote omitted] as one possible method of promoting allocative efficiency that is consistent with the goal of protecting customers from monopoly power.

Q80. How did the Commission define its regulatory objectives in Order No. 637?

A80. In Order No. 637, the Commission clearly restated its regulatory responsibility under the Natural Gas Act: to ensure that pipeline rates and services are just and reasonable and not unduly discriminatory. The Commission recognized that just and reasonable rates and services need to be designed to achieve two principal objectives. They should promote competitive and efficient markets, while mitigating market power and preventing undue discrimination, especially for the Commission's "prime constituency, captive customers vulnerable to pipelines' market power."

Q81. Why has the Commission been so concerned with protecting long-term firm captive customers?

A81. The Commission clearly recognized in Order No. 637 that the long-term firm captive customers currently pay the maximum recourse rates for transportation capacity during peak and off-peak periods and the fixed costs of the pipeline while the short-term customers benefit by paying lower market prices during off-peak periods reflecting the reduced demand on the pipeline. Yet, the short-term customers are not subject to the competitive market rate for capacity during peak periods because the rate is capped by the recourse rate. In reality, since short-term shippers pay a discounted rate during off-peak periods, they do not pay an equivalent share of the fixed costs of the pipeline for their MDQ. The Commission recognizes that, under such conditions, higher short-term rates for peak periods are appropriate and the general reallocation of revenue responsibility among the customer classes could be done in the Section 4 rate case proceeding, when the pipeline seeks to implement its short-term rate proposal.

Q82. Have other interstate pipeline companies utilized the Commission policy elucidated in Order No. 637 and filed for and/or been granted higher short-term rates than their long-term recourse rates?

A82. Yes. The Commission approved a settlement in the Texas Gas Transmission, LLC proceeding in Docket No. RP00-260 that allowed for higher peak winter demand rates for short-term services with no revenue sharing requirement. On September 18, 2006, Northern Border filed a settlement with the Commission in Docket No. RP06-72 that permits Northern Border to charge higher short-term firm and IT rates on a monthly basis, with no revenue sharing requirement. The Commission recently approved a settlement in Docket No. RP06-407 that allows Gas Transmission Northwest Corporation to charge higher short-term firm and IT rates on a monthly basis.

PNGTS Proposal

Q83. Please describe PNGTS' short-term rate proposal?

A83. PNGTS witness Haag is sponsoring the PNGTS Tariff Sheets which reflect PNGTS' proposal to charge a maximum rate for short-term firm service ("STF"), interruptible service ("IT"), and park and loan service ("PAL") that is equal to 250% of the maximum reservation component of the recourse rate that applies to long-term firm service, plus the applicable commodity component.

Q84. How has PNGTS ensured that its proposal to charge short-term rates, capped at 250% of the long-term firm recourse rate, is within the guidelines of Order No. 637?

A84. As explained in the direct testimony of PNGTS witnesses Haag and Reed, PNGTS faces a significant and non-transitory decontracting issue caused by (a) a lack of demand for its transportation services and (b) other numerous good alternative sources of natural gas supply in its primary destination market. As shown in PNGTS witness Haag's testimony, PNGTS has total annualized firm contract demand as of the end of the test period that is at least one-third less than the 210,000 Mcf/d that PNGTS has used to derive rates in this proceeding. Therefore PNGTS' customers are only paying for their own contracted and reserved capacity on the PNGTS system.

As described by PNGTS witness Reed, PNGTS is faced with difficult market conditions. Nonetheless, PNGTS is proposing a reservation charge crediting mechanism to benefit its long-term firm customers, within the guidelines of Order No. 637. See PNGTS First Revised Tariff Sheet Nos. 204 and 205 - Rate Schedule FT Reservation Charge Crediting Mechanism.

Q85. Please explain the justification for potentially higher rates for short-term services on PNGTS in greater detail?

A85. First, to the extent that PNGTS is allowed to charge higher short-term rates, as Commission Order No. 637 allows, PNGTS may see an increase in the total amount of revenue from short-term services. PNGTS may be able to charge higher short-term rates on higher demand days than would be possible if the short-term rates remain capped at the long-term recourse rates for the non-winter period. Natural gas pipeline companies are very capital intensive and, given the large fixed costs of pipeline infrastructure investments, it is unlikely that pipeline company management will make investments in pipeline facilities if they are unable to recover some of their fixed costs in longer-term firm contracts. This proposal is expected to increase the recovery of fixed costs from all transportation contracts.

Second, higher short-term rates may contribute to satisfying the overall revenue requirement of PNGTS, and a portion of these revenues may lower the net revenue contribution from its long-term firm shippers. The third benefit is that to the extent that short-term rates are determined by market conditions, higher rates for short-term services will provide more efficient price signals on the short-term value of PNGTS pipeline capacity. Pipelines and their customers carefully monitor the capacity release and short-term markets for daily price information about capacity. To the extent that prices rise in these daily markets, it will encourage end users and LDCs to sign up for longer-term firm contracts instead of speculating that they can meet their peak demand requirements through a combination of IT, capacity release, and short-term services. The Commission clearly recognizes that, in competitive markets, price efficiently allocates capacity to customers that value it the most. This should also be the case for short-term service on PNGTS.

Q86. Are short-term shippers treated unfairly?

A86. No. Short-term transportation customers can continue to rely on shorter-term contracts rather than contracting for the same MDQ twelve months of the year. That is, short-term customers take none of the risk of holding pipeline transportation capacity over the long term. For instance, they do not assume the risk of holding capacity when demand is weak and they retain the options of purchasing alternative transportation capacity in the capacity release market from a firm shipper or IT capacity from PNGTS. Yet, short-term customers can still contract with PNGTS to purchase long-term firm capacity and pay the long-term firm recourse rate, thereby limiting their exposure to short-term market conditions that may determine a higher price for short-term service.

As explained in PNGTS witness Reed's testimony, PNGTS has one of the highest cost transportation routes to the Boston market. Short-term shippers can utilize a number of less expensive transportation paths to the Boston market than PNGTS, such as the Tennessee system or the Algonquin system. The existence of these good alternative pipeline transportation paths will thereby limit the potential for PNGTS to charge higher short-term rates.

Moreover, implementation of PNGTS' short-term rates will enable shippers who most highly value the capacity on a short term basis to reflect that assessment when basis differentials are higher, at any time of the year. Markets served by PNGTS generally experience two peak periods: a limited period during the summer when electric demand is higher than average and natural gas-fired peakers are burning gas and during the winter when heating load is higher than average. PNGTS is requesting authority to charge short-term rates for service when market conditions cause the value of PNGTS' transportation capacity to increase on any particular day of the year. As such, it would not make sense to design traditional seasonal rates that would limit PNGTS' ability to capture (non-seasonal) upward swings in capacity value, including provision of such available capacity to the market that places the highest value upon that capacity.

Shippers electing to enter into long-term contracts will be able to utilize long term recourse rates. In addition, transportation customers will have to weigh their potential exposure to higher short-term transportation rates against the certainty provided by entering into long-term firm recourse rate contracts. Adding this element to the customer decision-making process can provide an additional impetus for signing long-term firm contracts.

Q87. What is an additional factor that the Commission should consider in determining whether to allow PNGTS to charge short-term rates?

A87. The evidence provided in this proceeding clearly indicates that there will be a significant and non-transitory oversupply of pipeline transportation capacity in the PNGTS market area. This excess capacity is detailed in the direct testimony of PNGTS witness Reed in Exhibit No. PNG-6. This excess pipeline capacity should moderate any potential for higher short-term transportation rates in PNGTS' delivery market. In addition, PNGTS witness Haag's testimony shows the value of transportation capacity on PNGTS has rarely exceeded 250% of FT rates (stated on a daily basis) over the past two year period.

Q88. Does the PNGTS proposal raise any market power concerns for short-term shippers?

A88. No. PNGTS does not have the ability to exercise market power under this proposal. First, there will be substantial future excess delivery capacity into PNGTS' market area, including pipeline and LNG supplies, meaning that PNGTS will face significantly greater competition going forward. Second, the existence of a vibrant capacity release market that competes directly for PNGTS' short-term customers will provide a good alternative source of transportation capacity and short-term customers would be able to avoid a price increase by taking capacity release, although FERC recently proposed to lift the rate cap on the capacity release market. Allowing the pipeline to compete on price for short-term capacity with the capacity release market will promote a more efficient market and allow buyers who value the capacity to obtain it. In addition, PNGTS' short-term pricing will have to compete with free off-peak capacity. As a result, there are numerous good alternatives to PNGTS' short-term services.

PNGTS' Proposal is consistent with Commission policy and economic principles

Q89. Does the Commission require a specific rate design for short-term rates?

A89. No. The Commission is very clear that no one specific method is required.

The Commission in Order No. 637 has stated at ¶ 31,091 at 31,291:

> The Commission will not adopt any one method of developing peak/off-peak rates, but will leave the details of implementation of peak/off-peak rates to individual pipelines.
>
> As illustrated by the comments, there is more than one reasonable way to implement peak/off-peak rates based on value of service concepts…The Commission will consider any reasonable method of implementation that is consistent with the general principles discussed in this section, but the pipeline will have the burden to show that its proposed method is just and reasonable.

Q90. Please relate your discussion of the Commission's efforts to rely on competition in its regulation of the gas industry to PNGTS' request to charge a rate for short-term transportation service that is capped at 250% of the long-term firm rate.

A90. The actions of the Commission, starting with Order No. 436, demonstrate that the Commission will rely on competitive market forces as often as possible, consistent with statutory mandates, in overseeing natural gas markets. These actions have resulted not only in competition in the gas commodity market, but have also resulted in increased competition in transportation pipeline paths between origin and destination markets. PNGTS currently faces a serious and fundamental set of problems, including the very low value of PNGTS' pipeline capacity that will result from excess interstate pipeline capacity in its New England service area, combined with decontracting by its traditional end-use customers and PNGTS customers taking service using short-term firm, interruptible and capacity release service. PNGTS is asking the Commission for the ability to recognize the changing value that markets put on locational differentials in its transportation markets and allow short-term shippers to pay the market value of pipeline capacity.

Q91. Are the short-term rates PNGTS is proposing consistent with the Commission's policy and rate design objectives?

A91. Yes. PNGTS' short-term rate proposal is wholly consistent with the pricing mechanisms contemplated by the Commission in Order No. 637, and Order No. 678, Rate Regulation of Certain Natural Gas Storage Facilities, issued June 19, 2006. In particular, Order No. 637 and Order No. 678 address the shortcomings of uniform cost-of-service rates and the cost recovery issues faced by pipelines such as PNGTS that are confronted with both decontracting and an increasing reliance by shippers on short-term and seasonal services. Short-term services are defined to include short-term firm service, interruptible service, and multi-year seasonal contracts.

The Commission supported pipeline implementation of seasonal rates in Order No. 637 on the basis that such rates promote several important policy goals. The Commission recognized that the use of such rates could (1) remove one of the biases favoring short-term contracts; (2) reduce the need for discounts and reliance on discount adjustments because short-term shippers will share more of the pipeline's costs; and (3) increase efficiency in short-term markets by allowing prices to better reflect demand during peak periods. The Commission in Order No. 637 stated at ¶ 31,091 at 31,288:

> Thus, peak/off-peak pricing for short-term services could promote several important policy goals. It could remove one of the biases favoring short-term contracts, and could lower the share of costs allocated to long-term transportation customers. It could increase efficiency in short-term markets by allowing prices to better reflect demand during peak periods. Therefore, as discussed below, the Commission will permit pipelines to implement value-based

> peak/off-peak rates for their short-term transportation services, within the pipeline's current cost-based revenue requirement.

PNGTS' short-term rate proposal accomplishes these same policy objectives.

In addition, the short-term rates that PNGTS is proposing are consistent with the stated objectives found in Part 284.10(b) of the Commission's regulations. Part 284.10(b) distinguishes peak and off-peak rates stating that rates for peak periods should be designed to ration capacity while rates for off-peak periods should be designed to maximize throughput. Short-term rates meet this objective by allowing the pipeline to charge more for short-term services during peak periods while allowing the pipeline to continue to discount rates during off-peak periods. In addition the Commission in Order No. 637 at 31,293 stated:

> [A] shorter term contract is riskier for the pipeline, and a higher rate would compensate the pipeline for this additional risk. A shorter term contract provides greater flexibility and less risk to the shipper, and a higher rate would recognize and require payment for these benefits.

Q92. Current Commission policy allows natural gas pipeline companies to charge higher short-term rates than their long-term firm recourse rate. What do you think of this policy in light of the current market fundamentals in New England?

A92. I think that this Commission policy helps address one of the major challenges facing the industry today. Considering the weak market fundamentals in the immediate future for the PNGTS gas transportation market, shippers can rely on short-term, capacity release and interruptible transportation services rather than long-term contracts. In the past, and particularly under SFV rate design, the majority of an interstate pipeline company's cost of service was recovered from long-term shippers, and most pipelines were either fully contracted or close to capacity at least on a peak day basis. New England markets are now characterized by excess transportation capacity and by customers that simply have no economic incentive to sign long-term contracts. It is also clear, given the level of surplus pipeline capacity and the stagnant natural gas demand in New England, that the ability to charge short-term rates in excess of the long-term firm recourse rate will promote allocative efficiency for short-term services.

Q93. Please summarize your conclusions regarding PNGTS' short-term rate proposal.

A93. Based on the evidence PNGTS has provided and the competitive environment in which PNGTS must operate, I conclude that: (a) PNGTS has correctly applied the Commission policy in Order No. 637; (b) the evidence provided by PNGTS' witnesses clearly indicates that PNGTS cannot raise the price of short-term rates above the existing recourse rate except on rare high demand days; and (c) the Commission should allow PNGTS to charge short-term rates for STF, IT and PAL capped at 250% of the long-term firm recourse rate for service on the PNGTS system.

Contractual Provisions and Business Risk

Q94. Please identify the unique contractual provisions that PNGTS entered into with its long-term shippers that are currently restricting PNGTS' ability to market its pipeline capacity?

A94. As described by PNGTS witness Haag, there are 3 contractual provisions that PNGTS entered into with its long-term firm customers that are currently restricting PNGTS' ability to market its pipeline capacity. These contractual provisions are the Most Favored Nations clause (MFN), Capacity Turnback Rights (CTR), and Off-Peak Transportation Rights (OTR).

Q95. What do you conclude about the impacts of these unique contractual provisions?

A95. The MFN clause prevents PNGTS from attracting new customers and hinders its ability to meet competitive market challenges from an expanding Maritimes system and other capacity expansions serving New England natural gas markets. CTR allows long-term firm shippers to turn back capacity. OTR allows long-term firm shippers the right to utilize any unsubscribed summer (May-October) capacity at no incremental cost. The net impact of these 3 contractual provisions is to limit the ability of PNGTS to derive additional revenues from its transportation service.

Competitive Circumstances in the Interstate Pipeline Business

Q96. Have you reviewed the list of proxy group members contained in Mr. Moul's testimony?

A96. Yes, I have.

Q97. Given the current unique marketing and operational challenges facing PNGTS, is it your opinion that PNGTS has business risks comparable to the entities represented in Mr. Moul's proxy group?

A97. No. PNGTS has unique marketing and operating characteristics that expose it to much greater business risk than is typically found in members of the proxy group.

Q98. Please explain.

A98. Most of the entities represented in the proxy group have one or more of the following characteristics:

a. They directly access one or more primary supply sources from which volumes available for transportation are projected to grow or at least remain roughly stable (e.g., the Rockies; shale production formations);

b. They serve markets with growing populations and/or with expected growth in natural gas demand (e.g., the southeast U.S., the desert southwest);

c. A much higher proportion of their capital investment in pipeline facilities has already been recovered:

d. They do not have a deferred depreciation regulatory asset to recover, but rather have collected a fair share of "current" depreciation from existing ratepayers.

Q99. Please contrast the situation generally faced by the proxy group pipelines with that of PNGTS?

A99. PNGTS' primary source of supply, namely the WCSB, faces a dramatic drop in exportable supplies, as described above in my testimony. Additional natural gas demand growth in PNGTS' market area is also limited. In fact, the population of PNGTS' market area is increasing very slowly (Massachusetts, Maine and New Hampshire experienced population growth of only 1.9% from 2000 to 2005 – U.S. Census Bureau). See Schedule No. 27 of Exhibit No. PNG-15.

Schedule No. 28 of Exhibit No. PNG-15 shows that the average level of capital recovery (percent depreciated) for the 30 major interstate pipelines is 47%. Although PNGTS is observing its tenth year of operations, it has recovered a far smaller portion of its capital costs than the industry average. PNGTS' capital cost recovery level is impacted by the deferred depreciation regulatory asset, which is a departure from the standard method of recovering depreciation in the industry.

Q100. Please summarize your conclusion regarding PNGTS' risk status relative to a typical pipeline owned by a proxy group member.

A100. In my experience in the natural gas pipeline industry I would rank PNGTS as the single riskiest pipeline I have ever analyzed. Given the documented problems in this testimony concerning WCSB future gas supply, the unique competition faced by PNGTS in its market area, and the level of unrecovered plant investment that will have to be recovered from future rate payers, PNGTS is facing an unprecedented level of risk that is much greater than the companies in Mr. Moul's proxy group, in my opinion.

Q101. Does that conclude your testimony?

A101. Yes, it does.

Appendix A

CURRICULUM VITAE

NAME	:	Barry E. Sullivan
HOME ADDRESS	:	2548 Lavall Court Davidsonville, MD 21035
EDUCATION	:	Bachelor of Arts Degree in Economics University of Massachusetts at Boston Graduate Work at University of York, England
PRESENT POSITION	:	President Brown, Williams, Moorhead & Quinn, Inc. 1155 15th Street N.W., Suite 400 Washington, D.C. 20005
NATURE OF WORK PERFORMED WITH FIRM	:	Mr. Sullivan joined the firm in September 2005. He was elected President of BWMQ in April 2006. Since joining BWMQ, Mr. Sullivan has filed expert witness testimony on market power in the GTN proceeding in Docket No. RP06-407, an expert report in the USGen proceeding in Docket No. RP06-391, and oil pipeline ratemaking testimony in the TAPS proceeding in Docket No. IS05-82. Mr. Sullivan has over 27 years of experience in the natural gas pipeline, oil pipeline and electric utility industries. His areas of expertise include formal market power analysis and all facets of natural gas, oil pipeline and electric utility ratemaking.
PREVIOUS EMPLOYMENT	:	Mr. Sullivan was employed by the Federal Energy Regulatory Commission from March 1979 to September 2005. He retired as a Supervisor in the Technical Analysis Division of the Office of Administrative Litigation. Mr. Sullivan was a technical expert for the entire 26 years he was at the Commission and provided testimony in many formal proceedings. The areas of his expertise included: formal market power analysis, market based rates, cost allocation and rate design, oil pipeline regulation, electric utility regulation, depreciation, Mcf/mileage studies, refunctionalization studies, offshore regulation, negotiated

rates, discount studies, and other regulatory issues. Mr. Sullivan has applied his expertise relating to natural gas pipeline, oil pipeline and electric utility issues in a wide range of formal proceedings at the Commission. He has developed many creative and innovative approaches to deal with these and related issues in administrative proceedings at the Commission.

As a Supervisor in the Office of Administrative Litigation, Mr. Sullivan supervised, initiated, directed and coordinated the preparation and presentation of the Commission's technical Trial Staff's settlement and testimony position on all matters set for formal hearing in natural gas pipeline, oil pipeline and electric utility proceedings. These issues include formal market power analysis, market based rates, rate design; seasonal rates; distance based rates; separation of services (unbundling); discounting; capacity release; capacity assignments; interruptible transportation rates; storage rate design; refunctionalization studies; stranded costs; restructuring issues; incremental versus rolled-in rates; depreciation and negative salvage; cost of service and rate base issues; oil pipeline rates; tariffs and operational issues; and the resolution of contract disputes.

Mr. Sullivan has testified as an expert witness on market power and market based rates, cost classification, allocation and rate design, billing determinants, depreciation, and other rate related issues in numerous natural gas rate proceedings, oil pipeline proceedings and electric proceedings. He has been responsible for various presentations to FERC Commissioners on such topics as Offshore Gathering Policy, Negotiated Rates and Discounting, Enron and Manipulation of the Western Energy Markets in 2000-2001, and Section 5 rate case proceedings.

A list of the cases that Mr. Sullivan supervised while at the Commission is attached as Appendix A-1. A list of the cases in which Mr. Sullivan provided testimony and/or testified is attached as Appendix B.

Appendix A-1

Formal Proceedings Supervised by Mr. Sullivan

Applicant Name	Docket Number	Role	Case Type
AES OCEAN EXPRESS V FGT	RP04-249	Sponsor	Complaint Gas Quality on FGT
ALPINE TRANSPORTATION COMPANY	IS01-0033-000	Sponsor	Oil Pipeline Cost Based Rates
ANR PIPELINE COMPANY	CP00-0391-000	Sponsor	Gas Section 7 Certificate Proceeding
ANR PIPELINE COMPANY	RP02-0335-000	Sponsor	Gas Section 5 Cost Based Rates
ANR PIPELINE COMPANY	RP04-435-000	Sponsor	Complaint on Gas Quality Hydrocarbon Dew Point
ARCO PRODUCTS	OR96-2-000	Sponsor	Oil Pipeline Cost Based Rates
BIG WEST OIL CO v. ANSCHUTZ RANCH EAST	OR01-0003-002	Sponsor	Complaint Oil
BIG WEST OIL CO v. FRONTIER PIPELINE CO	OR01-0002-002	Sponsor	Complaint Oil
BOSTON EDISON COMPANY	EL02-0123-000	Sponsor	Complaint/Electric Transmission Rates, losses, Transmission Upgrades
BP TRANSPORTATION (ALASKA) INC	IS01-0504-000	Sponsor	Oil Pipeline Cost Based Rates
CANYON CREEK COMPRESSION COMPANY	RP02-0356-000	Sponsor	Gas Section 4 Cost Based Rates
CINERGY SERVICES INC.	ER01-0200-000	Sponsor	Electric Contractual Dispute
CITY OF DETROIT, MICHIGAN v. DETROIT EDI	EL00-0071-000	Sponsor	Electric Contractual Dispute
COLORADO INTERSTATE GAS COMPANY	RP01-0350-000	Sponsor	Gas Section 4 Cost Based Rates
CONOCO PIPE LINE COMPANY	IS01-0444-000	Sponsor	Oil Pipeline Cost Based Rates
CONOCO PIPE LINE COMPANY	IS01-0445-005	Sponsor	Oil Pipeline Cost Based Rates
EASTERN SHORE NATURAL GAS COMPANY	RP02-0034-000	Sponsor	Gas Section 4 Cost Based Rates
ENRON POWER MARKETING INC.	EL03-180 et al.	Sponsor	Western Market Show Cause Proceeding
ENRON AFFILIATED QF'S (INVESTIGATION OF)	EL03-0047-000	Sponsor	Complaint/Electric - Not Otherwise Categorized
ENTERGY OPERATING COMPANIES	ER99-3084-000	Team Leader	Electric Transmission Rate, Ancillary Services and/or Terms and Conditions
ENTERGY SERVICES, INC.	ER05-696	Sponsor	Electric Transmission Rate, Ancillary Services and/or Terms and Conditions
EQUITRANS	RP05-164	Sponsor	Gas Section 4 Cost Based Rates
EXPRESS PIPELINE LLC	IS02-0081-000	Sponsor	Oil Pipeline Cost Based Rates
EXXON-MOBILE PIPELINE COMPANY	IS00-0221-000	Sponsor	Oil Pipeline Cost Based Rates
FRENCH BROAD ELECTRIC MEMBERSHIP CORP V.	EL00-0076-000	Sponsor	Electric Contractual Dispute
HIGH ISLAND OFFSHORE SYSTEM	RP03-221	Sponsor	Gas Section 4 Cost Based Rates
KERN RIVER GAS TRANSMISSION	RPO4-274	Sponsor	Gas Section 4 Cost Based Rates
KINDER MORGAN OPERATING L.P.	IS02-0230-000	Sponsor	Oil Pipeline Cost Based Rates

MIDAMERICA OIL PIPELINE	IS05-216	Sponsor	Oil Pipeline Cost Based Rates
MILFORD POWER COMPANY, LLC	ER05-163	Sponsor	Electric Cost Based Rates RMR
NEW ENGLAND POWER COMPANY	ER01-0745-000	Sponsor	Electric Interconnection of Transmission Facilities
NATURAL GAS PIPELINE COMPNAY	RP01-503-002	Sponsor	Complaint on Gas Quality Hydrocarbon Dew Point
NORTHERN NATURAL GAS COMPANY	RP01-0395-000	Member	Fuel Adjustment Rates
NORTHERN NATURAL GAS COMPANY	RP98-0203-000	Member	Gas Section 4 Cost Based Rates
NSTAR SERVICES CO v. NEPOOL	EL00-0062-010	Sponsor	Complaint/Electric Transmission Rates, losses, Transmission Upgrades
PG&E GAS TRANSMISSION, NW CORPORATION	RP99-0518-019	Sponsor	Gas Market Based Rates
PINE NEEDLE LNG COMPANY, L.L.C.	RP02-0407-000	Sponsor	Gas Section 4 Cost Based Rates
PIONEER PIPE LINE COMPANY	IS01-0108-000	Sponsor	Oil Pipeline Cost Based Rates
PLATTE PIPE LINE COMPANY v. EXPRESS PIPE	IS02-0384-000	Sponsor	Oil Pipeline Cost Based Rates
PORTLAND NATURAL GAS TRANSMISSION SYSTEM	RP02-0013-000	Sponsor	Gas Section 4 Cost Based Rates
PSEG POWER CONNECTICUT, LLC	ER05-231	Sponsor	Electric Cost Based Rates RMR
PUB. UTIL. Comm. (CPUC) v. El PASO NAT.	RP00-0241-006	Subject Expert	Gas Market Based Rates
PUB. UTIL. COMM. (CPUC) v.EL PASO NAT.	RP00-0241-000	Subject Expert	Complaint/Gas or Oil - Not Otherwise Categorized
SFPP, L.P. (PHASE I - MARKET POWER)	OR98-0011-000	Team Leader	Complaint/Gas or Oil - Not Otherwise Categorized
SFPP, L.P. (PHASE II - COST-OF-SERVICE)	OR98-0011-001	Sponsor	Complaint/Gas or Oil - Not Otherwise Categorized
SHELL OFFSHORE INC v. TRANSCO ET AL	RP02-0099-000	Member	Complaint/Gas or Oil - Not Otherwise Categorized
SOUTHERN LNG INC	RP02-0129-000	Sponsor	Gas Section 4 Cost Based Rates
SOUTHERN NATURAL GAS COMPANY	RP99-0496-000	Team Leader	Gas Section 4 Cost Based Rates
SOUTHERN NATURAL GAS COMPANY	RP04-523	Sponsor	Gas Section 4 Cost Based Rates
SUFFOLK COUNTY ELECTRICAL AGENCY	TX96-0004-000	Sponsor	Electric Transmission Rate, Ancillary Services and/or Terms and Conditions
SUMMIT POWER NW LLC, v. PORTLAND GENERAL	RP01-0433-000	Sponsor	Complaint/Gas or Oil - Not Otherwise Categorized
TEXAS GAS TRANSMISSION CORPORATION	RP00-0260-000	Subject Expert	Gas Section 4 Cost Based Rates
TRAILBLAZER PIPELINE COMPANY	RP03-0162-000	Sponsor	Gas Section 4 Cost Based Rates
TRANSCONTINENTAL GAS PIPELINE CORPORATIO	RP01-0245-000	Sponsor	Gas Section 4 Cost Based Rates
TRANSWESTERN PIPELINE COMPANY	RP97-0288-009	Sponsor and Witness	Gas Section 4 Cost Based Rates
VENICE GATHERING SYSTEM,L.L.C.	RP01-0196-000	Sponsor	Gas Section 4 Cost Based Rates
VIKING GAS TRANSMISSION COMPANY	RP02-0132-000	Sponsor	Gas Section 4 Cost Based Rates
WEST TEXAS LPG PIPELINE LIMITED PARTNERS	IS02-0331-000	Sponsor	Oil
WESTERN RESOURCES, INC	EC97-0056-000	Member	Merger Proceeding
WILLISTON BASIN INTERSTATE PIPELINE COMPANY	RP00-107	Sponsor	Gas Section 4 Cost Based Rates

Appendix B

Formal Proceedings In Which Barry E. Sullivan Testified:

Docket No. CP79-80, Trailblazer Pipeline Company;
Docket No. RP80-121, United Gas Pipeline Company;
Docket Nos. RP80-97, and RP81-54, Tennessee Gas Pipeline Company;
Docket Nos. RP8l-l7 and RP8l-57, Midwestern Gas Transmission Company;
Docket No. CP80-l7, Trans Anadarko Pipeline System;
Docket No. RP82-46, South Georgia Natural Gas Company;
Docket No. RP85-39, Wyoming Interstate Company, Ltd.;
Docket No. RP85-60, Overthrust Pipeline Company;
Docket No. RP84-94, Trailblazer Pipeline Company;
Docket Nos. IS85-9 and OR85-l, Kuparuk Transportation Company;
Docket No. CP85-437 et al., Mojave Pipeline Company;
Docket No. RP88-197-000, Williston Basin Interstate Pipeline Company;
Docket No. RP90-109-000, Pacific Gas Transmission Company;
Docket No. RP90-8-000, Transcontinental Gas Pipe Line Corporation;
Docket No. RP90-119-000, Texas Eastern Transmission Corporation;
Docket No. RP85-39-009, Wyoming Interstate Company, Ltd;
Docket No. RP93-55-000, Trailblazer Pipeline Company;
Docket No. RP94-72-000, Iroquois Gas Transmission System;
Docket No. RP95-112-000, Tennessee Gas Pipeline Company;
Docket No. RP95-364-000, Williston Basin Interstate Pipeline Company;
Docket No. RP95-362-000, Koch Gateway Pipeline Company;
Docket No. RP91-203-062, Tennessee Gas Pipeline Company;
Docket No. RP97-126-000, Iroquois Gas Transmission System;
Docket No. RP97-373-000, Koch Gateway Pipeline Company;
Docket No. RP98-203-000, Northern Natural Gas Company;
Docket No. OR98-11-000, SFPP, L.P.;
Docket No. RP97-288-009 through 016, Transwestern Pipeline Company;
Docket No. RP02-99-000, Shell Offshore Inc., v Williams Field Services;
Docket No. EL02-114-000, Portland General Electric Company,
Docket No. EL03-154 and EL03-180, Enron Power Marketing, Inc., and
Docket No. RP06-407, Gas Transmission Northwest; and
Docket No. IS05-82, Anadarko/Tesoro versus TAPS Carriers Proceeding.