UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Portland Natural Gas Transmission System	)))	**Docket No. RP10-___**

Prepared Direct Testimony
of
John J. Reed

Q. Please state your name and business address.

A. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

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

A. I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting firm specializing in financial and economic services to the energy industry.

Q. Please describe your professional background and experience.

A. I have thirty years of experience in the North American energy industry. Prior to my current position with Concentric, I have served in executive positions with various consulting firms and as Chief Economist with Southern California Gas Company. I have provided expert testimony on financial and economic matters on numerous occasions, including numerous proceedings regarding cost allocation and rate design matters, before the Federal Energy Regulatory Commission ("FERC"), various Canadian regulatory agencies including the National Energy Board ("NEB" or "Board"), state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. A copy of my résumé and a listing of the testimony I have sponsored previously are included as Exhibit Nos. PNG-39 and PNG-40, respectively.

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

A. I am sponsoring testimony on behalf of Portland Natural Gas Transmission System ("PNGTS" or "the Company").

Q. What is the purpose of your testimony?

A. I have been asked by PNGTS to 1) address the business risks facing PNGTS; 2) compare the risk profile of PNGTS to the other members of the proxy group in conjunction with other PNGTS witnesses; 3) help position PNGTS within the spectrum of risk represented by the proxy group; and 4) address certain extraordinary and non-recurring events pertaining to discretionary revenues on PNGTS.

Section I: Executive Summary

Q. Please summarize your principal conclusions.

A. My principal conclusions are:

1. PNGTS is now, and has been for some time, operating in a very competitive environment serving the Boston-area market. Unfavorable and deteriorating receipt-end and delivery-end market dynamics, combined with contractual limitations, hinder the Company's ability to secure any significant commitments for long-term firm transportation ("FT") service. Recent developments have only served to worsen PNGTS' competitive position and increase its business risk.
2. The introduction of large supplies of Marcellus Shale gas into the Northeast U.S. supply mix will further decrease, or eliminate altogether, basis differentials in the Northeast U.S., and indirectly, on PNGTS. The resulting decrease in the value of FT capacity on PNGTS will eliminate any economic incentive for shippers to enter into or renew FT service contracts.
3. Based on qualitative and quantitative analyses I present in my testimony, as well as the evidence presented by witnesses Sullivan, Haag and Lovinger, it is evident that PNGTS faces business risks far greater than most members of the proxy group used by witness Hevert to calculate a return on equity ("ROE") range of reasonableness.

4. Adjustments to certain historical base period numbers are appropriate in order to account for extraordinary and non-recurring events pertaining to discretionary revenues on PNGTS. Without recognition of these adjustments, the use of historical base period numbers, which are stale and unrepresentative of future operating circumstances, will produce levels of discretionary revenues which are not sustainable for PNGTS.

Q. How is the remainder of your prepared direct testimony organized?

A. In Section II, I describe the competitive position of PNGTS in the current market and the circumstances that have led to PNGTS' unusually high business risk and vulnerable economic condition, including being the highest cost path to bring gas to the Boston-area market, inability to secure long-term FT contract renewals, and the relatively high level of exposure to contract renewal risk (given the short weighted average duration of PNGTS' existing FT contracts compared to its competitors). In Section III, I discuss recent developments related to production of new shale gas supplies and how these developments are likely to affect the recontracting behavior of existing FT shippers on PNGTS. In Section IV, I compare PNGTS to each member of witness Hevert's proxy group from the perspective of business risk. In Section V, I address certain extraordinary and non-recurring events pertaining to discretionary revenues on PNGTS and describe market changes that have occurred which significantly impact PNGTS' future discretionary revenue opportunities. Section VI details my conclusions regarding PNGTS' business risk on a standalone basis and compared to the members of witness Hevert's proxy group.

<u>Section II: PNGTS' Competitive Position and Business Risk</u>

Q. What determines the demand for transportation service on PNGTS?

A. There are two main factors that drive demand for transportation service on PNGTS. The first is the level of end-use demand in the market that PNGTS serves. Higher demand for natural gas by these end-use customers, as well as the addition of new end-use customers, increases the price of gas in that region, all else being equal. Shippers (pipeline customers) will use the pipeline to access gas at a lower-priced hub and deliver it to end-use customers where the price is higher. To that end, the greater the basis differential between PNGTS' primary receipt point at Pittsburg, NH and other delivery points along PNGTS, the greater the value of transportation service on PNGTS. It is important to note, in addition, that the underlying commodity price of natural gas and alternative fuels may affect demand regardless of the relationship of basis differentials.

The other main factor that drives demand for transportation service on PNGTS is the availability of alternative or competing infrastructure to deliver gas to the same end-use customers. Demand for natural gas in New England is met with supplies from several sources, including gas transported on other interstate pipelines, gas withdrawn from storage facilities along various pipelines, and gas received from LNG import terminals. The basis differentials on the other pipelines and the delivered cost of re-gasified LNG from LNG import terminals both contribute towards determining the competitiveness of PNGTS' services.

Going forward the value for PNGTS' capacity is likely to decrease from already depressed levels because of forces that affect prices at Pittsburg and PNGTS' primary delivery point at Dracut, MA. Anything that causes the price at Pittsburg to go up without a corresponding downstream increase in price, or prices at Dracut to go down without a corresponding upstream decrease in price, decreases the value of capacity on PNGTS.

Q. **How would you characterize PNGTS' current competitive position?**

A. PNGTS is in an intensely competitive environment given capacity serving the Boston-area market. This is a function of factors that fall into three main categories: 1) receipt-end market dynamics; 2) delivery-end market dynamics (including delivered cost disadvantages); and 3) contractual and operational limitations.

Receipt-end Market Dynamics

There are five major natural gas production areas in North America that have a realistic potential to serve demand in the market area served by PNGTS: the Western Canada

Sedimentary Basin ("WCSB"), the Rocky Mountain region, the Appalachian basin (specifically Marcellus Shale), the Gulf Coast producing areas (on-shore and off-shore), and Atlantic Canada (specifically the Sable Island Offshore Energy Project). There has been some speculation regarding the potential for new unconventional supplies from the Utica Shale play, located in Eastern Canada near Montreal, and extending over the U.S./Canada border into New York and Pennsylvania. As I will discuss later, the lack of development at the Utica Shale makes determining its production potential and economic viability too speculative to seriously consider in this discussion.

PNGTS connects to the Trans Quebec & Maritimes Pipeline ("TQM") at Pittsburg, New Hampshire (East Hereford, Quebec), on the Canadian border. It also connects with Maritimes & Northeast Pipeline ("M&NE") in Westbrook, Maine. The level of demand for transportation service on PNGTS depends largely on the natural gas supplies that can be accessed at Pittsburg. Because M&NE has postage stamp rates, access to supplies at Westbrook, Maine are only relevant in the case of a "reversal of flow scenario" which would send supplies north to Quebec through East Hereford. A "reversal of flow" scenario is unlikely to be economical for several reasons. First, there would have to be evidence of a long-term switch in basis differentials between Quebec and Dracut. Table 1 provides the monthly average basis differential between Dracut and Waddington, NY (a nearby export point) between January, 2007 and March, 2010 (adjusted for the approximate \$0.15/Dth transport cost between Waddington and Sainte-Genevieve-de-Berthier in Quebec).

Table 1

Basis Differential: Dracut, MA vs. Quebec ($/Dth)

	2007	2008	2009	2010	AVG
January	1.29	2.06	3.88	1.00	2.06
February	0.87	1.24	1.03	0.61	0.94
March	0.71	0.22	0.78	0.06	0.44
April	0.40	0.23	0.09		0.24
May	0.24	0.22	0.03		0.16
June	0.33	0.48	0.12		0.31
July	0.38	0.65	0.10		0.38
August	0.54	0.23	0.08		0.28
September	0.31	0.38	0.12		0.27
October	0.24	0.27	0.02		0.18
November	0.25	0.69	0.09		0.34
December	3.80	0.94	0.90		1.88
Average	$0.78	$0.63	$0.60	NA	$0.62

There is no evidence of a long-term switch in basis differentials between Quebec and Dracut. Second, if basis differentials do reverse, the market would likely support shipping Marcellus supplies through Niagara on Tennessee Gas Pipeline ("Tennessee") ahead of supplies on PNGTS and TQM. As shown in Table 2 the demand charges alone associated with firm transport to Quebec on PNGTS and TQM are 100% higher than demand charges associated with firm transport to Quebec on Tennessee, TransCanada's Mainline and TQM.[1]

1 Quebec delivery point is Sainte-Genevieve-de-Berthier. Rates used in this calculation are currently effective rates for the respective pipelines as of 4/21/10.

Table 2

Path 1 - Marcellus Gas to Quebec	**Demand Charge ($/Dth)**
Tennessee (Zone 4 - Zone 5)	0.11
TransCanada (Niagara to Quebec)	0.42
Total Demand Charges	0.53
Path 2 - Westbrook Gas to Quebec	**Demand Charge ($/Dth)**
PNGTS (Westbrook to Pittsburg)	0.90
TQM (East Hereford to Quebec)	0.16
Total Demand Charges	1.06
Premium to Path 1	**100%**

Third, PNGTS can't offer firm service from East Hereford north without facilities modifications that would likely require customer commitments to justify the investment. Furthermore, to the extent PNGTS would need to discount to attract long-term backhaul contracts, existing shippers' MFN contract clauses create an economic barrier. Fourth, most of the growth in Eastern Canada is related to new gas-fired power generation in Ontario which is more proximate to, and therefore more economically served by, Dawn rather than East Hereford.

My opinion that a reversal of flow on PNGTS is unlikely is shared by the NEB, which stated in its "Reasons for Decision" in Docket No. RH-1-2008, issued in March 2009:

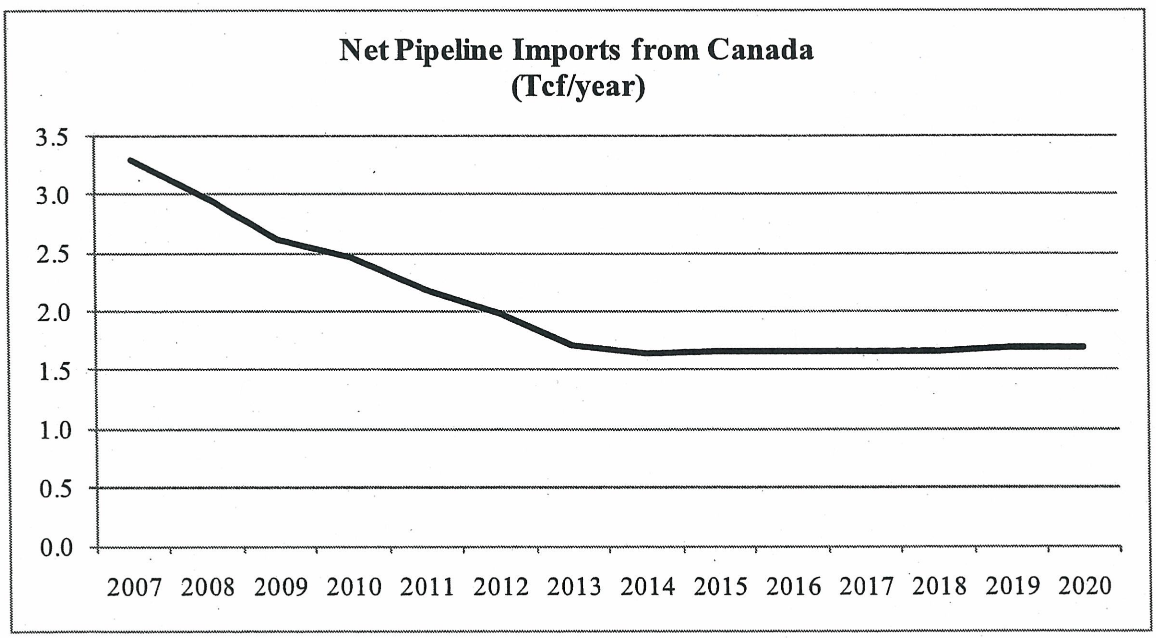
> In addition, the Board notes that while PNGTS is capable of flow reversal, which would deliver gas into TQM, there are issues involved. For this to occur there would have to be a fundamental change in market and price conditions. The Quebec market would require higher prices than the New England market, and that higher price would likely create an increased market and competitive risk. The Board places little weight on the concept that a potential reversal of PNGTS represents a reduced business risk for TQM.[2]

[2] NEB's "Reasons for Decision" in Docket No RH-1-2008, p. 47, Issued March, 2009.

Supplies available at Pittsburg are primarily determined by the level of production in the WCSB, Canadian demand for those supplies, and supplies available at the Dawn market hub ("Dawn"). WCSB supplies are shipped east on TransCanada's pipeline system (the "Canadian Mainline"). Decreased production out of the WCSB, coupled with increased Canadian demand, are expected to significantly reduce Canadian exports to the U.S.

Figure 1 shows the U.S. Energy Information Administration's ("EIA") latest forecast of Canadian supply exports to the U.S.[3] As shown in Figure 1, a significant decline in WCSB production, combined with increasing Canadian domestic demand, produces substantial reductions in predicted exports to the U.S. over the next several years.

Figure 1



As noted by witness Sullivan, and as illustrated in Figure 2, the NEB projects that by 2028 Canadian domestic gas consumption will equal Canadian domestic gas production and Canada's position as a net gas exporter could potentially come to an end.[4]

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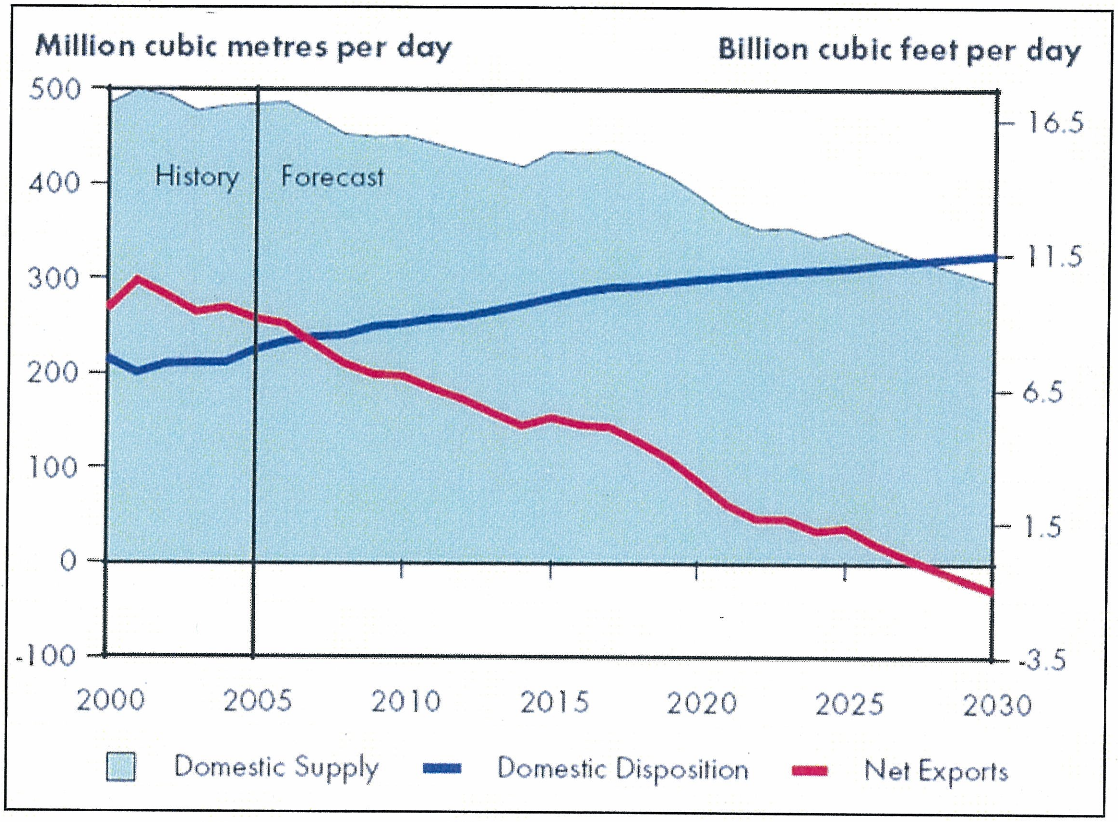
3 Energy Information Administration "2010 Annual Energy Outlook", December, 2009, Table 116.

4 NEB's "Canada's Energy Future: Reference Case and Scenarios to 2030", November, 2007, p. 49.

Figure 2 – Canadian Natural Gas Demand/Supply Balance



The TransCanada publication titled "Western Canadian Sedimentary Basin (WCSB): Myths and Realities – A Practical Guide to the Potential of the WCSB" offers a more hopeful outlook on WCSB production. However, it is important to note, that located so far east, PNGTS is the most marginal export pipeline for Canadian supplies. Therefore, PNGTS will likely be the first pipeline affected by further reductions in Canadian exports to U.S. markets, and the last to recover if Canadian exports rebound in the future.

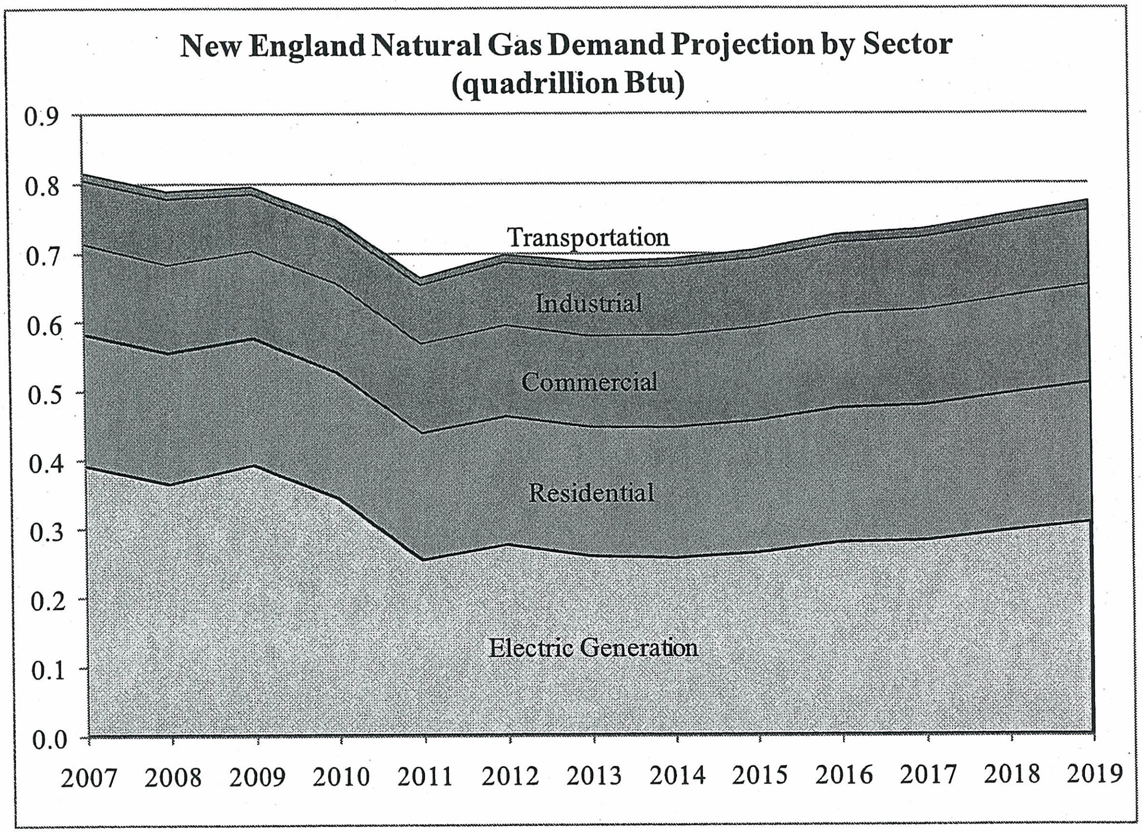
There are multiple pipeline interconnections and storage facilities located in close proximity to Dawn, primarily the systems of ANR, ANR Storage, MichCon and Great Lakes. Supplies from the Rockies, the U.S. midcontinent and the WCSB may all be available at various times at Dawn. Additionally, the interconnection with the Vector pipeline system ties Dawn to the Chicago area markets (and prices) primarily served by Alliance and Northern Border. Therefore, PNGTS shippers may also use Dawn as an indirect source of supply for their PNGTS deliveries.

Delivery-end Market Dynamics

Q. How are delivery-end market dynamics affecting PNGTS' competitive position?

A. The New England market for sales of natural gas is becoming increasingly competitive. It is important to note that there are several natural gas infrastructure projects underway or recently completed which compete to serve natural gas demand in New England. In its latest forecast, the EIA projected aggregate New England natural gas demand to **decrease** at an annual average rate of 0.43% from 2007 through 2019 (these dates coincide with the first year of the EIA analysis and the year in which the last of PNGTS' existing long-term FT contracts expire respectively). Demand for natural gas for New England electric generation is projected to **decrease** by 1.99%. This indicates that PNGTS will likely not see any demand for FT service from the two gas-fired electric generating stations located on its northern facilities. Figure 3 shows the EIA's natural gas demand projection for New England by sector.

Figure 3[5]



There are currently eleven major interstate pipelines that either directly or indirectly serve the New England market in addition to PNGTS. The pipelines with direct access to the New England market are: Algonquin Gas Transmission Company ("Algonquin"), Tennessee Gas Pipeline Company ("Tennessee"), Iroquois Gas Transmission System ("Iroquois"), and M&NE. The pipelines with indirect access to the New England market are: Texas Eastern Transmission Co. ("TETCO"), Transcontinental ("Transco"), Dominion Transmission, Inc. ("DTI"), Columbia Gas Transmission, Inc. ("Columbia"), Millennium Pipeline Company LLC ("Millennium"), Empire Pipeline ("Empire") and National Fuel Gas Supply ("NFGS").

In addition to these pipelines, there are three operating LNG import facilities and one entering service in 2010:

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[5] EIA's "2010 Annual Energy Outlook".

- The Distrigas terminal in Everett, Massachusetts (owned by GDF/Suez and operated by its subsidiary, Distrigas of Massachusetts Corp.) has storage capability of 3.4 Bcf, maximum daily sendout capability of 1 Bcf in vapor via pipeline (715 MMcf/day on a sustainable basis), and an additional 100 MMBtu/day sendout capability in liquid via truck. Distrigas interconnects with both the Algonquin and Tennessee systems.
- The Northeast Gateway facility, located offshore Cape Ann, Massachusetts (owned and operated by Excelerate Energy), has a maximum sendout capability of 800 MMcf/day in vapor via pipeline. Northeast Gateway connects to the Algonquin system via Algonquin's Hubline.
- Canaport LNG in Saint John, New Brunswick (owned and operated by Repsol and Irving Oil) has storage capability of 6.6 Bcf, soon to be 9.9 Bcf with the addition of a third 3.3 Bcf storage tank expected to be in-service in the first half of 2010. Canaport LNG has a firm sendout capacity of 1 Bcf/day and connects to M&NE at the Maine border via the 90-mile Brunswick Pipeline.
- Neptune LNG, located 10 miles offshore Gloucester, Massachusetts, will have a maximum sendout capability of 700 MMcf/day when it enters commercial operation, which is expected to be in the first half of 2010. Neptune, like Northeast Gateway, will connect to the Algonquin system via Algonquin's Hubline.

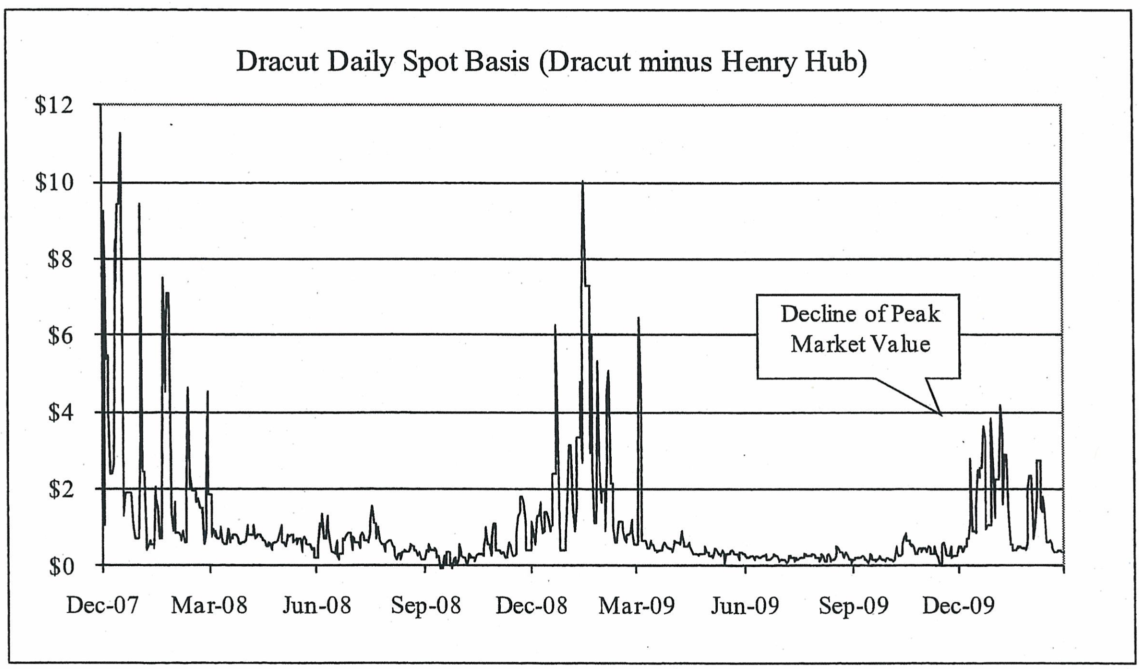
Many LDCs throughout the region also have on-system LNG to meet their peak day needs. Specifically, in New England, there is approximately 16.2 Bcf of on-system LNG storage capacity at over 40 facilities, with a combined vaporization capability of 1.36 Bcf/day.[6] These strategically placed facilities help the Northeast LDCs serve their peak needs and reduce the need for pipeline gas to reach their market pockets, especially on peak consumption days.

6 Northeast Gas Association's "2009 Statistical Guide".

Q. Please explain why increases in the deliverability of revaporized LNG to the Boston-area harm PNGTS.

A. Demand for firm transport capacity on PNGTS has been derived, in large part, from shippers' expectations that the Boston-area market will continue to experience infrequent but sizable spikes in prices during short periods of peak demand, that are not accompanied by a corresponding upstream price spike. These price spikes have been the major contributor to shippers' ability to recover the cost of their firm contracts on PNGTS. Prior to the construction of Canaport, Northeast Gateway and Neptune, the Boston-area market was one of the highest priced basis differential markets in the United States (as measured by Dracut minus Henry Hub). The scarcity of deliverability in peak periods into the region drove up the price volatility, which in turn increased demand for (and value of) pipeline capacity to deliver supply into the market. However, after the Canaport and Northeast Gateway LNG projects went into service, this basis differential (Dracut minus Henry Hub) dropped from a peak over $11 down to a new lower peak of $4. Table 3 shows the sharp erosion of peak daily winter basis at Dracut over the last few years.

Table 3



This is a permanent decline in PNGTS capacity value that is likely to accelerate in the near future. Deliverability of LNG into the Boston-area market is expected to increase with the addition of a 3rd tank at Canaport and Neptune LNG entering commercial operation. This additional capacity coupled with projected decreases in New England natural gas consumption will significantly reduce both the magnitude and frequency of price spikes in the Boston-area market. The resulting decrease in price volatility (and the reduction in basis differentials on PNGTS) will reduce, or eliminate altogether, arbitrage opportunities that have been the main source of value for shippers with firm capacity on PNGTS.

A recent Gas Daily article on planned increases in deliveries from Canaport LNG validates this projection:

> Repsol plans to nearly double its output from its Canaport liquefied natural gas terminal next winter, to 800,000 Mcf/day, to take advantage of peak demand in New England, a company official said. ... However several regional traders in New England said that sustained throughput of that magnitude would seriously dampen prices and volatility when spikes are common. [7]

Fewer opportunities to take advantage of these "basis blowouts" will make contracting for firm transport capacity on PNGTS even less economic. In a market with several competing alternatives, PNGTS' prospects for attracting new long-term FT shippers are increasingly difficult.

Q. How does PNGTS compare to other pipelines serving the Boston-area market on a "delivered cost" basis?

There are several routes that can be used to deliver gas to the Boston-area market. PNGTS' location makes it the least cost competitive path to bring gas to the Boston-area. I analyzed four pipeline routes, each path originating at Dawn, to bring gas to Boston. Table 4 summarizes the results of my analysis. The analysis presented in Table 4 assumes gas at Dawn costs $5.50, which is the average of the monthly NYMEX Henry Hub

[7] "Repsol to Hike Canaport LNG Flows Next Winter", Gas Daily, March 11, 2010.

futures contracts (as of 4/21/2010) for the next 24 months ($5.20) plus the average basis differential between Henry Hub and Dawn over the last 24 months ($0.30). Sources for tariff data are the "Currently Effective Rates" from respective pipeline tariffs as of 4/21/2010. "Scenario A" assumes PNGTS' currently effective FT rate (as of 4/21/10), "Scenario B" assumes a PNGTS FT rate of $0.62/Dth as proposed by the Portland Shippers Group in Docket No. RP08-306. The details of this analysis are provided in Exhibit No. PNG-41. As shown in Table 4, as of March 31, 2010, it was $1.20 (or 215%) more expensive to utilize PNGTS than the cheapest available alternative transportation path. Even using the lower rate proposed by the Portland Shippers Group in Docket No. RP08-306 ($0.62/Dth) results in a transport cost of $1.48, which is 165% more expensive than the cheapest available alternative transportation path.

Table 4

Dawn to Boston Transport Cost	Transport Cost	Premium to Path 1
Path 1		
TransCanada (Dawn to Niagara)	0.21	
Tennessee (Niagara (Zone 5) to Boston (Zone 6))	0.35	
Delivered to Boston	**$0.56**	**0%**
Path 2		
TransCanada (Dawn to Waddington)	0.44	
IGT (Waddington (Zone 1) to Wright (Zone 1))	0.28	
Tennessee (Wright (Zone 5) to Boston (Zone 6))	0.36	
Delivered to Boston	**$1.09**	**94%**
Path 3		
TransCanada (Dawn to Waddington)	0.44	
IGT (Waddington (Zone 1) to Brookfield (Zone 2))	0.44	
Algonquin (Brookfield to Boston)	0.29	
Delivered to Boston	**$1.18**	**110%**
Path 4		
TransCanada (Dawn to East Hereford)	0.63	
PNGTS (East Hereford to Dracut) Scenario (A)	0.90	
PNGTS (East Hereford to Dracut) Scenario (B)	0.62	
Tennessee (Dracut to Boston)	0.23	
Delivered to Boston Scenario (A)	**$1.76**	**215%**
Delivered to Boston Scenario (B)	**$1.48**	**165%**

What Table 4 does not show is that for new sources of natural gas supply made available at points other than Dawn, shippers will be able to select transportation paths to the Boston-area market that put PNGTS at even more of a disadvantage. This disadvantage indicates that incremental supplies from Marcellus shale, the Rockies or the Chicago market are likely to further reduce any incremental demand for service on PNGTS. For example, FERC staff recently noted

> When REX reached Lebanon, Ohio, last spring, natural gas from the Rockies gained greater access to eastern markets, lowering prices to East Coast consumers and raising prices for Rockies producers. This price difference between the Rockies and Appalachia has declined from as much as $1.80 per MMBtu before REX East entered service to 30-35 cents in August. Early indications in forward prices indicate that the prices will converge further when REX is completed. Eastern and Western U.S. gas markets are becoming coupled.[8]

Operational and Contractual Limitations

Q. Does PNGTS face operational and contractual limitations which affect its level of business risk?

A. Yes. PNGTS' ability to compete with other pipelines serving the Boston-area market is impaired by several operational limitations. First, PNGTS is an intermediate pipeline. The vast majority of contracted capacity is used to deliver gas to interconnecting facilities along the Jointly Owned Facilities or the terminus of PNGTS at Dracut, MA. Very few contracted customers are served exclusively by PNGTS. As noted by witness Haag, only 5% (8,600 Dth/d) of current firm contracted service must use PNGTS to obtain physical deliveries of natural gas. The majority of shippers can choose an alternate path, thereby bypassing PNGTS, as economics dictate. Additionally, these shippers are less likely to rely on PNGTS for a large portion of their capacity requirements, and are more inclined to utilize interruptible services or to enter into short term contracts rather than long-term contracts, increasing PNGTS' exposure to contract renewal risk.

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8 FERC "Winter 2009/2010 Energy Market Assessment", November 19, 2009, p. 6.

Second, PNGTS has no storage capabilities, system LNG facilities, or propane air facilities. This decreases the value of firm capacity to PNGTS shippers. As noted above, all of the competing pipelines (or affiliates of competing pipelines serving New England) except M&NE have one or more of the aforementioned operational attributes. The highly seasonal nature of the market PNGTS serves makes the lack of these service offerings even more detrimental to PNGTS' competitive position.

Third, as described in more detail by witness Haag, PNGTS is exposed to risks related to the Joint Facilities. Specifically, the Joint Facilities Ownership and Operating Agreements hinder PNGTS' operational flexibility and the consultative requirements of the Joint Facilities Definitive Agreements require PNGTS to provide M&NE (its primary competitor) access to proprietary competitive information should PNGTS plan to alter the configuration or operation of the Joint Facilities. Furthermore, the unit rate associated with M&NE's capacity on the Joint Facilities is lower than PNGTS' rate, placing PNGTS at a significant competitive disadvantage at the shared delivery points along the Joint Facilities, the markets where the vast majority of PNGTS' deliveries are made. None of the competing pipelines serving the Boston-area market face this combination of cost disadvantage and competitive restriction.

I am also familiar with the contractual issues, explained in more detail by witness Haag, which increase PNGTS' business risk and impair its ability to compete with other pipelines serving the Boston-area market. These contractual provisions include: 1) Most Favored Nations; 2) Decontracting; and 3) Off-peak Transportation. Not one PNGTS competitor has this combination of contract restrictions.

Q. What is the relevant benchmark to use when comparing the competitiveness of FT service on PNGTS?

A. FT service on existing pipelines is the relevant benchmark for determining the competitiveness of PNGTS. Pipeline contracting is dynamic in nature. Each of the pipelines used in my delivered cost analysis have FT service contracts expiring on a regular basis. Shippers are continually making decisions about the most economic way to buy and transport gas at the lowest possible cost. The reason that little, if any, unsubscribed capacity exists on these pipelines is because existing shippers typically choose to roll over their contracts on the other pipelines for FT service, as opposed to choosing an alternate resource such as PNGTS to fulfill their needs. This real world economic decision-making by shippers is the best evidence available that the market does not consider PNGTS to be a competitive path to bring gas to the New England market.

Q. Have you done any analysis to support your assertion that shippers are continuously rolling over their FT service contracts on pipelines that compete with PNGTS?

A. Yes, I have. Using data from FERC Form 549B, Index of Customers, I analyzed the firm transportation contracts for Algonquin, Iroquois, M&NE, Tennessee and PNGTS for the years 2006 through 2009. For each quarter, I looked at the amount of newly contracted FT capacity, and the amount of that new FT capacity that was rolled over from an expired contract and the amount of new FT capacity contracted from non-rolled over contracts. The results of my analysis are presented below.

Algonquin Gas Transmission

As shown in Table 5, shippers are renewing their contracts on Algonquin and significant new FT service commitments have been made in the past four years.

Table 5

Algonquin Gas Transmission – FT Service Contracts				
Quarter Ending	**Maximum Daily Transportation Quantity (Dth)**	**New Contracts This Quarter (Dth)**	**Roll Over of Existing Contracts (Dth)**	**New Contracts From New Shippers (Dth)**
12/31/2009	2,097,037	889,894	879,894	10,000
9/30/2009	1,911,474	26,452	26,452	0
6/30/2009	2,263,906	205,058	197,058	8,000
3/31/2009	2,298,778	134,333	134,333	0
12/31/2008	1,757,997	676,475	450,975	225,500
9/30/2008	1,572,434	5,292	5,292	0
6/30/2008	1,936,866	94,669	94,669	0
3/31/2008	1,972,303	12,489	10,000	2,489
12/31/2007	1,682,431	372,482	351,982	20,500
9/30/2007	1,516,868	5,292	5,292	0
6/30/2007	1,881,300	83,404	83,404	0
3/31/2007	1,928,525	0	0	0
12/31/2006	1,752,138	190,073	190,073	0
9/30/2006	1,612,575	5,292	5,292	0
6/30/2006	1,977,007	45,965	45,965	0
3/31/2006	2,081,460	16,853	16,853	0

Notes: 1. Excludes all contracts initiated under the Algonquin Firm Transportation – Canal Lateral rate schedule ("AFT-CL")

2. Number in MDTQ column represents contracted MDTQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

Iroquois Gas Transmission

This analysis for Iroquois shows that there have been significant volumes of capacity rollovers on the system in the past three years and that the contracted demand has remained relatively constant.

Table 6

Iroquois Gas Transmission System – FT Service Contracts				
Quarter Ending	Maximum Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	Roll Over of Existing Contracts (Dth)	New Contracts From New Shippers (Dth)
12/31/2009	1,547,701	90,710	70,110	20,600
9/30/2009	1,610,865	45,014	24,914	20,100
6/30/2009	1,562,911	133,650	121,900	11,750
3/31/2009	1,569,889	203,167	188,852	14,315
12/31/2008	1,366,051	112,558	112,558	0
9/30/2008	1,462,801	45,350	20,100	25,250
6/30/2008	1,406,336	133,576	89,476	44,100
3/31/2008	1,437,436	20,000	10,000	10,000
12/31/2007	1,337,974	190,766	181,660	9,106
9/30/2007	1,359,174	30,100	30,100	0
6/30/2007	1,317,851	99,798	99,798	0
3/31/2007	1,457,151	49,440	34,640	14,800
12/31/2006	1,376,867	216,583	153,343	63,240
9/30/2006	1,371,607	34,100	34,100	0
6/30/2006	1,311,754	279,957	162,907	117,050
3/31/2006	1,367,008	20,000	0	20,000

Note: Number in MDTQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

Maritimes & Northeast Pipeline

M&NE had essentially stable firm contracted capacity over the period 2006 to 2009. With the addition of firm commitments in 2009 for new capacity on its Phase IV expansion from Repsol, the maximum daily transportation quantity under firm contracts has increased from 420,000 Dth/day to 833,317 Dth/day (net of turned back capacity from existing shippers). Nearly all of the contracted capacity is under long-term contracts that expire after 2013. M&NE experienced the expiration of only one contract in the three year period. This contract expired on March 31, 2007 and was rolled over until March 31, 2008. At that time, it was transferred to Emera Energy Services Inc. ("Emera") who agreed to purchase 43,200 dekatherms of firm capacity for eight years. More significantly, M&NE was successful in securing 25 year firm commitments for new capacity in its Phase IV expansion. Including Repsol's contract for FT service to transport volumes from Canaport LNG, MTDQ commitments on M&NE have grown by more than 130% since 2006.

Table 7

Maritimes & Northeast Pipeline – FT Service Contracts				
Quarter Ending	Maximum Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	Roll Over of Existing Contracts (Dth)	New Contracts From New Shippers (Dth)
12/31/2009	833,317	18,767	0	18,767
9/30/2009	833,317	0	0	0
6/30/2009	833,317	0	0	0
3/31/2009	360,575	790,117	60,117	730,000
12/31/2008	360,575	0	0	0
9/30/2008	360,575	0	0	0
6/30/2008	360,575	43,200	0	43,200
3/31/2008	360,575	0	0	0
12/31/2007	360,575	0	0	0
9/30/2007	360,575	0	0	0
6/30/2007	360,575	43,200	43,200	0
3/31/2007	360,575	0	0	0
12/31/2006	360,575	0	0	0
9/30/2006	360,575	0	0	0
6/30/2006	360,575	0	0	0
3/31/2006	360,575	0	0	0

Notes: 1. Excludes all contracts initiated under the Maritimes & Northeast Lateral Firm Transportation rate schedule ("MNLFT").

2. Number in MDTQ column represents contracted MDTQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

3. M&NE's MDTQ capacity increased to 833,317 Dth/day as of 1/15/09.

4. New Contracts This Quarter for quarter ending 3/31/2009 does not net out the capacity that was turned back by existing shippers in order to accommodate Repsol's new 730,000 Dth of capacity.

Tennessee Gas Transmission

Tennessee has also been having success in securing rollover commitments from existing customers and new contracts from new shippers. Tennessee is constantly re-contracting its firm capacity. Clearly the market finds Tennessee to be a cost-effective transportation route for natural gas into the New England market.

Table 8

Tennessee Gas Transmission – FT Service Contracts				
Quarter Ending	Maximum Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	Roll Over of Existing Contracts (Dth)	New Contracts From New Shippers (Dth)
12/31/2009	1,140,145	37,000	37,000	0
9/30/2009	1,098,245	0	0	0
6/30/2009	1,140,145	0	0	0
3/31/2009	1,140,145	15,728	15,728	0
12/31/2008	1,129,145	7,220	7,220	0
9/30/2008	1,125,925	0	0	0
6/30/2008	1,110,925	15,000	15,000	0
3/31/2008	1,110,925	0	0	0
12/31/2007	978,625	132,300	132,300	0
9/30/2007	978,625	0	0	0
6/30/2007	993,625	15,000	0	15,000
3/31/2007	1,003,225	0	0	0
12/31/2006	1,048,917	34,335	34,335	0
9/30/2006	1,045,602	45,692	45,692	0
6/30/2006	1,045,602	6,000	6,000	0
3/31/2006	1,047,302	0	0	0

Notes: 1. Based upon 20 LDCs with service territories in New England (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont). Table excludes all contracts initiated under the Firm Transportation Backhaul ("FT-BH") and Firm Transportation Incremental Lateral ("FT-IL") rate schedules.

2. Number in MDQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

PNGTS

As discussed earlier, PNGTS has experienced unsold firm capacity every year for the last several years. In 2005 and 2006 PNGTS experienced capacity de-subscriptions totaling 62,000 Dth/day. This capacity has not been acquired by a replacement long-term shipper. In addition, since its inception of service, PNGTS, unlike every other pipeline in New England, has never had service commitments that have allowed it to expand capacity.

Quite simply, while the market has supported keeping all of the competitors essentially fully contracted into New England and supported expansions on these pipelines, no shippers have found that PNGTS is the right route to expand beyond existing firm long-term capacity.

Q. What were you able to conclude from the results of your analysis of the firm transport contracts on PNGTS and its major competitors?

A. The results clearly show that competing pipelines are continually securing contract renewals for expiring FT service contracts and attracting new FT service commitments. My analysis also demonstrates that despite the foregoing efforts, market conditions and MFN constraints have prevented PNGTS from selling its unsubscribed FT capacity on a firm, long-term basis.

Over the past three years, all new contracts for FT service on PNGTS have been short-term, ranging from 29 days to 365 days and averaging only 131 days. It is clear from the data that PNGTS' market share is declining and its ability to initiate long-term firm transportation contracts is nearly non-existent. Table 9 summarizes the weighted average durations of new FT contracts in the past three years for PNGTS and its four main competitors:

Table 9

Weighted Average Duration of New FT Contracts (2007-2009)	
M&NE	22.2 years
Tennessee	16.6 years
Algonquin	5.5 years
Iroquois	2.7 years
PNGTS	**131 days**

PNGTS' inability to attract new long-term FT commitments is in stark contrast to the results for Algonquin, Iroquois, M&NE, and Tennessee. These data can only be interpreted in one way: PNGTS is at a significant competitive disadvantage to its competitors.

Q. What efforts has PNGTS made to market unsubscribed capacity on its system?

A. PNGTS has undertaken the following:

- Engaging in vigorous marketing, including several open seasons;
- Requesting that PNGTS shippers consider increasing or extending their levels of subscription on the system;
- Seeking markets for unsubscribed capacity on its system through postings on its EBB;
- Direct and continuous contact with new and existing markets and suppliers on PNGTS for short, intermediate and long-term capacity;
- Maintaining contact with developers, governmental agencies, trade organizations and producer groups to promote PNGTS services;
- Solicitation and business development efforts of potential new markets/interconnects on and near the PNGTS pipeline;
- Seeking creative solutions to fit PNGTS capacity to the needs of new and existing customers;
- Promoting PNGTS services in numerous natural gas industry venues.

Q. Please discuss the contract utilization of existing shippers with contracts for long-term FT service on PNGTS.

A. Table 10 presents the utilization rates of PNGTS' long-term FT shippers. As demonstrated in Table 10, the 2009 weighted average utilization rate for existing long-term FT shippers was 10%, a 75% decline since 2005.

Table 10 [9]

	Contract Quantity (Dth)			Long-Term Shipper Utilization Rates				
	Annual	**Winter**	**Wtd Avg**	**2009**	**2008**	**2007**	**2006**	**2005**
Bay State Gas Co.	4,900	40,600	21,817	0%	17%	25%	37%	47%
DTE Energy Trading Inc.	30,000		30,000	35%	75%	41%	41%	41%
EnergyNorth Natural Gas Inc.	1,000		1,000	5%	2%	0%	0%	0%
HQ Energy Services Inc.	15,000		15,000	0%	0%	0%	0%	0%
Mead Westvaco Corp	5,000		5,000	0%	14%	15%	37%	41%
Northern Utilities Inc.	1,000	33,000	14,750	0%	36%	6%	81%	96%
TransCanada Gas Services LTD	15,000		15,000	0%	0%	0%	0%	0%
Wausau Paper of NH	4,600		4,600	0%	8%	84%	79%	87%
Wtd Avg LT Shipper Utilization Rate				**10%**	**30%**	**22%**	**35%**	**40%**

The low utilization of FT capacity by existing shippers bodes poorly for PNGTS in its quest to attract new, long-term FT shippers. Essentially all of the flow on the PNGTS system is being done by either capacity release capacity holders or heavily discounted discretionary services. The fact that all this transport is readily available for low rates undercuts PNGTS' ability to sell new capacity at recourse rates.

Q. What were the results of TransCanada's most recent Mainline FT contract renewals and what implications do these results have on PNGTS?

A. Contracts for firm transportation service on TransCanada's Mainline require a six month renewal notice. On May, 3, 2010 TransCanada released a report of non-renewals on their system for contracts effective November 1, 2010. Of the 92,995 GJ/day of contract demand eligible for renewal that delivered gas to East Hereford, the point of interconnection with PNGTS, **zero** was renewed. The unattractiveness of using PNGTS to ship supplies into the Boston-area market has been confirmed by the relinquishment of upstream capacity. While there was previously a high degree of correlation between upstream commitments and commitments on PNGTS, now because PNGTS is utilized so little, shippers are comfortable giving up their upstream commitments.

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9 Long-term shipper utilization rates do not account for flows associated with asset management arrangements.

The 100% rate of contract non-renewals for contracts delivering to East Hereford is significant but not surprising given recent experience. There were **zero** deliveries to East Hereford during 20 of the 30 days of April 2010. In the short-term this bodes poorly for utilization on PNGTS. Over the long-term this bodes poorly for the renewal of long-term FT contracts

Section III: Recent Developments Related New Shale Gas Supplies

Q. Please describe recent developments related to new shale gas supplies and how these developments are likely to impact demand for firm transport service on PNGTS.

A. The most significant development in the U.S. natural gas industry in the last decade relates to the increased potential of shale gas to supply domestic natural gas demand. The most prominent emerging shale gas play in the U.S. is the Marcellus Shale in the Appalachian region of Pennsylvania, West Virginia, Ohio and New York. The Marcellus Shale is already supplying an increasing percentage of Northeast U.S. natural gas needs and the role of Marcellus Shale gas is only expected to grow for many years to come. Technological developments in horizontal drilling techniques have allowed producers to economically access shale gas, a prospect that was not feasible just a few years ago. In a November, 2009 article in the Wall Street Journal, Daniel Yergin commented on U.S. shale gas developments:

> The supply impact has been dramatic. In the lower 48, states thought to be in decline as a natural gas source, production surged an astonishing 15% from the beginning of 2007 to mid-2008. This increase is more than most other countries produce in total.
>
> Equally dramatic is the effect on U.S. reserves. Proven reserves have risen to 245 trillion cubic feet (Tcf) in 2008 from 177 Tcf in 2000, despite having produced nearly 165 Tcf during those years. The recent increase in estimated U.S. gas reserves by the Potential Gas Committee, representing both academic and industry experts, is in itself equivalent to more than half of the total proved reserves of Qatar, the new LNG powerhouse. With more drilling experience, U.S. estimates are likely to rise dramatically in the next few years. At current levels of demand, the U.S. has about 90 years of proven and potential supply—a number that is bound to go up as more and more shale gas is found.

> ... Some areas like Pennsylvania and New York, traditionally importers of the bulk of their energy from elsewhere, will instead become energy producers.[10]

In its 2009 Statistical Guide, the Northeast Gas Association ("NGA") estimated that Marcellus Shale may hold as much as 250 Tcf of natural gas, and Penn State geologists estimated in mid-2009 that it may hold as much as 500 Tcf.[11] The NGA Statistical Guide also states:

> Already, [sic], the interstate pipelines in the Northeast are working to increase their interconnections to bring these new supplies online. Gas from Marcellus is already flowing into the Northeast, and in the next 3 to 5 years supplies are expected to emerge into the market in a compelling way. This development has the potential to transform the gas supply dynamic in the region.[12]

In its December, 2009 Regional Market Update, the NGA stated:

> The Northeast, long accustomed to being "at the end of the pipeline," now finds itself located next to - and indeed on top of – potentially one of the largest natural gas basins in the U.S.
>
> In an October 2009 report on unconventional gas shales, the Congressional Research Service noted that "the natural gas produced from the eastern portion of the Marcellus Shale is of high enough quality that it requires little or no treatment for injection into transmission pipelines."
>
> ...The interstate pipeline companies who serve the Appalachian region report numerous requests for interconnects from area producers, large and small. Gas from the Marcellus is already flowing into the region, and the next few years promise further, greater volumes.
>
> ...Recent supply developments have the potential of transforming the traditional paths of supply sources into the [Northeast U.S.] region, creating a more diverse supply mix and a more robust delivery network.[13]

Recent industry activity supports the hypothesis that Marcellus shale production will recharacterize the U.S. natural gas supply mix. Specifically:

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10 "America's Natural Gas Revolution" by Daniel Yergin and Robert Ineson. Wall Street Journal, November 2, 2009.

11 Northeast Gas Association "2009 Statistical Guide", p. 42.

12 *Ibid,* at 42.

13 Northeast Gas Association "Regional Market Update", December, 2009, p. 8-10.

- Active rig count is up 59% for the Marcellus since October 2008, while rig counts have fallen everywhere else in U.S. except at Haynesville.[14]
- In mid-Dec. 2009, Exxon Mobil announced the acquisition of XTO Energy. Exxon Mobil made this acquisition in large part to exploit XTO's expansive leaseholds located in the Marcellus shale area.[15] This transaction demonstrates how large players with the ability to move quickly are trying to capitalize on the opportunity Marcellus shale production presents.
- On December 21, 2009, Ultra Petroleum signed an agreement to purchase an additional 80,000 acres in the Pennsylvania Marcellus Shale, expanding its holdings in the region to approximately 250,000 acres.[16]
- According to a Tudor-Pickering report, more than 6 Bcf/d of new pipeline capacity, 250 MMcf/d of processing capacity, and 40 MMcf/d of fractionation capacity have been announced related to Marcellus.[17]
- Key players have announced increased production plans for 2010:
    - Chesapeake Energy estimates 220 MMcf/d (which is more than double its 2009 production) and 400 MMcf/d in 2011.[18]
    - Range Resources estimates 180-200 MMcf/d, which is double its 2009 production and eight times its 2008 production.[19]
    - Seneca Resources' (a subsidiary of National Fuel Gas) estimates Marcellus production of 30-50 MMcf/d by the end of 2010 (with an estimated $200 million in additional investment) and production of 60-100 MMcf/d by the end of 2011 (with an estimated $350 million of investment).[20]

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14 Bentek Energy LLC, "U.S. Natural Gas Market Outlook", September 17, 2009, p. 11.

15 ExxonMobil SEC Form 10-K for the Fiscal Year Ended 12/31/2009, p.47.

16 News Release: "Ultra Petroleum Announces Strategic Marcellus Acquisition and Pennsylvania Operations Update", December 21, 2009.

17 International Oil Daily, "Marcellus Puts U.S. Appalachian Basin in the Spotlight", January 8, 2010.

18 Chesapeake Energy, "January 2010 Investor Presentation", p. 14.

19 Range Resources, "Company Presentation - January 2010", p .27.

20 National Fuel Gas, "2009 Annual Report and Form 10-K", p. 4-5.

Recent market reactions to the potential impact of Marcellus production only reinforce this hypothesis. Regarding the impact on supply diversity:

- "Large end-users said Friday they are eager to start buying gas from the Marcellus Shale, not only for the price break that comes with shorter transport but for the greater reliability of a basin that doesn't lie in the path of hurricanes. 'Geographic diversity is important to us', Peco Energy Manager for Gas Supply and Transportation Carlos Thillet told Platt's Appalachian Gas Conference in Pittsburgh." [21]

Regarding supply cost:

- "Having producers right in the area cuts down on the basis and provides a solution to hurricanes", Competitive Power Ventures Senior Vice President for Energy Management, Sherman Knight, agreed. [22]
- "Being close to a 10 Bcf/d market is a good thing for producers," South Jersey Resources Group Business Development Officer Tim Hale said, advising Marcellus drillers to get their gas on the closest high-pressure mainlines headed for premium northern markets. [23]
- National Grid Director of Gas Contracting and Compliance John Alloca said his "company can start purchasing Marcellus gas immediately. The challenge is getting capacity to our city-gates, most of which are in urban areas such as Long Island." [24]
- "NiSource Gas Transmission & Storage (NGT&S) team continues to aggressively pursue a variety of growth opportunities across its system, with particular emphasis on projects linked to the company's extensive pipeline and storage network overlaying the Marcellus Shale production area in Appalachia. In addition to developing new gas transmission and storage projects, NGT&S is working closely with natural gas producers, processors and other industry participants to identify the

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[21] Platt's Gas Daily, November 2, 2009, p.1.

[22] *Ibid*, at 5.

[23] *Ibid.*

[24] *Ibid.*

most efficient means to bring growing supplies of Marcellus production to market over the course of the next several years." [25]

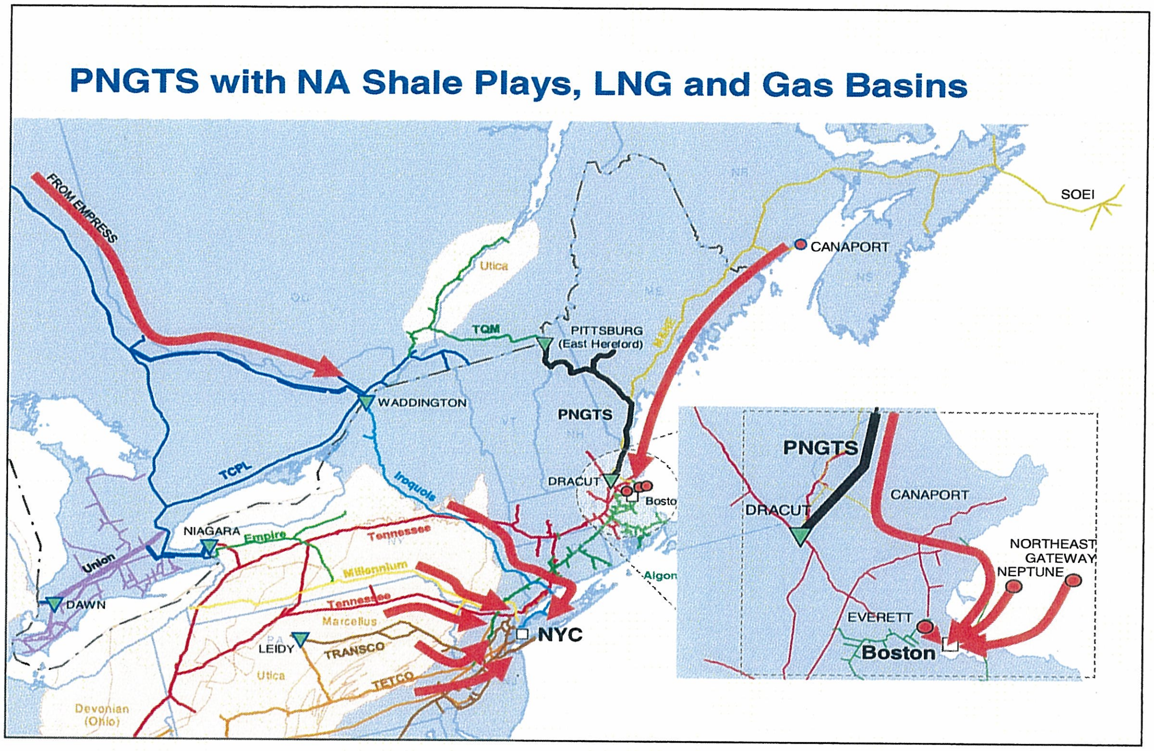
Q. How are these developments likely to impact demand for firm transport service on PNGTS?

A. The single biggest impact, from the perspective of PNGTS, will be a reduction in or elimination all together of, the value of firm transport capacity on PNGTS. The introduction of Marcellus shale gas into the Northeast will reduce both the absolute cost of gas and the volatility of gas pricing resulting in the substantial reduction, or elimination, of whatever basis differential existed on PNGTS. The loss of basis, coupled with the ensuing reduction in price volatility, will significantly reduce or eliminate any demand for firm transport capacity on PNGTS that had not already disappeared as a result of increased supplies of revaporized LNG from Canaport (and now/soon Northeast Gateway LNG and Neptune LNG) serving peak day demand needs in the Boston-area market.

Figure 4 provides a visual representation of the transportation paths likely to be utilized to deliver additional supplies from Marcellus Shale, as well as Canaport, Northeast Gateway and Neptune, to the Northeast U.S. market. Witness Sullivan provides details on the 30+ Northeast pipeline expansion projects filings the interstate natural gas pipeline industry has filed with FERC in Exhibit Nos. PNG-7, PNG-10 and PNG-13:

[25] *Ibid.*

Figure 4



As described above, supplies from Marcellus Shale are not likely to reach PNGTS.

The fact that there are several new pipeline projects in various stages of development designed to deliver supplies to New York City, and not Boston, supports the prognosis that Marcellus supplies are not likely to reach PNGTS. Instead, Marcellus supplies are likely to displace supplies delivered (and eliminate demand for FT service) on PNGTS. In addition, Algonquin's HubLine/East to West Project is being developed "to expand Algonquin's interstate natural gas transmission system in response to significant interest from customers needing transportation capacity in order to accommodate increased receipts of natural gas from emerging natural gas supplies, including liquefied natural gas (LNG), sourced at the east end of the Algonquin system for redelivery to high growth markets in the Northeast Region."[26] The same economics that support the development of new pipeline capacity to take supplies **away from the Boston-area market** undermine any expectation of demand for long-term firm transport service on PNGTS, the marginal

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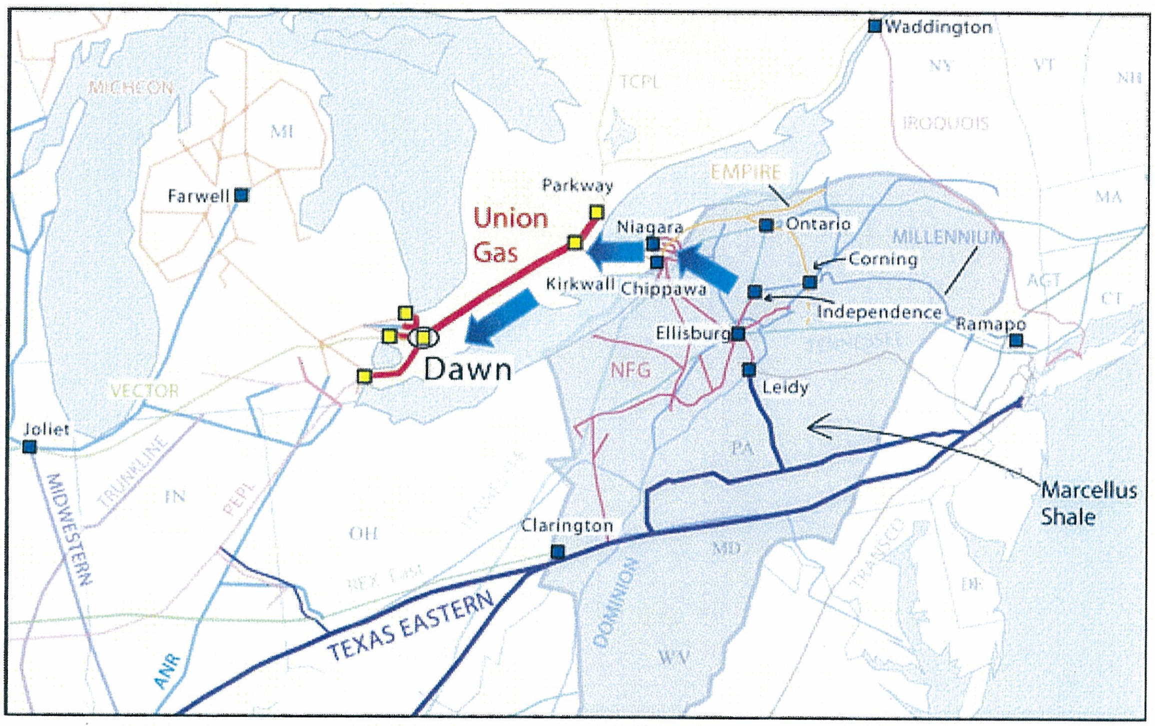
26 http://www.easttowestexpansion.com/

pipeline **serving the Boston-area market**. There is simply no economic incentive for existing shippers to renew expiring FT contracts for a long-term, or for new shippers to sign new long-term contracts for FT service on PNGTS.

Q. What is the likelihood of Marcellus Shale gas reaching PNGTS through Dawn?

Figure 5 is a map from the Union Gas website.[27] As this map illustrates, Union Gas anticipates Marcellus supplies linking to Dawn through Niagara (not linking to PNGTS). As I described earlier in Table 4, PNGTS is the least attractive route to get Dawn supplies to the Boston-area market. Even with Marcellus supplies entering the Union Gas or TransCanada systems at Niagara or Kirkwall, PNGTS is the least economic route to get these supplies to the Boston-area market.

Figure 5



[27] http://www.uniongas.com/storagetransportation/resources/maps/index.asp

Q. Do you consider the Utica Shale to be a viable source of future supplies for PNGTS shippers?

A. No. There are three main reasons I do not consider the Utica Shale formation in Quebec to be a viable source of future supplies for PNGTS shippers. First, it is an unproven resource and exploration is still in its infancy. While some gas companies have begun exploring in the area, there is no meaningful record of production. Talisman Energy Inc, one of the first companies to move forward with an E&P strategy in Quebec, is planning to drill four horizontal pilot wells in Quebec and won't know much about production potential until later this year.[28] Second, Since Quebec doesn't produce oil or natural gas commercially, there are no laws specifically designed to govern oil and gas operations. According to a recent article in the National Post, Quebec's Natural Resources Minister Nathalie Normandeau wants to introduce legislation in the fourth quarter of 2010 that would create a framework for regulating the production of natural gas in the Province. In the article, Edward Kallio, director of Gas Consulting at Ziff Energy Group, characterizes the Utica Shale as "relatively small, but it's a nice resource to have on your doorstep". Mr. Kallio said he wouldn't expect production in Quebec to start prior to 2015.[29] Third, any production out of the Utica Shale would likely be consumed in Quebec, as a way to reduce Quebec's dependence on gas supplies from Western Canada. Ms. Normandeau states in the article "If we are able to start producing gas, I can see a day when it will play a bigger role than oil in meeting our energy needs" (natural gas accounts for 13% of Quebec's energy consumption, while oil accounts for 38%).[30] I do not consider a relatively small unproven resource, which is more valuable to Quebec as a local energy resource than as an export for which local consumption could realistically outpace production capacity, located in a province with no law or regulatory framework in place to govern gas operations, a viable source of supplies for PNGTS shippers going forward.

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[28] National Post, "Quebec Mulls Law to Attract Oil, Gas Players", April 27, 2010.

[29] *Ibid.*

[30] *Ibid.*

Section IV: Business Risk: PNGTS Vs. Members of Witness Hevert's Proxy Group

Q. Do you agree with the methodology used by witness Hevert to select an appropriate ROE proxy group?

A. Yes. Witness Hevert followed the guidance provided by the Commission in Opinion No. 486-B and the *Proxy Group Policy Statement*[31], and by the United States Court of Appeals for the District of Columbia Circuit in the Petal Gas Storage decision.[32] Witness Hevert's screening criteria and adherence to Commission precedent resulted in a proxy group of five companies: Boardwalk Pipeline Partners, L.P., Energy Transfer Partners, L.P., Southern Union, Spectra Energy, and TC Pipelines, L.P. Witness Hevert provides a description of each member of the proxy group in his direct testimony.

Q. Please provide a brief description of each of the proxy companies.

A. Following is a brief description of each of the proxy companies. Witness Hevert provides more detail on each company in his discussion of proxy group selection.

Boardwalk Pipeline Partners L.P.

Boardwalk Pipeline Partners, L.P. ("Boardwalk" or "BPP") through its operating subsidiaries, owns and operates approximately 14,200 miles of natural gas pipelines, directly serving customers in twelve states and indirectly serving customers throughout the northeastern and southeastern United States through interconnections with unaffiliated pipelines.[33] In 2009, the system transported approximately 2.1 trillion cubic feet of gas, with average daily throughput of 5.7 billion cubic feet. The three major individual pipelines included in the Boardwalk partnership are discussed below.

Gulf Crossing Pipeline is a new natural gas pipeline that provides transportation service from the Barnett Shale in Texas and the Caney/Woodford Shale in Oklahoma. The pipeline begins near Sherman, Texas and extends for approximately 360 miles to the

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31 Composition of Proxy Groups for Determining Gas and Oil Pipeline Return Equity, 123 FERC ¶ 61,048 (2008) (Proxy Group Policy Statement).

32 Petal Gas Storage L.L.C. v. FERC, 496 F.3d 695, 699 (D.C. Cir. 2007).

33 Boardwalk Pipeline Partners, L.P., 2009 Securities and Exchange Commission ("SEC") Form 10-K, p. 3.

Perryville, Louisiana area. The peak day delivery capacity of the system is approximately 1.4 Bcf per day and is expected to increase to 1.7 Bcf per day from the addition of compression, which is expected to be placed in service in the first quarter of 2010.[34] End-markets include the Midwest, Northeast, Southeast and Florida through interconnections with affiliated and unaffiliated pipelines.

Texas Gas Transmission originates in Louisiana, East Texas and Arkansas and runs north and east through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, Indiana, and into Ohio, with lines also extending into Illinois. The system consists of approximately 6,110 miles of pipeline with a peak-day delivery capacity of approximately 4.3 Bcf per day in addition to nine storage fields located in Indiana and Kentucky. Directly-served markets include eight states in the South and Midwest. Indirect access to markets in the Northeast is accomplished through interconnections with unaffiliated pipelines.[35]

The Gulf South Pipeline system is located along the Gulf Coast in the states of Texas, Louisiana, Mississippi, Alabama, and Florida. The system contains approximately 7,700 miles of pipeline with a peak-day delivery capacity of approximately 6.2 Bcf per day as well as two natural gas storage fields located in Louisiana and Mississippi. Markets directly served by Gulf South are generally located in eastern Texas, Louisiana, southern Mississippi, southern Alabama, and the Florida panhandle. Markets in the northeastern and southeastern U.S. also are indirectly served by Gulf South through interconnections with other pipelines and storage facilities[36].

Energy Transfer Partners L.P.

Energy Transfer Partners ("ETP") owns and operates approximately 10,000 miles of natural gas pipeline with an additional 180 miles approved for construction. ETP also

[34] *Ibid*, at 3-5.

[35] *Ibid*.

[36] *Ibid*.

has an interest in joint ventures that have 500 miles of natural gas pipeline with a further 185 currently under construction.

Transwestern Pipeline comprises 2,700 miles of pipeline extending from West Texas through eastern and northwest New Mexico with its terminus at the boundary of California. The system has a capacity of 2.1 Bcf/d.[37]

In April 2010, ETC Tiger Pipeline Company, a wholly owned subsidiary of ETP, received approval from FERC to begin construction on a 175-mile pipeline stretching from eastern Texas to eastern Louisiana. The pipeline has a capacity of 2.0 Bcf/d and is expected to be in service in the first half of 2011. It will interconnect with at least seven natural gas pipelines at various points in Louisiana.[38]

ETP constructed the Midcontinent Express pipeline through a 50/50 joint venture arrangement with Kinder Morgan Partners. The 500-mile natural gas pipeline, which originates near Bennington, Oklahoma and terminates at an interconnection with the Transcontinental Gas Pipeline in Butler, Alabama, was placed in service in August 2009. The pipeline has a capacity of 1.4 Bcf/d.[39]

In October 2008, ETP entered into a 50/50 joint venture with Kinder Morgan Partners to develop the Fayetteville Express pipeline. The pipeline, which is currently under construction, originates in Conway County, Arkansas and terminates at an interconnection with Trunkline Gas Company in Quitman County, Mississippi. The 185-mile pipeline is expected to have an initial capacity of 2.0 Bcf/d.[40]

ETP's transmission assets, located in Texas providing service at rates regulated by FERC, include the Energy Transfer Fuel system, which extends from west Texas across north and East Texas and south near Houston; the ETC Katy Pipeline system, which links the

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37 Energy Transfer Partners, L.P., 2009 SEC Form 10-K, at 8.

38 SNLFinancial, *FERC Approves Energy Transfer Partners' $1.2B Tiger Pipeline*, April 12, 2010.

39 Energy Transfer Partners, L.P., 2009 SEC Form 10-K, at 2-3.

40 *Ibid.* at 3.

east Texas assets of Energy Transfer Fuel to the Oasis Pipeline system; Houston Pipe Line in the Carthage Hub area in Panola County, Texas; and Oasis Pipeline that runs from the Permian Basin in west Texas to natural gas supply and market areas in southeast Texas, and ultimately to the Katy Hub. These represent over 7,600 miles of transmission pipeline.

Southern Union

Southern Union Gas Company ("Southern Union" or "SUG") is engaged in the transportation, storage and local distribution of natural gas in the U.S. Pipeline operations include Panhandle Eastern Pipeline Company, LP ("PEPL"), Trunkline Gas Company ("Trunkline"), Southwest Gas Storage Company ("Southwest Gas"), and Sea Robin Pipeline Company ("Sea Robin"), and a 50.00 percent ownership interest in Florida Gas Transmission Company, LLC ("FGT").

PEPL's system contains four large diameter pipelines extending from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, and Ohio to its terminus in Michigan with a total system length of 6,000 miles[41].

Trunkline's system consists of two large diameter pipelines extending from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois and Indiana to its end point on the Indiana-Michigan border with a total system length of 3,500 miles.

Sea Robin is comprised of two offshore Louisiana supply systems extending approximately 81 miles into the Gulf of Mexico. The total length of the Sea Robin system is 400 miles.[42]

[41] Southern Union Gas Company, 2009 SEC Form 10-K, p. 3, 4.

[42] *Ibid.*

FGT is a 5,000-mile pipeline extending from south Texas through the Gulf Coast region of the U.S. to south Florida with a peak day capacity of 2.3 Bcf per day. The system primarily receives gas from producing basins along the Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico. Florida Gas is a transporter of natural gas to the Florida energy market, delivering 66.00 percent of natural gas consumed in the state. The system also contains 60 interconnections with other major interstate and intrastate pipelines, providing customers with a diverse supply portfolio. FGT has announced plans for a Phase VIII expansion from Mississippi to central and south Florida that is scheduled to be in service in 2011. The Phase VIII Expansion Project will consist of approximately 483.2 miles of pipeline in Alabama, Mississippi and Florida. The project will provide an annual average of 820,000 MMBtu/day of additional firm transportation capacity.[43]

Panhandle owns five natural gas storage fields in Illinois, Kansas, Louisiana, Michigan and Oklahoma, respectively, with a total working gas storage capacity of approximately 61 Bcf. Four fields are operated by Southwest Gas and one is operated by Trunkline.

Through Trunkline LNG Company, LLC, Southern Union owns and operates an LNG terminal in Lake Charles, Louisiana with a peak day delivery capacity of 2.1 Bcf per day and a storage capacity of 9.0 Bcf.

Spectra Energy

Spectra Energy Corporation ("Spectra") is involved in the transmission, storage, distribution, gathering and processing of natural gas. It owns and operates 13,710 miles of U.S. transmission pipelines in 2009.[44]

Spectra's pipeline assets include Texas Eastern, Algonquin, a 78.00 percent ownership in M&NE,[45] a 25.50 percent ownership in Gulfstream[46] and a 50.00 percent ownership in

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43 *Ibid.*

44 Spectra Energy Corp., 2009 SEC Form 10-K, p. 5.

45 *Ibid*, at 9.

Southeast Supply Header, LLC ("SESH"), which began operations in September 2008. Therefore, Spectra's business is highly concentrated in the transmission of natural gas. Spectra's major pipeline assets include:

- Texas Eastern, which delivers gas from Texas and Louisiana to Ohio, Pennsylvania, New Jersey, and New York. The pipeline consists of 8,700 miles of onshore pipeline, 500 miles of offshore pipe, 73 compressor stations and three storage fields;
- Algonquin, which transports natural gas from New Jersey to New England with 1,100 miles of pipeline and seven compressor units;
- M&NE, which consists of approximately 343 miles of pipeline in Maine, New Hampshire and Massachusetts and seven compressor stations;
- Gulfstream, which delivers natural gas from Mississippi and Alabama across the Gulf of Mexico to Florida over 745 miles; and
- SESH, which spans from Louisiana to Alabama consisting of a 274-mile natural gas pipeline and three compression stations.

In addition, Spectra owns or is a part owner of natural gas storage facilities in Maryland, Pennsylvania, Texas and Louisiana.

<u>TC PipeLines L.P.</u>

TC PipeLines ("TCP") through its operating facilities is engaged in the transportation of natural gas to a variety of downstream markets in the U.S. TC PipeLines has an ownership interest in four operating subsidiaries: Great Lakes Gas Transmission Limited Partnership ("Great Lakes"), Northern Border Pipeline Company ("Northern Border"), and Tuscarora Gas Transmission Company ("Tuscarora"), and North Baja Pipeline, LLC ("North Baja").

The Great Lakes system consists of 2,115 miles of pipeline through Minnesota, northern Wisconsin and Michigan. Great Lakes also delivers gas to storage fields and

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[46] *Ibid*, at 11.

interconnects with other interstate gas pipelines. Great Lakes is jointly owned by TC PipeLines and TransCanada[47].

Northern Border extends for 1,249 miles from Montana to its terminus in North Hayden, Indiana. The pipeline system provides pipeline access to the Midwestern U.S. from natural gas reserves in the WCSB. Northern Border also transports natural gas produced in the Williston Basin of Montana and North Dakota, and the Powder River Basin of Wyoming and Montana, as well as synthetic gas produced at the Dakota Gasification plant in North Dakota. TC PipeLines has a 50.00 percent interest in Northern Border.[48]

Tuscarora is a 240-mile transportation system originating in Malin, Oregon at an interconnection with existing facilities of Gas Transmission Northwest Corporation. The pipeline extends through northeastern California and northwestern Nevada to its terminus near Wadsworth, Nevada. Sixteen delivery points allow for the transportation of natural gas to Oregon, northern California and northwestern Nevada.[49]

North Baja is an 80-mile natural gas transmission system that extends from southwest Arizona to a point on the California-Mexico border.[50]

Q. How does PNGTS compare, from a risk perspective, to the members of witness Hevert's proxy group?

A. I have analyzed the business risk of PNGTS relative to other members of the proxy group. In almost every instance, the results of my analyses indicate that PNGTS is riskier than the members of witness Hevert's proxy group.

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47 TC Pipelines, L.P., 2009 SEC Form 10-K, p. 15.

48 *Ibid*, at 16.

49 *Ibid*, at 17.

50 *Ibid*, at F-7.

Q. What analysis did you conduct that led you to this conclusion?

A. For each member of witness Hevert's proxy group, I performed the following analyses:[51]

1. Contract Expiration Analysis: The timing of and degree to which existing contracts for FT service expire, thereby exposing the pipeline to recontracting risk.
2. Contract Renewal Analysis: The success the pipeline has had in recent years in renewing expiring contracts for FT service.

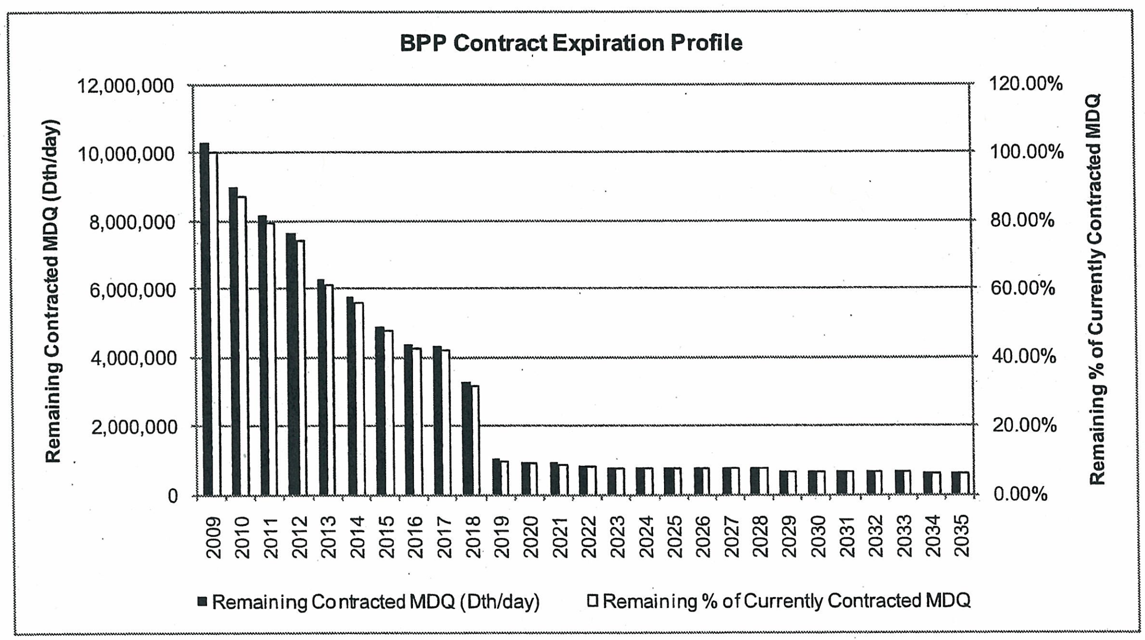
Q. Please discuss the results of these analyses.

A. Following are the results of the analyses, presented on a company-by-company basis.

Boardwalk Pipeline Partners, L.P.

Contract Expiration Analysis: Figure 6 provides a timetable for the expiration of BPP's existing FT service contracts.

Figure 6



Contract Renewal Analysis: Table 11 details the success BPP has had in renewing expiring contracts and attracting new shippers over each of the last 12 quarters.

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[51] Both analyses rely on data from FERC Forms 549B, Index of Customers.

Table 11

Boardwalk Pipeline Partners L.P. - FT Service Contracts[52]

Quarter Ending	Max. Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	New Contracts - Existing Shippers (Dth)	New Contracts - New Shippers (Dth)
12/31/2009	8,086,989	916,608	897,308	19,300
9/30/2009	7,702,304	299,163	111,076	188,087
6/30/2009	8,081,340	2,585,079	2,273,209	311,870
3/31/2009	8,432,283	174,727	85,969	88,758
12/31/2008	6,524,398	1,192,107	529,276	662,831
9/30/2008	6,860,644	317,185	215,685	101,500
6/30/2008	6,048,096	919,126	869,176	49,950
3/31/2008	7,031,994	1,475,910	1,226,719	249,191
12/31/2007	5,243,955	508,279	461,179	47,100
9/30/2007	4,638,467	241,467	214,467	27,000
6/30/2007	4,923,927	1,088,519	1,016,019	72,500
3/31/2007	5,968,496	90,969	90,969	0

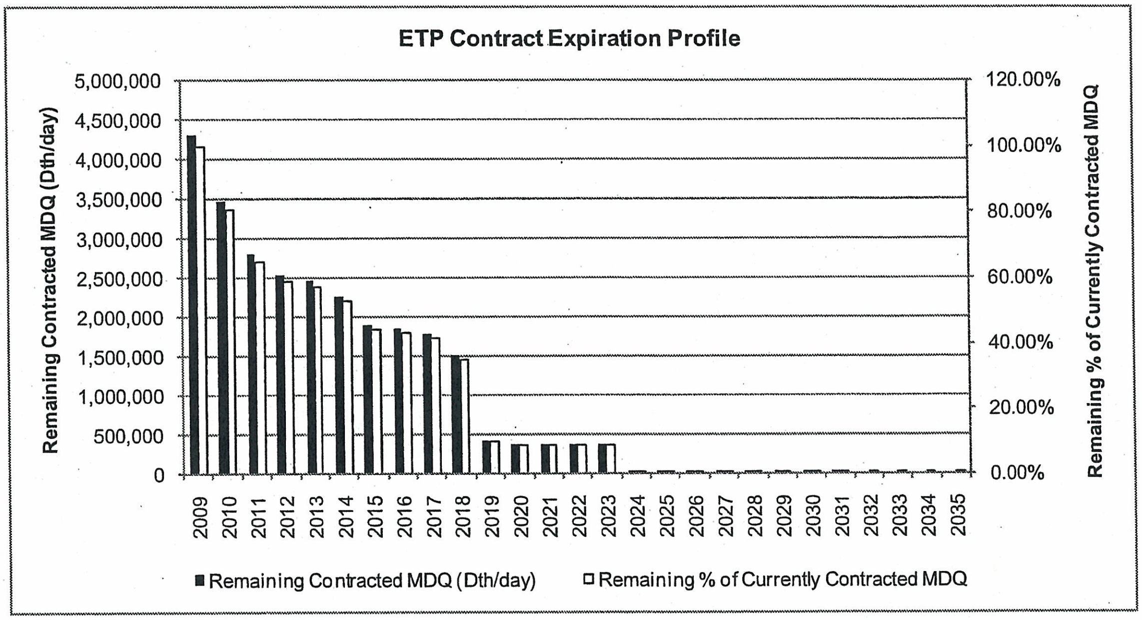
Note: Number in MDTQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

Energy Transfer Partners, L.P.

Contract Expiration Analysis: Figure 7 provides a timetable for the expiration of ETP's existing FT service contracts.

52 The increase in MDTQ for Boardwalk Pipeline Partners, LP between 2007 and 2009 is due primarily to system expansions and not decreasing unsubscribed capacity.

Figure 7



Contract Renewal Analysis: Table 12 details the success ETP has had in renewing expiring contracts and attracting new shippers over each of the last 12 quarters.

Table 12

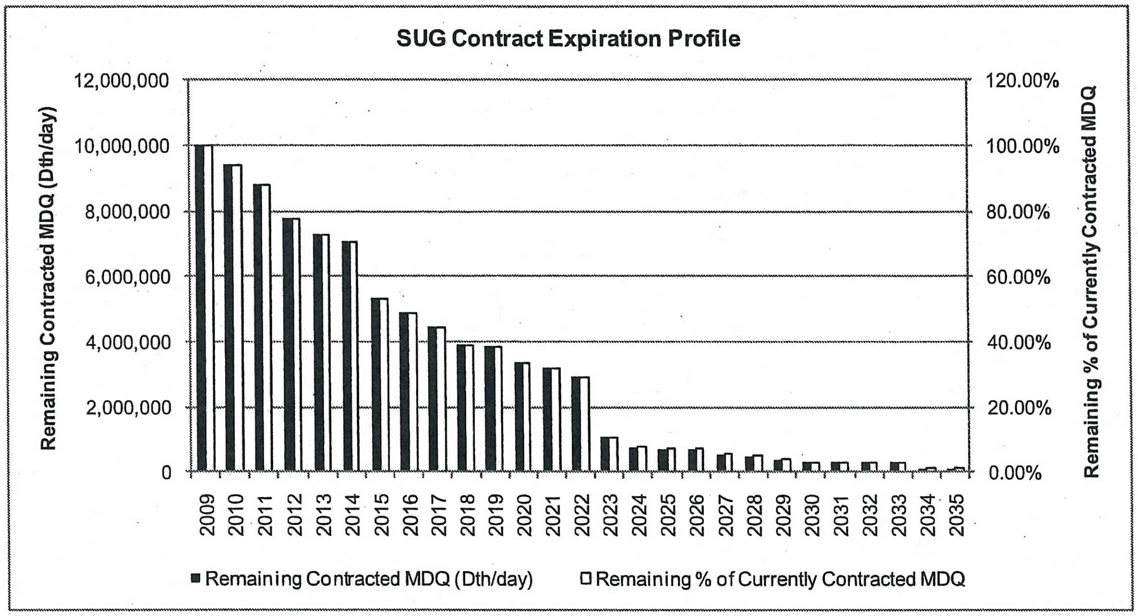
ETP - FT Service Contracts				
Quarter Ending	Max. Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	New Contracts - Existing Shippers (Dth)	New Contracts - New Shippers (Dth)
12/31/2009	2,972,366	279,011	279,011	0
9/30/2009	2,880,661	80,000	80,000	0
6/30/2009	2,846,461	270,990	210,990	60,000
3/31/2009	2,908,261	401,307	97,307	304,000
12/31/2008	2,812,371	372,925	372,925	0
9/30/2008	2,740,918	266,775	235,185	31,590
6/30/2008	2,644,034	370,972	274,472	96,500
3/31/2008	2,764,961	243,680	198,680	45,000
12/31/2007	2,854,339	226,794	223,794	3,000
9/30/2007	2,871,608	52,500	52,500	0
6/30/2007	2,870,863	870,631	865,631	5,000
3/31/2007	3,110,992	262,926	255,426	7,500

Note: Number in MDTQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

<u>Southern Union ("SUG")</u>

Contract Expiration Analysis: Figure 8 provides a timetable for the expiration of SUG's existing FT service contracts.

Figure 8



Contract Renewal Analysis: Table 13 details the success SUG has had in renewing expiring contracts and attracting new shippers over each of the last 12 quarters.

Table 13

SUG - FT Service Contracts

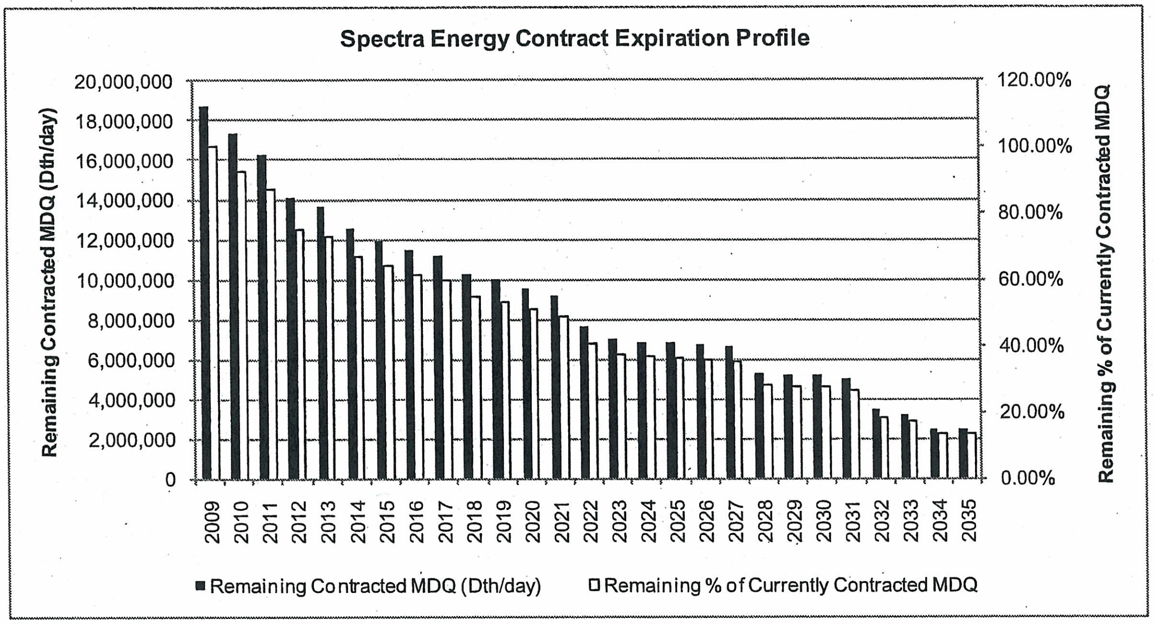
Quarter Ending	Max. Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	New Contracts - Existing Shippers (Dth)	New Contracts - New Shippers (Dth)
12/31/2009	5,685,944	118,591	118,591	0
9/30/2009	5,886,637	48,500	48,500	0
6/30/2009	5,894,219	264,700	114,029	150,671
3/31/2009	5,723,851	52,100	2,100	50,000
12/31/2008	5,723,898	240,598	168,740	71,858
9/30/2008	5,573,439	130,000	30,000	100,000
6/30/2008	5,360,938	272,419	149,318	123,101
3/31/2008	5,863,799	55,705	650	55,055
12/31/2007	5,249,081	503,769	370,491	133,278
9/30/2007	5,107,201	27,090	22,090	5,000
6/30/2007	5,197,189	354,066	326,505	27,561
3/31/2007	6,032,677	47,100	45,000	2,100

Note: Number in MDTQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

<u>Spectra Energy</u>

Contract Expiration Analysis: Figure 9 provides a timetable for the expiration of Spectra's existing FT service contracts.

Figure 9



Contract Renewal Analysis: Table 14 details the success Spectra has had in renewing expiring contracts and attracting new shippers over each of the last 12 quarters.

Table 14

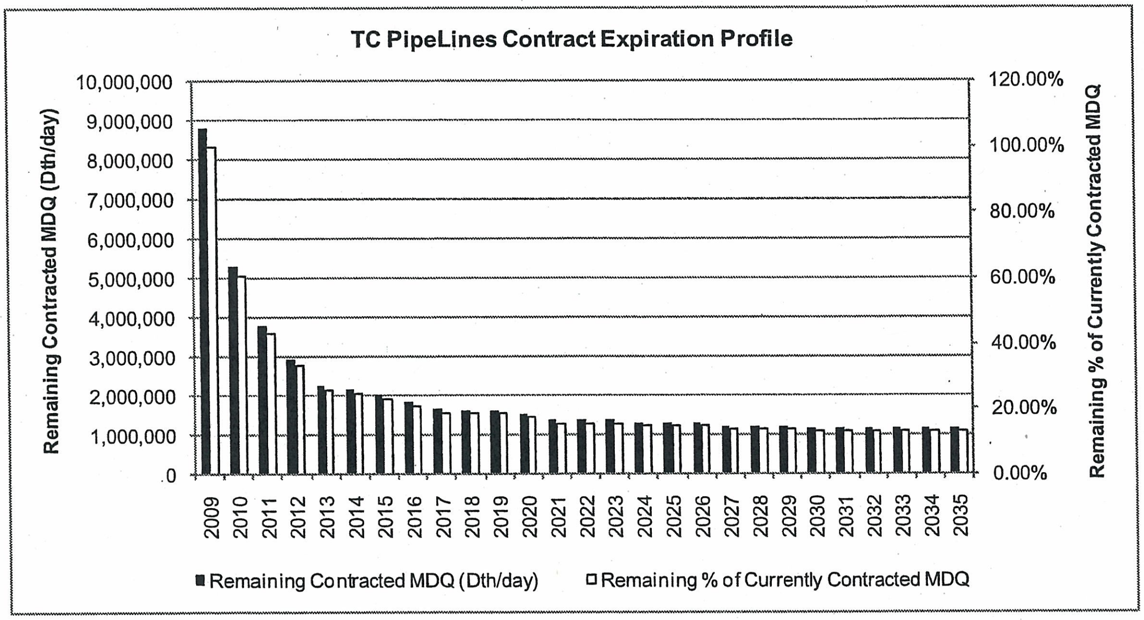
Spectra Energy - FT Service Contracts				
Quarter Ending	Max. Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	New Contracts - Existing Shippers (Dth)	New Contracts - New Shippers (Dth)
12/31/2009	13,579,741	2,861,106	2,682,339	178,767
9/30/2009	13,456,928	260,830	254,580	6,250
6/30/2009	13,400,654	1,248,435	1,101,435	147,000
3/31/2009	13,322,396	1,266,680	471,680	795,000
12/31/2008	12,281,613	2,037,163	1,801,663	235,500
9/30/2008	12,215,050	640,872	520,872	120,000
6/30/2008	11,713,707	2,477,654	2,414,218	63,436
3/31/2008	12,010,888	129,719	127,230	2,489
12/31/2007	11,273,590	1,916,156	1,730,256	185,900
9/30/2007	11,415,727	148,692	121,292	27,400
6/30/2007	11,393,697	1,111,258	1,059,458	51,800
3/31/2007	9,723,503	160,465	155,397	5,068

Note: Number in MDTQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

TC PipeLines L.P.

Contract Expiration Analysis: Figure 10 provides a timetable for the expiration of TCP's existing FT service contracts.

Figure 10



Contract Renewal Analysis: Table 15 details the success TCP has had in renewing expiring contracts and attracting new shippers over each of the last 12 quarters.

Table 15

TCP - FT Service Contracts

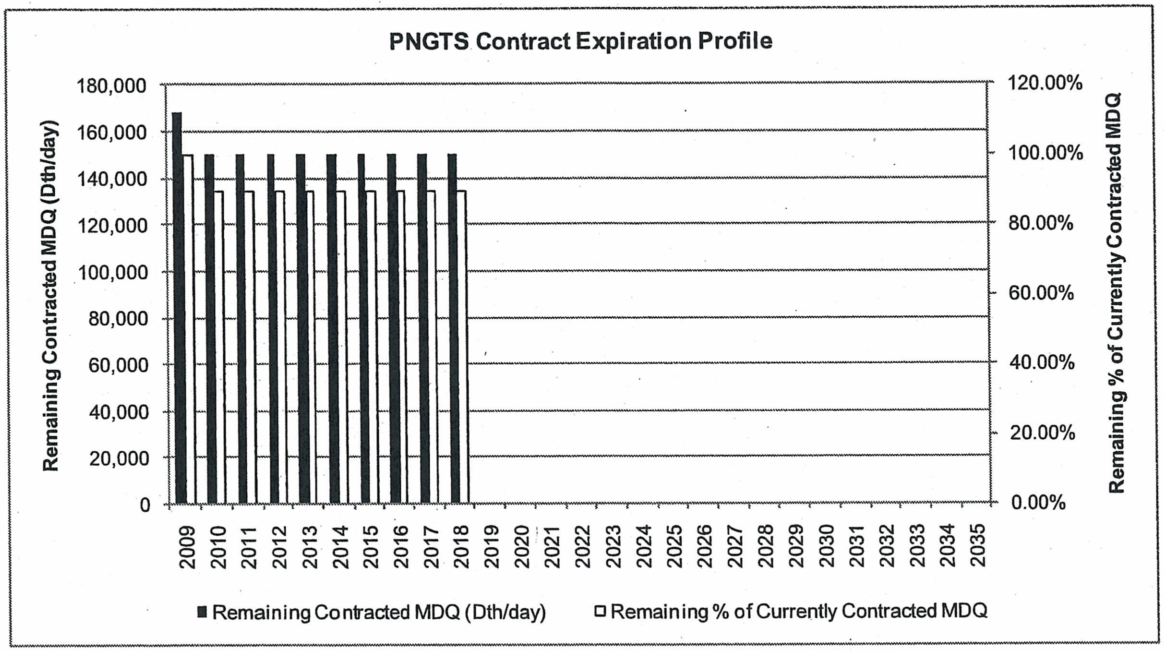
Quarter Ending	Max. Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	New Contracts - Existing Shippers (Dth)	New Contracts - New Shippers (Dth)
12/31/2009	6,196,882	930,759	922,368	8,391
9/30/2009	6,352,525	549,624	494,624	55,000
6/30/2009	6,462,565	1,185,666	1,149,264	36,402
3/31/2009	8,722,502	760,255	756,684	3,571
12/31/2008	6,907,161	2,172,916	2,052,449	120,467
9/30/2008	6,476,890	287,985	240,155	47,830
6/30/2008	6,453,558	742,886	652,886	90,000
3/31/2008	9,161,614	259,547	259,547	0
12/31/2007	7,336,700	1,218,494	972,088	246,406
9/30/2007	7,479,838	473,659	453,499	20,160
6/30/2007	6,790,086	1,056,583	1,051,543	5,040
3/31/2007	9,519,514	1,126,687	1,122,017	4,670

Note: Number in MDTQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.

<u>PNGTS</u>

Contract Expiration Analysis: Figure 11 provides a timetable for the expiration of PNGTS' existing FT service contracts.

Figure 11



Contract Renewal Analysis: Table 16 details the experience PNGTS has had in renewing expiring contracts and attracting new shippers over each of the last 12 quarters.

Table 16

PNGTS - FT Service Contracts				
Quarter Ending	Max. Daily Transportation Quantity (Dth)	New Contracts This Quarter (Dth)	New Contracts - Existing Shippers (Dth)	New Contracts - New Shippers (Dth)
12/31/2009	86,600	0	0	0
9/30/2009	86,600	10,000	10,000	0
6/30/2009	87,600	11,000	10,000	1,000
3/31/2009	168,200	18,000	18,000	0
12/31/2008	161,600	5,000	5,000	0
9/30/2008	196,600	100,000	70,000	30,000
6/30/2008	111,600	15,000	0	15,000
3/31/2008	217,405	0	0	0
12/31/2007	193,805	0	0	0
9/30/2007	208,805	65,000	0	65,000
6/30/2007	143,805	32,000	32,000	0
3/31/2007	217,405	0	0	0

Note: 1. Number in MDTQ column represents contracted MDQ as of the first day of the quarter. The numbers in subsequent columns represent the contracting activity throughout that quarter.
2. The source for Table 16 is PNGTS.

Figure 12 shows the percentage of existing FT contracts set to expire by 2019 for PNGTS and members of the ROE proxy group.

Figure 12

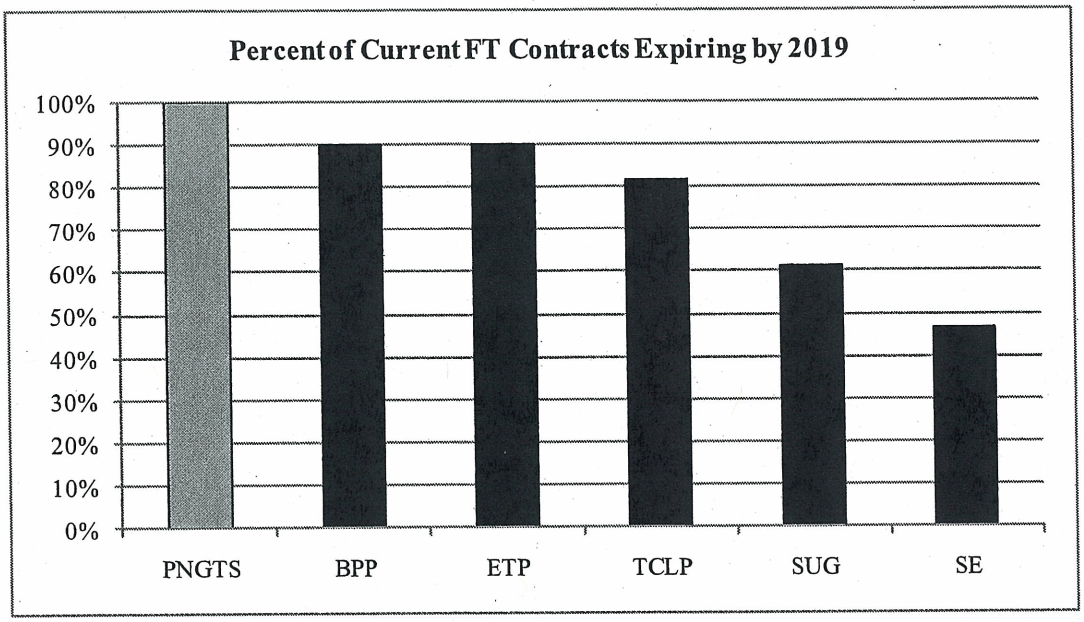
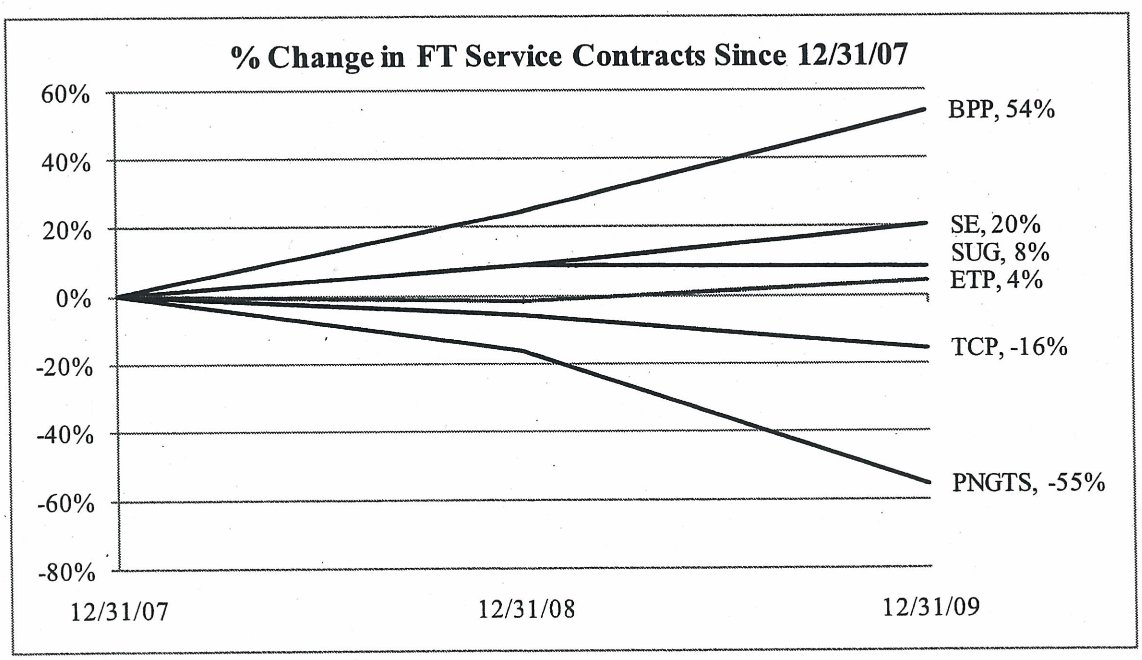


Figure 13 shows the percentage change in FT service contracts as of December 31 of the last three years for PNGTS and members of the ROE proxy group.

Figure 13



Relative to the rest of witness Hevert's proxy group companies, PNGTS:

1. Has experienced the ***largest*** percentage decrease in contracted FT capacity.
2. Has the ***highest*** percentage of total capacity exposed to renewal risk as of 2019; and
3. Has had the ***least*** success in renewing existing contracts for FT service and attracting new FT contracts.

Based on the results of these assessments of capacity subscription and renewal-related risk, PNGTS is likely the riskiest, and certainly substantially above average in terms of risk, when compared to the other members of witness Hevert's proxy group.

Q. In addition to trends in subscribed capacity, what other factors are important to investigate to determine the overall business risk of the proxy group companies?

A. There are several additional factors that indicate the extent to which a pipeline is in a strong competitive position and therefore possesses less business risk. Completed expansion projects and expansion projects for which authorization have been requested from the FERC are a clear indication of market demand for pipeline capacity. All of the proxy group members own pipelines that have expanded their systems over the last several years and all proxy group members have several planned expansion projects. Exhibit No. PNG-42 provides a detailed review of these completed system expansion projects and planned FERC-approved system expansion projects. With no historic or planned expansions, PNGTS is again at the bottom of the list in terms of demand for new capacity on its pipeline.

Q. How does PNGTS' credit rating compare to the members of the proxy group?

A. Table 17 compares the S&P credit ratings of PNGTS and the proxy group companies.

Table 17 – S&P Credit Ratings [53]

Company	Issuer Rating	Outlook
PNGTS	BBB-	Negative
Boardwalk Pipeline Partners LP	BBB	Stable
Energy Transfer Partners LP	BBB-	Negative
Southern Union Company	BBB-	Stable
Spectra Energy	BBB+	Negative
TC Pipelines LP	Not Rated	Not Rated

No member of the proxy group has a worse credit rating than PNGTS (BBB- with a "negative" outlook). This is the lowest investment grade rating available from S&P. Any further deterioration in its rating will move PNGTS into "junk bond" status.

Q. What rational does S&P provide for PNGTS' BBB- credit rating?

A. [redacted]

[53] Source: S&P Website as of 4/21/2010.

[redacted]

[redacted]

Section V: Base Period Adjustments

Q. Are PNGTS' base period discretionary service revenues sustainable?

A. No. PNGTS' base period discretionary service revenues generated from interruptible transportation service ("IT") and park and loan service ("PAL") were impacted by certain extraordinary and non-recurring events. These events artificially inflated discretionary service revenues during the base period. I am proposing certain adjustments in order to normalize the base period numbers.

Q. What base period discretionary service revenue adjustments are you proposing?

A. Table 18 summarizes my proposed adjustments, followed by a detailed explanation of each of the items in the table and how they affect revenues.

Table 18

Adjustments	**IT**	**PAL**	**Total**
Lower Future Seasonal Multiplier	($311,427)	($21,124)	($332,551)
SOEI Maintenance	($197,275)	($13,078)	($210,354)
Higher Upstream Costs	($658,220)	N/A	($658,220)
Total Adjustments	($1,166,923)	($34,202)	($1,201,125)
Recorded Revenue (Net of ACA)	$3,194,134	$617,156	$3,811,289
Total Adjustments	($1,166,923)	($34,202)	($1,201,125)
Adjusted Test Year Revenue	$2,027,211	$582,954	$2,610,165

<u>Lower Multiplier</u>

During the period of November 1, 2008-March 31, 2009 a 250% recourse rate multiplier was in effect for short term services, consistent with PNGTS' filed rates in Docket No. RP08-306. In a subsequent settlement filed with FERC on May 11, 2009, the multipliers

54 [redacted]

for the rate for short-term services, which include IT and PAL, were decreased to the levels shown in Table 19:

Table 19

Month	Settlement Multipliers (effective June 1, 2009)	RP08-306 Filed Multipliers (effective September 1, 2008)
January	150%	250%
February	150%	250%
March	60%	250%
April	60%	250%
May	60%	250%
June	100%	250%
July	100%	250%
August	100%	250%
September	60%	250%
October	60%	250%
November	150%	250%
December	150%	250%

Given that lower rate multipliers are now in effect, it would be incorrect to presume that PNGTS could generate the same level of discretionary revenues it attained during the base period going forward. Adjusting the base year revenues to reflect the settlement multipliers reduces IT revenues by $311,427 and reduces PAL revenues by $21,124. These calculations are provided in Exhibit Nos. PNG-43 and PNG-44, respectively.

<u>Sable Offshore Energy, Inc. ("SOEI") - Non-routine Major Maintenance Outage</u>

The demand for short term transportation services on PNGTS is directly affected by the availability of supplies on M&NE. Prior to the Canaport liquefied natural gas facility coming on-line, the only direct sources of supply connected to the M&NE system were Sable Island and PNGTS (Corridor Resources has some small wells in New Brunswick that connect to M&NE Canada, but these are a very small percentage of the total flow on M&NE). Previous interruptions in Sable supply have created increased market opportunities for PNGTS. The base year included a 24 day total planned major maintenance outage of the SOEI system (August 8, 2009 – August 31, 2009). During this outage the flows from SOEI were completely interrupted and M&NE customers needed to source their gas from PNGTS and Canaport. The average IT flows on PNGTS during this outage were 22,219 Dth/day, with a peak of 106,079 Dth/day. These flows likely would not have occurred had SOEI remained online. In addition, this outage was a non-routine major maintenance event. The IT revenues beyond an average base, post-Canaport, summer level collected during this time period of $197,275 therefore cannot be reasonably expected to recur in future years and should be subtracted from the base year revenues. The PAL revenue should be reduced by $13,078 to reflect revenues that, similarly, wouldn't have been captured. These data supporting these proposed IT and PAL revenue adjustments are provided in Exhibit Nos. PNG-45 and PNG-46, respectively.

Canaport came on line approximately one month prior to the outage. Although it helped to meet the spot demand during August 2009, it is expected that, as time goes on, Repsol will capture a much greater portion of New England spot and term business as it adds market counterparties to their portfolio. Repsol's market penetration is already evident. During the August, 2009 Sable outage Canaport averaged flows of 163,000 Dth/day into the U.S. From the end of the Sable Outage to April 30, 2010, that average increased to 241,000 Dth/day. With the capacity to deliver up to 730,000 Dth/day on its firm M&NE contract, Repsol should continue to dramatically increase its market penetration.

Higher Upstream Costs

The market value of IT service on PNGTS is largely dependent on the difference between the market price at Dracut and the supply price at Pittsburg. Anything that increases the supply cost, all else equal, decreases the price that the market is willing to pay for IT service on PNGTS. Effective January 1, 2010, short-haul tariff rates on TCPL increased by 36% (from $0.4250/Dth to $0.5768/Dth). This change in upstream economics is not reflected in the majority of the base year revenues. Adjusting the base year IT revenues for the increase in upstream transport costs by multiplying the $0.1518 increase in Dawn to East Hereford rate by the adjusted base year average IT flow of 11,880 Dth/day results in a $658,220 reduction in IT revenues.[55] Supporting calculations for this adjustment are provided in Exhibit No. PNG-47. This quantification does not include the impact of the $0.526 increase in upstream long-haul unit rates which would further reduce the price the market would be willing to pay for IT service on PNGTS.

Section VI: Conclusions

Q. Please summarize your conclusions.

A. PNGTS has a much higher than average level of business risk compared to the members of witness Hevert's proxy group as well as the pipelines competing with PNGTS to serve the Boston-area market. Relative to these pipelines:

1. PNGTS' capacity level and long-term MDQ subscriptions are shrinking. PNGTS has experienced a ***decrease*** in contracted FT capacity of 45% for the three years ending 12/31/09, compared to an average ***increase*** of 15% for the other members of the proxy group.
2. PNGTS has almost no rolled-over long-term FT contracts. Other pipelines are regularly rolling over long-term FT contracts. The only FT contracts PNGTS has been able to secure over the last three years have been short-term in nature, ranging from 29 days to 365 days and averaging only 131 days.
3. The relatively short weighted average duration of PNGTS' existing FT contracts exposes it to significant renewal risk.
4. PNGTS is the highest cost, least economic route into the Boston-area market.
5. The New England market is overbuilt already with more supply on its way. PNGTS is not likely to see any additional demand for its services from the increase in domestic supplies.
6. New England market demand is expected to shrink.
7. Exports of natural gas produced in Canada to the U.S. are dropping. U.S. domestic production is growing.

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[55] Actual base year average daily IT volume of 13,058 Dth/day was adjusted downward by 1,177 Dth/day to account for the above-normal IT volumes PNGTS experienced due to the 24 day SIOE non-routine major maintenance outage in August, 2009.

8. PNGTS shares the worst bond rating of any S&P-rated member of witness Hevert's proxy group (only ETP shares PNGTS' BBB-/ON rating from S&P).

In addition to the conclusions regarding PNGTS' risk, I have concluded that PNGTS' base year revenues should be adjusted downward by $1,201,125 to account for extraordinary and non-recurring events pertaining to discretionary revenues on PNGTS. Without recognition of these adjustments, the use of historical base period numbers, which are stale and unrepresentative of future operating circumstances, will produce levels of discretionary revenues which are not sustainable for PNGTS.

Q. Does this conclude your direct testimony?

A. Yes.

AFFIDAVIT

STATE OF Massachusetts)
) ss.
COUNTY OF Middlesex)

John J. Reed, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of John J. Reed"; that, if asked the questions which appear in the text of said answering testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, answering testimony in this proceeding.

John J. Reed

Subscribed and sworn to before me, a Notary Public in and for Middlesex County, Massachusetts, this 10th day of May, 2010.

Joanne P. Bickford
Notary Public

My Commission expires:
Oct. 15, 2015

JOANNE P. BICKFORD
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS
MY COMMISSION EXPIRES
OCTOBER 15, 2015