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File No. 339583-000187

By Electronic Filing

January 28, 2015

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli

Re: Union Gas Limited ("Union")
Dawn Parkway 2016 Expansion Project
Board File No.: EB-2014-0261

Further to Procedural Order No. 1 dated November 18, 2014, please find enclosed responses to the IRs from Board Staff and Union Gas prepared by John A. Rosenkranz on behalf of Canadian Manufacturers & Exporters (CME), Federation of Rental-housing Providers of Ontario (FRPO) and Ontario Greenhouse Vegetable Growers (OGVG).

Yours very truly

Per Vincent J. DeRose
VJD/kt
Encls.
c. Karen Hockin (Union)
Crawford Smith (Torys LLP)
Intervenors EB-2014-0261
Paul Clipsham (CME)

OTT01: 6784403: v1

Written Evidence of John A. Rosenkranz for CME, FRPO, and OGVG

Answer to Interrogatory from Board Staff

Staff Interrogatory 1

Ref: Intervenor Evidence by John A. Rosenkranz prepared for CME, FRPO, OGVG, page 1 lines 26-29 and page 2 lines 2-5.

Preamble: The evidence proposed that the Board approve the proposed 2016 Dawn Parkway expansion with two conditions: 1) That Enbridge and Gaz Metro should be required to extend the terms of their existing contracts on the Dawn-Parkway transmission system to a date that is at least 5 years from the in-service date of the 2016 Dawn Parkway expansion. 2) That the Board should set a floor on the share of the Dawn Parkway system costs allocated to ex-franchise customers for transportation services, with a purpose to limit future cost shifting from ex-franchise transportation customers to Union's distribution customers.

Question:

a) Regarding the first condition proposed on behalf of CME, FRPO and OGVG, please discuss the Board's jurisdiction to require Enbridge and Gaz Metro to extend the terms for all of their Dawn-Parkway and Dawn-Kirkwall contracts.
b) Regarding the second condition proposed on behalf of CME, FRPO and OGVG, please discuss the Board's jurisdiction to set a cost allocation type condition outside of its rates proceedings.
c) Please confirm the Board staff's understanding that the proposed conditions are intended to:
    i) minimize uncertainty with respect to the level of demand (need) for the 2016 Dawn Parkway new capacity proposed by Union; and
    ii) minimize the potential risk to in-franchise distribution customers because ex-franchise turn back notification may not occur until after 2016.

Answer:

a) The recommended condition does not contemplate that the Board would assert jurisdiction over Enbridge or Gaz Metro. The Board would use its jurisdiction to approve or not approve the construction of new facilities by Union Gas to condition its approval on Union taking additional steps to demonstrate need. Union would ensure that the proposed facilities are supported by long-term commitments to Dawn-Parkway transmission capacity by negotiating term extensions for the existing contracts held by the two ex-franchise customers that are causing the new facilities to be built.

b) In approving Enbridge's construction of Segment A as part of the GTA Project in EB-2012-0451, the Board used its jurisdiction in a leave to construct proceeding to set a condition on how the costs of new gas transmission line would be allocated in a future rate proceeding if the start of transmission services was delayed. Defining how the costs of new facilities will be recovered in future rates at the time the facilities are approved reduces uncertainty for the applicant and ratepayers

c) Confirmed.

Written Evidence of John A. Rosenkranz for CME, FRPO, and OGVG

Answer to Interrogatory from Union Gas

Union Gas Interrogatory 1

Ref: Page 5, lines 21-23

Preamble: "All of the Dawn-Parkway transportation contracts held by Northeast U.S. LDCs with expiration dates in 2016 were recently extended to October 31, 2017. However there are several reasons that the turnback risk associated with these contracts is likely to increase."

Question:

Has Mr. Rosenkranz had any communications with the Northeast U.S. LDCs that would suggest that they intend to, or are likely to, turnback capacity on the Union Gas System? If so, please provide a summary of the communications, identify the customers and provide the amount of capacity that might be turned back.

Answer:

Mr. Rosenkranz has not had any communications with Northeast U.S. LDCs about their plans to renew or not renew contracts for Union Gas transportation services.

Written Evidence of John A. Rosenkranz for CME, FRPO, and OGVG

Answer to Interrogatory from Union Gas

Union Gas Interrogatory 2

Ref: Page 8, Table 6

Preamble: "Table 6: Delivered Cost of Gas into IGTS (US$/MMBtu)"

Question:

Please expand Table 6 from Mr. Rosenkranz's testimony to compare the delivered cost of gas into IGTS for each of 60 day service, 30 day service, and 10 day service.

Answer:

Delivered Cost of Gas into IGTS (US$/MMBtu)

	Transportation Path		Pipeline Fixed Cost	Basis vs. NYMEX	Gas Cost into IGTS				
					365 Days	90 Days	60 Days	30 Days	10 Days
1	Dawn-Iroquois	2014 Tolls	0.38	+ 0.25	+ 0.63	+1.77	+2.57	+4.88	+14.11
2	Dawn-Iroquois	2015 Tolls	0.57	+ 0.25	+ 0.82	+2.55	+3.76	+7.26	+21.23
3	Constitution Pipeline	Recourse Rate	0.65	- 0.25	+ 0.40	+2.35	+3.69	+7.62	+23.30
4	Dominion New Market	Recourse Rate	0.74	- 0.25	+ 0.49	+2.71	+4.29	+8.82	+26.90

Written Evidence of John A. Rosenkranz for CME, FRPO, and OGVG

Answer to Interrogatory from Union Gas

Union Gas Interrogatory 3

Ref: Page 6, lines 23-24

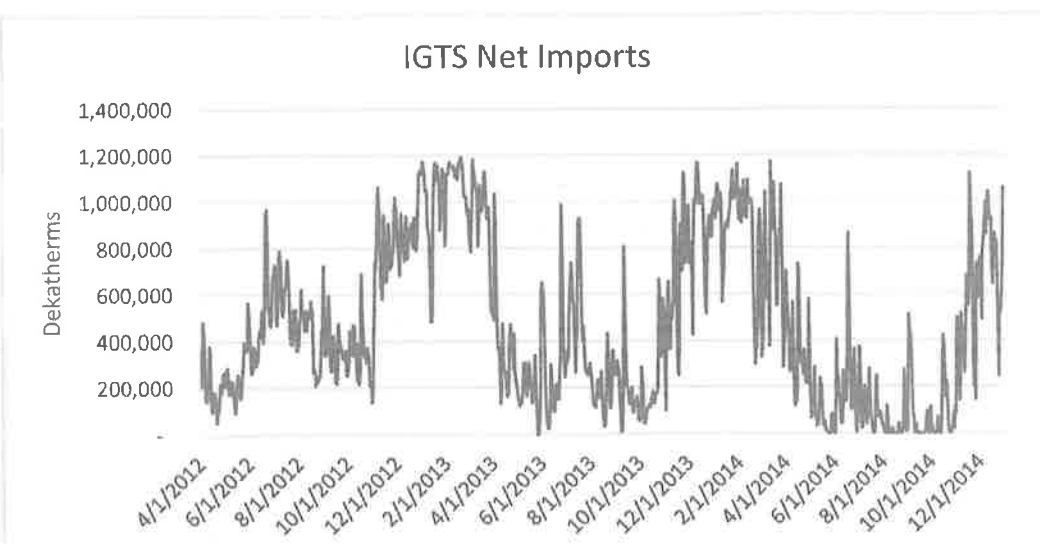
Preamble: "New pipeline projects that are currently in development will reduce IGTS shippers' dependence on Canadian pipeline services upstream of Iroquois."

Question:

a) Please provide the analysis relied upon by Mr. Rosenkranz to reach the conclusion that "the new pipeline projects that are currently in development will reduce IGTS shippers' dependence on Canadian pipeline services upstream of Iroquois." Please be specific, and differentiate between dependence on annual pipeline flows vs. pipeline capacity requirements for peak period services.
b) Are the pipelines identified in Table 5 of Mr. Rosenkranz's testimony expected to be used to provide high load factor service, or will they be used primarily to meet peak period requirements?
c) In the event you have not completed your analysis based on peak flow requirements, please update your analysis so that it is based on peak flow requirements.

Answer:

a) This conclusion was based on Mr. Rosenkranz's experience as a member of the Management Committee for the IGTS partnership in the late 1990s, and his review of subsequent IGTS expansion projects. Mr. Rosenkranz also examined TCPL daily scheduled receipts and deliveries of gas at Iroquois since April 2012, which were used to create Figure 1 on page 8. The daily analysis is shown. Finally, Mr. Rosenkranz examined scheduled receipts and deliveries at all IGTS points during the January 2013 cold snap. This analysis is included as an attachment.



Union Gas Interrogatory 3 (continued)

b) It is not certain how the additional pipeline capacity be used, but inferences can be made based on the characteristics of the shippers that have purchased long-term firm transportation service. With respect to Constitution Pipeline, two gas producers have contracted for the initial 650,000 Mcf/day of firm transportation capacity to Wright, NY. It would be reasonable to expect that these shippers will use Constitution Pipeline to deliver Marcellus gas production to markets throughout the year.

With respect to the Dominion New Market project, the two long-term firm shippers are gas distribution companies: Niagara Mohawk (NIMO) and Brooklyn Union Gas Company (BUG). Because distribution companies generally include baseload, winter season, and peaking resources in their gas supply portfolios, the new pipeline capacity could be used either to provide high load factor or peak period service. It is also possible that these companies will use the new pipeline capacity to replace existing gas supplies delivered into IGTS, which are currently being used mainly during peak winter periods. The contract review that Mr. Rosenkranz undertook to assess Dawn-Parkway turnback risk revealed that NIMO holds 55,123 GJ/day of Dawn-Parkway transportation service and 54,437 GJ/day of Parkway-Iroquois transportation service on TCPL. BUG holds three contracts for a total of 87,189 GJ/day of Dawn-Parkway transportation service, 86,168 GJ/day of TCPL Parkway-Iroquois transportation service, and 80,936 MMBtu/day of IGTS transportation service with receipt at Iroquois. The contracts for Dawn-Parkway transportation service currently have expiration dates of October 31, 2017 and October 31, 2018.

It is not known who would be the shippers on the proposed TGP pipeline project from Pennsylvania to Wright, NY, or how these shippers would utilize the new pipeline capacity.

Attachment to Union Gas Interrogatory 3

IROQUOIS SCHEDULED RECEIPTS AND DELIVERIES

Dth

		23-Jan-13			24-Jan-13			25-Jan-13		
		Receipt	Delivery	Net Receipt	Receipt	Delivery	Net Receipt	Receipt	Delivery	Net Receipt
TCPL	Waddington	141,548	1,218,801	1,077,253	204,281	1,083,352	879,071	208,080	1,242,164	1,034,084
St. Lawrence	Lisbon	7,341		(7,341)	4,841		(4,841)	2,601		(2,601)
St. Lawrence	Edwards	2,120		(2,120)	2,120		(2,120)	2,120		(2,120)
National Grid	Croghan	42,000		(42,000)	39,000		(39,000)	37,000		(37,000)
St. Lawrence	New Bremen	1,247		(1,247)	1,247		(1,247)	1,247		(1,247)
NYSEG	Burdick Xing	3,321		(3,321)	3,463		(3,463)	2,992		(2,992)
National Grid	Boonville	150		(150)	135		(135)	120		(120)
DTI	Canojaharie	9,971		(9,971)	12,697		(12,697)	15,216		(15,216)
TGP	Wright	302,046	20,185	(281,861)	263,360	77,837	(185,523)	285,908	10,563	(275,345)
Athens Gen.	Athens			0	0		0	0		0
Cent. Hudson	Pleasant Valley	43,326		(43,326)	43,826		(43,826)	26,826		(26,826)
				685,916			586,219			670,617
AGT	Brookfield	62,649	360,124	297,475	45,643	338,436	292,793	70,867	308,375	237,508
TGP	Shelton A	79,761	5,012	(74,749)	104,575		(104,575)	85,101		(85,101)
Yankee	New Milford	20,000		(20,000)	17,500		(17,500)	16,500		(16,500)
Yankee	Shelton B	12,500		(12,500)	10,000		(10,000)	9,000		(9,000)
SCG	Milford	39,658		(39,658)	40,075		(40,075)	38,267		(38,267)
B'port Power	Stratford	56,150		(56,150)	53,800		(53,800)	7,980		(7,980)
Milford Power	Milford B	92,099		(92,099)	85,793		(85,793)	69,980		(69,980)
NRG	Devon	0		0			0	0		0
GenConn	Devon B	0		0			0	0		0
				(220,407)			(207,168)			(141,727)
National Grid	Northport	40,000		(40,000)	40,000		(40,000)	40,000		(40,000)
National Grid	South Commack	433,785		(433,785)	399,263		(399,263)	432,885		(432,885)
Con Ed	Hunts Point	217,365		(217,365)	151,750		(151,750)	222,421		(222,421)
				(691,150)			(591,013)			(695,306)

Source: IGTS Operationally Available Capacity Report

Written Evidence of John A. Rosenkranz for CME, FRPO, and OGVG

Answer to Interrogatory from Union Gas

Union Gas Interrogatory 4

Ref: Page 9, lines 14-27

Preamble:

"Finally, as Marcellus shale gas production continues to grow, markets in Quebec and eastern Ontario may be able to reduce delivered gas costs by turning back Dawn-Parkway transportation service and replacing gas delivered through Dawn with Marcellus gas imported through Iroquois. Gas produced in the Northeast U.S. is expected to provide a greater share of the gas consumed in eastern Canada, and Iroquois provides a more direct route from the Marcellus producing areas in Pennsylvania to markets in Quebec than transportation paths that flow through Niagara or Dawn. Although the Iroquois path is not currently a viable alternative for Canadian markets—the interconnection at Iroquois does not allow gas to physically flow from IGTS into TCPL—this is expected to change. TCPL is offering Iroquois as a receipt point in its 2017 new capacity open season, and IGTS has proposed a project to reverse flows on the U.S. side of the border. In recent filings at the NEB, TCPL has described changes in market activity that indicate that 'Iroquois is trending toward becoming a physical receipt point into the Mainline system.' TCPL's long-term market study projects that Iroquois will become a net import point on an average annual basis as early as 2018."

Question:

a) Is the demand for pipeline capacity on the Dawn Parkway System and on IGTS determined by annual load requirements, or peak period requirements?
b) Please explain why annual flows on IGTS would impact the demand for peak period capacity on IGTS or for capacity to deliver natural gas to Iroquois.

Answer:

a) Mr. Rosenkranz's opinion is that the demand for pipeline capacity on the Dawn Parkway System and on IGTS is currently being driven mainly by gas requirements during the winter peak period, but that annual load requirements also enter into the decision to contract for firm transportation services.

b) Mr. Rosenkranz interprets this question to refer to the potential for new south-to-north contracts on IGTS. If shippers contract for south-to-north firm transportation service on IGTS to Iroquois, and firm transportation service on TCPL from Iroquois to markets in the EDA, this service will be available year-around, but could be used either for peak period or annual gas supply. Annual contracts for south-to-north service on IGTS and TCPL will not necessarily impact the demand for peak period capacity to deliver gas to Iroquois. As discussed elsewhere in Mr. Rosenkranz's testimony, the demand for Canadian transportation capacity to deliver natural gas to Iroquois is more likely to be affected by new pipeline capacity that will deliver gas into IGTS downstream of Iroquois.

Written Evidence of John A. Rosenkranz for CME, FRPO, and OGVG

Answer to Interrogatory from Union Gas

Union Gas Interrogatory 5

Ref: Page 12, lines 11-14

Preamble:

"Given the similarities between Union's situation and the situation faced by TCPL, the Board should provide an opportunity for stakeholders to consider whether a term-up provision like the provision approved for TCPL should be implemented by Union Gas for future expansion projects."

Question:

Please identify the similarities between Union's situation and the situation faced by TCPL.

Answer:

Both TCPL and Union are responding to requests for new short-haul services from Dawn to markets in Ontario and Quebec that require new facilities. Both TCPL and Union face uncertainty about the long-term demand for transportation services, and potential turnback by existing shippers, caused mainly by the expansion of Marcellus and Utica shale gas production in the Northeast U.S.

Written Evidence of John A. Rosenkranz for CME, FRPO, and OGVG

Answer to Interrogatory from Union Gas

Union.6

Reference: CV of John Rosenkranz

Question:

Please provide a list of all regulatory proceedings in which Mr. Rosenkranz has testified on matters specific to Gas Supply within the last 4 years and provide a copy of all testimony (written and transcripts).

Answer:

Mr. Rosenkranz has identified two cases in which he testified on matters specific to gas supply within the last four years:

Portland Natural Gas Transmission System Rate Case
Case #: FERC Docket RP10-729
Client: Maine Public Advocate
Scope: Rebuttal testimony on the market risks faced by the pipeline.

UNS Gas Inc. Rate Case
Case #: ACC Docket No. G-04204A-11-0158
Client: Arizona Corporation Commission Utilities Division Staff
Scope: Review gas procurement activities. Testimony with findings and recommendations.

The written testimony for these two cases is provided. Mr. Rosenkranz was not cross examined in either of these cases.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Portland Natural Gas Transmission System)　　Docket No. RP10-729-000

Prepared Answering Testimony of John A. Rosenkranz
On Behalf of
the Maine Public Advocate

Q. Please state your name and business address.

A. My name is John A. Rosenkranz. My business address is 56 Washington Drive, Acton, Massachusetts 01720.

Q. By whom are you employed?

A. I am Principal with North Side Energy, LLC, a consulting company.

Q. Please describe your professional background and experience.

A. I have over twenty years experience as a natural gas market analyst and project manager for natural gas pipeline companies, natural gas storage developers and power generation companies, including J. Makowski Company, PG&E Gas Transmission, and Calpine Corporation. Since 2006 I have been an independent consultant based in the Boston area, where my clients include electricity generators, energy regulators and other public power agencies. I have appeared as an expert witness before several state and provincial regulatory boards. I received a BA in economics from George Washington University and completed all course and examination requirements for a doctorate in economics at Northwestern University.

Q. Have you previously testified before the Federal Energy Regulatory Commission?

A. Yes. I submitted testimony on New England natural gas markets in the Maritimes & Northeast Pipeline RP04-360 rate proceeding.

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

A. I am sponsoring testimony on behalf of the Maine Public Advocate.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to portions of the pre-filed direct evidence of Portland Natural Gas Transmission System (PNGTS) witnesses John J. Reed and Barry E. Sullivan (PNGTS Witnesses). I also comment on adjustments to the base period discretionary revenue proposed by Mr. Reed.

Q. Please briefly summarize your testimony.

A. The PNGTS Witnesses state that recent developments have increased the competition faced by PNGTS and caused a permanent reduction in the value of PNGTS transmission capacity. In my opinion, these witnesses err in three main areas:

1. The PNGTS Witnesses fail to consider gas transmission capacity constraints that limit deliverability from LNG import terminals and other supply sources that are alternatives to natural gas transported by PNGTS. This causes them to overstate the degree of competition PNGTS faces from other gas supply infrastructure.
2. The PNGTS Witnesses mischaracterize the location and attributes of the primary end-use markets served by PNGTS. In particular, they downplay the requirements of markets in Maine and New Hampshire for which PNGTS is the sole supplier of natural gas.
3. The PNGTS Witnesses fail to consider all of the service options available to shippers on TransCanada PipeLines (TCPL) to deliver gas into PNGTS. This causes them to draw incorrect conclusions from the expiration of firm transportation service contracts upstream of PNGTS.

With respect to Mr. Reed's proposed adjustment to base period discretionary revenue, I explain why at least two of these adjustments should be rejected.

NATURAL GAS SUPPLY AND INFRASTRUCTURE

Q. Mr. Reed states PNGTS is harmed by increases in the deliverability of re-vaporized LNG to the Boston area (Exhibit PNG-38, p. 13). How does Mr. Reed

describe the deliverability from the Canaport, Northeast Gateway, and Neptune LNG import facilities?

A. Mr. Reed states that Canaport LNG has a firm sendout capacity of 1 Bcf/day, the Northeast Gateway facility has a maximum sendout capability of 800 MMcf/day and Neptune LNG will have a maximum sendout capability of 700 MMcf/day, for a total of 2,500 MMcf/day (Exhibit PNG-38, p. 12). In response to data requests, Mr. Reed clarified that these three facilities have a total peak sendout capacity of 2,350 MMcf/day and an average or sustainable deliverability of about 1,900 MMcf/day (Reponses to MPA-PNGTS 1-17 and MPA-PNGTS 1-18).

Q. Do these three LNG facilities represent a change in circumstances since the RP08-306 test period?

A. No. All three facilities were either in service or under construction during the RP08-306 test period. The size and location of these facilities were therefore known at the time of that proceeding.

Q. How do the sendout capacities cited by Mr. Reed overstate the actual deliverability from these facilities?

A. These numbers measure the physical capacity of the LNG terminal to inject natural gas into the natural gas transmission grid, but only if the pipeline capacity is available to take the gas away from the facility. In fact, the sendout capacity of each of these facilities exceeds the capacity on the downstream pipeline systems. In addition, because all three facilities deliver into the same downstream pipelines, there are limitations on the combined deliveries from the three terminals.

Q. Please explain.

A. Natural gas from the Canaport LNG terminal is delivered through Brunswick Pipeline, which has a single point of delivery into Maritimes & Northeast Pipeline (M&N) at Baileyville, ME. With the completion of the Phase IV Expansion Project in 2009, M&N has a total receipt capacity of approximately 850 MMcf/day. This restriction applies to the combined receipts from Brunswick Pipeline and M&N's Canadian affiliate (M&N Canada). Sendout from the Canaport LNG terminal is therefore limited to the M&N receipt capacity of 850 MMcf/day minus the quantity of gas being exported from production in Nova Scotia and New Brunswick

Northeast Gateway and Neptune LNG are offshore terminals that connect to the Algonquin Gas Transmission (AGT) HubLine pipeline in Massachusetts Bay. The HubLine pipeline is a subsea pipeline that extends from an interconnection with M&N at Salem, MA to Weymouth, MA, where it connects with the rest of the AGT system. AGT's capacity to receive gas from the HubLine pipeline at Weymouth is between 400 MMcf/day and 500 MMcf/day.[1] This takeaway constraint applies to sendout from the Northeast Gateway and Neptune LNG terminals and as well as deliveries of Canaport LNG and Nova Scotia and New Brunswick production that enter HubLine from M&N.

Q. What other recent developments reduce competition from imported LNG?

A. At the time of the RP08-306 proceeding, there were two major gas transmission projects in active development to expand M&N mainline capacity and increase AGT's capacity to receive gas from the HubLine pipeline. Neither of these projects has gone forward as planned.

The first project, the M&N Phase V Project, would have increased M&N's firm deliverability by 170 MMcf/day during the summer and 200 MMcf/day during the winter months. The proposed in-service date for this expansion was November 2010. M&N initiated the FERC pre-filing review of the Phase V project in March 2008, during the RP08-306 test period.[2] The project was cancelled in March 2009.

The second project, the HubLine/East to West Project (E2W Project), was intended to greatly expand AGT's capacity to receive gas from the Northeast Gateway, Neptune and Canaport LNG terminals through the HubLine pipeline. AGT explained that this

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[1] The AGT website showed "AGT East to West" design capacity of 434 MDth/day as of 1/07/2011.

[2] FERC Docket PF08-17.

project was necessary because the HubLine pipeline alone "does not permit the full leverage of the supplies that are now becoming available on Algonquin's east end".[3] The original E2W Project application in June 2008 included pipeline replacement and looping downstream of the HubLine terminus at Weymouth, MA to expand AGT's east-to-west transportation capacity to approximately 1 Bcf/day. The owners of the Northeast Gateway and Neptune LNG facilities committed to a total of 725 MDth/day of firm transportation service from HubLine receipt points.

In June 2009, after the end of the RP08-603 test period, AGT amended its FERC application so as to reduce significantly the scope of the E2W Project. The pipeline facilities needed to debottleneck the AGT system downstream of the HubLine pipeline were eliminated from the project, and the combined commitment of the Northeast Gateway and Neptune LNG owners for firm transportation service from HubLine receipt points was reduced from 725 MDth/day to 260 MDth/day.

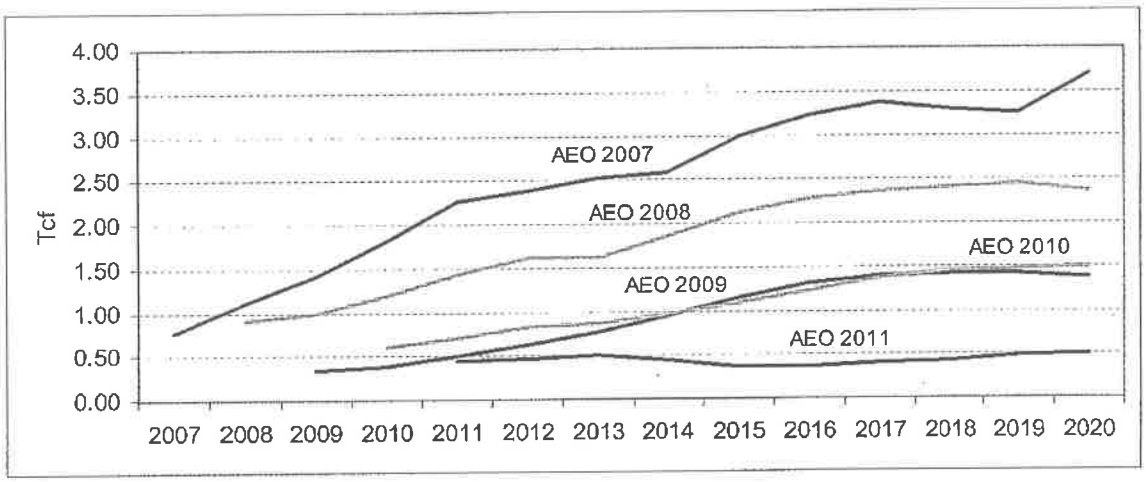
Q. Are there other recent developments that reduce the competition PNGTS faces from imported LNG?

Yes. The expectations for growth in LNG imports have changed considerably since the end of the RP08-306 test period. As Figure 1 illustrates, the Energy Information Administration (EIA) Annual Energy Outlook forecasts of net LNG imports into the U.S. for 2009 and 2010 showed much lower rates of growth than the 2007 and 2008 forecasts. The AEO2011 forecast released on December 16, 2010 is even lower, showing no growth in net LNG imports through 2010. According to the EIA, "U.S. net imports of LNG in the AEO2011 Reference case are lower than in the AEO2010 Reference case, due in part to less world liquefaction capacity and greater world regasification capacity, as well as increased use of LNG in markets outside North America.... Lower natural gas prices in the United States are also a contributing factor."[4] Although the Canaport LNG terminal is located in Canada, its primary purpose is to supply the U.S. market. It is therefore improbable that Canaport LNG

[3] "Application of Algonquin Gas Transmission, LLC for a Certificate of Public Convenience and Necessity", Docket No. CP08-420-000, p. 29.
[4] EIA, Annual Energy Outlook Early Release, Report Number DOE/EIA-0383ER(2011)

will be entirely immune to market developments that are expected to greatly reduce net LNG imports into the U.S.

Figure 1: EIA Forecasts of Net Imports of LNG through 2020



Source: Energy Information Administration, Annual Energy Outlook

PNGTS MARKETS

Q. Do you agree with Mr. Reed that the primary destination for natural gas shipped on PNGTS is the "Boston-area market"?

A. No, I do not. Mr. Reed defines the "Boston-area market" as "the geographic region of Boston and surrounding markets", which does not include markets in Maine (Response to MPA-PNGTS 1-6). Mr. Reed lists numerous natural gas supply alternatives that are generally available to serve end-users in New England as evidence that "PNGTS is in an intensely competitive environment given capacity serving the Boston-area market" (Exhibit PNG-38, p. 4). In fact, a substantial portion of the gas shipped on PNGTS is delivered to captive markets that have no other source of natural gas, or markets where the alternatives to PNGTS for firm physical gas supply are limited. The importance of PNGTS for industrial customers in Maine is described by Mr. Glenn S. Poole of Verso Paper in his testimony (Exhibit No. MPA-4).

PNGTS has eight active delivery meters supplying markets that must have access to PNGTS to meet their natural gas requirements. Five of these meters are located north of Westbrook, ME on PNGTS' wholly-owned pipeline. The other three points are delivery meters on the Joint Facilities pipeline that are exclusive PNGTS meters, meaning that PNGTS has 100 percent of the delivery meter capacity entitlement under the Ownership Agreement between PNGTS and M&N. For the year ending August 31, 2010, these captive points received an average of 49,950 Dth/day, and accounted for nearly one-half of the total gas delivered by PNGTS (see Exhibit No. MPA-2). The combined peak deliveries to these points was 135,750 Dth/day, and the coincident peak was 75,865 Dth/day. The remaining deliveries are made (a) at delivery meters on the Joint Facilities pipeline that can be supplied by either PNGTS or M&N (27%), (b) at the interconnection with Tennessee Gas Pipeline (TGP) at Dracut, MA (22%), or (c) at the interconnection with M&N at Westbrook, ME (1%).

Q. How do you reconcile this description of the PNGTS market with the fact that much of the firm transportation service sold by PNGTS has Dracut as a primary delivery point?

A. PNGTS was developed as an integrated pipeline system with postage stamp rates. This means that all firm shippers can deliver to any PNGTS delivery point—including meters on the Westbrook, Newington, and Rumford-Jay laterals—on a secondary basis with no added cost. Under these circumstances it has made sense for firm shippers on PNGTS to contract for all or some portion of their transportation service to the southern end of the pipeline at Dracut, regardless of the specific market this capacity was originally intended to serve. Contracting for capacity over the full length of the pipeline gives shippers the flexibility to divert gas to alternate markets and maximize any potential value from segmenting capacity.

Q. How do you describe PNGTS' competitive position at Dracut?

A. PNGTS is a source of winter-season supply for gas market participants who purchase gas at Dracut or use PNGTS capacity to deliver gas through this point. As shown by

Exhibit No. MPA-2, 87 percent of scheduled deliveries at Dracut during the 12 months ending August 31, 2010 were made during the five winter months.

Q. Mr. Sullivan states that PNGTS shippers with primary delivery rights at Dracut could switch to firm transportation service from TGP (Exhibit PNG-07, p.12). Do you agree?

A. No. Since PNGTS and M&N commenced operations in 1999, TGP has undertaken several expansion projects to supply incremental requirements from gas received at Dracut (see Table 1). Because TGP has not made corresponding expansions to west-to-east capacity into Dracut, or directly to these same markets, New England markets connected to TGP currently depend on Dracut receipts from PNGTS to meet peak day demand. This indicates that it would not be possible for all PNGTS firm customers with primary delivery rights at Dracut to switch to TGP service with delivery to Dracut without investments to expand TGP west-to-east capacity.

Table 1: Tennessee Gas Pipeline Expansions with Primary Receipt at Dracut, MA

Project	FERC Docket	Capacity (Dth/day)	Receipt Point	Delivery Point	In-Service Date
Eastern Express 2000	CP99-262	288,000	Dracut, MA	MA & CT delivery points	JAN 2001
Londonderry Lateral Expansion	CP00-48	130,000	Dracut, MA	Londonderry, NH	SEP 2001
Fitchburg Lateral Expansion	CP08-63	12,300	Dracut, MA	Lunenburg, MA	AUG 2009
Concord Expansion	CP08-65	30,000	Dracut, MA	Laconia, NH	OCT 2009
Northampton Lateral Expansion	CP11-36	6,100	Dracut, MA	Northampton, MA	NOV 2012

Q. Do non-renewals of FT contracts on TransCanada necessarily indicate a lack of demand for PNGTS transportation service?

A. No. Mr. Reed and Mr. Sullivan point to the non-renewal of TCPL contracts for Firm Transportation (FT) service to East Hereford as an indicator of the value for PNGTS transportation service. Mr. Reed states that "[t]he unattactiveness of using PNGTS to ship supplies to the Boston-area market has been confirmed by the relinquishment of upstream capacity" (Exhibit PNG-38, p. 25). Mr. Sullivan states that he "interprets a complete non-renewal of contracts to PNGTS as an indication that there is a lack of demand for pipeline transportation service on PNGTS" (Response to PSG-PNGTS-1.113)

Mr. Reed and Mr. Sullivan focus exclusively on TCPL contracts for FT service to East Hereford, and fail to consider other service options that TCPL shippers can use to deliver gas into PNGTS, such as Short Term Firm Transportation (STFT) service and diversions of FT service with primary delivery to a location other than East Hereford. Unlike most U.S. pipelines, TCPL's standard FT service requires a minimum initial or renewal term of one year. For this reason TCPL also offers STFT service, which has the same priority as FT service, but can be purchased for periods that are greater than six days and less than one year. Diversions allow FT shippers to deliver gas to another delivery point on a day-to-day basis whenever the capacity is available. The shipper pays a volumetric charge to make up any difference between the FT reservation rate to the new delivery point and the rate under the shipper's contract. Because the need for gas at East Hereford is seasonal, and TCPL has recently had open capacity on transportation paths upstream of this point, STFT, FT diversions, and IT services can be reasonable, lower-cost alternatives to FT service. Non-renewal of long-term FT contracts to East Hereford is related to the services and market conditions on TCPL, and does not necessarily indicate a lack of demand of transportation services on PNGTS.

ADJUSTMENTS TO DISCRETIONARY REVENUE

Q. How does Mr. Reed propose to adjust the base period discretionary revenue?

A. Mr. Reed proposes three adjustments to interruptible transportation (IT) and park and loan service (PAL) revenue for the base period. The first proposed adjustment applies to certain transactions during the month of March 2009, when the IT and PAL rate multiplier used by PNGTS was higher than the multiplier subsequently implemented in the RP08-306 proceeding. The "Lower Multiplier" adjustment reduces IT revenue by $311, 427 and PAL revenue by $21,124. The second proposed adjustment applies to a period of 24 days in August 2009 when Sable Island production was interrupted for major maintenance. The "SOEI Maintenance" adjustment reduces IT revenue by $197,275 and PAL revenue by $13,078. For the third proposed adjustment, labeled "Higher Upstream Costs", Mr. Reed reduces IT revenue by $658,220 because of an increase in TCPL tolls that took effect on January 1, 2010. The sum of these three proposed adjustments is $1,201,125. For the reasons explained below, at least two of the adjustments—the PAL portion of the SOEI Maintenance adjustment, and the entire amount of the Higher Upstream Costs adjustment—should be rejected.

Q. Why should the PAL portion of the SOEI Maintenance adjustment be rejected?

A. Mr. Reed explains that the Sable Island curtailment caused PNGTS to experience unusually high IT volumes during a 24-day period in August 2009, but he does not demonstrate any connection between high IT revenue and an increase in PAL revenue. In fact, the daily PAL revenue shown in Exhibit PNG-46 suggests that the reduction in throughput on PNGTS and M&N during the Sable Island curtailment period depressed the demand for PNGTS PAL service. Therefore, Mr. Reed's proposal to subtract $13,078 from the $13,146 of PAL revenue for the month of August 2009 should be rejected.

Q. Please explain why the Higher Upstream Costs adjustment should be rejected.

A. Mr. Reed proposes to reduce the base period IT revenue collected by PNGTS to account for fact that the 2010 transportation tolls on TCPL were higher than the 2009 tolls. The proposed adjustment is $0.1518/Dth, which Mr. Reed estimates to be the change in the TCPL Dawn to East Hereford toll, converted to U.S. dollars per Dth. Mr. Reed states that this proposed adjustment is necessary because "[a]nything that increases the supply cost, all else equal, decreases the price that the market is willing to pay for IT service on PNGTS" (Exhibit PNG-38, p. 56).

Even if Mr. Reed's rationale for this adjustment is accepted--and I explain below why it should not be--there are several problems with Mr. Reed's calculation of the proposed adjustment:

- Mr. Reed subtracts $0.1518/Dth from the actual IT revenue for 63 days for which the posted IT rate was less than $0.15/dth. The adjusted IT revenue for any day should not be less than zero.
- Mr. Reed applies the $0.1518/Dth adjustment to IT volumes during the months of January and February 2011, when the TCPL toll increase was already in effect. If the TCPL toll increase had any effect on PNGTS IT revenue, this effect would already be reflected in the actual revenue for these months.
- Mr. Reed applies the $0.1518/Dth adjustment to IT volumes for days when the IT rate was already capped at the maximum amount. For the days of March 2, 2009 and March 3, 2009, Mr. Reed already subtracted $1.71/Dth from the IT rate that PNGTS shippers actually paid with the Lower Multiplier adjustment, so no additional reduction is necessary.
- Mr. Reed applies an adjustment of $0.1518/Dth, despite evidence that PNGTS prices IT service in whole cents.

The result of these corrections, as shown by Exhibit No. MPA-3, is to reduce the potential adjustment for Higher Upstream Costs from $658,220 to $402,571. However, there are several reasons why the proposed Higher Upstream Costs adjustment should be rejected entirely:

- First, Mr. Reed's analysis is based on the assumption that PNGTS IT customers, or their suppliers, always purchase incremental FT or IT service from TCPL to the East Hereford delivery point. In fact, TCPL shippers can utilize existing TCPL FT capacity, for which the TCPL reservation toll is already a sunk cost, or diversions of existing FT service.
- Second, Mr. Reed implicitly assumes that PNGTS is able to perfectly discriminate with its IT pricing. Only if the actual IT rate charged by PNGTS extracts the entire customer margin for each transaction would an increase in upstream transportation costs result in a one-for-one reduction in the price the customer is willing to pay. In fact, an increase in upstream costs should affect the margins of both the transporter and the customer.

- Finally, Mr. Reed's proposed adjustment is based on an "all else equal" assumption. The 2010 TCPL toll increase that is the basis for Mr. Reed's adjustment affected rates on all transportation paths, not just the rate for transportation to East Hereford. Since TCPL is a significant transporter of natural gas to the Northeast market, a change in TCPL tolls will affect price levels at numerous supply and market points, and change the price differentials that influence the value of PNGTS IT services. More importantly, however, it is unreasonable to adjust base period discretionary revenue for a routine adjustment in TCPL tolls, without considering any of the other numerous factors that affect the value of IT service on PNGTS.[5]

Q. Please summarize your recommendation concerning the proposed adjustments to the base period discretionary revenue.

A. For the reasons stated above, the total adjustment to the base period discretionary should be no greater than $529,826. This is the sum of the Lower Multiplier adjustment ($332,551) and the IT portion of the SOEI Maintenance adjustment ($197,275).

Q. Does this conclude your testimony?

A. Yes. It does.

[5] TCPL tolls are typically reset for each calendar year, and may go up or down. TCPL is currently seeking stakeholder agreement on 2011 tolls to replace the tolls that went into effect on January 1, 2010.

Portland Natural Gas Transmission System

Scheduled Deliveries by Meter
(Dth)

Location	Operator	ANNUAL PERIOD 9/1/2009 - 8/31/2010				WINTER PERIOD 11/1/2009 - 3/31/2010			
		Total	Average	Max. Day	Min. Day	Total	Average	Max. Day	Min. Day
Berlin, NH	EnergyNorth	66,803	183	415	38	47,440	314	415	220
Rumford, ME	New Page	1,005,388	2,754	13,000	0	492,231	3,260	13,000	0
Rumford, ME	Rumford Power	3,076,504	8,429	44,400	0	24,000	159	12,000	0
Jay, ME	Verso Paper	9,555,903	26,181	45,650	13,000	4,580,999	30,338	45,000	13,000
Windham, ME	Maine Natural Gas	94,180	258	650	20	74,550	494	650	284
Eliot, ME	Unitil	1,021,590	2,799	6,400	1,450	598,745	3,965	6,400	2,800
Newington, NH	GP Gypsum	619,990	1,699	7,195	0	256,505	1,699	6,618	0
Newington, NH	Unitil	1,331,022	3,647	18,040	0	1,102,042	7,298	18,040	1,100
PNGTS Meters		16,771,380	45,950	135,750	14,508	7,176,512	47,527	102,123	17,404
Westbrook, ME	Unitil	6,373,826	17,463	46,331	5,045	4,113,025	27,239	46,331	10,375
Gorham, ME	Maine Natural Gas	2,147,194	5,883	39,720	0	513,800	3,403	39,384	0
Newington, NH	Newington Power	298,934	819	50,000	0	89,011	589	35,000	0
Newington, NH	PSNH	522,507	1,432	21,109	0	192,226	1,273	15,000	0
PNGTS/M&N Meters		9,342,461	25,597	157,160	5,045	4,908,062	32,504	135,715	10,375
Westbrook, ME	M&N	475,248	1,302	89,621	0	355,956	2,357	49,766	0
Dracut, MA	Tennessee Gas	7,568,451	20,735	176,498	0	6,562,530	43,460	176,498	0
TOTAL		34,157,540	93,584	559,029	19,553	19,003,060	125,848	464,102	27,779

Source: MPA-PNGTS-2.1

Higher Upstream Costs Adjustment

	IT Volumes (Dth)	Posted Price ($/Dth)	Revenue ($)	Adjusted Price ($/Dth)	Adj. Revenue ($/Dth)
3/1/2009	79,143	0.25	19,785.75	0.10	7,914.30
3/2/2009	97,463	0.25	24,365.75	0.10	9,746.30
3/3/2009	82,492	2.25	185,607.00	2.25	185,607.00
3/4/2009	99,629	2.25	224,165.25	2.25	224,165.25
3/5/2009	12,819	0.20	2,563.80	0.05	640.95
3/6/2009	4,819	0.20	963.80	0.05	240.95
3/7/2009	714	0.20	142.80	0.05	35.70
3/8/2009	714	0.20	142.80	0.05	35.70
3/9/2009	7,714	0.20	1,542.80	0.05	385.70
3/10/2009	81	0.15	12.15	0.00	0.00
3/11/2009	35	0.10	3.50	0.00	0.00
3/12/2009	439	0.15	65.85	0.00	0.00
3/13/2009	11,956	0.15	1,793.40	0.00	0.00
3/14/2009	439	0.10	43.90	0.00	0.00
3/15/2009	439	0.10	43.90	0.00	0.00
3/16/2009	439	0.10	43.90	0.00	0.00
3/17/2009	439	0.12	52.68	0.00	0.00
3/18/2009	439	0.10	43.90	0.00	0.00
3/19/2009	16,886	0.10	1,688.60	0.00	0.00
3/20/2009	7,439	0.12	892.68	0.00	0.00
3/21/2009	439	0.12	52.68	0.00	0.00
3/22/2009	439	0.12	52.68	0.00	0.00
3/23/2009	439	0.12	52.68	0.00	0.00
3/24/2009	9,519	0.15	1,427.85	0.00	0.00
3/25/2009	2,183	0.10	218.30	0.00	0.00
3/26/2009	439	0.10	43.90	0.00	0.00
3/27/2009	1,272	0.10	127.20	0.00	0.00
3/28/2009	340	0.10	34.00	0.00	0.00
3/29/2009	6,807	0.10	680.70	0.00	0.00
3/30/2009	340	0.10	34.00	0.00	0.00
3/31/2009	57,281	0.10	5,728.10	0.00	0.00
4/1/2009	71,512	0.15	10,726.80	0.00	0.00
4/2/2009	60,305	0.25	15,076.25	0.10	6,030.50
4/3/2009	41,408	0.12	4,968.96	0.00	0.00
4/4/2009	12,500	0.15	1,875.00	0.00	0.00
4/5/2009	12,500	0.15	1,875.00	0.00	0.00
4/6/2009	13,396	0.15	2,009.40	0.00	0.00
4/7/2009	124,886	0.20	24,977.20	0.05	6,244.30
4/8/2009	132,314	0.35	46,309.90	0.20	26,462.80
4/9/2009	96,510	0.35	33,778.50	0.20	19,302.00
4/10/2009	77,731	0.35	27,205.85	0.20	15,546.20
4/11/2009	88,880	0.35	31,108.00	0.20	17,776.00
4/12/2009	112,680	0.35	39,438.00	0.20	22,536.00
4/13/2009	46,748	0.35	16,361.80	0.20	9,349.60
4/14/2009	5,350	0.45	2,407.50	0.30	1,605.00

4/15/2009	1,250	0.18	225.00	0.03	37.50
4/16/2009	11,050	0.10	1,105.00	0.00	0.00
4/17/2009	550	0.10	55.00	0.00	0.00
4/18/2009	5,450	0.10	545.00	0.00	0.00
4/19/2009	15,450	0.10	1,545.00	0.00	0.00
4/20/2009	12,219	0.10	1,221.90	0.00	0.00
4/21/2009	1,987	0.10	198.70	0.00	0.00
4/24/2009	969	0.10	96.90	0.00	0.00
4/25/2009	10,000	0.10	1,000.00	0.00	0.00
4/26/2009	19,968	0.10	1,996.80	0.00	0.00
4/27/2009	43,668	0.10	4,366.80	0.00	0.00
4/28/2009	11,411	0.15	1,711.65	0.00	0.00
4/29/2009	2,500	0.15	375.00	0.00	0.00
5/1/2009	1,703	0.10	170.30	0.00	0.00
5/2/2009	1,179	0.10	117.90	0.00	0.00
5/3/2009	4,820	0.10	482.00	0.00	0.00
5/4/2009	13,515	0.10	1,351.50	0.00	0.00
5/5/2009	4,094	0.10	409.40	0.00	0.00
5/6/2009	5,000	0.10	500.00	0.00	0.00
5/7/2009	3,068	0.10	306.80	0.00	0.00
5/9/2009	4,160	0.10	416.00	0.00	0.00
5/10/2009	5,620	0.10	562.00	0.00	0.00
5/11/2009	7,379	0.10	737.90	0.00	0.00
5/12/2009	6,898	0.10	689.80	0.00	0.00
5/13/2009	3,497	0.10	349.70	0.00	0.00
5/15/2009	7,315	0.10	731.50	0.00	0.00
5/16/2009	10,023	0.10	1,002.30	0.00	0.00
5/17/2009	11,330	0.10	1,133.00	0.00	0.00
5/18/2009	3,948	0.10	394.80	0.00	0.00
5/19/2009	2,992	0.10	299.20	0.00	0.00
5/20/2009	3,058	0.10	305.80	0.00	0.00
5/21/2009	2,472	0.10	247.20	0.00	0.00
5/22/2009	2,285	0.10	228.50	0.00	0.00
5/23/2009	25,187	0.10	2,518.70	0.00	0.00
5/24/2009	2,845	0.10	284.50	0.00	0.00
5/25/2009	2,817	0.10	281.70	0.00	0.00
5/26/2009	8,079	0.10	807.90	0.00	0.00
5/27/2009	9,914	0.10	991.40	0.00	0.00
5/28/2009	5,579	0.10	557.90	0.00	0.00
5/29/2009	5,399	0.10	539.90	0.00	0.00
5/30/2009	2,729	0.10	272.90	0.00	0.00
5/31/2009	3,669	0.10	366.90	0.00	0.00
6/1/2009	2,993	0.10	299.30	0.00	0.00
6/2/2009	3,803	0.10	380.30	0.00	0.00
6/3/2009	5,869	0.10	586.90	0.00	0.00
6/4/2009	33,846	0.10	3,384.60	0.00	0.00
6/5/2009	28,717	0.10	2,871.70	0.00	0.00
6/6/2009	3,900	0.20	780.00	0.05	195.00
6/7/2009	3,879	0.20	775.80	0.05	193.95
6/8/2009	12,854	0.20	2,570.80	0.05	642.70

6/10/2009	2,552	0.20	510.40	0.05	127.60
6/12/2009	2,495	0.20	499.00	0.05	124.75
6/17/2009	2,614	0.20	522.80	0.05	130.70
6/19/2009	2,580	0.20	516.00	0.05	129.00
6/22/2009	5,500	0.20	1,100.00	0.05	275.00
6/23/2009	78,675	0.20	15,735.00	0.05	3,933.75
6/24/2009	2,451	0.20	490.20	0.05	122.55
6/26/2009	91,417	0.20	18,283.40	0.05	4,570.85
6/27/2009	17,962	0.20	3,592.40	0.05	898.10
6/28/2009	18,131	0.20	3,626.20	0.05	906.55
6/29/2009	18,349	0.20	3,669.80	0.05	917.45
6/30/2009	71,574	0.20	14,314.80	0.05	3,578.70
7/6/2009	25,000	0.20	5,000.00	0.05	1,250.00
7/7/2009	1,610	0.20	322.00	0.05	80.50
7/21/2009	2,295	0.20	459.00	0.05	114.75
7/22/2009	2,918	0.20	583.60	0.05	145.90
7/27/2009	5,223	0.20	1,044.60	0.05	261.15
8/1/2009	1,885	0.20	377.00	0.05	94.25
8/2/2009	1,885	0.20	377.00	0.05	94.25
8/3/2009	1,885	0.20	377.00	0.05	94.25
8/4/2009	1,550	0.20	310.00	0.05	77.50
8/5/2009	50	0.20	10.00	0.05	2.50
8/6/2009	50	0.20	10.00	0.05	2.50
8/7/2009	50	0.90	45.00	0.75	37.50
8/8/2009	50	0.60	30.00	0.45	22.50
8/9/2009	50	0.60	30.00	0.45	22.50
8/10/2009	50	0.60	30.00	0.45	22.50
8/11/2009	50	0.60	30.00	0.45	22.50
8/12/2009	50	0.60	30.00	0.45	22.50
8/13/2009	50	0.30	15.00	0.15	7.50
8/14/2009	10,441	0.22	2,297.02	0.07	730.87
8/15/2009	50	0.30	15.00	0.15	7.50
8/16/2009	50	0.30	15.00	0.15	7.50
8/17/2009	83,962	0.30	25,188.60	0.15	12,594.30
8/18/2009	79,159	0.30	23,747.70	0.15	11,873.85
8/19/2009	71,455	0.60	42,873.00	0.45	32,154.75
8/20/2009	51,596	0.30	15,478.80	0.15	7,739.40
8/21/2009	7,080	0.30	2,124.00	0.15	1,062.00
8/22/2009	25,050	0.35	8,767.50	0.20	5,010.00
8/23/2009	25,050	0.35	8,767.50	0.20	5,010.00
8/24/2009	106,079	0.35	37,127.65	0.20	21,215.80
8/25/2009	48,970	0.90	44,073.00	0.75	36,727.50
8/26/2009	23,764	0.50	11,882.00	0.35	8,317.40
8/27/2009	50	0.30	15.00	0.15	7.50
8/28/2009	50	0.50	25.00	0.35	17.50
8/29/2009	50	0.50	25.00	0.35	17.50
8/30/2009	50	0.50	25.00	0.35	17.50
8/31/2009	50	0.50	25.00	0.35	17.50
9/2/2009	365	0.20	73.00	0.05	18.25
9/14/2009	19,600	0.20	3,920.00	0.05	980.00

9/24/2009	1,660	0.20	332.00	0.05	83.00
9/25/2009	1,415	0.20	283.00	0.05	70.75
9/26/2009	1,055	0.20	211.00	0.05	52.75
9/27/2009	1,055	0.20	211.00	0.05	52.75
9/28/2009	37,955	0.20	7,591.00	0.05	1,897.75
9/29/2009	55	0.20	11.00	0.05	2.75
10/3/2009	1,827	0.20	365.40	0.05	91.35
10/4/2009	2,113	0.20	422.60	0.05	105.65
10/5/2009	2,438	0.20	487.60	0.05	121.90
10/8/2009	2,652	0.20	530.40	0.05	132.60
10/13/2009	2,300	0.20	460.00	0.05	115.00
10/16/2009	563	0.20	112.60	0.05	28.15
10/19/2009	22,628	0.20	4,525.60	0.05	1,131.40
10/20/2009	477	0.20	95.40	0.05	23.85
10/21/2009	972	0.20	194.40	0.05	48.60
10/22/2009	3,160	0.20	632.00	0.05	158.00
10/23/2009	3,317	0.20	663.40	0.05	165.85
10/24/2009	932	0.20	186.40	0.05	46.60
10/25/2009	982	0.20	196.40	0.05	49.10
10/26/2009	820	0.20	164.00	0.05	41.00
10/31/2009	500	0.20	100.00	0.05	25.00
11/2/2009	591	0.20	118.20	0.05	29.55
11/7/2009	13,408	0.20	2,681.60	0.05	670.40
11/8/2009	22,293	0.20	4,458.60	0.05	1,114.65
11/18/2009	18,803	0.20	3,760.60	0.05	940.15
12/9/2009	6,142	0.20	1,228.40	0.05	307.10
12/11/2009	49,146	0.75	36,859.50	0.60	29,487.60
12/17/2009	57,146	0.80	45,716.80	0.65	37,144.90
12/18/2009	84,110	0.90	75,699.00	0.75	63,082.50
12/19/2009	98,770	0.90	88,893.00	0.75	74,077.50
12/20/2009	98,770	0.90	88,893.00	0.75	74,077.50
12/21/2009	119,761	0.90	107,784.90	0.75	89,820.75
12/22/2009	98,289	1.35	132,690.15	1.35	132,690.15
12/23/2009	101,344	1.35	136,814.40	1.35	136,814.40
12/24/2009	2,220	0.25	555.00	0.10	222.00
12/29/2009	109,518	1.35	147,849.30	1.35	147,849.30
12/30/2009	81,642	1.00	81,642.00	0.85	69,395.70
1/1/2010	24,519	0.50	12,259.50	0.35	8,581.65
1/2/2010	18,038	0.50	9,019.00	0.35	6,313.30
1/3/2010	27,038	0.50	13,519.00	0.35	9,463.30
1/4/2010	75,679	0.50	37,839.50	0.35	26,487.65
1/5/2010	109,660	1.35	148,041.00	1.35	148,041.00
1/6/2010	97,333	1.35	131,399.55	1.35	131,399.55
1/7/2010	57,656	1.35	77,835.60	1.35	77,835.60
1/8/2010	69,620	1.00	69,620.00	0.85	59,177.00
1/9/2010	54,210	1.35	73,183.50	1.35	73,183.50
1/10/2010	74,210	1.35	100,183.50	1.35	100,183.50
1/11/2010	64,210	1.35	86,683.50	1.35	86,683.50
1/12/2010	6,806	0.40	2,722.40	0.25	1,701.50
1/18/2010	19,022	0.20	3,804.40	0.05	951.10

1/20/2010	6,695	0.20	1,339.00	0.05	334.75
1/29/2010	20,652	0.75	15,489.00	0.60	12,391.20
1/30/2010	20,652	0.75	15,489.00	0.60	12,391.20
1/31/2010	20,652	0.75	15,489.00	0.60	12,391.20
2/1/2010	61,085	0.85	51,922.25	0.70	42,759.50
2/2/2010	2,647	0.20	529.40	0.05	132.35
2/4/2010	17,596	0.25	4,399.00	0.10	1,759.60
2/5/2010	23,054	0.60	13,832.40	0.45	10,374.30
2/6/2010	25,894	1.20	31,072.80	1.05	27,188.70
2/7/2010	35,894	1.20	43,072.80	1.05	37,688.70
2/8/2010	25,894	1.20	31,072.80	1.05	27,188.70
2/9/2010	57	0.50	28.50	0.35	19.95
2/10/2010	12,869	0.50	6,434.50	0.35	4,504.15
2/11/2010	21,892	0.60	13,135.20	0.45	9,851.40
2/12/2010	6,090	0.60	3,654.00	0.45	2,740.50
SUM	4,766,038		3,058,579		

1.	Actual Revenue, excluding Sable outage period and 2010:	$1,822,872
2.	Adjusted Revenue, excluding Sable outage period and 2010:	$1,435,830
3.	Difference (Line 1 – Line 2)	$387,042
4.	Actual Sable outage period flows	533,256 Dth
5.	Sable outage-related flows (Exhibit PNG-47)	429,729 Dth
6.	Difference (Line 4 – Line 5)	103,527 Dth
7.	Sable outage period adjustment (Line 6 x $0.15)	$15,529
8.	Corrected Higher Upstream Costs adjustment (Line 3 + Line 7)	$402,571

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PORTLAND NATURAL GAS TRANSMISSION SYSTEM) DOCKET NO. RP10-729-000

AFFIDAVIT OF JOHN ROSENKRANZ

John Rosenkranz, being first duly sworn, states that he is the witness on behalf of the Maine Public Advocate Office whose Prepared Answering Testimony accompanies this affidavit; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he adopts said testimony as his sworn testimony in this proceeding.

John Rosenkranz

Date: 01/19/2011

Subscribed and sworn to before me, a Notary Public in and for Middlesex County, Massachusetts, this 19 day of January, 2011.

Notary Public
Commonwealth of Massachusetts
My Commission Expires Oct. 8, 2015

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. G-04204A-11-0158

(PUBLIC)

DIRECT TESTIMONY

OF

JOHN A. ROSENKRANZ

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

OCTOBER 28, 2011

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ATTACHMENTS

EXHIBITS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-11-0158
TESTIMONY OF STAFF WITNESS JOHN A. ROSENKRANZ

Mr. Rosenkranz presents the results of his review of UNS Gas' procurement activities for the period July 2008 through December 2010. This review includes the Purchase Gas Adjustor (PGA) filings, the Price Stabilization Policy, and the Company's interstate pipeline contract portfolio. Mr. Rosenkranz conducted a site visit on August 24-25, 2011, during which he interviewed gas procurement personnel, examined the available documentation for a sample of transactions, and observed the gas buying, nominating and scheduling process.

Mr. Rosenkranz finds that Company's gas procurement practices and price hedging program are generally reasonable, but is unable to confirm that UNS Gas has conducted an adequate review of its long-term pipeline capacity needs. Mr. Rosenkranz also identifies several areas of concern related to the Negotiated Sales Program (NSP), including an instance where core sales customers subsidized the Company for a negative margin on NSP sales through the PGA.

Based on his review, Mr. Rosenkranz makes specific recommendations related to the Company's price hedging practices, PGA reporting, and documentation of offers received in response to requests for proposals. Mr. Rosenkranz recommends that the Company file a comprehensive pipeline capacity plan with the Commission before committing to any further extensions of its existing El Paso Natural Gas transportation contracts, and implement significant changes to the NSP sales program to prevent cross-subsidies from core sales customers to the transportation customers participating in the program.

INTRODUCTION

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

A. My name is John A. Rosenkranz. I am Principal with North Side Energy, LLC, a consulting company. My business address is 56 Washington Drive, Acton, Massachusetts 01720.

Q. Please describe your professional and educational experience.

A. I have more than 20 years of experience in the areas of natural gas supply planning, fuel management for electricity generation, gas utility regulation, and pipeline and storage project management. I have worked as a consultant to natural gas distribution companies, helping to evaluate gas supply options and document these decisions. I have negotiated and managed long-term gas supply and transportation contracts for the operators of gas-fired power plants, and done market development and rate analysis for interstate pipeline and underground gas storage projects. I have been a witness in gas utility rate proceedings before the Federal Energy Regulatory Commission, the Maine Public Utilities Commission, and the Ontario Energy Board. I received a BA degree in economics from George Washington University, and completed all course and examination requirements for a doctorate in economics at Northwestern University. A copy of my resume is included as Attachment 1.

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

A. I was retained by the Arizona Corporation Commission Utilities Division Staff to examine the natural gas procurement activities of UNS Gas during the months of July 2008 through December 2010 (the Review Period). This review includes the monthly Purchased Gas Adjustor (PGA) filings, the Company's policies and procedures for natural gas procurement, and the methods used to solicit and evaluate natural gas supply and asset management proposals. I also looked at how UNS Gas has responded to the gas procurement recommendations that were accepted by the Company in Docket No. G-04204A-08-0571.

Q. How is this testimony organized?

A. This testimony has six main sections. The first section describes the categories of natural gas sales made by UNS Gas, and the types of natural gas purchase transactions the Company uses to meet these requirements. The second section describes the UNS Gas price hedging program, which is set out in the Price Stabilization Policy. The third section describes my review of UNS Gas' procurement practices. The fourth section examines the Company's interstate pipeline portfolio planning and capacity optimization activities. The fifth section covers my review of the PGA reports filed with the Commission for the 30 months of the Review Period. The final section addresses the Negotiated Sales Program.

Q. Please summarize your recommendations.

A. I have ten recommendations:

1. UNS Gas should consider modifying its price hedging program to: (a) lift the prohibition on non-discretionary purchases during the months of August, September, and October; (b) utilize other financial transactions, in addition to swaps; and (c) reduce the initial stabilization purchase quantities for delivery months that are two and three years out to reduce the risk of over-hedging due to overly-optimistic long-term sales forecasts.
2. The Company should ensure that there is a complete record of all final offers received, and any non-price factors used for evaluating offers, when it conducts a request for proposals process.
3. UNS Gas should submit a comprehensive pipeline capacity plan with the Commission before committing to any further extensions of its existing El Paso Natural Gas transportation agreements.
4. UNS Gas should modify the Purchased Gas Adjustor (PGA) reports to include the following information:
   (a) Report winter-period firm purchases and other call option transactions as a separate category on the Purchased Gas Detail Report.
   (b) Include the quantity of gas covered by financial hedge transactions.

(c) Report total NSP revenue, the total NSP margin, and the amount of NSP margin retained by the Company.

(d) Separate out the margins related to the affiliate contract for the Black Mountain Generating Station from the NSP margins for reporting purposes.

(e) Report, for each pipeline, (i) the total pipeline reservation cost before capacity release credits; (ii) the amount of capacity released during the month; and (iii) the capacity release credits received.

(f) Separately report excess gas sales that are done for balancing purposes and excess gas sales that are discretionary sales for resale, and show the margin calculation for each discretionary off-system sale.

5. UNS Gas should include asset management agreement (AMA) revenue in the calculation of the Natural Gas Cost Rate, not as an adjustment to the PGA Bank Balance.
6. Margin sharing on NSP sales should be changed from 50/50 to 75/25, with 75 percent of the margin going to ratepayers.
7. The pipeline transportation costs allocated to NSP sales in the PGA, and used for margin calculation purposes, should be the 100 percent load factor rate, not the variable cost.
8. UNS Gas should ensure that pipeline imbalance charges or penalties that are caused by NSP sales transactions are not passed through to core sales customers.
9. If, for any reason, UNS Gas has a negative margin on an NSP gas sale, this negative margin should be excluded from the NSP margin calculation for the PGA.
10. No later than the next rate application, UNS Gas should file a report with the Commission describing all aspects of the Negotiated Sales Program, quantifying the net benefits or costs of the program for core sales customers, and describing any proposed changes to the program.

GAS PROCUREMENT OVERVIEW

Q. Please describe the natural gas markets that are supplied by UNS Gas.

A. The principal focus of this Procurement Review is natural gas purchased and transported for core sales customers. The UNS Gas core sales market is predominantly temperature-sensitive residential and commercial customers. After a period of strong growth, the Company has noted that core market sales grew by less than one percent per year from 2008 to 2010.

In addition to core market sales, UNS Gas makes three other types of natural gas sales:

1. Sales to UNS Electric Generating Plants

   UNS Gas supplies gas to the UNS Electric Valencia and Black Mountain generating plants.[1] The Company holds separate pipeline transportation contracts for these plants, the costs of which are assigned directly to UNS Electric. If additional transportation capacity is needed, UNS Electric compensates UNS Gas for the use of its upstream pipeline contracts.

2. Negotiated Sales Program

   UNS Gas sells gas to transportation service customers under the Negotiated Sales Program (NSP) tariff. Most of the UNS Gas transportation customers are also NSP customers. The gas purchased for NSP customers is transported on the Company's interstate pipeline capacity and sold at the UNS Gas citygate. NSP customers pay a monthly price equal to a first-of-month index price, plus a negotiated premium. With minor exceptions, one-half of the margin from NSP sales is credited to core sales customers through the PGA. The rest of the NSP margin goes to UniSource Energy shareholders.

3. Sales for Resale

   UNS Gas resells excess gas to correct temporary imbalances between the Company's committed purchases and its immediate sales requirements. This gas is typically sold in the supply basin. UNS Gas also occasionally buys packages of gas for resale to an off-system buyer. Both types of transactions are included in "Excess Gas Sales" on the PGA report.

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[1] The Commission approved a special contract between UNS Gas and Unisource Energy Development Company for the Black Mountain Generating Station in Decision 70186. UNS Electric acquired the Black Mountain plant in July 2011. The accounting procedure for Purchased Gas Deferral & Expense, included in UDR 1.13, notes that there is currently no gas sales agreement between UNS Gas and UNS Electric for gas commodity supplied to the Valencia plant (see page 2 of 7).

As shown in the table below, UNS Gas purchased and sold approximately 14.5 Bcf of natural gas in 2010. Approximately 77 percent of the gas purchased went to core market sales. Sales to NSP customers and UNS Electric accounted for 13.5 percent and 7.5 percent, respectively. The remaining two percent was sold as excess gas.

UNS GAS DELIVERED QUANTITIES, 2010

	(Dekatherms)	(Percent)
Core Market	11,279,407	76.9%
NSP Scheduled Deliveries	1,984,517	13.5%
UNS Electric	1,104,149	7.5%
Excess Commodity Sales	302,661	2.1%
Total	14,670,734	100.0%

Source: UNS Gas Purchased Gas Adjustor filings

Q. How does UNS Gas purchase and deliver natural gas to these markets?

A. UNS Gas buys natural gas in the San Juan and Permian Basins, and delivers this gas to Arizona markets using firm transportation services on El Paso Natural Gas (EPNG) and Transwestern Pipeline. The Company enters into four basic types of natural gas purchase transactions:

1. Price Stabilization Purchases

   Under the Price Stabilization Policy, UNS Gas starts buying natural gas for core sales requirements three years before the delivery month. The Company has an objective of locking in prices for at least 45 percent of its projected core sales at least two months prior to the month of delivery. UNS Gas uses both fixed-price physical purchases and financial hedge transactions, such as swaps.

2. Monthly Purchases

   UNS Gas buys additional gas for core requirements, and all of the estimated NSP sales quantity, shortly before the start of each month. UNS Gas typically purchases about one-half of its unhedged core market sales requirement in monthly purchase transactions, which provide for delivery at a constant daily rate. This gas is either purchased at a fixed, negotiated price, or at a price based on a first-of-month market index.

3. Daily Purchases

   The rest of the core market gas supply, and all of the gas for the UNS Electric Valencia and Black Mountain power plants, is purchased in the day-ahead market. The price for this daily swing gas is usually tied to a daily market index.

4. Firm Winter Season Purchases

   To improve gas supply reliability during the winter months, UNS Gas enters into firm gas purchase agreements that give the Company the right, but not the obligation, to buy up to a maximum daily quantity of gas at a price based on a daily market index. These physical call options make UNS Gas less dependent on daily spot market purchases during periods of high demand, and can move the Company to a higher position in a supplier's curtailment queue if there is a supply disruption. These transactions generally include a fixed monthly fee in addition to the commodity price, or have a commodity price that adds a premium to the market index.

PRICE STABILIZATION POLICY

Q. Please describe the UNS Gas price hedging strategy.

A. The Price Stabilization Policy sets out the procurement methodology UNS Gas uses to promote natural gas price and supply stability for core customers. This policy identifies the types of physical and financial transactions that UNS Gas will enter into, defines specific hedge targets, and describes the responsibilities of the individuals involved in gas procurement-related activities.

The Price Stabilization Policy defines a mechanical, calendar-based hedging program. UNS Gas generally hedges a set quantity of gas for each future month, beginning three years out, in order to meet a minimum hedge target. The quantity for each hedge transaction is based on the Company's long-term sales forecast for the delivery month. The program is designed so that, for any delivery month, an equal quantity of gas is hedged in each forward hedge transaction. The Price Stabilization Policy also provides for discretionary hedge transactions to give the Company the flexibility to hedge a greater or lesser amount based on market conditions. The Price Stabilization Policy also states that UNS Gas will suspend non-discretionary hedge purchases during the August, September, and October because of concerns that hurricane activity during these months may increase volatility and distort forward natural gas prices.

Q. Did UNS Gas follow this hedge program during the Review Period?

A. Yes. Based on my review, the hedging activity undertaken by UNS Gas during the Review Period was consistent with the policies and procedures described in the Price Stabilization Policy.

Q. What recommendations concerning the Price Stabilization Policy were included in the last Procurement Review?

A. The Procurement Review from the last rate case included several recommendations related to the Price Stabilization Policy.

- *The Price Stabilization Policy should be changed to require consideration of purchases during the excluded months of August, September and October.*
- *UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern for stabilization transactions.*
- *All parties involved with gas procurement should acknowledge the Price Stabilization Policy by signing annually.*
- *A single person should be the "policy owner" of the Price Stabilization Policy.*
- *The Price Stabilization Policy should be amended for any strategy changes since TEP took over gas procurement in 2008, and updated at least annually.*

Q. How has the Company addressed these recommendations?

A. In response to data request JR 6.1, the Company explains that, although non-discretionary purchases are suspended during the months of August, September and October, the Price Stabilization Policy does provide for discretionary hedge transactions during these months, and that the Policy has been modified to make this explicit. In the same data response, UNS Gas also states (a) that the Company did not deviate from a ratable hedge purchase pattern during the Review Period, (b) that all Wholesale Energy department employees involved in gas procurement and scheduling for UNS Gas sign acknowledgement forms each year, and (c) that Ray Robey, Senior Portfolio Manager, currently acts as the "policy owner" for the Price Stabilization Policy.

To determine whether the Company has complied with the last recommendation listed above, I compared the Price Stabilization Policy for 2008 and the Price Stabilization Policy for 2010, and confirmed that the document was modified and expanded during the Review Period. For example, the Price Stabilization Policy now addresses capacity management products, such as same-day calls and swing agreements, and provides for physical or financial sales if the allowed hedge amounts are exceeded.

Q. Is the UNS Gas hedge program a reasonable approach to addressing natural gas price volatility?

A. Given UNS Gas' price stabilization objectives, the program described in the Price Stabilization Policy is a reasonable approach to shielding UNS Gas core market sales customers from short-term volatility in the natural gas market. By locking in the price for a significant portion of its expected core sales requirement at least two months ahead of time, and spreading these hedge transactions over a three-year period, the Company reduces the impact that any short-term price variations will have on the final gas price.

Q. Do you have any recommendations related to the Price Stabilization Policy?

A. Yes, I do. First, I agree with the recommendation from the last Procurement Review that the prohibition on non-discretionary hedge transactions during the months of August, September, and October should be eliminated. This would increase the number of hedge transactions and further reduce the impact that any short-term market price distortions will have on the final price paid by consumers. If the Company is concerned about market distortions during the hurricane season, it can always suspend stabilization purchases in a month when there are reasons to be concerned about weather-induced price volatility.

Second, UNS Gas should consider using other types of financial hedge transactions, as the Price Stabilization Policy currently allows. During the Review Period, all stabilization transactions were either physical forward purchases or financial swaps. The use of option collars, for example, would provide protection against price spikes, but still allow consumers to benefit from reductions in market prices. Based on the Company's supplemental response to data request JR 6.6, I understand that the Company has considered modifying its hedge targets and utilizing other financial instruments, but that no changes have been implemented.

Third, large errors in forecasting monthly sales requirements two and three years out have prevented the Company from achieving its objective of hedging equal quantities in each month of the price stabilization period, for all months of the Review Period. In particular, because actual market growth during this period was considerably lower than the Company's sales forecasts had projected, UNS Gas generally over-hedged in the early months of the stabilization period, and then under-hedged in later months in order to compensate. The Company's history of over-estimating the rate of sales growth is illustrated by Exhibit JR-1, which shows the long-term sales forecasts from 2006, 2008, and 2010 and the actual core market sales for the years 2007 through 2010. To reduce the potential distortion caused by inaccurate sales forecasts, UNS Gas should consider setting the hedge quantities in the first year of the three-year stabilization purchase period based on a more conservative market growth rate, or even a growth rate of zero. The Company can then adjust the hedge quantity upward, if necessary, as better information becomes available.

TRANSACTION REVIEW

Q. Who currently does the natural gas procurement for UNS Gas?

A. Since September 2008 natural gas purchasing and transportation scheduling for UNS Gas has been done by the TEP Wholesale Group. Before this date, gas was supplied by BP Energy, which also managed the Company's interstate pipeline capacity. In addition to managing gas procurement for UNS Gas, the TEP Wholesale Group also manages gas purchasing and transportation for certain Tucson Electric plants.

Q. Have there been benefits from bringing gas procurement in-house?

A. Yes. One of the main benefits is that UNS Gas now buys from a diverse portfolio of gas suppliers. For example, in December 2010 UNS Gas purchased gas from seven different suppliers, with the largest supplier accounting for just over 30 percent of the total quantity.

Q. Please describe your evaluation of the Company's gas buying and scheduling activities, and its processes and procedures for bidder award and evaluation.

A. I conducted a site visit on August 24-25, 2011. At that time I met with Wholesale Group and Energy Settlements personnel, examined the available documentation for a sample of transactions, and observed the gas buying, nominating and scheduling process. The transaction review included transactions of various lengths, including forward gas price stabilization purchases and financial hedge transactions, month-ahead gas purchases, and daily purchases. I also examined the documentation related to the request for proposals (RFP) process for a winter-season asset management transaction.

Q. What procedures does UNS Gas use for price stabilization transactions?

A. UNS Gas typically issues an RFP to approximately ten suppliers, identifying the quantities to be hedged for each month of the three-year price stabilization period. Suppliers may submit offers for physical forward sales, financial price swaps, or both. UNS Gas generally decides whether to enter into a physical or financial hedge depending on the offers received. In addition to price, UNS Gas considers other factors, such as credit and past experience with the supplier, when evaluating offers. UNS Gas uses a similar RFP process for winter season purchases and pipeline asset management transactions.

Q. Is the RFP process used by UNS Gas reasonable?

A. Yes. UNS Gas appears to be successful in obtaining competitive proposals from a number of different suppliers. The evaluation process, as described by the Company, also appears to be reasonable. However, I do have some concerns about the Company's practices for documenting the bid processes. For some of the transactions that I examined, the Company was not able to provide documentation for all of the offers received. In particular, there appeared to be no written record of offers that were provided by phone.

Q. What is your recommendation?

A. The Company should prepare and retain, for each RFP, a written summary of all final offers received, including offers that are communicated verbally. This record should include an explanation of any factors that used in selecting or rejecting offers, in addition to price.

PIPELINE CAPACITY OPTIMIZATION AND PLANNING

Q. Please describe the UNS Gas portfolio of upstream transportation contracts.

A. UNS Gas currently holds about 100,000 MMBtu per day of firm pipeline transportation capacity on an annual average basis. Firm interstate delivery capacity reaches [redacted] MMBtu per day during the winter period, and drops to [redacted] MMBtu per day during the summer months. The maximum monthly firm transportation capacity amount is [redacted] MMBtu per day, which occurs in December.

UNS Gas made several changes to its portfolio of upstream transportation contracts during the Review Period:

- In March 2009 UNS Gas began taking service under a new 15-year contract with Transwestern for service from the Blanco Hub to points on the new Phoenix Lateral. The Commission pre-approved cost recovery for this contract in Decision 69333, which was issued in February 2007.

- UNS Gas began service under EPNG contract H3228000 on November 1, 2009.
- UNS Gas extended the expiration dates for five existing EPNG contracts by one year, from August 31, 2011 to August 31, 2012.

Q. How does the pipeline capacity UNS Gas currently has under contract compare with its core market requirements?

A. UNS Gas holds a substantial amount of unutilized interstate pipeline capacity. This is illustrated by Exhibit JR-2, which compares the Company's total pipeline capacity to the average quantity delivered for core market sales for each month of 2010. Although the average monthly deliveries mask the fact that pipeline utilization would have been higher on individual days, and pipeline contracts should be sized to meet design peak requirements, not average use, this comparison does indicate that UNS Gas has more interstate pipeline capacity than it currently uses to meet core market requirements.

Q. Was a pipeline capacity surplus expected?

A. Yes. When UNS Gas committed to the Phoenix Lateral transportation service on Transwestern, it was anticipated that there would be some amount of excess pipeline capacity for a period of time. However, the subsequent drop-off in core market growth has caused the size and duration of the capacity surplus to be greater than expected. UNS Gas identified this risk in its application for pre-approval of Phoenix Lateral costs, and pointed to its ability to turn back expiring EPNG capacity beginning in 2011 as a tempering factor. (G-04204A-06-0627 Application at 5)

Q. What has UNS Gas done to mitigate the cost impact of surplus pipeline capacity for core market sales customers?

A. Since March 2009, UNS Gas has entered into asset management agreement (AMA) transactions with marketers to offset the fixed costs of surplus pipeline capacity With minor exceptions, the pipeline capacity that has been temporarily released to marketers in these AMA deals has been the additional Transwestern capacity that UNS Gas obtained with the Phoenix Lateral project. UNS Gas receives a percentage of the value of the transportation, based on the actual market prices at specified Transwestern receipt and delivery points.

Q. What portion of the fixed costs of the additional Transwestern capacity has UNS Gas been able to offset?

A. Over the Review Period, margin sharing payments and capacity release credits from AMA transactions amounted to [redacted] (see Exhibit JR-3). This is about [redacted] percent of the fixed reservation charges for the firm transportation service acquired with the Phoenix Lateral project over the same period.

Q. Are there opportunities for UNS Gas to undertake additional asset optimization to reduce the cost of gas to core ratepayers?

A. UNS Gas currently offers only a portion of its surplus Transwestern capacity for AMA deals, so it may be possible to do more. However, I was told that Company does not see significant value in offering additional Transwestern pipeline capacity for AMA transactions or capacity release. UNS Gas also does not see any opportunities to optimize underutilized capacity on EPNG because of the complexity of the EPNG transportation services, and the low value that UNS Gas would expect to receive for its EPNG capacity in the secondary market.

Q. Does UNS Gas retain any of the revenue from asset optimization transactions?

A. No. All of the revenue from AMA transactions and capacity release is currently credited to ratepayers through the PGA.

Q. If UNS Gas has surplus pipeline capacity, why did the Company obtain more firm transportation service on EPNG?

A. Contract H3228000 is a relatively small winter-period contract that adds to the Company's firm capacity rights on the Nogales lateral, which UNS Gas describes as a constrained portion of the EPNG system. Even with an aggregate surplus of pipeline capacity, it is reasonable for UNS Gas to obtain additional capacity on certain pipeline segments when these opportunities arise.

Q. Did UNS Gas consider terminating or modifying any of its existing EPNG contracts to reduce its capacity surplus?

A. The Company explained that the decision to extend these contracts by one year was based on considerations related to the EPNG 2008 rate case, which is still pending at the Federal Energy Regulatory Commission. I was told that UNS Gas is considering potential modifications to these EPNG contracts that could be implemented when these contracts next come up for renewal.

Q. Has the Company followed the pipeline capacity optimization recommendations from the last Procurement Review?

A. Not entirely. Two recommendations concerning the optimization of excess pipeline capacity were made in the last Procurement Review:

- *UNS Gas should conduct a thorough analysis of excess interstate pipeline capacity that could be optimized.*
- *If excess pipeline capacity is available, UNS Gas should seek potential counterparties, at least annually, to optimize all of its excess capacity on both the Transwestern and El Paso pipelines.*

Based on the Company's response to data request JR 6.9 and my interviews with UNS Gas personnel, I understand that UNS Gas estimates on an ad hoc basis the amount of excess pipeline capacity available in the near term, but has not undertaken a comprehensive long-term analysis. In terms of the second recommendation, since March 2009 UNS Gas has obtained a significant amount of revenue by releasing its newly-acquired Transwestern capacity in AMA transactions, but has been less active in optimizing its other under-utilized pipeline capacity.

Q. Were you able to evaluate UNS Gas' planning for future pipeline capacity needs?

A. No. I found no evidence that UNS Gas has undertaken an assessment of its future pipeline capacity needs since the start of the Review Period. Indeed, one of the primary inputs for pipeline capacity planning is a forecast of design peak day sales requirements, but this forecast has not been formally updated for UNS Gas since 2004.

Given the amount of surplus capacity UNS Gas currently holds, the risk of continued increases in pipeline transportation rates, and the opportunity to modify the EPNG contracts that will now expire in August 2012, having a comprehensive pipeline capacity plan is very important.

Q. What is your recommendation?

A. I recommend that the UNS Gas file a comprehensive pipeline capacity plan with the Commission before committing to any further extensions of its existing EPNG transportation agreements. This plan should include up-to-date forecasts of monthly and peak day core market requirements under normal and design conditions, and an assessment of the natural gas purchase and interstate pipeline delivery options that are expected to be available over a planning period of at least ten years. The pipeline capacity plan should also include an action plan for optimizing any underutilized pipeline capacity.

PGA REVIEW

Q. Please describe the monthly PGA report UNS Gas files with the Commission.

A. The monthly PGA report documents the calculation of the Cost of Natural Gas Rate, which is the gas commodity price charged to core sales customers. The Cost of Natural Gas Rate is defined as the total cost of gas for core customers for the most recent 12 months, divided by total sales over the same period. The core market cost of gas combines the following elements:

- The cost of gas purchased for core customers;
- Financial hedge costs (positive or negative);
- Pipeline transportation costs, including penalties;
- Core customers' share of the NSP margin;
- Revenue from excess gas sales;
- Core Market Imbalance cost;
- T-1 Imbalance Exchange cost; and
- Revenue from Asset Management Agreements.

Q. Are the prices UNS Gas pays for natural gas reasonable?

A. Using information from the PGA filings, I calculated the average price paid for natural gas for each month of the Review Period, excluding the fixed-price forward purchases made for hedging purposes. As illustrated by Exhibit JR-4, there is a close relationship between average cost for daily and monthly spot market purchases and the Gas Daily index price for day-ahead gas purchased in the San Juan Basin. Based on this information, the prices of gas purchased for core market sales appear to be reasonable.

Q. Did you review the interstate pipeline penalties incurred by UNS Gas during the Review Period?

A. Yes. In response to data request STF 14.2, UNS Gas provided an annotated monthly compilation of EPNG charges. I found that pipeline penalty costs were considerably lower during the Review Period than in the period covered in the last Procurement Review.

Q. Please summarize your findings regarding the monthly PGA filings.

A. The calculation of the Cost of Natural Gas Rate over the Review Period appears to be accurate. However, I found the information included in the monthly PGA filings to be deficient in several respects:

1. The unit cost of gas shown on the Purchased Gas Cost Detail report (Exhibit B2) is not always an accurate measure of the gas price paid by UNS Gas. The main problem is that reservation charges or commodity price premiums for physical call option transactions are not treated consistently, which leads to incorrect reporting of quantities or costs in some months. As a result, it is not always possible to make a meaningful comparison between the unit costs for first-of-month purchases and spot purchases reported in the PGA filings and the published market price indexes.

2. The PGA filing shows the quantity of gas hedged using fixed-price physical contracts, but does not identify the quantity hedged using financial hedge

transactions. This means that it is not possible to use the PGA reports to determine the total amount hedged for the month, to assess how the actual hedge quantities compare with the targets in the Price Stabilization Policy.

3. UNS Gas currently reports the gas cost and pipeline transportation cost for each NSP customer, and the amount of NSP margin amount credited to customers. The PGA filing does not show NSP revenue or the total NSP margin. There is no way to verify the NSP margin calculation, or the allocation of the margin between ratepayers and the Company.

4. The NSP margin credited to customers includes margins under the special contract for the Black Mountain Generating Station (BMGS). This is inconsistent with Decision No. 70186, which directed UNS Gas to separately report detailed information about pipeline capacity transactions between UNS Gas and BMGS in the PGA filing.

5. The PGA filing does not show pipeline capacity release credits. UNS Gas reports the pipeline reservation charges allocated to core market sales with capacity release credits already subtracted. UNS Gas has done AMA transactions that include both a margin sharing payment and a capacity release (or relinquishment) payment by the marketer. Because capacity release credits are not reported, some of the value of these optimization transactions is not shown. For example, for 2010 UNS Gas reports AMA revenue of $161,607.34 as a credit to the PGA Bank, but does not identify [redacted] of capacity release credits that were directly related to these transactions. Without the capacity release credits, the value of the Company's pipeline capacity optimization activity is understated by more than [redacted] percent. The current reporting also makes it impossible to identify any capacity optimization that is done directly by releasing capacity in the secondary market.

6. UNS Gas combines gas sales for short-term imbalance management and off-system sales (also referred to as sales for resale) as "excess commodity sales" for reporting

purposes, even though these are very dissimilar transactions. Balancing sales are generally sales of surplus gas to avoid transporter penalties or cash-out charges. These sales typically take place in the producing area, and do not involve the use of interstate pipeline transportation.

Off-system sales are discretionary transactions that involve the purchase of incremental gas, and the use of pipeline transportation capacity that would otherwise be underutilized. These are essentially asset optimization transactions. Because they are discretionary, these transactions should only be done if they create a positive margin for ratepayers, and represent the best use of the available pipeline transportation capacity. However, the current PGA reporting does not identify the purpose of the excess commodity sale, or show the resulting margin.

Q. Based on these observations, what additional information do you recommend that UNS Gas provide in the PGA filing?

A. The monthly PGA report should be modified to include the following information:

1. Create a separate category for winter-period firm purchases and other firm call option transactions to separate these transactions from monthly and daily spot market purchases on the Purchased Gas Cost Detail report.
2. In addition to reporting the core market impact of financial hedges, show the corresponding hedge quantity.
3. Report the total NSP revenue, the total NSP margin, and amount of the NSP margin retained by Company.
4. Separately report the margin calculation, and the allocation of the margin between Company and customers, under the special contract for BMGS.
5. Report, for each pipeline, (a) the total pipeline reservation cost, before capacity release credits; (b) the quantity of capacity released during the month; and (c) the capacity release credits received.
6. Separately report gas sales done for balancing and discretionary sales for resale, and show the margin calculation for each discretionary off-system sale.

Q. Should there be any changes to the Cost of Natural Gas Rate calculation?

A. Yes, I have one recommendation in this area. At present, UNS Gas treats revenue from AMA transactions as an adjustment to the PGA Bank Balance, not as a reduction to the current period cost of gas. Capacity release credits, on the other hand, reduce transportation costs and have a direct effect on the Cost of Natural Gas Rate. There is no reason to treat these two types of optimization transactions differently in the PGA, or not to include AMA revenue as a reduction to the gas cost. UNS Gas should modify the PGA calculation to include AMA revenue in the calculation of the Cost of Natural Gas Rate.

Q. Has UNS Gas addressed the PGA-related recommendations from the last Procurement Review?

A. It has. The last Procurement Review included two recommendations related to the preparation of the PGA filings:

- *UNS Gas should be required to supplement the information filed monthly to the Commission to tie out and support all entries of the PGA Bank Balance, and to specifically include the UNSG Core Market/System Supply Imbalance Report.*
- *Personnel from the Energy Settlements & Billing Department should receive additional training in the operating practices and terminology of the TEP Wholesale Department for gas procurement.*

In response to data request JR 6.1, UNS Gas reports that it has included the UNSG Core Market System Imbalance Report as Exhibit F of the PGA package since May 2009, and that the staff of the Energy Settlements and Billing department attended a two-hour class conducted by Wholesale Energy personnel on July 27, 2010.

NEGOTIATED SALES PROGRAM

Q. What is the purpose of the Negotiated Sales Program?

A. When the Commission first considered the Negotiated Sales Program in 1995, the Company identified three main objectives: (1) to provide an alternative source of supply for transportation customers; (2) to lower gas costs for firm sales customers through the sharing of margins on NSP sales; and (3) to provide the Company an opportunity to improve its earnings. (Decision 59399 at 9)

Q. How does the Company procure gas for NSP sales?

A. UNS Gas generally buys first-of-month priced gas to meet the expected requirements of the NSP customers prior to the start of each month. UNS Gas also enters into forward physical gas purchases or financial hedges for specific quantities of gas on behalf of individual NSP customers, if the customer requests this service. All of the costs of these hedges are to be paid by the NSP customer requesting the transaction.

Q. Does UNS Gas use separate supplier contracts or pipeline transportation contracts for NSP purchases?

A. No. UNS Gas purchases gas for NSP sales under the same contracts that it uses for core market purchases. Gas purchased on behalf of an individual NSP customer is recorded in a separate book in the UNS Gas transaction system, and UNS Gas also maintains a book for monthly gas purchased for the NSP sales "pool". Gas purchased for NSP sales is transported from the producing basins to the citygate using the same pipeline transportation contracts that are used for core market sales.

Q. As the program is currently administered, is there commingling of NSP gas supplies and gas supplies for core sales customers?

A. If the NSP customers consume each day the exact the amount of gas that was purchased for NSP sales going into the month, there should be no commingling of NSP supplies and gas purchased for core market sales. However, because each NSP customer's daily usage can fluctuate during the month, and forecasts may be inaccurate, UNS Gas enters into additional purchase and sales transactions during the month to keep supplies and consumption in balance. Since daily balancing for core market sales and NSP sales is done on a combined basis, NSP sales can affect the cost of gas for core customers. It also appears that any pipeline imbalance costs or penalties caused by NSP sales are not charged to the NSP customer responsible for the expense, but remain in the core market cost of gas.

Q. What pipeline transportation cost is allocated to NSP sales?

A. Core sales customers are directly credited only for the variable cost of pipeline transportation used for NSP sales. This is generally less than the value UNS Gas could obtain for this capacity under an AMA or capacity release transaction. Based on the negotiated prices charged to NSP customers, this also appears to be considerably less than the amount these customers are willing to pay for this transportation.

Q. Are there other costs associated with NSP sales?

A. Yes. UNS Gas must provide credit support for the natural gas purchases and financial hedge transactions it enters into on behalf of NSP customers. As Company witness Kennton C. Grant explains in his direct testimony (pages 15-17), these costs can be significant. Furthermore, since purchases for NSP sales are incremental to the purchases made for core market sales, the NSP purchases are more likely to be done outside the Company's supplier credit lines. The credit support costs for NSP sales will therefore be higher, on average, than the credit costs for core market sales. Finally, there also appear to be significant administrative costs associated with NSP sales. This includes the cost of marketing, gas management, and accounting personnel directly involved with NSP sales, plus associated overhead costs.

Q. Does a 50 percent share of NSP margins adequately compensate core sales customers for the costs and risks of these sales?

A. Based on the available information, it appears that core sales are not being adequately compensated for the value of the pipeline capacity being used, the risk of higher commodity and transportation charges in the PGA, and the additional credit and administrative costs associated with NSP sales. The average margin credit in the PGA for NSP sales was approximately $0.23 per MMBtu in 2009 and 2010. This is less than the fixed reservation cost for the firm transportation service used by the NSP customers, leaving aside any allowance for the other costs and risks related to the program. The 50 percent share of NSP sales margins that is retained for UniSource Energy shareholders also gives the Company a financial incentive to hold extra interstate pipeline capacity to support NSP sales, and favor NSP sales over other types of transportation capacity optimization transactions that may provide greater value to ratepayers.

Q. Did the Commission reject UNS Gas' proposal to retain 50 percent of margins on a similar non-core sales transaction?

A. Yes. In Decision 70186 the Commission rejected the Company's proposal to retain one-half of the margins under the sales agreement for Black Mountain Generating Station. The Commission accepted Staff's recommendation that the margin split between core customers and shareholders be set at a 75/25 split with 75 percent going to the core customers. (Decision 70186 at 7)

Q. What are your recommendations concerning the Negotiated Sales Program?

A. I have four specific recommendations concerning NSP sales:

(1) Margin sharing on NSP sales should be changed from 50/50 to 75/25, consistent with Decision 70186.

(2) Pipeline transportation costs should be allocated to NSP sales in the PGA and for margin calculation purposes at the 100 percent load factor rate, not the variable cost.

(3) NSP customers, or the Company, should be responsible for any pipeline imbalance charges or penalties that are caused by an NSP sales transaction. The Company should ensure that these costs are not passed through to core customers in the PGA.

(4) If, for any reason, UNS Gas has a negative margin on a gas sale to an NSP customer, that negative margin should not be passed through to core customers in the PGA. In Decision 72491, dated July 25, 2011, the Commission included a similar provision in approving a special gas procurement agreement proposed by Southwest Gas.

In addition, no later than the next UNS Gas rate case application, the Company should file a report with the Commission describing all aspects of the Negotiated Sales Program, quantifying the net benefits or costs of the program for core sales customers over the most recent 12-month period, and describing any proposed changes to the program. This report will help the Commission determine whether the Negotiated Sales Program continues to be in the public interest, whether any further modifications are required, and what share of NSP margins should be retained by the Company for UniSource Energy shareholders.

Q. Are you also recommending an adjustment to the PGA Bank Balance related to the Negotiated Sales Program?

A. Yes. UNS Gas should adjust the PGA Bank Balance to compensate core sales customers for the negative NSP sales margin that was recorded for the PGA Billing Month of February 2010. In its response to data request STF 14.6, the Company explains that this negative margin was caused by [redacted] for December 2009.

[redacted]

[redacted] The Company charged core sales customers for a portion of this shortfall by including a negative NSP margin in the calculation of the Cost of Natural Gas Rate. To compensate core customers, the Company should credit the PGA Bank the amount of [redacted], plus interest at the Monthly Interest Accrual Rate. The calculation of the base credit amount is shown in Exhibit JR-5.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT

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PROFESSIONAL EXPERIENCE

North Side Energy, LLC, Acton, MA — 2006 – Present
PRINCIPAL

Recent Projects:
- Expert witness for the Maine Public Advocate in pipeline and gas distributor rate proceedings.
- Restructured long-term gas supply, transportation, and energy management contracts for cogeneration plants in Connecticut and Florida.
- Advisor to the Ontario Power Authority on natural gas issues affecting long-term power contracts.
- Consultant to the Ontario Energy Board during the development of new gas transmission access and reporting rules.
- Prepared an assessment of the market for gas storage in the Northeast U.S. and Eastern Canada.

Calpine Corporation, Boston, MA — 2000 – 2006
DIRECTOR, GAS ORIGINATION

Developed and implemented fuel supply plans for gas-fired power plants. Negotiated and managed contracts with natural gas suppliers and transporters. Directed intervention in gas pipeline rate cases and other regulatory proceedings.
- Obtained regulatory approval for a direct-supply pipeline in Ontario.
- Worked with industrial gas users, distribution companies and state agencies to intervene in a natural gas pipeline rate case, leading to over $2 million in rate discounts for Maine gas consumers.
- Testified on the availability of natural gas supply and pipeline delivery capacity to support the permitting of a gas-fired power plant in Minnesota.
- Member of a commercial and legal team that obtained arbitration decisions enforcing long-term natural gas contracts with over $50 million in mark-to-market value.

PG&E Gas Transmission, Boston, MA and Portland, OR — 1997 – 1999
DIRECTOR, BUSINESS DEVELOPMENT

Identified and managed development projects and investment opportunities involving natural gas pipelines, underground storage and LNG peaking plants.
- Project manager for a $1.2 million geologic testing program at a prospective natural gas storage site.
- Owner representative and management committee member for two interstate pipeline partnerships in the Northeast U.S.

J. Makowski Co. (acquired by U.S. Generating Company), Boston, MA 1992 – 1997
MANAGER, PROJECT DEVELOPMENT
Supervised a team providing project management and marketing support for natural gas pipeline and storage projects. Conducted regional gas market studies for internal projects and outside clients.

VICE PRESIDENT - EnerPro, Inc., Chicago, IL 1990 – 1992
Consultant to gas distribution companies during post-Order 636 restructuring. Helped clients define gas portfolio objectives, draft requests for proposals, evaluate suppliers, and negotiate long-term contracts.

MANAGER, GAS MODELING GROUP - Planmetrics, Inc., Chicago, IL 1986 – 1990
Developed and implemented gas supply planning systems for gas distribution companies.

ADVISORY ECONOMIST - Chicago Board of Trade, Chicago, IL 1983 – 1986
Researched commodity markets for futures and options trading potential.

EDUCATION

Graduate study in Economics - Northwestern University, Evanston, IL
Completed all course requirements for Ph.D.

Bachelor of Arts, Economics - George Washington University, Washington, DC

REGULATORY PROCEEDINGS

Northern Utilities, Inc. (MPUC Docket No. 2011-92), August 2011. Testimony on the amortization of pipeline rate case expenses and peaking facility cost allocation, on behalf of the Maine Public Advocate.

Union Gas Limited (OEB Case No. EB-2011-0038), July 2011. Filed evidence on the allocation of costs and margins between utility and non-utility storage operations, on behalf of Ontario consumer groups.

Portland Natural Gas Transmission (FERC Docket No. RP10-729), January 2011. Rebuttal testimony on market risk, on behalf of the Maine Public Advocate.

Natural Gas Market Review (OEB Case No. EB-2010-0199), September 2010. Presented evidence on regulatory initiatives to respond to changes in natural gas markets, on behalf of Ontario consumer groups.

Maritimes & Northeast Pipeline (FERC Docket No. RP04-360), February 2005. Testimony on distance-based rate design, on behalf of Calpine Corporation.

Mankato Energy Center (Minnesota Public Utilities Commission, Case IP-6345/CN-03-1884), 2004. Testimony on the availability of natural gas supplies and transmission capacity for power generation in Minnesota, on behalf of Mankato Energy Center.

Wisconsin Electric Power (Wisconsin Public Service Commission, Case 05-CE-130), 2003. Rebuttal testimony on the availability of natural gas supplies and transmission capacity for power generation in Wisconsin, on behalf of Calpine Corporation.

PROFESSIONAL AND INDUSTRY ASSOCIATIONS

International Association for Energy Economics
Northeast Energy and Commerce Association

EXHIBIT JR-1

UNS Gas Sales Forecasts vs. Actual Sales

[REDACTED]

Source: Data request JR 6.7 and UniSource Energy Corp. SEC Form 10-Ks.

EXHIBIT JR-2

UNS Gas Pipeline Capacity vs. Core Sales Deliveries, 2010

[REDACTED]

Source: Data request RS 4.4 and UNS Gas PGA filings.

EXHIBIT JR-3

Asset Management Agreement Revenue

[REDACTED]

Sources: Response to JR 6.10
Monthly PGA Filings
Transwestern Pipeline invoices (Response to RS 4.3)

EXHIBIT JR-4

UNS Gas Core Purchase Cost (Excluding Hedges) vs. Gas Daily Index

[REDACTED]

Source: Data request JR 6.12 and UNS Gas PGA filings.

EXHIBIT JR-5

[REDACTED]

Source: UNS response to STF 14.6, Attachment 1