EB-2011-0210

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

Federation of Rental-housing Providers of Ontario (FRPO)

Reply Argument Compendium

August 23, 2012

EB-2010-0210

FRPO COMPENDIUM

unıongas

July 27, 2012

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

RE: EB-2011-0210 – Union Gas Limited – 2013 Rates Application – Day 8 Undertaking Responses

Dear Ms. Walli,

Please find attached Union's responses to undertakings J8.3, J8.4 and J8.5 from Day 8 of the EB-2011-0210 proceeding.

Yours truly,

[original signed by]

Chris Ripley
Manager, Regulatory Applications

cc: Crawford Smith, Torys
EB-2011-0210 Intervenors

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

Please provide a schedule disclosing how OM&A is being allocated as between the regulated and unregulated assets for 2013, on a storage pool-by-storage pool basis, and to provide rationale for the allocations affected and whether OM&A allocation should follow the capital cost allocation.

Storage assets are not functionally separated into distinct regulated and unregulated assets, so operating and maintenance work performance on the entire asset cannot specifically be separated between regulated and unregulated. As a result, costs are incurred against the entire asset and then proportioned to unregulated and regulated operations in the same allocation as the underlying capital costs.

This allocation approach is consistent with the Board-approved 2007 cost allocation methodology which was deemed to be "adequate for the purposes of separating the regulated and unregulated costs and revenues" as part of the NGEIR Decision (EB-2005-0051). This methodology was further reviewed in depth by an independent consultant, Black and Veatch (B&V) who concluded that "the conceptual underpinnings and resulting methodologies upon which Union's cost allocation process is based are well-conceived, thorough and reasonable in their treatment of storage-related plant and expenses". As part of the EB-2011-0038 deferral disposition proceeding, the B&V report was filed and subject to intervener review, prior to acceptance of the cost allocation methodology in the Board decision.

The Attachment identifies the 2013 O&M allocators used for each shared storage asset. The first section reflects the allocators used in the 2013 filed evidence. The second section reflects the updated Plant Accounting allocators (reference undertaking J8.5) that will be used for 2013 actual allocations.

OM & A Allocation by Storage Pool

	Section 1			Section 2		
	2013 Filed			Plant Accounting Update		
Pool Name	**Unreg**	**Reg**	**Total**	**Unreg**	**Reg**	**Total**
Bentpath	38%	62%	100%	38%	62%	100%
Bentpath East	38%	62%	100%	39%	61%	100%
Bickford	38%	62%	100%	38%	62%	100%
Black Creek	38%	62%	100%	38%	62%	100%
Bluewater	38%	62%	100%	42%	58%	100%
Both Creek	38%	62%	100%	38%	62%	100%
Dawn 156	38%	62%	100%	68%	32%	100%
Dawn 167	38%	62%	100%	31%	69%	100%
Dawn 47/49	38%	62%	100%	38%	62%	100%
Dawn 59/85	38%	62%	100%	65%	35%	100%
Dawn J	42%	58%	100%	42%	58%	100%
Dow A	39%	61%	100%	32%	68%	100%
Dow Moore	38%	62%	100%	38%	62%	100%
Edys Mills	38%	62%	100%	29%	71%	100%
Enniskillen	38%	62%	100%	41%	59%	100%
Mandaumin	38%	62%	100%	38%	62%	100%
Oil City	38%	62%	100%	36%	64%	100%
Oil Springs	38%	62%	100%	30%	70%	100%
Payne	38%	62%	100%	48%	52%	100%
Rosedale	38%	62%	100%	38%	62%	100%
Sombra	38%	62%	100%	37%	63%	100%
Terminus	38%	62%	100%	38%	62%	100%
Waubuno	38%	62%	100%	37%	63%	100%

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Vienneau

Please provide the resulting space and deliverability between regulated and unregulated for 2013.

The attachment provides the allocation of storage capacity and deliverability to the unregulated operation and is for illustrative purposes only. Union operates its storage operation (both wholly owned pools and 3rd party purchased storage) as an integrated business and does not specify by storage pool the storage capacity and deliverability that is assigned to the unregulated operation.

Filed: 2012-07-27
EB-2011-0210
Exhibit J8.4
Attachment

	2006					2013					
			Non-Utility Allocation					Non-Utility Allocation			
Pool	Working Storage Capacity as of 12/31/2006 Note 1 (GJ)	Design Maximum Deliverability for W06/07 Note 1 (GJ/d)	Working Storage Capacity as of 12/31/2006 (37.66 Heat Value) (GJ)	Design Maximum Deliverability for W06/07 (37.66 Heat Value) (GJ/d)	Allocation Factor	Working Storage Capacity as of 12/31/2013 (37.75 Heat Value) (GJ)	Design Maximum Deliverability for W13/14 (37.75 Heat Value) (GJ/d)	Working Storage Capacity as of 12/31/2013 (37.75 Heat Value) (GJ)	Design Maximum Deliverability (37.75 Heat Value) (GJ/d)	Allocation Factor	UG Updated Allocation Factor (Note 1)
Bentpath	5,382,000	405,600	2,026,861	152,749	37.66%	5,395,000	474,100	2,031,705	178,546	37.66%	37.66%
Bentpath East	4,711,000	-	1,774,163	-	37.66%	5,043,000	-	2,099,168	-	41.63%	45.44%
Bickford	22,325,000	164,400	8,407,595	61,913	37.66%	22,378,000	188,100	8,427,688	70,838	37.66%	37.66%
Bluewater	2,007,000	13,300	755,836	5,009	37.66%	2,133,000	9,700	878,931	3,654	39.44%	48.94%
Booth Creek	1,962,000	-	738,889	-	37.66%	1,672,000	-	629,670	-	37.66%	37.66%
Dawn 156	28,121,000	467,300	10,590,369	175,985	37.66%	28,188,000	1,062,600	10,615,678	723,867	52.89%	68.44%
Dawn 167	4,990,000	19,200	1,879,234	7,231	37.66%	5,002,000	15,500	1,883,725	5,837	37.66%	37.66%
Dawn 47-49	4,937,000	55,200	1,859,274	20,788	37.66%	4,949,000	32,500	1,863,717	12,238	37.66%	37.66%
Dawn 59-85	5,977,000	492,100	2,250,938	185,325	37.66%	5,991,000	587,400	2,256,317	221,217	37.66%	77.46%
Dow A	6,462,000	74,700	2,433,589	28,132	37.66%	6,810,000	68,400	2,772,198	25,759	39.18%	49.21%
Edys Mills	2,587,000	40,100	974,264	15,102	37.66%	2,593,000	7,200	976,592	2,710	37.65%	47.89%
Enniskillen	3,581,000	51,000	1,348,605	19,207	37.66%	3,741,000	20,500	1,503,189	7,719	38.92%	49.40%
Mandaumin	3,909,000	29,400	1,472,129	11,072	37.66%	3,918,000	52,900	1,475,647	19,923	37.66%	37.66%
Oil City	1,725,000	27,900	649,635	10,507	37.66%	1,842,000	6,900	764,458	2,597	39.57%	48.94%
Oil Springs East	3,736,000	27,900	1,406,978	10,507	37.66%	3,963,000	27,000	1,628,861	10,170	39.38%	54.39%
Payne	24,946,000	161,500	9,394,664	60,821	37.66%	26,440,000	181,800	10,851,535	68,467	39.35%	56.76%
Rosedale	3,356,000	234,100	1,263,870	88,162	37.66%	3,364,000	207,700	1,266,890	78,221	37.66%	37.66%
Sombra	2,203,000	10,700	829,650	4,030	37.66%	1,170,000	10,300	440,542	3,880	37.66%	37.66%
Terminus	11,788,000	135,600	4,439,361	51,067	37.66%	11,816,000	124,500	4,449,970	46,887	37.66%	37.66%
Waubuno	10,179,000	46,400	3,833,411	17,474	37.66%	10,203,000	59,800	3,842,572	22,520	37.66%	37.66%
Dow Moore	6,114,000	106,800	2,302,532	40,221	37.66%	6,129,000	61,200	2,308,035	23,047	37.66%	N/A
Total - Allocated	**160,998,000**	**2,563,200**	**60,631,847**	**965,302**	**37.66%**	**162,740,000**	**3,198,100**	**62,967,088**	**1,528,097**	**43.24%**	

Note 1 - Union Gas Allocation factors updated in 2012 using the methodology outlined in undertaking EB-2011-0210 Exhibit JT1.41

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Vienneau

Please provide underlying the methodology used for capital additions in 2013.

In preparing the forecast for the 2013 rate case, Union categorized storage projects into 4 categories:

Description	Allocation Methodology
New Storage Asset – increase in capacity or deliverability	100% Allocation to unregulated
New Storage Asset – no increase in capacity or deliverability	Allocated regulated versus unregulated based on the historic allocation of assets at that location
Replacement Asset – no increase in capacity or deliverability	Allocated regulated versus unregulated based on the historic allocation of assets being replaced.
Replacement Asset – increase in capacity or deliverability	Cost of replacing the existing asset like for like is allocated regulated versus unregulated based on the historic allocation of assets being replaced. The cost of providing the incremental capacity or deliverability is allocated 100% to the unregulated operation. This results in a new blended rate for this asset.

Projects that included an allocation based on the historic allocation of the assets used the following to determine the appropriate unregulated rate:

Storage Pools

Storage only	S	Mandaumin, Bluewater, Dow Moore, Waubuno, Payne, Bickford, Sombra, Enniskillen, Bentpath, Terminus, Rosedale, Dawn 47-49, Dawn 59-85, Dawn 156, Booth Creek, Bentpath East, Black Creek
Storage & Transmission	ST	Oil City, Dawn 167, Oil Springs East, Edys Mills, Dow A Plant

Allocation to the unregulated operation is further defined by asset class:

Asset Class	Allocation to Unregulated
Land	S – 37.66%; ST – 19.86%
Land Rights	S & ST – 37.66%
Structures & Improvements	S – 37.66%; ST – 19.86%
Storage Wells	S & ST – 37.66%

Field Lines	S & ST – 37.66%
Compressor Equipment	S – 37.66%; ST – 19.86%
Measuring & Regulating Equipment	S – 37.66%; ST – 9.94%
Base Pressure Gas	S & ST – 37.66%

Compressor Stations

Storage & Transmission	ST	Plant A, Plant B, Plant C, Plant D, Plant F, Plant G
Transmission Only	T	Plant E, Dawn- Trafalgar Meter Runs, Tecumseh Measurement, TCPL Measurement, Great Lakes Header, Total Measurement
Dehy	D	Dawn Dehy

Allocation to the unregulated operation is further defined by asset class:

Asset Class	Allocation to Unregulated
Land	ST – 19.86%
Structures & Improvements	ST – 19.86%; T – 0%
Compressor Equipment	ST – 19.86%; T – 0%; D – 22.22%
Measuring & Regulating Equipment	ST – 9.94%

Allocation factors above are the factors used for the one time allocation of regulated and unregulated as of December 31, 2006.

Subsequent Review

In response to B&V's recommendation that more robust documentation be established, Union completed a comprehensive review of the unregulated storage allocation factors in early 2012. Union's methodology followed the approach outlined in EB-2010-0039 Exhibit A, Tab 4, page 14 of 22. On lines 5 – 9 Union describes the methodology for new storage assets as "If the project is a necessary part of normal business operations, then the new asset is split in the same way as the existing asset. If the project improves the efficiency or provides growth opportunities for the unregulated storage business, then the incremental cost of the project beyond the simple replacement is directly assigned to unregulated storage." Union illustrates this methodology in undertaking EB-2011-0210 Exhibit JT1.41.
The review identified that updates were required at 10 of the storage pools.

Storage Pool		Storage Well Allocator	Pool Allocator (includes all asset classes)
Bentpath	Reg	62.34%	62%
	Non Reg	37.66%	38%
Bentpath East	Reg	54.56%	61%

	Non Reg	45.44%	39%
Bickford	Reg	62.34%	62%
	Non Reg	37.66%	38%
Black Creek	Reg	N/A	62%
	Non Reg	N/A	38%
Bluewater	Reg	51.06%	58%
	Non Reg	48.94%	42%
Booth Creek	Reg	62.34%	62%
	Non Reg	37.66%	38%
Dawn 156	Reg	31.56%	32%
	Non Reg	68.44%	68%
Dawn 167	Reg	62.34%	69%
	Non Reg	37.66%	31%
Dawn 47-49	Reg	62.34%	62%
	Non Reg	37.66%	38%
Dawn 59-85	Reg	22.54%	35%
	Non Reg	77.46%	65%
Dow A	Reg	50.79%	68%
	Non Reg	49.21%	32%
Dow Moore	Reg	N/A	62%
	Non Reg	N/A	38%
Edys Mills	Reg	52.11%	71%
	Non Reg	47.89%	29%
Enniskillen	Reg	50.60%	59%
	Non Reg	49.40%	41%
Mandaumin	Reg	62.34%	62%
	Non Reg	37.66%	38%
Oil City	Reg	51.06%	64%
	Non Reg	48.94%	36%
Oil Springs East	Reg	45.61%	70%

	Non Reg	54.39%	30%
Payne	Reg	43.24%	52%
	Non Reg	56.76%	48%
Rosedale	Reg	62.34%	62%
	Non Reg	37.66%	38%
Sombra	Reg	62.34%	63%
	Non Reg	37.66%	37%
Terminus	Reg	62.34%	62%
	Non Reg	37.66%	38%
Waubuno	Reg	62.34%	63%
	Non Reg	37.66%	37%

After the factors were updated, the 2013 rate case evidence was reviewed. It was determined that the use of the revised allocation factors on maintenance capital projects would have increased the allocation to unregulated by approximately $50,000 in 2012 and $25,000 in 2013.

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-Housing Providers of Ontario ("FRPO")

Ref: Exhibit B1, Summary Schedule 2

For each hybrid utility/non-utility project (e.g. lines 1, 3, 4, 10, 11, 12, 13, 14, 15, 19, 20, 21) and General and Other project (e.g. lines 142-174) please describe, in detail, how the total project cost is allocated between utility and non-utility ("unregulated"), including any allocations of utility costs between storage and transmission.

Response:

Project expenditures have been allocated between regulated and unregulated based upon the asset that is being constructed (or is expected to be constructed in the case of the forecast). Union allocates these assets based upon the Board-approved 2007 cost study methodology. The methodology was approved by the Board in EB-2011-0038.

Description	Allocation to Unregulated	Comment
New Storage asset	100%	Based on the NGEIR decision (EB-2005-0551) any new storage assets that increase capacity or deliverability, constructed after the decision will be assigned to unregulated.
Replacement Storage asset or new storage assets that do not increase capacity or deliverability.	37.7%	Based on cost allocation methodology approved by the Board in EB-2011-0038.
Replacement Storage Asset plus improved operational efficiencies and /or growth opportunities	Replacement is allocated base on the historical (allocation) and cost of incremental capacity is allocated 100% to unregulated.	Allocated the portion of costs associated with the increased efficiency and/or growth of that storage operation to the unregulated storage operation.

Replacement of Storage & Transmission Assets – compression	19.9%	Based on cost allocation methodology approved by the Board in EB-2011-0038.
Replacement of Storage & Transmission Assets – Measuring & Regulating	9.9%	Based on cost allocation methodology approved by the Board in EB-2011-0038.
Replacement of Storage Assets – Dehydration	22.2%	Based on cost allocation methodology approved by the Board in EB-2011-0038.
General Assets	2.9%	All general plant (other than vehicles and heavy equipment) based on the cost allocation methodology that was approved by the Board in EB-2011-0038.

The asset allocation described above applies to the projects identified in Attachment 1.

Line No.	Function	Regulated Actual 2007	Total Actual 2007	Regulated Actual 2010	Total Actual 2010	Regulated Actual 2011	Total Actual 2011	Regulated Forecast 2012	Total Forecast 2012	Regulated Forecast 2013	Total Forecast 2013	In Service Date	Unregulated Allocation Factor	Cost Allocation Desciption	Justification
	Storage														
1	Dawn Plant F Compressor	1,744	2,176									December 29, 2006	19.9%	New storage and transmission compression assets.	This project forms part of the Dawn-Trafalgar Facilities Expansion Program (2006 - 2007 winter), which allows for the incremental expansion of system capacity by adding pipeline sections and compression capability, as required, to meet growth in market demand.
3	Dawn Plant J			5,757	10,004	15,426	26,805	1,169	2,031			September 30, 2011	42.5%	Replaced Dawn Plant A (Storage and Transmission asset) plus provided incremental capacity which is 100% unregulated.	The Dawn A plant reciprocating compressors, ranging from 35 to 50 years old exceed the legislated Provincial Air emissions standards. The existing A plant has to be replaced in order to comply with the legislation.
4	STO Dehy Incinerator Installations			766	1,228							November 3, 2010	37.7%	Dehydration Incinerator located at storage pools therefore replacement storage asset.	As part of the Comprehensive Certificate of Approval with MOE, benzene emissions from storage pool dehydrators were identified as unacceptable. MOE mandated that incinerators be installed on all 5 storage pool hydrators before the next operating season after 2008/2009.
10	27,600 Volt Dead Buss Closure					655	819					November 1, 2011	37.7%	Replacement of storage asset.	In the event of a utility (Hydro One) power failure all the individual plant generators at Dawn will start to feed emergency power to their specific areas of the Dawn Plant. If any one of these generators fail during operation and Hydro One power is still not available, that entire section of the facility will have NO POWER to support the associated plants continued operation. We need to have the ability to generate our own power from the 600 Volt system back up to our 27,600 Volt company owned network to allow an alternate power source to the failed area of the plant.
11	Dawn B Gas Generator Miidlife					1,170	1,462					October 1, 2011	19.9%	New storage and transmission compression assets.	The Dawn B RB211 is due for a midlife overhaul in order to maintain unit reliability. Overhauls must occur when the unit has operated for 25,000 hours, but recent repairs have extended the limit to 30,000 hours. The unit currently has operated in excess of 30,700 hours.
12	Dawn Fire Hydrant System Upgrade					626	783	400	500	200	250	August 31, 2013	19.9%	New storage and transmission compression assets.	The south yard fire hydrant system is antiquated, unreliable, does not have enough water capacity and the coverage is also inadequate. Recently the JHSC condemned the south yard fire pump because it failed to start the last 3 attempts and parts are not available for the 1943 Continental engine.
13	ECS Mandaumin Pool Modifications							408	680			November 1, 2012	37.7%	New storage with no incremental capacity	This project consists of construction of a separator, tank, and choker valves at wells 4, 6, and 7. These facilities will increase operational efficiency of the Mandaumin pool, allowing improved injection and withdrawal capacity.
14	STO Hagar Exhaust Stack Replacements							800	800			Summer 2012	0.0%	Regulated storage asset - not located at Dawn facility.	The purpose of this project is to reduce the KVGR exhaust noise by 25 dBA, and reduce the JVG, Turbine #1 and #2 exhaust noise by 15 dBA. This work has been identified in our Comprehensive Certificate of Approval and needs to be completed in order to comply with the CC of A.
15	STO Hagar Tank Painting							500	500			June 1, 2012	0.0%	Regulated storage asset - not located at Dawn facility.	The scope of the project is to repaint the entire LNG Storage Tank. It is currently degraded and outer tank metal is exposed to harsh elements of Northern Ontario weather. The paint is peeled on various sections exposing primer last barrier of protection.
19	Emergency Shut Down Valve									320	534	November 1, 2013	37.7%	New storage with no incremental capacity	This project will install Emergency Shutdown Valves (ESV) on all injection/withdrawal wells. The initial phase of this project targets pools that contain wells with the highest risk consequence ratings. High consequence wells were selected based upon: proximity to the nearest residence, distance from Dawn and maximum well flow.
20	CS - Sewage Lagoon Upgrade					805	1,005					December 15, 2011	19.9%	Asset that supports both the storage and transmission assets.	Recently the need for additional upgrades has become necessary due to age of the system and the fact that over the years of use, capacity has diminished. The need to add additional treatment to the wastewater effluent has also become necessary following the recommendations of the licensed Lagoon operator and the engineering companies Union Gas has hired to study the Lagoon operation. Now there is a requirement to make upgrades to the Lagoon to meet the wastewater guidelines as set out by the Ministry of the Environment.
21	Storage Projects listed above	$ 1,744	$ 2,176	$ 9,993	$ 14,702	$ 18,682	$ 30,874	$ 4,449	$ 5,964	$ 6,440	$ 7,157		N/A	Subtotal of above lines.	

Line No.	Function	Regulated Actual 2007	Total Actual 2007	Regulated Actual 2010	Total Actual 2010	Regulated Actual 2011	Total Actual 2011	Regulated Forecast 2012	Total Forecast 2012	Regulated Forecast 2013	Total Forecast 2013	In Service Date	Unregulated Allocation Factor	Cost Allocation Desciption	Justification
22	Storage Projects less than $500,000	3,926	5,028	1,938	3,159	5,123	5,985	6,965	8,341	5,122	6,329				
23		$ 5,670	$ 7,204	$ 11,931	$ 17,861	$ 23,805	$ 36,859	$ 11,414	$ 14,305	$ 11,562	$ 13,486				
	General														
142	SCADA Replacement	796	820	3,152	3,247	2,588	2,666					December 22, 2011	2.9%	General Assets allocation rate.	This project is to replace the SCADA host system (not field equipment or telemetry infrastructure), as the hardware and software is >10 years old and obsolete. The SCADA system is used to operate the Union Gas transmission, storage and distribution systems.
143	Customer Support Reliability	564	581									January 28, 2007	2.9%	General Assets allocation rate.	Ensure funding is available for Contract Resources and third party IS vendors to maintain compliance with internal and external mandates. These dollars will be utilized to hire contractors and professional services in support of Union Gas IT applications.
144	ESPM (NGEIR)	1,876	1,932	0								June 15, 2008	2.9%	General Assets allocation rate.	In response to the OEB Natural Gas Electric Interface Review ("NGEIR") process, Union Gas entered into a Settlement Agreement on June 13, 2006. As part of this Agreement, Union committed to offering new exfranchise power services. This capital project will fund the changes required to offer these new services.
145	Cafeteria Equipment Upgrade - Safety Initiative	111	114	0								November 20, 2008	2.9%	General Assets allocation rate.	Upgrade the kitchen equipment and food display units in order to offer healthier food options in a reinvented atmosphere that encourages Union Gas employees to choose the cafeteria over dining elsewhere.
146	IT Demand Management - Bus Development/S&T					2,719	2,801					ongoing	2.9%	General Assets allocation rate.	Uses allocate IT capital to group a dozen smaller projects into a single submission to be managed by IT Demand Management, based on emerging demands.
147	Probability and Risk Optimization			1,167	1,202	579	597					February 28, 2012	2.9%	General Assets allocation rate.	This project reviews the historical use of assets (molecule, space, Dawn to Parkway transportation, and deliverability) to determine opportunity for increased revenues.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

Ref: J.B-8-10-2, Attachment 1, Line 3

Union states that the non-utility storage plant allocation factor for the Dawn Plant J project should be 42.5% because (a) it is a storage and transmission asset, and (b) the project created incremental capacity.

Please show in detail how the 42.5% allocation factor was calculated.

Identify the costs that were allocated and the costs that were direct assigned, with an explanation for each.

Please provide the resulting increase in working capacity and deliverability for each storage pool.

The cost of replacing Dawn Plant A in the existing location with engines that provide the same horsepower was allocated based on the original Dawn Plant A allocation. The cost of changing locations and increasing the engine to provide incremental horsepower was charged 100% to the unregulated operation, which resulted in a new blended rate for this facility.

Dawn Plant J is a compressor plant that was constructed to replace the existing horsepower at Dawn Plant A which was decommissioned to meet the requirements of our Comprehensive Certificate of Approval Program. This project did not increase the working capacity or deliverability of individual storage pools.

Dawn Plant J
Blended Allocation to Unregulated Storage

	Millions	Regulated	Unregulated
Dawn A Plant - Current Allocation		80.14%	19.86%
Cost of replacing existing	$ 29.9	$ 24.0	$ 5.9
Revenue Generating	$ 11.8		$ 11.8
	$ 41.7	$ 24.0	$ 17.7
New Blended % for Dawn A / J		57.55%	42.45%

EVIDENCE OF J. ROSENKRANZ ON BEHALF OF CME, CCC, CCK, & FRPO

Answers to Board Staff Interrogatories

Interrogatory #1

Ref: Rosenkranz Evidence

Preamble: Mr. Rosenkranz's 4th recommendation is as follows: Union should provide a more detailed description of its proposed methodology for assigning replacement project costs to non-utility storage and utility storage.

Questions/ Requests:

a) Please provide a suggested methodology for assigning replacement project costs to non-utility storage and utility storage.

Response:

In EB-2011-0038 proceeding, the Board approved a methodology for the one-time separation of non-utility storage plant and utility storage plant for the existing storage pools that were in service at the time of the NGEIR Decision. This methodology used an arithmetic average of the storage space and storage deliverability allocation factors from the EB-2005-0520 cost study to calculate a non-utility storage factor of 37.7%.

Union proposes that the costs of plant additions that are replacement or maintenance projects, and do not result in an increase in storage space or deliverability, will be allocated between non-utility storage and utility storage using the same factors as were used in the original allocation of the base assets (Exhibit J.B-6-16-1). For storage pools where storage space and deliverability has remained unchanged, this makes sense. However, since the time of the NGEIR Decision, Union has expanded the space and/or deliverability of nearly half of the pre-NGEIR storage pools. All of the additional space and deliverability created by these expansions went to Union's non-utility storage operation. For these expanded pools, the original plant allocation factors, based on the storage space and deliverability that existed in 2006, are no longer valid. As the proportion of non-utility storage plant for a storage pool increases, the non-utility storage business should pay a greater portion of the maintenance and replacement project costs, and O&M costs.

Union should therefore update the allocation factors for each of the pre-NGEIR storage pools to reflect the increase in storage space and/or deliverability that has occurred since the NGEIR decision. The revised allocation factors can be calculated using an arithmetic average of storage space and storage deliverability percentages, just as was done for the one-time separation plant separation that was approved by the Board. An example showing how the non-utility allocation factors for the storage pools in service at the time of the NGEIR Decision would be updated is provided in the Attachment.

ATTACHMENT
SUGGESTED METHODOLOGY FOR UPDATING NON-UTILITY STORAGE FACTOR

	Storage	Maximum	Non-Utility Allocation			Post-NGEIR Expansions						
	Capacity	Deliverability	as of 12/31/2006			(Example)		Storage	Storage	Updated Non-Utility Allocation		
Storage Pool	12/31/2006	W06/07	Space	Deliv.	Factor	Space	Deliv.	Space	Deliv.	Space	Deliv.	Factor
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Bentpath	5,382,000	405,600	2,029,014	152,911	0.377			5,382,000	405,600	2,029,014	152,911	0.377
Bentpath East	4,711,000	0	1,776,047	0	0.377			4,711,000	0	1,776,047	0	0.377
Bickford	22,325,000	164,400	8,416,525	61,979	0.377			22,325,000	164,400	8,416,525	61,979	0.377
Bluewater	2,007,000	13,300	756,639	5,014	0.377	500,000		2,507,000	13,300	1,256,639	5,014	0.439
Booth Creek	1,962,000	0	739,674	0	0.377			1,962,000	0	739,674	0	0.377
Dawn 156	28,121,000	467,300	10,601,617	176,172	0.377			28,121,000	467,300	10,601,617	176,172	0.377
Dawn 167	4,990,000	19,200	1,881,230	7,238	0.377			4,990,000	19,200	1,881,230	7,238	0.377
Dawn 47-49	4,937,000	55,200	1,861,249	20,810	0.377			4,937,000	55,200	1,861,249	20,810	0.377
Dawn 59-85	5,977,000	492,100	2,253,329	185,522	0.377		500,000	5,977,000	992,100	2,253,329	685,522	0.534
Dow A	6,462,000	74,700	2,436,174	28,162	0.377			6,462,000	74,700	2,436,174	28,162	0.377
Edys Mills	2,587,000	40,100	975,299	15,118	0.377			2,587,000	40,100	975,299	15,118	0.377
Enniskillen	3,581,000	51,000	1,350,037	19,227	0.377			3,581,000	51,000	1,350,037	19,227	0.377
Mandaumin	3,909,000	29,400	1,473,693	11,084	0.377			3,909,000	29,400	1,473,693	11,084	0.377
Oil City	1,725,000	27,900	650,325	10,518	0.377			1,725,000	27,900	650,325	10,518	0.377
Oil Springs East	3,736,000	27,900	1,408,472	10,518	0.377			3,736,000	27,900	1,408,472	10,518	0.377
Payne	24,946,000	161,500	9,404,642	60,886	0.377	2,000,000		26,946,000	161,500	11,404,642	60,886	0.400
Rosedale	3,356,000	234,100	1,265,212	88,256	0.377			3,356,000	234,100	1,265,212	88,256	0.377
Sombra	2,203,000	10,700	830,531	4,034	0.377			2,203,000	10,700	830,531	4,034	0.377
Terminus	11,788,000	135,600	4,444,076	51,121	0.377			11,788,000	135,600	4,444,076	51,121	0.377
Waubano	10,179,000	46,200	3,837,483	17,417	0.377			10,179,000	46,200	3,837,483	17,417	0.377
Dow Moore	6,114,000	106,800	2,304,978	40,264	0.377			6,114,000	106,800	2,304,978	40,264	0.377
	160,998,000	2,563,000	60,696,246	966,251	0.377	2,500,000	500,000	163,498,000	3,063,000	63,196,246	1,466,251	0.433

Cols. (b) & (c) — *EB-2011-0038, Exhibit B3.29* *(Units are GJ and GJ/day)*
Column (d) — *(b) * (f)*
Column (e) — *(c) * (f)*
Column (i) — *(b) + (g)*
Column (j) — *(c) + (h)*
Column (k) — *(d) + (g)*
Column (l) — *(e) + (h)*
Column (m) — *((k)/(i)+(l)/(j))/2*

Federation of Rental-housing Providers of Ontario ("FRPO")
Supplemental Questions

1) In J8.5, what is meant by the "use of revised allocation factors on maintenance capital projects"?

   a) Specifically, what is the definition of maintenance capital projects?

   b) If maintenance capital projects does not mean all O&M that is allocated using the gross capital allocators, please provide the resulting impact for all O&M in 2013.

Response:

The allocation factors used to create the test year forecast filed in support of the 2013 rate proposals were based on the 2007 approved allocation factors used for the one time allocation of unregulated storage plant.

The allocation factors provided in the undertaking response were updated to reflect the effect of the new unregulated storage investment since 2007. The effect of using the revised allocation factors on storage capital expenditures for 2012 and 2013 decreases the utility storage assets by $50,000 in 2012 and $25,000 in 2013. The revenue requirement impact of these adjustments is not material (less than $10,000).

a) Maintenance capital projects replace existing capacity/deliverability or add assets that do not increase capacity or deliverability.

b) As noted in Exhibit A2, Tab 2, Page 8, there are four methods used to allocate costs to unregulated O&M. Not all O&M is allocated using asset based allocation factors.

   - Actual O&M related to the operation of the storage facilities was allocated to the unregulated storage operation using the same allocators applied to the assets for that facility.
   - Administrative and general expenses and benefits in support of unregulated storage operations were allocated in proportion to storage O&M.
   - O&M costs related to the development of new storage assets are assigned based on an estimate of time spent annually on the development of unregulated projects.
   - O&M costs related to the Regulatory department for development of new storage assets, are assigned based on an estimate of time spent annually on the development of unregulated projects.

   The following schedule categorizes the 2013 Forecast non utility allocation (Exhibit D1, SS2 Updated) by the methods noted above.

A2, Tab 2 Categories	$(M's)
Operation of Storage Facilities	6.2
Admin, General & Benefits	5.8
Development of New Storage Assets - Other	0.6
Development of New Storage Assets - Regulatory	0.3
Sub Total	12.9
Donations	0.7
Exhibit D1, SS2 Updated, Line 30 Non Utility Allocations	13.6

The pool by pool allocation factors provided in response to undertaking J8.3 show the approved factors at the time of the initial allocation used to determine the 2013 unregulated costs, and the revised allocations reflecting the additional investment since 2007. Using the revised allocations would decrease the utility O&M by $100,000.

Federation of Rental-housing Providers of Ontario ("FRPO")
<u>Supplemental Questions</u>

2) J8.5 did not address investments made in projects such as Plant A/J (JT1.34) and, we suspect, most of the projects identified in the above referenced J1.4 of EB-2009-0101 (such as the Dawn Delivery Deliverability project).

a) Please provide the ratio of the total gross plant in utility and non-utility projects for 2013.

b) Using the ratio, please provide the resulting impact on allocated O&M for 2013.

Response:

Undertaking J8.3 requested the regulated and unregulated allocation of O&M by storage pool, as these costs are allocated in proportion to the asset allocation.

Undertaking J8.5 provided the methodology for allocating capital additions. Contrary to the preamble, this response does address the methodology used for all storage capital expenditures including new unregulated storage expenditures as well as replacement expenditures. The Dawn A/J project is an example of a project that combines both replacement and increased capacity. See J8.5 middle of page 1, last row of the first table. This category is described as a Replacement Asset that increases capacity or deliverability. The allocation methodology is described as follows "Cost of replacing the existing asset like for like is allocated regulated versus unregulated based on the historic allocation of assets being replaced. The cost of providing the incremental capacity or deliverability is allocated 100% to the unregulated operation. This results in a new blended rate for this asset." Undertaking JT1.34 outlines how the allocation factor for Dawn Plant A/J was determined. The allocation factor (57.55% regulated and 42.45% unregulated) is applied to both the capital expenditure and the O&M associated with this facility.

The Dawn Deliverability project and the two Delta pressuring projects identified in J1.4 of EB-2009-0101 (page 2, Note 5, lines 4, 5 & 9) were not referenced in evidence as they are projects that increased the deliverability or capacity of Union's system and the capital cost associated with those projects was allocated 100% to the unregulated operation. The impact of these projects on facilities that existed at December 31, 2006 is reflected in the updated allocation factors. The storage pools that were upgraded since that time, and the revised factors, are set out in the table starting at the bottom of page 2 of J8.5. There were 10 pools impacted – Bentpath East, Bluewater, Dawn 156, Dawn 59-85, Dow A, Edys Mills, Enniskillen, Oil City, Oil Springs East and Payne.

Union Gas Limited
EB-2011-0210

ILLUSTRATED IMPACT OF UPDATED GENERAL PLANT ALLOCATION FACTOR

		12/31/07	
1	Non-Utility Storage Plant	172,572	EB-2011-0038, Exhibit A, Tab 4, p.13
2	Total Plant (excl. Gen. Plant)	5,198,766	EB-2011-0038, Exhibit A, Tab 4, p.13
3	Percent Non-Utility to Total	3.32%	EB-2011-0038, Exhibit A, Tab 4, p.13
4	Storage Support Allocator	2.52%	EB-2011-0038, Exhibit A, Tab 4, p.13
5	General Plant Factor	2.92%	Average of Line 3 and Line 4
		12/31/10	
6	Total Utility Plant in Service	5,913,764	EB-2011-0210, Exhibit B6, Tab 2, Schedule 2, Page 3, Line 12
7	General Plant	247,525	EB-2011-0210, Exhibit B6, Tab 2, Schedule 2, Page 3, Line 11
8	Non-Utility Storage Plant	305,645	EB-2011-0038, Exhibit B3.3, Page 4, Attachment 1, Line 9
9	Total Plant (excl. Gen. Plant)	5,971,884	Line 6 - Line 7 + Line 8
10	Percent Non-Utility to Total	5.12%	Line 8/Line 9
11	Storage Support Allocator	2.90%	EB-2011-0038, Exhibit A, Tab 4, Attachment 1 (B&V Report), Schedule 13
12	General Plant Factor	4.01%	Average of Line 10 and Line 11

Units: $000

Union Gas Limited
EB-2011-0210

APPLICATION OF UPDATED GENERAL PLANT ALLOCATION FACTOR

		2010	2011	2012	2013	
	Total					
13	General Plant	32,775	39,047	37,724	38,492	EB-2011-0210, Exhibit B1, Summary Schedule 2
14	Vehicles	8,900	11,104	8,000	8,005	EB-2011-0210, Exhibit B1, Summary Schedule 2, Line 134
15	Other General Plant	23,875	27,943	29,724	30,487	Line 13 - Line 14
	Utility					
16	General Plant	31,697	37,731	36,475	37,215	EB-2011-0210, Exhibit B1, Summary Schedule 2
17	Vehicles	8,500	10,604	7,640	7,645	EB-2011-0210, Exhibit B1, Summary Schedule 2, Line 134
18	Other General Plant	23,197	27,127	28,835	29,570	Line 16 - Line 17
19	Non-Utility Allocation	678	816	889	917	Line 15 - Line 18
20	Updated Factor	4.01%	4.01%	4.01%	4.01%	Line 12
21	Updated Plant Allocation	957	1,121	1,192	1,223	Line 15 * Line 20
22	Under-Allocation to Non-Utility	279	305	303	306	Line 21 - Line 19

Units: $000

MR. QUINN: That will shorten things up considerably.

MR. MILLAR: JT1.11.

Mr. Quinn, you had asked a question before. Did you want that...

MR. QUINN: Yes, included, if they look at Washington 10 as a receipt point on their Chicago-to-Dawn Vector contract.

MR. MILLAR: That's JT1.11.

UNDERTAKING NO. JT1.11: TO ADVISE WHETHER WASHINGTON 10 A RECEIPT POINT ON THE CHICAGO-TO-DAWN VECTOR CONTRACT; WHETHER THERE IS A DOCUMENTED PROCEDURE FOR CAPACITY RELEASE

MR. QUINN: Thank you. I had missed the fact that D16 is under panel 4, but I thought it would be on this panel.

So you can defer the answer to this, but I am going to refer you to D-16-10-2, because it's more capacity management than cost allocation, and I am just trying to understand, again, the principles Union uses with the system integrity space.

MS. CAMERON: Can you repeat the IR number again, please?

MR. QUINN: Sorry, J.D-16-10-2.

MS. CAMERON: I have it.

MR. QUINN: What we were asking was you have three-and-a-half PJs that's left empty for fall contingency, but then you have a further six PJs that you fill for winter need.

I guess our question was: Why don't you use the three-and-a-half PJs that you have empty in the fall, and use that space as part of your six PJs that you have to fill for the winter, and fill that space in December? What reason would Union have not to do it that way?

[Witness panel confers]

MR. SMITH: Mr. Quinn, is there a portion of the (b) response to that that is not responsive to the question you asked?

MR. QUINN: Yes. I am not saying to fill the space in addition to the six PJs; I'm saying use the three-and-a-half as part of the six, so you are not having to keep two separate sets of system integrity space, one empty and one full.

The empty space can, a couple of months later, become the full space, and that's what I would call asset optimization.

MR. ISHERWOOD: I will try and supplement the actual answer here, but to the extent that space stayed empty in the fall because it wasn't needed in the fall, your premise is, then, to fill it in December, which would be an expensive month to fill it.

And to the extent the cold weather didn't come around and you needed to empty it, you would then be carrying expensive gas into the summer, and you would empty it to be ready for the next fall. So you would be filling it unnecessarily with expensive gas, and forced to empty it in the following spring, summer, to make room again for the following fall.

MR. QUINN: Your assumption is December gas is going to be expensive gas; is that correct?

MR. ISHERWOOD: Typically it is, yes.

MR. QUINN: Typically it is? Okay. So what is the value of the storage space?

MR. ISHERWOOD: The summer/winter differential.

MR. QUINN: The summer/winter differential? So can you, by way of undertaking, show us a numeric example for the last three years that demonstrates that keeping the space empty has saved ratepayers money?

MR. SMITH: No.

MR. QUINN: Why not? That's -- this is getting clarity on a technical question. The witness has told us that it's more expensive, and I would like to see that demonstrated.

MR. SMITH: We will do it.

MR. QUINN: Okay. Thank you.

MR. MILLAR: JT1.12.

UNDERTAKING NO. JT1.12: TO PROVIDE A NUMERIC EXAMPLE FOR THE LAST THREE YEARS THAT DEMONSTRATES THAT KEEPING THE SPACE EMPTY HAS SAVED RATEPAYERS MONEY

MR. QUINN: Lastly, then, I did have one more question that I think is this panel, but it's in D14.

Again, it shows panel 2, but it's a capacity-related question, so we can answer it here or answer it tomorrow, but under -- these are the list of questions that we submitted -- D14, and the reference is D3, tab 2, schedule 5, page 2. We have asked the question --

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Isherwood

Please provide a numeric example for the last three years that demonstrates that keeping the space empty has saved ratepayers money.

The table below captures the revenue from selling gas molecules in the summer months, and the cost of purchasing gas molecules in the winter months for the last three years.

Table 1

	Sell Gas (July)	Buy Gas (Jan)	Net Cost ($ per GJ)
2010/11	4.59	5.64	(1.05)
2011/12	4.96	5.45	(0.49)
2012/13	2.58	3.52	(0.94)

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Quinn

Please provide contingency spaced numbers for December.

The table provided at JT1.12 has been updated to include December:

Table 1

	Sell Gas (July)	**Buy Gas** (Dec)	**Net Cost** ($/GJ)
2010/11	4.59	5.51	(0.92)
2011/12	4.96	5.41	(0.45)
2012/13	2.58	3.46	(0.88)

Monthly Natural Gas Price Index Summary July 2010

One-Month Spot Gas Price Indexes for July, 2010

	Low	High	Index	Last	Chg.
Alberta (C$/GJ)					
AECO One Month	3.5200	4.3500	3.9103	3.6000	0.3103
AECO Bidweek	3.5200	3.9225	3.7112	3.7297	-0.0185
Border (Empress)	3.4250	4.2675	3.8246	3.5283	0.2963
Border-AECO Differentia	-0.0950	-0.0825	-0.0857	-0.0717	-0.0140
B.C. (C$/GJ)					
Station 2 (Month)	3.5000	3.8500	3.6666	3.4423	0.2243
Station 2 (Bidweek)	3.5000	3.8500	3.6666	3.4778	0.1888
Export (US$/MMBtu)					
N. Border, N. Natural					
Ventura	4.6100	4.6850	4.6425	4.0770	0.5655
Chicago	4.5000	4.8450	4.7696	4.0943	0.6753
Pacific Gas Transmission					
ABC	3.8000	3.8500	3.8330	3.3600	0.4730
Kingsgate	4.1500	4.2000	4.1830	3.7100	0.4730
Stanfield	4.2400	4.3200	4.2831	3.8284	0.4547
Malin	4.2900	4.3700	4.3331	3.8784	0.4547
PG&E Citygate	4.6300	4.7700	4.6893	4.3526	0.3367
Kern River Stn. (SoCal)	4.5100	4.6100	4.5720	3.9600	0.6120
Kern River Stn. (PG&E)	4.5500	4.5800	4.5680	3.9300	0.6380
TransCanada Pipelines					
Emerson	3.9800	4.3900	4.1859	3.9911	0.1948
Parkway	4.7300	5.0700	5.0162	4.5510	0.4652
Dawn	4.7000	5.0300	4.9844	4.5155	0.4689
Iroquois	5.0570	5.1595	5.1396	4.5907	0.5489
Niagara	4.9420	5.0345	5.0149	4.5237	0.4912
Westcoast Pipeline					
Huntingdon	3.8900	4.1700	4.0645	3.7532	0.3112
Into Tennessee Pipeline at					
Dracut	5.1100	5.1200	5.1190	4.5300	0.5890

(US$/MMBtu)	Low	High	Index	Last	Chg.
U.S. Del. to Pipeline (Avg.)	3.92	4.86	4.59	4.00	0.59
Texas, Oklahoma					
Houston Ship Channel	4.77	4.83	4.81	4.05	0.76
Northern Natural	4.56	4.66	4.60	3.95	0.65
Tennessee Zone 0	4.58	4.66	4.61	3.94	0.67
Valero	4.60	4.70	4.65	3.99	0.66
South Louisiana					
ANR Southeast	4.58	4.68	4.62	4.12	0.50
Columbia Gulf	4.67	4.68	4.68	4.11	0.57
Henry Hub	4.71	4.72	4.72	4.16	0.56
Tennessee Zone 1	4.68	4.69	4.69	4.11	0.57
Transco 65	4.75	4.80	4.77	4.18	0.59
Trunkline	4.65	4.70	4.68	4.11	0.57
Tetco E. LA	4.74	4.75	4.75	4.19	0.56
Texas Gas	4.66	4.68	4.67	4.12	0.56
Rockies/California/Appalachia					
Northwest Rocky Mountain	3.92	4.20	4.05	3.58	0.47
El Paso Keystone	4.47	4.56	4.53	3.80	0.73
El Paso San Juan	4.13	4.36	4.27	3.66	0.61
El Paso-Topock	4.55	4.58	4.57	3.95	0.62
California Border-SoCal	4.55	4.58	4.57	4.01	0.56
Columbia	4.84	4.86	4.85	4.32	0.53
Midcontinent					
ANR Southwest	4.45	4.50	4.47	3.86	0.61
Chicago Citygate	4.50	4.85	4.77	4.09	0.68
Northern - Demarcation	4.42	4.66	4.54	4.07	0.47
Panhandle	4.23	4.52	4.43	3.87	0.56
NGPL Midcont	4.41	4.50	4.47	3.82	0.65

Source: Canadian Enerdata Ltd. price survey.

Canadian Gas Price Reporter Price Index Name Changes

In conjunction with the migration of Natural Gas Exchange (NGX) products to the Intercontinental Energy Exchange (ICE) trading platform, the official names of the NGX natural gas price indices that appear in Canadian Gas Price Reporter (CGPR) have **changed on November 1, 2007**. The new names are intended to more clearly identify the locations and onscreen products on which the indices are based and to follow a clear, consistent naming convention.

The list below contains the old index name, the new index name and the CGPR page and/or table reference where the index appears. Note that CGPR line references (e.g. 2A, 5A, 7A) are included in the new names.

To further assist customers with the transition, CGPR contains footnotes that link the new index name with its former name in the respective table where the index appears. In addition, the name change list will appear on this page of CGPR indefinitely for reference purposes.

If you have any comments or questions, please contact richardz@enerdata.com or call Richard at 905-642-8167.

NAME CHANGE LIST
Effective November 1, 2007

Page 2 - Daily Spot Gas Price at AECO C & Nova Inventory Transfer Table
New Table Name - NGX AB-NIT Same Day Index
New Index Names
NGX AB-NIT Same Day Index (1A)
NGX AB-NIT Same Day Index (2A)
NGX AB-NIT Same Day Index (3A)
NGX AB-NIT Same Day Index (4A)
NGX AB-NIT Same Day Index (5A)

Page 3 - Canadian Natural Gas Supply Prices Table
Current Index Name / New Index Name
AECO "C" & N.I.T. One Month Spot / NGX AB-NIT Month Ahead Index (7A)
AECO "C" & N.I.T. "Bid-Week" Spot / NGX AB-NIT Bidweek Index

Page 11 - Monthly Canadian and U.S. Natural gas price summary Table
Current Index Name / New Index Name
Alberta Spot Price – AECO C/N.I.T. (7A) / NGX AB-NIT Month Ahead Index (7A)
Alberta Bidweek Spot Price – AECO C/N.I.T. (7A1) / NGX AB-NIT Bidweek Index
Alberta Daily Spot Price – AECO C/N.I.T. - 2A / NGX AB-NIT Same Day Index (2A)
Alberta Daily Spot Price – AECO C/N.I.T. - 4A / NGX AB-NIT Same Day Index (4A)
Alberta Daily Spot Price – AECO C/N.I.T. - 5A / NGX AB-NIT Same Day Index (5A)

The following changes were effective October 1.
Old Name, Page/New Name
NGX Station #2 Daily Spot Price Index, p. 15/NGX Spectra Station #2 Day Ahead Index
NGX Alberta Next Day Price Index, p. 16/NGX AB-NIT Day Ahead Index
NGX Union Dawn Daily Spot Price Index, p. 16/NGX Union-Dawn Day Ahead Index
NGX Empress Transport Spot Day Price Index, p. 16/NGX AB-NIT/TCPL-Empress Transport Day Ahead Index

Monthly Natural Gas Price Index Summary December 2010

One-Month Spot Gas Price Indices for December, 2010

	Low	High	Index	Last	Chg.
Alberta (C$/GJ)					
AECO One Month	3.3500	3.8900	3.6025	3.1983	0.4042
AECO Bidweek	3.5750	3.8900	3.7061	3.1421	0.5640
Border (Empress)	3.1750	3.7700	3.4516	3.0831	0.3685
Border-AECO Differential	-0.1750	-0.1200	-0.1509	-0.1152	-0.0357
B.C. (C$/GJ)					
Station 2 (Month)	3.6000	3.9000	3.7381	3.1228	0.6153
Station 2 (Bidweek)	3.6300	3.7940	3.7226	3.0818	0.6408
Export (US$/MMBtu)					
N. Border, N. Natural					
Ventura	4.5200	4.5600	4.5400	3.3300	1.2100
Chicago	4.3700	4.6475	4.4772	3.4799	0.9974
Pacific Gas Transmission					
ABC	3.7100	3.9400	3.8180	3.0802	0.7378
Kingsgate	4.0600	4.2900	4.1680	3.4302	0.7378
Stanfield	4.1600	4.3900	4.2680	3.5302	0.7378
Malin	4.2100	4.4400	4.3180	3.5802	0.7378
PG&E Citygate	4.5700	4.7400	4.6350	3.9562	0.6788
Kern River Stn. (SoCal)	4.2400	4.3200	4.2925	3.1700	1.1225
Kern River Stn. (PG&E)	4.2200	4.3000	4.2733	3.1525	1.1208
TransCanada Pipelines					
Emerson	4.1800	4.5200	4.3620	3.5331	0.8289
Parkway	4.7000	5.0800	4.9635	3.8244	1.1391
Dawn	4.6000	4.9100	4.8135	3.7517	1.0618
Iroquois	5.3500	5.7100	5.5843	3.8920	1.6923
Niagara	4.8100	5.1200	5.0235	3.8017	1.2218
Westcoast Pipeline					
Huntingdon	4.7700	5.0800	4.9686	3.7549	1.2137
Into Tennessee Pipeline at					
Dracut	5.7800	5.8000	5.7900	3.6500	2.1400

(US$/MMBtu)	Low	High	Index	Last	Chg.
U.S. Del. to Pipeline (Avg.)	3.96	5.98	4.28	3.19	1.09
Texas, Oklahoma					
Houston Ship Channel	4.05	4.17	4.13	3.30	0.84
Northern Natural	4.04	4.18	4.12	3.25	0.88
Tennessee Zone 0	4.11	4.28	4.17	3.19	0.98
Valero	4.15	4.30	4.22	3.24	0.98
South Louisiana					
ANR Southeast	4.21	4.25	4.24	3.25	0.99
Columbia Gulf	4.22	4.24	4.23	3.23	1.00
Henry Hub	4.26	4.27	4.27	3.29	0.98
Tennessee Zone 1	4.24	4.25	4.25	3.25	1.00
Transco 65	4.28	4.30	4.29	3.29	1.01
Trunkline	4.21	4.23	4.22	3.24	0.99
Tetco E. LA	4.23	4.25	4.24	3.30	0.94
Texas Gas	4.20	4.22	4.22	3.22	1.00
Rockies/California/Appalachia					
Northwest Rocky Mountain	3.96	4.08	4.01	2.92	1.09
El Paso Keystone	4.08	4.16	4.12	2.98	1.14
El Paso San Juan	4.04	4.24	4.10	2.96	1.14
El Paso-Topock	4.22	4.30	4.27	3.16	1.11
California Border-SoCal	4.24	4.32	4.29	3.17	1.12
Columbia	5.96	5.98	5.97	3.36	2.61
Midcontinent					
ANR Southwest	4.00	4.14	4.09	3.03	1.06
Chicago Citygate	4.37	4.65	4.48	3.48	1.00
Northern - Demarcation	4.39	4.54	4.46	3.40	1.06
Panhandle	4.00	4.14	4.08	3.00	1.08
NGPL Midcont	4.10	4.14	4.12	3.06	1.06

Source: Canadian Enerdata Ltd. price survey.

AECO Monthly Prices - November 2010 Trading

			Price (C$/GJ)		
Month	**# Trades**	**Volume (TJ)**	**Low**	**High**	**Average**
M-Dec 10	998	3,128.1	3.350	3.890	3.6025
M-Jan 11	309	715.0	3.420	3.920	3.6691
M-Feb 11	43	101.7	3.500	3.895	3.6829
M-Mar 11	49	115.0	3.390	3.810	3.6371
M-Apr 11	16	38.0	3.455	3.790	3.5592
M-May 11	5	9.5	3.455	3.730	3.5408

Dawn Monthly Basis - November 2010 Trading

			Price (C$/GJ)		
Month	**# Trades**	**Volume (TJ)**	**Low**	**High**	**Average**
M-Dec 10	289	1,346.8	0.430	0.590	0.5465
M-Jan 11	102	414.3	0.310	0.455	0.4031
M-Feb 11	54	279.7	0.290	0.455	0.4084
M-Mar 11	55	335.3	0.350	0.460	0.4233
M-Apr 11	4	17.5	0.350	0.415	0.3914
M-May 11	1	5.0	0.305	0.305	0.3050

Monthly Natural Gas Price Index Summary July 2011

One-Month Spot Gas Price Indices for July, 2011

	Low	High	Index	Last	Chg.
Alberta (C$/GJ)					
AECO One Month	3.4800	4.1900	3.7166	3.6558	0.0608
AECO Bidweek	3.4800	3.6900	3.5840	3.8036	-0.2196
Border (Empress)	3.3100	4.0350	3.5536	3.4829	0.0707
Border-AECO Differential	-0.1700	-0.1550	-0.1630	-0.1729	0.0099
B.C. (C$/GJ)					
Station 2 (Month)	3.1750	3.8000	3.2817	3.5432	-0.2615
Station 2 (Bidweek)	3.1750	3.3232	3.2614	3.5464	-0.2850
Export (US$/MMBtu)					
N. Border, N. Natural					
Ventura	4.2250	4.2850	4.2508	4.2963	-0.0455
Chicago	4.3000	4.5000	4.3802	4.4040	-0.0238
Pacific Gas Transmission					
ABC	3.8000	3.8500	3.8300	3.7399	0.0901
Kingsgate	4.1500	4.2000	4.1800	4.0899	0.0901
Stanfield	4.1300	4.2700	4.1939	4.1899	0.0039
Malin	4.1800	4.3200	4.2439	4.2399	0.0039
PG&E Citygate	4.5700	4.6800	4.6500	4.5532	0.0968
Kern River Stn. (SoCal)	4.4800	4.6000	4.5150	4.3300	0.1850
Kern River Stn. (PG&E)	4.4200	4.6300	4.4800	4.3000	0.1800
TransCanada Pipelines					
Emerson	4.0500	4.2950	4.2012	4.3734	-0.1722
Parkway	4.5100	4.7070	4.6913	4.7397	-0.0483
Dawn	4.4600	4.6570	4.6413	4.6898	-0.0485
Iroquois	4.7300	4.9270	4.9113	4.9017	0.0096
Niagara	4.4800	4.6870	4.6633	4.7198	-0.0565
Westcoast Pipeline					
Huntingdon	3.9100	4.0850	3.9929	4.0336	-0.0407
Into Tennessee Pipeline at					
Dracut	4.8000	4.8200	4.8100	4.6700	0.1400

(US$/MMBtu)	Low	High	Index	Last	Chg.
U.S. Del. to Pipeline (Avg.)	3.87	4.60	4.29	4.25	0.04
Texas, Oklahoma					
Houston Ship Channel	4.38	4.41	4.39	4.22	0.17
Northern Natural	4.12	4.28	4.22	4.24	-0.02
Tennessee Zone 0	4.20	4.29	4.25	4.25	0.00
Valero	4.25	4.35	4.30	4.30	0.00
South Louisiana					
ANR Southeast	4.30	4.33	4.31	4.27	0.04
Columbia Gulf	4.30	4.33	4.31	4.26	0.05
Henry Hub	4.35	4.36	4.36	4.33	0.03
Tennessee Zone 1	4.34	4.37	4.36	4.29	0.07
Transco 65	4.34	4.39	4.38	4.34	0.04
Trunkline	4.30	4.34	4.32	4.29	0.03
Tetco E. LA	4.33	4.35	4.34	4.29	0.05
Texas Gas	4.30	4.32	4.31	4.26	0.05
Rockies/California/Appalachia					
Northwest Rocky Mountain	3.87	4.09	3.95	4.00	-0.05
El Paso Keystone	4.10	4.31	4.19	4.16	0.03
El Paso San Juan	4.05	4.23	4.11	4.06	0.05
El Paso-Topock	4.42	4.44	4.43	4.25	0.18
California Border-SoCal	4.48	4.60	4.52	4.38	0.14
Columbia	4.47	4.49	4.48	4.53	-0.05
Midcontinent					
ANR Southwest	4.19	4.24	4.23	4.17	0.06
Chicago Citygate	4.30	4.50	4.38	4.40	-0.02
Northern - Demarcation	4.33	4.38	4.36	4.36	0.00
Panhandle	4.05	4.19	4.12	4.11	0.01
NGPL Midcont	4.09	4.23	4.18	4.17	0.01

Source: Canadian Enerdata Ltd. price survey.

AECO Monthly Prices			June 2011 Trading		
			Price (C$/GJ)		
Month	# Trades	Volume (TJ)	Low	High	Average
M-Jul 11	800	2,884.1	3.480	4.190	3.7165
M-Aug 11	175	440.4	3.470	4.123	3.7187
M-Sep 11	14	31.0	3.550	4.190	3.8067
M-Oct 11	16	28.9	3.600	4.203	3.8624
M-Nov 11	1	0.5	4.100	4.100	4.1000
M-Dec 11	39	65.5	3.790	4.355	4.2558

Dawn Monthly Basis			June 2011 Trading		
			Price (C$/GJ)		
Month	# Trades	Volume (TJ)	Low	High	Average
BM1-Jul 11	306	1,377.7	0.270	0.340	0.2900
BM1-Aug 11	111	487.8	0.220	0.300	0.2541
BM1-Sep 11	47	241.8	0.235	0.300	0.2624
BM1-Oct 11	92	512.6	0.280	0.360	0.3158
BM1-Nov 11	85	515.0	0.310	0.375	0.3406
BM1-Dec 11	32	161.0	0.333	0.365	0.3537
BM1-Jan 12	45	274.1	0.290	0.315	0.3009
BM1-Feb 12	6	30.0	0.300	0.310	0.3033

Monthly Natural Gas Price Index Summary December 2011

One-Month Spot Gas Price Indices for December, 2011

	Low	High	Index	Last	Chg.
Alberta (C$/GJ)					
AECO One Month	3.0100	3.5000	3.2062	3.1914	0.0148
AECO Bidweek	3.0100	3.2500	3.1081	3.1779	-0.0698
Border (Empress)	2.6100	3.1500	2.8255	2.8521	-0.0266
Border-AECO Differential	-0.4000	-0.3500	-0.3807	-0.3393	-0.0414
B.C. (C$/GJ)					
Station 2 (Month)	3.0500	3.1300	3.0905	2.9229	0.1676
Station 2 (Bidweek)	3.0900	3.1300	3.1007	2.9229	0.1778
Export (US$/MMBtu)					
N. Border, N. Natural					
Ventura	3.5100	3.6500	3.5533	3.7076	-0.1543
Chicago	3.6100	3.8250	3.6858	3.7774	-0.0916
Pacific Gas Transmission					
ABC	3.0100	3.1100	3.0506	3.0449	0.0057
Kingsgate	3.3600	3.4600	3.4006	3.3949	0.0057
Stanfield	3.4300	3.5300	3.4706	3.4649	0.0057
Malin	3.4800	3.5800	3.5206	3.5149	0.0057
PG&E Citygate	3.8000	3.8400	3.8150	3.8660	-0.0510
Kern River Stn. (SoCal)	3.6000	3.7500	3.7044	3.6300	0.0744
Kern River Stn. (PG&E)	3.5600	3.6300	3.5931	3.6100	-0.0169
TransCanada Pipelines					
Emerson	3.4375	3.7000	3.5388	3.6602	-0.1214
Parkway	3.9790	4.1200	4.0246	4.0613	-0.0367
Dawn	3.8490	3.9700	3.8832	3.9979	-0.1147
Iroquois	4.7890	4.9500	4.8387	4.4102	0.4286
Niagara	3.9190	4.0700	3.9751	4.0853	-0.1102
Westcoast Pipeline					
Huntingdon	3.8600	4.0200	3.9372	3.6614	0.2758
Into Tennessee Pipeline at					
Dracut	5.9400	5.9900	5.8600	4.0600	1.8000

(US$/MMBtu)	Low	High	Index	Last	Chg.
U.S. Del. to Pipeline (Avg.)	3.24	3.83	3.36	3.49	-0.13
Texas, Oklahoma					
Houston Ship Channel	3.27	3.29	3.28	3.52	-0.24
Northern Natural	3.25	3.32	3.28	3.44	-0.16
Tennessee Zone 0	3.27	3.34	3.30	3.46	-0.16
Valero	3.25	3.32	3.30	3.44	-0.14
South Louisiana					
ANR Southeast	3.28	3.30	3.29	3.45	-0.16
Columbia Gulf	3.28	3.30	3.29	3.47	-0.18
Henry Hub	3.35	3.37	3.36	3.52	-0.16
Tennessee Zone 1	3.32	3.36	3.34	3.51	-0.17
Transco 65	3.35	3.37	3.36	3.49	-0.13
Trunkline	3.29	3.32	3.31	3.48	-0.17
Tetco E. LA	3.31	3.33	3.32	3.44	-0.12
Texas Gas	3.28	3.30	3.29	3.44	-0.15
Rockies/California/Appalachia					
Northwest Rocky Mountain	3.38	3.48	3.43	3.46	-0.03
El Paso Keystone	3.25	3.35	3.30	3.41	-0.11
El Paso San Juan	3.24	3.34	3.28	3.38	-0.10
El Paso-Topock	3.34	3.51	3.46	3.56	-0.10
California Border-SoCal	3.56	3.63	3.63	3.66	-0.03
Columbia	3.39	3.41	3.40	3.56	-0.16
Midcontinent					
ANR Southwest	3.35	3.50	3.42	3.50	-0.08
Chicago Citygate	3.61	3.83	3.69	3.80	-0.11
Northern - Demarcation	3.52	3.56	3.54	3.63	-0.09
Panhandle	3.30	3.45	3.37	3.41	-0.04
NGPL Midcont	3.31	3.46	3.35	3.44	-0.09

Source: Canadian Enerdata Ltd. price survey.

AECO Monthly Prices			November 2011 Trading		
			Price (C$/GJ)		
Month	# Trades	Volume (TJ)	Low	High	Average
M-Dec 11	825	3,099.3	3.010	3.500	3.2062
M-Jan 12	302	845.0	3.105	3.513	3.2645
M-Feb 12	51	156.3	3.150	3.513	3.3102
M-Mar 12	48	175.1	3.130	3.490	3.2363
M-Apr 12	60	158.5	3.075	3.420	3.1800
M-May 12	2	7.6	3.155	3.220	3.1559

Dawn Monthly Basis			November 2011 Trading		
			Price (C$/GJ)		
Month	# Trades	Volume (TJ)	Low	High	Average
BM1-Dec 11	215	1,041.0	0.465	0.540	0.4960
BM1-Jan 12	75	370.5	0.360	0.440	0.3862
BM1-Feb 12	68	327.5	0.360	0.420	0.3847
BM1-Mar 12	104	506.9	0.380	0.428	0.4000
BM1-Apr 12	14	73.1	0.313	0.380	0.3590

Table 1
populated from CGPR reports

	July	December	Net ($/GJ)
2010/11	4.9844	4.8135	0.1709
2011/12	4.6413	3.8832	0.7581

provides to you your benchmark that you're meeting -- trying to meet in terms of the transportation planning?

MR. QUIGLEY: We tell them how much gas we are planning to have in the ground, and then they tell us whether that is sufficient in order to meet design day.

MR. QUINN: Okay. So the way I am understanding, it is an iterative process potentially?

MR. QUIGLEY: Correct.

MR. QUINN: But the idea is you must -- they are expecting you would have a certain amount of gas in storage to meet deliverability requirements, and it is your responsibility, through an iterative process, if necessary, to meet that?

MR. QUIGLEY: Correct.

MR. QUINN: Okay, thank you. And so with that clarity, you touched on SENDOUT as being a five-year plan. Would it be fair to say, then, that SENDOUT is not really used for that last iterative portion of ensuring the amount of gas is available in storage?

MR. QUIGLEY: SENDOUT is not used to determine the deliverability requirement from storage. It's used to determine the amount of inventory that in-franchise customers will have in the ground on March 1st.

MR. QUINN: And so in this iterative process, do you rerun SENDOUT, or do you intuitively say, We need 100 units and we're looking at only 90 units being available to us; therefore, we need to buy more supply? Would that be more like what actually occurs from a practice point of view?

MR. QUIGLEY: From a practical point of view, we would define how much inventory is in the ground. If it's not sufficient, we would go -- we would look to provide -- look to re-plan to have sufficient inventory in the ground on March --

MR. QUINN: What tools would you use to determine how you best access that incremental supply?

MR. QUIGLEY: That would -- we would look at how much supply we need to land, and then determine the best way to serve that.

MR. QUINN: And just for clarity, how would you go about doing that?

MR. QUIGLEY: There's a number of different methods. We could look at -- we would look at, first, is there a firm service that we would need to acquire in order to provide that inventory.

MR. QUINN: Okay. Maybe it would help -- what time of year would this process be occurring?

MR. QUIGLEY: Late spring, early summer.

MR. QUINN: So at that point, you have a range of potential services, and I am hearing from you your preference is to seek firm service delivery to meet what might be a February obligation?

MR. QUIGLEY: Correct.

MR. QUINN: Okay, thank you. Now, one of the areas that has escaped my understanding, and maybe you can help us understand this a bit better, we talked about the north and you talked about some of the challenges relative to the

Manitoba area.

I want to deal with the north, in general, but I think it would be helpful to focus on the eastern end of your north system, which is where you would have your greatest need to get gas, from a pressure point of view.

I understand you have UDC, which you reflected earlier, and I thank you for defining it. When you are expecting UDC in the eastern area, you have now -- in your responses it wasn't separated out. You have 10.4 pJs of planned UDC.

Would you know, offhand, approximately how much of that is in the east versus how much is in the Manitoba area?

MR. QUIGLEY: In the east there would be 1.2 pJs in the eastern delivery area.

MR. QUINN: I wanted -- that is helpful. Thank you. If it is 1.2 pJs in the east, it will give us a frame of reference which may be helpful later on.

So if your plan suggests there is 1.2 pJs, is there a specific contract that is attached to that 1.2 pJs? In other words, there's a contract that you know will be empty for part of the year, but it's an annualized contract that is going to be not filled on a planned basis for that 1.2 pJs?

MR. QUIGLEY: Correct. That would be the Empress to eastern delivery area contract on TCPL, and it would not be filled in the month of March.

MR. QUINN: Okay. Now, your eastern delivery area is quite broad. I guess -- I'm sorry, I was thinking of eastern delivery zone. So you say eastern delivery area.

You have multiple contracts to the eastern delivery area, though, do you not?

MR. QUIGLEY: Correct.

MR. QUINN: Okay. From those multiple contracts, is one of those contracts labelled as: This is the contract that would go unfilled on a planned basis for March deliveries?

MR. QUIGLEY: We would not model the specific contract. We would lump the contracts together as being available to serve the eastern delivery area, and the UDC would just be calculated in total.

MR. QUINN: Okay, thank you. So we started touching on it before about the alternatives that would be considered. I am going to deal first with UDC, because we're on that.

So on a planned basis, you say in the eastern delivery area you've got 1.2 pJs that would not be filled in the month of March. You also indicated that you would use firm service. Your choices would be looking at firm service to meet needs.

Have you considered or does your model allow you to consider, as opposed to using a firm annual contract, the opportunity to use a monthly contract for the months of the winter that it is expected to be needed?

MR. QUIGLEY: Well, as we've outlined by Mr. Shorts in the gas supply planning principles, we look to use long-term firm assets to serve our long-term end user obligations in the delivery area.

The issue would be, to eliminate that UDC, we would have to turn back 365-day capacity on that pipe, which is flowing at 100 percent load factor in 11 of the 12 months of the year, which means that we would need to replace that capacity 11 of the 12 months of the year with a short-term service that is not guaranteed to be renewable, in any one year, to serve average annual demands in the delivery area.

MR. QUINN: Okay. So if I summarize that, because it is a firm service need, your belief is that long-term contracts are the best way to serve that economically?

MR. QUIGLEY: Correct. Because UDC is all occurring in one month, but the only way to eliminate that UDC is to turn back 365-day firm pipe, which now means we don't have enough firm capacity to serve our average annual demands in the delivery area.

So then we would have to go out in the marketplace and try and find services for 11 of those 12 months.

MR. QUINN: Now, we just touched on -- and I think it was Ms. Evers that talked about -- one of the panel members was talking about short-term firm.

So you are aware that you can buy short-term firm service for the entire winter, November to March?

MS. HODGSON: Yes, we are.

MR. QUINN: And you could buy that for each individual month of the winter season?

MS. HODGSON: If it's available. If it's been offered in the open season that TCPL issues, yes.

MR. QUINN: Okay. Right now TCPL has an open season that is open; are you aware of that?

MS. HODGSON: I am aware of that.

MR. QUINN: And is there any delivery area that you have that is not available for winter delivery?

MS. HODGSON: The SSM DA is unavailable from Empress, the long-haul.

MR. QUINN: So the Sault Ste. Marie, to be clear?

MS. HODGSON: Correct.

MR. QUINN: The eastern delivery area, though, is available?

MS. HODGSON: I believe so, yes.

MR. QUINN: Okay. Well, I want to focus in -- because your area is broad and it is challenging enough, some of the content, I am going to try to focus on the eastern delivery area, and hopefully that's helpful.

So right now they have an open season that allows for the entire month –- sorry, the entire winter to be bid on; is that accurate?

MS. HODGSON: That's accurate.

MR. QUINN: And at the end of that process, then, they determine if they still have capacity available, and then you can buy on a monthly basis; is that accurate?

MS. HODGSON: That's typically how it works.

MR. QUINN: So for 2012, the winter that starts November 2012 moves into the 2013, which is a gas supply year that you are planning for, which is part of this application; is that accurate?

MS. HODGSON: Sorry, that was a long one. Can you say that again?

MR. QUINN: Okay. Just to focus on the 2013 application as we have it, decisions about this winter starting November 1st, 2012 have impact on your 2013 rate application?

MS. HODGSON: For the first three months of it, yes.

MR. QUINN: For the first three months?

So for the eastern delivery area, we now have the entire winter and there would be still a period in -- later on in July where you may be able to get monthly firm service?

MS. HODGSON: It's possible.

MR. QUINN: Okay. Well, we can probably address that later on with -- maybe it is best I turn to it now, given where we're at.

I had provided a reference document that went in on Monday night, and I provided to Board Staff copies, and I think they may have reached the Board Panel. If not, there is a coloured document that I want to refer to, but we probably should give it an exhibit number.

MS. HELT: We can mark as Exhibit K3.1 the document entitled: "TransCanada Pipelines Limited, Proceeding RH-003-2011, response to APPrO 14."

EXHIBIT K3.1: DOCUMENT ENTITLED "TRANSCANADA PIPELINES LIMITED, PROCEEDING RH-003-2011, RESPONSE TO APPRO 14."

MR. SMITH: Members of the Panel, if I might just raise a brief evidentiary issue. I don't want to put too much on this, but this is an interrogatory by TCPL in another proceeding.

And if my friend intends to use it -- as I believe he does -- to ask questions, and if an answer is given, that's fine. But you can't simply incorporate hearsay from another proceeding by giving it an exhibit number. It needs to be actually discussed with the witness.

And there are a number of documents like this in people's compendia; for example, cross-examination from other proceedings by witnesses who aren't Union witnesses.

So I do raise this as an evidentiary matter that we need to be cognizant of when marking documents. Thank you.

MS. HELT: The other document is entitled: "Union Gas Limited answer to interrogatory from Federation of Rental-housing Providers of Ontario," filed in EB- 2012-0087. That will be Exhibit K3.2.

EXHIBIT NO. K3.2: DOCUMENT ENTITLED "UNION GAS LIMITED ANSWER TO INTERROGATORY FROM FEDERATION OF RENTAL-HOUSING PROVIDERS OF ONTARIO," FILED IN EB-2012-0087.

MS. HARE: We don't have those documents.

MS. HELT: We will be providing them to you.

[Board Staff distributes documents]

MR. QUINN: I understand the Union witnesses have already received a copy of this document. The one I'm referring to first is the K3.1, the TCPL interrogatory.

MR. SOMMERVILLE: Just so we're absolutely clear on the record as to what this document is, this K3.1, this is a response by TransCanada Pipelines Limited in a National Energy Board proceeding to an inquiry of an interrogatory from APPrO?

MR. QUINN: That's accurate, yes.

MR. SOMMERVILLE: Thank you.

MR. QUINN: Hearing Mr. Smith's caution, I believe that I will manage that area, because the graph is illustrative but informing, and it is historical -- historically accurate and hopefully will depict the picture.

But I want to turn to the witness panel to ask -- and I'm not sure who is best to answer this question, but in viewing this document, what I want to refer to predominantly is the chart.

In our view, the chart provides a concise visual representation of how gas is contracted for and how it flows for the northern line of TCPL over a two-year period starting November 2009.

Stopping there, would you agree that that is what we're looking at here?

MR. SHORTS: Yes, that's what we see.

MR. QUINN: Okay. And I think for everybody's benefit -- and I could attempt to do this, but if I could ask Mr. Quigley, if you could describe the separation that is done here in terms of the green lines, and then what the red lines mean to you.

MR. QUIGLEY: The dark green line, it is my understanding, is the firm transport requirement on the northern Ontario line. So that would be, to my understanding, the amount of firm transport long-haul that's been contracted for.

The red line -- the solid red line, I believe, has been described as the firm capacity on the northern Ontario line.

The dotted red line would be the capacity -- it's capacity, all units available. I'm assuming they're talking about compressor units.

And the bright green line is the contract -- would be the contract capacity for firm transport and -- short-term firm transport.

MR. QUINN: Okay. Thank you. Just to make sure we are crystal-clear in that area, I read the dark green line as the baseline of annual firm transport contracts; is that consistent with your explanation?

MR. QUIGLEY: I didn't prepare the graph, so...

MR. SMITH: This is the problem.

[Laughter]

MR. SMITH: This is a TCPL document. My friend putting propositions is fine, but they don't become evidence unless they're adopted by the witness.

MS. HARE: Understood.

MR. QUINN: I think that is why I was asking if I had a similar interpretation of the graph on an...

Is my question, Mr. Smith, adequate in terms of asking --

MR. SMITH: I think we have the witness's answer.

MR. QUINN: And that was?

MR. QUIGLEY: Could you re-ask your last question, please?

MR. QUINN: I read the dark green line as being the firm annual transport contracts that are flowing on the northern line of TCPL. Is that accurate, from your perspective?

MR. QUIGLEY: That would be my understanding, looking at this graph, having not prepared the graph.

MR. QUINN: Okay, accepted.

And then so the lighter green line shows the supplemented transport that is contracted short-term firm? Would you agree with that?

MR. QUIGLEY: I would agree.

MR. QUINN: Okay. So going back again, this shows the winters starting in November 2009, 2010.

As I read the 2009 period, we see that the amount of gas contracted on the TransCanada system varies, it looks like, potentially month by month to meet winter demands. Would that be your understanding looking at it, also?

MR. QUIGLEY: That's how I would interpret it.

MR. QUINN: Okay. And so to, again, make sure we're clear, and maybe I missed your explanation, but the northern Ontario line flow, the blue part is the actual flow on the system during -- well, for each month that we're -- that's depicted on the chart? Would you agree with that?

MR. QUIGLEY: That is how it is described on the graph.

MR. QUINN: Okay. If we move then forward to 2010, you would see that the graph for the short-term firm supplemented contracting is a lot more jagged.

Would you have an interpretation of what that would mean for 2010?

MR. QUIGLEY: I couldn't say why it is more jagged.

MR. QUINN: Would you agree with me it is very possible that this is people contracting for shorter periods of time than one month, potentially down to one week?

MR. QUIGLEY: I couldn't say why it is more jagged.

MR. QUINN: Okay. You are aware that the TCPL, to the extent they have available capacity, allows parties to contract firm service on a weekly basis?

MR. QUIGLEY: Yes, that's my understanding.

MR. QUINN: Okay. So from looking at 2010, we have a situation where the amount of contracted space varies considerably throughout the winter, and my interpretation would be, reasonably speaking, that that is people contracting for less than a month. Is that a possible interpretation, from your perspective?

MR. SMITH: Well, Madam Chair, I have a serious concern about this.

MS. HARE: No, I agree with you. I think the witness answered that he didn't know.

MR. QUINN: Okay.

MS. HARE: So now you are asking him to speculate, and I don't think that is fair.

MR. SMITH: I have a further concern that I want to raise now.

TCPL is going to testify in this proceeding. I have a serious concern about my friend's interpretations subsequently being put to TCPL, because that's after Union testifies.

If my friend wanted to do any of this, this is a 2011 document, and interrogatories could have been asked of TCPL. We would have had advance notice of TCPL's position. We have no information, and propositions are being put to the witnesses. I think it is manifestly unfair.

MR. QUINN: I will abide by that. Respectfully, I apologize to the panel if I am asking for speculation. I was just seeking interpretation.

But I was trying to gain clarity, and trust that I will move on from there and will be asking Union about its evidentiary basis.

MR. THOMPSON: Could I just interject here, Madam Chair?

This document is also included in a compendium that we circulated with respect to the gas supply witness panel. It hasn't been filed yet, and perhaps I should file it now. But the point I wanted to try to everyone's attention, that there is a second page to the answer that is in the compendium that's not with K3.1, and it makes the very

UNION GAS LIMITED

Undertaking of Mr. Buonaguro
To Ms. Evers

Please quantify capacity assignments done on a monthly basis, a seasonal basis, and an annual basis.

Please see the Attachment.

Capacity Assignments*
GJ/d

Line No.	Receipt Point	Delivery Area		Winter 07/08					Summer '08						
				Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	June '08	Jul '08	Aug '08	Sept '08	Oct '08
1	Empress	Eastern Zone	TOTAL	-	35,000	35,000	35,000	35,000	65,753	80,753	60,753	60,753	60,753	65,753	65,753
2			Monthly		35,000	35,000	35,000	35,000	13,000	28,000	8,000	8,000	8,000	13,000	13,000
3			Seasonal						52,753	52,753	52,753	52,753	52,753	52,753	52,753
4	Empress	Northern Zone	TOTAL	-	-	-	-	-	5,000	5,000	5,000	5,000	5,000	5,000	5,000
5			Seasonal						5,000	5,000	5,000	5,000	5,000	5,000	5,000
6	Empress	Western Zone	TOTAL	-	-	-	-	-	-	-	-	12,000	12,000	8,000	5,000
7			Monthly									12,000	12,000	8,000	5,000

Line No.	Receipt Point	Delivery Area		Winter 08/09					Summer '09						
				Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	June '09	Jul '09	Aug '09	Sept '09	Oct '09
8	Empress	Eastern Zone	TOTAL	28,000	48,000	48,000	48,000	48,000	77,556	97,556	97,556	108,556	108,556	108,556	97,556
9			Monthly		20,000	20,000	20,000	20,000	9,556	29,556	29,556	40,556	40,556	40,556	29,556
10			Seasonal						40,000	40,000	40,000	40,000	40,000	40,000	40,000
11			Annual	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
12	Empress	Northern Zone	TOTAL	8,000	8,000	8,000	8,000	8,000	-	-	-	-	40,000	-	30,000
13			UDC										40,000		30,000
14			Seasonal	8,000	8,000	8,000	8,000	8,000							
15	Empress	Western Zone	TOTAL	-	-	-	-	-	-	-	-	-	-	-	20,000
16			UDC	-	-	-	-	-	-	-	-	-	-	-	20,000

Line No.	Receipt Point	Delivery Area		Winter 09/10					Summer '10						
				Nov '09	Dec '09	Jan '10	Feb '10	Mar '10	Apr '10	May '10	June '10	Jul '10	Aug '10	Sept '10	Oct '10
17	Empress	Eastern Zone	TOTAL	80,000	80,000	80,000	80,000	80,000	92,832	92,832	92,832	92,832	92,832	92,832	92,832
18			Seasonal	20,000	20,000	20,000	20,000	20,000	32,832	32,832	32,832	32,832	32,832	32,832	32,832
19			Annual	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
20	Empress	Northern Zone	TOTAL	20,062	20,062	-	-	-	-	30,000	40,000	40,000	40,000	40,000	20,000
21			UDC							30,000	40,000	40,000	40,000	40,000	20,000
22			Monthly	20,062	20,062										
23	Empress	Western Zone		-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Receipt Point	Delivery Area		Winter 10/11					Summer 11						
				Nov '10	Dec '10	Jan '11	Feb '11	Mar '11	Apr '11	May '11	June '11	July '11	Aug '11	Sept '11	Oct '11
24	Empress	Eastern Zone	TOTAL	60,000	60,000	60,000	60,000	60,000	60,000	96,796	110,000	110,000	110,000	110,000	110,000
25			Monthly							36,796	50,000	50,000	50,000	50,000	50,000
26			Annual	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
27	Empress	Northern Zone	TOTAL	-	-	-	-	-	40,000	40,000	49,000	49,000	49,000	49,000	49,000
			UDC							5,000					
28			Monthly						40,000	35,000	49,000	49,000	49,000	49,000	49,000
29	Empress	Western Zone	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Receipt Point	Delivery Area		Winter 11/12					Summer 12	
				Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12
30	Empress	Eastern Zone	TOTAL	74,796	60,000	60,000	60,000	80,000	117,796	117,796
31			Monthly	74,796	60,000	60,000	60,000	80,000		
32			Seasonal						117,796	117,796
33	Empress	Northern Zone**	TOTAL	-	-	-	-	-	42,000	50,500
			UDC							2,000
34			Monthly							8,500
35			Seasonal						40,000	40,000
36	Empress	Western Zone**	TOTAL	-	-	-	-	33,340	30,000	33,430
37			UDC	-	-	-	-	33,340	30,000	33,430

* not including capacity assignments to Union's franchise customers
** updated

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Cameron

Please advise how much was turned back and how much was kept over the period shown in the tables.

Please see Attachment.

	Transportation Capacity Quantity (GJ/d)				Quantity Turned Back or Expired (GJ/d)				Quantity Expired (GJ/d)				Quantity Turned Back (GJ/d)			
	CDA	EDA	NCDA	Total Eastern Zone	CDA	EDA	NCDA	Total Eastern Zone	CDA	EDA	NCDA	Total Eastern Zone	CDA	EDA	NCDA	Total Eastern Zone
01-Nov-06	201,881	85,989	11,039	298,909												
01-Nov-07	91,870	85,989	11,039	188,898	110,011	-	-	110,011	71,735			71,735	38,276			38,276
01-Nov-08	71,327	85,989	11,039	168,355	20,543	-	-	20,543	4,846			4,846	15,697			15,697
01-Nov-09	71,327	61,156	11,039	143,522	-	24,833	-	24,833		20,188		20,188		4,645		4,645
01-Nov-10	71,327	61,156	11,039	143,522	-	-	-	-				0				-
01-Nov-11	71,327	59,251	10,756	141,334	-	1,905	283	2,188				0				-
01-Nov-12*	67,327	59,251	10,756	137,334	4,000	-	-	4,000	0	0	0	0	4,000	0	0	4,000

Note: Nov 1, 2012 subject to change

UNION GAS LIMITED

Undertaking of Ms. Cameron
To Mr. Quinn

Please advise where Union directed annualized assignment of gas for each month between November 2009 and March 2012; to multiply the demand charge to the Eastern Zone versus where the gas was directed, and to advise the difference in cost between those places for any of those months; and if there is a difference, if any of the Eastern Zone gas has been directed to another zone, to provide the difference in demand charge between the respective zones, and to multiply that by the number of units delivered for that month.

The attachment provides the contracted delivery areas applicable to annual capacity assignments of Empress to EDA transportation.

In all months, Union purchased supplies at Empress on behalf of sales services customers. Union also met the custom requirements in each delivery areas as planned.

With respect to capacity assignments, Union arranged for delivery of the gas supplies to another location in its franchise having regard to customer need and gas supply planning. For example, in November 2009, the EDA capacity was used to serve Union's WDA.

The net value of this transaction represents the difference in demand charges between the Empress to EDA toll and the toll to the delivery point (for November, 2009 the delivery point was Empress to WDA), as shown in Column M. The actual value Union received for this transaction, net of incremental costs, is shown in Column N. The transactions using Empress to EDA capacity are a subset of the optimization of Eastern Zone capacity as described in J7.6. The net proceeds represent regulated revenue and were dependent upon the RAM program.

Even with the change in the delivery point, Union met all the demands in the EDA. Using November 2009 as an example, the deliveries of 20,000 GJ/d to the WDA reduced the need for STS withdrawals from Dawn to Union WDA. This resulted in incremental gas supplies of 20,000 GJ/d at Dawn. These additional gas supplies at Dawn were delivered to the EDA using STS withdrawals from Dawn to Union. This series of transactions facilitated the transfer of gas supplies from WDA to Dawn to EDA and met the consumption requirements in the EDA.

Empress to EDA Annual Capacity Assignments

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Redelivery Point (GJ/d)				Demand Charge ($/GJ/mo)				Demand Charge ($000's)				Difference in Demand Charges ($000's)	Net Proceeds* ($000's)
	WDA	**NDA**	**SWDA** (Dawn)	**TOTAL**	**WDA**	**NDA**	**SWDA** (Dawn)	**EZ (EDA)**	**WDA**	**NDA**	**SWDA** (Dawn)	**EZ (EDA)**		
Nov-09	20,000			20,000	$ 16.70445	$ 25.63374	$ 28.08670	$ 33.37571	$ 334	$ -	$ -	$ 668	$333	$76
Dec-09	20,000			20,000	$ 16.70445	$ 25.63374	$ 28.08670	$ 33.37571	$ 334	$ -	$ -	$ 668	$333	$69
Jan-10	20,000			20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ 476	$ -	$ -	$ 955	$480	($87)
Feb-10	20,000			20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ 476	$ -	$ -	$ 955	$480	($28)
Mar-10	20,000			20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ 476	$ -	$ -	$ 955	$480	($32)
Apr-10			20,000	20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ -	$ -	$ 796	$ 955	$160	$234
May-10			20,000	20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ -	$ -	$ 796	$ 955	$160	$241
Jun-10			20,000	20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ -	$ -	$ 796	$ 955	$160	$238
Jul-10			20,000	20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ -	$ -	$ 796	$ 955	$160	$242
Aug-10			20,000	20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ -	$ -	$ 796	$ 955	$160	$238
Sep-10			20,000	20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ -	$ -	$ 796	$ 955	$160	$240
Oct-10			20,000	20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ -	$ -	$ 796	$ 955	$160	$242
									Subtotal: Impact of Annual Capacity Assignment ($000's):				$3,223	$1,674
Nov-10	10,000	10,000		20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ 238	$ 367	$ -	$ 955	$350	$168
Dec-10	10,000	10,000		20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ 238	$ 367	$ -	$ 955	$350	$120
Jan-11	10,000	10,000		20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ 238	$ 367	$ -	$ 955	$350	$176
Feb-11	10,000	10,000		20,000	$ 23.79107	$ 36.72520	$ 39.79320	$ 47.77094	$ 238	$ 367	$ -	$ 955	$350	$115
Mar-11	10,000	10,000		20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ 323	$ 497	$ -	$ 1,277	$458	$197
Apr-11			20,000	20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ 1,078	$ 1,277	$199	$191
May-11			20,000	20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ 1,078	$ 1,277	$199	$204
Jun-11			20,000	20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ 1,078	$ 1,277	$199	$196
Jul-11			20,000	20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ 1,078	$ 1,277	$199	$203
Aug-11			20,000	20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ 1,078	$ 1,277	$199	$209
Sep-11			20,000	20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ 1,078	$ 1,277	$199	$203
Oct-11			20,000	20,000	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ 1,078	$ 1,277	$199	$197
									Subtotal: Impact of Annual Capacity Assignment ($000's):				$3,253	$2,179
**Nov-11				-	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ -	$ -	$0	$0
Dec-11				-	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ -	$ -	$0	$0
Jan-12				-	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ -	$ -	$0	$0
Feb-12				-	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ -	$ -	$0	$0
Mar-12				-	$ 32.29092	$ 49.65158	$ 53.88793	$ 63.84842	$ -	$ -	$ -	$ -	$0	$0

* Net Proceeds represents net revenue from the capacity release/exchange transaction, less incremental costs incurred as a result of the transaction.

** No annual or seasonal assignments of Empress-EDA capacity were completed for the winter of 2011/2012.

MR. QUINN: Thank you.

MR. MILLAR: J7.2.

UNDERTAKING NO. J7.2: TO PROVIDE THE AMOUNT OF CAPACITY AVAILABLE TO RESPECTIVE DELIVERY AREAS FOR ENTIRE WINTER OF THIS YEAR.

MR. QUINN: Now, Mr. Isherwood, we talked a lot about the release of the capacity you instruct your counterparty to deliver to a certain area, whether it be Dawn or the EDA, if it is a winter delivery and it was a contract for the EDA.

My question for you is: Is that counterparty required to undertake a firm service contract to meet their delivery obligations that Union has instructed them to take?

MS. CAMERON: When we enter into the agreement with the counterparty, it is a firm agreement that we execute between them and I, or between them and Union Gas.

And we request that we will deliver to them each and every day firm at Empress, and they will deliver to us firm each and every day at Dawn, for example, in a summer example.

There are penalties within that contract for non-performance. As well, we only enter into transactions with creditworthy parties.

MR. QUINN: So, again, my question is: Are they required to demonstrate that they have underpinning firm contracts?

MS. CAMERON: They have demonstrated by executing the contract with us that says they will meet their firm market commitments.

MR. QUINN: That isn't what I asked. Do you ask them to demonstrate to you that they have a firm contract that underpins your --

MR. ISHERWOOD: We do not police how they deliver the gas. It is up to them to deliver the gas to us as per the contract.

MR. QUINN: So the answer is you do not require them to demonstrate that they have a firm contract underpinning their obligations to you?

MR. ISHERWOOD: We do not. We do not think we need to.

MR. QUINN: You are familiar with the system reliability proceeding that Enbridge had?

MR. ISHERWOOD: At a high level, yes.

MR. QUINN: And part of the issue there was their concern about delivery obligations, their franchise not being underpinned by firm service? Is that your high level understanding?

MR. ISHERWOOD: I believe the Enbridge experience is actually it had some supply failures.

MR. QUINN: And they were concerned that contracts were not underpinned by firm service? Is that your high level understanding?

MR. ISHERWOOD: That's correct.

MR. QUINN: But Union is not concerned?

MR. ISHERWOOD: We manage the concern through the contract and the penalties and dealing with parties that we're comfortable with, and creditworthy.

MR. QUINN: But you don't require them to demonstrate to you that they have firm service underpinning their contract?

MR. ISHERWOOD: We don't police how they get there.

MR. QUINN: Thank you.

Yesterday Union provided an update -- actually, technically, it was provided to me by e-mail Tuesday night, and it was the undertaking that we were trying to go through with panel 2 from EB-2012-0087, B7.7, and Union provided an update to that. Thank you. Mr. Millar has copies of it there.

MR. MILLAR: Yes. This will be Exhibit K7.1.

EXHIBIT NO. K7.1: UNDERTAKING B7.7 FROM EB-2012-0087.

MR. MILLAR: I have copies for the Panel.

MR. QUINN: Now, clarity was provided yesterday, Ms. Cameron, in terms of how Union contracts versus how the capacity is actually utilized.

And we have the Union panel's description of the change to the note 3, which I think we will rely on that, because I don't think we can read it off the screen. Thanks, Ryan.

But I am going to just -- I am not going to focus on note 3. I just want to focus on the bottom line, "TCPL, Union, CDA, Empress to Parkway." I think that view is fine. Thank you.

What I would like to ask Union by way of undertaking, there's obviously a considerable amount of transportation upstream supply portfolio. Union was able to extract value from new services introduced by upstream transportation providers in excess of what was achieved historically. An example of these new services includes TCPL's Firm Transport Risk Alleviation Mechanism (FT-RAM), Storage Transportation Service Risk Alleviation Mechanism (STS-RAM), and Dawn Overrun Service – Must Nominate (DOS-MN). These new services provided increased opportunities for transportation and exchange transactions in the market. These opportunities were also influenced by favourable market conditions experienced in 2008."

Now, an analogy has recently opinion suggested to the difference between various economy and executive class airfare. In my submission -- I may have to deal with this in reply -- but just briefly, two things.

One, it misses the history, that the optimization activity is no different than the Board-approved optimization activity Union has always engaged in, dating back to the early 1990s.

And it implies -- wrongly, in my submission -- that ratepayers are receiving a lesser service, and that is manifestly not the case. And there was a good deal of evidence in relation to this from both Mr. Isherwood and Ms. Cameron, but ratepayers are receiving gas exactly as they need it, and have done so in the past and are forecast to do so going forward.

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Quinn

With reference to Exhibit K7.1, please provide breakdown of where gas was actually delivered by assignees and how the amount of short-term exchange revenue was generated.

Please see the Attachment.

The attachment outlines the delivery locations related to assignments of Empress to Parkway (CDA) capacity for 2011. For all capacity assignments, Union continued to purchase supplies at Empress. As part of the transaction, Union enters into an exchange with the same counterparty to redeliver the gas to an alternate location in Union's franchise area. The net revenue reflects the value of the entire transaction, which is comprised of the capacity release less the cost of the alternate transportation arrangement. A detailed description and example of the net revenue generated from this type of transaction can be found at J7.6. The revenue attributable to the Empress to Parkway capacity releases is included in the attachment.

The balance of the revenue of $11.3 million earned from Empress-Parkway optimization was due to exchanges from RAM optimization. These types of exchanges were described at hearing transcript Volume 6, Page 130 Line 21 to Page 131 Line 26. In this case, Union leaves the Empress to Parkway Firm Transportation (FT) pipe empty, and then uses interruptible transport to move Union's gas supply from Empress to a delivery location. Union manages the incremental cost of the interruptible transportation through the use of RAM credits generated from the empty Empress to Parkway pipe. Any remaining RAM credits are used to facilitate incremental exchange activity.

The exchange transactions which are supported through RAM optimization are reviewed on a daily, weekly and monthly basis for weather, Union market requirements, and market opportunities to optimize RAM credits. In addition, since Union has retained the capacity, in the event of higher risk days where interruptible transportation may be cut, supplies can be transported on the firm transportation contract to the appropriate market area. For example, on a cold day in January, Union would forgo the generation of RAM credits and flow Empress supplies on a firm basis using the Empress to Parkway transportation capacity.

All net proceeds, regardless if earned via a capacity assignment/exchange transaction or an exchange from RAM optimization, are dependent upon Union's proactive use of the RAM program and are reflected as regulated exchange revenue.

Empress - Parkway (CDA) Capacity Assignments for 2011

	Redelivery Point				Net Proceeds*	
GJ/d	WDA	NDA	SWDA (Dawn)	TOTAL	($000's)	
Jan-11	20,000	20,000		40,000	$	450
Feb-11	20,000	20,000		40,000	$	290
Mar-11	20,000	20,000		40,000	$	306
Apr-11			40,000	40,000	$	408
May-11			68,000	68,000	$	716
Jun-11			68,204	68,204	$	761
Jul-11			68,204	68,204	$	787
Aug-11			68,204	68,204	$	787
Sep-11			68,204	68,204	$	761
Oct-11			68,204	68,204	$	787
Nov-11			66,000	66,000	$	1,722
Dec-11	30,000	30,000		60,000	$	1,241

* Net proceeds represent net revenue from capacity release/exchange transaction, less incremental costs incurred as a result of the transaction.

EB-2011-0210

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

Federation of Rental-housing Providers of Ontario

Reference Document for Union Gas Panel #2

Reference:

Application, Section 3.6.1, page 25 and Figure 3-13 (NOL Flow vs. NOL Capacity).

Preamble:

TCPL discusses NOL flows.

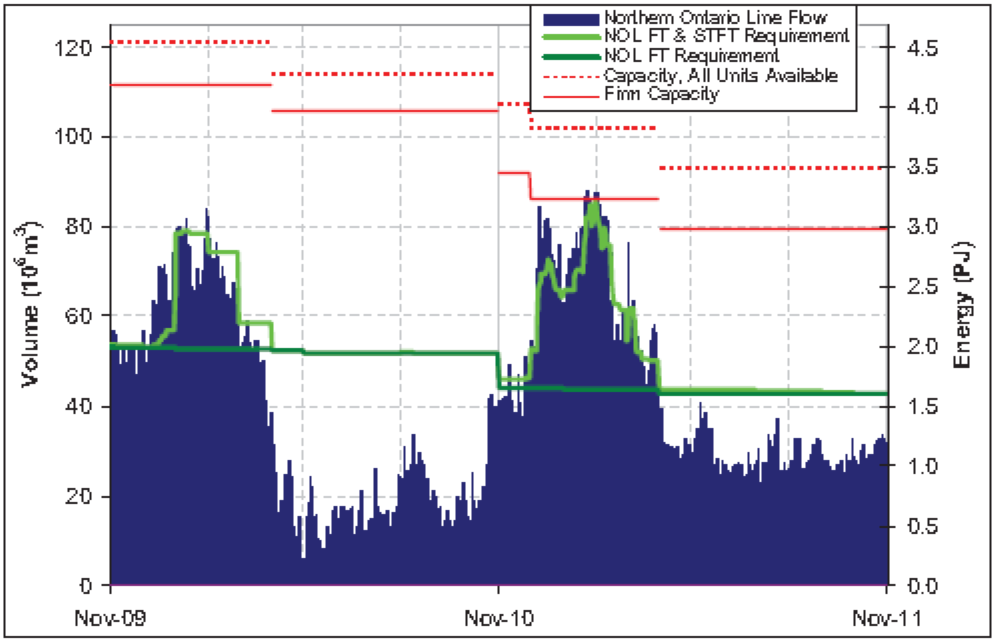
Request:

a. Please redraw the graph in Figure 3-13 to show FT volumes separately from STFT volumes for both the contracted volumes and the nominated volumes.

b. For the period shown in the graph, please indicate by season, the average term for STFT contracts.

Response:

a.



3, as well. So during that period, we were relying on just a single line through the NOL. And in fact, that was the smallest of the three lines.

And with that, we were able to maintain firm service. Yes.

MR. QUINN: Thank you. Now, just to be more precise in my question, I guess what I was asking is: When was the last time that TCPL did not have an open season for ST FT for North Bay and east for an entire winter period?

Would you know the answer to that question?

[Witness panel confers]

MR. EMOND: I just canvassed the panel, and I don't think any of us can recollect a time that we weren't posting at least some short-term firm for the winter season. We typically post it in the summer, before the season, and -- but I don't think we've got sort of the records in front of us to verify that.

MR. QUINN: Okay. I don't know that we need the exact date, but for the purposes of our understanding, you're saying it's been decades since ST FT was not tendered as an open season for the entire winter period, for the eastern zone as an example?

MR. EMOND: Yeah. I think that's safe to say.

Now, I should qualify that, just to be careful.

There are portions of the eastern zone, it telescopes, and as you get farther east, there is less capacity on a peak winter day.

So as you get down towards Montreal, it would be, obviously, tighter, but certainly we've seen a lot of non-renewal of long-haul over the last decade, and in particular over the last three to four years.

And going forward, we would expect even more non-renewals of long-haul. And we've recently come out with a new long-term forecast that just, over the last month, dropped our throughput by close to a Bcf, again, from the west.

So what that has created, particularly in the last three years -- and we see it increasing -- is an awful lot of excess capacity in our system through the NOL to North Bay.

MR. QUINN: Great. Thank you.

I am going to shift a little bit more back towards the content we have been discussing today, earlier with the Union witness panel, and that is the covering the need for the -- I am going to be specific. The discharge side of the Parkway compressors, the loss of critical unit is to supplement flows that would be on the discharge side of the Parkway compressors.

Would it be fair to say that most of the capacity that leaves Parkway is destined for Maple and points east?

MR. EMOND: Yes, most of the gas that TransCanada receives at the discharge side of Parkway would go to Maple and points east of there.

So TransCanada does have a few meter stations into the GTA, east of Parkway, but many of the contracts on our system from Parkway go to Iroquois or Gaz Métro, points

Clearly - maybe I will start a step back, because I was asked by the second panel to ask this of the ex-franchise panel, Mr. Isherwood, to you, that when you are delivering gas, you've got a contract, and I will use the EDA as example.

My understanding is the gas need not in the summer arrive in the EDA if your flows are low, like is evidenced on this graph.

MR. ISHERWOOD: Right.

MR. QUINN: Who tells the assignee where the gas should go?

MR. ISHERWOOD: Who do you identify as the assignee?

MR. QUINN: A third party. Whoever you have assigned the capacity to, they are to deliver gas, but they need not deliver to the EDA, because its ultimate destination is Dawn.

MR. ISHERWOOD: Right.

MR. QUINN: My first question is: My understanding is it does not need to go the EDA? It can be diverted to Dawn?

MR. ISHERWOOD: So the one option would be we would just leave the contract from Empress to EDA empty, and we would flow from Empress to Dawn on IT and we would do that ourselves. That's one option.

MR. QUINN: Okay. I want to break this down, if I may stop you there.

What you're saying is you now take back the responsibility somehow of landing the gas in Ontario?

MR. ISHERWOOD: The S&T group will optimize the gas supply plan, and, again, a lot of these decisions are made because of FT RAM being a feature of FT.

So if there's economics and if the market requires exchanges, and we try to generate FT RAM credits, one way of doing that would be to leave the Empress to EDA contract empty. That would create FT credits -- or IT credits, sorry, and we would flow that gas from Empress to Dawn on an IT basis.

MR. QUINN: So what you've just described, then, is not an assignment. This is a choice by Union to leave the pipe empty, bank the credit and find a cheaper path to Dawn?

MR. ISHERWOOD: And what happens in that case --

MR. QUINN: Sorry, is that correct?

MR. ISHERWOOD: That's correct. And, Mr. Quinn, just to expand on that, when we do the IT volumes from Empress to Dawn, that path is going to be cheaper than the path from Empress to EDA.

So at the end of the day, we will end up with extra FT credits and we will do other market-based exchanges to derive value out of that. But as the gas supply panel testified to, in all of that case, we're still buying the same gas at Empress and we're still delivering that same gas to Dawn; just on that day we're doing it differently. And I call that option A.

Option B was the option that you had started your question with, which was we assigned the Empress to EDA contract to a third party, and, as part of that deal, they would deliver gas, the same volume of gas we bought at Empress, to Dawn.

So both option A and option B have exactly the same result. They just pay us the differential, if you want, as an S&T benefit.

MR. QUINN: Okay. I want to camp on that second alternative, because that's what I was trying to ask, but I appreciate the understanding on the Union-held S&T, FT RAM scheme that you had.

So the assigning of the Empress to EDA contract, the third party then has the choice to go to Dawn, or do you tell them on any given day where they should land the gas?

MS. CAMERON: We provide the direction where we want the gas to arrive.

MR. QUINN: Each month, or during the winter is it more frequently?

MS. CAMERON: For the term of the transaction. So if the transformer was a one-month transaction, we would tell them for -- the delivery point will be consistent for the term of the transaction.

MR. QUINN: Okay. So on an annual transaction, you will tell them where to deliver the gas each and every month?

MS. CAMERON: For an annual transaction we would say, for the winter months, deliver it at location A, and for the summer months, deliver it at location B.

MR. QUINN: Okay. Now, would location A --

specifically, if the gas is EDA, would location A be,
Deliver the gas in the EDA for the winter months?

MS. CAMERON: It could be.

MR. QUINN: You've got a contract. You've got a defined need to go to the EDA, but you're saying would assign away that contract and tell them to transport the gas somewhere else?

MS. CAMERON: I could have them deliver it to a different delivery area, yes.

MR. QUINN: So the northern delivery area, the western delivery area?

MS. CAMERON: Yes.

MR. QUINN: I guess my question would be: Why wouldn't you contract for those delivery areas if that's what your need is? If you know a year in advance, 12 months in advance, of a gas year that your needs are in the northern delivery area not the eastern delivery area or let's use western delivery area -- well, let's use the western delivery area.

If your need is in the western delivery area, why are you contracting for the eastern delivery area?

MS. CAMERON: I'm sorry, I'm not -- could you be more specific with your question?

MR. QUINN: Okay. You have an annual contract -- maybe what we should do is turn up J.C-4-7-10.

If our ready-reference person could keep that other graph handy, we might need to flip back to it.

So attachment 2, I believe it is of that -- sorry, attachment 1, my mistake -- has the amount of assignments, capacity assignments. Now, to differentiate, these are not the in-franchise customer assignments that Mr. Shorts was talking about before. These are ex-franchise customer assignments; is that correct?

MS. CAMERON: Yes.

MR. QUINN: Okay. So if we just start -- because I am going to try to stay consistent with the chart, if we start in November of 2009, you have 80,000 gJs that stems through from November 2009 to October 2010, a minimum of 80,000 gJs.

I think if we're interpreting your graph correctly, that was annualized assignment?

MS. CAMERON: That is not correct.

MR. QUINN: Okay. Help us with that.

MS. CAMERON: If I can take you to the undertakings that were filed I believe last night --

MR. QUINN: J3.6?

MS. CAMERON: Yes.

MR. QUINN: I was going to go there next. Thank you.

MS. CAMERON: And if you look at line 26 -- oops, sorry. I apologize. Line 19, you will see that there is an annual assignment for the eastern zone for 60,000 a day.

And I believe just now, I believe Mr. Smith mentioned that we had also filed the undertakings from day 4, and if you could look to Exhibit J4.2? And, once again, we're looking at the same time period. You will see on line 10 there is an assignment of 20,000 a day, and on line 11 an assignment of 60,000 a day. That will reconcile to the 80,000 that was in the original attachment that was filed as an undertaking.

So when we look at the amount back on J3.6, and I apologize for flipping back and forth, but that an annual assignment of 60,000, no more of that is the 20,000 of EDA.

So the 20,000 in EDA capacity that was demonstrated on the graph is all of the capacity that was assigned on an annual basis. It wasn't 60,000. It wasn't 80,000. On an annual basis, 20,000 of capacity was assigned to the EDA.

MR. QUINN: So you're saying 20 -- I'm sorry, 60,000 -- I'm looking at J3.6, and I think what you have on the screen here is -- this is the challenge with technology, but that is J4. -- oh, it's 3.6, okay.

So you have 60,000 gJs to the eastern zone. Let's just focus on that. That is an annual assignment?

MS. CAMERON: That is an annual assignment made up of 20,000 to the EDA and 40,000 to the CDA. So that 20,000 is the same 20,000 that we would see on the chart that we've looked at several times today.

MR. QUINN: Okay. Well, then just so -- and this is all in the eastern zone? That's why you've got the EDA and CDA?

MS. CAMERON: Yes.

MR. QUINN: So for the annualized -- I am conscious of the clock. I think I would like to ask for the winter, starting November 2009 to March of 2012, can you tell us, of that annual assignment, where you had the gas directed, where you had your assignee direct the gas to for each month during that period?

MR. SMITH: Yes, we will do that.

MR. QUINN: Okay. And what I would like to ask, that if you could also add to that what the demand charge -- multiply out what the demand charge would be to the eastern zone versus where you had the gas directed, and what the difference of cost would be for any of those months.

If there is a difference, if any of the eastern zone gas has been directed to another zone, what the difference in demand charge is between the respective zones, and multiply that by the number of units delivered for that month.

MS. CAMERON: You're interpreting costs -- you mean the TransCanada toll?

MR. QUINN: Demand charge for the TransCanada toll.

MR. SMITH: Yes, we will do that.

MR. QUINN: Okay. I think that is an appropriate time to break, thank you.

MR. MILLAR: J6.5.

UNDERTAKING NO. J6.5: TO ADVISE WHERE UNION DIRECTED ANNUALIZED ASSIGNMENT OF GAS FOR EACH MONTH BETWEEN NOVEMBER 2009 AND MARCH 2012; TO MULTIPLY THE DEMAND CHARGE TO THE EASTERN ZONE VERSUS WHERE THE GAS WAS DIRECTED, AND TO ADVISE THE DIFFERENCE IN COST BETWEEN THOSE PLACES FOR ANY OF THOSE MONTHS; AND IF THERE IS A DIFFERENCE, IF ANY OF THE EASTERN ZONE GAS HAS BEEN DIRECTED TO ANOTHER ZONE, TO PROVIDE THE DIFFERENCE IN

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-Housing Providers of Ontario ("FRPO")

Ref: Exhibit A2, Tab 1, Schedule 1, page 25, line 12

Union states that it "is not projecting optimization revenue as a result of excess Dawn-Parkway capacity due to turnback."

a) Which services does Union include in the definition of "optimization revenue" for transportation assets?

b) Does Union agree that a reduction in the amount of Dawn-Trafalgar capacity sold as long-term firm transportation service will increase the capacity available for sale as short-term firm and interruptible transportation service?

c) Has Union assumed that any Dawn-Trafalgar transportation capacity that will be freed up by non-renewal will have no value as short-term firm or interruptible transportation service? Please explain.

Response:

a) Union includes C1 Short-Term Firm Transportation as optimization revenue for Dawn-Parkway capacity.

b) The reduction in the amount of Dawn-Parkway transportation capacity sold as Long-Term Firm Transportation service could increase the capacity available for sale as Short-Term Firm and Interruptible Transportation service.

c) In the 2013 forecast, the Dawn to Parkway transportation capacity that was not contracted as M12 Long-Term Transportation is not available for sale as it was utilized in the Gas Supply Plan to eliminate Winter Peaking Service requirements, which benefits all Union customers.

   Union is forecasting some available capacity commencing November, 2013. The market for this capacity will be dependent upon TCPL tolls, available downstream capacity and market dynamics.