UNION GAS LIMITED

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IN-FRANCHISE REVENUE



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **14**

DATE: **August 23, 2012**

BEFORE: **Marika Hare** **Presiding Member**

Karen Taylor **Member**

So the key to the whole forecast is the weather normalization methodology. Heating degree days is one of the major independent variables in the regression equations to forecast normalized average consumption per customer.

So for the general service residential markets, it is used, as well as for the large commercial industrial and greenhouse sectors.

Now, the Excel files that Union provided are the regional results and regional data, and they were provided in response to one of our IRRs at Exhibit C -- J.C-2-3-2, show the history and analysis details supporting the 2013 degree day forecasts for the south, which is 3,599 heating degree days, and the north, 4,626 heating degree days. This is based on Union's proposed 20-year trend methodology.

Energy Probe has concerns about Union's heating degree day forecast fundamentals that affect both the current 30-- the 20-year forecast methodologies, and also the -- obviously affect the 20-year trend forecast methodology.

And the basis of this is that Union's evidence for comparing heating degree day methodologies is based on Pearson Airport data. And you see that at transcript volume 2, page 21.

However, the test year volume forecast is produced using historical actual heating degree day data from 16 weather stations weighted according to actual volume and lags three years; i.e., 2013 is based on HDD and total volumes up to 2010.

Now, this is then used with the test year heating degree day forecast based on either the current, which is the blend, or the 20-year trend to produce the general service volumetric forecast, and that is discussed at the transcript volume page 20 -- volume 2, page 22, and also set out in undertaking J1.1.

There is, to our mind, also an issue whether the eastern delivery area climate is sufficiently different. It is 25 percent of the, quotes, "northern", and whether heat sensitive volumes rather than total volumes should be used in the regression equations.

The normalized average use per customer, NAC, for each rate class is derived from the actual volumes normalized to the same heating degree day forecast as the test year. That is shown at C1, tab 1, figures 5 to 8.

Now, Union claims that it conducted a review of heating degree day forecast methodology in 2004 and adopted the Pearson Airport-based methodology for comparison of the forecasts, and the transcript reference is volume 1, page 33.

However, Union has not investigated zone-based heating degree day forecasting methodologies as was done by Enbridge Gas Distribution, and that resulted in three zone forecast, and that was approved by the Board for EGD. And that is discussed at the transcript volume 1, page 34.

In our view, it is not reasonable for Union to state that its heating degree day forecasts, based on Pearson data, lead to a conclusion that the 20-year trend is

superior to the 30-year trend -- to the 30-year average, sorry, or to the 55-45 blend.

The reason is, there is only two choices: A, 30-year average, and B, 20-year trend; both based on Pearson Airport data. How can you demonstrate one is superior? Yes, one over the other. But does that answer the question, which is: Which heating degree day forecast methodology gives the best results for Union's geographically diverse regions?

So Union is basing its forecast of degree days for 2013 on equations that are not, in our view, statistically significant, even at the 85 percent confidence level. That can be seen in the equation shown in Exhibit J1.2.

Now, my statistics are very rusty, to say the least, but the data in J1.2 does not impress me. The significance of the F statistic is 0.153, meaning that the regression equation is significant at a confidence level of only about 84.7 percent. The time variable in the equation is also significant at about 85 percent confidence. The R squared, which indicates the amount of the variance explained in the data, is only 6.1 percent.

So we suggest the following, that Union needs to do the work to demonstrate whether the best HDD forecast is a regional HDD forecast, and this is either two or three regions, the eastern area, using actual weather data from the 16 weather stations, for which the long-term data are available.

Now, we note also that Enbridge's 20-year trend for

and I will come back do this in a moment - you also have to be a bit -- you have to be concerned with symmetry, because symmetry is just a pseudonym for fairness.

You don't want a forecast that always overstates or always understates, obviously, what the degree days would be, because given the use that we're going to put the forecast to, that would be unfair. That, I think, is a self-evident proposition.

But returning to accuracy, which is a bit more subtle and a bit more complicated, what we did, what BOMA did is we examined a reply set down on page 50, we examined carefully some tables that were provided by Union as part of an IR response to a question, I believe, from Mr. Aiken. It is J.C-2-2-1.

You may remember my stumbling effort to cover this in cross-examination, but in any event, table 2 on that page - and I don't have it in front of me, nor do you, so I will describe it to you. Table 2of that response shows, for each year from 1985 to 2011 inclusive, the Toronto Airport actual degree days.

Now, I heard what Dr. Higgin had to say about Toronto Airport, and I agree with him. This use of Toronto Airport is just -- that I am going to suggest is the same -- is sort of you use it to make a point here, because we're talking about methodology, and the Toronto Airport has the longest data going back the furthest of any place in Ontario.

So, anyway, be that as it may - and you can decide the

strength of that comment - the Toronto Airport actual degree days are compared with forecasts for each of those years from 1985 to 2011 using the 20-year trend and the 55-45 blend methods, respectively. That is all it does.

Let me then carefully go through the next paragraph. BOMA has suggested and Union has agreed, subject to check - this is at V1, page 109 - that the forecast of degree days using the 55-45 blend method results in a number of degree days that is closer to the actual number, because the table I have described here has three columns, actual number, forecast of what that number would be using 20-year trend, and forecast of that number using the 30-year -- the 55-45 blend. That is all it has on that table.

So what you find, if you examine it, is that the 55-45 blend results in a number of degree days that is closer to the actual numbers than the forecast using the 20-year trend in 14 of the 26 years, and that's at V1, 109.

Therefore, Union's statement in the second short paragraph on that page underneath the table -- and it says, quote:

> "Please note that the 20-year declining trend produces weather normal estimates that is closest to the actual weather."

That is not correct. It is simply not correct, and you can determine that by looking at the table yourselves. And if I am wrong, you can keep heap scorn on me.

In BOMA's view, this fact and Union's admission is a very important point, in that it answers the question -

really answers the question, I think -- we think: Which method is more accurate?

In the hearing, Union's witnesses, after agreeing with BOMA's observations, tried to move the discussion quickly to various statistical tests of accuracy and claimed they produced a more accurate result. But it was not able or did not try, in any event, to explain away the results in the table.

To repeat, the only result that should concern us here is: Which forecasting tool yields the number of degree days that is closer to the actual degree days in more years? Our emphasis.

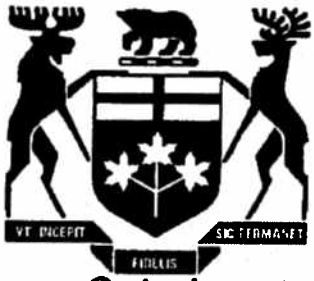
Neither the prefiled evidence nor the witnesses were able to demonstrate that their test for accuracy was superior to the simple test. If we track just the last ten years, on the same table, each method was closest in five of the ten.

So the findings hold whether one looks at the full 26-year period with which Union has used to devise its 20-year trend, or just the last ten years.

Now, you will say next, Well, what about symmetry? Looking at the symmetry of the two methods in the same table, the ratio of over-forecast to under-forecast of degree days were very close. It was 16 to 10 for the 20-year trend and 17 to 9 for the 55-45 blend.

So my conclusion is, from a fairness point of view, there is no substantial discrepancy.

Now, the third -- you will recall there were five



ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **1**

DATE: **July 10, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

acceptable weather-normalization methodology is to set a weather-normal level that will best reflect what future weather is expected to be?

MR. GARDINER: Yes.

MR. AIKEN: Am I correct that the analysis that you did was based on heating degree-days from Pearson Airport?

MR. GARDINER: The analysis in the evidence is done on Pearson, as well as the analysis was done for the two regional areas that we serve, the north and the south.

MR. AIKEN: Is Pearson Airport in your franchise territory?

MR. GARDINER: It's not in the middle of our franchise. It's located between the two portions, and it's highly correlated, the weather data for Pearson International Airport is highly correlated with the data for the franchise areas that we serve.

MR. AIKEN: Now, you mentioned that you did the analysis on your southern and northern service areas.

Did you file that -- excuse me. Did you file that information in the evidence?

MR. GARDINER: The information regarding the franchise area analysis was provided in several interrogatories.

MR. AIKEN: Am I correct that you do have heating degree-days that come from a number of weather stations -- I believe it is 15 or 16 -- across your southern and northern service areas?

MR. GARDINER: That is correct.

MR. AIKEN: Is my understanding also correct that you



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **2**

DATE: **July 12, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

So as you discussed with Mr. Aiken, Union uses Pearson Airport data, and then uses this to derive a southern and northern degree forecast. And that is discussed at the transcript, volume 1, pages 29 and 30.

So what I would like to now add to that is just an explanation, if you could, of how Union then uses that forecast together with, I think, a blend of southern and northern, or a whole franchise amount, to come up with the volumes for the general service regression forecast. We will stop there at the general service.

If you could just quickly go through how that is and how the blend is derived?

MR. GARDINER: Okay. The first issue is Toronto Pearson and the northern region, southern -- the Union weather-normal.

In the evidence, we presented analysis on Toronto Pearson, and the reason we did that was to demonstrate the concept. In 2004, when we argued the concept initially, we used Toronto Pearson because it was a central, common, with long data, data series on weather. So we used that to demonstrate the concept.

Because Toronto Pearson and the Union Gas franchise weather data is highly correlated, we felt comfortable in using Toronto Pearson as a demonstration source of data, place of -- a place we could use to say, you know, when you look at long trends in weather, given the advice from our consultants that we had, external consultants, doing the analysis of the different methods that were used, Toronto

was a good laboratory data population.

And so I want to make clear we do not use Toronto Pearson Airport data to establish, say, the southern normal. Okay? Because the southern and Pearson are highly correlated and the exercises we did on the analysis on the 20-year trend, we saw the similar story. It is getting warmer. Okay?

So I just want to make that clear, that Pearson, really we used it for our weather evidence, for the argument for the 20-year declining trend. And we carried on because in 2004 that was the weather station for -- under analysis.

We said: Well, okay. We did it there. We will continue it. We also provided the other two so it was complete.

Now, in the demand forecast, we have a northern region data and we have southern franchise data. And we established normals for both of those.

And, as Mr. Aiken asked yesterday, there are about 16 weather stations. The majority are in the north, and there is about six in the south.

We collect each day the weather data, the average of the minimum and max of the daily temperatures, and from the average daily temperature convert that into heating degree-day at 18 degrees Celsius base.

Collect that for each of them. So for example, Sarnia, London, Hamilton.

To come up with the southern heating degree-day

HEATING DEGREE DAYS below 18C

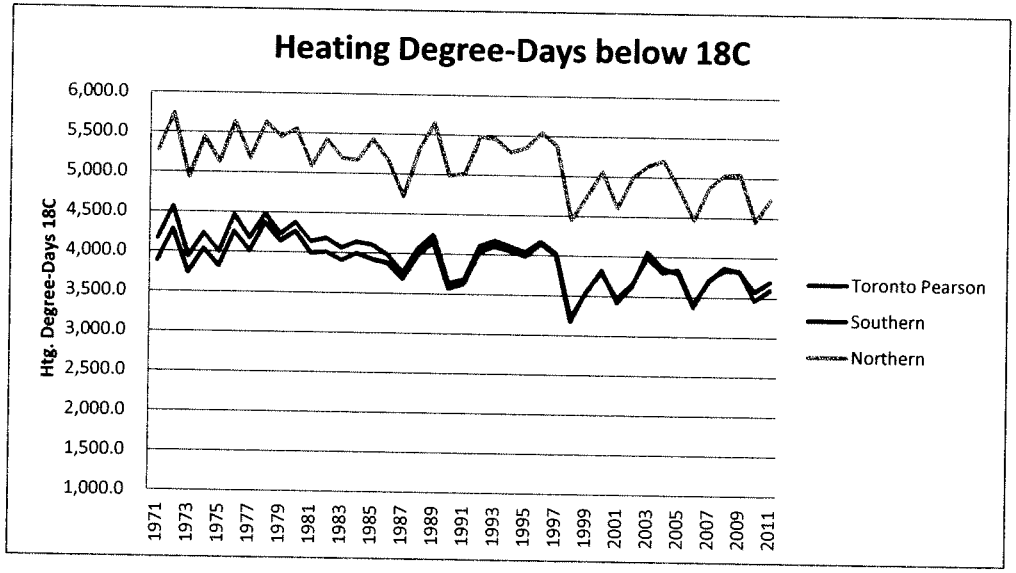
Year	Toronto Pearson	Southern	Northern
1971	4,165.7	3,884.3	5,274.1
1972	4,571.8	4,282.0	5,741.8
1973	3,946.7	3,738.0	4,941.0
1974	4,235.6	4,035.9	5,445.9
1975	4,005.2	3,821.1	5,134.0
1976	4,475.0	4,255.7	5,643.3
1977	4,181.0	4,013.9	5,188.1
1978	4,484.8	4,370.0	5,639.5
1979	4,235.5	4,143.0	5,457.9
1980	4,382.3	4,264.9	5,558.7
1981	4,144.6	3,998.1	5,092.3
1982	4,187.2	4,010.9	5,429.7
1983	4,065.8	3,908.1	5,195.3
1984	4,143.9	3,997.2	5,174.7
1985	4,109.0	3,926.2	5,437.8
1986	3,986.9	3,881.8	5,175.2
1987	3,765.3	3,683.6	4,722.4
1988	4,075.6	3,986.4	5,316.7
1989	4,245.5	4,153.9	5,654.2
1990	3,635.7	3,571.5	4,993.8
1991	3,685.8	3,631.2	5,018.5
1992	4,111.9	4,030.7	5,488.9
1993	4,181.2	4,104.9	5,460.3
1994	4,109.8	4,054.8	5,293.6
1995	4,042.0	3,987.0	5,357.8
1996	4,176.8	4,152.5	5,550.0
1997	4,033.9	4,005.1	5,384.1
1998	3,219.2	3,174.9	4,457.4
1999	3,541.3	3,553.5	4,754.0
2000	3,826.1	3,791.6	5,065.1
2001	3,423.1	3,468.6	4,612.9
2002	3,631.5	3,652.1	5,006.5
2003	4,064.3	3,988.1	5,146.5
2004	3,861.9	3,806.6	5,216.2
2005	3,796.8	3,837.5	4,865.8
2006	3,378.5	3,407.4	4,472.7
2007	3,719.4	3,699.9	4,887.8
2008	3,836.0	3,869.1	5,039.7
2009	3,835.8	3,824.1	5,049.0
2010	3,464.9	3,573.6	4,461.5
2011	3,599.2	3,695.1	4,741.0

Correlation Since 1971

	Toronto	Southern	Northern
Toronto	100.0%		
Southern	96.7%	100.0%	
Northern	93.2%	92.3%	100.0%

Correlation Since 1985

	Toronto	Southern	Northern
Toronto	100.0%		
Southern	97.8%	100.0%	
Northern	94.6%	91.0%	100.0%



J.C. 2-2-1b

Toronto Pearson Airport HDD

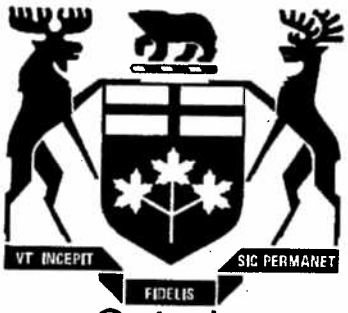
YEAR	ACTUAL	30 Yr. Avg.	20 Yr. Trend	55:45 Blend	20 Yr. Trend	55:45 Blend
1985	4,109	4,161	4,266	4,208	157	99
1986	3,987	4,176	4,203	4,188	216	201
1987	3,765	4,182	4,165	4,174	399	409
1988	4,076	4,189	4,147	4,170	72	95
1989	4,246	4,183	4,092	4,142	-153	-103
1990	3,636	4,179	3,999	4,098	363	462
1991	3,686	4,179	3,987	4,093	301	407
1992	4,112	4,187	4,015	4,109	-97	-2
1993	4,181	4,174	3,908	4,054	-274	-127
1994	4,110	4,166	3,803	4,002	-307	-107
1995	4,042	4,166	3,865	4,030	-177	-12
1996	4,177	4,168	3,859	4,029	-318	-148
1997	4,034	4,166	3,874	4,035	-159	1
1998	3,219	4,155	3,843	4,015	624	796
1999	3,541	4,152	3,911	4,044	370	503
2000	3,826	4,143	3,909	4,038	83	212
2001	3,423	4,107	3,768	3,954	345	531
2002	3,631	4,082	3,688	3,905	57	273
2003	4,064	4,066	3,708	3,905	-357	-160
2004	3,862	4,041	3,610	3,847	-252	-15
2005	3,797	4,010	3,581	3,817	-216	20
2006	3,379	4,014	3,642	3,847	264	468
2007	3,719	4,001	3,670	3,852	-50	132
2008	3,836	3,994	3,682	3,854	-154	18
2009	3,836	3,958	3,586	3,791	-249	-45
2010	3,465	3,942	3,548	3,765	83	300
2011	3,599	3,921	3,582	3,768	-17	169

Occurrence Closest

All Years	12	14

Highlighting shows closest to Actual

Total Sum Error	553	4,375
Average Error	**20**	**162**



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **15**

DATE: **August 24, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Karen Taylor	**Member**

provide the best forecast. If that includes re-specifying a few equations on an annual basis, then so be it.

As for subjectivity, Union already employs it through the decision to include or not include dummy variables for inclusion in its average use and volumetric equations.

A significant flaw in the view of LPMA is that Union is basing its forecast of degree days for the test year based on equations that are not statistically significant at even an 85 percent level of confidence. This can be seen in the equations shown in Exhibit J1.2 that was used to forecast 3,599 degree days for the south region.

In the ANOVA table, or the analysis of variance table, the significance of the F statistic is 0.153, meaning the regression is significant at a confidence level of only 84.7 percent. The time variable in the equation is also significant at only an 85 percent level of confidence. What is really disturbing is that the adjusted R-squared, which indicates the amount of variance explained in the data, is only 6.1 percent.

LPMA submits that the Board should direct Union to do a comprehensive review of at least the same forecasting methodologies as reviewed by Enbridge in both their EB-2006-0034 and in their current EB-2011-0354 rates proceedings, and provide that analysis at the next rebasing application.

Further, to recognize that a high level of correlation in weather does not necessarily lead to the same methodology being the most accurate forecasting method,

REGN 1) SUMMARY OUTPUT: Actual HDD = f(Trend, 30 Year Moving Average)

Regression Statistics	
Multiple R	34%
R Square	11%
Adjusted R Square	-6%
Standard Error	206.30
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	54,065	27,032	0.64	0.55
Residual	10	425,604	42,560		
Total	12	479,669			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	- 6,040.848	11,461.29	- 0.527	61.0%	- 31,578	19,497
X Variable - Trend	- 3.517	8.82	- 0.399	69.8%	- 23	16
X Variable - 30MA	7.260	11.82	0.614	55.3%	- 19	34

NOT SIGNIFICANT

Confidence level 30% - 45%

REGN 2) RESIDUAL OUTPUT: Actual HDD = f(55:45 Weather Normal)

Observation	*Actual Y*	*Predicted Y*	*Residuals*
2000	3,792	3,762	30
2001	3,469	3,736	-267
2002	3,652	3,745	-93
2003	3,988	3,718	270
2004	3,807	3,663	144
2005	3,838	3,725	113
2006	3,407	3,723	-315
2007	3,700	3,754	-54
2008	3,869	3,669	200
2009	3,824	3,656	168
2010	3,574	3,618	-45
2011	3,695	3,605	90
2012	*3,301*	3,541	-240

SUMMARY OUTPUT: Actual = f(55:45 Normal)

Regression Statistics	
Multiple R	30%
R Square	9%
Adjusted R Square	1%
Standard Error	199.39

Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	42,328.4	42,328.4	1.1	0.3
Residual	11	437,340.9	39,758.3		
Total	12	479,669.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-425.0	3,984.3	-0.107	92%	-9,194.4	8,344.5
X Variable 55:45 NRML	1.1	1.0	1.032	32%	-1.2	3.4

NOT SIGNIFICANT

Confidence level 70% for X Variable

RESIDUAL OUTPUT

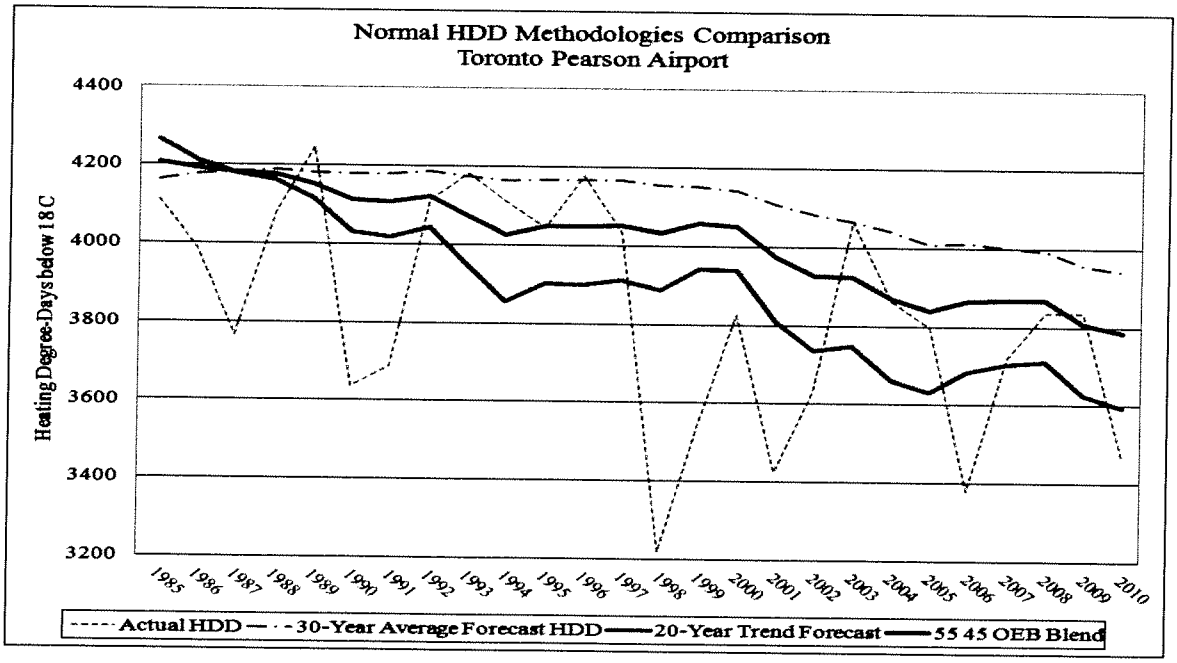
Observation	*Actual Y*	*Predicted Y*	*Residuals*
2000	3,792	3,775	16
2001	3,469	3,758	-290
2002	3,652	3,747	-95
2003	3,988	3,730	258
2004	3,807	3,708	98
2005	3,838	3,705	133
2006	3,407	3,691	-284
2007	3,700	3,683	17
2008	3,869	3,657	212
2009	3,824	3,642	182
2010	3,574	3,624	-50
2011	3,695	3,608	87
2012	*3,301*	3,586	-285

revenue forecast estimates in the general service market by about $7 million when compared to the 20-year declining trend method.

The 20-year declining trend weather normal is a symmetric weather normal and does not possess a colder weather bias. Figure 1 below illustrates the greater symmetry of the 20-year declining trend method (solid red line) against current blended method (solid black line). The 20-year declining trend passes through the middle of the actual heating degree-days observations (dashed line) since 1985. In contrast, the blended method is significantly biased towards the top (colder weather) of the actual weather.

Figure 1

Comparison of Weather Normalization Methods



2) Statistical Accuracy - The method should result in a point estimate that has a minimum variance over time between the normal HDD and the actual HDD value. Accuracy is an error measure that indicates over time the difference between the estimator and actual weather. The most precise accuracy measurement tool is the RMSE. For the RMSE, smaller test results mean greater accuracy.

3) Simplicity - The method and its results should be easily understood and administered. Simplicity addresses the need for internal and external stakeholders to understand and accept the approach that is being taken to calculate the weather normal. The greater the reliance on simple arithmetic methods and limited steps between the input data and the results, the easier it will be to understand the outcome.

4) Sustainability - The new method should stand the test of time and not require significant amendments in the near future. Sustainability is a qualitative assessment of the company being able to understand and maintain the tools underlying the method, over an extended period. The greater the reliance on external participants in the calculation of the methods the lower the assessment of its sustainability.

5) Stability - The new method should result in year over year normalized HDD estimate that does not vary significantly. Stability is a measure of variation; the standard deviation is used to measure variance. Increasing instability means that the fluctuation

from one year's forecast to the next is increasing over time. The increase in variation of the historical weather statistics is a direct contributing factor to increasing instability. For stability, a smaller standard deviation means that the method provides a more stable estimate because the difference between the forecast HDDs in two consecutive years is less significant.

Table 1
Weather Normal Forecast Estimate vs. Actual Weather

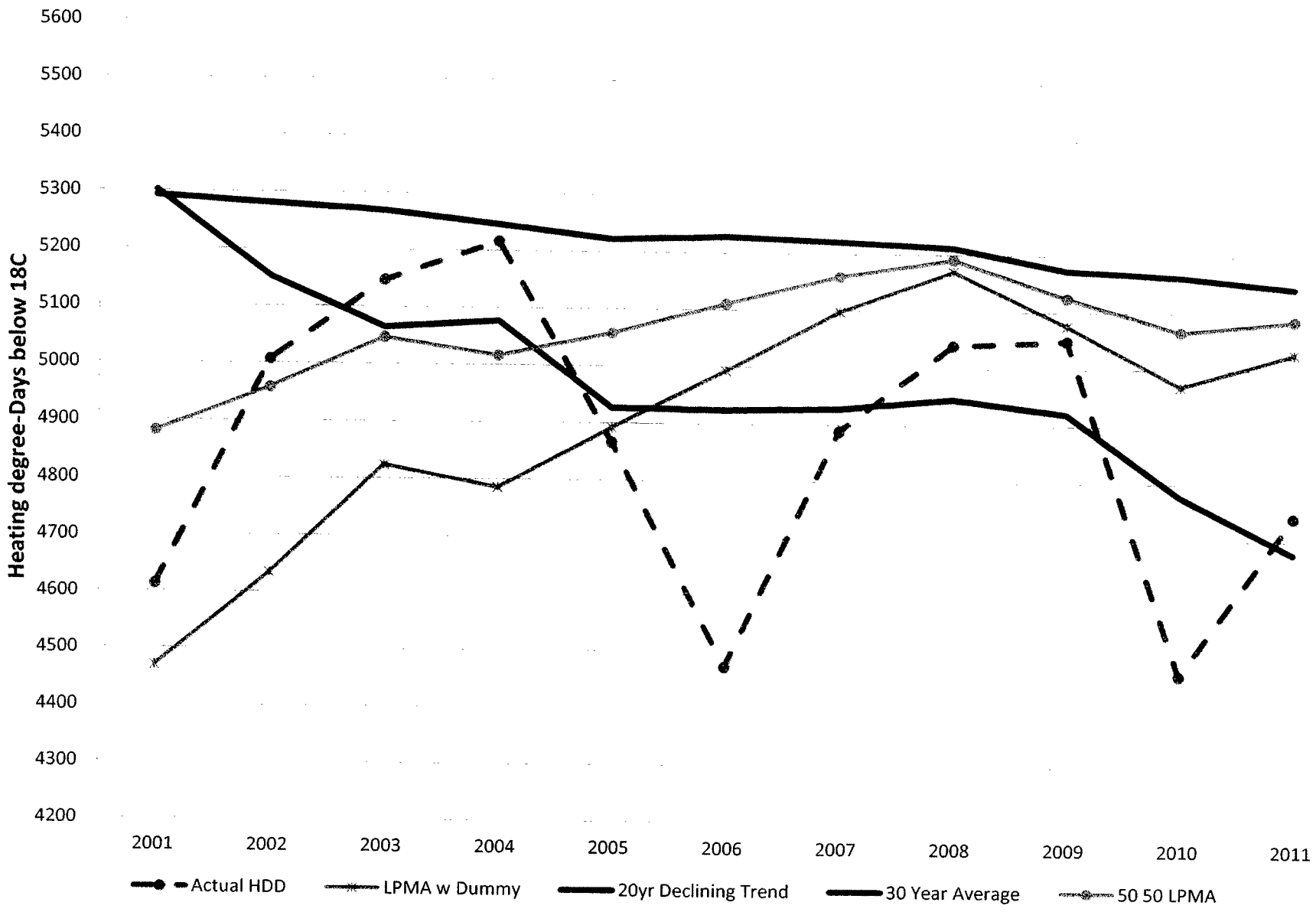
Weather normal forecast estimate versus actual annual level
25 Observations: estimates for 1985 to 2010 inclusive

	30 yr Avg.	20 Yr DT	55:45 Blend
Root Mean Square Error: RMSE	375	**269**	306
Average Variance from Actual	276	**56**	177
Std Deviation of Variance	259	269	255
Mean Percent Error	-7.7%	**-1.9%**	-5.1%

The statistical metrics in bold font in the table above show that the 20-year declining trend method ("20 Yr DT") is the superior weather normalization method. This is indicated by three of the four statistical metrics that compare the 20-year declining trend method to the current blended weather normal method and the 30-year average method used by Union before 2004. The RMSE average variance from actual and the mean percent error are accuracy measurements. The standard deviation of the variance is a stability measurement. The 20-year declining trend is a simple and sustainable weather normalization method.

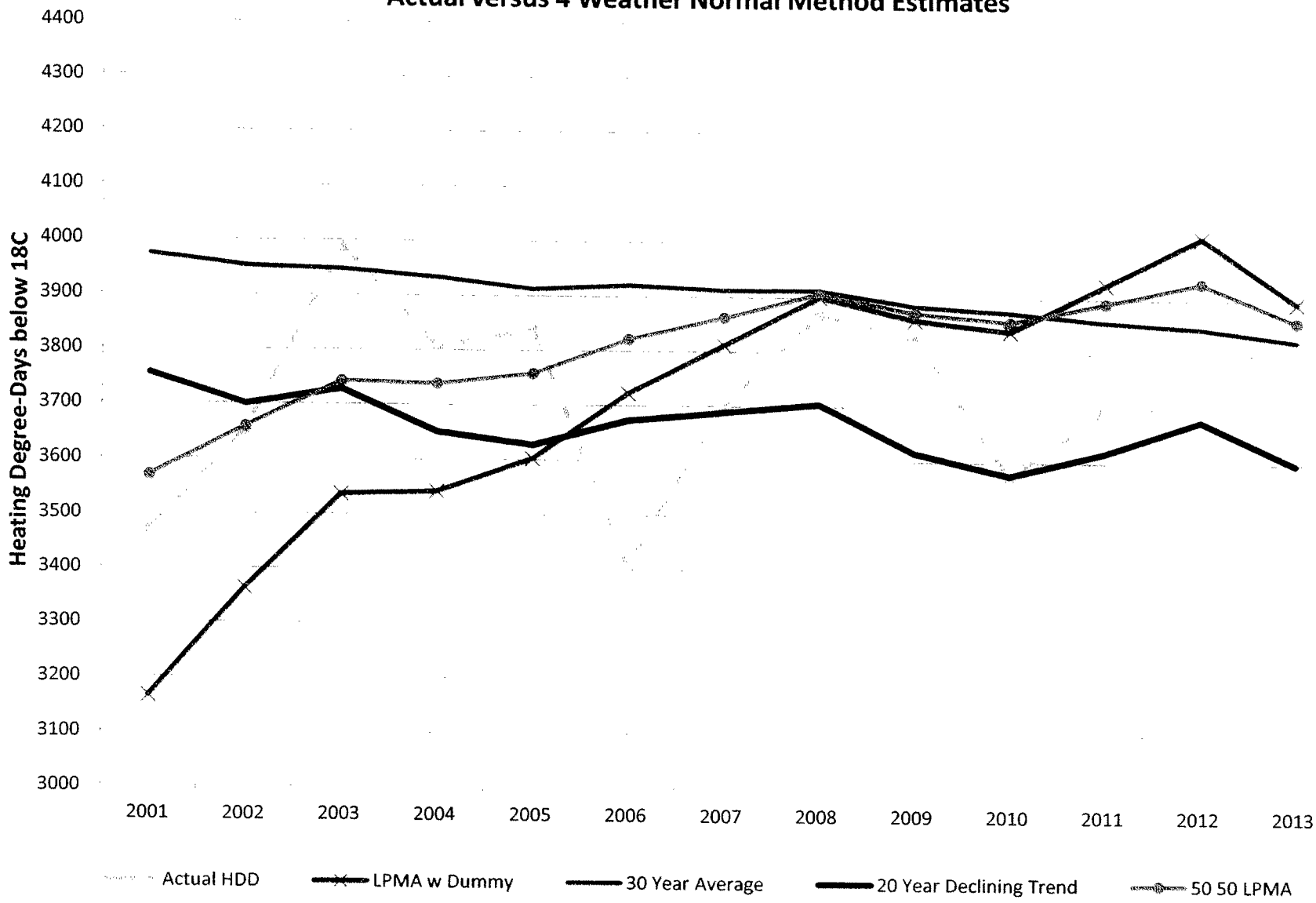
UNION NORTH HDD: Actuals & Normals

Actual versus 4 Weather Normal Method Estimates



Union South HDD: Actuals & Normals

Actual versus 4 Weather Normal Method Estimates



NORTHERN WEATHER NORMALS: Evaluation Scores & Rankings

Indicators	Accuracy		Symmetry		Stability		
	MAPE	RMSPE	MPE	% > Fcst	STDEV		
LPMA with Dummy 98	5.6%	0.00%	1.1%	13.6%	333		
20 Yr Declining Trend	4.3%	0.00%	2.5%	4.5%	270		
50:50 LPMA Blend	5.3%	0.00%	5.1%	31.8%	254		
~~Evaluation Factors & Rankings~~						**Total Score**	**Rank**
LPMA with Dummy 98	3	3	1	2	3	12	3
20 Yr Declining Trend	1	1	2	1	2	7	1
50:50 LPMA Blend	2	2	3	3	1	11	2

Note: Evaluation factors based on Enbridge evaluation approach for weather normal decision

CONCLUSION: LPMA with dummy model is inferior to 20 year declining trend method

SOUTHERN WEATHER NORMALS: Evaluation Scores & Rankings

Summary - South Indicators	Accuracy MAPE		Symmetry MPE	% OFrcst	Stability STD		
Method							
LPMA w Dummy 98	**6.25%**	**7.0%**	**-1.2%**	**5%**	**249**		
50:50 LPMA	**4.11%**	**5.4%**	**2.3%**	**23%**	**106**		
20 Yr. declining Trend	**4.15%**	**2.0%**	**-1.0%**	**14%**	**53**		
Evaluation Factors & Rankings						**Total Score**	**Rank**
LPMA w Dummy	3	3	1	1	3	11	3
50:50 LPMA	1	2	3	3	2	11	2
20 Yr. declining Trend	2	1	2	2	1	**8**	**1**

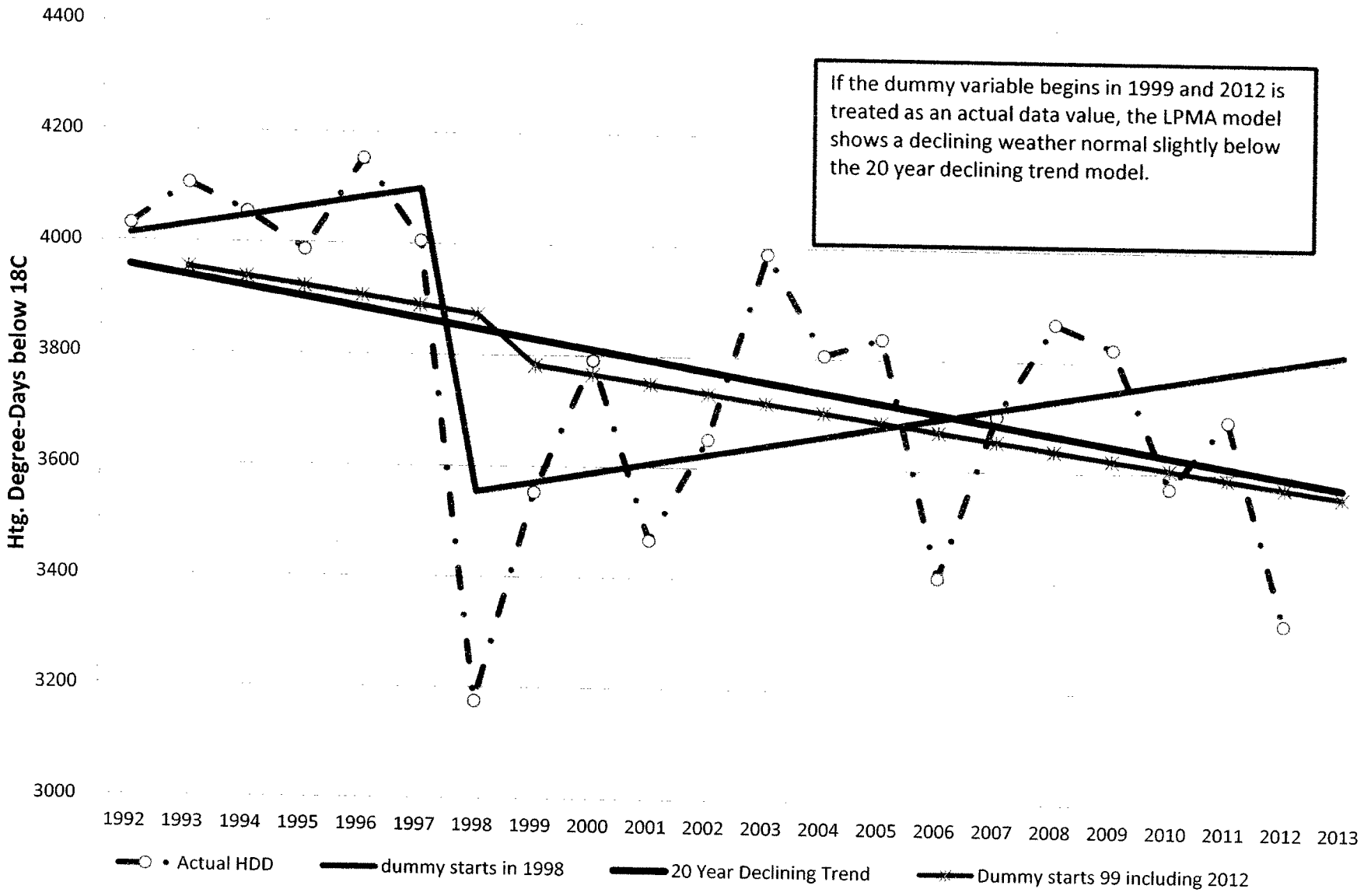
Note: Evaluation factors based on Enbridge evaluation approach for weather normal decision

CONCLUSION: LPMA with dummy model is inferior to 20 year declining trend method

Southern HDD Actuals & Normals: LPMA & 20 Year Trend

Estimation time span is 1992 to 2011

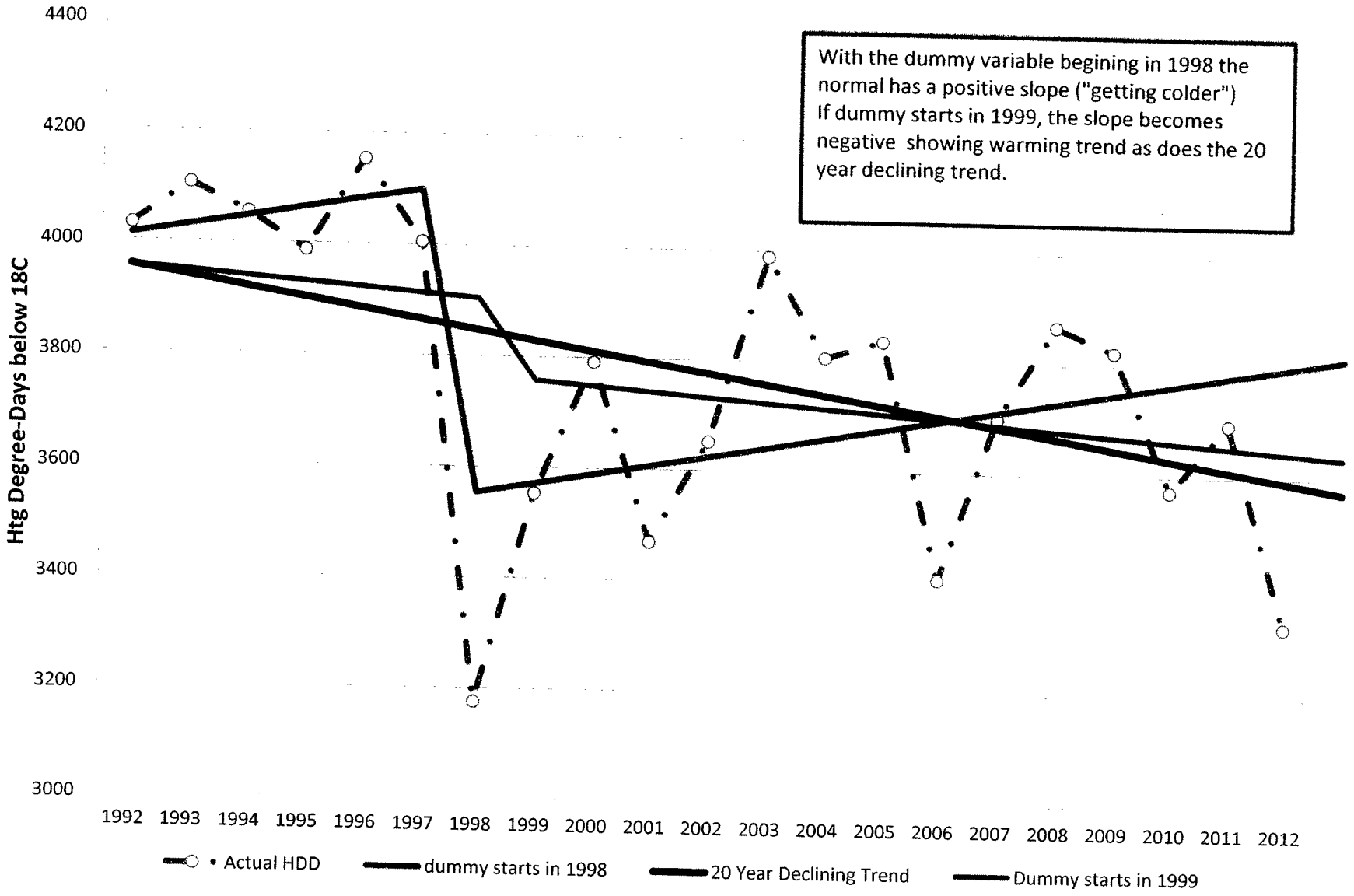
2012 is 6 months actual & 6 estimated



Southern HDD Actuals & Normals: LPMA & 20 Year Trend

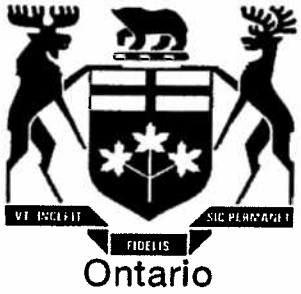
Estimation time span is 1992 to 2011

2012 is 6 months actual & 6 estimated



Ontario Energy Board

Commission de l'énergie de l'Ontario



EB-2006-0034

IN THE MATTER OF AN APPLICATION BY:

ENBRIDGE GAS DISTRIBUTION INC.

2007 RATES

DECISION WITH REASONS – PHASE 1

July 5, 2007

FORECAST OF DEGREE DAYS

The forecasting of degree days establishes the basis on which the Company can project its expected revenues and from that derive its projected sufficiency or deficiency.

Issue 2.3 reads "Is the forecast of degree days appropriate?"

The Company originally proposed to use the Central region degree day forecast of 3,617 degree days based on the 20-Year Trend method. In addition to the Central region application this forecasting methodology would apply to both Niagara and Eastern regions. The use of this forecast methodology would result in a revenue deficiency of $12.9 million, compared to the last Board-approved degree day forecast.

In its argument–in-chief, the Company amended its proposal by requesting approval of separate forecasting methodologies and forecasts for its Niagara and Eastern regions.

The nine methods evaluated by the Company are: the Naïve method, 10-Year moving average method, 20-Year moving average method, 30-Year moving average method, 50/50 method[2], de Bever method[3], de Bever with Trend method[4], 20-Year Trend method and the Energy Probe method[5]. The Company compared the actual degree days with the forecast degree days for each methodology for each year for the 1990 to 2005 period. The Company then ranked these methods using the following measures: Accuracy (as represented by Mean Absolute Percent Error and Root Mean Square Percent Error), Symmetry (as represented by Mean Percent Error and Percent Over-Forecast) and Stability (as represented by Standard Deviation).

[2] Also referred to as the Union method, is a weighted average of the 20-Year Trend method and the 30 Year Average.
[3] "The de Bever [method] is a regression model and features a long-term and short-term component. The former takes the form of a constant, while the latter is accomplished via a five-year weighted average of degree days (lagged two years). The model is estimated over a period equal to the estimated periodicity of the weather cycle". C2/T4/S1
[4] "The de Bever with Trend [method], as the name implies, adds a trend variable to the previously approved de Bever method". C2/T4/S1
[5] "Energy Probe [method] adds both a trend and a five-year simple moving average to the basic de Bever model". C2/T4/S1

Based on its review, the Company now proposes to use a mix of degree day forecast methodologies. The Company argues that its analysis indicates that it is appropriate to move away from using the de Bever methodology and in its place the Board should adopt the method that is best suited to each of its three regions. Accordingly, the Company is requesting approval for the 20-Year Trend method (and forecast of 3,617 degree days in the Central region), the Energy Probe method (and forecast of 4,410 degree days) in the Eastern region and the 50/50 method (and forecast of 3,546 degree days) in the Niagara region. This new proposal reduces the revenue deficiency related to weather from $12.9 million to $11.7 million.

While intervenors and Board Staff have raised a number of issues with the Company's proposal, the majority of the discussion has focused on the proposed use of the 20-Year Trend method in the Central region.

The Company argues that the current Board-approved method, which was approved in 1990, is no longer appropriate to accurately predict an increasingly volatile and downward trend in heating season degree days.

The Company presented evidence to support its claim that, in recent years, weather has become increasingly volatile and exhibits a warming trend. The Company also presented detailed empirical evidence based on its examination of the different methods. Its analysis, the Company argued, clearly indicates that the 20-Year Trend method produces better forecasts than any of the other methods for the Central region.

Schools and CCC argued that the Company has not made a case sufficient for the Board to adopt a new methodology, particularly a complex mix of various approaches. While Schools accepted the use of a linear trend to forecast degree days, it raised a number of issues with respect to the methods tested, the design of the ranking system, and the length of the test period. Schools also argued that the Board should adopt an interim solution and the issues of weather risk and degree day forecasts should be addressed in a generic proceeding.

CCC submitted that Enbridge has not demonstrated that the 20-year trend is a sufficiently robust and flexible model and that the Board should continue with the de Bever methodology, or set the 2007 degree day forecast using the methodology approved by the Board for Union Gas.

IGUA argued that the Company should not be allowed to change its degree day methodology before the results of the Board's pending weather normalization review are known. IGUA argued that Enbridge's forecast should be determined based on the methodology currently embedded in its rates. IGUA characterized this methodology as the "adjusted" de Bever methodology and it consists of reducing the forecast produced by an application of the Board approved de Bever methodology by 43 degree-days. Accordingly, IGUA argued the 2007 degree day forecast should be 3,805 degree days.

Board Staff identified certain concerns with the Company's proposed methodology, but did not advocate the use of any one particular method.

Energy Probe supported the Company's proposal to use the best performing method in the three regions. However, it argued that the analysis used to assess the performance of the different methodologies, is flawed. Energy Probe submitted that the Board should approve the Energy Probe methodology for the Central and Eastern regions and the 10-year moving average methodology for the Niagara region.

Board Findings

The Board considers the following to be the two issues to be considered with respect to the proposed change in methodology: Has the Company made a sufficient case to alter the currently used methodology? If it has, then what is the appropriate degree-day forecasting methodology (or methodologies) for setting test year rates? The Board deals with each question below.

Has the Company made a sufficient case to alter the currently used methodology?

CCC submits that Enbridge has not made a case sufficient for the Board to adopt a new methodology, particularly a complex mix of various approaches. Schools argues that the Board has an approved degree day forecasting method for Enbridge which was established after a thorough debate with expert evidence and that, from a strict legal point of view, the de Bever method is the default method; since the Company has not met the onus to supplant it, the de Bever method should be used. IGUA, supported by VECC, argues that pending the results of the weather normalization review, Enbridge's forecast should be determined based on the methodology currently embedded in its rates.

The Company argues that it has presented detailed evidence to indicate that the current method is no longer appropriate and notes that those are sufficient grounds to warrant a change in methodology. In response to IGUA's arguments, the Company argues that no such methodology has ever been presented or approved by the Board. The Company further argues that in the years since 2003 the degree day forecasts have been settled and are not premised in any degree day forecasting methodology.

The Board notes that the settlement agreement in the last rates case for the Company (EB-2005-0001) does not make any specific characterization nor does it explain the basis for the degree day adjustment agreed to by the parties from the level proposed by the Company. It merely notes that the parties have agreed to reduce the degree day forecast by 43 degree days. The Board considers the adjustment to be the result of a negotiated settlement rather than being underpinned by any scientific or statistical reasons.

The Board believes that given that the sole purpose of a forecasting methodology is to accurately forecast weather it is simply appropriate to select a method based on the empirical findings.

In the Boards view, the aforementioned evaluation of nine various methodologies presented by the Company reasonably demonstrates that the de Bever method has not produced the most accurate forecasts compared to other methods.

What is the appropriate degree-day forecasting methodology (or methodologies) for setting test year rates?

Having found that the utility has made a compelling case to consider a change in methodology, the Board then must make a determination on an appropriate degree day forecasting methodology.

The Company has presented historical weather data and argues that this data reveals that weather is increasingly volatile and displays a warming trend, especially in the Central region. The Central region is particularly relevant in this context, because it accounts for over 80% of the Company's volumes.

The Board is satisfied that the historical weather data presented by the Company can be interpreted to support the premise that an underlying warming trend and increasing volatility in weather does exist. However, the Board does not find this to be determinative in the selection of the most appropriate model. The Company has presented various methods. Some of these are based on simple moving averages, while others are more sophisticated.

Based on the evidence and arguments, the Board concludes that a linear trend method is an appropriate method to be used. The moving average methods, while they do capture the trend, exhibit a considerable lag, thus making it an inferior method to the linear method. While the Naïve method captures the randomness in the data, it can result in an abrupt and substantial change, which could lead to rate shock. The de Bever method, as noted earlier also has its limitations.

The selection of the trend is a critical factor in the determination of an appropriate forecast. The evidence the Company has presented indicates that a linear regression trend based on 20 years of data, compared to the other eight commonly used methods, generates forecasts that display greater accuracy. for the Central Region having accepted the analysis presented by the Company as part of its review of the nine comparable methodologies, the Board accepts the Company's amended proposal to

apply the 20-Year Trend method in the Central region, the Energy Probe method in the Eastern region and the 50/50 method in the Niagara region.

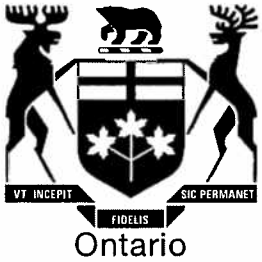
Union Gas Franchise Areas
Comparision of Weather Normal Methods
3 Year Regulatory Lag

Summary SOUTH	Accuracy		Symmetry		Stability	2013
	MAPE	RMSPE	MPE	% OFrcst	STD	Nrml
Energy Probe	5.37%	8.01%	3.04%	60.00%	155.99	3,652
30 Yr AVERAGE	7.39%	10.15%	7.25%	93.33%	52.84	3,824
20YDT	5.44%	7.21%	1.11%	46.67%	98.10	3,599
50:50Nrml	5.70%	8.22%	4.18%	60.00%	74.35	3,712
55:45Nrml	5.75%	8.38%	4.49%	60.00%	72.06	3,723

RANK SOUTH	Accuracy		Symmetry		Stability	TOTAL SCORE	RANK
	MAPE	RMSPE	MPE	% OFrcst	STD		
Energy Probe	1	2	2	2	5	12	2
30 Yr AVERAGE	5	5	5	3	1	19	5
20YDT	**2**	**1**	**1**	**1**	**4**	**9**	**1**
50:50Nrml	3	3	3	2	3	14	3
55:45Nrml	4	4	4	2	2	16	4

Summary NORTH	Accuracy		Symmetry		Stability	2013
	MAPE	RMSPE	MPE	% OFrcst	STD	Nrml
Energy Probe	6.55%	8.43%	3.20%	60.00%	240.7	4,817
30 Yr AVERAGE	6.95%	8.71%	6.95%	100.00%	44.7	5,093
20YDT	3.42%	4.46%	0.30%	50.00%	136.9	4,626
50:50Nrml	4.41%	5.98%	3.62%	80.00%	90.2	4,859
55:45Nrml	4.61%	6.21%	3.96%	80.00%	85.6	4,883

RANK NORTH	Accuracy		Symmetry		Stability	TOTAL SCORE	RANK
	MAPE	RMSPE	MPE	% OFrcst	STD		
Energy Probe	4	4	2	2	5	17	4
30 Yr	5	5	5	4	1	20	5
20YDT	**1**	**1**	**1**	**1**	**4**	**8**	**1**
50:50Nrml	2	2	3	3	3	13	2
55:45Nrml	3	3	4	3	2	15	3



ONTARIO ENERGY BOARD

BOARD STAFF SUBMISSION

Union Gas Limited

2013 Rates Application

Board File No. EB-2011-0210

August 17, 2012

OPERATING REVENUE

Weather Methodology and Normalized Average Consumption

Union's demand forecasting methodology is based on a multiple regression analysis within the general service market. Union has proposed to use a 20-year declining trend to derive the total Heating Degree Days estimates for 2012 and 2013. The Heating Degree Days is a significant variable that is used to derive the Normalized Average Consumption ("NAC") forecast. Forecast estimates for NAC are prepared for the residential customers by individual rate class. The NAC consumption forecast for residential and commercial customers incorporates assumptions related to several demand variables: weather normal, energy efficiency, total bill amounts, fall season weather and structural trend variables.

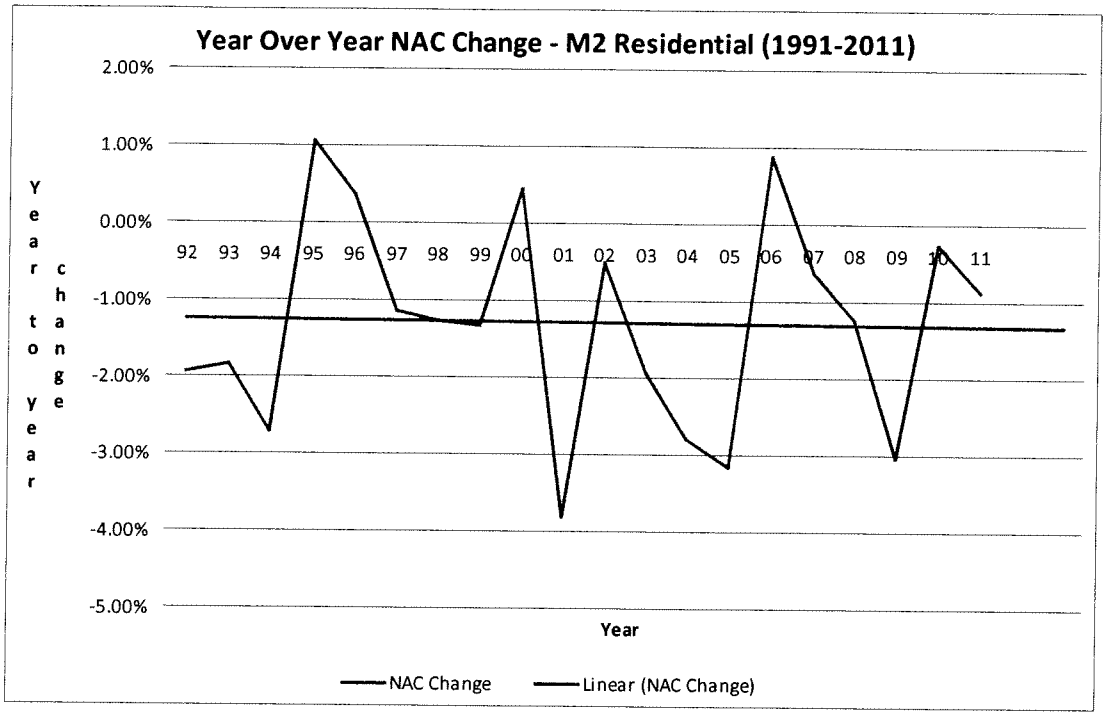
At the oral hearing, Union submitted that its use of a 20-year declining trend was the most appropriate and superior to other methodologies[1], especially as compared to the 30-year declining trend and the current Board approved methodology which is a hybrid using a 55/45 weight of the 30-year and 20-year declining trend. However, Union confirmed that it did not investigate any other methodologies including those that have been examined by Enbridge[2]. Union has indicated that the root mean square error of the current regression model proves that it is an accurate model and the trend line shows that the 20-year trend intersects the middle of the data demonstrating better symmetry as compared to the 30-year trend or the hybrid approach. In its Argument-in-Chief Union indicated that on a weather normalized basis, it is forecasting an increase of about 0.7% in throughput volume relative to 2007 Board approved levels.[3]

Normalized Average Consumption ("NAC")

Board staff have used the Rate M2 NAC data presented in Exhibit J1.4 and compared it to the forecast for 2011 and 2012 that has been derived using the 20-year trend. Union itself did not produce a trend line for NAC; it produces its forecast with a regression model using the variables described above. The year over year percentage NAC changes have been presented graphically below:

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[1] Oral Hearing Transcript, EB-2011-0210, Vol. 1 at p.33.
[2] Oral Hearing Transcript, EB-2011-0210, Vol. 1 at p.32.
[3] Union Argument-in-Chief, EB-2011-0210, Vol. 13 at p.12.



As can be noted from the above graph, the trend line does not show a significant downward sloping curve. The trend line has been forecasted into 2012 and 2013 and does not show a pronounced decrease in 2012 and 2013 but is within the range of a 1.5% annual decline. However, Union has forecasted a 5.1% reduction from 2011 to 2013. In other words, the 20-year declining trend as proposed by Union may be yielding a pronounced downward sloping curve resulting in a much lower NAC even though it may be cutting through the middle of the data indicating better symmetry. On the other hand, Union has claimed that the 30 year trend has a bias towards over-forecasting HDD as it does not capture the general change in weather that has occurred in the recent past.

Board staff submit that Union's use of a 20-year declining trend may lead to under-forecasting HDD and consequently throughput. This is supported by the comparison of the total NACs from 2007 to 2011 and forecasts for 2012 and 2013 as presented in J.C-1-1-2. Union's total NAC as noted in J.C-1-1-2 has declined from 3,975 m^3 in 2007 to 3,830 m^3 in 2011, a drop of 145 m^3 or 3.7% over a four year period. At the same time, the forecasted NAC for 2013 is 3,610 m^3 or a decline of 5.7% over 2011 actuals.

The actual NAC for the total commercial market when compared to the forecast for 2011 shows a variance of 5.7% as noted in J.C-1-2-4. In other words, the commercial market was under-forecasted by 5.7%. In response to an interrogatory (J.C-1-1-2), Union has indicated that the residual error is 5.8% which refers to the error that cannot be explained by the regression model. Board staff submit that this is a large residual error for a regression model.

In the general service or old M2 residential rate, the difference between actual and forecasted NAC for 2011 is 37 cubic meters. At the oral hearing, Union submitted that the 1.7% error is within the two percent forecast accuracy and of this only 1% or 22 cubic meters is the unexplained error.[4] This 1% error in NAC translates to approximately $3.5 million in revenues for the M1 rate class.[5].So although the 1% error seems inconsequential and considered within an acceptable range by Union when discussing forecast accuracy or the NAC estimate, the revenues underpinning that error are significant. Indeed, if this residual error is removed, then the annual reduction in NAC is about 1.5%, which is very similar to the trend line produced in the graph showing year over year NAC changes..

In Union's 2004 rates case (RP-2003-0063), Union's weather evidence discussed seven methodologies. However, in the current rates case Union has presented only one methodology, the 20-year declining trend. In other words, Union has not discussed other methodologies such as the ARIMA[6], de Bever trend[7], moving averages, etc. Board staff submit that since Union has not discussed alternative methodologies, the Board does not have sufficient information or the confidence that the 20-year declining trend is the most accurate and appropriate methodology. In fact, Board staff would argue that based on arguments presented earlier, the 20-year declining trend has a bias towards under-forecasting as evident from the NAC comparison. In its Argument-in-Chief, Union has submitted that intervenors have not

[4] Oral Hearing Transcript, EB-2011-0210, Vol. 2 at p.128.
[5] Oral Hearing Transcript, EB-2011-0210, Vol 2 at p.137.
[6] ARIMA (Auto Regressive Integrated Moving Average model) is a broad class of time-series models that, when stationarity has been achieved by differencing follows an ARIMA model. An ARIMA model is a type of time-series forecasting model that can be autoregressive, moving average, or a combination of the two. In an ARIMA model, the series to be forecast is expressed as a function of previous values of the series (autoregressive terms) and previous error terms (the moving average terms).
[7] The de Bever method is a regression model that features a long-term and short-term component. The former takes the form of a constant, while the latter is accomplished via a five-year weighted average of degree days. The model is estimated over a period equal to the estimated periodicity of the weather cycle.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit C1, Tab 1, Figures 5 - 8, Original & Updated

For each of Figures 5 through 8, please explain the difference in the 2011 forecast average use as compared to the normalized actual use. For example, why is the actual residential old rate M2 normalized actual use of 2,264 m3 1.7% or 37 m3 higher than the 2011 forecast? How many months of actual data were included in the 2011 forecasts?

Response:

The difference between the forecast average use and the normalized actual use ("NAC") in 2011 is explained by:

- The variance between the actual and the assumed non weather related demand variables; and
- The regression residual estimate.

The non weather demand variables include furnace energy efficiency ("FEI"), persons per household ("PPH"), total bill amount, exchange rates ("FX"), fuel oil prices and the Demand Side Management ("DSM") related NAC impacts.

The table below provides a variance explanation of the observed usage variance for the four principal markets. A summary discussion on each market is provided below:

1. Southern residential customers: about 40% of the total positive 1.7% NAC variance is explained by the actual demand drivers. Variance in the FEI assumption is the largest factor. The remaining 1% difference (or 22 cubic metres per customer) is unexplained by the equation. The unexplained error is considered a reasonable forecast error as it falls below the 2% error band.
2. Northern residential customers: about 35% of the total negative 0.8% NAC variance is explained by the actual demand drivers. Variance in the FEI assumption is the largest factor. The remaining 1.4% difference (or -31 cubic metres per customer) is unexplained by the equation, but is considered as reasonable forecast error as it falls below the 2% error band.
3. Total commercial market: the total variance is 5.7% attributable to the other unexplained variance. The year 2011 saw another spike in usage, continuing a pattern seen since 2006. Normalized average consumption per customer was high in November and

December 2011 which depicts the presence of an agricultural process related load in the total customer mix. The normalized usage data for the first four months of 2012 was 8,887 m^3 per customer and since the first four months represent approximately 54% of the annual usage, this suggests that average usage will be below 16,500 m^3 per customer by year end. This confirms that 2011 commercial usage displayed another high year seen in the saw tooth pattern since 2006.

4. Total industrial market: the total variance was -2.8%, and is attributable to both the alternate fuel oil price and other factors.
5. In aggregate, the total NAC forecast accuracy in 2011for all 1.36 million general service customers was 1%.

The historical database underlying the statistical analysis for the forecast in evidence is:

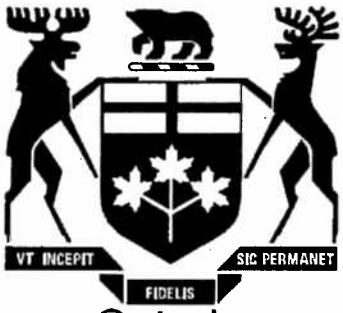
- Residential South Use Eqn. monthly data from April 1993 to December 2010;
- Residential South Volume Eqn. monthly data from June 1995 to December 2010;
- Residential North Use Eqn. monthly data from April 1994 to December 2010;
- Residential Volume Eqn. monthly from May 1996 to December 2010;
- Commercial monthly data from January 1991 to December 2010; and
- Industrial quarterly data from Quarter 1,1997 to Quarter 4 2010.

The residential time periods provided improved regression fit and residuals results than using longer historical time periods.

With respect to the 2011 forecast usage and volume estimates presented in the four charts in the original evidence, the 2011 annual estimates are all forecast estimates. These estimates are weather normalized at the 2013 weather normal.

NAC FORECAST VARIANCE ANALYSIS - YEAR 2011

Residential South				
Year	Res M2 former Actual NAC	Res M2 former Forecasted NAC	NAC variance	% variance
	m^3	m^3	m^3	
2011	2,264	2,227	37	1.7%
NAC variance explained by:				
FEI			13	0.6%
PPH			1	0.0%
Total Bill			0	0.0%
DSM			1	0.0%
Other			22	1.0%
Residential North				
Year	Res 01 Actual NAC	Res 01 Forecasted NAC	NAC variance	% variance
	m^3	m^3	m^3	
2011	2,269	2,288	-19	-0.8%
NAC variance explained by:				
FEI			12	0.5%
PPH			2	0.1%
Total Bill			-1	-0.1%
DSM			-1	0.0%
Other			-31	-1.4%
Total Commercial Market				
Year	All Commercial Actual NAC	All Commercial Forecasted NAC	NAC variance	% variance
	m^3	m^3	m^3	
2011	17,006	16,092	914	5.7%
NAC variance explained by:				
Fall weather			-19	-0.1%
DSM			-7	0.0%
Other			940	5.8%
Total General Service Rate Industrial				
Year	All Industrial Actual VOL	All Industrial Forecasted VOL	VOL variance	% variance
	10^3 m^3	10^3 m^3	10^3 m^3	
2011	476,483	490,330	-13,847	-2.8%
Volume variance explained by:				
Exchange Rate			-2,246	-0.5%
HFO			29,505	6.0%
DSM			-490	-0.1%
Other			-40,616	-8.3%



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **15**

DATE: **August 24, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Karen Taylor	**Member**

is 6,455 customers, while in 2009, when the impact of the recession -- sorry, when the impact of the recession hit the housing market, Union over-forecast by 2354 additions. That is taken from Exhibit J.C-1-1-5.

They state, Union states that the average range over the four budgets is 4,253 customers.

Now, Union has not provided any evidence to suggest that they view this under-forecast as a problem or that they have taken any measures to address it.

LPMA submits that the Board should increase the general service customer forecast by 4,250 in both the bridge and test years.

Based on the sensitivities shown in Exhibit A2, tab 1, schedule 2, 5,000 additional customer attachments in 2003 reduces the deficiency by approximately $200,000.

By adding customers in the bridge year, the impact would be double that in the test year, so the addition of 4,250 in both years should reduce the deficiency by about half a million dollars.

LPMA notes that Board Staff have submitted that Union should include the 800 customers associated with the expansion in Red Lake in the 2011 forecast. LPMA agrees, but if the Board accepts the increases proposed by LPMA, then it is submitted that these customer additions should be considered be included in the increase of 4,250 in the 2013 test year.

I am moving on to issue 3 and that is:

"Is the 2013 contract customer demand forecast

appropriate?"

LPMA's main concern with the contract forecast is the unsupported reduction in the overrun forecast provided by Union.

In the response to Exhibit JT1.1-7, Union is forecasting only 0.6 million in overrun revenues in the test year, despite recording actual overrun revenues that average nearly $2 million a year over the 2007 through 2011 period, including 2.4 million for the most recent actual year.

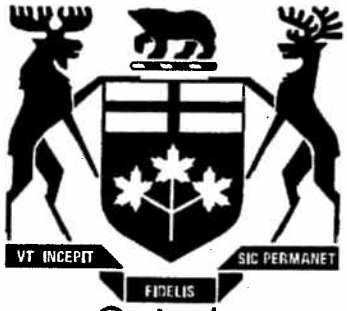
LPMA submits that Union has not provided any credible evidence for any of the reductions shown for the non-power markets shown in the response to Exhibit JT1.1-7.

The overrun revenues from these non-power markets have been very stable over the 2007 through 2011 period, averaging over just 1.7 million per year.

LPMA submits that this is a reasonable forecast for the test year, given the levels recorded in the past.

With respect to the power market, Union's forecast of nothing is not credible. Union has added additional generators over the 2007 through 2011 period, and the last year of actual revenue is 0.6 million in 2011.

Union also did not forecast any power market overrun revenue in 2012. However, by the end of June of this year, Union had collected 0.3 million from the Halton Hills generating facility. That is at transcript volume 1, page 100. On an analysed basis, this equates to 0.6 million, the same is recorded in 2011.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **1**

DATE: **July 10, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

of general service customers, maybe three.

What is the latest month for which you could provide the actual number of general service customers in 2012?

MR. GARDINER: June.

MR. AIKEN: Could you provide -- you may have it in front of you, but could you provide the actual number of general service customers, then, for June 2012, and what the corresponding forecast was for June of 2012? Just in aggregate, all of the general service customers, rate classes?

MR. GARDINER: As I am looking for the chart, the table, since the forecast was prepared last year, we have been tracking below forecast.

Ah, found it. The actual number total bill customers at June 2012 is 1,366,306.

The bridge year estimate for June 2012 is 1,366,705. The difference, a negative difference of 399. This difference, since the forecast was prepared in early 2011, has averaged a negative 1,058.

MR. AIKEN: So then with respect to the accuracy of the forecast, I think I know the answer to this question, but which tends to be more accurate, the forecast of the total number of customers or the forecast of total volumes?

MR. GARDINER: I'm sorry, Mr. Aiken, can you repeat that?

MR. AIKEN: Yes. With respect to the accuracy the forecast, which tends to be more accurate, the forecast of the total number of customers or the forecast of total

volumes?

MR. GARDINER: From a percent variation, the customer forecast, in total bill customers, is more accurate than volumes.

MR. AIKEN: And can you briefly explain why that is the case?

MR. GARDINER: Because the total customer base is like 1.3 million customers and we're adding new accounts, new customers, for sake of discussion say 18,000, and the variation is on the 18,000, because it is an estimate: How many new customers are we going to have?

So if you are out by 1,000 customers on 18, that is like 5 percent, but on the base of 1.3 million, it is a tiny little fraction.

MR. AIKEN: Okay, thank you. Those are my questions.

MS. HARE: Thank you. Who is next in the order? Oh, Mr. Wolnik.

CROSS-EXAMINATION BY MR. WOLNIK:

MR. WOLNIK: Yes, I think I am next. Panel, I am John Wolnik. I represent the Association of Power Producers of Ontario. I think I am familiar to all of you.

I want to focus today on the contract revenue side. So, Ms. Van Der Paelt, I think this is primarily your evidence that is found in C1, tab 2, section 4.

I think -- I thought I heard Mr. Smith say that your evidence was C1, tab 1. I may be mistaken, though, but it is C1, tab 2; right?

MS. VAN DER PAELT: That's correct. It is C1, tab 2.

market.

And from 2005 to 2010 it was declining -- it is flat to decline, and in 2011 we have an uptick.

MR. BRETT: And you... All right.

MR. GARDINER: But in most years it was flat, with the exception of 2011.

MR. BRETT: Now, in the... But my statement, do you agree with me my statement was correct, that from 2006 to 2011, inclusive, you have an increasing -- you have an increase in the M2, the old M2, which -- as well as the two rates, the two smaller volume rates in the northern section, the rate 01 and 10? Do you agree with me perhaps further that in terms of volumes here, it is the old M2 that is the major volumetric driver?

MR. GARDINER: Well, the old M2 is the larger class in commercial.

Now, if I take you to the interrogatory response to J.C-1-2-4, page 2 of 3, I am responding to Mr. Aiken's question regarding the spike in -- well, the NACs in 2011.

And the reason I bring your attention to the top paragraph that starts "December 2011", I am talking about the commercial market. And when I did the variance analysis, which is on page 3 of 3 in that same interrogatory response, the residual, which is unexplainable, is the largest portion, okay? That is the reason for the spike.

And I responded in the -- on page 2 that then we had data up to April, and the commercial NAC was receding from

the spike, okay? It was no longer 17,000. It was indicating 16,500, and that is what I am seeing today.

So the spike that occurred in 2011, I don't know where it's coming from. It occurred, okay, but it is receding, based on data that I have currently.

So long story short, I see a hockey stick with a blade, and there's a jagged pattern that happens.

MR. BRETT: Well, I think your comment -- would you agree that -- I mean, there is a jagged pattern. There is no question that it seemed -- would you agree that the actuals, that the NAC have exhibited a considerable amount of volatility year to year? You talked of a saw tooth pattern on page 3?

MR. GARDINER: Yes.

MR. BRETT: You'd agree with that?

MR. GARDINER: Yes.

MR. BRETT: You'd agree that what you see as a spike and I might see as an uptick, as part of a secular up-trend?

MR. GARDINER: Well --

MR. BRETT: I guess you -- would you agree that those numbers, those lines are capable of more than one -- they're capable of more than one interpretation, more than one reasonable interpretation?

MR. GARDINER: Well, my interpretation is I see it going up, going down. I see a variable, the harvest variable that explains the other -- the first two up and down saw tooth pattern.

earlier, is because of the residual that is in the 2007 -- 2011 actual. 2011 actual NAC was high.

MR. BRETT: Would you agree that the residual is effectively a comment? Having a residual of that magnitude is effectively saying that your model is deficient to some degree?

MR. GARDINER: No. It could be an outlier.

MR. BRETT: Well, what do you mean by an "outlier"?

MR. GARDINER: As I was explaining earlier about structural dummy -- about use of dummy variables in regression analysis, you can use them to account for outlying data. So --

MR. BRETT: So you use them to - sorry, go ahead. I'm sorry. I apologize. Go ahead.

MR. GARDINER: So I just finished 2011. Okay? And I am looking at my data in 2012 so I can see patterns, to say: Okay. Is it an outlier or is it real? Right now, I just know it is unexplained -- unexplainably high, and I know from my year-to-date information that it is receding.

So that tells me it is a spike and it is a candidate for being an outlier, but not yet.

MR. BRETT: Because you have just four months of data?

MR. GARDINER: Right.

MR. BRETT: Out of 12?

MR. GARDINER: Correct.

MR. BRETT: But you use the dummy variable to effectively eradicate outliers?

MR. GARDINER: Correct.

RP-2003-0063
EB-2003-0087
EB-2003-0097

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 for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

Union asserted that the design of the T3 rate ensured that consumption variances had no material impacts on other classes and using Kitchener's forecast would increase Kitchener's rates.

Union submitted that OPG's criticism of the forecast contract demand methodology used by Union ignored Union's evidence with respect to the relationship between the M7 class and T1 semi-bundled service. Union asserted that its evidence showed that M7 customers had advised Union that they intended to switch to T1 semi-unbundled service. Union argued that any variances should be assessed by looking at the sum of both classes, an exercise that would show no significant variance. As Union has now signed T1 contracts with the large customers which caused the historical variances between M7 and T1 customers, Union argued that these historical variances were unlikely to occur in 2004.

Union stated that OPG's position with respect to Rate 25 was tantamount to a request that the Board disregard the IMO's forecast of when nuclear plants would be in service. Further, Union argued that the technical factors that OPG stated Union should have considered in its forecast, were explicitly considered by the IMO in its forecast.

Board Findings

The Board believes that the contract class forecast should incorporate the input of the customers, in the belief that the contract customers possess some relevant information that Union may not have access to. As such, the Board believes that Union should work cooperatively with these individual customers to develop forecasts that both parties can agree on. The Board recognizes that there may be cases in which agreement can not be achieved at this stage; should this be the case, the Board expects the parties to communicate with Board staff, informing staff of the impasse in negotiations and requesting any staff assistance that may bring the parties to agreement. If this second stage should not be successful, the Board expects both parties to inform the Board to seek Board resolution of the dispute. The Board expects that any outstanding differences in this regard will be brought to the Board's attention well in advance of the associated rates proceeding.

With respect to the T3 forecast, the Board urges Kitchener and Union to work together, again in a timely fashion, to resolve such specific issues as normalization of load and asset allocations.

With respect to OPG's concerns, that Union historically had significantly underestimated R25 interruptible and M7 firm volumes and had ignored what OPG considered to be key elements in deriving its forecasts, the Board reiterates its views on these matters as expressed above. Regarding OPG's proposal to adjust Union's R25 interruptible and M7 firm revenue and volume forecasts, the Board finds that it is unable, on the evidence before it, to accept OPG's forecast, notwithstanding the Board's view that the OPG's views may have some merit.

Notwithstanding the Board's reservations, for the 2004 test year the Board accepts Union's contract customer forecast. The Board expects that Union's 2005 contract customer forecast will address the Board's concerns as expressed above.

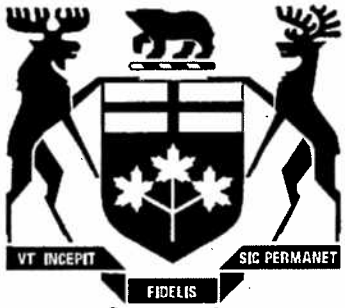
4.3 S&T REVENUE ISSUES

Union's Request

Union is requesting the Board's approval for both the level of its S&T revenues and its proposals for allocating deferred margins between the shareholder and the customer.

Background

As part of its EBRO 499 Decision, the Board determined that S&T revenues would be deferred and forecast revenue levels would be shared between the ratepayer and the shareholder. In EBRO 499, Union had forecast approximately $5.6 million in S&T revenues for 1999, 90% of which was included in rates, effectively splitting forecasted S&T revenues 90:10 in favour of the ratepayer, with any net revenues above this amount to be shared 75:25 in favour of the ratepayer.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **15**

DATE: **August 24, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Karen Taylor	**Member**

other revenues.

LPMA accepts the test year other revenue forecast as being appropriate, as seen in Exhibit C1, summary schedule 6. The forecast for 2013 is just over 23 million, a level similar to that posted in 2010 and 2011.

Other revenues were higher in the previous two years by about three million. The reduction, according to Union, is a decline in the number of direct purchase general service customers, as more customers have returned to system gas, and a reduction in delayed payment charges, which were high in 2008 and '09 due to the economic downturn.

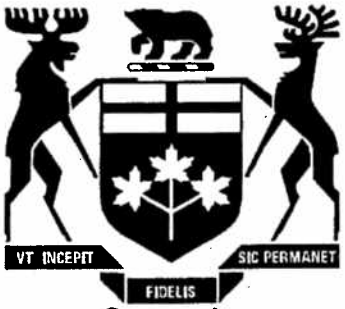
With respect to the cost and pricing -- and price of these services, Union indicated that it reviews the costs on an annual basis, and that since Board approval is required to change these changes -- sorry, to change these charges, it would file the necessary cost data to support any proposed changes. And the reference for that is Exhibit J.C.E-5-2-3, part a).

Union is not proposing any changes to the fees charged, and LPMA accepts that no change is needed.

Issue number 6:

> "Has Union levied proper charges and allocation to non-regulated business and affiliates, and provided proper credit for those charges and allocations in calculating revenue requirement to be recovered from regulated ratepayers?"

LPMA supports the recommendations of Mr. Rosenkranz,



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **2**

DATE: **July 12, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

regression analysis, when I am doing the analysis, I'm comparing -- I'm regressing one set of data against another set of data to get some coefficients.

And then that is telling me that I can't sort of say: Well, okay. I will add this to that number for this year and do something.

I'm being very strict on the analysis, following the regression analysis method.

And then I am basically saying: Well, okay. There's some higher consumption. Because bills have been low in the recent past, we may have some higher consumption.

It's like a secondary effect.

MS. HARE: Okay. Thank you.

Ms. Newbury, how are other revenues --

[Laughter]

MR. GARDINER: Sorry. I was jerked awake.

[Laughter]

MS. HARE: I was not -- that's the first time a witness did not answer one question.

How are other revenues tracking year to date against your budget?

[Laughter]

MR. SMITH: Sorry, we'll give an undertaking.

MS. NEWBURY: I have that information.

MR. SMITH: You better know this.

MS. NEWBURY: As of June year to date, we are tracking below budget by $1.6 million.

MS. HARE: Thank you. And I think Ms. Taylor has a

EX-FRANCHISE
REVENUE

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please update table from JT1.13 to reflect year-to-date June actual and forecasts, and break out FT RAM credits included in line 4 as a separate line item.

Please see the Attachment.

UNION GAS LIMITED
Summary Revenue from Storage and Transportation of Gas

e No.	Particulars ($000's)	Actual 2012 (June YTD) (a)	Forecast 2012 (June YTD) (b)	Difference (c)
	Transportation			
1	M12 Transportation	67,669	67,716	(47)
2	M12-X Transportation	2,208	2,215	(7)
3	C1 Long-term Transportation	3,643	3,391	252
4	C1 Short-term Transportation	6,017	6,467	(450)
5	Exchanges - Base	6,628	4,000	2,628
6	Exchanges - Net RAM	19,859	6,997	12,862
7	C1 Rebate Program	-	-	-
8	M13 Transportation	152	182	(30)
9	M16 Transportation	287	312	(25)
10	Other S&T Revenue	513	533	(20)
11	Total Transportation Revenue	106,976	91,813	15,163
	Storage			
12	Short-term Storage Services	5,834	3,125	2,709
13	Off-Peak Storage/Balancing/Loan Services	1,259	1,250	9
14	Total Storage Revenue	7,093	4,375	2,718
15	Total S&T Revenue	114,069	96,188	17,881

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit C1, Tab 3

For the period 2007-2013 please provide a schedule setting out forecast and actual (where available) S&T revenue, including all components.

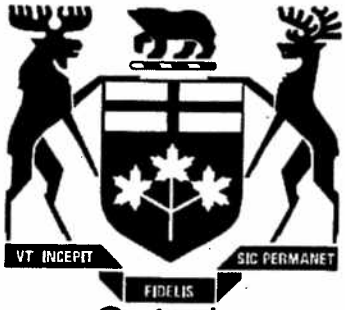
Response:

Please see Attachment 1.

UNION GAS LIMITED
Summary Revenue from Storage and Transportation of Gas
Years Ending December 31

Particulars ($000's)		Board Approved 2007 (a)	Actual 2007 (b)	2008 (c)	2009 (d)	2010 (e)	2011 (f)	Forecast 2012 (g)	2013 (h)
Transportation									
M12 Transportation	(1)	120,667	121,812	133,833	138,681	142,421	138,273	133,972	121,109
M12-X Transportation		-	-	-	-	-	1,477	5,942	13,499
C1 Long-term Transportation		2,900	2,093	5,790	6,642	6,288	7,570	6,554	5,246
C1 Short-term Transportation and Exchanges		4,000	9,030	23,266	29,781	32,554	44,228	32,186	20,186
C1 Rebate Program		(2,178)	(1,874)	-	-	-	-	-	-
M13 Transportation		864	649	529	462	386	323	366	367
M16 Transportation		553	240	474	609	610	642	581	581
Other S&T Revenue		895	975	1,193	1,150	1,072	1,092	1,067	1,067
Total Transportation Revenue		127,701	132,925	165,085	177,325	183,331	193,605	180,668	162,055
Storage									
Short-term Storage Services		13,887	16,211	15,777	17,745	14,886	9,036	6,590	8,988
Off-Peak Storage/Balancing/Loan Services	(2)	4,075	8,050	7,550	11,169	6,001	1,928	2,500	2,500
Total Storage Revenue		17,962	24,261	23,327	28,914	20,887	10,964	9,090	11,488
Total S&T Revenue		145,663	157,186	188,412	206,239	204,218	204,569	189,758	173,543

(1) Includes M12 Transportation overrun.
(2) Includes Enbridge LBA.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **15**

DATE: **August 24, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Karen Taylor	**Member**

MR. MILLAR: Yes, I do. VECC filed a letter which clarified the sentence that you had asked about. I had meant to bring it down so we could either read it onto the record or you would formally adopt it. I think you have seen the letter, but I forgot to bring it down. I apologize.

We can deal with that after lunch, if that would suit.

MS. HARE: If I had known that, I wouldn't have asked.

[Laughter]

MS. HARE: We will deal with it after lunch.

MR. MILLAR: It's embarrassing. Thank you.

MS. HARE: Mr. Aiken, can you proceed, then, please?

CONTINUED FINAL ARGUMENT BY MR. AIKEN:

MR. AIKEN: Thank you. I am continuing with issue 4 under operating revenue. The issue is: Is the 2013 S&T forecast appropriate?

Attachment 1 to Exhibit J.C-4-5-2 provides a listing of the accounts that fall under this heading. LPMA will be making submissions on each of the five main components, being the M2 long-term transportation, other long-term transportation, other storage and transportation services, short-term transportation and exchanges, and, finally, short-term storage and balancing services.

I will also be making or dealing with the FT RAM revenues as a separate issue.

So starting with the M12 long-term transportation revenues, which are lines 1 and 2 in attachment 1 to Exhibit J.C-4-5-2, it can be seen that these revenues had

an increasing -- or had been increasing steadily up to 2010.

The actual 2011 level and the forecast for 2012 are just over $140 million, with a reduction of 5.3 million forecast for the test year relative to 2012.

A review of Exhibit J6.3 shows that on a year to date June basis, the actual revenues are tracking very close to the forecast in 2012.

However, as noted, there is a decrease of more than $5 million between the bridge and test year forecasted revenues for these line items. Union provides a rationale for this decline on page 5 of Exhibit C1, tab 3.

LPMA accepts the variance explanation as being reasonable. These changes are all related to the turnback of M12 capacity that began in 2011, and is forecast to continue in 2012 and 2013.

Some of this capacity has been used to generate new sales, but the net impact is a reduction in forecasted revenues based on contracts currently in place. LPMA notes, on the response provided in Exhibit J8.10, Union indicates that based on changes to M12, M12X and C1 long-term firm contracts, since the forecast was completed there is an increase of $280,000. LPMA submits that this increase should be reflected in the forecast.

LPMA submits that the acceptance of the forecast does not mean that the capacity that is not currently contracted for has no value. Union has a lot of available capacity on the Dawn to Parkway system, at more than 200,000 gJs per

day. That, again, is Exhibit J8.10.

As the Board is aware, there is significant changes taking place in the source and movement of gas in eastern North America. This unused capacity may be contracted for in 2013. LPMA submits that any variance from the forecast, both up and down, should be captured in a variance account and shared 90 percent to ratepayers and 10 percent to the shareholder.

The second component of the S&T forecast is the other long-term transportation, which is comprised of lines 3, being C1 long-term transportation; line 6, being M13 transportation; and line 7, being M16 transportation in attachment 1 of Exhibit J.C-4-5-2.

LPMA accepts the M13 transportation forecast, and I will make separate submissions on the M16 transportation revenues later on.

With respect to the C1 long-term revenues, LPMA accepts that the decrease between 2012 and 2013 is related it the impact of the M12X conversion noted on page 8 of Exhibit C1, tab 3.

However, LPMA notes that the year to date June 2012 revenues for this line item shown on Exhibit J6.3 is more than 7 percent higher than the forecast. Based on this under-forecast in the bridge year, LPMA submits that the 2013 forecast should be increased by the same proportion, resulting in an increase of $400,000 in the test year forecast.

The third component of the S&T forecast is other S&T

revenues shown on line 8 of Exhibit J.C-4-5-2. These revenues have been stable over the period shown. The June year-to-date actuals are on forecast as shown in Exhibit J6.3. As a result, LPMA submits that the revenue forecast for the test year is appropriate.

The fourth component of the S&T forecast is the short-term transportation and exchanges. This is shown on line 4 of the attachment to Exhibit J.C-4-5-2. This line item includes FT RAM-related revenues, which will be discussed separately.

The attachment to Exhibit J6.1 shows the short-term transportation and exchange revenues excluding the FT RAM revenues and costs.

These revenues have been 21.4 million in 2010, 22.5 million in 2011, and the forecast for 2012 and 2013 are 17.986 million and 21.86 million, respectively.

Table 3 on page 10 of Exhibit C1, tab 3 shows the short-term transportation revenue component of these figures. Actuals of 12.8 million in 2010 and 12.5 million in 2011 are followed by a forecast of 11.1 million for both 2012 and 2013.

This reduction is explained by the insufficient take-away capacity on TCPL capacity downstream of Parkway. LPMA accepts these forecasts based on the evidence.

The base exchanges make up the difference in the figures we have just gone through, meaning that these exchanges total about 8.6 million in 2010, 9.7 million in 2011 and are forecast to be 6.9 million in 2012 and

9.1 million in 2013.

LPMA submits that the forecast for base exchange revenues are significantly understated. In particular, a review of line 5 at Exhibit J6.3 shows that the actual base exchange revenue for the year to date June is more than 2.6 million, or 66 percent, higher than the forecast for the same period.

In fact, the actual revenue to June of more than 6.6 million is less than $300,000 from the forecast for the entire 2012 bridge year.

Union states at page 13 of Exhibit C1, tab 3 that the exchange revenues of 9.1 million exceeds the actual revenues earned in years prior when the FT RAM program is removed. This is not likely to be the case when 2012 is completed.

LPMA submits that the Board should increase the 2013 forecast of 9.1 million to reflect the under-forecast that is taking place in 2012. Union forecasts $4 million on, a year-to-date basis, for June out of the total of 6.9 million for the year, or about 58 percent.

Reflecting the same ratio, but applying it to the 6.6 million of actual revenues in the first six months of 2012, would result in an annual figure of about 11.4 million.

Union has provided no evidence that base exchange revenues will decline in 2013 compared to this year. In fact, their own forecast is for an increase. LPMA submits that the Board should increase the base exchange forecast

for the test year from 9.1 million to 11.4 million, the same level as projected for 2012.

The fifth component of the S&T revenue forecast is short-term storage and balancing services and is made up of lines 10 and 11 on the attachment to Exhibit J.C-4-5-2.

As can be seen in Exhibit J6.3, the June year-to-date revenues for off-peak storage balancing and loan services is very close to the forecast, which is one-half of the annual forecast.

Since 2012 is on track to hit the forecast and the forecast for 2013 is the same level, LPMA submits that the forecast of 2.5 million for this line item is acceptable.

However, as can be seen in Exhibit J6.3, the year-to-date June revenues for short-term storage services is more than 2.7 million, or 87 percent, ahead of the forecast for the bridge year. Moreover, the year-to-date June actual revenue of 5.8 million is just under the forecast for the entire year of 6.6 million.

Using the same methodology as for the base exchanges, the projected -- the projected 2012 forecast, based on the proportion of the forecast for the first half of the year, applied to the actual revenue for that period is 12.3 million.

LPMA submits that the 2013 forecast should be increased to the projected 2012 level of 12.3 million from the current forecast of 8.988 million.

This reflects a correction for the continued under-forecasting of Union. LPMA notes that the forecast of

12.3 million is still below the levels recorded in 2007 through 2010, despite more excess utility space projected to be available in 2013 than in those years.

This increase in the amount of excess storage helps to offset the decline in storage prices projected.

Finally, with respect to the five components of the S&T forecast, LPMA submits that there should be no sharing of the test year revenue forecast between ratepayers and Union for all of the S&T accounts discussed, with the exception of the 90 percent-10 percent sharing that the Board has approved for the short-term storage and balancing services account.

In other words, LPMA submits that 100 percent of the forecast revenues should be reflected in rates. Union should not receive an automatic percentage of these forecasted revenues. Any automatic slice of the pie may reduce Union's hunger to exceed the revenue forecast built into rates.

Because of the uncertainty and poor forecasting history of Union associated with many of the accounts, LPMA further submits that the Board should establish variance accounts for all of the S&T accounts, other than the short-term storage and balancing services where one already exists.

LPMA proposes that the variance accounts be symmetrical with the gains or losses shared 90 percent to ratepayers and 10 percent to the shareholder. This sharing is the same as the Board has approved for the short-term

storage and balancing services.

The 10 percent incentive that Union receives has certainly worked well for short-term storage and balancing services, as Union continues to exceed the forecast on a regular basis.

Obviously, the 10 percent incentive is more than enough encouragement for Union. There is no reason or evidence to suggest that Union would not be as stimulated to earn a 10 percent share on these other S&T accounts.

With respect to the FT RAM issue, LPMA notes that in their argument in-chief Union proposes to include 11.6 million related to the FT program in 2013 rates, and establish a variance account to capture any additional revenue or any revenue shortfall.

Alternatively, Union suggested that a deferral account could be set up to track revenues related to the FT RAM program. Under both scenarios, Union proposes that revenues be shared 75/25 in favour of ratepayers.

LPMA submits the first issue that the Board needs to decide is whether the FT RAM credit program is an S&T activity or a cost of gas activity.

LPMA submits it is the latter. FT RAM credits that Union is currently accounting for through S&T revenues are earned when Union acquires the gas supply it has purchased. This gas supply is delivered through alternative routes that cost less than the FT RAM credit that Union earns.

In short, Union is proposing -- or, sorry, Union is using upstream pipeline capacity that is being paid for in

its entirety by system gas customers to generate S&T revenues. It does this by selling this capacity in the market and providing gas deliveries at a lower cost for the gas it has purchased and needs delivered.

Union has stated that ratepayers are being held whole because they are getting the service that they are paying for, in that the gas is being delivered to Union as needed.

LPMA submits, however, that system gas customers are paying for one service and receiving a lower-cost service. The difference in cost goes to Union, with some of it shared with ratepayers. Of course the ratepayers that share in the profits are not the same group of customers that pay the costs.

In particular, Union proposes to uses FT RAM credits to lower distribution rates. Lower distribution rates benefit both system gas customers and direct purchase customers. In other words, system gas customers would be footing the bill for lower distribution rates for direct purchase customers and higher Union Gas shareholder profits.

LPMA submits the Board should not tolerate either one of those subsidies.

Union does not make a profit on the cost of gas. It is a flow-through cost to system gas customers. LPMA submits that the cost of gas includes the cost of getting the gas to the Union system. The actual cost of gas, including the actual cost of getting it to Union, is what system customers should be paying, no more, no less. It is

a pass-through of the actual costs.

LPMA notes that, in their argument at page 17, Board Staff acknowledges that Union needs some incentive to optimize, and proposes that 90 percent of the revenues generated through optimization activities related to the transportation capacity that in-franchise customers have paid for should go to offset gas costs, with the remaining 10 percent flowing to utility earnings.

LPMA strongly disagrees. Union should not receive any incentive to get the best cost of gas it supplies its system gas customers.

They would essentially be getting a mark-up on the actual cost of upstream transportation. The next thing you will know is that they will be looking for a mark-up on the gas commodity cost.

If the Board determines that any revenues generated by this optimization activity, with or without a mark-up going to Union, should accrue to gas -- system gas customers, then this is the end of the story. There is no need to look at the allocation of the revenues to ratepayers, since all the ratepayer benefit flows to the system gas customers. There are no issues as to what the proper amount forecast to be received in 2013 is, as all of the revenue would flow through the PGVA on a monthly basis.

However, if the Board determines that the FT RAM revenues should not flow to the system gas customers, but should flow through S&T revenues, then LPMA submits that the amount included in the 2013 forecast and how it is

In 2013, short-term peak storage revenue increases from 2012 by $2.4 million. The main reason for this increase is due to a forecast recovery in storage prices, which increases revenue by $1.7 million. The forecast for 2013 assumes new contracts are sold at $0.85 Cdn/GJ, compared to $0.55 Cdn/GJ in 2012. In addition, the storage space available in 2013 is higher than in 2012, resulting in an increase in revenue of $0.7 million.

The short-term space available for sale and average prices from 2010 actual to the 2013 forecast are summarized in Table 6.

Table 6

Short-term Storage Space and Average Prices

	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Short-term Peak Storage Space at October 31	10.2 PJ	10.1 PJ	12.6 PJ	13.0 PJ
Average Price (new contracts) - $Cdn/GJ	$1.39	$0.66	$0.55	$0.85

The impact of reduced volatility of gas prices at Dawn can be seen in the reduction in off-peak, balancing and loan revenue between 2010 and 2011. Stable gas prices and reduced volatility significantly reduces the value of these off-peak services because there are limited month-to-

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit C1, Tab 3, Original & Updated

a) Please provide further details on the capacity forecast to be turned back in 2013 at lines 17-19 of page 6. In particular, please provide the details of the amounts to be turned back and the current status of this forecast turn back.

b) Please explain the drop from $3.5 million to $1.8 million in the St. Clair/Bluewater system short-term transportation revenue shown in Table 3 of the updated evidence.

c) Please explain the increase in exchange revenue shown in Table 4 for 2011 of $31.7 million versus the original forecast of $25.3 million. How many months of actual data were included in the original forecast for 2011?

d) Does Union have any more recent forecasts for the average price for short-term storage space in 2012 and 2013? If yes, please provide these forecasts and the information/assumptions used to generate these forecasts.

Response:

a) 2013 turnback is discussed at Exhibit C1, Tab 3, Original and Updated, page 6.

Dawn-Kirkwall Turnback:

The 2013 forecast includes turnback of 286,198 GJ/d for Dawn-Kirkwall. Since the forecast was completed, Union received notice of our customers' election to turn back 186,664 GJ/d, effective November 1, 2013. The remaining 99,534 GJ/d of Dawn-Kirkwall contracts have been extended to October 31, 2014.

Dawn-Parkway Turnback:

The forecast also includes turnback of 67,000 GJ/d for Dawn-Parkway. Since the forecast was completed, Union received notice of our customers' election to turn back 123,212 GJ/d. Of this, 121,212 GJ/d is effective November 1, 2013 and the balance is effective April 1, 2013.

b) The 2011 Short-Term Transportation Actual Revenue of $3.5 million for St.Clair/Bluewater system reflects the return of the St. Clair Line as a utility asset, per EB-2012-0048. In 2011,

the St. Clair Line contributes $2.0 million to the Short-Term Transportation revenues.

The forecast of 2012 and 2013 Short-Term Transportation revenue assumed that the St. Clair Line would not be returned as a utility asset, and therefore does not include any St. Clair Line revenue.

c) The 2011 revenue outlook of $25.3 million included actual data to June and forecasted activity for the remainder of 2011. During the last six months of 2011, Union transacted a higher quantity of exchanges than forecast, and realized an increase in forecasted values.

d) Union has not updated the forecast for Short-Term Storage for 2013. However, the average short-term peak storage value of contracts executed in 2012 is $0.84 CDN/GJ.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

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DATE: **August 23, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Karen Taylor	**Member**

We acknowledge that what occurred during the IRM period is the subject of another proceeding, and we do not intend to make any submissions on it.

I raise this point simply to say that the amounts earned in that period have inevitably sharpened the focus on establishing what I submit are the appropriate governing principles to consider that issue for 2013.

And those principles, in my respectful submission, are the following. Revenues generated from the use of utility assets paid for by ratepayers should flow to the benefit of ratepayers. And I think it bears repeating that that foundational principle of regulation is an important one and needs to be borne in mind.

A corollary of that is that Union should be obliged to optimize the use of these assets for the benefit of its ratepayers.

The second principle is that gas supply planning and related transportation planning should be based on, to the extent possible, the actual needs of the in-franchise customers.

Gas supply planning and related transportation planning should not be used to generate additional profits for Union's shareholder.

We agree with Board Staff's analysis, that the evidence shows that Union is planning for more capacity than is required. Ratepayers, as a result, bear an additional cost for that. Union uses the excess capacity to generate revenue under its storage and transportation

operations.

In our respectful submission -- I will return to this in the context of the case I handed up to you -- Union is preferring the interests of its shareholder over those of its ratepayers. And in my respectful submission, the Board is required to redress that balance.

Rebalancing, the third principle is that rebalancing the interests of ratepayers and shareholders requires for 2013 at least three things.

It requires, first, that Union move to more precisely forecast its gas supply needs, and we adopt the analysis that my friend Mr. Millar has just provided you with on that issue.

It also requires that ensuring the benefits of any additional revenues are appropriately allocated to ratepayers, and ensuring that there are deferral accounts in place to protect ratepayers.

Now, with respect to the FT RAM issue, we support the view, we take the view that amounts generated from FT RAM credits should be classified as gas transportation cost reductions and flowed back to ratepayers through the gas supply deferral accounts.

Revenues are generated by optimizing assets used to meet Union's gas supply plan each year; these assets are paid for by utility ratepayers and we see no reason why Union's shareholder should profit from these transactions.

Union's proposal for the FT RAM revenues should, in our respectful submission, be rejected.

Tolls Task Force, dated January 7th, 2009, entitled: "FT RAM, STS RAM, STS LRAM permanent tariff feature," states that:

> "RAM is a tool to mitigate unabsorbed demand charges and provides greater flexibility in order to give shippers increased confidence in contracting for long-haul FT service on the TransCanada main line."

And that:

> "The motivation behind RAM is to promote the renewal of incremental contracting for long-haul FT service."

Now, you will see as you get into this subject that there is somewhat different characterizations from time to time. The basic idea is put differently, but the basic idea seems to remain pretty constant.

Now, that resolution of the Tolls Task Force was unanimously approved on January 7th, 2009, and was sent to the National Energy Board under cover of a letter from TransCanada on January 16th, 2009.

The NEB approved the amendments effective November 1st, 2009, shortly thereafter.

Now, the NEB had previously, as you know, approved a pilot project version of FT RAM and also a gradual expansion to its applicability, in a series of orders and letters over the period 2004 to 2007. So there had been a whole series of these, which are detailed in the interrogatory response I talked about.

of the history, just in the interests of time. I would note one or two things in passing.

The RAM proposal, and a lot of the enhancements to it, were proposed by Shell Energy North America Canada, which is the largest natural gas marketer in North America.

That is the first thing.

The next thing I would say -- I am at the top of page 14. The point I would make is FT RAM has been in place continuously since November 2004. This is not some sort of one-year-long demonstration project, or...

This is a fundamental attribute of the TransCanada toll, of the TransCanada tariff, and it was put in place to try and do something about what they thought would be upcoming increases in the tolls.

Now, my next -- that is the history. Now, then I want to now sort of deal with how RAM has been applied.

Now, Union's evidence is that the value of assignments of capacity was largely due to the FT RAM credits that were transferred to the marketer, along with the capacity, and that the FT RAM credits enhanced the value of the capacity.

The evidence filed by TransCanada in the ongoing proceeding before the NEB, and the excerpt from which I have given you, makes it clear that over 90 percent of the FT RAM credits earned have not been exercised by the shippers that hold mainly long-term firm transportation on TransCanada and who earn the credits.

Rather, they have been exercised by third parties, mainly gas marketers to whom the LDC shippers, including

Union, have assigned the FT capacity, notwithstanding the fact that they acquired it to transport gas to specific areas of their franchise.

Union has referred to this activity as assigning capacity, quote, "when the line is full", as distinguished from assigning capacity which is currently not being utilized, which was the original intent of the program.

The same evidence - this is at page 25 of 39, figure 8.4 which I gave you - is that the exercise of the credits has resulted in a very large revenue reduction to the revenue that could otherwise have been payable to TransCanada as IT revenue due to the exercise of the FT RAM credits, which revenue would have had the effect of reducing FT tolls.

The amount of potential -- and I stress "potential", in fairness, but the amount of potential IT revenue offset by RAM credits has increased from about 50 million in 2004 to $400 million in the first half of 2011 alone. That is a total of 2 billion over the period 2004 to 2011, and considerably more since then.

The gaming of the system by marketers and LDCs has produced the opposite result that TransCanada intended. It has resulted in a cannibalization of potential FT revenue by essentially free IT service.

For example, over 90 percent of the gross potential IT service revenue in 2010, 90 percent, was offset by RAM credits. As noted above, the NEB amended TransCanada's toll structure to build the FT RAM reduction directly into

the calculation of the toll and has gradually, over the period 2004 to 2009, increased the number of transportation services that are eligible.

So I am going to skip through now to the -- let me just cite one point on page 16. TransCanada, again, states in the evidence that I left with you that its FT tolls would decrease if the FT RAM is eliminated.

It alleges - and I stress "it alleges" - that the large amounts of virtually free IT service funded by RAM have cannibalized its FT service. Assuming only -- and this is the example it uses. Assuming only a 50 million increase in discretionary IT revenue, TCPL states that the Empress-Dawn toll would decline by 6 cents per gJ.

We consider that -- we consider that to be a very conservative example. If it were 150 million rather than 50 million, it would be an 18 cent per gJ reduction.

As noted above, Union's shareholder has earned substantial revenue from the FT RAM feature of the TCPL tolls, but it has earned those revenues not by purchasing IT service to benefit its ratepayers, but by entering into these various types of transactions.

Now, I am not going to -- I am going to skip ahead and talk about -- go to page 17. So what's happened, in our view, is Union's S&T department has essentially commandeered these credits as a method of, quote, "supercharging" the value of the TCPL capacity Union held, and entered into a variety of transactions with marketers in which Union assigned the TCPL capacity and associated FT

submission.

[Laughter]

MS. HARE: No, I realize that, but also Mr. Buonaguro asked whether or not we need him tomorrow. So if in fact somebody else can answer that same question, because you both made the same point -- and I take it Mr. Aiken is going to say the same thing?

MR. QUINN: I want to get clarity in your question, because -- maybe it just the way I heard it. I was confused when you said whether it is ex-franchise or in-franchise.

MS. HARE: Don't some of those FT RAM credits -- aren't they the result of ex-franchise transactions, as well?

MR. QUINN: From the definitions I have come to understand from Union, those transactions that would be to a point off of their system and a point on their system, ex-franchise in nature, are generally done through base exchanges as opposed to FT RAM.

FT RAM predominantly -- well, the lion's share of FT RAM has been generated by the gas supply contracts to gas here in Ontario, and therefore -- and Mr. Smith, I am sure, could respond to this at his opportunity -- but in terms of clarity, the vast, vast majority have been through the gas supply program.

And therefore if the credits are created by the program, then the credits should stay in the program and be used for the benefit of the gas supply program, and that is

the way the costs and revenues should be allocated.

MS. HARE: Okay. Thank you.

MS. TAYLOR: Before we move on with that point, and I did ask this question earlier, part of the issue, I think, that is before us is an issue with the specification of what is in and what is out, and the treatment.

MR. QUINN: Yes.

MS. TAYLOR: What is gas supply versus what is optimization, what is in-franchise versus ex-franchise.

The distinction appears to me, for purposes of 2013, to have been lost, in that all assets, whether they're in-franchise or ex-franchise, have been commingled for the purposes of optimization.

So if we're going forward with this approach, my concern would be mis-specification, again, potentially, of what is in gas supply versus what is in optimization, without having to undertake an audit exercise every 12 months to verify that something is in the right spot.

I don't think your answer has helped me, because we are not just strictly speaking about FT RAM, because that program could, in fact, disappear midway 2013, and then, as Mr. Brett this morning said, could be replaced by the son of FT RAM, in which case we've mis-specified it again and it would not be picked up in the way that the Board would potentially intend.

MR. QUINN: The way I would distinguish the two is if the assets were purchased for gas supply need, then those should reside with the gas supply, be classified -- cost

and benefits stay and remain classified with the gas supply program.

I will give you an example, which may be helpful to my friends, but it is a realistic example.

The STS service is a service that Union needs to have in place to be able to run its fully integrated operations.

That STS service allows Union to get gas out of Dawn and deliver it to -- it could be North Bay, it could be Cornwall. That service in and of itself is needed, but it is not needed all the time. And they can't use it all the time because the weather doesn't allow them to use it.

To the extent that that service has been contracted and rightsized to the peak day needs of, an example, in Cornwall, and they don't need that STS service that day to Cornwall, they actually can generate STS RAM credits.

And to the extent that they have STS RAM credits, those were based upon the delivery -- peak day delivery needs of the customers, and therefore, with the rightsizing of capacity, Union cannot use those assets on that day because of the weather, therefore for Union to optimize those assets as part of what it has done historically, that to me would be a prudent application of its discretion.

And yes, those benefits should flow into what we would encourage as that future deferral account to be re-established, and it would capture the revenues for those types of situations.

MS. TAYLOR: Sorry, and that revenue, that deferral account would be cleared when?

MR. QUINN: That deferral account would take the shape somewhat of the 179-69 that was there previously, and then would be deferred -- would be disposed of with other deferral accounts in the subsequent year, and yes, with an allocation to ratepayers and shareholders.

MS. TAYLOR: And how is the Board going to distinguish -- so we have a principle-based approach coming out of this decision. How are we going to specify with -- given everything people have said in front of us, the principle-based approach may not have worked necessarily in the past, according to some; others, yes.

How is the Board going to distinguish that separation of red and blue molecules when it is appropriate to monetize for optimization versus when it should be a pass-through?

MR. QUINN: That is a very good question. Off the top of my head, I think a pragmatic and I think practical solution would be that long-haul contracts and FT RAM credits associated with long-haul contracts would be gas costs, because it is landing the gas here in Ontario.

Once it is inside of Ontario and it is integrated with Union's storage and the services it provides amongst its assets inside of Ontario, the use of that gas, including, as I referenced, the STS service, could be said to be the effective utilization of contracts.

So you would have FT firm transport long-haul contracts as being gas supply, internal to Union's franchise. If they do optimizations of STS contracts or

they find a way to get gas from point A to point B and make that cost differential generate a margin, then that would be more consistent with our view of what the historic 179-69 deferral account would have captured.

MS. TAYLOR: Before we leave this point -- and I don't want to keep pushing it, but you yourself, in this submission, have recommended that we make use of other services rather than long-term firm.

So there may be, if you're talking about a TransCanada system, that they would continue to use but not necessarily long-term firm, there would be the potential for embedded options in other TransCanada services that would not meet that definition.

So then when it comes back to specifying the nature of these deferral accounts that would settle up or not settle up annually or through QRAM, we still have a problem, potentially, sorting this all out.

MR. QUINN: One of the fundamental premises that I used that -- because I was doing the speed read, may have been lost. But the fundamental premises is rightsizing. So if gas is needed in Thunder Bay in the winter, contract for the gas in Thunder Bay. To the extent that they have an STS service, summer needs could be diverted to Dawn and not flowed to Thunder Bay, and they could use the STS service or they could use IT.

That is totally gas supply. So getting the gas from the supply point -- in this case, the Western Canadian Sedimentary Basin -- to Ontario, that is landed gas cost.

In fact, Union has a deferral account to manage differences in landed gas cost, and to the extent that there is a differential created, that is the easiest way of managing benefits and costs that flow on the landed cost of gas.

But to the extent the gas gets to Ontario and is inside of Union's franchise area, to the extent that they're able to then manage the costs better or find a market opportunity, then that would be defined as optimization, and would flow to a deferral account like 179-69.

MS. TAYLOR: Thank you.

MS. HARE: I have just one other question. I want to make sure I understand what you're saying about the system integrity space.

You gave a number of $3 million if they did, in fact, follow your recommendation.

Is that a maximum number? Does that assume that nothing -- that three and a half is empty? And that then they just use the six?

MR. QUINN: What we're saying is the three and a half gets used twice. It gets used in the fall. And if part of it is filled, because they actually had to use it --

MS. HARE: Right.

MR. QUINN: -- then it is already ready for part of the winter.

So the winter, they're holding an additional six. If you move the three and a half in, that means there is three



Ontario

ONTARIO ENERGY BOARD

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BEFORE:

Marika Hare	Presiding Member
Paul Sommerville	Member
Karen Taylor	Member

Now, we will have to see what people say about that, but it's apparent that a substantial part of this case was dominated by FT RAM-related optimization activities undertaken by Union through the IRM period, as I talked about at some extent in my own overview to this case.

Let me make two broad responses at this time. The first is no one disputes that TCPL, in its Mainline application now before the NEB, is actively advocating the discontinuance of the FT RAM program. That is not in dispute.

Whether that happens on January 1, 2013 or up to May 2013, we don't know. But we do know that there is a great deal of uncertainty around that, and TCPL's proposal, at least, is to discontinue the FT RAM program.

And this drives inevitably, in my submission, to a reduction, a considerable reduction, in the forecast because, as the evidence was from both Ms. Cameron and Mr. Isherwood, the exchange activity that took place during the period of IRM was driven in large part - not entirely, but driven in large part - by FT RAM.

And you will have seen in the evidence a discussion of base exchanges and FT RAM exchanges, and this was done for clarity, but it is interesting how sometimes things can get more confusing.

The evidence is, from Mr. Isherwood -- and I will take to you it, but the evidence is that they're not substantively different, but they were disaggregated to show how a substantial part of Union's past activity is at

risk in 2013 because of TCPL's proposal.

And it is important to bear in mind, as well, members of the Board, that at the time this application was put together it was anticipated that FT RAM would be discontinued in 2012. And you see, therefore, a forecast of zero for exchanges that have any connection to FT RAM.

Now, the second broad response, as I said at the outset, is this case is not about revising the parameters of incentive regulation agreed to by the parties in 2007, and it would be inappropriate, in my submission, for the Board to attempt to do that and for parties to suggest it.

Now, what is an exchange? At tab 13 is Exhibit K6.4. I just wanted to take you to one portion of K6.4, which is Exhibit J20.10, which was filed by Union in the 2003-0063 case.

That was an interrogatory that asked to explain the nature and mechanics of an exchange, and you will see the description under (a), that:

> "An exchange is a contractual agreement between party A and party B involving the exchange of physical gas from one location to another. An exchange can only happen between a point on Union's system and a point..."

Sorry:

> "...a point on Union's system and a point off of Union's system. The exchange must also happen on the same day at the same time."

And this was the subject of some cross-examination,

and I have included at tab 14 of the compendium an excerpt from volume 6 of the hearing July 19.

If you turn to page 77 of the transcript, this is evidence of Mr. Isherwood talking about exchanges, and he adopts the definition that Union used in 2003-0063. And you will see that on page 17 -- sorry, page 77. What you will see at the bottom of page 77, line 26, he says:

> "That is a pretty consistent definition going back pretty far into our history, actually. It is no different today than it was back in 2003. We would talk today, and we will be talking today, about exchanges, and some start in our system and some end in our system, but it is always with another party."

Then he talks about deferral account treatment relating to exchanges, and what he observes there is that at least as far as he was able to determine, there has been a deferral account relating to upstream optimization and exchange activity going back to 1993, and perhaps even earlier.

So this has been a feature of the regulatory arrangement, with the exception of the period of IRM, going back at least to 2003.

Now, what you will see also described at tab 13 in Exhibit K6.4 at page 3 of tab 13 - again, this is the Exhibit EB-2003-0063, page 6 of 6, but what you will see there from that excerpt, and what you heard in evidence in this case, is that exchanges and optimization generally are

market-based opportunities which are not guaranteed to be available on a future planned basis.

In other words, while Union may forecast a certain level of exchange activity and has, indeed, forecast a certain level of exchange activity which goes into its forecast of regulated revenues, what those particular exchanges will be in 2013 is unknown. Who the counterparties will be, on what portion of Union's system or off Union's system, and when those exchanges will take place are all unknown. They are consequential and not planned, even though Union does forecast a certain level of activity.

Now, the optimization activities undertaken by Union during IRM - and this goes back to my two broad responses I indicated before - and forecast for 2013 are the very same optimization activities Union has always undertaken, and that's no different whether you include FT RAM or not.

And I have included at the compendium, tab 15, an excerpt from volume 7 of the transcript. There are other excerpts I may need to pull up at a later date, but you will see at tab 15, at page -- all the way over at page 137 and continuing over all the way through 139 and 140, cross-examination of Mr. Isherwood, and later, Ms. Elliott.

But as Mr. Isherwood testified, the activities, exchange activities Union has engaged in since 2003 as it relates to FT RAM are substantially the same as those that it undertook before and those that it will undertake in 2013.

The only difference is in FT RAM, which is a difference, perhaps, of degree, but not a difference in kind.

And you will have the evidence over at page 139, but when account 179-69 was effective, it would have captured the exchange activity that took place during IRM, and that exchange activity would have been shared 75/25. As it was, that account was not in existence; I suspect some will argue for its reinstitution.

You also have -- and I will just give you the cite because I did not include it -- you also can see similar evidence in this volume, at least, at pages 183 to 185, and no doubt there are others.

I have included also on this point at Exhibit K7.4, and you can see that at the very back of tab 13 -- and this is actually -- K7.4 is an interrogatory that came out of the EB-2009-0101 case. And I won't belabour this point, but it is worth observing EB-2009-0101 was Union's 2008 earnings-sharing proceeding. It was the first earnings-sharing proceeding after IRM came into effect, and Union's S&T revenues at that point were substantially, very substantially above Board-approved levels, which led to overearnings.

And Board Staff asked, in part, about that. And I won't read the interrogatory to you in its entirety, but just focussing on the last paragraph, what Union advised Board Staff and all parties at that time was that:

"Union had focussed on further optimizing its

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.

Now, one final anticipatory comment on this.

The argument may also be that ratepayers are to pay the actual cost of transportation incurred by the utility; i.e., that they should pay transportation costs net of optimization activity.

And in my submission, to the extent that suggestion is made, the suggestion is flatly incorrect. And you really only need to think about it based on the history, but were it otherwise, there would never have been any upstream optimization activity and there certainly would not have been upstream optimization exchange revenue deferral accounts.

Indeed, there would have been no need for them. You would simply have had the purchase gas variance account, and the other gas supply-related or transport-related deferral accounts, which have been in existence and have existed in concert with the transportation exchange deferral account.

The FT RAM or exchange revenue would have been captured in the PGVA or, as I said, in the various other cost gas deferral accounts. And that has never been the case, going back to the early 1990s.

And that is different -- and this is an important distinction -- it is different than what is actually a flow-through.

And what it is actually a flow-through in the PGVA and the gas commodity and transportation deferral accounts is gas commodity changes and transportation toll changes, and

those have been rolled through to ratepayers through the currency of IRM, and it is important not to mix apples and oranges and to keep the two concepts separate.

Put simply, the 179-69 account captured optimization activity and exchange activity. It was closed.

The PGVA and northern tolls transportation deferral account and the other gas cost deferral accounts capture commodity changes and toll changes, and those have been in effect, again, back from the '90s all the way through the currency of IRM.

Now, let's just return to what should actually be at issue.

And what we have in this case is a forecast by Union of exchange revenue for 2013 of $9.1 million, attributable entirely to non-FT RAM-related exchanges. And you can see that figure in a few places, but where you will see it easily is behind tab 1 of my compendium, which is an excerpt of Exhibit C1, tab 3, at page 12.

You can also see it at J.C-4-7-9, attachment 2, which is perhaps useful to turn up. That is at tab 8 of the compendium.

You will see in J.C-4-7-9, attachment 2 the breakout of the exchange revenue, so to disaggregate the RAM-related exchanges.

And in line 1, you will see Union's forecast on the far right-hand side of $9.1 million, which compares to actual experience from 2007, starting at a low of three million and bouncing up as high as 9.7, but in my

submission, 9.1 is right in the ballpark.

And you don't need to turn this up, but there was discussion of the $9.1 million forecast at tab 15 of the compendium, which is an excerpt of the transcript day 7 at pages 18 to 22, Mr. Isherwood testifying to past experience and what he foresees as being achievable in 2013.

Now, there is an open question, I suppose, as to what to do with FT RAM and Union's forecast for 2013. It was asked what its forecast would be for 2013 if the RAM program were to be continued and its forecast was $11.6 million.

And that forecast can also be seen at Exhibit J.C-4-7-9, which is at tab 8 of the compendium we were just at, and you can see that at page 2 of 3 in answer to question c). And what Union says -- and this is worth repeating, that what Union says about its forecast of $11.6 million, it:

> "...assumes the structure and parameters of TCPL's RAM program does not change materially, and is based on actual 2011 activity. The 2013 revenue decreases compared to the 2012 forecast are due to expected TCPL toll reductions, price anomaly corrections, and turnback of some of TCPL's (sic) capacity on TCPL."

I mean, there are a lot of moving parts there, not least of which, of course, is what the NEB does with the FT RAM program. I don't know. I mean, we're only looking at book ends, continue/don't continue, but there could be something in the middle. As Mr. Isherwood testified, and

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Pages 2 and 3

In what years did TCPL offer an FT RAM credit? Were Union's FT RAM revenue subject to the Earnings Sharing Agreement in each year over the recent IRM period? Please discuss, showing amounts of FT RAM credits in each year. If not, why not? Please discuss fully. Were the FT RAM credits Z-factors for each IRM year during which Union participated in them? Please discuss.

Response:

Please see Attachment 1 for a timeline of what years TCPL offered RAM credits. Please see the response at Exhibit J.C-4-7-1 c).

Please see the response at Exhibit J.C-4-7-9 d) for the amount of RAM credits generated by year. RAM credits do not meet the Z-factor criteria in Union's current IRM.

TransCanada

TransCanada PipeLines Limited
450 - 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1

Tel: (403) 920-2046
Fax: (403) 920-2347
Email: murray_sondergard@transcanada.com

January 16, 2009

National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

Filed Electronically

Attention: Ms. Claudine Dutil-Berry, Secretary

Dear Ms. Dutil-Berry:

Re: TransCanada PipeLines Limited ("TransCanada")
Amendments to TransCanada's Canadian Mainline Transportation Tariff

TransCanada hereby files an application with the National Energy Board ("Board") pursuant to Section 60(1)(b) of the *National Energy Board Act* for an order or orders approving certain amendments to TransCanada's Mainline Transportation Tariff's Interruptible Transportation ("IT") Toll Schedule. The proposed amendments were presented to the Tolls Task Force ("TTF") and were unopposed by the TTF in Resolution 04.2009, FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature, voted on January 7, 2009.

TTF Resolution 04.2009 describes amendments to the IT Toll Schedule to add the current Risk Alleviation Mechanism ("RAM") for Firm Transportation ("FT") Service, Storage Transportation Service ("STS") and Storage Transportation Linked Service ("STS-L") as permanent features of the Mainline transportation services.

The FT-RAM pilot was originally approved by the Board in a letter dated July 15, 2004 as a feature of FT service for a one year period commencing November 1, 2004 per TTF Resolution 02.2004. The FT-RAM pilot was subsequently extended for a period of one year by the Board in a letter dated September 6, 2005 as per TTF Resolution 20.2005 and again by the Board in a letter dated April 21, 2006 as per TTF Resolution 05.2006. Modifications to apply the FT-RAM pilot to short-haul contracts were made effective April 1, 2006 by Board Order TG-1-2006, and in accordance with the Board's decision in RHW-2-2005.. In a letter dated March 2, 2007, the Board approved an additional two-year extension of the FT-RAM pilot commencing November 1, 2007 as per TTF Resolution 03.2007 and extended the FT-RAM pilot to include Storage Transportation Service (STS-RAM) and Storage Transportation Service Linked (STSL-RAM) for a two-year term commencing November 1, 2007 as per TTF Resolution 02.2007.

During the various RAM pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users TransCanada notes that use of the RAM mechanism does not limit the service entitlements of current FT service.

In support of its application, TransCanada attaches for the Board's information blacklined and clean copies of the IT Toll Schedule and a copy of TTF Resolution 04.2009. TransCanada proposes that these changes become effective November 1, 2009.

Should the Board require additional information, please contact Stella Morin at (403) 920-6844 or stella_morin@transcanada.com.

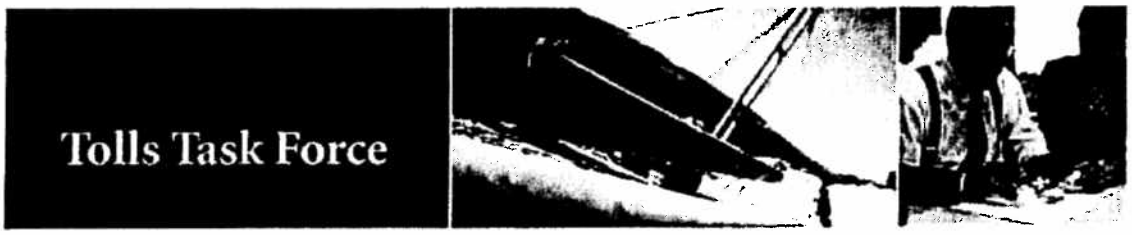
Yours truly,

Original Signed by

Murray Sondergard
Director, Regulatory Services

Attachments

cc: Tolls Task Force (on-line notification)
Mainline Customers (on-line notification)



2008 TOLLS TASK FORCE ISSUE	
Date Accepted As Issue: September 4, 2008	**Resolution:** 04.2009
Date Issue Originated: September 4, 2008	**Sheet Number:** 1 of 3
Issue Originated By:	Shell Energy North America (Canada) Inc.
Individual to Contact: Tomasz Lange	**Telephone Number** (403) 216-3580

ISSUE: FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature

RESOLUTION:

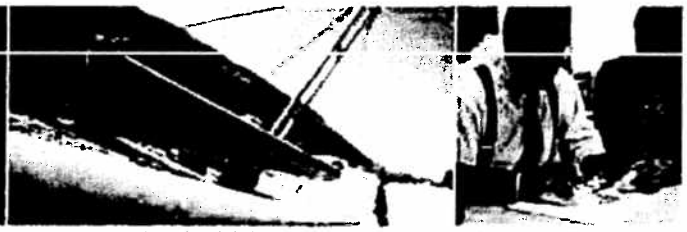
The TTF agrees to the addition of the current FT - Risk Alleviation Mechanism (FT-RAM), STS-RAM and STSL-RAM pilots, to the TransCanada tariff as permanent features of the transport services effective November 1, 2009 as per the attached black lined IT Toll Schedule.

BACKGROUND:

On May 6, 2004 the TTF approved, as an unopposed resolution, the initial FT-RAM pilot (Resolution 02.2004) for a one-year period beginning November 1, 2004. The initial pilot program was adopted as a flexibility feature of long-haul FT contracts only. Long-haul FT contracts are those contracts, which have a primary receipt point originating from Empress or Saskatchewan.

On August 3, 2005 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional one-year term commencing November 1, 2005 and ending October 31, 2006 (Resolution 20.2005).

On February 24, 2006 the NEB approved an application by Coral Energy Canada (now Shell Energy North America (Canada) Inc.) for modifications to the FT-RAM pilot effective April 1, 2006 and ending October 31, 2006, to extend FT-RAM credits to short-haul contracts, which when combined with a long-haul contract create a continuous long-haul contract (Board Order TG-1-2006 in RHW-2-2005 proceeding).



The short-haul and long-haul contracts must be held by the same shipper and must share a common location; i.e. the receipt point of the short-haul contract must be the same as the delivery point of the long-haul contract. For example, a Dawn to EDA short-haul contract when combined with a long-haul contract from Empress or Saskatchewan to SWDA if held by the same shipper, effectively results in a long-haul contract to EDA. In keeping with the intent of the FT-RAM Pilot of encouraging firm long-haul contracts, FT-RAM credits will be granted on the full path or both contracts.

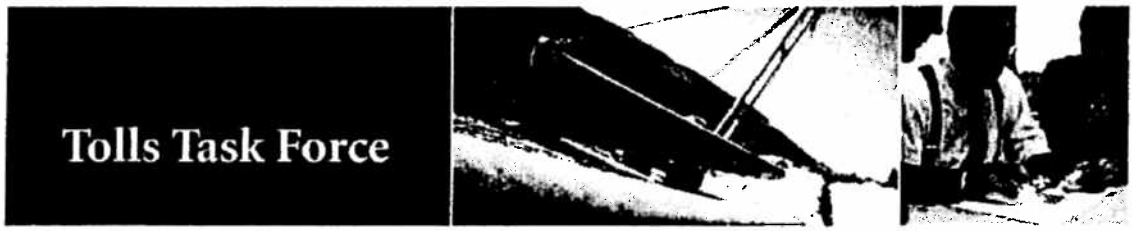
On April 5, 2006 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot, as modified by the NEB in the RHW-2-2005 decision, for an additional one-year period commencing November 1, 2006 and ending October 31, 2007 (Resolution 05.2006).

On February 9, 2007 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 03.2007)

Also on February 9, 2007 the TTF approved, as an unopposed resolution, a new RAM pilot for Storage Transportation Service and Storage Transportation Service Linked (STS-RAM and STSL-RAM) for a two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 02.2007). On July 4, 2007 the TTF approved, as an unopposed resolution, tariff language for the STS-RAM and STSL-RAM pilot (Resolution 08.2007). STS service was originally designed to work in combination with LDC held long-haul FT service on TransCanada and with market storage. It was designed to allow LDCs to meet seasonal and daily fluctuations in market demand while maintaining their long-haul service at a high load factor. STS shipper must hold long-haul FT. The flow of gas and the capacity rights are virtually identical under STS and STSL. The only difference is that under STS, the long-haul contract is held by the LDC, whereas under STSL, the end-users and marketers hold the long-haul contract.

RAM is a tool to mitigate unabsorbed demand charges and provides greater flexibility in order to give shippers increased confidence in contracting for long-haul FT service on the TransCanada Mainline. The motivation behind RAM is to promote the renewal of and incremental contracting for long-haul FT service. During the various pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users. The mechanism will not limit the service entitlements of current FT service.

VOTING RESULTS:



Unopposed resolution at the January 7, 2009 TTF meeting in Calgary.

K14.4

current bid mechanism. Overall, the changes will ensure that IT, STFT and ST-SN services are appropriately priced in the current business environment.

TransCanada expects the incremental annual discretionary revenue impact of implementing the proposed changes to IT, STFT and ST-SN services to be within a range of $20 to $80 million, based on historical and forward-looking analysis. For ~~illustrative~~ toll calculation purposes, TransCanada has included an incremental $20 million in annual discretionary revenue.[15] To the extent the pricing changes reduce migration to shorter-term discretionary services and encourage more FT service contracting, additional benefit could be realized.

John J. Reed of Concentric addresses the proposed changes to the pricing of IT and STFT services in his expert evidence presented as Appendix C4 to the Application. Mr. Reed determines that the proposal is consistent with the Board's tolling principles of economic efficiency, user-pay, and no unjust discrimination. Mr. Reed also concludes that TransCanada's short-term service pricing proposal provides sufficient protection against the potential for market power abuses. He concludes that the proposal is consistent with these principles and that it will improve the ability of the Mainline to compete.

8.3 Elimination of RAM

TransCanada proposes to eliminate the RAM feature associated with certain firm services. RAM is the mechanism through which eligible firm shippers receive dollar credits for their Unutilized Demand Charges (UDCs) that they can apply against their monthly IT service invoices. When introduced, the objective of RAM was to promote incremental contracting for, and renewal of, long-haul firm services. This objective has not been met.

[15] This amount is included in the 2012 ~~Illustrative~~ Toll Impact calculation in the "Services" column in Attachment 9.2.

As further discussed in Section 3.0 (Business Environment), the level of firm long-haul contracting on the Mainline has declined significantly in recent years. The RAM feature has led to reduced net IT service revenues, which in turn has led to upward pressure on the level of the FT tolls. The availability of the RAM feature is coming at a significant cost to FT toll payers through higher tolls. TransCanada therefore proposes to eliminate the RAM feature.

Description and History of RAM

RAM is a UDC mitigation tool whereby dollar credits are applied against a shipper's IT service invoice at the end of each month based on any UDCs from that shipper's eligible contracts. The RAM feature is applicable to the following firm service contracts:

- Long-haul FT contracts originating in Alberta and Saskatchewan;
- Short-haul FT contracts linked to a long-haul FT contract at a common location (that is, the short-haul FT contract is an extension of a long-haul FT contract held by the same shipper); and
- STS and STS-L contracts.

Any RAM credits a shipper generates in a month are applied against the shipper's monthly IT service invoice regardless of the paths used for IT service and the time the IT service was used in that month. The effect of this mechanism is that RAM credits can be used to reduce a shipper's monthly IT invoice to near zero levels. Section 4.1 of the current IT Toll Schedule outlines the RAM credit calculations and how RAM credits can reduce the invoice payable each month for IT service. The wording for Section 4.1 is available in the black-line version of the IT Toll Schedule included in Appendix C6 to the Application (Mainline Tariff).

RAM was originally introduced under the FT-RAM pilot that was approved by the Board as a feature of long-haul FT service for a one year period commencing

November 1, 2004 in accordance with TTF Resolution 02.2004.[16] The FT-RAM pilot was subsequently extended and modified pursuant to a number of TTF Resolutions[17] and Order TG-1-2006.[18] The pilot designation was lifted in 2009.[19]

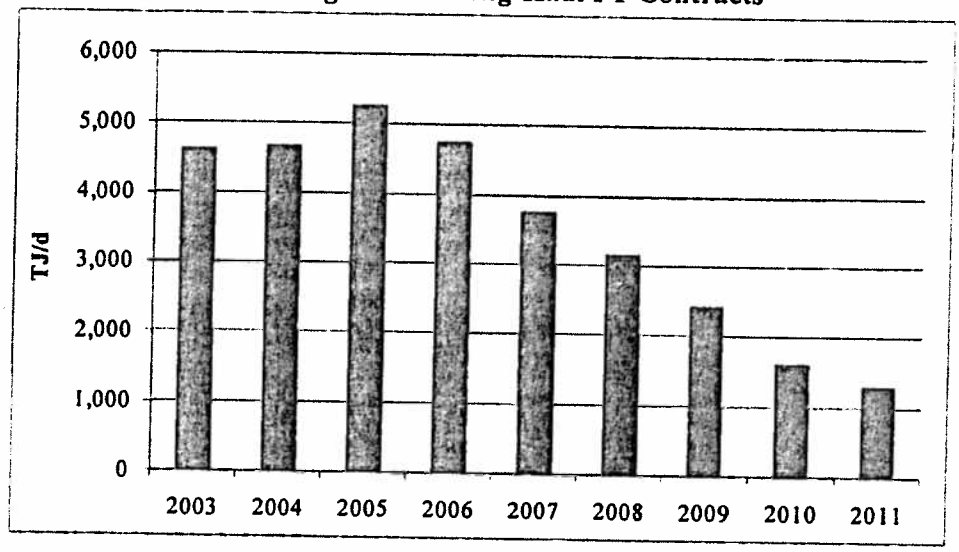
Impact on Firm Contracts

RAM was introduced to promote incremental contracting for, and renewal of, long-haul firm service. In the initial years following implementation, although there was no conclusive evidence that the objective of RAM was being achieved, some parties expressed the view in the RHW-2-2005 proceeding that RAM had influenced their decision to contract for FT service.[20]

However, the present situation is significantly different from the circumstances at the time of the RHW-2-2005 proceeding. As discussed in Section 3.0 (Business Environment), and as shown in Figure 8-3 below, long-haul FT service contracts have declined significantly.

[16] NEB letter decision of July 15, 2004.
[17] TTF Resolutions 20.2005, 05.2006, 02.2007 and 03.2007.
[18] Order TG-1-2006, attached to Decision RHW-2-2005 pertaining to an application by Coral Energy Canada Inc. to amend the FT RAM pilot.
[19] TTF Resolution 04.2009.
[20] *RHW-2-2005 Decision*, page 17.

Figure 8-3: Long-Haul FT Contracts



Note: Information for 2011 is forecast information and is based on data as of June 30, 2011.

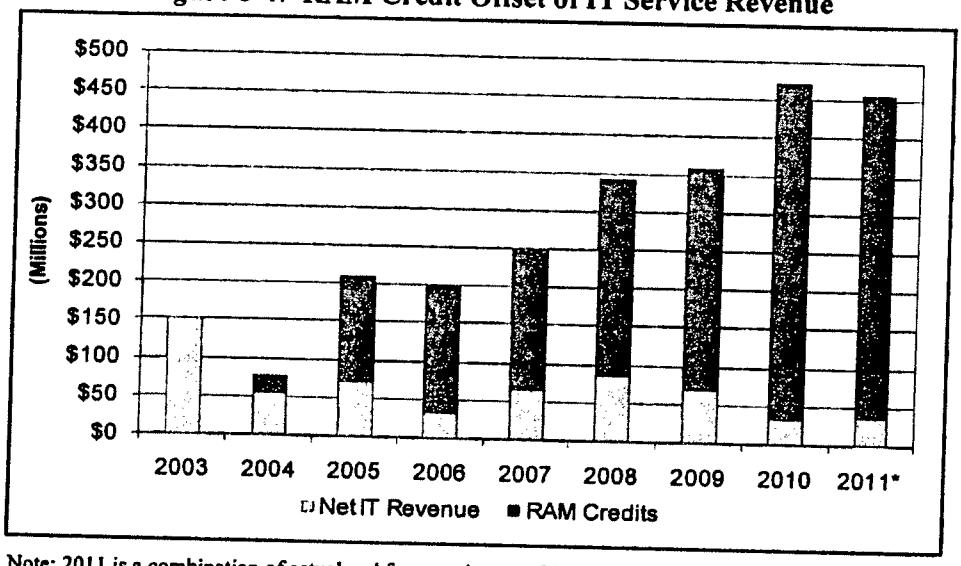
The dramatic decrease in long-haul FT contract levels since 2005 demonstrates that RAM is not meeting the original objectives of retaining and encouraging long-haul contracts. Even the parties who indicated that their contracting decisions had been impacted by the FT-RAM pilot in the RHW-2-2005 proceeding have substantially decreased their long-haul FT contract levels since that time.

Impact on IT Revenue

RAM has negatively impacted the amount of IT service revenue that TransCanada collects and applies against the Mainline gross revenue requirement, which in turn has acted to increase tolls for all Mainline shippers. Since RAM's inception, a substantial and widening difference has existed between the gross amount of IT service revenue on the system and the net amount of IT service revenue that TransCanada actually collected. This difference between gross and net revenues reflects the fact that IT service revenue is being offset by RAM credits.

For instance, in 2003, the last full year before RAM was implemented, gross and net IT service revenues were $151 million. In 2010, Mainline gross IT service revenue was $473 million. However, $440 million was offset with RAM credits, such that only $33 million of net IT service revenue remained to be applied against the gross revenue requirement. Over 90% of gross IT service revenue in 2010 was offset by RAM credits. Figure 8-4 below shows that the portion and amount of IT revenue offset by RAM credits has dramatically increased since 2004.

Figure 8-4: RAM Credit Offset of IT Service Revenue



Note: 2011 is a combination of actual and forecast data as of June 30, 2011.

Users of RAM versus Firm Contract Holders

Comparing the largest users of RAM credits to the amount of RAM-eligible firm transportation held by these shippers provides additional insight into the current use of the RAM feature.

Table 8-3 below compares the RAM-eligible firm contract holdings of the top five RAM credit users in 2010 against the amount of RAM credits those same shippers used in 2010. While the top five RAM credit users in 2010 accounted for over half of

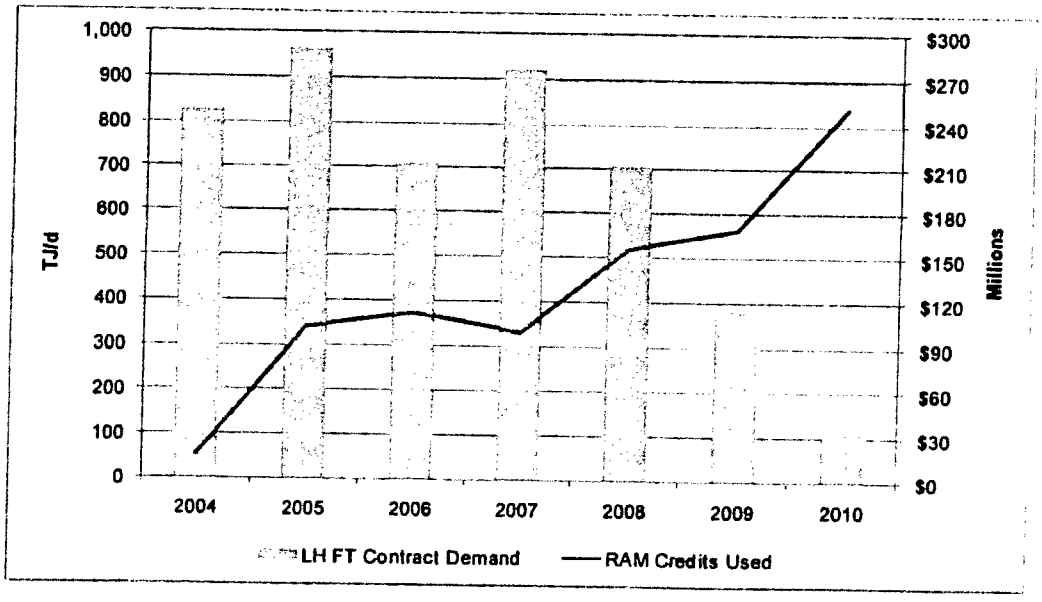
the use of RAM credits on the Mainline, the same five users represented approximately seven percent of the amount of RAM-eligible firm contracts. The fact that the largest users of RAM are not significant RAM-eligible firm contract holders reinforces the conclusion that RAM is not encouraging additional firm contracting.

Table 8-3: Analysis of 2010 Top Five RAM Users

Item	IT Invoices Offset by RAM Credits		RAM-Eligible Firm Contract Holdings (FT, STS, STS-L)	
	$	% of Total	TJ/d	% of Total
Top Five RAM Users	Approximately $251 million	57%	106 TJ/d	7%

The disconnection between RAM usage and contracting has significantly widened over time. Figure 8-5 below compares the RAM credit usage of the same top five 2010 RAM users to their long-haul FT contract demand over time. While their RAM credit usage has dramatically increased since 2004, their long-haul FT contract levels have dramatically decreased over the same period.

Figure 8-5: Contracting Behaviour of 2010 Top Five RAM Users



TransCanada understands that this discrepancy is made possible through temporary assignments of FT capacity to these shippers. While these users of RAM credits have benefitted from significant reductions in their monthly IT service invoices, this usage has negatively impacted discretionary revenues and resulted in upward toll pressure for all toll payers. In essence, RAM has resulted in the pricing of firm services reflecting the pre-purchase of some IT service enjoyed by a few high-volume RAM users. However, firm shippers who use their FT contracts at high load factors derive little benefit from RAM, yet their FT tolls effectively reflect the cost of RAM credits enjoyed by other shippers.

Impact on Revenue Opportunities

RAM credits earned on a particular path on a particular day can be applied to reduce a shipper's invoice for IT service used on any path on the system and at any time during the month. Additionally, as RAM credits are dollar amounts instead of equal quantity amounts (i.e., one GJ of UDC for one GJ of IT service), shippers often use RAM to transport many more GJs of IT service than the amount of GJs of UDC they incurred during the month. For instance, RAM credits earned by not using one GJ of a long-haul contract on one day may be used to reduce an IT service invoice for transportation of several GJs of IT service on a shorter path anywhere on the system on a different day or days. The ability to utilize RAM credits on an "out of path", "out of time", and "out of quantity" basis is contributing to the loss of net discretionary revenue on the system, which is resulting in higher Mainline tolls.

Often, RAM credits are gradually collected by shippers during a month and utilized in a concentrated fashion on a few high demand days and paths. Given the current amount of uncontracted capacity on the Mainline, such peak days would normally be expected to contribute substantial discretionary revenues that would be credited against the gross revenue requirement. Instead, while large quantities of gas flow on such peak days, a substantial amount flows without generating incremental revenues

as it is offset by RAM credits. Elimination of RAM will help ensure that flow during peak periods results in actual incremental discretionary revenues.

Impact of RAM Elimination

The elimination of RAM is expected to result in increased diversions, increased contracting for STFT service and increased net IT revenues. The incremental revenues generated will be applied against the gross revenue requirement to contribute to lowering all Mainline tolls.

While RAM will no longer be offered as a tool to mitigate UDCs, TransCanada will continue to provide other means to help shippers mitigate their UDCs. These include diversion rights, Alternate Receipt Point (ARP) rights and assignment rights that are attributes of several Mainline firm services.

Without RAM, it is expected that shippers will mitigate UDCs they accrue on FT service contracts by first utilizing diversions to meet market opportunities previously met by the use of RAM credits. However, it is important to note that diversions can only be used on a one-to-one quantity basis on the same day an FT contract is not fully utilized. In other words, for each GJ of unutilized FT service contract demand, the shipper can only mitigate that GJ by diverting it to another location on the day. In contrast, RAM credits are dollar amounts, which enable RAM users in some cases to deliver many more times the amount of GJs to a location than could another shipper who solely used diversions. This suggests that in the absence of RAM, the market opportunities currently met by RAM would not be met by diversions alone.

To meet any market opportunities over and above those which can be accommodated through diversions, TransCanada expects shippers to contract for incremental STFT service on a seasonal, monthly or weekly basis and to use IT service when necessary for daily purposes. While the total usage of IT is likely to diminish as a result of the elimination of RAM, TransCanada expects that at least a portion of the IT service that

is currently offset by RAM credits would continue to flow and generate incremental revenue.

In total, TransCanada expects an increase in annual discretionary revenue in the range of $50 to $150 million if RAM is eliminated, based on historical analysis that accounts for the expected shipper behaviour changes mentioned above. This range of incremental discretionary revenue likely is conservative, particularly when considering that the IT revenue offset by RAM credits is expected to exceed $400 million in 2011. For the purposes of illustrating the 2012 toll impact due to the elimination of RAM, TransCanada has included an incremental $50 million in annual discretionary revenue.[21] This amount has the effect of lowering the 2012 ~~Illustrative~~ Empress to Union SWDA FT toll by 6¢/GJ.

John J. Reed of Concentric, whose expert evidence is presented as Appendix C4 to the Application, addresses the appropriateness of eliminating the RAM feature. He concludes that the elimination of RAM is appropriate in the current market circumstances and it is consistent with the Board's tolling principles of user-pay and no unjust discrimination. Mr. Reed also explains that shippers will continue to have other opportunities to mitigate their unused capacity.

8.4 Multi-Year Fixed Price Service

TransCanada proposes a new MFP service that is similar to FT service except that the applicable tolls are set in advance for periods ranging from three to five years. MFP service was developed in response to shipper interest in a service that provides toll certainty over an extended period of time. By offering longer-term toll certainty, MFP service may promote additional contracting on the Mainline, which would result in incremental firm billing determinants to the benefit of all Mainline shippers. MFP

[21] This amount is included in the 2012 ~~Illustrative~~ Toll Impact calculation in the 'Services' column in Attachment 9.2.

TransCanada

NewsRelease

TransCanada and Stakeholders Reach a Settlement for 2001 and 2002 Canadian Mainline System Services and Pricing

CALGARY, Alberta – February 22, 2001 – (TSE: TRP) (NYSE: TRP) – TransCanada PipeLines Limited today announced it has reached a settlement regarding 2001 and 2002 services and pricing on its Canadian Mainline natural gas transmission system that resolves all issues other than cost of capital. The parties agreed that the issue of cost of capital would be determined in a different forum. The settlement is the result of broad industry negotiations and represents a balance of interests among most of the negotiating parties.

"We are pleased to have reached this settlement, which will assist in meeting the needs of TransCanada's customers and shareholders," said Doug Baldwin, TransCanada's President and Chief Executive Officer. "The settlement provides the foundation for further discussions to ensure the Canadian Mainline System continues to compete effectively for market demand and natural gas supplies. It's also another example of what can be accomplished by working collaboratively with industry stakeholders."

Highlights of the Settlement

Revenue Requirement:
The settlement establishes the Canadian Mainline System's fixed operating, maintenance and administration; post employment benefits; and regulatory commission (OM&A) costs for the next two years. All other elements of the 2001 and 2002 revenue requirements will be treated on a flow through basis. OM&A variances between actual costs and those agreed to in the settlement will accrue to TransCanada's account.

OM&A costs for 2001, commencing January 1, 2001, are fixed at $223 million. Commencing January1, 2002, the OM&A costs for 2002 are fixed at $216.5 million. These amounts are subject to adjustments from the final 2000 Merger and Cost Benefit Agreement account.

Depreciation is based on a composite rate of 2.75 per cent in 2001, compared to 2.65 per cent in 2000. In 2002, the composite depreciation rate will increase to 2.90 per cent.

Contract Demand:
Contract demand will be estimated each year. Variance between forecast and actual contract demand will be deferred and recovered in the following test year.

Incentives:
The settlement includes various incentive programs to assist in balancing the cost incentive provided by the fixed OM&A agreement. Specific incentive programs include:

Fuel Gas and Power Incentive - to minimize total delivered costs. Details of this incentive are to be determined by April 30, 2001.

Foreign Exchange Program - to reduce foreign exchange costs on Interest and Transportation by Others in foreign currencies. Savings, to a benchmark, are shared equally between TransCanada and its shippers. This program will terminate December 31, 2002.

Interest Rate Management Program - to reduce interest costs by managing fix/floating rates. Savings are shared equally between TransCanada and shippers. This program will terminate December 31, 2002.

Revenue /Asset Management Mechanism:
Revenue/Asset Management Mechanism - a commission to TransCanada of varying percentages to provide an incentive to reduce asset costs and generate incremental revenue. Revenue to TransCanada from this mechanism is capped at $5 million.

Services:
Firm Service (FT) - will be provided with Make-up and Authorized Overrun Service (AOS) rights as described below:

FT Make-up - the Demand Charge associated with each FT shipper's unutilized FT Demand rights in each month will be credited towards that FT shipper's Interruptible Service (IT) invoice at the end of each month. This service will terminate December 31, 2002.

AOS - four per cent of each FT shipper's monthly contract demand charges will be credited to that shipper's IT invoice each month. This service will terminate December 31, 2002.

Short Term Firm Service (STFT) – there is no change to the existing STFT offering. STFT will remain as a biddable service with a floor price of 100 per cent of the FT toll.

IT – will remain as a biddable service. The price is based on a proxy for marginal fuel, plus commodity toll, plus a contribution to fixed costs. The floor price for IT can vary between 80 per cent of the FT toll and 120 per cent of the FT toll.

Future Business Model:
The parties acknowledged that a competitive pipeline system is in the interest of all stakeholders and will enable TransCanada to meet its needs and those of its customers, supporting the long-term viability of the TransCanada system. By the end of August 2001, TransCanada will work to present to the stakeholders, a specific business and regulatory model for the future that will allow it to compete effectively for market demand and gas supplies. Discussions with stakeholders regarding any new model, including a code of conduct, will be initiated on or before September 17, 2001 and completed by February 28, 2002.

This settlement will form the basis of a formal agreement between the parties. Once TransCanada and the parties have completed the agreement (anticipated by the end of this March), TransCanada will apply to the National Energy Board for approval of the agreement.

TransCanada is a leading North American energy company. It is focused on natural gas transmission, power, and gas marketing services, complemented by employees who are expert in these businesses. The company's network of approximately 38,000 kilometres of pipeline transports the majority of western Canada's natural gas production to the fastest growing markets in Canada and the United States. TransCanada's common shares trade under the symbol TRP on the Toronto and New York stock exchanges. Visit us on the internet at www.transcanada.com for more information.

Note: All dollar amounts are expressed in Canadian funds, unless otherwise indicated.

(For a complete version of the Settlement, please visit TransCanada's web site at www. transcanada.com and follow the links to this news release.)

– 30 –

Media Inquiries:	Glenn Herchak/Kurt Kadatz	(403) 267-3309
Analyst Inquiries:	David Moneta	(403) 267-8521

d. Permanent demand destruction, offsetting the contract revenue increases described above, of $3.0 million is a direct result of significant additional plant closures in Union's large infranchise contract markets.

2008 General Service Revenues

The actual total general service delivery revenue in 2008 was $574.9 million (Appendix A, Schedule 9, Column (r), line 6), prior to adjustments, compared to the 2007 Board approved forecast of $565.2 million (Appendix A, Schedule 9, Column (f), line 6). The primary contributors to the variance of $9.7 million were colder than normal weather in 2008 ($3.6 million) and rate class migration from contract rate classes to general service rate classes ($2.1 million). The remaining variance of $4.0 million was due to variances in the forecast level of customer additions, demand price elasticity related normalized average consumption ("NAC") variances, non demand side management ("DSM") related energy conservation, the Average Use ("AU") factor and the unbilled revenue accrual.

TRANSPORTATION REVENUE

Revenue from exfranchise transportation services increased by $37.7 million in 2008 relative to 2007 Board approved levels. This was primarily driven by increases in short-term transportation and exchange revenue of $23.3 million. Increases in long-term transportation revenue of $14.5 million as a result of the expansion of Union's Dawn Trafalgar transmission system, offset by increases in depreciation and cost of capital

identified below, also contributed to the increased transportation revenue in 2008. The increase in short-term transportation and exchange revenue is explained in more detail below.

Short-Term Transportation and Exchange Revenue

As noted above, short-term transportation and exchange revenues accounted for $23.3 million of the $37.7 million increase in exfranchise transportation revenue in 2008 over 2007 Board approved levels. The increased revenue was a result of increased customer activity and service values due to colder than normal weather late in the year and new market opportunities. In addition, Union put a greater focus on the gas supply transportation portfolio optimization starting in 2007. This focus continued through 2008. Union also invested in incremental sales staff to capture the incremental revenue opportunities and deliver these services to customers. Union's approach to the marketing of transactional services and the financial results for 2008 were the direct result of the IR framework and the elimination of the transportation deferral accounts.

Union notes that Board approved distribution rates in 2008 include $6.9 million in short-term transportation and exchange margin. To achieve the total net margin of $6.9 million as embedded in the 2008 distribution rates, Union must achieve gross transactional revenue (before deduction of costs) of approximately $10 to $12 million.

K7.4

Filed: 2009-04-21
EB-2009-0101
Exhibit B
Tab 1
Schedule 4

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 11

Question:

Union stated that new market opportunities, in part, account for the increase in short-term transportation and exchange revenues.

a) Please describe the nature and characteristics of these new market opportunities.

Response:

Over the last number of years, end use customers have been decontracting firm long haul transportation capacity in favour of recontracting shorter term short haul transportation and commodity purchases at Dawn. This reflects in part a desire by end use customers for shorter term contracts and a lower long term transport contract commitment and related financial exposure.

The increased demand for shorter term short haul services has provided Union with the opportunity to sell increased transportation and exchange services into the market. These services are for terms as short as one day. As described in Exhibit A, Page 7 of 29, lines 10 to 15, to both respond to and support this increased market demand and provide the customer support for these transactions, Union increased its Chatham-based sales staff by two positions in 2008, refocused the contract and customer support staff and initiated process and IT systems changes. The overall objective was to capitalize on these opportunities and optimize and market Union's assets and related services.

Union also focused on further optimizing its 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.

EB-2009-0101

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 for an order or orders amending or varying the rate or rates charged to customers as of July 1, 2009 in connection with the sharing of 2008 earnings under the incentive rate mechanism approved by the Ontario Energy Board on January 17, 2008

SETTLEMENT AGREEMENT

June 4, 2009

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2009-0101, of the disposition of Calendar 2008 earnings sharing under a settlement agreement approved by the Board on January 17, 2008 in EB-2007-0606 (the "IR Settlement Agreement") for Union Gas Limited ("Union"). By Procedural Order No.1 dated April 28, 2009, the Board scheduled a Settlement Conference to commence May 27, 2009. The Settlement Conference was duly convened, in accordance with Procedural Order No. 1, with Mr. George Dominy as facilitator. The Settlement Conference proceeded until May 28, 2009.

The settlement presented in this Agreement is comprehensive in that the agreement that has been reached settles all issues in this proceeding.

The Agreement is supported by the evidence filed in the EB-2009-0101 proceeding.

The purpose of this proceeding was:

(a) to provide Union's calculation of its 2008 utility earnings for the purposes of earnings sharing pursuant to Section 10.1 of the IR Settlement Agreement. Section 10.1 of the IR Settlement Agreement provides:

> *"If in any calendar year Union's actual utility return on equity is more than 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such excess earnings will be shared 50/50 between Union and its customers. For the purposes of the earnings sharing mechanism, Union shall calculate its earnings using the regulatory rules prescribed by the Board from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings. All revenues that would be included in revenues in a cost of service application shall be included in the earnings calculation and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation.*
>
> *Parties acknowledge that the DSM related Shared Savings Mechanism (SSM) and Lost Revenue Adjustment Mechanism (LRAM) and storage related deferral accounts are outside of the earnings sharing mechanism identified above."*

(b) to consider Union's application pursuant to section 9.1 of the IR Settlement Agreement. Section 9.1 provides:

> *"The parties agree that if there is a 300 basis point or greater variance in weather normalized utility earnings above or below the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, Union will file an application to the Board, with appropriate supporting evidence, for a review of the price cap mechanism. During the course of that review, the Board may be asked to determine whether it is appropriate to continue the price cap mechanism for future years and, if so, with or without modifications. All parties including Union will be free to take such positions as they consider appropriate with respect to that application, including without limitation; a) proposing that a component of the IR Plan, including the X factor, be adjusted, b) proposing that IR plan be terminated, and c) taking any other positions as the party may consider relevant and the Board agrees to hear. Union shall file such application as soon as reasonably possible in the year following the year in which the over earnings threshold is met, unless all parties to this Agreement agree otherwise at that time."*

It is acknowledged and agreed that none of the provisions of this Agreement is severable. If the Board does not, prior to the commencement of the hearing of the evidence in EB-2009-0101, accept the Agreement in its entirety, there is no Agreement (unless the parties to the Agreement agree that any portion of the Agreement the Board does accept may continue as a valid agreement).

It is further acknowledged and agreed that parties to the Agreement will not withdraw from this Agreement under any circumstances except as provided under Rule 32.05 of the Board's Rules of Practice and Procedure.

The participants in the Settlement Conference agree that all positions, negotiations and discussion of any kind whatsoever which took place during the Settlement Conference and all documents exchanged during the conference which were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Agreement.

The role adopted by Board Staff in Settlement Conferences is set out on page 5 of the Board's Settlement Conference Guidelines. Although Board Staff is not a party to this Agreement, as noted in the Guidelines, "Board Staff who participate in the settlement conference are bound by the same confidentiality standards that apply to parties to the proceeding".

The evidence supporting the Agreement is set out in the Agreement. Abbreviations will be used when identifying exhibit references. For example, Exhibit B1, Tab 4, Schedule 1, Page 1 will be referred to as B1/T4/S1/p1. There are Appendices to the Agreement which provide further evidentiary support. The structure and presentation of the settled issues is consistent with settlement agreements which have been accepted by the Board in prior cases. The parties agree that this Agreement and the Appendices form part of the record in the proceeding.

In Procedural Order No. 1 in this proceeding, the Board granted intervenor status to all intervenors of record in EB-2007-0606 and EB-2008-0220. The following entities participated in the Settlement Conference:

Building Owners and Managers Association of the Greater Toronto Area ("BOMA")
Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Industrial Gas Users Association ("IGUA")
City of Kitchener ("Kitchener")
London Property Management Association ("LPMA")
School Energy Coalition ("SEC")
The City of Timmins ("Timmins")
Union Gas Limited ("Union")
Vulnerable Energy Consumers Coalition ("VECC")
Wholesale Gas Services Purchasers Group ("WGSPG")
Energy Probe ("EP")
Federation of Rental-housing Providers of Ontario ("FRPO")

The parties to this Agreement include all of the above noted entities except IGUA (the "parties"). The parties to this Agreement represent major stakeholders and constituencies with an interest in Union's rates.

The parties to this settlement encourage the Board to accept this Agreement in its entirety. The parties to this Agreement also support finalization of the rate order in these proceedings to enable implementation of this Agreement in Union's July 1 QRAM.

1. Earnings Sharing Calculation and Off Ramp Amendments

(Complete Settlement)

The parties agree that, upon approval of this Agreement by the Board, the IR Settlement Agreement shall, for the entire IR term, 2008 to 2012, be amended as follows (for the assistance of parties and the Board, the agreed upon amendments to the IR Settlement Agreement are blacklined below):

> 9.1 [Section 9.1 of the IR Settlement Agreement shall be deleted in its entirety.]
>
> 10.1 The parties agree that there will be an earnings sharing mechanism, based on actual utility earnings. If in any calendar year Union's actual utility return on equity is more than 200 basis points <u>but not more than 300 basis points</u> over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such excess earnings will be shared 50/50 between Union and its customers. <u>In addition to the above, if in any calendar year Union's actual utility return on equity is more than 300 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such earnings in excess of 300 basis points will be shared 90/10 between customers and Union (i.e., customers will be credited 90% and Union will be credited 10%).</u> For the purposes of the earnings sharing mechanism, Union shall calculate its earnings using the regulatory rules prescribed by the Board from time to time, and shall not make any material

changes in accounting practices that have the effect of reducing utility earnings. All revenues that would be included in revenues in a cost of service application shall be included in the earnings calculation and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation. For greater clarity, Union's one time accounting adjustment in 2008 to true up an unbilled revenue accrual to reflect Union's current rate structure and billing cycles, in the amount of $3.6 million, is an adjustment that is excluded from the calculation of actual utility earnings, whereas the use of actual unaccounted for gas volume is an expense that would be recorded in the calculation of actual utility earnings.

The parties believe that these amendments to the Board-approved IR Settlement Agreement are in the public interest. The amendments are intended to modify the IR formula so as to in produce rates which are just and reasonable during the IR term. The Agreement:

1. clarifies possible ambiguities in the calculation of earning sharing in section 10.1 of the IR Settlement Agreement arising from the relationship between the use of actual utility earnings and the *proviso* in section 10.1 restricting any adjustments in the calculation of actual utility earnings to those adjustments to actual earnings that would be made in a cost of service filing. Intervenors took the position, for example, that none of the adjustments proposed by Union in the calculation of 2008 actual utility earnings were appropriate. Union took the position that all of its proposed adjustments were in accordance with the IR Settlement Agreement. This Agreement avoids the cost and uncertainty of litigation over these disputes, now and in the future, by resolving which adjustments to the calculation of actual utility earnings, for the purposes of earnings sharing, are appropriate;

2. provides additional potential benefits to customers during the term of the IR plan, 2008 to 2012, in circumstances where Union's actual utility income exceeds the amount

calculated by the application of the Board's ROE formula in any year of the IR plan by over 300 basis points, by crediting 90% of such earnings to customers.[1] The consumer protection afforded by the "off ramp" provision for review in section 9.1 of the IR Settlement Agreement has been replaced with crediting 90% of earnings over the 300 basis point threshold to customers, i.e., Union will have a modest incentive to pursue even greater productivity initiatives and customer bills will go down, all else equal, to the extent Union delivers earnings in excess of the 300 basis point threshold. The parties acknowledge that the elimination of the "off ramp" review in section 9.1 is without prejudice to all rights afforded under section 6.1 (Z Factors) of the IR Settlement Agreement;

3. provides greater certainty and incentive for Union to explore and make investments in productivity improvements during the term of the 2008 to 2012 IR plan;

4. continues to provide for annual reviews during the term of the IR plan during which intervenors will be able to carefully review the reasons and calculation of sharing for all earnings in excess of 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan.

5. avoids complex, lengthy and highly controversial and contested disputes over the potential for termination of the IR plan and the need for a new full cost of service proceeding. In this case, intervenors took the position, for example, that the proper calculation of weather normalized utility earnings in 2008 was materially in excess of the 300 basis point threshold which gave intervenors the right to seek a review of the IR plan, the consideration of adjustments to the components of the IR plan, including base rates, and the termination of the IR plan and a return to cost of service rates, just as Union would have had the right to take the same position had the company under-earned by an equivalent amount. Union took the position that the IR plan was working as contemplated and producing significant benefits for customers and that the termination of

---

1 Union does not currently forecast exceeding the 300 basis point threshold in 2009 or 2010.

incentive regulation after the first year of the five year plan was premature and inappropriate. Union will be applying in 2012 for 2013 cost of service rebasing in any event; and

6. avoids complex, lengthy and highly controversial and contested disputes over 2007 base rates and the potential for further adjustments to those base rates during the IR plan. For example, intervenors took the position that Union's 2007 normalized utility earnings were materially higher than the forecast available during the period in which the IR Settlement Agreement was negotiated and that adjustments to the IR plan, such as altering the size of the earnings sharing deadband, altering the level of earnings sharing, and adjustments to 2008 earnings sharing and/or to base rates during the IR term could be made to take account of this positive variance. Union took the position that such variances were not relevant to 2008 earnings sharing and that no adjustments to the IR plan or to base rates during the IR term, except those, such as Z factors, expressly contemplated by the IR Settlement Agreement, should be made. This issue involved a number of potentially controversial disputes, including disputes over the appropriate calculation methodology, the extent to which the likelihood of favourable variances, and the extent of those variances, was, or ought to have been, known to all parties when the IR Settlement Agreement was negotiated and whether base rate adjustments of this kind are appropriate during the IR term.

The financial consequences of this Agreement for the calculation of 2008 earnings sharing under the IR Settlement Agreement are set out in Appendix A attached to this Agreement. The adjustments in the Agreement to Union's original proposal are the result of compromise by the agreeing parties of their respective positions on the matters listed above. In all of the circumstances, the parties have agreed to increase the customer share of Union's 2008 earnings from the proposed $15.2 million to $34.2 million, as outlined in Appendix A.

Consistent with past practice, the customer portion of the amount calculated in Appendix A shall be allocated to rate classes in proportion to Board approved return on equity as set out in the allocation schedule in Appendix B attached to this Agreement. Of the $34.2 million customer

share of earnings for 2008, approximately $19.6 million will be allocated to small volume general service customers and approximately $3.2 million will be allocated to large volume general service customers. Approximately $4.7 million will be allocated to the large volume contract customers and approximately $6.7 million to M12 shippers such as Enbridge Gas Distribution Inc. ("EGD"), Gaz Métropolitain inc. ("GMi"), and TransCanada PipeLines Limited ("TCPL"). Approving the settlement reflected in the Agreement, therefore, will benefit all customers but, in particular, will provide benefits to small volume general service customers.

Evidence References:

1. A/p.9-20, A/p.27-29, A/App. B/S.1, A/App. B/S.2, A/App. B/S.3, A/App. D/S.1, A/App. D/S.2
2. Technical Conference, pp. 19-28, 33-34
3. B/T1/S6, B/T2/S1, B/T2/S3, B/T4/S7, B/T4/S8, B/T5/S3
4. J1.1

EB-2009-0101
Settlement Agreement
Appendix A

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ended December 31, 2006

Line No.	Particulars ($000's)	2006 (a)	Non-Utility Storage (b)	Adjustments (c)		2006 Utility (d)=(a)-(b)+(c)
	Operating Revenues:					
1	Operating revenue	$ 1,869,283	$ -	$ (3,654)	i	1,865,629
2	Storage & Transportation	243,317	78,230	-		165,087
3	Other	33,818	-	(7,530)	ii	26,288
4		2,146,418	78,230	(11,184)		2,057,004
	Operating Expenses:					
5	Cost of gas	1,171,320	8,082	-		1,163,238
6	Operating and maintenance expenses	335,115	12,028	(516)	iii	322,571
7	Depreciation	185,219	4,966	-		180,253
8	Other financing	-	-	535	iv	535
9	Property and capital taxes	65,895	953	-		64,942
10		1,757,549	26,029	19		1,731,539
11	Earning Before Interest and Taxes	$ 388,869	$ 52,201	$ (11,203)		$ 325,465
	Financial Expenses:					
12	Long-term debt					143,548
13	Unfunded short-term debt					2,806
14						146,351
15	Utility income before income taxes					179,114
16	Income taxes					31,300
17	Preferred dividend requirements					5,066
18	Utility earnings					142,726
19	Long term storage premium subsidy (after tax)					10,676
20	Short term storage premium subsidy (after tax)					7,484
21						18,160
22	Earnings subject to sharing					$ 160,886
23	Common equity					1,205,198
24	Return on equity (line22 / line 23)					13.35%
25	Benchmark return on equity					10.81%
26	50% Earnings sharing %					1.00%
27	90% Earnings sharing to ratepayer % (line 24 - line 25 - line 26)					1.54%
28	50% Earnings sharing $ (line 26 x line 23 x 50%)					6,026
29	90% Earnings sharing to ratepayer $ (line 27 x line 23 x 90%)					16,697
30	Total earnings sharing $ (line 28 + line 29)					22,723
31	Pre-tax earnings sharing (line 30 / (1 minus tax rate))					$ 34,170

Notes:

i) Accounting adjustment

ii) Shared Savings Mechanism

iii) Donations (394)
EB-2008-0304 costs (122)
(516)

iv) Customer deposit interest

UNION GAS LIMITED
Allocation of 2008 Earning Sharing to Rate Classes

Line No.	Particulars	Rate Class	C2007 Return on Equity Allocation (1) ($000's) (a)	2008 Earning Sharing ($000's) (b)	
	Northern & Eastern Operations Area				
1	Small Volume General Firm Service	01	44,549	(5,867)	
2	Large Volume General Firm Service	10	8,234	(1,084)	
3	Medium Volume Firm Service	20	4,263	(561)	
4	Large Volume High Load Factor Firm Service	100	5,641	(743)	
5	Large Volume Interruptible Service	25	1,913	(252)	
6	Wholesale Transportation Service	77	8	(1)	
7	Total Northern & Eastern Operations Area		64,608	(8,509)	
	Southern Operations Area				
8	Small Volume General Service Rate	M1	104,130	(13,715)	
9	Large Volume General Service Rate	M2	15,828	(2,085)	
10	Firm Industrial and Commercial Contract Rate	M4	4,220	(556)	
11	Interruptible Industrial & Commercial Contract Rate	M5A	2,587	(341)	
12	Special Large Volume Industrial & Commercial Contract Rate	M7	2,617	(345)	
13	Large Wholesale Service Rate	M9	219	(29)	
14	Small Wholesale Service Rate	M10	10	(1)	
15	S & T Rates for Contract Carriage Customers	T1	12,835	(1,691)	
16	S & T Rates for Contract Carriage Customers	T3	1,546	(204)	
	Storage and Transportation				
17	Cross Franchise Transportation Rates	C1	186	(24)	
18	Storage & Transportation Rates	M12	50,557	(6,659)	
19	Transportation of Locally Produced Gas	M13	39	(5)	
20	Storage & Transportation Services - Transportation Charges	M16	55	(7)	
21	Total Southern Operations Area		194,830	(25,661)	
22	Total		259,438	(34,170)	(2)

Notes:
(1) Allocated costs per 2007 Decision in EB-2005-0520
(2) Earning Sharing balance for Disposition as per EB-2009-0101, Settlement Agreement, Appendix A



ONTARIO ENERGY BOARD

FILE NO.: **EB-2008-0101**

VOLUME: **1**

DATE: ***June 8, 2009***

BEFORE:

Gordon Kaiser	**Presiding Member and Vice-Chair**
Paul Vlahos	**Member**
Paul Sommerville	**Member**

MR. KAISER: He who has the compendium goes first, a long-standing rule. Mr. Thompson.

SUBMISSIONS BY MR. THOMPSON:

MR. THOMPSON: Thank you, Mr. Chairman, Members of the Board. You have the compendium which I will be referring to. It does duplicate some of the materials that Mr. Penny has already referenced.

There are other documents that I will refer to. Unfortunately, I don't have copies, and I couldn't circulate them last night. I am technically inept to do this electronically, but I did provide an e-mail notice of what I would be referring to, and one was excerpts from the Board's decision in EB-2008-0304.

That's your decision, Mr. Kaiser, in November of 2008 dealing with Union's restructuring application. I will make a couple of references to that. I don't think you will need copies.

The second item that I will refer to is Rule 43 of the Rules of Procedure, and, again, I can just read that when I come to that point. It's not terribly long.

CME strongly supports the settlement and urges you to approve it. Why? Because it resolves contentious earnings sharing adjustment calculation issues for 2008 which are issues of substance. It resolves those issues now and for future years, and it resolves them on a basis that is favourable to ratepayers.

Mr. Penny had addressed this perhaps in a slightly different way, and I will provide the ratepayer rationale,

CME's rationale, for this aspect of the agreement.

It is spelled out in paragraph 1 of the settlement agreement. You will find the settlement agreement at tab 1 of my belief. And when I say paragraph 1, I mean paragraph 1 of the rationale. That is at page 5. Mr. Penny has already read that into the record.

The resolution of the matter is on the basis that the historic presentation of actual utility earnings in a cost of service filing does not include normalized UFG. The normalized UFG calculation is only included in the forecasted statement of income expenses which are presented in a cost of service filing for a prospective test year.

So the parties have agreed that the meaning to be ascribed to this section of their agreement is that the cost consequences of the actual historical test year filing are to be reflected in the calculation of actual utility earnings.

As Mr. Penny has indicated, this adjustment brings the sharing from about $15 million to about $23 million, and the additional $11 million comes from the resolution of the other item of the agreement that he addressed in his submissions.

This outcome on the earnings sharing calculation issue is favourable to ratepayers, and there is nothing in the questions circulated by Board Staff or in the IGUA letter that should prompt you to question this feature of the settlement proposal.

Turning to the second feature of the settlement

proposal, which is essentially the adjustment to the sharing -- the over-earnings sharing percentages specified in the original settlement agreement for the years 2008 to 2012, inclusive, as well as the removal of the -- I call them "off-ramp" provisions of the agreement in article 10.1.

The settlement of both issues was linked, but I will address this issue in my submissions separately.

Now, the starting point for CME's submissions on this point are the provisions of the agreement describing the parties' rights, and you will find those in the settlement agreement. They are reproduced at page 2 of the document that is under tab 1.

I think it's useful to look at this clause as to what the rights of the parties were when the over 300 basis points earnings variance occurred, or, for that matter, when 300 basis points under the Board-approved occurs.

First of all, Union must file -- it says "will file an application to the Board for review". So the review is mandatory. It's not discretionary, in terms of the filing of it. And:

> "During the course of that review, the Board may be asked to determine whether it is appropriate to continue the price cap mechanism for future years, and, if so, with or without modifications. All parties, including Union, will be free to take such positions as they consider appropriate with respect to that application, including,

without limitation: A, proposing that a component of the IR plan including the X factor be adjusted; B, proposing that the IR plan be terminated; and C, taking any other positions as the party may consider relevant and the Board agrees to hear."

So the point is this is a very broad rights clause for both Union and the ratepayers. And it includes the right to request that any component of the IR plan be adjusted as well as a right to request that the plan be terminated.

So there is nothing in this agreement, in my submission, that suggests that we should be turning a blind eye to over-earnings in year 1 of a five-year plan. The prematurity issue that the Board raises in question one clearly is something that is incompatible with the provisions of this agreement.

When under-earnings occur or over-earnings occur more than 300 basis points from the Board's approved return, a review is mandatory, and I submit that in that review, the matters to be examined are the causes for the variance and ascertain whether an adjustment or adjustments to any planned component or termination of the plan are called for.

That's exactly what the parties did in this case.

Let me turn to the level of over-earnings we are talking about in this case. Just to put it in a basis points context, you can see from the appendix A to the agreement at Tab 1, that the return on equity that flows

from the adjustment being made to eliminate the UFG deduction that Union had included there at line 24 is 13.35 percent. That's versus the Board approved of 8.81 percent. So we are talking here in this particular year, 2008, of a 454 basis points overage.

Now, on the weathered-normalized aspect of this, you can get a ballpark for this number from the calculation that Mr. Penny mentioned in his submissions with respect to the company's response to CME interrogatory number 1, and you will find that at page 71 of Mr. Penny's compendium.

If you go over to page 73, what the company is showing there is the -- a modified off-ramp calculation as per CME question 1. What we had asked in that question was for the -- all adjustments to be removed except the DSM adjustment which appeared at line 3. But what you do have in this calculation is the normalizing adjustment in column 1 -- sorry, line 1 of column C. You will see there that the return on equity at line 24 normalized, weather-normalized is 13.17 percent. Now this is a little high because the accounting adjustment has also been taken out. But we make it that the number, after adjusting for that accounting item, would be in excess of 13.0 percent. So we are dealing with a weather-normalized actual earnings for 2008 that exceeds 400 basis points. It's 419 if you take 13 as the estimate. But it exceeds 400 basis points.

What do these levels of over-earning mean in terms of the reasonableness of Union's revenue requirement and rates for 2008? Well, Union indicated to us that 100 basis

points grossed up for taxes is -- 100 basis points on equity is $18 million. So at 454 basis points, looking at this from a cost of service rebasing perspective, Union's rates are some $82 million higher than they would be had they just come in at the Board-approved 8.81 percent. At 400 basis points, they would be about $72 million.

So we are dealing here with some very material amounts, and in terms of what would the Board do if this goes to hearing, would it turn a blind eye to these amounts? We don't think so. And in reaching that conclusion, we suggest the Board would unlikely turn a blind eye to a request by Union for adjustments to the plan following a $72 million under-earnings in the first year of the operation of the plan.

So we say there is a real issue here in terms of the ratepayer rights.

In the context, as well, of what off-ramp relief is all about and in that context, I have provided at tab 2 of the brief, excerpts from the Board's July 21, 2001, decision in Union's first PBR, performance regulation case, and the subject of off-ramps was discussed in section 2.7.6.

I won't read this, but at page 155 in the Board's findings, these findings make it clear that the off-ramp relief is designed to remedy a situation super-normal profits or a situation of under earnings which creates a threat to the integrity of the utility. What we have here, in my submission, is a case of super-normal earnings in

year one of the IR plan.

Now, what are the causes of this situation? One of them is the UFG is lower than expected by $15.6 million, that would be about 87 basis points.

Another major reason which wasn't addressed by Mr. Penny in his submissions, but it was important to intervenors, is that the level of 2007 base rates turned out to be $34.1 million. This is normalized actual, 2007 base rates, $34.1 million higher than Board-approved ROE. You can see this at Tab 6 of our brief in the second page of that tab there is an exhibit that Union provided as provided showing the normalized actual over-earnings of 2007 of $34.1 million; that's in the final column.

Now was that what we were aware of when the initial agreement was negotiated? The answer to that is no. What we were aware of is shown on the previous page, which was normalized at actual over-earnings it's shown there of $19,227,000 but you need to add the tax -- sorry, you need to add the weather-normalization and tax in the amount of $3.4 million which comes up to $22.6 million which is shown on the first page under Tab 6.

As a result -- and we didn't learn this until I think it's in January of 2009, when the Board actually ordered Union to provide its 2007 normalized actual results, Union had not been -- that order was made in the context of the Board's approval of Union's 2009 rates.

Union was taking the position that it did not need to produce that information to intervenors under the terms of

the Board-approved plan.

So we learn in January of 2009 that a significant factor pertaining to the negotiation of the initial agreement was not $22.6 million. It was more than 150 percent more, $34.1 million.

That raises this entire issue of disclosure and the kinds of discussions that were held and the rulings the Board made in the decision I mentioned earlier about the restructuring application.

We take the position -- at least CME takes the position that this is a live issue in this case that was up for resolution, that a 150 percent deviation from estimate is a misrepresentation. Whether it's innocent or not innocent, it gives rise to equitable remedies, and that's what this review clause is all about, in my respectful submission.

One outcome might be an adjustment to base rates of $11 million, and, if one looked at that, that would be, over five years, an amount of some $57.5 million. The actual difference between the 22.6 and the 34.1 is 11-1/2-million dollars.

Other possible outcomes would be an adjustment to the dead band. Would we have agreed to a 200 basis point dead band if we had known normalized actual earnings for 2007 were $11.5 million more than what was represented?

Another outcome would be a variance of the sharing ratio over 200, and that's really the route that we took in this for the purposes of reaching a settlement.

All of these possible outcomes would in issue if this settlement is not approved, and this is in addition to the ambiguity in the agreement with respect to sharing over 300, to which Mr. Penny has referred.

So what have the parties done to resolve these issues? As Mr. Penny has outlined, they have agreed to adjust the earnings sharing component of the IR plan for the years 2008 to 2012, inclusive, and increase the ratepayer's share to 90 percent over 300 basis points.

Ratepayers have agreed, except for IGUA, who has essentially abstained here, that we will get 90 percent of everything over 300, and, in exchange, we can eliminate the trigger from the agreement.

The financial implications of the settlement Mr. Penny has pointed out, but it might be useful to just give you the math here in terms of some basis points scenarios.

At 300 basis points, under the initial agreement, Union would get 250 of it and the ratepayers would get 50. Three hundred basis points would be $52 million, so Union's shareholder gets 45 and ratepayers get 9.

At 400 basis points, you would have 72 million of earnings. Under the original agreement, the shareholder would get 54; ratepayers get 18. Now the shareholder gets 46.8, the ratepayer gets 25.2. You can go do the math for higher basis rates scenarios, as well.

The point is that this settlement, as far as CME is concerned, is favourable to ratepayers.

We also suggest that the settlement is more beneficial

to ratepayers than the Board's 3GIRM trigger mechanism is to electric utility ratepayers. I have attached the 3GIRM report segment dealing with off-ramps at tab 4.

In that plan or that -- that's not an agreed plan. That's an imposed arrangement. There is no earnings sharing mechanism, and there is a trigger at 300 basis points. So the utility gets everything up to 300 and everything over 300, unless the Board makes some order in the review proceeding that is triggered in that case.

In Union's situation, as a result of the deal that we made, Union gets 250 basis points for earnings up to $300, and then to get to 300 it would actually have to earn over 800 basis points, because it only gets 10 basis points of every 100 over 300.

So the scenario of Union having a licence to earn over 300 basis points, in my respectful submission, is not terribly realistic, because to achieve over 300 for its shareholder they would actually have to earn in excess of 800 basis points above the Board-approved ROE.

Does the agreement eliminate -- the agreement to eliminate the automatic review at 300 basis points dilute ratepayer protection when they get 90 percent of everything over 300? We submit, no.

First, as Mr. Penny has pointed out, the reviews of over-earnings are not eliminated. They take place over-earnings over 200, and all causes can be explored in the context of that process.

Second, the agreement doesn't give Union the licence

to earn more than 300 basis points for shareholders, I have already mentioned.

Third, what is the likelihood of anything over 300 occurring in future years? Because if it doesn't occur, we have given up nothing under either agreement.

Now, in its evidence filing, you don't need to turn this up, but Union has forecast its ROE for 2010. I think it's at 10.37 percent. This is not in my brief, unfortunately. This is at - I will just give you the reference - Exhibit A, appendix C, schedule 2, page 1.

And based on the assumptions that are built into that forecast, that's slightly less than 200 basis points above the ROE that's assumed. In 2010, they are forecasting 8.94 percent ROE, which, again, would be less than the 300 basis points, and I think less than the 200 basis points.

So if we give their forecasts credence - and that can be sometimes risky - they are not going to get there, but even if their forecasts are off when we get 90 percent of everything over and above 300, in my submission, substantively what you have is a cost of service type offering.

Finally, when you ask yourself what are you giving up when you let this trigger go in exchange for the 90 percent of everything over 300, you have to consider what are the probabilities of a review being conducted as we approach the end of the five-year IR plan.

These reviews only take place after a year has been completed. So a 2011 review would come up if it occurred

sometime in 2012. A 2012 review would come up in 2013. And we know that Union's rebasing application is going to be filed either at the end of 2011 or early 2012 for 2013.

So CME thinks it's highly unlikely there would be any full-scale plan or review undertaken either with respect to 2011 or 2012.

So when you put all this together, we are not really giving up much of anything as far as CME is concerned and we think that we've replaced it with what might be termed a more defined situation than that that existed in the initial agreement.

So with that, let me just turn to the Board Staff questions and the matters raised in those questions.

Dealing with the first point: Is the settlement premature? We submit clearly not premature. It's timely. The facts giving rise to this 2008 review are on the table and they give rise to very substantive issues that the parties have been able to resolve. So nothing premature about it at all.

Secondly, Staff questions whether there is a need for a full hearing. I agree with Mr. Penny. The whole purpose of settlement agreements is to avoid the need for a full hearing. That was the purpose of the initial five-year deal and if a five-year deal can be approved without a full hearing, certainly a four-year adjustment to the five-year deal should be capable of being approved without a full hearing. The case Mr. Penny cites certainly supports that proposition.

But then you go on to ask yourself: What is there to hear? As Mr. Penny says nobody is proposing there be an outcome more beneficial to ratepayers than the settlement proposal, so there is really nothing to hear, in our respectful submission.

The third question of Staff related to risks associated with eliminating the trigger mechanism, and it's risks to the parties, really, because the Board is not bound by what the parties do. And in Rule 43 of your Rules of Practice and Procedure, it states:

> "The Board may at any time indicate its intention to review all or part of any order or decision and may confirm, vary, suspend or cancel the order or decision serving a letter on all parties to the proceedings."

So even if some very strange and unexpected circumstances did materialize which called into question the continued appropriateness of this deal, the Board itself can do what is necessary to initiate the review.

Whatever risks there are, and CME doesn't see any, the parties have accepted them in this arrangement. We don't see any dilution of either ratepayer or utility protection. In fact, we submit there is some added ratepayer benefit in that it defines in advance what ratepayers get over the 300 basis points. The fact that we allow Union to keep 10 of it, in my respectful submission, maintains an incentive for Union to do better. The major incentives of this particular five-year deal are with the 200 basis points

dead band and the 50/50 sharing over 200.

So we don't see that very much has been given up and it's arguable that the agreement has been strengthened in terms of ratepayer protection, not weakened.

On the issue of no retroactive ratemaking, we agree with Mr. Penny this does not involve retroactive rate making. There is this ambiguity of sharing over 300. What we have addressed in the settlement is an as yet unresolved item with respect to 2008 earnings sharing, as well as matters pertaining to the automatic 2008 review and reviews beyond 2008. The resolution of these two items is linked in the settlement, but that's the way settlements work and there is no reason, in our submission, why you would -- or why you should find that linkage as inappropriate.

There are these major benefits to ratepayers in the agreement.

At the last schedule, the last page -- this is under Tab 1 of our brief. You will see the allocation of the amounts to ratepayer classes, and by and large the beneficiaries of this settlement are the smaller ratepayers, and that's referenced in the settlement agreement itself at page 7, it's under Tab 1 at page 7, the second last paragraph -- full paragraph on the page.

The financial consequences of this agreement for the calculation of 2008 earnings sharing under the RSM are set out in Appendix A attached to this agreement. The adjustments in the agreement to Union's original proposal are the result of compromise by the agreeing parties of

their respective positions on matters listed above. In all of the circumstances, the parties have agreed to increase the customer share of 2008 earnings from the proposed $15 million to $24.2 million.

And then starting at the bottom:

> "Of the $34.2 million customer share of earnings, approximately 19.6 will be allocated to small volume general service customers and approximately 3.2 million will be allocated to large volume general service customers. Approximately 4.7 will be allocated to large volume contract customers, and approximately 6.7 to M-12 shippers."

It goes on and says:

> "Those benefits will flow back to the customers of the M-12 shippers."

So it's a settlement that is favourable to all customers. If it's not approved, the customers that will suffer the most are the smaller customers.

The settlement agreements, we submit, are in the public interest. This particular agreement is in the interest of ratepayers and the shareholder. It resolves a potentially protracted hearing process and does not dilute the incentive effect of the initial agreement.

CME submits that the Board should not hesitate to approve the deal as fair and reasonable for ratepayers and for Union shareholders. Those are my submissions.

MR. KAISER: Thank you, Mr. Thompson.

Various Proceedings Where FT RAM Was Not Disputed

1	EB-2007-0918	January 2008 QRAM
2	EB-2008-0033	April 2008 QRAM
3	EB-2008-0109	July 2008 QRAM
4	EB-2008-0220	2009 Rates
5	EB-2008-0281	October 2008 QRAM
6	EB-2008-0371	January 2009 QRAM
7	EB-2009-0052	2008 Deferral Account Disposition
8	EB-2009-0054	April 2009 QRAM
9	EB-2009-0101	2008 Earnings Sharing and IR Review
10	EB-2009-0147	July 2009 QRAM
11	EB-2009-0275	2010 Rates
12	EB-2009-0313	October 2009 QRAM
13	EB-2009-0410	January 2010 QRAM
14	EB-2010-0039	2009 Deferral Disposition and Earnings Sharing
15	EB-2010-0040	April 2010 QRAM
16	EB-2010-0148	2011 Rates
17	EB-2010-0201	July 2010 QRAM
18	EB-2010-0265	October 2010 QRAM
19	EB-2010-0359	January 2011 QRAM
20	EB-2011-0025	2012 Rates
21	EB-2011-0029	April 2011 QRAM
22	EB-2011-0038	2010 Deferral Disposition and Earnings Sharing
23	EB-2011-0135	July 2011 QRAM
24	EB-2011-0297	October 2011 QRAM
25	EB-2011-0382	January 2012 QRAM
26	EB-2012-0070	April 2012 QRAM

UNION GAS LIMITED

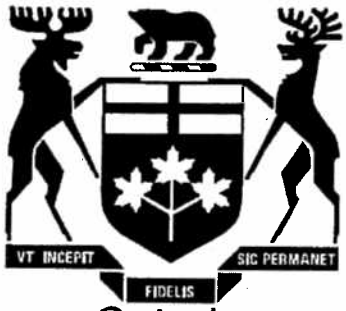
Undertaking of Mr. Thompson
To Mr. Isherwood

Please provide the impact on revenue requirement if interruptible contracts for services were firm.

If the M16 interruptible contracts were firm, net transportation revenue would increase by approximately $0.8 million per year, reducing the revenue deficiency by the same amount. M16 revenues would increase by $0.9 million. However, the firm M16 transportation contracts would reduce the firm capacity available as C1 St. Clair to Dawn transportation and result in reduced revenues. The reduction in C1 St. Clair to Dawn revenue would be $0.1 million.

Firm M16 service is not available or practical for all current customers taking interruptible M16 service as service is limited by local market demands or would require significant storage facilities additions (i.e compressor).

GAS SUPPLY



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **3**

DATE: **July 13, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

management system insofar as it relates to gas transportation choices and decisions and gas supply decisions that ensure that the consequences to the entire company are taken into effect, not just the consequences to the people in that particular area.

I think that's what you're saying.

MR. SHORTS: If we knew exactly what the consequences would be, we would take those into account to our own customers.

But the issue is we just do not have a reliable way to understand what those total impacts are going to be.

MR. BRETT: Obviously. Okay.

The just one or two clean-up questions. Am I in time or am I over now?

MS. HARE: No, you have five minutes.

MR. BRETT: Five minutes?

MS. HARE: Yes, because we would like to take our lunch break at 1:00 o'clock, and that would take you to the --

MR. BRETT: Well, then, I am fine, because I am into the -- I have rounded third, so to speak.

Okay. Now, you talked about a gas supply plan and you made this -- in your evidence, you speak of a five-year gas supply plan, and then you go on to say that -- you outline the assumptions and the principles under which -- that apply to that plan.

Do you recall that, in your evidence-in-chief?

MR. SHORTS: Yes.

MR. BRETT: Now, is there an actual document somewhere in Union that says -- that is a five-year gas supply plan that you revise each year? Does that document exist?

MR. QUIGLEY: Well, the outcome of the plan is in the gas purchase expense schedules that have been filed.

So that shows the costs to serve Union's customers, based on the gas plan.

MR. BRETT: So what you -- yeah. Okay. I think I understand that.

What you show us is the -- is the transportation cost, total cost of transportation, and you list the transportation contracts and you list at a very high level the -- unlike what you used to do, but you list at a very high level the supply arrangements.

But there's -- but that's different than a plan. A plan usually is some sort of a written document that lays out your strategies and how you're going to proceed over the next five years to achieve the goals that you state in your five principles.

Are you telling me you don't have such a document?

MR. QUIGLEY: There's not a written -- like, the preamble of the evidence, D1, tab 1, is the written plan for 2013, which is part of the five-year plan.

The gas purchase expense schedules list all of the costs that have come out of that plan.

I'm not -- I'm -- I'm struggling a bit with what exactly you're asking for.

MR. BRETT: Well, really, I'm saying that you've

identified something called a five-year plan. You then go on to talk about what you're going to do in the test year, which is the first year in a five-year period. You make a general statement about, Well, the first two years are the most important, and the other three years sort of follow on the first two years. Period.

I mean, there is no discussion of a five-year time horizon and how it might change. I mean, what developments are happening, what things are happening out on the marketplace that might, you know, change your -- the proportions of the gas, for example, that you have delivered into Ontario.

In another table in your evidence, you talk about the amounts of gas delivered to Ontario increasing quite substantially, as an example, over the years to 2017, but there is no text to explain that or why that's happening.

So I guess my question is -- I don't think you have a five -- I mean, I'm asking whether you have anything more than what you've set out here, I guess.

I guess you're telling me: No, we don't. That that's what we have.

MR. QUIGLEY: Well, I would suggest -- I believe Exhibit E2 lays out the market dynamics that Union is operating in.

The test year is actually year 3 of the plan. In this case, 2011 is year 1, 2012 is year 2 and 2013 is year 3.

MR. BRETT: So there's not -- I think you're telling me you don't have a plan that you could file with us, with

the Board? I was going to ask you to file a plan.

MR. QUIGLEY: Well, the gas purchase expense schedules are the outcome of the plan.

So that tells you the cost, the volumes that were flowing in the test year, the costs to serve the customers.

So I'm not sure -- I'm struggling a bit with...

MR. BRETT: Well, I think there is not much more we could say at this stage.

And I think that those are my questions. Thank you very much.

MS. HARE: Okay. Thank you. We will break -- oh, Ms. Taylor?

MS. TAYLOR: Sorry, if you don't have a plan, how do you know that you're in year 3 of it?

Like, honestly, you must have a plan, a document that says back two years hence ago, you had a strategy for procuring gas and transportation over the next five years, if that is your defined framework. You are now in year 3 of it.

I'm assuming you have some benchmark document that says: I'm 60 percent of plan or 70 percent, and this is why my procurement strategy is or is not working. It is working great in this other area.

I'm sorry, I just didn't find the answer that you don't have a document that you're managing to credible.

MR. QUIGLEY: Well, we have a volumetric plan that we're managing to on an annual basis.

And you know, at a high level, in Exhibit -- just give

me one second here.

MR. SMITH: Well, why don't we just -- why don't we just reflect on it over the lunch hour?

I am sure there is something that -- there must be, whether it is Excel spreadsheets or whatever it is, there is probably something.

MS. TAYLOR: Okay.

MR. SMITH: There's back-up.

MS. TAYLOR: Point out to me, and I will go find it again.

MR. SMITH: Yes, I think -- I mean, you have the output. The implication of that is there is an input schedule.

MS. TAYLOR: Yes.

MR. SMITH: And a detail output. So we will see what we can find.

MS. TAYLOR: Okay. Thank you.

MS. HARE: We will break until 2:00 o'clock.

When we come back at two o'clock, we will hear submissions on the letter, Mr. Thompson, that you sent in about the evidence that you would like withdrawn.

MR. THOMPSON: Thank you.

MS. HARE: Thank you.

--- Luncheon recess taken at 1:02 p.m.

--- On resuming at 2:11 p.m.

MS. HARE: Thank you. The Board has considered the issue of the undertaking request -- oh, I'm sorry, I took my glasses off. Now I can't see.

[Laughter]

MR. SMITH: Well, the only reason I -- this may change nothing, but we did have an opportunity -- given the request was to rerun the gas supply plan, I wanted to -- I thought it might be helpful to tell you what we've been able to learn about the gas supply plan, and that may or may not have any bearing on the decision.

But the gas supply plan, as I understand it, is not so much a written document. It is two Excel spreadsheets.

MS. HARE: You're responding to Ms. Taylor's question at the end?

MR. SMITH: That's right. But the undertaking request, as I understand it, is to essentially run -- rerun the gas supply plan, which will give you some sense of why the timing is such. So, anyway, the gas supply plan is two spreadsheets, totalling approximately 60 tabs and 42,000 lines of information.

We're prepared to make it available. Monthly there is an update that -- as I understand it, not so much of the plan, but of utilization. We can make those available, too.

So there is -- that's why I say there is a good deal of information. We're prepared to make it available in response to the request. Have I got that right, Mr. Quigley?

MR. QUIGLEY: Yes, that's correct.

MS. TAYLOR: You don't have a summary?

MR. SOMMERVILLE: It is only 42,000 lines of text?

MR. QUIQLEY: We tried to squeeze another one in, but it wouldn't fit.

MS. HARE: The highlights of it are in the evidence; is that correct?

MR. SMITH: The output, yes.

MS. TAYLOR: That's sufficient.

MR. SMITH: Thank you.

MS. HARE: All right. So we have considered the issue of the undertaking request, and we've concluded that we will not compel Union to provide a response to the undertaking.

The Board has little interest in hypothetical constructs. The key assumption underlying the request is that the purchase of all of the transportation for the eastern delivery area would be a short-term transportation, which we believe is not realistic.

And, therefore, the outcome of the analysis would be of little evidentiary value.

MR. QUINN: If I may speak to that? I accept the decision, and --

MS. HARE: That's good.

MR. QUINN: -- I was not asking for all to be short term. I thought some could be layered in, but I understand from the explanation of the gas supply plan that it's not going to be delivered. We will be challenged, I guess, to provide any other alternative to their current planning in the evidence, and I will have to accept that.

MS. HARE: And you can of course in your submissions

argue for a change in the mix. That would be up to you.

MR. QUINN: Okay.

MS. HARE: Mr. Thompson, then, would you speak to the letter that you wrote concerning the evidence that you would like withdrawn as part of the interrogatory response?

ADMISSIBILITY OF PORTIONS OF JT1.55

SUBMISSIONS BY MR. THOMPSON:

MR. THOMPSON: Yes. Thank you for allowing me this opportunity to speak to the matter.

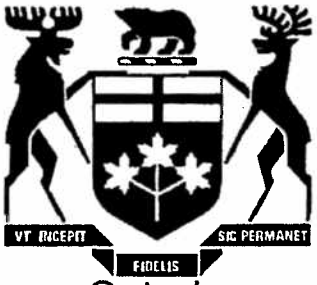
What you will need to follow this is the letter that I sent on July 9th, which has attached to it the initial letter that I sent to Union June 22nd, Mr. Smith's response, and then my letter to the Board.

The second thing you will need available is the response to JT1.55 and its attachments. That's the evidence that I am concerned about.

Then, finally, if you would have it at hand, it is Mr. Aiken's compendium, K1.1, and I wanted to the excerpt from the Board's cost of capital report, which is at page 12 of 16 of that material.

So if I might just start with the June 22 letter, which is attached to my July 9 letter, this was written -- you can see from the last paragraph of the letter that we were hoping to be able to persuade Union to withdraw this information without having to trouble the Board with our concern.

Mr. Smith responded to that the day before the hearing commenced, and then we sent our letter to the Board.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME: 6

DATE: July 19, 2012

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

whether Union had taken its pro rata share and whether the full benefits would, in effect, flow through to ratepayers.

And the answer we have below, which was what?

MR. ISHERWOOD: The answer was it actually flowed through the S&T transactional account, and to the extent that it helped us earn our forecasted amount, it was the first contribution, if you want, towards ratepayers.

And, ultimately, if it contributed towards earnings sharing, it would also contribute towards ratepayer benefit that way.

MR. SMITH: This was obviously the subject of some dispute in the 0220 case. And can I ask you to turn to page 21 of the compendium? What was the Board's decision with respect to that proposed treatment?

MR. ISHERWOOD: So on page 21, the second paragraph from the bottom under the title "Upstream Transportation Changes", it talks -- it gives the Board's decision in terms of agreeing with Union's position that ratepayers were already benefitting from the forecast that was built into rates. As well, it can ultimately contribute to earnings sharing, as well, and that this was normal activity towards the transportation exchange account.

MR. SMITH: A couple of other questions. We have filed at Exhibit J3.1 an answer to an undertaking given to Mr. Quinn, and that was to draw a chart.

If I could just ask that that be pulled up. And perhaps this is for you, Mr. Shorts, but could you just tell me what it is that we're looking at here?

MR. SHORTS: Sure. I will start from the bottom, just to give everybody an idea of what we're showing under this graph.

If we look at the blue area, the blue area represents the daily deliveries into Union's EDA for its in-franchise sales service and bundled customers.

This would exclude our transportation or T-service customers, because they are responsible for bringing their own transportation and supply into the zone each day.

If we go up to the first horizontal line at approximately 60,000, so that yellow line represents the contracted Empress to EDA Union long haul transportation capacity.

I will then move up to the green line, and the green line, which is just below 100, that is the long haul EDA to -- or Empress to EDA long haul capacity, as well as the firm short haul Parkway to EDA capacity that is contracted for.

I'm going to skip right up to the red line at the top, which is just over 160,000 shown, and that represents the contracted Empress to EDA long haul, the short haul firm Parkway to EDA I just mentioned, as well as our firm STS withdrawal rates.

And it is this line that is the firm capacity or the firm portfolio that is used to serve the design day in the plan for the EDA.

Now, a couple of things just to note. You will see that the yellow line or the EDA capacity, that long haul

capacity from Empress to the EDA, really serves two purposes.

It not only serves as part of that portfolio of peak day or design day assets, but it also serves to meet those annual delivery needs.

So, for example, if you look at the area in the graph where the blue lines are below the yellow line, that would simply be a time period in which, on a given day, the demands coming into the eastern delivery area were in excess of the daily requirements, and that gas would be STS-injected into Dawn storage to be used later.

And, likewise, when the blue lines are above that, that firm pipe is supplemented by those other assets, so either the firm short haul or the STS withdrawal rates.

One thing to also note is that during this time period, from November of 9 to March 2012, that gas supply was purchased each and every day at Empress. So it was needed there for annual needs, and there was no UDC incurred because of those supplies.

MR. SMITH: Thank you, Mr. Shorts. And just a couple of last questions. We had similarly provided, as we agreed to do, an update to Exhibit B7.7, which was a response to an interrogatory in a different proceeding, the 0087 proceeding.

And, Ms. Cameron, perhaps this is for you, but I would just ask you to focus on the TCPL-Union CDA and just describe what is being captured under the optimization percentage referred to there.

or did I miss some differentiating feature?

MR. SHORTS: You can also -- like a bank account, if you have overdraft protection, you could withdraw more than what was in that bank account.

MR. QUINN: Okay. Well, we will get to that in a moment, then.

MR. ISHERWOOD: I think the one differentiation Mr. Shorts was making was you can't buy gas at Dawn and put it into the STS account. It has to come off the TCPL system from the EDA or WDA, for example. Then it is counted as an injection into the account.

MR. QUINN: It has to come from the EDA system, as an example. Let's use EDA to make it simple, Mr. Isherwood, and that has to be coming long haul transport to the EDA?

MR. ISHERWOOD: That is coming long haul transport into Ontario.

MR. QUINN: The long haul transport to your service area, in this case, the eastern delivery area, creates a deposit like it would into a bank account?

MR. ISHERWOOD: Yes, the gas that is required in the EDA that day. You can go back to the graph Mr. Shorts talked about this morning. You say the kind of sine waves, the peaks and the valleys. That whole valley period, you would be expecting injections into the STS account.

MR. QUINN: We will get back to those graphs, but I just want to take this one step at a time, because unfortunately I didn't get clarity.

So like a bank account, you make your deposits in good

[Mr. Millar passes out the exhibit]

MS. HARE: So we are on page 5 of this compendium; is that correct?

MS. CAMERON: Yes. If you go to page 5 of the compendium, in the seventh grouping of customer information, you will see "Union Gas" is in the middle of that, and the first "Union Gas" line, it starts with 11, 4-2.

The contract start date is listed there as April of 1992, and that refers to the STS service. I can't be certain that it didn't exist before then, but I think this does support that it has existed for quite some time.

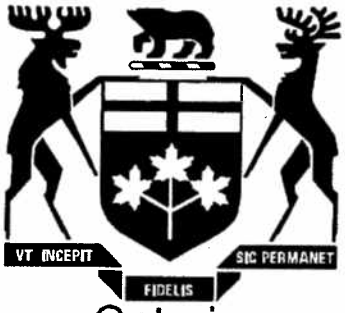
MR. QUINN: So historically this service was used for some time to be able to meet peak winter demands. When did Union --

MR. ISHERWOOD: Actually the purpose of the service is to make sure the FT contracts can flow on a hundred percent load factor, or as close to that as possible.

So it not only helps you serve the winter peak, but also helps you serve the summer valley and provide a spot for that to go back to Dawn. So it really is a very unique tool. It is a great service TCPL offers that allows us to balance our system, summer and winter.

It is just as important in the summer as it is in the winter. Otherwise gas would be very expensive in Ontario.

MR. QUINN: Okay. Well, I am trying to work backwards from the graph into where Ms. Cameron led us, but I think I will just do it this way.



Ontario

ONTARIO ENERGY BOARD

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VOLUME: **14**

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BEFORE:	**Marika Hare**	**Presiding Member**
	Karen Taylor	**Member**

shippers to demonstrate that their delivery obligations to Union are underpinned by firm contracts.

This is a very important point.

In Union's argument-in-chief, Union's counsel seemed to take offence at the depiction of the resulting assignment service as lesser service, which is found on page 34 of volume 13.

But clearly it is. Reviewing the outcomes presented in Exhibit J6.5, for the gas year of November 2010 to October 2011, Union customers are paying for firm service to, say, Cornwall and receiving assigned winter service in Kenora or Thunder Bay that Union has not substantiated as being underpinned by firm contracts.

Given that these assignments generate IT credits that must be used in the same month, it is highly probable that some or possibly all of the gas that arrives in northwestern Ontario in these assignment arrangements arrives using IT transport, the same interruptible transport that Union Gas supply panel said it ought not rely on in its examination in-chief, which, again, can be found on page 17 and 18 of volume 3, which is, again, near the front of our compendium.

To drive that point home, I want to review another reference, which is Exhibit J7.3, which can be found on page 56 and 57.

In this reference, we actually need to provide the net proceeds provided from assignments of Empress-to-CDA capacity in calendar 2011.

As you can see from the table, while the assignments were sent to Dawn in the summer, gas that was contracted to arrive at the CDA was assigned to the WDA and NDA. The net proceeds of this arrangement was about $9 million.

Now, we did neglect to ask for the difference in demand charges and what the difference in demand charges to the respective areas would be, to be comparable to Exhibit 6.5, but doing the simple math using the demand charges found on Exhibit 6.5, the amount of demand charge differential between deliveries at CDA and where the gas actually arrived at WDA and NDA was $8.8 million.

In our view, customers should not be treated this way, because no one has looked under the hood of the black box.

On my third point, for TransCanada capacity, the Union Gas supply plan relies on long-term firm service contracts that have been avoided or turned back by all customers, including prudent utilities in Canada and the US for the last number of years.

The declining level of annual firm transport contracts is well known in the industry, and the evidence of the continued reduction can be found in Exhibit K3.1, which you've viewed many times in this proceeding.

So while other utilities and shippers like Enbridge have moved to shorter-term arrangements such as winter STFT, Union has continued to keep the long annual FT contract.

When asked why they did not move to shorter-term arrangements like a winter STFT contract, the answer was

the capacity may not be available and they may not be able to re-contract for annual -- for the annual FT contract. And again, that can be found in the front of my compendium in the transcript from volume 3.

With respect, that position clearly does not reconcile with the current situation with TCPL contracting.

These are gas supply experts, who work in the same department under Mr. Isherwood that handles the interventions into the TCPL filings at the NEB.

Information commonly known among experts and non-experts is that firm contracting on the main line is diminishing significantly, resulting in spare capacity that cannot be sold.

The often referred to Exhibit K3.1 shows exactly that.

The result is the capacity available for annual -- the result is capacity available for annual FT contracts.

The information is publicly available through TCPL's index of customers, but Union's department under Mr. Isherwood is much better resourced than that.

However, when I posed the question about the availability of STFT to Union's gas supply panel, captured on pages 21 to 23 of volume 3 earlier in the compendium, the barrier was presented that the service may not be available. As can be seen on page 22, the witnesses said the service was not available to Sault Ste. Marie delivery area.

What the witness did not say is that the delivery area is not served directly by TransCanada pipeline, but off of

Great Lakes' system under an arrangement with TCPL.

Clearly I was deflected. However, we were able to ask experts on STFT from TCPL -- which can be found on pages 115 and 116 of volume 9 -- when the last time STFT was not available from North Bay east, and with the exception of a caveat that they placed on Montreal, outside of Union's territory, the answer was: STFT has been available for decades.

In our submission, there are no other reasons why Union is not seeking the same alternatives to pursue the advantages of STFT.

One point that should not be lost in this discussion is Union's choice. Union had an understanding and years of using the FT RAM program.

There is a choice to use the FT RAM program for gas supply, but Union -- and Union confirms that on page 130 of the transcript in volume 7, which can be found on page 62.

Gas could flow, ostensibly, in a contract to Cornwall, could actually be diverted to Dawn and flowed IT. That would create approximately 20 percent more gas available at Dawn for the same price.

Therefore, the gas supply department has had the choice and the knowledge that it could have exercised to evolve its gas supply planning to use FT RAM credits for the benefit of the gas supply program.

Before I get to the issue of the classification of the FT RAM credits, I want to summarize our position. And if there are questions by the Board Panel, I could answer them

at that time, but I also want to address a question that the Board Panel asked to Staff.

Our submission summarized is that Union's pattern of utilization demonstrates the actual need, but its contracting practices are in excess of the actual need.

Number two, Union's customers have been paying more than they ought to due to the incentives enjoyed by the shareholders, and the summary of those incentives are captured throughout the evidence in this proceeding.

Union has not considered -- on our third point -- Union has not considered other viable options employed by other utilities. And I might add those options have been considered at the request of and subsequently approved by this Board for utilities such as Enbridge.

Our fundamental belief is the appropriate classification of the benefits of FT RAM credits would address most of the important concerns that we have.

Establishing a return to a more equitable return of the benefits and attributes of gas supply contracts to ratepayers would reduce ratepayers' risk for 2013.

Then, without the exorbitant profit incentives, the rightsizing of asset rights to serve the gas supply needs of its customers can be evaluated, defined and implemented.

And I must add, because of my experience, other alternatives should be considered.

We recognize that Union has entered into contracts for the gas year of November 2012 through October 2013, and it would not be in the public interest to change those



2000 through 2011
GJs/day

Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
TransCanada Pipeline - North Long Haul														
Empress to Union MDA FT	Empress	Union MDA	4,522	4,522	4,522	4,522	4,522	4,522	4,522	4,522	4,522	4,522	4,522	4,522
Empress to Union WDA FT	Empress	Union WDA	83,957	83,957	83,957	63,957	63,957	63,957	59,458	49,842	44,482	42,538	39,880	39,880
Empress to Union NDA FT	Empress	Union NDA	137,243	137,243	137,243	97,243	87,165	86,801	86,801	86,801	84,365	80,881	76,546	67,625
Empress to Union SSMDA FT	Empress	Union SSMDA	33,225	33,225	33,225	33,225	32,372	32,372	32,185	32,069	32,069	29,505	9,443	9,143
Empress to Union NCDA FT	Empress	Union NCDA	11,039	11,039	11,039	11,039	11,039	11,039	11,039	11,039	11,039	11,039	11,039	10,756
Empress to Union EDA FT	Empress	Union EDA	88,657	88,657	88,657	85,989	85,989	85,989	85,989	85,989	85,989	61,156	61,156	59,251
TCPL FT Long Haul - Total			358,643	358,643	358,643	295,975	285,044	284,680	279,994	270,262	262,466	229,641	202,586	191,177
TransCanada Pipeline - South Long Haul														
Empress to Union CDA FT	Empress	Union CDA	229,848	149,037	137,068	174,081	171,581	191,281	201,881	91,870	71,327	71,327	71,327	71,327
TransCanada Storage Transportation Service Firm Withdrawal														
NCDA	Parkway	Union NCDA	13,704	13,704	13,704	13,704	13,704	13,704	13,704	13,704	13,704	13,704	13,704	13,704
WDA	Parkway	Union WDA	11,420	11,420	11,420	31,420	31,420	31,420	31,420	31,420	31,420	31,420	31,420	31,420
SSMDA	Dawn	Union SSMDA	35,022	35,022	35,022	35,022	35,022	35,022	35,022	35,022	35,022	35,022	35,022	35,022
NDA	Parkway	Union NDA	8,375	8,375	8,375	48,375	48,375	48,375	48,375	48,375	48,375	48,375	48,375	48,375
EDA	Parkway	Union EDA	68,520	68,520	68,520	68,520	68,520	68,520	68,520	68,520	68,520	68,520	68,520	68,520
TCPL Firm STS Withdrawal - Total			137,041	137,041	137,041	197,041	197,041	197,041	197,041	197,041	197,041	197,041	197,041	197,041
TransCanada Storage Transportation Service Firm Injection														
WDA	Union WDA	Parkway				3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150
EDA	Union EDA	Parkway	47,571	47,571	47,571	47,571	47,571	47,571	47,571	47,571	47,571	47,571	47,571	47,571
NDA	Union NDA	Parkway	57,100	57,100	57,100	49,100	49,100	49,100	49,100	49,100	49,100	49,100	49,100	49,100
TCPL Firm STS Injection - Total			104,671	104,671	104,671	99,821	99,821	99,821	99,821	99,821	99,821	99,821	99,821	99,821

Information provided is consistent with the best records available.

Canadian Mainline Winter 2011/2012 Open Season for STFT and ST-SN
July 7-14, 2011

TransCanada's Canadian Mainline is currently posting the following firm transportation services in this Short Term Capacity Open Season (the "Open Season") for service in the 2011/2012 Winter season (November 1, 2011 to March 31, 2012). No partial period bids will be accepted in this Open Season.

Table 1: Available Short Term Capacity (GJ/d) - Summer 2011[1]

Posted System Segments for STFT and ST-SN[2]	November 1, 2011 to March 31, 2012 (GJ/d)
Empress to	
South Saskatchewan Delivery Area (SSDA)	5,660,000
Manitoba Delivery Area (MDA)	5,660,000
Western Delivery Area (WDA)	1,290,000
Northern Delivery Area (NDA)	1,290,000
North Bay Junction	1,290,000
Central Delivery Area (CDA)	1,290,000
Eastern Delivery Area (EDA)[3]	900,000
Eastern Delivery Area (GMi EDA)	0
Sault Ste Marie Delivery Area (SSMDA)	33,500
Southwest Delivery Area (SWDA)	705,000
Emerson 1	753,750
Emerson 2	1,528,500
Kirkwall	528,000
Niagara	528,000
Chippawa	246,300
Iroquois	766,000
Napierville	120,000
Philipsburg	15,000
East Hereford[4]	157,125
North Bay Junction to	
Central Delivery Area (CDA)	1,931,250
Kirkwall to	

Niagara	759,000
Chippawa	246,300
St. Clair to	
Union SWDA	1,020,000
Union Dawn to	
Kirkwall	528,000
Niagara	528,000
Chippawa	246,300
Union CDA	68,000
Union Parkway Belt	
Union CDA	336,000
STSN Metering Capacity (Subject to Segment Capacity)	
Goreway CDA	61,000
Victoria Square #2 CDA	50,000
Thorold CDA	75,000

[1] TransCanada is not accepting bids from all export points (excluding Emerson) unless otherwise listed in the table above.

[2] May not be available on all paths. Please contact your Mainline Customer Account Manager if you are interesting in bidding on this service.

[3] Capacity available to Enbridge EDA, Union EDA, and Cornwall only.

[4] Shippers and prospective shippers should be aware that TransCanada has posted firm capacity to East Hereford that is in excess of the downstream firm take-away capacity on PNGTS. PNGTS may have interruptible capacity available on certain days, depending on operating conditions. When insufficient interruptible take-away capacity is available on PNGTS, those FT shippers on TransCanada that are unable to flow their gas downstream of East Hereford may instead nominate diversions to alternate Delivery Points or, if applicable, obtain FT-RAM credits for use elsewhere on the TransCanada system.

[5] Includes all points listed in Table 1. Is subject to each delivery points' available capacity listed.

Open Season & Bidding Procedure Highlights

- **Bids must be received by TransCanada no later than 8:00 a.m. Calgary time on Thursday, July 14, 2011**
- Term: November 1, 2011 to March 31, 2012 block only. No Partial period bids will be accepted.
- System Segment Capacity:
  - Some posted segments share common capacity. A successful bid on one system segment may reduce the capacity on another system segment in any Mainline Open Season.
  - Any bids that pertain to common capacity will be evaluated together for allocation purposes.

- Each capacity segment requested must be on an individual bid form.
- Conditional Bidding: STFT bids can be conditioned on another STFT bid.
  - If an STFT bid is conditional on another STFT bid, if either STFT bid requires a reduction to the maximum daily quantity, the maximum daily quantity for the other STFT bid will be reduced by the same percentage.
  - Please submit each set of conditional bids in a separate fax, to provide clarity on which bids are related.
- Min Acceptable Quantity: May be specified by bidder in the event that prorating capacity is necessary.
- There are no Diversions, Alternate Receipt Points, FT-RAM or Renewal Rights with any STFT service.
- Transportation sales in the Daily Existing Capacity Open Season will affect the available capacity in this STFT Open Season.

How To Bid

Service applicants must submit a binding Short Term Firm Transportation Contract, Exhibit "A" Addendum, Paper Version or Electronic Version, to TransCanada's Mainline Contracting Department at 1.403.920.2343. Bids under this Open Season must be received by 8:00 a.m. Calgary time on Thursday, July 14, 2011.

Questions

If you have any questions or would like to obtain a form to bid in this Short Term Firm Open Season, please contact your Mainline Customer Account Manager.

Calgary

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Completed bids must be faxed by 8 am Calgary time on July 14, 2011 to Mainline Contracting @ 1.403.920.2343.

Appendix

LINKS to Additional Information:

- Short Term Firm Transportation Contract, Exhibit "A" Addendum Paper Version
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- 2011 Interim Mainline Tolls Effective March 1, 2011
- Index of Customers showing recent contracts and renewals
- Other TransCanada Information: www.transcanada.com/customerexpress

GST/HST Procedures for STFT - FOR EXPORT POINTS ONLY

TransCanada is required to charge the Goods and Services Tax (GST) or Harmonized Sales Tax (HST), whichever is applicable, on transportation of gas that is consumed in Canada. The GST is set at 5% while HST is set at 13% in Ontario.

Shippers may provide a Declaration which notifies TransCanada that the Shipper's STFT contract is intended to serve an export market and should be charged 0% GST or 0% HST, on any Unutilized Demand Charges (UDC).

The Declaration Form is available at the following link:

STFT GST/HST Declaration

Shippers may also zero-rate GST or HST on the associated transportation demand, commodity and pressure charges by making a **Declaration on the nomination** line in NrG Highway.

Please note:

- A Declaration cannot be applied retroactively.
- A separate STFT GST/HST Declaration form must be used for each Exhibit "A" (STFT Bid form)
- If a Shipper zero-rates their nomination but does not execute a Declaration for the STFT the Shipper will be charged 0% GST or 0% HST on their nomination but all associated UDCs will be charged the current applicable GST or HST rate.

Electronic STFT Bid Form:

- The Electronic STFT Bid Form will require you to select Yes or No for GST/HST applicable export points. If Yes is selected, the Declaration form will automatically be filled in for you and must be executed and attached to your bid.

Please refer to the following website for additional information on GST/HST regulations and rebates: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/gst-tps/gnrl/txbl/trnsprttn/menu-eng.html.

For more information on TransCanada's GST/HST practices, contact mainline_contracting@transcanada.com.

Canadian Mainline Winter 2012/2013 Open Season for STFT and ST-SN
July 19-26, 2012

TransCanada's Canadian Mainline is currently posting the following firm transportation services in this Short Term Firm Capacity Open Season (the "Open Season") for service in the 2012/2013 Winter season (November 1, 2012 to March 31, 2013). TransCanada will be accepting bids for individual monthly blocks up to the full Winter 2012/2013 term in this Open Season. TransCanada will be accepting bids in this Short Term Firm Open Season until 8:00 a.m. Calgary time on July 26, 2012. The capacity available in located in the tables below.

Table 1: Available Short Term Capacity (GJ/d) – Winter 2012/2013[1]

Paths not listed in Table 1 may have capacity available, please contact your Mainline Customer Account Manager.

Posted System Segments for STFT	November 2012 (GJ/d)	December 2012 (GJ/d)	January 2013 (GJ/d)	February 2013 (GJ/d)	March 2013 (GJ/d)
Empress to (Domestic)					
South Saskatchewan Delivery Area (SSDA)	5,680,300	5,680,300	5,680,300	5,680,300	5,680,300
Manitoba Delivery Area (MDA)	5,680,300	5,680,300	5,680,300	5,680,300	5,680,300
Western Delivery Area (WDA)	1,543,200	1,543,200	1,543,200	1,543,200	1,543,200
Northern Delivery Area (NDA)	1,543,200	1,543,200	1,543,200	1,543,200	1,543,200
North Bay Junction	1,543,200	1,543,200	1,543,200	1,543,200	1,543,200
Central Delivery Area (CDA)	1,543,200	1,543,200	1,543,200	1,543,200	1,543,200
Eastern Delivery Area (EDA)[2]	962,200	962,200	962,200	962,200	962,200
Eastern Delivery Area (GMi EDA)	295,000	295,000	295,000	295,000	295,000
Southwest Delivery Area (SWDA)	170,100	170,100	170,100	170,100	170,100
Empress to (Export)					
Emerson 1	753,700	753,700	753,700	753,700	753,700
Emerson 2 [3]	3,433,800	3,433,800	3,433,800	3,433,800	3,433,800
Kirkwall	170,100	170,100	170,100	170,100	170,100
Niagara	170,100	170,100	170,100	170,100	170,100
Chippawa	170,100	170,100	170,100	170,100	170,100
Iroquois	769,000	769,000	769,000	769,000	769,000
Napierville	124,500	124,500	124,500	124,500	124,500
Philipsburg	15,600	15,600	15,600	15,600	15,600
East Hereford[3]	157,500	157,500	157,500	157,500	157,500

Table 2: Available Short Term Capacity (GJ/d) – Winter 2012/2013[1]

Paths not listed in Table 2 may have capacity available, please contact your Mainline Customer Account Manager.

Posted System Segments for STFT	November 2012 (GJ/d)	December 2012 (GJ/d)	January 2013 (GJ/d)	February 2013 (GJ/d)	March 2013 (GJ/d)
Dawn to					
Kirkwall	273,200	273,200	273,200	273,200	273,200
Niagara	273,200	273,200	273,200	273,200	273,200
Chippawa	273,200	273,200	273,200	273,200	273,200
Parkway to					
Southwest Delivery Area (SWDA)	170,100	170,100	170,100	170,100	170,100
Kirkwall	170,100	170,100	170,100	170,100	170,100
Sault Ste. Marie to					
Union SSMDA	0	0	0	0	0
St. Clair to					
Union SWDA	1,638,900	1,638,900	1,638,900	1,638,900	1,638,900
Kirkwall to					
Niagara	871,300	871,300	871,300	871,300	871,300
Chippawa	303,300	303,300	303,300	303,300	303,300

Table 3: Available Short Term Capacity (GJ/d) – Winter 2012/2013[1]

The System Segments listed below with a receipt point of Emerson 2 are limited as a result of physical receipt capability. Paths not listed in Table 3 may have capacity available, please contact your Mainline Customer Account Manager.

Posted System Segments for STFT	November 2012 (GJ/d)	December 2012 (GJ/d)	January 2013 (GJ/d)	February 2013 (GJ/d)	March 2013 (GJ/d)
Emerson 2 to					
Points Downstream [4]	58,300	58,300	58,300	58,300	58,300

Table 4: Available Short Term Capacity (GJ/d) – Winter 2012/2013[1]

Paths not listed in Table 4 may have capacity available, please contact your Mainline Customer Account Manager.

Posted System Segments for ST-SN	November 2012 (GJ/d)	December 2012 (GJ/d)	January 2013 (GJ/d)	February 2013 (GJ/d)	March 2013 (GJ/d)
ST-SN Metering Capacity (Subject to Segment Capacity)					
Empress to					
Goreway CDA	51,100	51,100	51,100	51,100	51,100
Victoria Square #2 CDA	41,800	41,800	41,800	41,800	41,800
Thorold CDA	63,000	63,000	63,000	63,000	63,000
Schomburg CDA	14,300	14,300	14,300	14,300	14,300

[1] TransCanada is not accepting bids from all export points (excluding Emerson) unless otherwise listed in the tables above.
[2] Capacity available to Enbridge EDA, Union EDA, KPUC, and Cornwall.
[3] Shippers and prospective shippers should be aware that TransCanada has posted firm capacity to Emerson 2 and East Hereford that is in excess of the downstream firm take-away capacity on Great Lakes and PNGTS.
[4] Delivery capability subject to downstream capacity as noted in Table 1.

Open Season & Bidding Procedure Highlights

- **Bids must be received by TransCanada no later than 8:00 a.m. Calgary time on Tuesday, July 26, 2012**
- Term: November 1, 2012 to March 31, 2013. Minimum one (1) month term.
- Bids must end on the last day of a month.
- System Segment Capacity:
  - Some posted segments share common capacity. A successful bid on one system segment may reduce the capacity on another system segment in any Mainline Open Season.
  - Any bids that pertain to common capacity will be evaluated together for allocation purposes.
  - Each capacity segment requested must be on an individual bid form.
- Conditional Bidding: STFT bids can be conditioned on another STFT bid.
  - If an STFT bid is conditional on another STFT bid, if either STFT bid requires a reduction to the maximum daily quantity, the maximum daily quantity for the other STFT bid will be reduced by the same percentage.
  - Please submit each set of conditional bids in a separate fax, to provide clarity on which bids are related.
- Minimum Acceptable Quantity: May be specified by bidder in the event that prorating capacity is necessary.
- There are no Diversions, Alternate Receipt Points, FT-RAM or Renewal Rights with any STFT service.
- Transportation sales in the Daily Existing Capacity Open Season will affect the available capacity in this STFT Open Season.

How To Bid

Service applicants must submit a binding Short Term Firm Transportation Contract, Exhibit "A" Addendum, Paper Version or Electronic Version, to TransCanada's Mainline Contracting Department at 1.403.920.2343. Bids under this Open Season must be received by 8:00 a.m. Calgary time on Tuesday, July 26, 2012.

Questions

If you have any questions or would like to obtain a form to bid in this Short Term Firm Open Season, please contact your Mainline Customer Account Manager.

Calgary	
Gordon Betts Phone: 1.403.920.6834 Email: gordon_betts@transcanada.com	**Michael Mazier** Phone: 1.403.920.2651 Email: mike_mazier@transcanada.com
Toronto	
Amelia Cheung Phone: 1.416.869.2115 Email: amelia_cheung@transcanada.com	**Reena Mistry** Phone: 1.416.869.2159 Email: reena_mistry@transcanada.com
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GST/HST Procedures for STFT - FOR EXPORT POINTS ONLY

TransCanada is required to charge the Goods and Services Tax (GST) or Harmonized Sales Tax (HST), whichever is applicable, on transportation of gas that is consumed in Canada. The GST is set at 5% while HST is set at 13% in Ontario.

Shippers may provide a Declaration which notifies TransCanada that the Shipper's STFT contract is intended to serve an export market and should be charged 0% GST or 0% HST, on any Unutilized Demand Charges (UDC).

The Declaration Form is available at the following link:

STFT GST/HST Declaration

Shippers may also zero-rate GST or HST on the associated transportation demand, commodity and pressure charges by making a **Declaration on the nomination** line in NrG Highway.

Please note:

- A Declaration cannot be applied retroactively.
- A separate STFT GST/HST Declaration form must be used for each Exhibit "A" (STFT Bid form)
- If a Shipper zero-rates their nomination but does not execute a Declaration for the STFT the Shipper will be charged 0% GST or 0% HST on their nomination but all associated UDCs will be charged the current applicable GST or HST rate.

Electronic STFT Bid Form:

- The Electronic STFT Bid Form will require you to select Yes or No for GST/HST applicable export points. If Yes is selected, the Declaration form will automatically be filled in for you and must be executed and attached to your bid.

Please refer to the following website for additional information on GST/HST regulations and rebates: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/gst-tps/gnrl/txbl/trnsprttn/menu-eng.html.

For more information on TransCanada's GST/HST practices, contact mainline_contracting@transcanada.com.

TransCanada Pipelines Limited (TransCanada), NOVA Gas Transmission (NGTL), Foothills Pipe Lines Ltd (Foothills) Application for Approval of the Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013 (Application)

Hearing Order RH-003-2011

File OF Tolls Group 1 – T211-2011-04-01

UGL Interrogatories Response to TCPL

1.1 Reference:

(i) Written Evidence of the MAS, page 5, lines 5-7.

Preamble: In reference (i), MAS states that "All three MAS members are physically connected to the TransCanada Mainline and must rely on TransCanada's services to meet their customers' gas needs. As a result, MAS consider that all three LDCs are captive shippers of TransCanada's system." TransCanada seeks additional information to understand the extent of any captivity to the Mainline and how it may have or could change over time.

Requests:

(a) Please provide the particulars of the transportation arrangements of Union other than on the Mainline for each year from 2000 to 2012.

(b) Please identify the amount of gas delivered to Union pursuant to direct purchase agreements with third parties (e.g., marketers) for each year from 2000 to 2012.

(c) For each year from 2000 to 2012, please identify the total cost of Union supply and transportation portfolio and the share of such costs attributable to Mainline transportation.

(d) (i) Please identify all initiatives undertaken or anticipated by Union that have or may contribute to a reduction in reliance on the Mainline; and

(ii) Quantify the potential impact on Mainline billing determinants, including but not be limited to changes in contracting practices from long-haul to short-haul, from the WCSB to other basins, system expansions that may bypass in whole or in part Mainline segments and tariff provisions that would allow gas to connect directly to the franchises of Union.

Where applicable to (i) or (ii), provide any open season documents and regulatory application references.

Response:

a) Please see Attachment 1 for a breakdown of Union's system transportation portfolio for the time period requested. The information for 2005 and 2011 was also provided in MAS' response to CAPP 17 a). Union's November 1, 2012 system transportation portfolio has not yet been finalized. Union has attempted to assemble a lot of information in a short amount of time and believes the revised response to be responsive to TCPL's request.

b) Direct purchase customers deliver to Union the same amount of gas as they consume, pursuant to certain tolerances, or in the case of T-Service or unbundled, subject to their use of storage during their contract year.

The amount of gas consumed by direct purchase customers for the years 2000 through 2012 YTD is detailed in the table below. 2012 YTD represents January through April consumption only.

Direct Purchase Volumes by Year in 10^3m^3	
Year	**Total**
2000	11,255,367
2001	10,471,789
2002	11,765,252
2003	11,447,810
2004	11,411,045
2005	10,963,622
2006	10,452,781
2007	10,805,180
2008	10,579,517
2009	9,605,913
2010	10,044,928
2011	10,409,340
2012 YTD	3,846,994

c) The following table provides the total cost of Union's system supply and transportation portfolio and the share of such costs attributable to Mainline transportation.

Year	Total Union System Supply & Transportation Costs ($ millions)	Mainline Transportation Costs ($ millions)	Mainline Transportation Share of Total Costs
2000	870.0	124.0	14%
2001	1,200.8	104.5	9%
2002	580.6	101.7	18%
2003	1,154.3	109.0	9%
2004	1,036.6	86.0	8%
2005	1,243.6	90.4	7%
2006	924.3	79.2	9%
2007	855.4	86.0	10%
2008	1,262.7	111.1	9%
2009	720.7	90.2	13%
2010	678.2	124.1	18%
2011	776.8	156.2	20%
2012 YTD	185.2	48.5	26%

d)

(i) and (ii) Union declines to provide the requested information on the grounds that the request is unreasonable. The time, effort and exercise involved in the preparation of a response are not warranted by the probated value of the result. However, Union considers several factors including landed costs, operational and contractual flexibility and diversity of supply when developing its supply and transportation portfolio. At any given time the interaction of these factors may have resulted in, or be cause for, an increase or decrease to its level of contracting on the Mainline.

Please refer to MAS' response to CAPP 1 a) for further details on Union's Parkway Expansion Project. MAS' response to CAPP 11 c) lists other Union/Spectra projects that would bring U.S. supply to Ontario.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2000
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2004
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2003
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2004
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2003
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2002
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2003
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2007
8	Empress to Union EDA FT	Empress	Union EDA	2,668	GJ	01-Nov-2003
9	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
10	Empress to Union NDA FT	Empress	Union NDA	128,480	GJ	01-Jan-2004
11	Empress to Union NDA FT	Empress	Union NDA	2,169	GJ	01-Nov-2003
12	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
13	Empress to Union WDA FT	Empress	Union WDA	79,764	GJ	01-Jan-2004
14	Empress to Union WDA FT	Empress	Union WDA	2,249	GJ	01-Nov-2003
15	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2008
16	Empress to Union SSMDA FT	Empress	Union SSMDA	30,474	GJ	01-Jan-2004
17	Empress to Union SSMDA FT	Empress	Union SSMDA	187	GJ	01-Nov-2003
18	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
19	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2005
20	TCPL FT - Total			358,643	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
21	NCDA	Parkway	Union NCDA	13,704	GJ	01-Apr-2003
22	WDA	Parkway	Union WDA	11,420	GJ	01-Apr-2003
23	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Apr-2003
24	NDA	Parkway	Union NDA	8,375	GJ	01-Apr-2003
25	EDA	Parkway	Union EDA	68,520	GJ	01-Apr-2003
26	TCPL Firm STS Withdrawal - Total			137,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
27	EDA	Union EDA	Parkway	47,571	GJ	01-Apr-2003
28	NDA	Union NDA	Parkway	57,100	GJ	01-Apr-2003
29	TCPL Firm STS Injection - Total			104,671	GJ	
	Centra Transmission Holdings Inc.					
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2004
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2004
32	CTHI FT - Total			8,473	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2000
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	36,100	GJ	01-Nov-2001
2	Empress to Union CDA FT	Empress	Union CDA	31,931	GJ	01-Nov-2001
3	Empress to Union CDA FT	Empress	Union CDA	50,341	GJ	01-Nov-2002
4	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2003
5	Empress to Union CDA FT	Empress	Union CDA	2,471	GJ	01-Apr-2002
6	Empress to Union CDA FT	Empress	Union CDA	7,672	GJ	01-Aug-2001
7	Empress to Union CDA FT	Empress	Union CDA	5,108	GJ	01-Sep-2001
8	Empress to Union CDA FT	Empress	Union CDA	5,438	GJ	01-Jan-2003
9	Empress to Union CDA FT	Empress	Union CDA	1,393	GJ	01-Nov-2006
10	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
11	Empress to Union CDA FT	Empress	Union CDA	10,770	GJ	01-Nov-2007
12	Empress to Union CDA FT	Empress	Union CDA	43,122	GJ	01-Nov-2007
13	Empress to Union CDA FT	Empress	Union CDA	8,478	GJ	01-Nov-2003
14	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
15	TCPL FT - Total			229,848	GJ	
	Alliance Pipelines/Vector Pipelines					
16	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	10*3*M3	01-Dec-2015
17	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
18	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
19	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
20	Alliance/Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
21	PEPL FT	Panhandle Field Zone	Ojibway (Union)	55,000	DTH	01-Nov-2002
22	PEPL - Total			58,028	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
23	Trunkline FT	East Louisiana	Bourbon	30,550	DTH	01-Nov-2002
24	PEPL EFT	Bourbon	Ojibway (Union)	30,000	DTH	01-Nov-2002
25	TGC/PEPL FT - Total			31,652	GJ	
	Other:					
26	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
27				211,011	GJ	
28	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	31-Oct-2005
29				121,331	GJ	
30	TCPL	Empress	Emerson II	5,655	GJ	01-Nov-2001
31	GLGT	Emerson II	St Clair	5,065	Dth	01-Nov-2001
32	TCPL	Empress(ST.Clair)	Dawn	5,065	Dth	01-Nov-2001
				5,655	GJ	

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UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2001
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2004
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2003
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2004
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2003
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2002
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2003
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2007
8	Empress to Union EDA FT	Empress	Union EDA	2,668	GJ	01-Nov-2003
9	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
10	Empress to Union NDA FT	Empress	Union NDA	128,480	GJ	01-Jan-2004
11	Empress to Union NDA FT	Empress	Union NDA	2,169	GJ	01-Nov-2003
12	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
13	Empress to Union WDA FT	Empress	Union WDA	79,764	GJ	01-Jan-2004
14	Empress to Union WDA FT	Empress	Union WDA	2,249	GJ	01-Nov-2003
15	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2008
16	Empress to Union SSMDA FT	Empress	Union SSMDA	30,474	GJ	01-Jan-2004
17	Empress to Union SSMDA FT	Empress	Union SSMDA	187	GJ	01-Nov-2003
18	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
19	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2005
20	TCPL FT - Total			358,643	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
21	NCDA	Parkway	Union NCDA	13,704	GJ	01-Apr-2003
22	WDA	Parkway	Union WDA	11,420	GJ	01-Apr-2003
23	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Apr-2003
24	NDA	Parkway	Union NDA	8,375	GJ	01-Apr-2003
25	EDA	Parkway	Union EDA	68,520	GJ	01-Apr-2003
26	TCPL Firm STS Withdrawal - Total			137,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
27	EDA	Union EDA	Parkway	47,571	GJ	01-Apr-2003
28	NDA	Union NDA	Parkway	57,100	GJ	01-Apr-2003
29	TCPL Firm STS Injection - Total			104,671	GJ	
	Centra Transmission Holdings Inc.					
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2004
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2004
32	CTHI FT - Total			8,473	GJ	

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UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2001
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	50,341	GJ	01-Nov-2002
2	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2004
3	Empress to Union CDA FT	Empress	Union CDA	2,471	GJ	01-Apr-2003
4	Empress to Union CDA FT	Empress	Union CDA	5,438	GJ	01-Jan-2003
5	Empress to Union CDA FT	Empress	Union CDA	1,393	GJ	01-Nov-2006
6	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
7	Empress to Union CDA FT	Empress	Union CDA	10,770	GJ	01-Nov-2007
8	Empress to Union CDA FT	Empress	Union CDA	43,122	GJ	01-Nov-2007
9	Empress to Union CDA FT	Empress	Union CDA	8,478	GJ	01-Nov-2003
10	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
11	TCPL FT - Total			149,037	GJ	
	Alliance Pipelines/Vector Pipelines					
12	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	10*3*M3	01-Dec-2015
13	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
14	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
15	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
16	Alliance/Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
17	PEPL FT	Panhandle Field Zone	Ojibway (Union)	55,000	DTH	01-Nov-2002
18	PEPL - Total			58,028	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
19	Trunkline FT	East Louisiana	Bourbon	30,550	DTH	01-Nov-2002
20	PEPL EFT	Bourbon	Ojibway (Union)	30,000	DTH	01-Nov-2002
21	TGC/PEPL FT - Total			31,652	GJ	
	Other:					
22	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
23				211,011	GJ	
24	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	31-Oct-2005
25				121,331	GJ	
26	TCPL	Empress	Emerson II	8,396	GJ	01-Dec-2001
27	GLGT	Emerson II	St. Clair GLGT	7,600	Dth	01-Dec-2001
28	TCPL	St. Clair	Dawn	8,018	GJ	01-Dec-2001
				8,018	GJ	

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UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2002
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2005
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2004
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2005
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2004
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2004
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2004
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2007
8	Empress to Union EDA FT	Empress	Union EDA	2,668	GJ	01-Nov-2003
9	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
10	Empress to Union NDA FT	Empress	Union NDA	128,480	GJ	01-Jan-2005
11	Empress to Union NDA FT	Empress	Union NDA	2,169	GJ	01-Nov-2004
12	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
13	Empress to Union WDA FT	Empress	Union WDA	79,764	GJ	01-Jan-2005
14	Empress to Union WDA FT	Empress	Union WDA	2,249	GJ	01-Nov-2004
15	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2008
16	Empress to Union SSMDA FT	Empress	Union SSMDA	30,474	GJ	01-Jan-2005
17	Empress to Union SSMDA FT	Empress	Union SSMDA	187	GJ	01-Nov-2004
18	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
19	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2005
20	TCPL FT - Total			358,643	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
21	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2005
22	WDA	Parkway	Union WDA	11,420	GJ	01-Jan-2005
23	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2005
24	NDA	Parkway	Union NDA	8,375	GJ	01-Jan-2005
25	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2005
26	TCPL Firm STS Withdrawal - Total			137,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
27	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2005
28	NDA	Union NDA	Parkway	57,100	GJ	01-Jan-2005
29	TCPL Firm STS Injection - Total			104,671	GJ	
	Centra Transmission Holdings Inc.					
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2009
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2009
32	CTHI FT - Total			8,473	GJ	

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UNION GAS LIMITED

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Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	38,372	GJ	01-Nov-2004
2	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2004
3	Empress to Union CDA FT	Empress	Union CDA	2,471	GJ	01-Apr-2003
4	Empress to Union CDA FT	Empress	Union CDA	5,438	GJ	01-Jan-2003
5	Empress to Union CDA FT	Empress	Union CDA	1,393	GJ	01-Nov-2006
6	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
7	Empress to Union CDA FT	Empress	Union CDA	10,770	GJ	01-Nov-2007
8	Empress to Union CDA FT	Empress	Union CDA	43,122	GJ	01-Nov-2007
9	Empress to Union CDA FT	Empress	Union CDA	8,478	GJ	01-Nov-2003
10	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
11	TCPL FT - Total			137,068	GJ	
	Alliance Pipelines/Vector Pipelines					
12	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	10*3*M3	01-Dec-2015
13	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
14	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
15	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
16	Alliance/Vector - Total			84,405	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
17	Trunkline FT	East Louisiana	Bourbon	30,550	DTH	01-Nov-2003
18	PEPL EFT	Bourbon	Ojibway (Union)	30,000	DTH	01-Nov-2003
19	TGC/PEPL FT - Total			31,652	GJ	
	Other:					
20	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
21				211,011	GJ	
22	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	31-Oct-2005
23				121,331	GJ	

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UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2003
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2005
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2004
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2005
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2004
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2004
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2004
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2007
8	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
9	Empress to Union NDA FT	Empress	Union NDA	88,480	GJ	01-Jan-2005
10	Empress to Union NDA FT	Empress	Union NDA	2,169	GJ	01-Nov-2004
11	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
12	Empress to Union WDA FT	Empress	Union WDA	59,764	GJ	01-Jan-2005
13	Empress to Union WDA FT	Empress	Union WDA	2,249	GJ	01-Nov-2004
14	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2008
15	Empress to Union SSMDA FT	Empress	Union SSMDA	30,474	GJ	01-Jan-2005
16	Empress to Union SSMDA FT	Empress	Union SSMDA	187	GJ	01-Nov-2004
17	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
18	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2005
19	TCPL FT - Total			295,975	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
20	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2005
21	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2005
22	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2005
23	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2005
24	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2005
25	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
26	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2005
27	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2005
28	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2005
29	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc.					
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2009
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2009
32	CTHI FT - Total			8,473	GJ	
	Nova					
33	Nova	AECO	Empress	535	10*3*M3	01-Nov-2004

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UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2003
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	20,000	GJ	01-Nov-2004
2	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2004
3	Empress to Union CDA FT	Empress	Union CDA	26,372	GJ	01-Nov-2004
4	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2005
5	Empress to Union CDA FT	Empress	Union CDA	5,400	GJ	01-Nov-2004
6	Empress to Union CDA FT	Empress	Union CDA	1,393	GJ	01-Nov-2006
7	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
8	Empress to Union CDA FT	Empress	Union CDA	10,770	GJ	01-Nov-2007
9	Empress to Union CDA FT	Empress	Union CDA	43,122	GJ	01-Nov-2007
10	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
11	TCPL FT - Total			174,081	GJ	
	Alliance Pipelines/Vector Pipelines					
12	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015
13	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
14	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
15	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
16	Alliance/Vector - Total			84,405	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
17	Trunkline FT	East Louisiana	Bourbon	52,910	DTH	01-Nov-2005
18	PEPL EFT	Bourbon	Ojibway (Union)	52,000	DTH	01-Nov-2005
				54,863	GJ	
19	Trunkline	East Louisiana	Bourbon	5,088	DTH	01-Nov-2004
20	PEPL	Bourbon	Ojibway (Union)	5,000	DTH	01-Nov-2004
				5,275	GJ	
21	Vector (L.P.)	Chicago	Cdn/US Interconnect	80,000	Mmbtu	01-Nov-2008
22	Vector Canada	Cdn/US Interconnect	Dawn	84,405	GJ	01-Nov-2008
				84,405	GJ	
	Other:					
23	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
24				211,011	GJ	
24	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	31-Oct-2005
25				121,331	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2004
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2006
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2005
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2006
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2005
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2005
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2005
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2007
8	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
9	Empress to Union NDA FT	Empress	Union NDA	1,300	GJ	01-Nov-2005
10	Empress to Union NDA FT	Empress	Union NDA	79,271	GJ	01-Jan-2006
11	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
12	Empress to Union WDA FT	Empress	Union WDA	59,764	GJ	01-Jan-2006
13	Empress to Union WDA FT	Empress	Union WDA	2,249	GJ	01-Nov-2005
14	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2008
15	Empress to Union SSMDA FT	Empress	Union SSMDA	29,621	GJ	01-Jan-2006
16	Empress to Union SSMDA FT	Empress	Union SSMDA	187	GJ	01-Nov-2005
17	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
18	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2006
19	TCPL FT - Total			285,044	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
20	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2006
21	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2006
22	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2006
23	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2006
24	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2006
25	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
26	**WDA**	Union WDA	Parkway	3,150	GJ	01-Jan-2006
27	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2006
28	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2006
29	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc.					
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2009
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2009
32	CTHI FT - Total			8,473	GJ	
	Nova					
33	Nova	AECO	Empress	535	10**3*M3	01-Nov-2005

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2004
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	20,000	GJ	01-Nov-2005
2	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2005
3	Empress to Union CDA FT	Empress	Union CDA	23,872	GJ	01-Nov-2005
4	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2006
5	Empress to Union CDA FT	Empress	Union CDA	5,400	GJ	01-Nov-2005
6	Empress to Union CDA FT	Empress	Union CDA	1,393	GJ	01-Nov-2006
7	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
8	Empress to Union CDA FT	Empress	Union CDA	10,770	GJ	01-Nov-2007
9	Empress to Union CDA FT	Empress	Union CDA	43,122	GJ	01-Nov-2007
10	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
11	TCPL FT - Total			171,581	GJ	
	Alliance Pipelines/Vector Pipelines					
12	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015
13	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
14	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
15	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
16	Alliance/Vector - Total			84,405	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
17	Trunkline FT	East Louisiana	Bourbon	35,672	DTH	01-Nov-2005
18	PEPL EFT	Bourbon	Ojibway (Union)	35,000	DTH	01-Nov-2005
19	Trunkline/Panhandle - Total			36,927	GJ	
20	Trunkline FT	East Louisiana	Bourbon	22,422	DTH	01-Nov-2007
21	PEPL EFT	Bourbon	Ojibway (Union)	22,000	DTH	01-Nov-2007
22	Trunkline/Panhandle - Total			23,211	GJ	
23	Vector (L.P.)	Chicago	Cdn/US Interconnect	110,000	Mmbtu	01-Nov-2008
24	Vector Canada	Cdn/US Interconnect	Dawn	116,056	GJ	01-Nov-2008
25	Vector - Total			116,056	GJ	
	Other:					
26	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
27				211,011	GJ	
27	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	31-Oct-2005
28				121,331	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2005
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point (a)	Primary Delivery Point (b)	Contract Quantity (c)	Contract Units per Day (d)	Contract Termination Date (e)
	TransCanada Pipeline					
1	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-06
2	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-06
3	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-06
4	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-06
5	Empress to Union NDA FT	Empress	Union NDA	1,300	GJ	01-Nov-06
6	Empress to Union SSMDA FT	Empress	Union SSMDA	187	GJ	01-Nov-06
7	Empress to Union WDA FT	Empress	Union WDA	2,249	GJ	01-Nov-06
8	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-07
9	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-07
10	Empress to Union NDA FT	Empress	Union NDA	78,907	GJ	01-Jan-07
11	Empress to Union SSMDA FT	Empress	Union SSMDA	29,621	GJ	01-Jan-07
12	Empress to Union WDA FT	Empress	Union WDA	59,764	GJ	01-Jan-07
13	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-07
14	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-07
15	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-09
16	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-08
17	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-09
18	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-09
19	TCPL FT - Total			284,680	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
20	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-07
21	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-07
22	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-07
23	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-07
24	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-07
25	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
26	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-07
27	NCDA	Union NCDA	Parkway	0	GJ	01-Jan-07
28	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-07
29	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-07
30	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc					
31	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	mcf	01-Jan-09
32	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	mcf	01-Jan-09
33	CTHI FT			8,473	GJ	
	Nova Gas Transmission Ltd.					
34	Nova FT	AECO	Empress	535	10^3	01-Nov-06
35	NOVA FT			20,004	GJ	

* *Recently renewed on a 1-year rolling basis*

December, 2005

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2005
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point (a)	Primary Delivery Point (b)	Contract Quantity (c)	Contract Units per Day (d)	Contract Termination Date (e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	19,700	GJ	01-Nov-06
2	Empress to Union CDA FT	Empress	Union CDA	1,393	GJ	01-Nov-06
3	Empress to Union CDA FT	Empress	Union CDA	20,000	GJ	01-Nov-06
4	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-06
5	Empress to Union CDA FT	Empress	Union CDA	23,872	GJ	01-Nov-06
6	Empress to Union CDA FT	Empress	Union CDA	5,400	GJ	01-Nov-06
7	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-07
8	Empress to Union CDA FT	Empress	Union CDA	10,770	GJ	01-Nov-07
9	Empress to Union CDA FT	Empress	Union CDA	43,122	GJ	01-Nov-07
10	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-09
11	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-12
12	TCPL FT - Total			191,281	GJ	
	Alliance/Vector					
13	Alliance	Northern Alta.	Cdn/US interconnect	2266.2	10^3m^3	01-Dec-15
14	Alliance(L.P.)	Cdn/US interconnect	Chicago City Gate	80,000	mcf	01-Dec-15
15	Vector(L.P.) FT1	Chicago City Gate	Cdn/US Interconnect	80,000	Dth	01-Dec-15
16	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-15
17	Alliance/Vector - Total			84,405	GJ	
	Vector					
18	Vector (L.P.) FT 1	Chicago City Gate	Cdn/US Interconnect	80,000	MmBtu	01-Nov-08
19	Vector Canada FT 1	Cdn/US Interconnect	Dawn	84,404	GJ	01-Nov-08
20	Vector			84,404	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipeline					
21	Trunkline FT	East LA	Bourbon	22,449	Dth	01-Nov-07
22	PEPL EFT	Bourbon	Ojibway	22,000	Dth	01-Nov-07
23	TGC/PEPL			23,211	GJ	
	Panhandle Eastern Pipeline Field Zone					
24	PEPL FT	Field Zone	Ojibway (Union)	25,000	Dth	01-Nov-10
25	PEPL			26,376	GJ	
	Exchange					
26	Empress to Parkway	Empress	Union CDA	8,619	GJ	01-Nov-08
	Other:					
27	St. Clair Pipelines L.P. (St. Clair Pipeline)	International Border	St. Clair Valve (Union)	200,000	mcf	01-Nov-08
28				213,479	GJ	
29	St. Clair Pipelines L.P. (Bluewater Pipeline)	International Border	Bluewater Valve (Union)	115,000	mcf	01-Nov-08
30				122,750	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2006
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point (a)	Primary Delivery Point (b)	Contract Quantity (c)	Contract Units (d)	Contract Termination Date (e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2008
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2007
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2008
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2007
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2007
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2007
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2007
8	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
9	Empress to Union NDA FT	Empress	Union NDA	78,907	GJ	01-Jan-2008
10	Empress to Union NDA FT	Empress	Union NDA	1,300	GJ	01-Nov-2007
11	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
12	Empress to Union WDA FT	Empress	Union WDA	57,514	GJ	01-Jan-2008
13	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2008
14	Empress to Union SSMDA FT	Empress	Union SSMDA	29,621	GJ	01-Jan-2008
15	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
16	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2008
17	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	01-Nov-2016
18	TCPL FT - Total			309,994	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
19	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2008
20	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2008
21	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2008
22	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2008
23	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2008
24	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
25	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2008
26	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2008
27	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2008
28	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc.					
29	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2009
30	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2009
31	CTHI FT - Total			8,473	GJ	
	Nova					
32	Nova	AECO	Empress	20,000	GJ	01-Nov-2008

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2006
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	1,393	GJ	01-Nov-2007
2	Empress to Union CDA FT	Empress	Union CDA	20,000	GJ	01-Nov-2007
3	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2007
4	Empress to Union CDA FT	Empress	Union CDA	23,872	GJ	01-Nov-2007
5	Empress to Union CDA FT	Empress	Union CDA	19,700	GJ	01-Nov-2007
6	Empress to Union CDA FT	Empress	Union CDA	5,400	GJ	01-Nov-2007
7	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2008
8	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
9	Empress to Union CDA FT	Empress	Union CDA	10,770	GJ	01-Nov-2007
10	Empress to Union CDA FT	Empress	Union CDA	43,122	GJ	01-Nov-2007
11	Empress to Union CDA FT	Empress	Union CDA	10,600	GJ	01-Nov-2007
12	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
13	TCPL FT - Total			201,881	GJ	
	Alliance Pipelines/Vector Pipelines					
14	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015
15	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
16	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
17	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
18	Alliance/Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
19	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	01-Nov-2010
20	PEPL - Total			26,376	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
21	Trunkline FT	East Louisiana	Bourbon	22,422	DTH	01-Nov-2007
22	PEPL EFT	Bourbon	Ojibway (Union)	22,000	DTH	01-Nov-2007
23	TGC/PEPL FT - Total			23,211	GJ	
	Vector Pipelines					
24	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Nov-2008
25	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Nov-2008
26	Vector - Total			84,405	GJ	
	Nova					
27	Nova	AECO	Empress	20,000	GJ	01-Nov-2008
	Other:					
28	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
29				211,011	GJ	
30	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	01-Nov-2009
31				121,331	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2007
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point (a)	Primary Delivery Point (b)	Contract Quantity (c)	Contract Units (d)	Contract Termination Date (e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2009
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2008
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2009
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2008
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2008
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2008
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2008
8	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
9	Empress to Union NDA FT	Empress	Union NDA	78,907	GJ	01-Jan-2009
10	Empress to Union NDA FT	Empress	Union NDA	1,300	GJ	01-Nov-2008
11	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
12	Empress to Union WDA FT	Empress	Union WDA	47,898	GJ	01-Jan-2009
13	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2008
14	Empress to Union SSMDA FT	Empress	Union SSMDA	29,505	GJ	01-Jan-2009
15	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
16	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2009
17	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	01-Nov-2016
18	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	01-Nov-2017
19	TCPL FT - Total			305,262	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
20	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2008
21	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2008
22	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2008
23	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2008
24	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2008
25	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
26	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2008
27	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2008
28	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2008
29	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc.					
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2009
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2009
32	CTHI FT - Total			8,473	GJ	
	Nova					
33	Nova	AECO	Empress	20,000	GJ	01-Nov-2009

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2007
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	20,000	GJ	01-Nov-2008
2	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2008
3	Empress to Union CDA FT	Empress	Union CDA	4,846	GJ	01-Nov-2008
4	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2009
5	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
6	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
7	TCPL FT - Total			91,870	GJ	
	Alliance Pipelines/Vector Pipelines					
8	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015
9	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
10	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
11	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
12	Alliance/Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
13	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	01-Nov-2010
14	PEPL - Total			26,376	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
15	Trunkline FT	East Louisiana	Bourbon	20,458	DTH	01-Nov-2012
16	PEPL EFT	Bourbon	Ojibway (Union)	20,000	DTH	01-Nov-2012
17	TGC/PEPL FT - Total			21,101	GJ	
	Vector Pipelines					
18	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Nov-2008
19	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Nov-2008
20	Vector - Total			84,405	GJ	
	Nova					
21	Nova	AECO	Empress	20,000	GJ	01-Nov-2009
	Other:					
22	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
23				211,011	GJ	
24	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	01-Nov-2009
25				121,331	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2008
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point (a)	Primary Delivery Point (b)	Contract Quantity (c)	Contract Units (d)	Contract Termination Date (e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2010
2	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2009
3	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2010
4	Empress to Union EDA FT	Empress	Union EDA	4,985	GJ	01-Nov-2009
5	Empress to Union EDA FT	Empress	Union EDA	5,709	GJ	01-Nov-2009
6	Empress to Union EDA FT	Empress	Union EDA	13,320	GJ	01-Nov-2009
7	Empress to Union EDA FT	Empress	Union EDA	3,616	GJ	01-Nov-2009
8	Empress to Union EDA FT	Empress	Union EDA	5,878	GJ	01-Nov-2009
9	Empress to Union NDA FT	Empress	Union NDA	77,771	GJ	01-Jan-2010
10	Empress to Union NDA FT	Empress	Union NDA	6,594	GJ	01-Nov-2009
11	Empress to Union WDA FT	Empress	Union WDA	42,538	GJ	01-Jan-2010
12	Empress to Union WDA FT	Empress	Union WDA	1,944	GJ	01-Nov-2009
13	Empress to Union SSMDA FT	Empress	Union SSMDA	29,505	GJ	01-Jan-2010
14	Empress to Union SSMDA FT	Empress	Union SSMDA	2,564	GJ	01-Nov-2009
15	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2010
16	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	01-Nov-2016
17	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	01-Nov-2017
18	TCPL FT - Total			297,466	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
19	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2009
20	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2009
21	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2009
22	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2009
23	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2009
24	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
25	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2009
26	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2009
27	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2009
28	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc.					
29	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Jan-2010
30	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Jan-2010
31	CTHI FT - Total			8,473	GJ	
	Nova					
32	Nova	AECO	Empress	20,000	GJ	01-Nov-2010

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2008
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point (a)	Primary Delivery Point (b)	Contract Quantity (c)	Contract Units (d)	Contract Termination Date (e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2009
2	Empress to Union CDA FT	Empress	Union CDA	4,303	GJ	01-Nov-2009
3	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2010
4	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
5	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2009
6	TCPL FT - Total			71,327	GJ	
	Alliance Pipelines/Vector Pipelines					
7	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015
8	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
9	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
10	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
11	Alliance/Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
12	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	01-Nov-2010
13	PEPL - Total			26,376	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
14	Trunkline FT	East Louisiana	Bourbon	20,467	DTH	01-Nov-2012
15	PEPL EFT	Bourbon	Ojibway (Union)	20,000	DTH	01-Nov-2012
16	TGC/PEPL FT - Total			21,101	GJ	
	Vector Pipelines					
17	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	81,000	DTH	01-Dec-2015
18	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	85,460	GJ	01-Dec-2015
19	Vector - Total			85,460	GJ	
	Nova					
20	Nova	AECO	Empress	20,000	GJ	01-Nov-2010
	Other:					
21	St.Clair Pipelines L.P. (St.Clair Pipeline)	St Clair/Border	StClair/Border	200,000	MCF	01-Nov-2008
22				211,011	GJ	
23	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Int. Border	Bluewater/Int Border	115,000	MCF	01-Nov-2009
24				121,331	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2009
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2010
2	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2011
3	Empress to Union NDA FT	Empress	Union NDA	76,546	GJ	01-Jan-2011
4	Empress to Union NDA FT	Empress	Union NDA	4,335	GJ	01-Nov-2010
5	Empress to Union WDA FT	Empress	Union WDA	42,538	GJ	01-Jan-2011
6	Empress to Union SSMDA FT	Empress	Union SSMDA	29,505	GJ	01-Jan-2011
7	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2011
8	Empress to Union EDA FT	Empress	Union EDA	8,675	GJ	01-Nov-2010
9	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2011
10	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	01-Nov-2016
11	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	01-Nov-2017
12	TCPL FT - Total			264,641	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
13	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2011
14	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2011
15	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2011
16	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2011
17	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2011
18	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
19	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2011
20	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2011
21	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2011
22	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc.					
23	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Nov-2011
24	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Nov-2011
25	CTHI FT - Total			8,473	GJ	
	Other:					
26	Nova	Aeco	Empress	20,000	GJ	01-Nov-10

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UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2009
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2011
2	Empress to Union CDA FT	Empress	Union CDA	21,346	GJ	01-Nov-2010
3	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2010
4	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2012
5	Empress to Union CDA FT	Empress	Union CDA	4,303	GJ	01-Nov-2010
6	TCPL FT - Total			71,327	GJ	
	Nova					
7	NIT to Empress	NOVA/NIT	Empress	20,000	GJ	01-Nov-2010
	Alliance Pipelines/Vector Pipelines					
8	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015
9	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
10	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
11	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
12	Alliance/Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
13	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	01-Nov-2010
14	PEPL - Total			26,376	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
15	Trunkline FT	East Louisiana	Bourbon	20,467	DTH	01-Nov-2012
16	PEPL EFT	Bourbon	Ojibway (Union)	20,000	DTH	01-Nov-2012
17	TGC/PEPL FT - Total			21,101	GJ	
	Vector Pipelines					
18	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	81,000	DTH	01-Dec-2015
19	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	85,460	GJ	01-Dec-2015
20	Vector - Total			85,460	GJ	
	Other:					
21	St.Clair Pipelines L.P. (St.Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	200,000	MCF	01-Nov-2012
22				213,479	GJ	
23	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	115,000	MCF	01-Nov-2012
24				122,750	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2010
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2012
2	Empress to Union EDA FT	Empress	Union EDA	8,675	GJ	01-Nov-2012
3	Empress to Union NDA FT	Empress	Union NDA	76,546	GJ	01-Jan-2013
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	01-Jan-2013
5	Empress to Union SSMDA FT	Empress	Union SSMDA	9,443	GJ	01-Jan-2013
6	Empress to Union EDA FT	Empress	Union EDA	52,481	GJ	01-Jan-2013
7	Empress to Union NCDA FT	Empress	Union NCDA	9,494	GJ	01-Jan-2013
8	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2013
9	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	01-Nov-2016
10	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	01-Nov-2017
11	TCPL FT - Total			237,586	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
12	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2012
13	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2012
14	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2012
15	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2012
16	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2012
17	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
18	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2012
19	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2012
20	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2012
21	TCPL Firm STS Injection - Total			99,821	GJ	
	Centra Transmission Holdings Inc.					
22	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Nov-2012
23	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Nov-2012
24	CTHI FT - Total			8,473	GJ	

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UNION GAS LIMITED

Summary of Upstream Transportation Contracts - Effective November 1, 2010
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2013
2	Empress to Union CDA FT	Empress	Union CDA	13,149	GJ	01-Nov-2012
3	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2012
4	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2013
5	Empress to Union CDA FT	Empress	Union CDA	12,500	GJ	01-Jan-2016
6	TCPL FT - Total			71,327	GJ	
	Alliance Pipelines/Vector Pipelines					
7	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015
8	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015
9	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015
10	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
11	Alliance/Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
12	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	01-Nov-2017
13	PEPL - Total			26,376	GJ	
	Trunkline Gas Company/Panhandle Eastern Pipe Line					
14	Trunkline FT	East Louisiana	Bourbon	20,467	DTH	01-Nov-2012
15	PEPL EFT	Bourbon	Ojibway (Union)	20,000	DTH	01-Nov-2012
16	TGC/PEPL FT - Total			21,101	GJ	
	Vector Pipelines					
17	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	81,000	DTH	01-Dec-2015
18	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	85,460	GJ	01-Dec-2015
19	Vector - Total			85,460	GJ	
	Vector Pipelines					
20	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	15,000	DTH	01-Nov-2011
21	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	15,826	GJ	01-Nov-2011
22	Vector - Total			15,826	GJ	
	ANR/GLGT/TCPL:					
23	ANR	Shelbyville	Farwell	10,100	Dth	01-Nov-11
24	GLGT	Farwell	St. Clair (TCPL)	10,000	Dth	01-Nov-11
25	TCPL	St. Clair (TCPL)	Union SWDA	10,551	GJ	01-Nov-11
26	ANR/GLGT/TCPL - Total			10,551	GJ	
	ANR/MCON:					
27	ANR	Shelbyville	Willow Run	10,200	Dth	01-Nov-11
28	MCON	Willow Run	St. Clair (Union)	10,000	Dth	01-Nov-11
29	ANR/MCON - Total			10,551	GJ	
	Other:					
30	St.Clair Pipelines L.P. (St.Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	200,000	MCF	01-Nov-2012
31				213,479	GJ	
32	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	115,000	MCF	01-Nov-2012
33				122,750	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED
Summary of Upstream Transportation Contracts - Effective November 1, 2011
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2012
2	Empress to Union EDA FT	Empress	Union EDA	8,675	GJ	01-Nov-2012
3	Empress to Union NDA FT	Empress	Union NDA	67,625	GJ	01-Jan-2013
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	01-Jan-2013
5	Empress to Union SSMDA FT	Empress	Union SSMDA	9,143	GJ	01-Jan-2013
6	Empress to Union EDA FT	Empress	Union EDA	50,576	GJ	01-Jan-2013
7	Empress to Union NCDA FT	Empress	Union NCDA	9,211	GJ	01-Jan-2013
8	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2013
9	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	01-Nov-2016
10	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	01-Nov-2017
11	Parkway to Union CDA FT-NR	Parkway	Union CDA	64,000	GJ	01-Nov-2012
12	Parkway to Union CDA FT	Parkway	Union CDA	16,000	GJ	01-Nov-2012
13	TCPL FT - Total			306,177	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
14	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2013
15	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2013
16	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2013
17	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2013
18	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2013
19	TCPL Firm STS Withdrawal - Total			197,041	GJ	
	TransCanada Storage Transportation Service Firm Injection					
20	NCDA	Union NCDA	Parkway	0	GJ	01-Jan-2013
21	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2013
22	SSMDA	Union SSMDA	Parkway	0	GJ	01-Jan-2013
23	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2013
24	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2013
25	TCPL Firm STS Injection - Total			99,821	GJ	
	Michigan Consolidated Gas Company (MichCon)/Great Lakes Gas Transmission (GLGT)/TransCanada Pipeline (TCPL)					
26	TCPL to Union SSMDA	S.S. Marie	Union SSMDA	6,143	GJ	01-Nov-2014
27	GLGT to TCPL	Belle River Mills	S.S. Marie	5,829	DTH	01-Nov-2014
28	MichCon to GLGT	MichCon Generic	Belle River Mills	5,829	DTH	01-Nov-2014
29	MichCon/GLGT/TCPL FT - Total			6,143	GJ	
	Centra Transmission Holdings Inc.					
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Nov-2012
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Nov-2012
32	CTHI FT - Total			8,473	GJ	

Information provided is consistent with the best records available.

UNION GAS LIMITED
Summary of Upstream Transportation Contracts - Effective November 1, 2011
Southern Operations Area

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
		(a)	(b)	(c)	(d)	(e)
	TransCanada Pipeline					
1	Dawn to Union CDA FT	Dawn	Union CDA	60,000	GJ	01-Nov-2012
2	Empress to Union CDA FT	Empress	Union CDA	5,699	GJ	01-Feb-2013
3	Empress to Union CDA FT	Empress	Union CDA	13,149	GJ	01-Nov-2012
4	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2012
5	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2013
6	Empress to Union CDA FT	Empress	Union CDA	12,500	GJ	01-Jan-2016
7	TCPL FT - Total			131,327	GJ	
	Alliance Pipelines Vector Pipelines					
8	Alliance	Northern Alberta	Cdn US Interconnect	2,266.2	103M3	01-Dec-2015
9	Alliance (L.P.)	Cdn US Interconnect	Vector	80,000	MCF	01-Dec-2015
10	Vector (L.P.) FT1	Chicago	Cdn US Interconnect	80,000	DTH	01-Dec-2015
11	Vector Canada FT1	Cdn US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015
12	Alliance Vector - Total			84,405	GJ	
	Panhandle Eastern Pipe Line Field Zone					
13	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	01-Nov-2017
14	PEPL - Total			26,376	GJ	
	Trunkline Gas Company Panhandle Eastern Pipe Line					
15	Trunkline FT	East Louisiana	Bourbon	20,467	DTH	01-Nov-2012
16	PEPL EFT	Bourbon	Ojibway (Union)	20,000	DTH	01-Nov-2012
17	TGC PEPL FT - Total			21,101	GJ	
	Vector Pipelines					
18	Vector (L.P.) FT1	Chicago	Cdn US Interconnect	$1,000	DTH	01-Dec-2015
19	Vector Canada FT1	Cdn US Interconnect	Dawn (Union)	$5,460	GJ	01-Dec-2015
20	Vector - Total			$5,460	GJ	
	Other:					
21	St.Clair Pipelines L.P. (St.Clair Pipeline)	St. Clair Intl Border	St. Clair Intl Border	200,000	MCF	01-Nov-2012
22				213,479	GJ	
23	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater Intl Border	Bluewater Intl Border	115,000	MCF	01-Nov-2012
24				122,750	GJ	
25	TransCanada Pipeline (1)	Niagara	Kirkwall	21,101	GJ	01-Nov-22
26				21,101	GJ	
	Exchange Rate 1 US =	0.981354269	CAD			
	Conversion Factor	1.055056				

Note:
(1) Contract start date is November 1, 2012

Information provided is consistent with the best records available.

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.

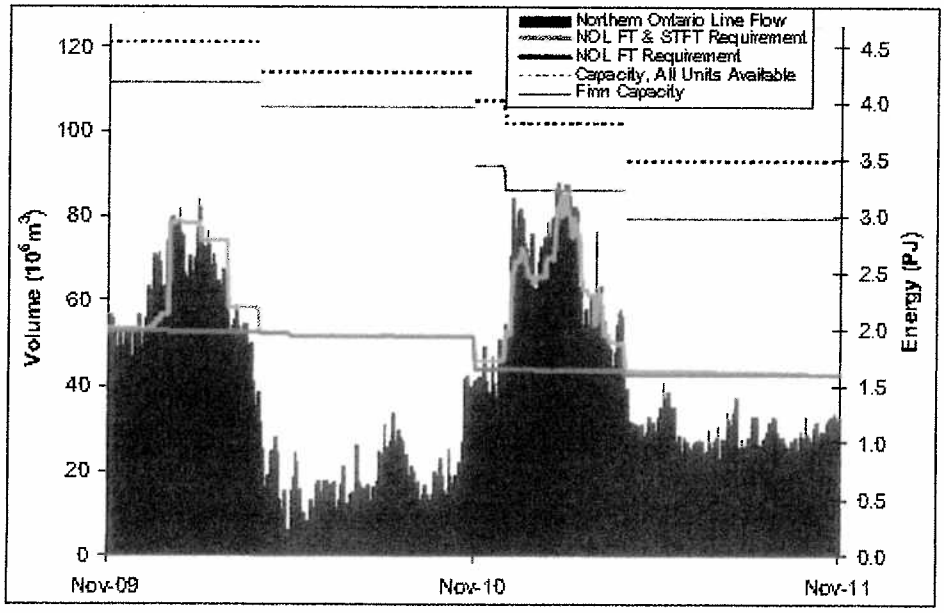
Request:

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.



UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Quinn

Please provide the amount of capacity available to respective delivery areas for entire winter of this year.

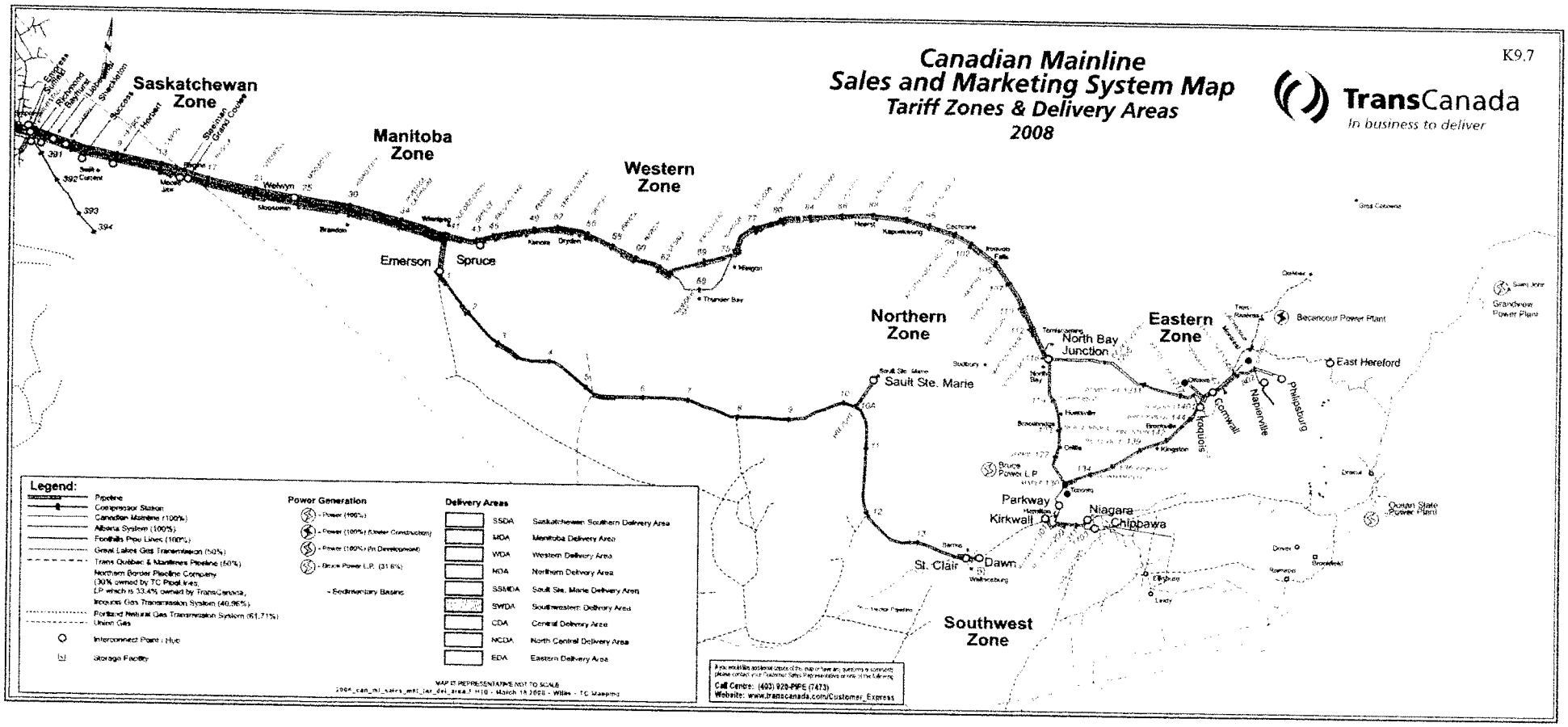
For TCPL transportation paths impacting Union, capacity available in TCPL's Winter 2012/2013 STFT Open Season dated July 9-17, 2012 is as follows:

TCPL Path	Quantity Available/Not Available for seasonal STFT (GJ/d)
Empress to Union NCDA*	1,585,700
Empress to Union EDA	962,200
Empress to Union NDA	1,585,700
Empress to Union WDA	1,585,700
Empress to Union SSMDA	Not Available
Empress to Union MDA	5,722,800
Empress to Union CDA	1,585,700
Sault Ste. Marie to Union SSMDA	33,600
Dawn to Union CDA	Not Available
Parkway to Union CDA	Not Available
Dawn to Union EDA	Not Available
Parkway to Union EDA	Not Available
Niagara to Kirkwall**	Not Available

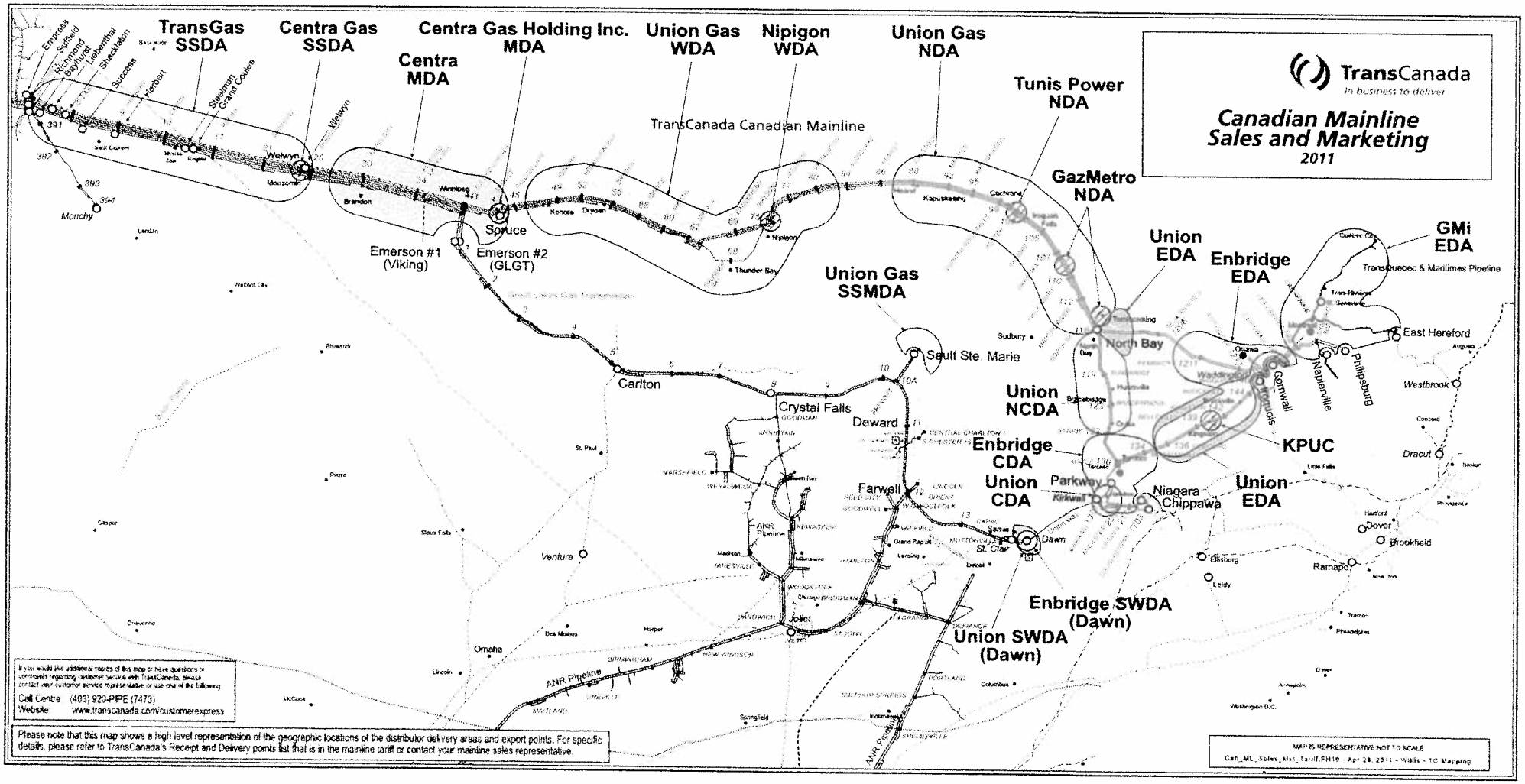
* Assumes capacity offered Empress to CDA would include Union NCDA, Enbridge CDA, and Union CDA delivery areas.

**Contract start date is November 1, 2012.

A copy of TCPL's Open Season offering is attached.


Canadian Mainline
Sales and Marketing System Map
Tariff Zones & Delivery Areas
2008
TransCanada
In business to deliver
Saskatchewan Zone
Manitoba Zone
Western Zone
Northern Zone
Eastern Zone
Southwest Zone
Emerson
Spruce
Sault Ste. Marie
North Bay Junction
East Hereford
Parkway
Kirkwall
Niagara
Chippawa
St. Clair
Dawn
Legend:
Pipeline
Compressor Station
Canadian Mainline (100%)
Alberta System (100%)
Foothills Pipe Lines (100%)
Great Lakes Gas Transmission (50%)
Trans Quebec & Maritimes Pipeline (50%)
Northern Border Pipeline Company (30% owned by TC Pipelines LP which is 33.4% owned by TransCanada, Income Gas Transmission System (40.96%)
Portland Natural Gas Transmission System (61.71%)
Union Gas
Interconnect Point / Hub
Storage Facility
Power Generation
Power (100%)
Power (100%) (Under Construction)
Power (100%) (In Development)
Bruce Power L.P. (31.6%)
= Sedimentary Basins
Delivery Areas
SSDA Saskatchewan Southern Delivery Area
MDA Manitoba Delivery Area
WDA Western Delivery Area
NDA Northern Delivery Area
SSMDA Sault Ste. Marie Delivery Area
SWDA Southwestern Delivery Area
CDA Central Delivery Area
NCDA North Central Delivery Area
EDA Eastern Delivery Area
MAP IS REPRESENTATIVE NOT TO SCALE
Call Centre: (403) 920-PIPE (7473)
Website: www.transcanada.com/Customer_Express

K10.4

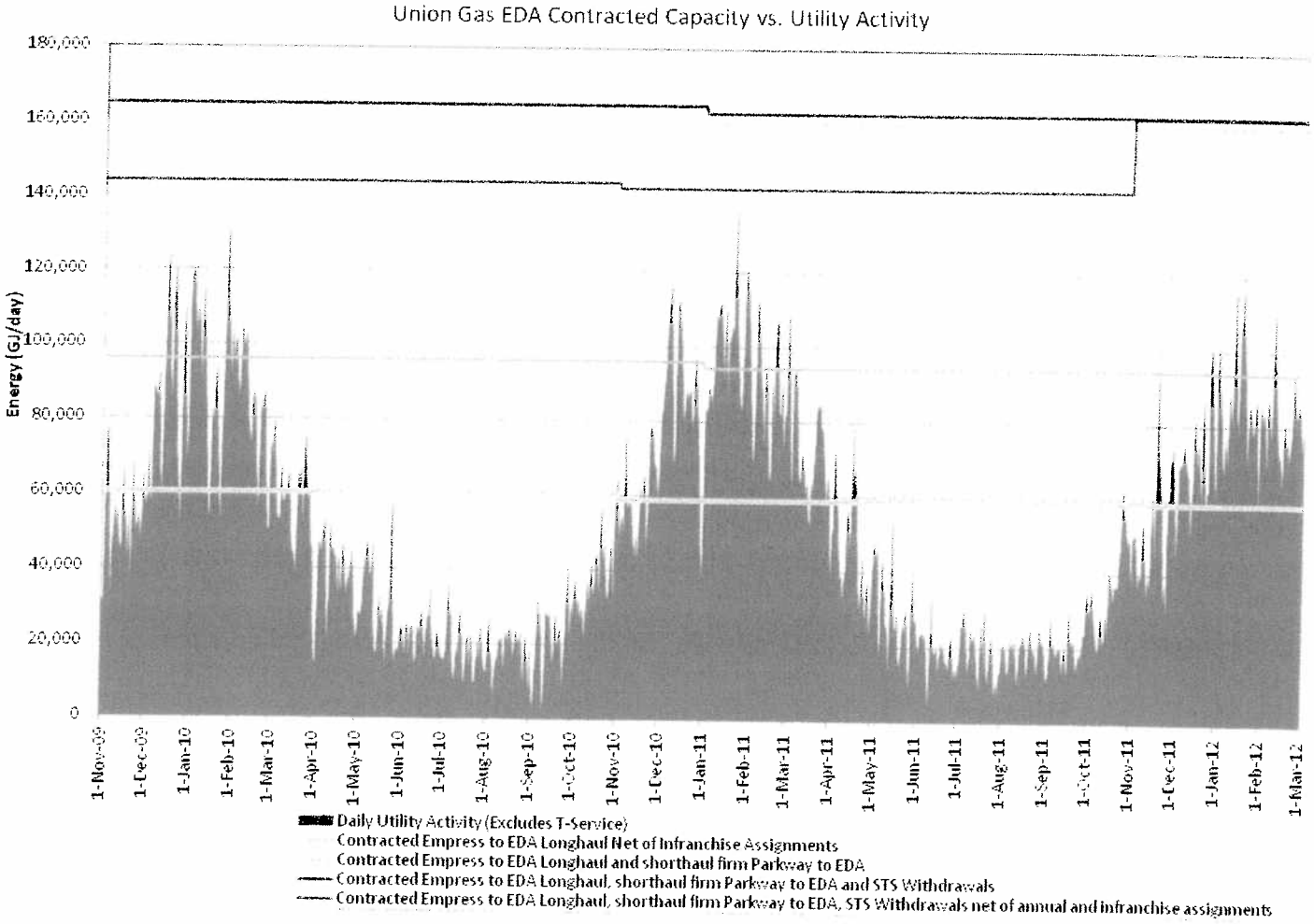

TransGas SSDA
Centra Gas SSDA
Centra Gas Holding Inc. MDA
Centra MDA
Union Gas WDA
Nipigon WDA
Union Gas NDA
Tunis Power NDA
GazMetro NDA
Union EDA
Enbridge EDA
GMi EDA
Union Gas SSMDA
Union NCDA
Enbridge CDA
Union CDA
KPUC
Union EDA
Enbridge SWDA (Dawn)
Union SWDA (Dawn)
TransCanada Canadian Mainline
TransCanada
In business to deliver
Canadian Mainline Sales and Marketing
2011
Empress
Suffield
Richmond
Bayhurst
Lieberthal
Shackleton
Success
Herbert
Steelman
Grand Coulee
Monchy
Welwyn
Brandon
Winnipeg
Spruce
Emerson #1 (Viking)
Emerson #2 (GLGT)
Kenora
Dryden
Nipigon
Thunder Bay
Kapuskasing
Cochrane
Iroquois Falls
Timmins
Sudbury
North Bay
Ottawa
Cornwall
Napierville
Philipsburg
East Hereford
Transquebec & Maritimes Pipeline
Westbrook
Dracut
Sault Ste. Marie
Carlton
Crystal Falls
Deward
Farwell
Parkway
Kirkwall
Niagara
Chippawa
Dawn
St. Clair
Sarnia
Ventura
Joliet
Omaha
ANR Pipeline
Ellisburg
Leidy
Ramapo
Dover
Brookfield
Call Centre (403) 920-PIPE (7473)
Website www.transcanada.com/customerexpress
Please note that this map shows a high level representation of the geographic locations of the distributor delivery areas and export points. For specific details, please refer to TransCanada's Receipt and Delivery points list that is in the mainline tariff or contact your mainline sales representative.
MAP IS REPRESENTATIVE NOT TO SCALE

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Quigley

Please provide contracted FT and contracted STFT to Union's Eastern delivery area, actual deliveries received from TCPL for in-franchise customers, November 1, 2009 to March 31, 2012.

The attached graph reflects Union's contracted capacity and daily utility activity on TCPL in the Eastern Delivery Area.



Note: The Gas supply plan utilizes firm TCPL services (Longhaul, Shorthaul and STS) as shown above to meet design day obligations.

RP-2003-0063
EB-2003-0087
EB-2003-0097

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 for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

redemptions and new issues had decreased its embedded debt cost to a forecast 8.45% in 2004, from the 1999 Board approved cost of 9.61%.

Union noted that some questions had been raised during the hearing about the net average cash position, with the suggestion being made that an average net cash position is somehow inappropriate and would imply that the level of debt issued by Union in 2002 was too large. Union submitted this was not the case and that unfunded short-term debt, or cash position, was simply reflective of the seasonal cash flow of the business. Union's monthly cash position for the years 2002 to 2004, showed that Union was in a cash position during the summer and shoulder months and then drawing on lines of credit in the winter to the extent of $197 million by December 2004, leaving $168 million to deal with unforeseen circumstances.

Union stated that it was important to note that it could not issue debt effectively in small amounts, and it was therefore necessary to wait until capital needs were such that there was sufficient justification for long-term debt financing. However, this did not preclude the possibility of taking advantage of favourable market conditions at a given point in time.

Union also noted that in 2002, at the time it had undertaken the financing, it was carrying a high level of deferred receivables, which was one of the factors that had caused it to issue the debt. However, at the present time this was not forecast to be a significant problem.

Positions of the Parties

A number of Intervenors expressed concerns about Union's unfunded short term debt level. The argument was made that due to the perceived prefinancing of Union's most recent long term debt issue, ratepayers were being charged 8.5 % on the long term debt component of the capital structure, while only receiving a credit of 4.15% on the pre-funded component. This, it was argued, inappropriately burdened ratepayers with an added cost of $5.6 million. A variety of ways of dealing with this perceived inequity were proposed.

IGUA also expressed concern that Union's actual equity ratio, which was, as of December 31 for 2002, 2003, and 2004 respectively 31%, 32.4% and 30%, had fallen considerably below the 35% deemed common equity level which the Board applies in deriving rates. IGUA took the view that if this situation was to persist, Union's equity ratio for rate-setting purposes should be reduced.

LPMA/WGSPG and VECC argued that where Union's common equity ratio and risk was concerned, the changes in the monthly fixed charges proposed by Union in this proceeding and the increases that took place under PBR, along with weather hedges, are more than significant enough to warrant a review of the company's business and forecast risk.

LPMA/WGSPG and VECC therefore submitted that consideration of both these issues should be delayed until the 2005 proceeding at which time both intervenors and Union could bring forward evidence/experts to deal with any changes in business risk associated with these matters.

Union's Position

Referring to the level of long term debt, Union noted that it could not cost-effectively raise debt in the market in small tranches. Union noted that debt issues were necessarily lumpy in their impact on capital structure. Union also argued that intervenors who were questioning its long-term debt levels were ignoring the fact that even with the level of long-term debt Union had issued, it still found it necessary to draw substantially on its short term credit facilities during the course of the year, and, in the absence of the long-term debt issue, would have exceeded its short term borrowing capability in 2004. Union's forecast maximum short-term indebtedness would have reached $397 million, exceeding the 2004 capacity of $365 million.

Union further explained that the average cash position in the short-term unfunded debt component of the capital structure arose principally because the level of deferred charges carried by the Company are anticipated to be significantly lower in 2004 than they had been in the past because of the new prospective recovery mechanism approved by the Board for Union beginning in May 2003. Union stated that at the time it had issued its long-term debt in 2002, it could not have been

known that the new mechanism would become standard practice, and, as such, Union's level of long-term debt should not be considered to be inappropriate.

Union submitted that there was no evidence that it had in any way been imprudent in raising its 2002 debt. Union stated that it had an opportunity to raise debt capital at favourable rates and had appropriately taken advantage of it.

Union argued that IGUA's submission that its approved equity should be reduced to reflect historic equity ratio levels for 2002, 2003 and 2004 should be rejected on the basis that IGUA's calculations were both computationally and conceptually incorrect. According to Union, the IGUA calculations understated the true equity ratios by 3% to 5%.

Board Findings

The Board issued its Decision in RP-2002-0158 on January 16, 2004. In that Decision the Board rejected the proposal made by Union and EGDI respecting changes to the formula used to establish ROE. Accordingly, the rate of return on common equity applicable to the revenue requirement established in this case is based upon the existing ROE Guidelines. As of December 2003, the long term Government of Canada bond yield was 6.00 %. The Board finds that the corresponding ROE for Union shall be 9.62% The new rate schedules arising from this Decision will reflect this ROE.

The Board finds that Union is in compliance with its deemed capital structure. Union's evidence revealed that with respect to long-term debt it had marginally exceeded the 65% debt component of its approved capital structure. This excess was offset by a negative short-term debt balance. Insofar as the variance was marginal, the Board considers this practice to be acceptable. If taken to more significant levels, this approach to the debt side of the capital structure equation could become problematic in certain market conditions. The Board considers that utility management should be in a position where it can conduct the business confidently and conventionally, without fear that the regulator will intrude to second guess decisions which are reasonable at the time they are made. Such divergences

as have been highlighted in the evidence with respect to aspects of the capital structure are not of a magnitude so as to require Board intervention.

The Board accepts the proposed capital structure of 35.0% common equity, 3.5% preferred equity and 61.5 % long and short term debt for 2004.

Throughout the proceeding intervenors raised issues respecting the adjustment of Union's risk premium as it affects its approved return on common equity. The risk premium element of the return on equity formula is designed to reflect the extent to which the utility is exposed to genuine business risk. Intervenors suggested that changes in weather methodology, the adoption of hedge strategies related to weather, and the increase in monthly fixed charges ought to be reflected in a reduced risk premium. This would have the effect of reducing Union's overall approved return on common equity. The Board applies the ROE formula to the revenue requirement established for the utility. Parties are free to submit evidence respecting the accuracy of the risk premium in subsequent proceedings.

RP-2003-0063
Rate Order
Working Papers
Schedule 6

UNION GAS LIMITED
Calculation of Requested and Approved Rate of Return
Calendar Year Ending December 31, 2004

Line No.	Particulars ($000's)	As Filed Capital Structure	As Filed Cost Rate (%)	As Filed Requested Return	Per Board Capital Structure	Per Board Cost Rate (%)	Per Board Return
		(a)	(b)	(c)	(a)	(b)	(c)
1	Long-term debt	$ 2,009,458	8.45%	$ 169,799	2,009,458	8.45%	169,799
2	Unfunded short-term debt (1)	(130,778)	4.15%	(5,427)	(122,794)	4.15%	(5,096)
3	Total debt	1,878,680		164,372	1,886,664		164,703
4	Preference shares	109,539	5.44%	5,959	109,539	5.44%	5,959
5	Common equity	1,070,579	11.63%	124,455	1,074,879	9.62%	103,403
6	Utility rate base	$ 3,058,798		$ 294,786	3,071,082		274,066

Note:
(1) "Per Board" reflects Board's rate base adjustment on Schedule 2

EB-2005-0520
Rate Order
Working Papers
Schedule 3

UNION GAS LIMITED
Summary of Cost of Capital
Year Ending December 31, 2007

Line No.	Particulars	Utility Capital Structure ($000's) (a)	Utility Capital Structure (%) (b)	Cost Rate % (c)	Requested Return ($000's) (d)
	As filed				
1	Long-term debt	$ 2,090,667	61.27	7.68%	$ 160,559
2	Unfunded short-term debt	(152,817)	(4.48)	3.16%	(4,831)
3	Total debt	1,937,850	56.79		155,728
4	Preference shares	109,469	3.21	4.71%	5,161
5	Common equity	1,364,880	40.00	9.63%	131,438
6	Total rate base	$ 3,412,199	100.00		$ 292,327
	Per Settlement Agreement				
7	Long-term debt	$ 2,082,334	61.66	7.66%	$ 159,403
8	Unfunded short-term debt	(30,396)	(0.90)	1.55%	(472)
9	Total debt	2,051,938	60.76		158,931
10	Preference shares	109,469	3.24	4.71%	5,161
11	Common equity	1,215,792	36.00	9 63%	117,081
12	Total rate base	$ 3,377,199	100.00		$ 281,173
13	Change (Line 12 - Line 6)	(35,000)			(11,154)
	Per Board Decision				
14	Long-term debt	$ 2,082,334	61.66	7.66%	$ 159,403
15	Unfunded short-term debt	(30,396)	(0.90)	1 55%	(472)
16	Total debt	2,051,938	60.76		158,931
17	Preference shares	109,469	3.24	4.71%	5,161
18	Common equity (1)	1,215,792	36.00	8.54%	103,829
19	Total rate base	$ 3,377,199	100.00		$ 267,920
20	Change (Line 19 - Line 12) (2)	-			(13,252)

Notes:
(1) 2007 Return on Equity (ROE) using the Board's ROE Guidelines, updated to reflect the October 2006 Consensus Forecast
(2) 2007 Return on Equity (ROE) change before tax is $20,745.

EB-2011-0210

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (Sched. 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.

SETTLEMENT AGREEMENT

June 28, 2012

UNION GAS LIMITED
Summary of Cost of Capital
Calendar Year Ending December 31, 2013

Line No.	Particulars	Utility Capital Structure ($000's) (a)	Utility Capital Structure (%) (b)	Cost Rate % (c)	Requested Return ($000's) (d)
	As Filed				
1	Long-term debt	2,257,972	60.35	6.50%	146,868
2	Unfunded short-term debt	(115,296)	(3.08)	1.31%	(1,510)
3	Total debt	2,142,676	57.27		145,358
4	Preference shares	102,248	2.73	3.05%	3,117
5	Common equity	1,496,617	40.00	9.58%	143,376
6	Total rate base	3,741,542	100.00		291,851
	Per Settlement Agreement				
7	Long-term debt	2,234,597	60.17	6.53%	145,957
8	Unfunded short-term debt	(108,513)	(2.92)	1.31%	(1,422)
9	Total debt	2,142,676	57.25		144,535
10	Preference shares	102,248	2.75	3.05%	3,117
11	Common equity	1,485,555	40.00	9.58% (2)	142,316
12	Total rate base	3,713,887	100.00		289,969
13	Change	(27,655) (1)			(1,883)

Notes

(1) Reductions to rate base

general	(12,000)
gas in inventory	(15,655)
	(27,655)

(2) Per Section 4.3 of the settlement agreement

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit E1, Tab 1, page 8 and E3, Tab1, Schedule 1

Union plans to issue an additional $125 of long-term debt at an effective rate of 3.90% in 2013. Union has also indicated that there are no scheduled redemptions of long-term debt between the date of filing and December 31, 2013.

a) Please explain why Union intends to issue long-term debt when its proposed capital structure shows negative unfunded short-term debt of $115 million.

b) In issuing $125 million of long-term debt Union will pay an effective rate of 3.90%. Would Union have paid a lower effective rate if its equity component was 40%? Please provide a detailed response.

Response:

a) As stated in Exhibit E1, Tab 1, p. 6 the short-term debt included in the utility capital structure differs from the actual short-term borrowings. Items such as construction work in progress and deferred pension costs have a significant impact on the amount of short-term borrowings. In addition, Union's cash position varies significantly due to the seasonal nature of its business which impacts the average balance. Lastly, the timing of the requirement for cash comes before a proposed change in equity. An increase in equity would be naturally offset by debt. Long-term debt changes cannot happen quickly by their very nature. The cash position will slowly return to short-term debt as the long-term debt level adjusts through maturities and reduced issues.

Union issues long-term debt as required to avoid exceeding its credit facility which is at risk of occurring in the fourth quarter of 2012. It is not cost effective to issue debt in small amounts and would be administratively burdensome. Though Union issues debt in larger amounts that may result in low short-term debt levels or even a cash position, Union only obtains long-term debt financing when prudent and tries to take advantage of favourable market conditions.

The Board has previously found this practice to be acceptable as noted in RP-2003-0063 on pp. 112-113 in the Board's Decision with Reasons:

> *"The Board finds that Union is in compliance with its deemed capital structure. Union's evidence revealed that with respect to long-term debt it had marginally exceeded the 65% debt component of its approved capital structure. This excess*

was offset by a negative short-term debt balance. Insofar as the variance was marginal, the Board considers this practice to be acceptable. If taken to more significant levels, this approach to the debt side of the capital structure equation could become problematic in certain market conditions. The Board considers that utility management should be in a position where it can conduct the business confidently and conventionally, without fear that the regulator will intrude to second guess decisions which are reasonable at the time they are made. Such divergences as have been highlighted in the evidence with respect to aspects of the capital structure are not of a magnitude so as to require Board intervention."

In RP-2003-0063 the proposed short-term debt level was projected to be -4.28%. Union has proposed a lower level of -3.08% for 2013.

b) The rating agencies have indicated that their implicit assumption is that Union's allowed equity component will be increased to a level which is consistent with the allowed levels for other utilities, in line with Union's evidence. It is unlikely, however, that going to 40% equity will be sufficient to result in a rating upgrade or significantly impact the expected cost of debt.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **15**

DATE: **August 24, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Karen Taylor	**Member**

obtained through contested interrogatories indicate that Union and Spectra in fact view this project as a pre-build and a launching pad for an expansion of Union's transportation corridor.

Viewed in either context, TransCanada believes that the Parkway West project is, at best, premature, and, at worst, an example of the redundant infrastructure with which the Board should be concerned because of the costs that it will impose on Ontario gas consumers.

As the Board is aware, looking back a few years, from TransCanada's participation in the 2010 Natural Gas Market Review, TransCanada has a significant investment in natural gas transportation infrastructure in Ontario.

That infrastructure is being paid for, to a significant extent, by Ontario gas consumers. As a result of changes in supply opportunities available to North American gas consumers, and most recently Marcellus shale gas, portions of TransCanada's Mainline infrastructure and, in particular, its northern Ontario line, have capacity available.

TransCanada is also interested in this proceeding because the Parkway West project interconnects with the TransCanada system, and TransCanada is alleged to be a beneficiary of the loss of critical unit protection that this project will provide.

Finally, needless to say, TransCanada is interested in this proceeding because TransCanada is a major shipper on Union and will be among those paying for any new facilities

costless solution of short-term firm service on TransCanada's underutilized system, or a mix of solutions, such as a certain amount of service to Parkway on TransCanada's Hamilton line, a certain amount of service at Parkway through displacement accomplished by Dawn-to-Dawn TCPL service, feeding Great Lakes backhaul, and a certain amount of STF -- STFT service. So it could be all of one, or some of each, depending on what, in collaborative discussions with Union, is decided to be the most economical, flexible and reliable way of providing that service.

The point here is that Union has not seriously explored these options. TransCanada first learned of Union's sudden interest in loss of critical unit protection at Parkway in a meeting a few days before the application for this proceeding was filed.

And this was not a meeting to explore options, but a meeting in which Union informed TransCanada of its intention to build the Parkway West project.

Disappointingly, Union opened its Parkway West project panel with evidence in-chief to the effect that Union had dismissed, without any consultations, without discussions, had dismissed TransCanada's four alternatives. And TransCanada believes that the Board ought to be concerned about the dismissive, backhanded approach that Union took towards TransCanada's alternatives.

TransCanada found Union's evidence in-chief on this topic at the opening of their Parkway West panel and its

summary dismissal of the alternatives -- alternatives to a huge capital investment -- TransCanada found that evidence to be uninformed, as one would expect comments to be uninformed in the absence of consultations with TransCanada about these available alternatives.

I said this before and I will say it again: TransCanada is not here to convince the Board that there is a better alternative to a new compressor site, a new compression infrastructure at Parkway, nor what the specific better alternative is.

TransCanada is here because Ontarians are paying billions of dollars for TransCanada infrastructure that was designed and built to deliver gas to Ontario gas consumers, and that could provide better alternatives for loss of critical unit protection at Parkway, should it be determined that loss of critical unit protection into the TransCanada system at Parkway is even needed.

TransCanada also observed in its evidence that the part of the Parkway West project that involves a new connection to Enbridge is simply an unnecessary expenditure.

In this case, TransCanada's position isn't because TransCanada can provide a less expensive alternative, but simply because the new connection is pointless. It will not materially increase reliability for service to the GTA.

The new compressor site and its connection to Enbridge at Parkway makes sense for Union's shareholder as a pre-build for Union's proposed Parkway extension to bypass the

And this is an example of why, in TransCanada's submission, the Board needs to be proactive in requiring that Union explore these options, options that may be in the interests of Ontario gas consumers.

It appears to TransCanada that Union would rather expand its Dawn-to-Parkway system than provide TransCanada with a virtually costless service within the Dawn yard that allows TransCanada to feed Parkway with its existing Ontario -- northern Ontario line and North Bay-to-Maple infrastructure.

And the only way that Ontario gas consumers will be spared the cost of Union's refusal to cooperate with TransCanada in this regard is with the Board's oversight.

Another option is adding cheap compressibility to TransCanada's Hamilton line, which, as the Board will be aware, comes up from Niagara Falls to the Hamilton area, to Parkway.

This line provides huge benefits to both Union and Enbridge, in the sense that for relatively modest capital expenditure it allows Ontario gas consumers - as noted, both Union customers and Enbridge customers - to use existing TransCanada infrastructure to add reliability to both franchises.

Union would add reliability to its Burlington and Bronte delivery areas, and Enbridge would acquire a third source of supply independent of TransCanada's northern Ontario line and independent of Union's Dawn to Parkway service.

the opportunity to review the transcripts and, in particular, BOMA's submissions on NEB approval first before the Board does anything?

MR. CAMERON: We're --

MS. HARE: Sorry, before this Board does anything.

MR. CAMERON: The answer to your question is, yes, I did review those submissions.

We've thought a lot about the sequencing of events related to the Parkway West project and the potential alternatives, and the roadblock, if I can call it that, that we come up against is Union's announcement that it intends to apply for leave to construct the Parkway West project in the near future, perhaps just by logistics of it, in advance of this Board's decision in this case, and that will be a fait accomplis.

They will have filed it and, subject to this Board's scheduling of it, we're going to have to deal with it. And we can make this observation, that to TransCanada's point of view it sure would make a lot more sense if Union and TransCanada, and probably Enbridge, sat down and got their senior engineers and senior management together and worked out what happens in the Parkway area and the Parkway to Maple corridor before everybody runs off building hundreds of millions of dollars of infrastructure.

But we appear to be stymied by this, as I call it, fait accompli. Union is going to file its leave-to-construct and we're going to be in a proceeding where we will have to debate the issue there.

2010 Natural Gas Market Review

Stakeholder Conference

Presentation by Union Gas

October 7-8, 2010

Agenda

uniongas

1. Principles for Effective Gas Markets in Ontario
2. ICF Market Report and Supporting Trends
3. Market Response to Changing Supply Dynamics
4. Looking Out – Next 5 Years

Principles for Effective Gas Markets in Ontario

uniongas

Ontario will achieve a competitively priced, reliable gas market when there is:

1. A robust market hub with growing liquidity
2. No undue influence from any basin, route or company
3. A working market

Liquidity at the Dawn Hub is essential for providing cost-effective gas supply to Ontario

Trend – Increasing TCPL Tolls



uniongas

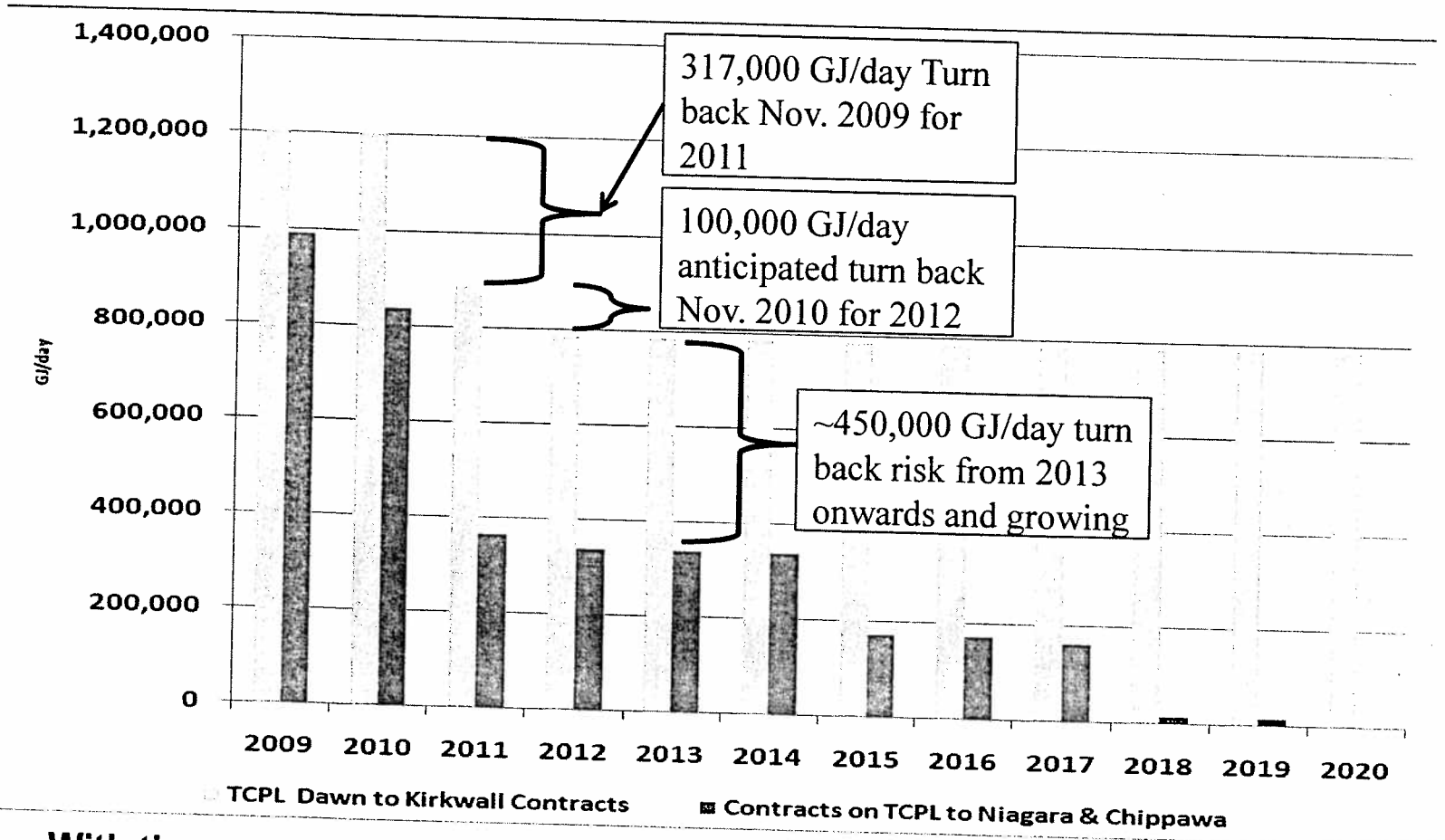
- Declining flows on TCPL have lead to increasing tolls. Over the last 24 months tolls from Empress to Parkway (Union CDA) have increased from $1.03/GJ to $1.64/GJ (59% increase)

- For 2011, continued contract reductions will result in further escalation in tolls under the current rate setting methodology.

WCSB supply shipped on TCPL to Ontario is now Union's most expensive supply option

Trend - De-Contracting Risk of Dawn to Kirkwall (TCPL)

uniongas



With the emergence of Marcellus supply, TCPL's need for Dawn – Kirkwall capacity for exports is diminishing. Dawn –Trafalgar asset must be re-purposed.

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Market Response



uniongas

1. Dawn Gateway Pipeline Project
2. Reversal of Dawn – Exports into Great Lakes Gas Transmission
3. Reversal of Kirkwall and Marcellus projects to supply Ontario
4. TCPL Mainline Competitiveness Initiative
5. System Supply – Supplying the North Differently and Sourcing Marcellus

Still required... Expansion of Parkway to Maple

The market is responding with competitive options

Urgent Need to Expand Parkway to Maple

uniongas

Purpose

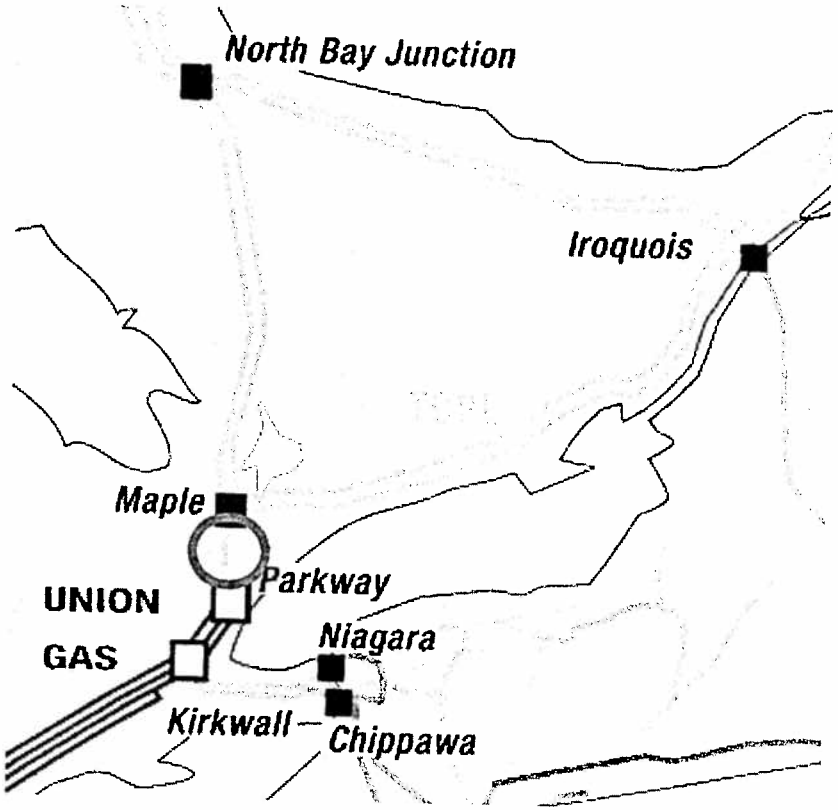
- To relieve capacity constraint between Parkway and Maple. Current pipe is a 36" single line built in 1958 that is at capacity

Project Requirements

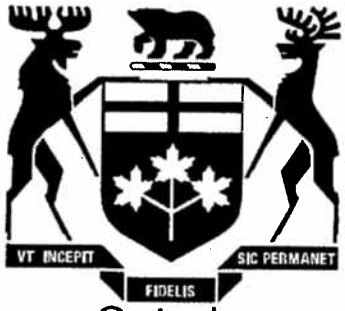
- Expand and/or build Parkway to Maple
- Incremental volume –1,000,000 GJ/d
- In-service 2013 or sooner

Benefits

- **Supports liquidity and growth at Dawn**
- Provides increased security of supply for Ontario
- Provides greater diversity of supply for Ontario
- Allows Dawn-Trafalgar system to be re-purposed from Kirkwall exports to Parkway exports



Bottleneck from Parkway to Maple is limiting the movement of supply into and around Ontario



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out of Dawn in the most cost-effective manner throughout this time and has minimized capital expenditures and the resulting transportation costs to Ontario consumers. This access has been provided through a combination of physical expansions, the flexibility of the integrated TransCanada system that has allowed for deliveries along different paths for the existing infrastructure, the use of innovative services, and through back-hauls, and this has resulted in the most efficient movement of gas around and through Ontario.

TransCanada observes the emphasis that Union Gas has in its presentation related to the need for additional infrastructure between Parkway and Maple. To be clear, TransCanada is not limiting the movement of supply into and around Ontario.

TransCanada intends to continue to provide unrestricted access to all points on its system to meet the changing needs of the market, and is prepared to build future infrastructure, future expansions, as required.

The evolving market that we have seen has resulted in both costs and benefits to Ontario. During the last decade, the mainline revenue requirement has declined from about $2.2 billion in the year 2000 to less than $1.75 billion, or approximately $1.72 billion today.

The TransCanada rate base has decreased over this period from $9.4 billion to approximately $6.5 billion today. Operation and maintenance costs, or O&M costs, the single large costs that TransCanada can control, have been

had a question.

MR. QUINN: Yes, thank you, Neil. Dwayne Quinn on behalf of the Federation of Rental-Housing Providers Ontario. Steve, I appreciate your presentation. I understand and I respect TransCanada's understanding of the North American market from not only the TCPL mainline, but obviously your pipelines owned in your corporation.

You addressed fairly early on in your presentation your awareness of the submissions that Union has made and will be delivering tomorrow indicating a bottleneck between Maple and Parkway. I would like to ask a question and possibly a follow-up, but does TransCanada have ideas of other ways that that need that Union is trying to address, in terms of diversity of supply to the north -- does TransCanada have an idea of another way of managing that same issue?

MR. POHLOD: You know, TransCanada always takes a look at what it believes the most appropriate way to manage capacity is at any given point in time. I guess what I took a little bit of exception to is the fact that it's not TransCanada's position that there is a bottleneck between Parkway and Maple.

The parties that have wished to contract and move gas from Dawn to market, wherever that market has been, have been able to do so. The extent to which parties have requested new capacity from Dawn to market, in open seasons, they have been awarded that capacity. They have been awarded contracts. We don't believe that path has

been bottlenecked.

I believe that as we move forward, if there is increasing demand for increased volumes along that path, then potentially there could be a future bottleneck, and that future bottleneck may have to be relieved by building capacity through that path, if there is a bottleneck.

MR. QUINN: So the underlying premise of a bottleneck is something you might debate, and we may have that opportunity in the future. I guess, then, the further follow-up question would be you had alluded to in the presentation about the Ontario Energy Board's obligation and opportunity to look at the total cost of gas to the Ontario consumer. Part of what is very difficult obviously to quantify is the value of diversity of supply.

Would you support -- and you are probably aware Mr. Rosenkrantz has done a study on behalf of some of the representative ratepayers here. Would you support the Ontario Energy Board looking at any incremental facilities in the macro; in other words, looking at the implications to existing and proposed infrastructure using the bottom line of increased -- or in terms of what the cost of gas is to the Ontario consumer?

MR. POHLOD: The overall cost of gas to the Ontario consumer, I believe that is what is appropriate.

MR. REED: I think the only thing I would add that is we have also said that considerations go beyond Ontario. Certainly the actions of Ontario's customers of TCPL very much affect costs upstream and downstream.



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more or less economic. And our concern would be, if parties want to start loading up costs in the short-haul to kind of offset some costs in the long-haul, we really want to make sure the short-haul stays competitive. If costs go out of line on the short-haul path, then it will start to empty as well, and that would be a bad day for Union, it would be a bad day for TransCanada, it would be a bad day for Ontario.

So that's really a strong focus for us, to make sure short-haul stays, paying the fair rate for sure, but staying competitive.

And the point which I'll get to in a few minutes as well, and I'll say it again, just how important that Parkway to Maple path is becoming for Ontario.

I'm sure we'll be getting lots of questions on this slide. And we'd like to have some robust discussion on this slide, but it really shows the difference between the Union south portfolio and how we buy gas for Union south and how we buy gas for Union north.

The colour coding here is -- tells a story. Union south is very diversified. We're buying gas from every major producing region in both Canada and the U.S., heavily weighted towards western Canada supply still, both on TCPL and on Alliance Vector, but also looking at Chicago and Rockies and mid-continent and Gulf of Mexico.

The divergent view is one on the north portfolio. This is really across northern Ontario, from Kenora through to Cornwall. It's 100 per cent today reliant on western

process is a western reference price, Alberta reference price. There's probably some need in the future to convert that to an Ontario or Dawn price. That's -- nothing in the works for that today, but certainly something we would look at doing.

On this slide I want to talk about sort of the Parkway to Maple path. And I just want to correct an impression I may have left on this slide. I think Steve Pohlod had mentioned yesterday that TCPL -- he made the point that basically Union Gas presentation, there was a lot of emphasis on this path. He made a point of saying that TCPL is not limiting the movement of supply in and around Ontario, and I apologize if that was the perception this slide was leaving people. That was not the intent. The intent of this slide was not that it was a limiting factor today. It's just how important this piece of pipe is in the future.

If you look at the map, Parkway to Maple, Parkway is where TCPL and Union Gas interconnect. If you look at the piece of pipe between Parkway and Maple, it's a single piece of pipe, 36 inches in diameter.

If you look at the pipe coming down from North Bay, it's two pipes, a 36-inch and a 30inch. Between Maple and Iroquois, it's two pipes, 36- and 20-inch.

Now, the Union Gas system, they actually have a 48-inch, a 34-inch and a 26-inch pipeline, so a lot of pipe in and around Parkway, a lot of pipe in and around Maple, and we have a single pipeline between the two.

And if you think of bringing supply through Dawn and expanding optionality either to the folks in the northern delivery area or the eastern delivery area, it has to go through that point.

So I think TCPL mentioned yesterday they're looking at a build. They're kind of compiling numbers and that type of thing. And it's really to open up that pipe to get gas moving from south to north. That pipe is going to be a critical piece of infrastructure and I would say a strategic piece of infrastructure for Ontario.

It definitely adds liquidity, health of liquidity at Dawn and growth of Dawn. It helps with security of supply. It helps with diversity of supply.

So for us going forward, that's probably one of the most important things as the province we need to be at least watching. And I think the market will work. It's just going to be critical.

So just to wrap up, sort of looking out the next five years, we sort of have five bullet points in terms of what we think is required from the growing supply sources and the changing supply sources, and to continue to grown Dawn and liquidity of Dawn.

And the first I just talked about really is that Parkway to Maple piece of pipe. And Parkway to Maple, I should mention Parkway, again, is Pearson Airport. Maple essentially is Canada's Wonderland. So it's not a long piece of pipe. I think it's 47 or 50 kilometres, but -- it may not be long, but it's very critical.

Continuing to let the market work and adapt, I think what I was trying to demonstrate on the few things happening at Dawn, reversal and critical reversal. The market is active. People are contracting. People are trying to get paths established to try to move gas in new directions. It's all very positive, and our thought would be that the market continue to work.

Continue timely approval for regulatory services and facilities, a good example here is a Dawn to Dawn TCPL rate was filed in mid-June and was approved six or eight weeks later, very quick approval from the OEB, something that's very much appreciated by us and by our customers.

Continue to support alternative forms of regulation, when Gateway went to the Ontario Energy Board, they were requesting an alternative form of regulation, similar to what the NEB offers in their group 2 category, and the Board was very receptive to looking at that and to allowing Gateway to proceed within Ontario under that same framework.

And, really, the last point is support from the province, whether that is from the ministry or through the OEB, in terms of the growth of Dawn and Dawn liquidity, and the growth of incremental supply paths into Ontario.

And with that, I will turn it over to questions.

MR. MCKAY: Can I just remind everyone to identify themselves if they have questions for Union, just so that we can have a record of whose questions are coming from who? Thanks. Khalil.

QUESTION AND ANSWER SESSION:

MR. VIRANEY: Khalil Viraney, Board Staff. I just have a question on, do you see any impact of Quebec shale gas if it goes ahead for Ontario and Union?

MR. ISHERWOOD: Quebec shale gas would definitely impact Ontario. And I think it was discussed yesterday in terms of how big it actually becomes. But initially what will happen is the consumers in Quebec will get a first crack at using it, obviously. I mean, it makes the most sense.

So Gaz Métropolitain today relies heavily on western Canadian supply, and also Dawn supply. So as more domestic supply starts to develop in around Quebec City and flows into Quebec City and Montreal, naturally it would back off either long haul on TransCanada or even some of the short haul services out of Dawn.

MR. BUTTERS: Dave Butters, APPrO, for Mark Isherwood. Mark, the Parkway to Maple expansion is central to Union's presentation in order to allow the balance of Ontario to access shale gas, and I'm wondering, does Union see that it might build that pipeline, that expansion?

MR. ISHERWOOD: I think the most logical choice is TransCanada. It's sort of their path and their assets, and, as I understand, they're looking at it today. Whether Union would build it or not, I'm not sure, but if TransCanada didn't build it, I think somebody in the market might. There are lots of pipeline companies that would see that as an opportunity.

to zero and we have 800,000 intermittently coming into Ontario, I think Niagara may not be as robust as it is today. That's one direction it could take.

So I wouldn't say Niagara would turn into a hub as good or as deep as Dawn, but it's a pricing point. I think what Niagara is missing is the multiple pipes, multiple directions, storage, and pure volume.

MR. MONDROW: Okay. All right. I just want to move on to my second area then. This is, I think, a relatively simple question. The Parkway to Maple expansion possibility, is that kind of equivalent to your rubric of diversity of supply to the north? I mean, is that the fix for the lack of current diversity supply to the north, or is there more?

MR. ISHERWOOD: It's probably the most logical option. I will add -- I had a question earlier about Utica Shale, so Utica Shale could obviously come into Ontario without touching Parkway to Maple.

People yesterday talked about Iroquois volumes reversing. That could come into Ontario as well without affecting Parkway to Maple. But the most logical, in terms of getting access to the Gulf, the Gulf Shale, the Rex gas coming in through Ohio, that gas is going to have to come through -- more likely to come through, more logically come through, I guess, Dawn and southern Ontario through Parkway into Maple.

And Marcellus can probably go a couple of different directions. Iroquois is certainly an option in the future.

The more logical option, and the one that's more advanced today, based on the contracting already in place, is through Kirkwall and Parkway.

MR. MONDROW: Okay. That's great. Thanks.

MS. PIETT: Ian, I wondered if I could add something to that question.

MR. MONDROW: Sure.

MR. PIETT: You asked about, is that the answer to the solving the north diversity issues. That would certainly help. There would be more that we would need from TransCanada as well. And we've talked to them about that, and we're working on some solutions, hopefully.

But the amount of gas that we have now proposed to go to the north is base load, so we would run that every day to the north, the north -- the NDA, as well as the EDA.

If we wanted to increase that volume to a greater diversity, then we would need different services, such as a winter peaking service that's renewable every year and so on.

So we would need different flexibility on the TCPL services than what they offer now to go further. We also need to have competitive short-haul tolls, because it wouldn't land cost-effectively if the short-haul tolls doubled, for instance.

MR. MONDROW: They're competitive now, but your concern is that they may become uncompetitive, subject to how the mainline work goes.

MS. PIETT: Exactly.

should be burning on the system.

But at the present time, we're not running a lot of compression on the mainline, so to actually move physically move the gas on that path is very cost-effective, and in frequent. And we expect it's going to be very infrequent that we'd be doing that.

MR. MONDROW: No, I appreciate that, and the map makes that pretty instinctive. But even reinforcing this Parkway to Maple -- or expanding, I guess, is probably the right word -- I guess the Parkway to Maple shut will displace volumes, and in that case all across the mainline, not just upstream of Empress. So the same dynamic, it seems to me, the same push and pull, is at play, although I appreciate that it's a different route.

MR. BELL: Yeah, absolutely, and that was the point that Steve was making, and TransCanada made in their presentation the other day. The trade-off of having to supply diversity has a cost associated with that. We need to consider the costs.

MR. MONDROW: Right. And bringing gas in from Quebec shale is obviously going impact you. So I guess I'm just trying to highlight, in my own mind, that these are -- that's the manifestation of the rubric that we got from Steve yesterday, which is you have to consider costs and benefits.

So it's not a simple equation if you're going to look at it on that sort of expanded basis.

MR. BELL: Absolutely. And that's what we've been

doing by utilizing this path versus expanding out of the Parkway and Maple path for the number of years that we've done that.

MR. MONDROW: Right. Thanks.

MR. MCKAY: Dwayne.

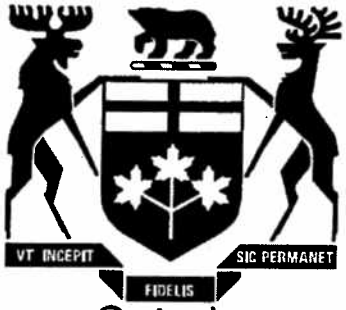
MR. QUINN: Dwayne Quinn, FRPO. Don, I just wanted to clarify this further. I'm trying to get clarification, Don, if I may, because this is a concept we're all trying to get our heads around, especially in a forum like this. There are options for bringing supply diversity, and we all can understand there may be cost with that. But when you come right down to the ratemaking implications that Union is referring to, if you're having the option of backhauling on Great Lakes, in essence, you are going to be just reducing costs on Great Lakes on a seasonal basis. Would you say that's accurate?

You're reducing the net flow in to Dawn, so you're reducing your fuel costs on Great Lakes?

MR. BELL: That's correct, if the gas physically flows.

MR. QUINN: Okay. So there is a potential cost savings or a profit increase on Great Lakes. But to the extent that that actually reduces your seasonal forecast for how much throughput is going to go through the north lake or essentially through Emerson, does that not have a positive pressure on the toll for the mainline?

MR. BELL: First of all, I think that the statement that you made about having a positive effect on Great Lakes



Ontario

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BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. WOOD: Yes. J.B-1-7-14 part f), the numbers used were taken from J.B-1-7-1, so those numbers were corrected, as well.

MR. SMITH: I see. So you have just flowed through the correction?

MR. WOOD: Yes.

MR. SMITH: Just a couple of brief questions for you, Mr. Redford, before I tender you for cross-examination.

Can you please provide for the Panel a description, a high-level description, of the Parkway West project and what it involves?

MR. REDFORD: Yes, I can. The Parkway West project is a reliability project. It really has two components.

First component is a loss of critical unit provision for coverage of the existing Parkway compressors. That will be a new compressor located on a new site.

The second item would be a second feed for Enbridge at Parkway to -- for Parkway Consumers, and the Lisgar feed back-up.

MR. SMITH: And just so it is clear for the record, what is Lisgar, and what is Parkway Consumers?

MR. REDFORD: Lisgar and Parkway Consumers are locations at Parkway where Union delivers into the Enbridge delivery system. And that volume between the two locations is about 1.6 pJs a day.

MR. SMITH: Okay. Can you just tell me why Union has proposed the project?

MR. REDFORD: Union -- well, there's two components.

So the LCU, we started looking at LCU, loss of critical unit coverage, as early as 2010. And, really, it is a result of increased flows through Parkway.

In 2005, Parkway discharged about a half a pJ a day into the TCPL system. Today it is about four times that, and we predict that to grow to about 3 pJs per day. And that's -- really, it's the only spot in our system and, as near as we can tell, in the transmission system in Ontario that is without loss of critical unit protection.

The second feed into Enbridge, we started discussing with Enbridge some reliability concerns that they had about feeding their system, and it was an item that Enbridge had brought up in discussions. As part of those discussions, Enbridge had looked at a third feed into the Toronto area, into the GTA.

We talked about Parkway West and a second feed for that Parkway (Cons) and Lisgar as a means of satisfying the reliability for the Parkway (Cons) and Lisgar volumes.

MR. SMITH: Can you just tell me the approvals being sought by Union in this proceeding in relation to the project?

MR. REDFORD: We are seeking no approvals.

MR. SMITH: Okay. That being the case, when do you anticipate seeing approvals?

MR. REDFORD: We would file a leave to construct application in September or October of this year for the components of the project which would be typically covered under leave to construct. We would look for approval for

pipeline headers between the Dawn-Trafalgar system and the station itself -- and the Parkway West station itself.

As part of that application, we would include a full description of the project, full economics, which would include the compression and the metering facilities, and also rate impacts.

Rate -- or cost recovery would be sought at the time that the 2014 rates are set in whatever process or proceeding is used to determine that.

MR. SMITH: Now, in its evidence, TCPL proposes certain alternatives to the project.

Have you had a chance to look at those, sir?

MR. REDFORD: I have.

MR. SMITH: And can you tell me Union's response to those alternatives?

MR. REDFORD: Yes, I can. There were four alternatives proposed. The first alternative was Empress to Union CDA, either STFT, a contracted service, to replace loss of critical unit.

The second alternative was a new compressor in the vicinity of Parkway. The third alternative was use of the domestic line, an upgrade to their domestic line, plus two compressors located, again, in the vicinity of Parkway.

The fourth alternative was an option using Great Lakes Gas Transmission, and flowing across the northern Ontario line.

I will start with the second alternative, which is a new compressor at Parkway. The second alternative is

similar, but not the same, as Union's. It is a physical reliability solution. It is a loss of critical unit to replace Plant B, seemingly, and appears to be at this point less developed than the Parkway West project that we're proposing.

While the details aren't fully available, that project, in order to work, would need to be located directly in the vicinity of Parkway.

MR. SMITH: Okay. So that's alternative 2. Let's maybe go back to alternative 1.

MR. REDFORD: Alternative 1 is the short-term firm transportation. The short-term firm transportation, it is a biddable service on TransCanada's system. It is not renewable. And, in our view, there is no guarantee of availability, and that really is not a substitute for a loss of critical unit protection or loss of critical unit coverage.

TransCanada had suggested that Union could purchase STFT in the event of an outage. Our belief is that that is not -- that's not prudent. That capacity may not be available when you need it. And when you need it most is going to be the coldest time of the year, and that is the time that people are looking for capacity.

If Union were to look at something like that option, we would have to take capacity over a longer period of time, which could be hundreds of millions of dollars on an annual basis.

Another component of that, of that option or that

alternative, was for Union to buy gas at Empress, and then sell gas at Dawn or wherever we were receiving the gas.

While we buy and sell gas for our customers, for our in-franchise customers, it is really not in Union's business to be buying gas and selling gas on the day at two different spots like that, specifically when they're not necessarily in-franchise customers that we're covering.

So for those number of reasons, STFT really does not work for us.

MR. SMITH: What about option 3?

MR. REDFORD: Option 3 is the use of the domestic line. It was two compressors and an upgrade to the domestic line. It seemingly is a bit of a hybrid between physical and contractual solution.

I think for Union we would have to contract 1.1 pJs a day of coverage on the domestic line to make sure that we have loss of critical unit coverage, and I think there isn't a rate at this point for that. But even in the evidence, TCPL had identified that the annual cost of that service would be more than what the annual cost of the Parkway West facilities are for the LCU.

MR. SMITH: And does that cover option 3?

MR. REDFORD: That covers option 3.

MR. SMITH: Option 4?

MR. REDFORD: Option 4, really, I would look at it in the same light as option 1, that if we were to take capacity to backstop the loss of critical unit at Parkway, we would have to take it over a longer period of time than

on an event, and our view is that that cost is multiple millions of dollars, much more than the annual cost of the LCU at Parkway, a physical solution.

It also -- it isn't detailed as to how that service would be provided, so we would have concerns about capacity. We're not sure whether Great Lakes would even have the ability to serve 1.1 pJs a day of backhaul.

MR. SMITH: Thank you very much. Those are my questions and I tender you for cross-examination.

MS. HARE: Thank you. I understand, Mr. Cass, that you are first up?

CROSS-EXAMINATION BY MR. CASS:

MR. CASS: Yes, I do have a few questions, Madam Chair. Thank you. Because I wasn't here when the Board took appearances and also perhaps for the benefit of the witnesses, I should maybe identify myself.

I am Fred Cass and I am here on behalf of Enbridge Gas Distribution, and I do have only a very few questions. In fact, the examination-in-chief did cover some of the ground that I was going to cover with my questions. Perhaps I could just start by ensuring that I have it correctly.

Union is not asking for any approval in this case by way of the Board granting approval for the Parkway West project. That approval, to the extent that leave to construct is required for any particular facilities, will be in a later leave to construct application; is that correct?

MR. REDFORD: That is correct.

MR. CASS: What is the purpose of Union raising the issue in this case? What is Union looking for here?

MR. REDFORD: We included the Parkway West information and costs into the rates filing. Under the filing guidelines the Board requests that any projects where spends are greater than half-a-million dollars be identified, and that's why Parkway West was included.

MR. CASS: Okay, thank you. So I did want a little more information, if you don't mind, about the forthcoming leave to construct application. In that context, you referred specifically to something you called "headers". Could you just describe a little more, please, what you are referring to when you talk about these headers?

MR. REDFORD: I can. Ideally we would love to purchase an option on property directly across the 407 from Parkway. There is not enough room on the Parkway site, the existing Parkway site, to locate another compressor and have enough buffer around the site. So we needed to move off the site to do so.

The property right across the 407 was not available, and we attempted a number of times to try and secure that land, but to no avail.

So we took the nearest property we could get, which was about a kilometre north, almost directly north of that property. So we will have to build a pipeline or pipelines from the Trafalgar lines to this property in the north, and those are the "headers" that we talk about.

MR. CASS: And you would be seeking leave to construct

from the Board for those pipelines?

MR. REDFORD: For those headers, yes. For those pipelines, yes.

MR. CASS: Now, in the context of seeking the Board's leave to construct those pipelines, would Union then consider that to be the Board's approval, if granted, of the proposal for loss of critical unit protection?

MR. REDFORD: We would still have to seek cost recovery in our 2014 rate proceeding, whatever that takes form.

MR. CASS: Yes. But to the extent that the Board grants any sort of project approval, the context in which Union would be looking for approval of the proposed headers is the context in which the Board would consider this overall loss of critical unit protection?

MR. REDFORD: Correct. We would expect that to be part of the -- we would expect the loss of critical unit to be part of the discussions in that leave-to-construct application.

MR. CASS: Okay. So would it follow, then, that I would I be right in thinking that options and alternatives can be dealt with in that leave-to-construct proceeding?

MR. REDFORD: I would expect them to.

MR. CASS: Okay. Would that include, for example, options and alternatives that TransCanada Pipelines Limited might want to bring forward?

MR. REDFORD: Yes. I would agree.

MR. CASS: And so -- sorry?

MR. REDFORD: That's fair. I think that's where they would come up.

MR. CASS: All right. So would I be right in thinking that all interested parties -- so this would include TransCanada, and it would also include Enbridge, which I represent -- will be able to participate in that leave-to-construct proceeding, and there have a full examination of options an alternatives?

MR. REDFORD: I would agree with that.

MR. CASS: Would I also be right in thinking, then, at least in Union's view, that in light of what we just discussed, and bearing in mind also that Enbridge has not been an active participant in this proceeding, that Union's 2013 rate case is not the best proceeding for the Board to try to reach decisions about options and alternatives to the Parkway West project?

MR. REDFORD: I would agree with that, yes.

MR. CASS: Okay. Thank you, Madam Chair. Those are my questions.

MS. HARE: Thank you.

Mr. Cameron, I believe you are next to cross-examine?

MR. CAMERON: I will just be one second. Thank you.

MS. HARE: Sure.

CROSS-EXAMINATION BY MR. CAMERON:

MR. CAMERON: Mr. Redford, let me begin on the point you were discussing just now with Mr. Cass, and that's the land issue.

I understand that you, Union, secured an option to

approvals, so I don't know what decision there would be in that regard. Our plan is to file September or October.

MR. MacINTOSH: Thank you.

Without having to look up any of the interrogatory responses, I note that TransCanada Pipelines, having proposed some alternatives to Parkway West, proposed -- in answer to a Board Staff interrogatory -- proposed a consultation between stakeholder groups to review the options to Parkway West.

What is Union's position on such an approach?

MR. REDFORD: We have consulted with Enbridge. In fact, have consulted with Enbridge at length with respect to Parkway West project.

We had looked at a physical solution, and had not talked to TransCanada.

MR. MacINTOSH: I think the proposal was perhaps for a wider group than just Enbridge, as a proposal by TCPL. And I am asking what Union's position is on that type of a consultation.

MR. REDFORD: We could, I think, at this point -- at this point, we have alternatives that TCPL has proposed and have evaluated those.

I don't know at this point if there is a need to consult, but certainly if we felt in our evaluation that there was information that we needed from TransCanada, then we would certainly involve them or ask them to be involved.

MR. MacINTOSH: And other stakeholders, as well?

MR. REDFORD: Other stakeholders would have an

opportunity to input in the leave to construct application.

MR. MacINTOSH: Thank you, Madam Chair. Those are my questions.

MS. HARE: Thank you. Mr. Thompson, would you like to proceed?

I am looking at the time estimates that were given some time ago, so they may have changed. I have Mr. Brett as being 45 minutes and you, Mr. Thompson, as 20 minutes. So looking at the time, if those estimates still stand, then it would make sense to go with Mr. Thompson.

Mr. Brett, do you still think you will be 45 minutes?

MR. BRETT: I do. I think it could be -- and I mentioned -- I spoke with Mr. Millar this morning and said that it might be between 45 and an hour.

MS. HARE: All right. And you, Mr. Thompson?

MR. THOMPSON: Well, hard to say. I don't think it will be as long as Mr. Brett, but it could go beyond 4:30. I am in your hands.

MS. HARE: Everybody is coming back tomorrow, in any event, so why don't we --

MR. SMITH: I'm not coming back.

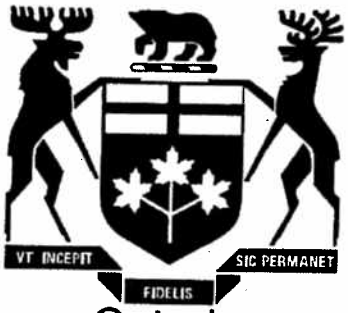
[Laughter]

MR. SOMMERVILLE: You can't.

MR. SMITH: Yes, I will be here.

[Laughter]

MS. HARE: All right. So we are done for today and we will start tomorrow with you, Mr. Brett, then Mr. Thompson, and then Mr. Millar. And then we will proceed to



Ontario

ONTARIO ENERGY BOARD

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BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

term --

MR. WOOD: Yes, physical flow.

MR. BRETT: Physical flow?

MR. WOOD: Yes.

MR. BRETT: At the moment, I take it you're saying there are zero imports?

MR. WOOD: I believe that is what was filed in evidence.

MR. BRETT: Yes. I mean, I have all of these references. I just wanted to get a very high-level view of that.

MR. REDFORD: In 2006-2007, we actually imported more gas at Parkway than we exported. There was a distinct reverse in how Parkway was used in about 2009. I think until that time, there was about, somewhere in the range of 100 Bcf a year was the maximum net discharge at Parkway.

MR. BRETT: Until 2009?

MR. REDFORD: Yes. I can't remember what year it was. It was before 2009.

2009 and 2010 we discharged between 300 and 400 Bcf a year, which was a distinct difference in the usage. And when we look at the --

MR. BRETT: Sorry, a distinct difference meaning an increase, an increase in exports?

MR. REDFORD: An increase in exports, correct.

MR. BRETT: Okay.

MR. REDFORD: And if you look at schedule 2 of my evidence of tab 9, there is a graph that shows the --

MR. BRETT: Let me just get that up. Sorry.

MR. REDFORD: Sorry. I will slow down.

MR. BRETT: This is your picture here? Yes, okay, I've got it.

MR. REDFORD: Correct. What this graph shows is the gray band is the 2006 to 2009 range of Parkway activity of the net flow through Parkway.

And that would be something relatively typical you would see. The graph starts in November and ends in March. It would be exports at that point. That's where -- eastern peaking system. So we would be exporting out of or discharging out of Parkway to TCPL.

Then in the April through, let's say, September to October, we would be net importing. So that the gray band falls below the line. That's fairly typical of traditional use.

MR. BRETT: All right.

MR. REDFORD: If you look at -- the blue line and the green line represent winter 2009/2010 and represent winter 2010/'11. We did not see that traditional dip below the line. We did not see those -- that traditional summer imports typically would be to fill storage. Storage was filled from elsewhere.

So what we're seeing is Parkway now discharging on a 365 basis, which in the past was not the case.

MR. BRETT: All right. And previous to that, you talked about 2006/2007. You would have volumes -- you'd have large imported volumes in most months; is that what

you're saying? Is that what that graph is showing? It's fairly -- I mean...

MR. REDFORD: Prior to 2009?

MR. BRETT: Yes.

MR. REDFORD: Well, I think we had a classic summer/winter split where, in the winter, we discharged into the TCPL system.

MR. BRETT: Right.

MR. REDFORD: In the summer, we received gas at Parkway, which --

MR. BRETT: You moved that physically to Dawn, then?

MR. REDFORD: Yes, which could fill storage.

MR. BRETT: Yes, okay. All right. Well, let me move on from that. I just wanted to get that straight.

Now, going back to the issue of the loss of unit protection, and just -- let me just hone in a little bit on some of this.

I think we discussed earlier the fact that the Parkway west project includes new interconnection with Enbridge, this one-kilometre pipeline and header and measurement.

And I call that a third connection with Enbridge, because there is already two connections; right? There is a connection on the input side of Parkway and there is a connection at Lisgar. So this is a third connection with Enbridge?

MR. WOOD: That's correct.

MR. BRETT: Okay. Now, has Enbridge -- in connection with this third connection that you are proposing as part

of Parkway West, has Enbridge contracted for new gas from you at this stage, additional gas to what it is taking through the two existing connections?

MR. REDFORD: No. There is no existing -- or there's no, pardon me, incremental volumes associated with the Parkway West project.

MR. BRETT: So this third connection with Enbridge is not associated, at the moment at least, with incremental gas contracted supplies?

MR. REDFORD: Correct.

MR. BRETT: Is it likely to be in the future?

MR. REDFORD: Likely not that connection.

MR. BRETT: Likely not that connection?

MR. REDFORD: That specific connection.

MR. BRETT: Okay.

MR. REDFORD: But the Parkway West site --

MR. BRETT: Right.

MR. REDFORD: -- is the likely spot for the GTA project to connect into the Dawn-Trafalgar system.

MR. BRETT: So this would be rather -- this would be, rather, the pipeline that would run -- are you telling me that the pipeline that would run to Albion would start at the Parkway West, sort of the joint venture pipeline with Enbridge?

MR. REDFORD: Or --

MR. BRETT: Or your pipeline?

MR. REDFORD: Or Enbridge's pipeline alone.

MR. BRETT: All right. That would come right from

Parkway West?

MR. REDFORD: It could come from Parkway West.

MR. BRETT: All right. Now then just one other thing on the background of this. Now, TCPL did get approval from the NEB, as you know, back in May for an additional 4 pJs of capacity downstream of Parkway.

Does that mean that as part of that -- as far as you understand, does that mean as part of the construction under that, that is currently going on, they will have to effectively increase their take-away capacity from Parkway by 4 petaJoules?

MR. WOOD: We believe that is the case, yes.

MR. BRETT: So, in other words, they will go from roughly 2 to 2.4, if you are right about your current estimate of two?

MR. WOOD: That's our estimate, yes.

MR. REDFORD: And that is what would be included in the 2012 eastern Canadian Mainline expansion.

MR. BRETT: That's the one that they -- right. That's the one they got approval for in May from the NEB.

MR. REDFORD: Right.

MR. BRETT: And which I guess they're designing and planning and building as we speak?

MR. REDFORD: We hope so.

MR. BRETT: Sorry?

MR. REDFORD: We hope so.

MR. BRETT: We hope so; yes. Now, a couple of other summary questions. The existing Parkway compressors,

If you look at the top of page 4, do you have that? It is up on the screen here, if that helps.

MR. REDFORD: I have that.

MR. BRETT: Okay. You will notice there that in those first three little bullets, after the first bullet you talk about -- I will just read this:

> "Union held discussions in late 2011 and early 2012 with Enbridge to understand their concerns regarding security of supply at Parkway..."

MR. SOMMERVILLE: I think those dates are wrong as stated in your question, Mr. Brett.

MR. BRETT: I see.

MR. SOMMERVILLE: It is 2010 and 2011.

MR. BRETT: All right. Sorry, thank you. Thank you. 2010 and 2011.

> "... to understand their concerns."

And you say here:

> "Enbridge expressed concern about this level of dependency given the projected impact of a Parkway outage, and Enbridge was considering a new independent third feed into the GTA."

Just help me with this a little bit. When you say here that Enbridge was considering an independent third feed, this would be a feed that didn't come through Parkway at all; is that right?

MR. REDFORD: It could have been a feed that either came through Parkway or did not. They looked at various options.

MR. BRETT: What do you mean by an independent third feed into the GTA?

MR. REDFORD: They were looking at another means of supplying -- supplying the GTA. And after discussing it with Enbridge, a connection at Parkway West into the GTA project met their requirements for an independent third feed.

MR. BRETT: Okay. So it would be independent of what? Independent of their existing feeds; is that the idea?

MR. REDFORD: Correct.

MR. BRETT: And when you say there your proposal met their needs, what would have been -- broadly speaking, what would have -- how else might they have done that? What else might they have done?

MR. REDFORD: One of our presentations in here discusses some of the options.

There was a Kirkwall to Parkway bullet line. There was a Kirkwall to downtown Toronto bullet line, basically, that would either parallel or go near the existing Trafalgar system and connect in either somewhere away from Parkway or, in the case of the downtown version, connect right into downtown Toronto.

MR. BRETT: Okay.

MS. HARE: Excuse me, Mr. Redford. You used the words "bullet line". What does that mean?

MR. REDFORD: Oh, sorry. A bullet line would mean it runs independent of any other system, so it wouldn't be tied into Union's Trafalgar system anywhere, or any other

system, until it hit the -- until it hit the Enbridge franchise.

So it would be a direct feed with no other connections between Kirkwall and Enbridge's system.

MS. HARE: Okay, thank you.

MR. REDFORD: Yes.

MR. BRETT: And then you go on to say that:

> "In July of 2011, Union and Enbridge formed a study team to evaluate security of supply at Parkway and to look for synergistic solutions to reinforce Parkway, create an independent feed for Enbridge and to expand capacity on the constrained Parkway-to-Maple path."

So you had these discussions, and then I gather -- first of all, did -- these discussions went on for a period of time?

MR. REDFORD: For the back half of 2011.

MR. BRETT: '11?

MR. REDFORD: Yes. Second half.

MR. BRETT: And then you, as I understand

MR. REDFORD: And --

MR. BRETT: Sorry.

MR. REDFORD: I should correct myself, sorry.

It was initially raised to us in 2010, and then we had a joint team formed in the second half of 2011 to talk more about -- about solutions.

MR. BRETT: Okay. And then you -- eventually you came up with a solution, which is listed here at page 4. And

the solution has a number of components to it, but it -- you can all read them.

You would build and own Parkway West, and additional volumes could then be considered. A new feed into the GTA from Parkway West to a new city gate at Albion is built. Then Union builds and owns the remaining pipe from Albion to Maple.

And then the sum of all projects defined as the Parkway projects, so you have this package of Parkway projects.

Now, you have an MOU you reached; you reached a memorandum of understanding with Enbridge. There's two MOUs that are referred to on page 5 of this same document.

One of them is -- the one I am interested in at the moment is the MOU with Enbridge, which sets out the joint venture approach.

I take it that that MOU sort of -- am I right in suggesting that MOU would have contained the elements of this solution that you -- that I just -- that is -- that appears on page 4 here?

MR. REDFORD: It would have described them at a high level.

MR. BRETT: At a high level?

And is that MOU -- that MOU is not in the evidence, I don't think, is it?

MR. REDFORD: No. We -- at this time, Enbridge is pursuing the GTA project by themselves.

MR. BRETT: Right.

MR. REDFORD: So that portion to Albion, Enbridge is developing that project on their own.

And subject to what happens with incremental volumes to Maple, whether it's built through TCPL's system or whether it gets built through a Parkway extension project, we have not entered into the joint venture at this point.

MR. BRETT: I see. So you haven't progressed beyond the -- you still have the MOU, but you haven't taken it into a formal joint venture; is that what you're saying?

MR. REDFORD: That's correct.

MR. BRETT: But the MOU still is there. And the MOU, I gather, would contain what you just described, and it also, as you say, refers at a high level to these other elements of the solution here?

MR. REDFORD: Yes.

MR. BRETT: Just so I understood what you just told me, you're saying Enbridge has decided for the moment -- well, it has decided to effectively -- I mean, I don't have the geography in front of us, but effectively build a pipeline connecting their franchise area to the -- to Albion, which is a point on the Parkway-Maple line; is that right?

MR. REDFORD: Correct. Enbridge had planned to reinforce their system.

MR. BRETT: Right.

MR. REDFORD: They had pretty serious concerns about reliability, particularly feeding the City of Toronto and the GTA.

They plan to build that pipeline, whether we're part of it or not. They need that for their reliability.

Mr. Brett: I understand. And am I right in concluding from what you have said that if they go ahead and build that pipeline as you've described it, they would not be building a pipeline that would come directly to Parkway West and connect with you at Parkway West; is that right?

MR. REDFORD: That GTA project would connect at Parkway West.

MR. BRETT: The same line that you have just -- you have just described?

MR. REDFORD: Yes. That is the GTA project.

MR. BRETT: All right. So where does, then -- sorry, just so I have sort of a coherent picture, then, what is the role of Albion in this? I thought the pipeline was going to run to Albion -- from Albion.

MR. REDFORD: The pipeline is proposed to run to Albion. That is the point within Enbridge's system that Enbridge determined was the best spot to reinforce. That is where they determined they needed gas to reinforce the GTA.

MR. BRETT: Well, thank you. I misunderstood you.

So effectively that is the terminus of the line, and the other terminus of the line is Parkway West, is what you're saying?

MR. REDFORD: Correct.

MR. BRETT: Okay.

MS. TAYLOR: Mr. Brett, before you move on, the last bullet on that slide indicates that Union, I am assuming, has held an open season for the extension project and the Dawn-Parkway capacity, and that closed at the end of April.

So given the answer to Mr. Brett that Enbridge intends to pursue their own bullet solution, potentially, does that mean that you do not need the Parkway extension? Or is that facility in addition to the reinforcement activities that Enbridge is planning on their own?

MR. REDFORD: The results of the open season for the Parkway Extension Project were not at a point where we would move a project forward.

MS. TAYLOR: So that answers, perhaps, the second question I could have asked, but does the Parkway project, in view of the Enbridge solution, does the Enbridge solution preclude the extension? Were the two projects interchangeable, or comparable?

MR. REDFORD: So the way the -- the way we had proposed the project was that Enbridge was going to build into Albion, within the GTA. And then we would jointly own the pipe to Albion.

And then Union would build from Albion to Maple, to make the path from Parkway to Maple.

Absent -- absent our ability to enter into the joint venture, Enbridge is moving forward with the pipeline to Albion. That is their -- that is what they need to reinforce the GTA.

It was an opportunity, actually, to share -- to share

a common path, to share resources, to have one footprint through that corridor, both from a socio-economic perspective and environmental perspective, and, frankly, it was less costly, because we could share the costs of the joint venture pipeline.

But that is subject to having a market, and having the market step forward for that capacity.

MS. TAYLOR: So to be clear, then, so they were planning to build for part of the path, and your open season that would have completed the path has -- is not fully developed at this point; is that clear?

MR. REDFORD: Correct, yes.

MS. TAYLOR: Thank you.

MR. BRETT: Thank you. And just let me check my notes here.

So I understood you to say, just following up on Ms. Taylor's question, that the open season, you did finish the open season. You got results. But the results -- just so I understand clearly, that open season was premised on parties effectively transporting their gas on a pipeline that would originate in -- well, I know you took capacity all the way from Dawn.

But the pipeline would be a pipeline that originated in Parkway and ran to Albion as a joint venture, and then proceeded as a Union pipeline to Maple; right?

And so did you just set that aside, then, because the premise had changed? Or did you have interest from shippers, and to what extent did you have interest?

MR. REDFORD: We did have interest from shippers. We're still working with the market, to rationalize that path.

We were originally planning to be in service in 2004. That won't happen at this point, but we'll continue to work with the market.

And our belief is that either TCPL or -- or Union, or another party, for that matter, will expand through the corridor. I don't know that there is enough capacity in the marketplace for a Parkway extension project, as well as a closing of the Parkway to Maple loop on TCPL's pipeline.

MR. BRETT: Okay. So what you would be doing -- thank you. What you're doing is refashioning -- you would be refashioning or coming out at some point with, perhaps, with another open season to reflect the changed conditions, I guess?

MR. REDFORD: Perhaps.

MR. BRETT: Yes. And now this may be a little dated, given what you have just told me, but if I could turn you to page 8 of that same attachment, attachment 7, the last bullet there on page 8:

> "Parkway West facilities provide reliability and security of supply for customers east of Parkway and provide ability to re-contract existing capacity and pursue expansion capacity."

So Parkway West still is a sort of -- well, first of all, I guess that still holds, does it, to some degree?

MR. REDFORD: Yes. And I don't think that is --

that's not limited to expansion past Parkway. That would include expansion on the Dawn-Parkway system. You know, we believe that flows through Parkway will reach 3 pJs a day, at least 3 pJs a day, by 2015/2016, and we believe that that reliability that Parkway West provides will keep people contracted on the Dawn-Parkway path, including Enbridge.

And there was a real threat that Enbridge was not going to continue contracting on the Dawn-Parkway path, and that was the third feed into Toronto.

And it wasn't just the Parkway West reliability that convinced Enbridge that Dawn-Parkway is a good way to go. It was also the reliability of our pipeline system. So I would suggest that --

MR. BRETT: Okay.

MR. REDFORD: -- Parkway West not only allows us to -- you know, it might be a launching point, so to speak, or a spot where you could expand past Parkway, but it also allows us to expand on the Dawn-Parkway system as it is today.

MR. BRETT: All right, thank you. I just have got another couple of minutes here, and I may not even have that. Just let me go through this.

Oh, yeah. If I may come back to the -- I meant to actually ask this and I think we got a little sidetracked, but -- it was helpful but we got a little sidetracked.

I was going to ask you if you could -- I don't think it is in the evidence. I was going to ask you if you could

our senior folks, we would show all of the projects at Parkway as a set of projects, and those projects, some of those projects can go independent of others.

MR. THOMPSON: And in the presentation to these people, again, before you know the outcome of your open season, if you go to page 4 - and others have referred you to this - I wanted to refer you to the third bullet point under "Solution":

> "New Parkway compression will support Enbridge new feed into the GTA (Albion) via Joint Venture between Union and Enbridge and new demands from eastern markets."

That's the Parkway West compression, correct?

MR. REDFORD: No. That would be separate compression, and that would be contingent upon Enbridge appropriately building -- or appropriately building -- appropriately bidding, pardon me, in our Dawn-Parkway open season.

MR. THOMPSON: So that is the compression up near Maple that you were talking about previously? No?

MR. REDFORD: No. It could be located at Parkway West, but it is not the LCU.

MR. THOMPSON: All right. And so then to get to the point here, you were hoping for market support, and what is the status of market support? You're saying it is not good enough to go ahead now and you are working with the market. What does that mean?

MR. REDFORD: Well, I think I answered that previously, but, yeah, we're still working with the market

to rationalize support for that path.

As I said before, I think either Union or TransCanada is going to obtain the amount of market necessary to hit critical mass to expand through that corridor, probably not both.

MR. THOMPSON: All right. So that then brings me to my questions here. You have included a subset of what I submit is the suite of projects in this rate application that has a capital budget, as I understood it, of $80 million in 2013.

And there was an issue on the issues list of whether the capital budget for 2013 is appropriate, and I understood that stemmed from a draft issue that Union presented in its application.

But now you're saying, as I understand you, this request for LCU approval and the capital expenditures related to it are not the subject matter of this application in any way. Is that the position of Union, Mr. Redford?

MR. REDFORD: That Parkway West is not the subject of this application, or we are not seeking any approvals in this application for Parkway West; that's correct.

MR. THOMPSON: So does that mean that the $80 million in the capital budget, the appropriateness of that amount, is not to be evaluated in this case, but in the next round?

MR. REDFORD: I would say, yes, it is my understanding we're not seeking specific approval of the capital budget.

MR. THOMPSON: Well, are you seeking implicit approval

each of those hearings and make sure that they're determined in a reasonable period of time.

MR. THOMPSON: I will leave it for argument, Madam Chair, and move on.

Now, Mr. Redford, I would just like to get some clarity on how the NEB-approved expansion for TCPL fits into this multi-project concept that was under discussion.

Union's response to the TCPL project, response to the NEB -- there was a letter referenced at some point -- Union's response was basically their expansion was not enough, or words to that effect.

Is that a fair paraphrase of Union's response to it?

MR. REDFORD: I think that is a fair paraphrase of our view.

Our view is that there is more market that would go beyond Parkway, even beyond the 2012 main line expansion or what was received in the open season around that.

I think there is more market. We had interest in our open season, which would indicate that, indeed, there is an interest to get past Parkway, to Maple and points beyond.

MR. THOMPSON: All right. So is TransCanada dragging its feet on relieving the bottleneck? Is that what Union is suggesting?

MR. REDFORD: I don't know if that is what we're suggesting. I think one of the things we did was test the market, see what is out there.

We are -- again, as I said, one of us will need to build that pipeline. There is not enough capacity to

support -- at this time, there wouldn't be enough capacity to support TCPL expanding or Union expanding through Parkway to Maple. And if it was TCPL that expanded through that path, at a reasonable number, you know, half a pJ a day or more, then that would be great. We would be satisfied with that, and that fits right in with our projection that you would see three pJs a day through Parkway.

It's not -- that projection isn't really linked to the Parkway extension project. It is linked to activity through Parkway, throughput through Parkway.

MR. THOMPSON: Okay. So this may be to TransCanada's evidence, where they're talking about or suggesting further consultation between, as I understand it, Union, EGD, TransCanada, to respond to everyone's concerns.

And I accept that there is some urgency here. You want to get this done, or at least get the request in for approvals by the fall of this year.

My question of you is: Is there any realistic prospect of success of an exercise of the type that TransCanada is proposing, i.e., a Union/EGD/TCPL combination to solve all these concerns?

MR. REDFORD: Which concerns?

MR. THOMPSON: Well, the Union concerns that prompted you to meet with Enbridge, the Enbridge concerns that prompted Enbridge to meet with you, the GTA -- additional feed into the GTA that Enbridge wants. You want the bottleneck solved, and you want some more juice at Parkway

West in a compressor.

MR. REDFORD: Some of that, I think, can be dealt with independently. I think, as I mentioned yesterday, we have been consulting with Enbridge, that we have alternatives in front of us from TCPL, and that if we -- we thought we needed further information or assistance, that we would possibly reach out to TCPL.

MR. THOMPSON: Well, that's all very iffy. I just wondered if there is any realistic prospect of that. Are you saying unlikely, or are you saying maybe, or are you saying anything?

MR. REDFORD: Perhaps.

MR. THOMPSON: Perhaps. All right. Let's leave it there.

MS. HARE: If I could clarify, when you said, Mr. Redford, some of these issues can be dealt with independently, did you mean each issue discretely might be dealt with, or did you mean independent of any kind of involvement of the Board?

MR. REDFORD: Oh, independently.

MS. HARE: Independently each issue. So one issue might be solved and not the other?

MR. REDFORD: Yes. We could possibly work together on part of the -- part of those issues. Some of them -- some of them may not be linked.

MS. HARE: Okay, thank you. Ms. Taylor has a question.

MS. TAYLOR: I am scrambling to find my TransCanada

evidence.

You said that you now have alternatives. Is that because TransCanada filed them in conjunction with this proceeding?

MR. REDFORD: Correct.

MS. TAYLOR: So Mr. Thompson laid out a series of meetings going back to November 15th of 2010, which I guess is the first tangible evidence via a presentation.

Then these meetings extended to April of 2012, and he highlighted that the November 25th meeting was entitled "Reinforcing Ontario's Natural Gas Infrastructure", which was a meeting between -- and this is a series of meetings between two of the three parties that serve Ontario customers.

So why is it over this period of time that no effort appears to have been made to involve TransCanada in these discussions, if you are in fact talking about a comprehensive series of projects to reinforce Ontario's natural gas infrastructure -- consumers, sorry?

MR. REDFORD: Well, part that is we're competitors, and the path between Parkway and Maple is a competitive path, and we were looking at extending our system past Parkway to Maple. And I don't know that it's commonplace for competitors to go and let others know specifically what their plans are.

Our view was that the market needed -- there was some market need, and we wanted to try and make it happen.

MS. TAYLOR: Sorry. My understanding was that all of

these facilities would be pushed through Ontario rate base. Is that correct? So it was not my understanding, based on the application that I have seen or the discussion around Parkway, that any portion of these facilities would be allocated to Union's competitive storage and transportation business.

MR. REDFORD: No, you are correct. They would all go to rate base.

MS. TAYLOR: So my question is: Without involving TransCanada in this discussion, what confidence can the Board have that this is the best solution for Ontario ratepayers?

MR. REDFORD: Well, I believe there will be evidence in front of the Board to show that. I think it is -- it's obligated for us to show it, to show that our evidence is a best solution out there, including providing alternatives.

MS. TAYLOR: Thank you.

MR. THOMPSON: Just a couple of other points and I am done, and they relate to presentations that were part of the initial filing, i.e., before TransCanada's motion.

So these would be Union's initial responses to J.B-1-7-8, I think. Yes.

The first one I want to draw you to -- there are two attachments in the initial filing, attachment 3 and attachment 5. Attachment 3 was a presentation, I think it is in November of 2011. It was entitled "New Projects For the Canadian Marketplace".

And I wanted to draw your attention to the last page

[Laughter]

MR. REDFORD: And, as I said before, no matter which way you cut it, you have to -- if you want to go past Maple, you're going to have to take TCPL capacity.

So, in many respects, if you wanted to -- let's say a Parkway extension project occurred and you wanted to get to Union EDA or Montreal. You still have to contract on TCPL. We can't get you there.

MR. SOMMERVILLE: Thank you. Those are my questions.

MS. HARE: Thank you. Mr. Smith, re-direct?

RE-EXAMINATION BY MR. SMITH:

MR. SMITH: I do have some questions, Madam Chair. Thank you. Just to pick up on Member Sommerville's questions, you indicated earlier, Mr. Redford, about the importance of reliability to Enbridge under the Dawn-Parkway system, and you talked about the threat of de-contracting on the Dawn to Parkway system by Enbridge.

What is the consequence of that, and what would be the impact on Union and, directionally, its in-franchise customers?

MR. REDFORD: Well, I believe it is a real threat. Enbridge was looking at reliability to serve their customers in their franchise area.

They could have other options. We talked about the bullet line. In effect, what that would -- in order to get critical mass to build such a project, Enbridge would take some volumes off of the Dawn-Parkway system, which means that Dawn-Parkway may not be full. And if that is the

case, that's not a good situation for any of our ratepayers, whether that is in-franchise customers or M12 customers.

It is in everybody's best interest, within our ratepayers, to keep Dawn-Parkway full.

MR. SMITH: And let me just, if I could, turn up attachment 3(d). This is TCPL's answer to Union interrogatory 3(d), page 4 of 11, and I recognize this isn't your document. It is a TCPL document, but I think it might be of assistance here, visually, just to assist the Board.

So if I could ask that that be turned up? Do members of the Board have it in hard copy or not? We will wait for it to be turned up.

MS. HARE: We could get it.

MR. MILLAR: We have become spoiled.

MR. SMITH: Well, I understand how that happens, because it happens to me -- oops.

MR. SOMMERVILLE: If you have a copy you could distribute to the Panel --

MS. HARE: I think we have it here.

MR. SOMMERVILLE: Just kidding.

MR. SMITH: It has my incredibly helpful annotations on it.

Page 4 of 11, this is what is described by TCPL as build versus backhaul annual costs. But just so we have the points on the map here, where is Union?

MR. REDFORD: I am assuming Union is the red line.

critical unit coverage. So there would be a loss of critical coverage unit at Bright/Lobo, dependent on where the critical unit is, and that depends on operations. There is always a unit held in reserve.

Deliveries to Kirkwall and deliveries to Parkway (Cons) -- Consumers, sorry, and Lisgar would be loss of critical unit protected up to the point of suction at Parkway.

And the red arrows talk about the lack of LCU coverage or loss of critical unit coverage at Parkway, which is box C.

Also, it talks about the fact that the design day at Parkway has increased from half a Bcf in 2005 to 1.6 in 2011, and then a further 2.6 Bcf in 2015.

MR. SMITH: And are you aware of any response from TCPL to this presentation prior to this proceeding?

MR. REDFORD: I'm not -- I'm not aware. I was also not at this meeting.

MR. SMITH: Okay. Can I ask you to turn -- this may be for you, Mr. Wood, maybe for Mr. Redford. I'm not sure.

You were asked some time ago by Mr. Cameron about J.B-1-1-2, attachment 1; do you recall that? And he pulled up this diagram, which appears to be upside down. I know very little about this, except that.

You were asked some questions about it, but in reference to this exhibit, can you please just describe, then, pictorially how the LCU protection would work and what is, in fact, being protected?

MR. REDFORD: Okay. I can start to answer that. Mr. Wood can help when I run into trouble.

There are two compressor units at Parkway, Parkway A, Parkway B.

MR. SMITH: Just so we have it, so where is Parkway, then?

MR. REDFORD: Oh. Parkway is the gray lines, the grey dotted lines.

If you drew a big box around -- yes, a little smaller. Oh, thank you. A big box from measurement to TCPL, out along the -- down to the Trafalgar lines, out past the dotted gray line that is on the right that goes to the measurement, that is kind of Parkway.

MR. SMITH: And this may be completely unnecessary, and I apologize, but approximately how big is the Parkway site?

MR. REDFORD: That's a great question. I was going to say for -- well, I was going to say 65 acres, but I'm not sure that's...

MR. SMITH: That's fine. I just wanted to get a sense of the size of it. If it's more or less, that's fine.

Okay. Why don't we blow it back down and just describe exactly -- continue. If we could shrink it? Thanks.

MR. REDFORD: So there is two compressor units at Parkway, Parkway A and Parkway B.

Each has their own capacity when running as a single unit, together as -- when they run in parallel, so when

they run together, they're about 2.54 pJs a day of capacity. That 2.54 PJs a day capacity would equate to in the ballpark of 27,000 megawatts of energy.

So those two compressors would push enough gas and enough energy through Parkway that it would be equivalent to the largest single-day peak demand in electricity in Ontario that we've seen, and that was back in August of 2006, I believe.

The loss of critical unit is meant to protect the loss of one of those units, and the principle behind loss of critical unit is that you protect loss of the largest unit, which makes sense.

Parkway B is the largest unit. It's a 47,000-horsepower unit. And if it -- if it fails or it is not available, we would lose 1.1 pJs a day of throughput through that compressor, through the yard.

MR. SMITH: So just identifying in the map, where is the LCU protection going there?

MR. REDFORD: The LCU protection is going across the 407. Highway 407 abuts Parkway on the west side of the Parkway station. It is going across -- across the highway and about a kilometre north of the existing station.

MR. SMITH: And how does the LCU protection protect that 1.1 pJs of volume?

MR. REDFORD: How that protects the unit is there is a separate feed that runs up into the LCU compression. The LCU compression, if Parkway B or A kicked out, would flip the switch. You would start up that unit, and it would

come into line.

And it would be connected into the existing Parkway station so that those units could run in parallel. And the distinction is that if they ran in series, that, for instance, if the Parkway compressor, LCU compressor, was two miles up the road, if they ran in series you would effectively have to duplicate the Parkway station to get that capacity through.

You would lose the ability to move 2.54 pJs through the station, because the A plant and B plant can't handle that alone.

So you would effectively have more LCU compression required if you did not locate that compressor so that it could be run in parallel.

MR. SMITH: And just so I am clear, what sort of failures could happen to the compressors in A and B that you are protecting against?

MR. WOOD: There can be a number of failures. It is hard to give just a few. I mean, it's a moving component that is high-pressure and high-temperature. There could be foreign object damage to the engine. There could be oil leaks. There could be controls failures. There are multiple failures that could cause a loss of a compressor unit.

MR. SMITH: Now, Mr. Cameron put to you -- I'm not sure if this was his word or mine, but effectively a catastrophic failure of the system.

Is that what is being insured against in -- with the

LCU protection?

MR. WOOD: The discussion that we had yesterday was around disruption to Parkway Consumers and Lisgar, which is on the suction side. It does not go through compression.

The question asked was what kind of impact could cause both of those sites to lose -- to not be able to supply. And that was where we discussed a failure of the pipeline.

The LCU is a compressor, covers for a compressor, which is a more common event.

MR. SMITH: Okay.

MR. REDFORD: I would add that by having the separation between the existing Parkway station and the Parkway West station, if there was a catastrophic failure at Parkway, that the Parkway West station could provide some service.

It's not intended to -- it's not intended to replace full loss of Parkway, but because it is separated, if the valve can be shut off on the Trafalgar -- which would amount to the gray dot -- then it would be able to provide service, which otherwise wouldn't happen.

MR. SMITH: A final question. I just can't recall -- but you were asked some questions. We don't need to turn it up, but it was slide 9 of attachment 13 to 1-7-8, I believe.

You were asked a question about distance, roughing out the toll from Maple, and I would just ask whether or not Maple is a receipt or -- is a receipt or delivery point on TCPL's system?

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit B1, Tab 2, page 4

Union's evidence indicates that the major transmission projects for 2013 include the Parkway West project at a cost of $80.0 million and the Owen Sound Replacement project at a cost of $17.9 million. Please answer the following questions with respect to these projects:

a) Please provide additional information about the projects including need and benefits to ratepayers.

b) When was the need for these projects identified?

c) Please provide reasons for undertaking these projects in the Test Year and the impact of delaying the projected in-service date?

d) Please confirm if these projects will be used and useful in the Test Year.

Response:

Owen Sound Line Replacement

a) The Owen Sound Line was constructed in 1958 and is inspected periodically as part of Union Gas' Integrity Management Program. Results of scheduled inspections in 2011 have identified multiple integrity issues that could pose safety and security of supply concerns if not addressed.

The $17.9 million forecast for this project involves the removal and replacement of approximately 21 km of NPS 12 pipe to mitigate the identified integrity issues. The replacement pipe is located between the Owen Sound Valve Site and the Waterloo Gate Station. The replacement is size for size and provides a long-term solution for safety and security of supply.

b) The integrity concerns on the Owen Sound Line were identified in 2003 and have been addressed piecemeal since that time. The 2011 in-line inspection identified integrity issues spanning a 21 km length of the pipeline to the extent that replacement of individual sections is no longer a feasible solution.

c) The integrity concerns were identified as part of the Integrity Management Program in 2003 and reconfirmed as part of a scheduled inspection in 2011. Short-term mitigation of high risk anomalies were completed immediately, including two repairs and two short replacement sections. The long-term solution is a replacement of the section of the Owen Sound Line from the Owen Sound Valve Site to the Waterloo Gate Station. Based on the estimated planning and construction schedule, the Owen Sound Line Replacement is scheduled for completion in 2013. If the Owen Sound Line Replacement is delayed, the integrity concerns will become more serious as risk of failure increases.

d) The Owen Sound Line Replacement is scheduled for construction and in-service in 2013.

Parkway West Project

a) Description of the Existing Parkway Facilities

The existing Parkway Compressor Station is currently served by a single valve site and header system off of the Dawn-Parkway system. The Dawn-Parkway system at this location consists of three parallel pipelines – 26", 34" and 48". The nearest mainline valve site is the Milton Valve Site located 8.8 km west of Parkway.

Within the existing Parkway Compressor Station, Union connects to the Enbridge system on the suction side of the compressor (i.e. before compression). Union owns and operates custody transfer measurement at this interconnection, which is known as Parkway (Consumers). Also, within the existing Parkway Compressor Station, Union connects to the TCPL system on the discharge side of the station (i.e. after gas is compressed). Union owns and operates check measurement at this interconnection, which is known as Parkway (TCPL).

The Lisgar Station is located approximately 2 km east of the Parkway Compressor Station just north of the intersection of Winston Churchill Boulevard and Aquitane Avenue in Mississauga and is a direct connection between Union and Enbridge. Gas is delivered to Enbridge at the Lisgar Station through 26" and 34" pipelines that extend past the Parkway Compressor Station. Union owns and operates custody transfer measurement at this interconnection, which is known as Lisgar. The Trafalgar Compressor Station, located between the Parkway Compressor Station and Lisgar, was retired in March 2012.

A schematic of the existing Parkway Compressor Station, including Lisgar, is provided as Attachment 1.

Deliveries to Enbridge at Parkway and Lisgar

A significant amount of gas supply intended for delivery into the GTA and other parts of Ontario is either delivered at or passes through Parkway. Based on Enbridge design day

system demand of approximately 3.7 PJ/d, Union delivers to Enbridge approximately 57% of that supply at Parkway or through the Parkway compression.

Deliveries at Parkway (Consumers) and Lisgar are made to Enbridge directly in the market area. Enbridge contracts for deliveries of approximately 1.6 PJ/d with flexibility to designate the delivery of that gas between the Parkway (Consumers) and Lisgar interconnections. The Parkway (Consumers) interconnection has a maximum capability of approximately 1.4 PJ/d and the Lisgar interconnection has a maximum capability of 0.8 PJ/d (see response at Exhibit J.B-1-7-1). From the Parkway (Consumers) and Lisgar interconnections, Enbridge moves the gas through its in-franchise pipeline system to consuming markets located in the west and central portions of the GTA (from Lake Ontario to the northern limits of the GTA). The Enbridge system serves a large proportion of residential and commercial customers with heat sensitive demand (approximately 80% of consumption profile). In their 2013 Rate Case filing at Exhibit B, Tab 3, Schedule 1 (page 9 of 10), Enbridge states that they expect to continue to add approximately 40,000 customers per year, largely in the GTA. Continued population growth in the GTA will likely result in higher peak demands in the future on the Enbridge system.

Loss of Service – Enbridge Connections

A loss of delivery at Parkway (Consumers) and/or Lisgar would have significant and immediate impact on the Enbridge system. Exhibits J.B-1-7-13 and J.B-1-13-4 discuss potential outage scenarios for the feeds to Enbridge. An outage at Parkway (Consumers) would result in a delivery loss of 0.8-1.4 PJ/d into the Enbridge system during peak demand. An outage at Lisgar would result in a delivery loss of 0.2-0.8 PJ/d into the Enbridge system during peak demand. An outage of both the Parkway (Consumers) and Lisgar feeds into the Enbridge system would result in an immediate delivery loss of 1.6 PJ/d. Parkway is unique in that it is located directly in the market area. In the event of an outage, supply replacement will be immediately required with primary alternative supply through Enbridge's connections with TCPL. If service cannot be restored quickly or alternative supply cannot meet peak demands (after any load shedding opportunities), low system pressure or system outages would affect safety and health within parts of the Enbridge franchise.

Restoration of service for natural gas system outages is very time consuming requiring at least two visits to each customer; one to safely shut in the service and the other to safely restore the service ("light up"). Depending upon the extent of a system outage, restoration could be measured in days/weeks/months. Until service can be safely restored, the area affected by the outage would be without natural gas service, leading to health, safety and property damage issues.

An outage at Parkway (Consumers) and Lisgar during peak demand would impact regional gas flows to points east of Parkway in eastern Ontario, Quebec and the U.S. Northeast as the GTA consumes available supply. Natural gas-fired power generation facilities in the GTA would likely be impacted by low system pressures or system outages.

As part of the Parkway West Project, Union proposes a second, secure feed for gas supply to Enbridge that replicates the current connections at Parkway (approximately 1.6 PJ/d). This new Enbridge connection is proposed to be physically separated from the existing Parkway Compressor Station. The proposed second feed to Enbridge will increase the security and reliability of Dawn-Parkway supply for Enbridge GTA customers.

Deliveries to TCPL at Parkway

Union has the ability to move up to 2.54 PJ/d of gas through the existing Parkway compressors (Parkway A and Parkway B) into the TCPL system on a design day. Individually, Parkway A and Parkway B have delivery capability of 1.2 PJ/d and 1.8 PJ/d, respectively, based on the Winter 2011/2012 design day. Deliveries to TCPL are made on the discharge side of the existing Parkway compressors and then gas is transported through the TCPL system i) east of Parkway to Ontario, Quebec and U.S. Northeast markets with some gas being delivered by TCPL into the Enbridge system within the GTA and ii) south to the western portion of the GTA in Union's franchise as well as potentially further to the Niagara region. Currently contracts at Parkway (TCPL) are approximately 2.0 PJ/d, including 0.4 PJ/d delivered to Union's Northern and Eastern franchise areas as well as Union's franchise area in Oakville and Burlington. Union believes 2.0 PJ/d is about the maximum capacity of the measurement and the downstream piping owned and operated by TCPL. In the immediate future, deliveries into the TCPL system at Parkway are expected to increase by approximately 0.4 PJ/d (2012/2013) once proposed TCPL expansion facilities have been approved by the National Energy Board and placed into service. Union estimates that flows through compression located at Parkway could increase to 3.0 PJ/d in the 2015/2016 timeframe (see response at Exhibit J.B-1-7-2).

Loss of Service – TCPL Connections

Union has seen and expects to continue to see changing flow patterns at Parkway through the connection with TCPL. Flows through Parkway compression have significantly increased from less than 0.5 PJ/d in 2005 to approximately 2.0 PJ/d today resulting in an increase in operating hours for the Parkway compressors and an increase in number of days when both Parkway compressor units are operating. Flows through compression at Parkway are estimated to increase an additional 1.0 PJ/d by 2015/2016. Union believes that flows of this quantity into key eastern markets, including the GTA and other regions of Ontario, support the need for increased security and reliability.

In addition, flow through Parkway was typically bi-directional with gas flowing into Union from TCPL during summer months and gas flowing from Union to TCPL during winter months. Today, and as expected in the future, gas can be characterized as flowing primarily from Union into the TCPL system on a year-round basis.

Currently the volumes delivered to TCPL through Parkway compression are not fully covered by Loss of Critical Unit protection. As provided in Exhibit J.B-1-7-5, the addition of Parkway B in 2007 created some compression horsepower in excess of current demands and this excess horsepower has provided some Loss of Critical Unit protection in the event of a loss of Parkway A. However, the level of Loss of Critical Unit protection afforded by the excess Parkway B horsepower will decrease as flow increases through Parkway. Today, loss of Parkway B would result in a throughput shortfall of approximately 0.6 PJ/d (also see response at Exhibit J.B-1-7-12). As volumes grow and throughput through Parkway compression reaches 3 PJ/d there would be no Loss of Critical Unit protection. At a total throughput of 3.0 PJ/d, loss of Parkway B results in a shortfall of approximately 1.6 PJ/d and loss of Parkway A results in a shortfall of approximately 1.0 PJ/d.

Union believes that an outage of one of the Parkway compressors in the future will be significant for gas flow during peak demand to Ontario markets, such as the GTA and northern and eastern Ontario. Although Enbridge contracts for only a portion of the volumes discharged into the TCPL system, other customers within the GTA and northern and eastern Ontario, such as natural gas-fired power generators and direct purchase customers, may be served through Parkway exports. It is expected that the GTA, given its location adjacent to Parkway, could be significantly impacted, which could include low system pressure and system outages. The same may occur in other Ontario markets served by TCPL. Failure to deliver during peak conditions at Parkway would cause the market to lose confidence in the reliability of the Union delivery system and could lead to shippers choosing to decontract the Dawn-Parkway path in an effort to seek diverse, secure and reliable supply.

Union believes that Loss of Critical Unit protection at Parkway is appropriate and that the proposed facilities are the best reliability option. Alternatives considered are addressed at Exhibit J.B-1-1-7.

Parkway West Facilities and Costs

As described below, recently Union has made some changes to the timelines and has updated estimated capital costs for the proposed Parkway West Project.

i) Parkway West Land Purchase
Union recently extended its option to purchase the Parkway West land. Although there is a potential for the transaction to be completed in 2012, Union expects the option to be exercised in 2013. The purchase price of the land will be approximately $20 million.

The existing Parkway Compressor Station is located on the western edge of Mississauga. The property is situated between the 9th Line and Highway 407 with developers owning the adjacent properties to the south and north of the existing Parkway property. The existing Parkway Compressor Station does not provide enough land to install an additional compressor to provide Loss of Critical Unit protection while maintaining Union Gas design standards and does not provide enough land for future expansion. A second connection at the

existing Parkway Compressor Station will not provide the security and reliability needed for the Parkway (Consumers) and Lisgar feeds.

Residential housing development exists east of the existing Parkway Compressor Station and there are plans for future development north and south of the existing Parkway property. Much of the land west of Highway 407 in the vicinity of Parkway has been purchased by developers. The property proposed for the Parkway West Project is located west of Highway 407, north of Derry Road, in Milton. This property is relatively close to the existing Parkway Compressor Station, provides enough land for the facilities for the proposed Parkway West Project, and allows for future expansion, including additional compressor units and a connection for the proposed Enbridge GTA Project.

ii) Parkway West Metering and Headers
The Parkway West Metering and Headers are now proposed to be completed for November 1, 2014 and are proposed to be constructed concurrently with the proposed compression. The estimated cost of the measurement, control and piping facilities for the second Enbridge feed is approximately $35 million and the estimated cost of the measurement, control and piping facilities for the connection to TCPL is approximately $19 million.

Common facilities required to support the Loss of Critical Unit protection and the second connection to Enbridge include the valving and piping at the connection to the Dawn-Parkway system and the pipeline headers to connect the Dawn-Parkway system with Parkway West. Including lands, the cost of the common facilities is estimated to be approximately $55 million.

iii) Loss of Critical Unit Protection
The compression facilities for Loss of Critical Unit protection are expected to be approximately the same size as the largest compressor unit at the existing Parkway Compressor Station, Parkway B. These facilities are proposed to be completed for November 1, 2014 at an estimated cost of $108 million.

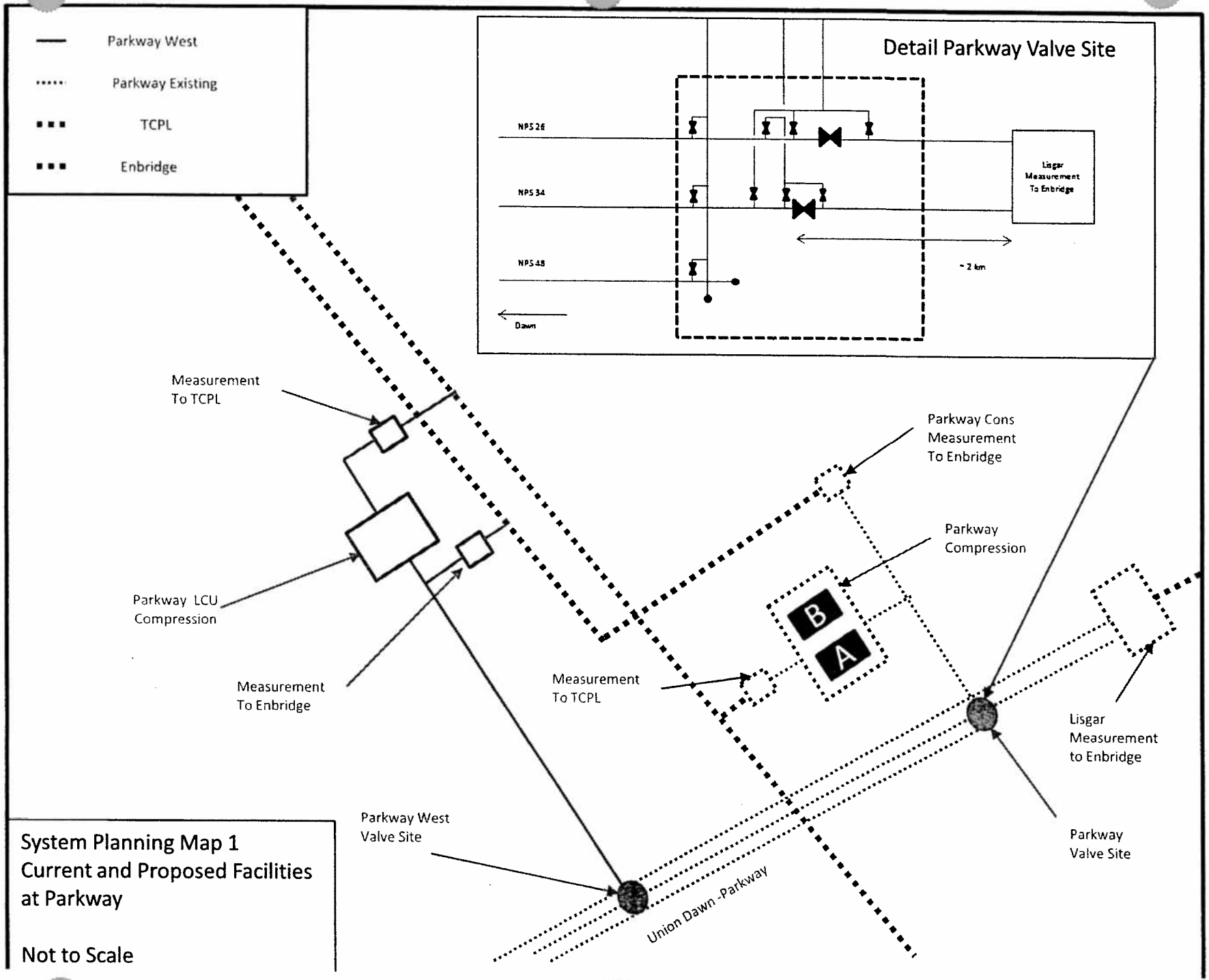
In total, the Parkway West Project will be placed into service in 2014 at an estimated cost of $217 million. None of the facilities will be completed and placed into service during the Test Year (2013).

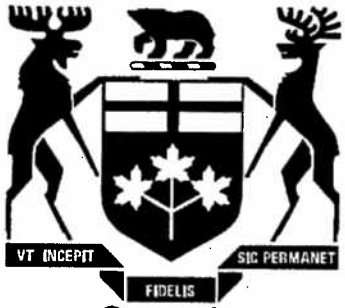
b) In 2008 Union identified that the Trafalgar compressor (6,000 HP) needed major upgrades to meet emission standards before the end of 2012. The Trafalgar compressor provided some flexibility to deliver at Parkway including partial horsepower backup for volumes flowing through the Parkway compressor (although not to the full contractual pressure requirement for discharge into the TCPL system). Union subsequently decided to retire the Trafalgar compressor effective March 2012 and identified a potential need for increased reliability at Parkway.

In 2010, the need for Loss of Critical Unit protection was considered based on the changing flow patterns at Parkway - increased flow through the compressors, transformation to year-round exports (from Union into TCPL) and the potential for increased throughput as a result of changing North American supply dynamics, such as increased production from emerging unconventional supply basins such as the nearby Marcellus, the shift from Western Canadian supply and long haul transportation to Dawn supply and short haul transportation, and the growth of gas-fired power generation in the GTA. Union estimated that flow through the Parkway compression could grow in excess of 1.0 PJ/d by 2015/2016 which includes over 0.4 PJ/d of incremental throughput as a result of proposed TCPL facilities expansion.

c) Please see the response at a) above.

d) Please see the response at a) above.


Parkway West
Parkway Existing
TCPL
Enbridge
Detail Parkway Valve Site
NPS 26
NPS 34
NPS 48
Dawn
Lisgar Measurement To Enbridge
~ 2 km
Measurement To TCPL
Parkway Cons Measurement To Enbridge
Parkway Compression
Parkway LCU Compression
Measurement To Enbridge
Measurement To TCPL
B
A
Lisgar Measurement to Enbridge
Parkway West Valve Site
Parkway Valve Site
Union Dawn -Parkway
System Planning Map 1
Current and Proposed Facilities at Parkway
Not to Scale



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **10**

DATE: **July 26, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. SMITH: And let me --

MR. STRINGER: Maybe I would just like to add, Mr. Smith, that, you know, if you look at our response to Union IR 13, we highlight the cost difference, based on our current requirements on our system of taking the Dawn-to-Dawn service and utilizing a Great Lakes St. Clair-to-Emerson contract, versus taking out incremental Union TCPL and expanding our system facilities.

And so the lower-cost option has been to use the Great Lakes St. Clair-to-Emerson service, relative to a 10-year commitment for TBO capacity on the Union Gas system, as well as expanding our own facilities.

And, you know, one thing to be cognizant of, as well, with respect to the contract between St. Clair and Emerson is it is relatively short-term. I don't have the exact end-date of that contract in front of me, but I think it's perhaps expires in 2014, but we can -- you know, we're always assessing the lowest-cost means of moving gas away from that area. And so if we determine that an expansion and corresponding TBO on the Union system is ultimately the lowest-cost option, then we have the ability to de-contract on the Great Lakes system and move to that option.

But, you know, that contract also gives us the flexibility to adapt to other things happening on the system, such as potential bypass, which we have seen evidence of here. And so it wouldn't necessarily be prudent to be taking out 10 years of Union TBO and expanding our facilities when there is a possibility that

we may be bypassed on the short-haul portion of our system.

MR. SMITH: You're talking about -- when you say "bypass" I take it what you're talking about is Union's Parkway extension project?

MR. STRINGER: Yes.

MR. SMITH: Am I correct, sir, that Union bid into your own competing open season?

MR. STRINGER: The results of that open season are not public. We're still in the precedent agreement stage.

MR. SMITH: Why don't you answer my question by way of undertaking filed confidentially?

I am correct, am I not, sir, that Union bid into your competing open season? And you can answer that by way of undertaking confidentially, if you wish.

[Witness panel confers]

MR. CAMERON: I don't know if we need an undertaking. I am going to see if I can -- just to avoid the couple cumbersomeness of a confidential undertaking, because it appears that Mr. Smith is making the assertion and is thus not concerned about the confidentiality of the fact that Union bid into the --

MR. SMITH: I am certainly not concerned about it. The witness has said several times that Union appears to be bypassing.

I would have thought the fact that Union is bidding into TCPL's open season is evidence they just want it done by somebody.

So I'm not concerned about the confidentiality of



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

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DATE: **June 1, 2012**

that's done long in advance of actually putting pipelines in the ground, because I understand it's a lengthy process to firm up the market.

Now, what I just wanted to get round to is the -- and I am sure you are getting this, I am sure this isn't the first time this question's been asked, but if you were -- let's put it this way.

If you were not going to proceed with your own Parkway expansion -- and I am not suggesting you are not. I mean, I think it's likely that you will, but if you weren't going to proceed with your own Parkway expansion sometime in the next few years, would you still be seeking this series of -- would you still be putting this project forward?

MR. SMITH: Sorry, which project?

MR. BRETT: The project that's defined in the evidence, in Mr. Redford's evidence, the Parkway West compression cum headers cum custody transfer cum valve changes.

MR. REDFORD: The answer is yes, we would still put the Parkway West project forward, independent of whether we build a Parkway extension project or not.

MR. BRETT: Okay. Okay. And I guess the -- and is the reason for that, whether or not you build the Parkway extension, was one of the reasons, whether or not you happen to build the Parkway expansion, somebody is going to build a Parkway expansion, therefore there is going to be additional flows going through Parkway one way or the other? Is that fair? I mean, is that what --

DEFERRAL ACCOUNTS



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **7**

DATE: **July 20, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

own contract to go from Washington 10 to Dawn, so we use that contract.

MR. MILLAR: So it is practical reasons, not a concern you would be sort of bidding for your own services?

MR. ISHERWOOD: It would be a little odd.

MR. MILLAR: Okay. But is that part of the reason, or is it simply that you never have need for that?

MR. ISHERWOOD: I would say we -- well, never is a long time.

MR. MILLAR: So there is no firm policy against you bidding on that capacity?

MR. ISHERWOOD: There is no practice to do it, that's for sure.

MR. MILLAR: Okay. But no written policy forbidding you from doing it?

MR. ISHERWOOD: No.

MR. MILLAR: Thank you. Mr. Thompson touched on storage encroachment, and I have a couple of follow-up questions there from a slightly different angle.

Mr. Isherwood, you or others on the panel are doubtless familiar with the EB-2011-0038 case. That was one of the earnings sharing cases. Is anyone on the panel familiar with that? There has been quite a lot of discussion of that case, and, indeed, I think extracts of the decision are already on the record.

MS. CAMERON: Yes, we are familiar.

MR. MILLAR: I understand in 2009, both October and November, you did encroach on some utility space; is that

correct?

MR. ISHERWOOD: That's correct.

MR. MILLAR: And in the Board's decision, without necessarily getting into it, the Board ordered you to monitor these situations to let us know when that happened?

MR. ISHERWOOD: Yes.

MR. MILLAR: And it did happen again in October of 2011; is that correct?

MR. ISHERWOOD: That's correct.

MR. MILLAR: And that is shown in -- I think it is C1, tab 6, appendix A. You don't have to pull that up, but that is on the record.

MR. ISHERWOOD: Correct.

MR. MILLAR: I understand, from your discussion with Mr. Thompson, Union doesn't pay any compensation for using that utility storage, do you?

MR. ISHERWOOD: No. We treat it in the same way we would treat an ex-franchise customer. So if an ex-franchise customer overran our storage, we would work with them. As long as their intent was to correct the situation as soon as they could, then we would not charge them the penalty, either.

MR. MILLAR: So there is no -- ratepayers did not accrue any revenue to their favour because of those encroachments?

MR. ISHERWOOD: Not from that encroachment, no.

MR. MILLAR: And you are not proposing that there be any -- Mr. Thompson talked about a penalty, but I am

talking more of a charge for usage. You're not proposing that Union's non-utility side would pay any amount for such encroachments in the future?

MR. ISHERWOOD: No, we are not proposing that. I think we took very quick corrective action and got back into balance fairly quickly.

MR. MILLAR: Let's assume for a moment that there was no excess storage space available on the utility side and you had to find an alternative place to put the gas.

How much -- can we get a ballpark figure of how much that would cost? I know it depends on volumes and how much space you need, et cetera, but surely there is a market cost for something like that.

MR. ISHERWOOD: In the incident that happened last October, we overran by 1.6 pJs, and when we got back from the Thanksgiving weekend, we actually did several different deals that moved 2 pJs off of our system to get back into balance.

And to move that 2 pJs off our system cost us $1.1 million.

MR. MILLAR: That is helpful. Thank you.

So it is certainly of assistance to you to have this non- -- if there is excess non-utility -- pardon me, utility space, it is certainly of assistance to you to be able to use that?

MR. ISHERWOOD: Our intent is not to use it.

MR. MILLAR: Yes, but you have?

MR. ISHERWOOD: Absolutely. And that is our intent

going forward, as well.

MR. MILLAR: And if you couldn't use it, there would be some cost to you to find an alternate place to --

MR. ISHERWOOD: There was a cost last fall.

MR. MILLAR: Thank you.

Do you recall in the Board's decision, I can pull it up if necessary on the screen, but the Board sort of referred to this practice as an insurance policy to allow you to have this sort of a backstop for your non-utility storage? You could -- or at least you had the practice of encroaching on utility storage.

Do you recall that?

MR. ISHERWOOD: Sort of.

MR. MILLAR: Do you agree with that characterization?

MR. ISHERWOOD: Well...

MR. MILLAR: An insurance policy?

MR. ISHERWOOD: I guess insurance policy, you would normally be paying for the policy.

MR. MILLAR: That was going to be my next question.

MR. ISHERWOOD: And that's why my testimony even last year was we would typically be monitoring our position, and, if we anticipated getting into a difficult position or overrun, we would take action before it actually happened.

And that's what I tried to explain this morning. The circumstances around the Thanksgiving weekend last fall is just such a rapid change in injections that it was unpredicted.

MR. MILLAR: Are there insurance policies for this

type of thing?

MR. ISHERWOOD: Not that I know of.

MR. MILLAR: So you wouldn't want to hazard a guess on a pricing scheme if you were to seek insurance instead of having the ability to use -- to encroach on utility space?

MR. ISHERWOOD: I think the one suggestion, and it might have been Mr. Quinn -- I can't remember which IR it was, but we do have -- on the utility assets, we do sell off-peak storage services that are intended to be very short term, a few weeks, a few days.

And we call it hub service, but it is basically readily available in the market, and people move gas in and out of the hub service pretty quickly and pretty frequently.

MR. MILLAR: That might be a comparable --

MR. ISHERWOOD: And I think what we said in our IR, or we certainly talked about, is it is not something we have ever done in the past, considered that to be a service available to us. But from an unregulated point of view, it may be a value to the unregulated business and a value to the regulated business.

MR. MILLAR: There would be a cost associated with that?

MR. ISHERWOOD: The base cost to use it is around 10 cents.

MR. MILLAR: Ten cents per?

MR. ISHERWOOD: Per gJ. There are lots of other parameters around it in terms of time, and that sort of

thing, but 10 cents is sort of the entry level.

MR. MILLAR: I won't press you further on it here, given the lateness of the day, but that is helpful. Thank you.

I think I just have one area left. I've got some questions about the short-term storage and margin-sharing account. Would this be the right panel for that?

Ms. Elliott, you are our expert on all DBA matters. Why don't I start and you can tell me if I have the wrong place?

MS. ELLIOTT: Yes.

MR. MILLAR: Could I ask you to turn up Exhibit J.DV-1-1-1?

And probably attachment 1 is what I am going to be referring to, but just for some of the background on this, I understand that Union's previous practice was to sell its non-utility storage space on a long-term basis and to sell its excess utility space on a short-term basis; is that right?

MS. ELLIOTT: That's correct.

MR. MILLAR: And your new proposal is to sell both long-term and short-term storage from non-utility storage space, while continuing to sell only short-term storage from excess utility storage space; is that right?

MS. ELLIOTT: That's correct.

MR. MILLAR: So there would be some overlap for what you are selling on the utility and non-utility side; in other words, you will be selling short-term from both?

PREFILED EVIDENCE

PATTI PIETT, DIRECTOR, STORAGE & TRANSPORTATION SALES

CAROL CAMERON, MANAGER, CAPACITY MANAGEMENT AND UTILIZATION

Non-Utility Balances for 2011

The Board, on page 16 of its EB-2011-0038 Decision, directed Union to monitor the inventory related to non-utility storage operations.

> *"The Board is of the view that there should be an ongoing monitoring of this potential encroachment so as to inform the Board as to the need to revisit this issue at a future date. The Board therefore finds that Union shall be required to monitor for and maintain records of all future encroachments and provide such information in its rebasing application."*

Appendix A shows the non-utility balances for October and November of 2011. As discussed in EB-2011-0038, October and November are the two critical months for peak storage.

During the 2011 injection season the non-utility storage balance exceeded the entitlement by approximately 2%. The non-utility balance on October 16, 2011 was 79.9 PJ compared to an entitlement of 78.3 PJ. The non-utility balance exceeded the non-utility entitlement starting on October 9, 2011 and ending on October 20, 2011, a total of 12 days.

Two events contributed to the amount and the duration of the non-utility storage balance exceeding entitlement. The first contributing event was warm weather over the period of October

8, 2011 through October 14, 2011. Over that time period Union experienced weather conditions that were 65% warmer than normal. The warm weather resulted in lower consumption across the continental Northeast. Lower consumption by customers resulted in Union's non-utility customers (i.e. other utilities) injecting more gas than was forecast and caused the non-utility balance to exceed the entitlement.

Secondly, the non-utility storage balance exceeding entitlement coincided with the Canadian Thanksgiving weekend. During the Canadian Thanksgiving weekend, Union operates with a reduced staff making it difficult to react to the non-utility storage balance. In addition, it is difficult to complete a mitigating transaction(s) to reduce the non-utility storage position as third parties who are typically involved in these transactions are also operating with reduced staff, if at all.

The first opportunity to react to the non-utility storage balance was October 11, 2011 for the October 12, 2011 gas day when Union began its mitigation actions. Without knowing the duration or possible future impacts of non-utility activities, Union moved more than 2 PJ of non-utility gas off the system in order to reduce non-utility balances. Union moved the non-utility gas off the system despite the fact that there was excess utility space available. The total mitigation costs to Union's non-utility business were approximately $1.1 million. The amount of the mitigation brought the non-utility balance to a sustainable level within the entitlement during the peak period. The full quantity of gas was removed from the system by October 20, 2011.

During the period that non-utility storage balances exceeded entitlement, Union met all contractual obligations as well as requests for discretionary storage services without interruption to any utility or non-utility storage activity.

As discussed during the 2010 Deferral Proceeding, EB-2011-0038, Union manages its storage balance to the October 31 gas day. At October 31, 2011 the Non utility balance was 95% of entitlement and stayed below the total non-utility entitlement throughout November of 2011.

Union will update the attached Exhibit C1, Tab 6, Appendix A and file it annually.

UNION GAS LIMITED
Non-utility Storage Balance
October and November, 2011

Calendar Day	October			November		
	Entitlement (PJ)	Balance (PJ)	Percent	Entitlement (PJ)	Balance (PJ)	Percent
1	78.3	76.1	97%	78.3	74.3	95%
2	78.3	76.3	97%	78.3	74.6	95%
3	78.3	76.4	98%	78.3	74.6	95%
4	78.3	76.6	98%	78.3	74.5	95%
5	78.3	76.7	98%	78.3	74.5	95%
6	78.3	76.6	98%	78.3	74.9	96%
7	78.3	77.0	98%	78.3	75.2	96%
8	78.3	77.8	99%	78.3	75.2	96%
9	78.3	78.7	100%	78.3	75.4	96%
10	78.3	79.4	101%	78.3	75.5	96%
11	78.3	79.5	102%	78.3	75.5	96%
12	78.3	79.6	102%	78.3	75.9	97%
13	78.3	79.5	102%	78.3	76.4	98%
14	78.3	79.6	102%	78.3	76.8	98%
15	78.3	79.8	102%	78.3	76.8	98%
16	78.3	79.9	102%	78.3	76.7	98%
17	78.3	79.7	102%	78.3	76.2	97%
18	78.3	79.4	101%	78.3	76.2	97%
19	78.3	79.2	101%	78.3	76.5	98%
20	78.3	78.0	100%	78.3	76.5	98%
21	78.3	77.7	99%	78.3	76.1	97%
22	78.3	77.7	99%	78.3	75.7	97%
23	78.3	77.5	99%	78.3	75.5	96%
24	78.3	77.3	99%	78.3	75.4	96%
25	78.3	77.2	99%	78.3	75.7	97%
26	78.3	76.8	98%	78.3	76.0	97%
27	78.3	76.0	97%	78.3	76.2	97%
28	78.3	75.5	96%	78.3	76.2	97%
29	78.3	75.1	96%	78.3	76.1	97%
30	78.3	74.8	95%	78.3	75.9	97%
31	78.3	74.5	95%			

COST ALLOCATION/
RATE DESIGN

PREFILED EVIDENCE OF

GREG TETREAULT, MANAGER, RATES AND PRICING

ROBIN STEVENSON, TEAM LEADER, PRODUCT AND SERVICES COSTING

The objective of the cost allocation process is to allocate the utility test year cost of service to customer rate classes. Its primary use is to support the rate design process. A fully distributed cost allocation study is used to provide an indication of cost responsibility at a specific point in time. It cannot, and should not be viewed, as a precise measurement of the actual cost to serve a particular rate class, much less a particular customer.

As described in Exhibit A2, Tab 2, the cost allocation study for the current test year no longer includes costs associated with Union's unregulated storage business. Only utility costs up to 100 PJ of storage space are included in the cost allocation study and used to allocate the cost of service to the utility rate classes.

Union allocates storage-related costs based on forecasted in-franchise demands and system integrity requirements. All remaining storage-related costs, up to 100 PJ of regulated storage space, are allocated to the "Excess Utility Storage Space" category. Union charges its unregulated storage business the costs allocated to the Excess Utility Storage Space category for its use of the regulated storage space that is not required to meet in-franchise requirements. The total revenue requirement in this category, less compressor fuel, unaccounted-for-gas ("UFG")

and non-utility system integrity costs, represents the cross charge to the non-utility. Accordingly, the allocators associated with regulated storage reflect only regulated activity. A description of the allocation of costs between Union's regulated and unregulated storage operations is provided at Exhibit A2, Tab 2.

To prepare the cost allocation study a three step approach is followed. The steps are:

1. Functionalization: The first step of the cost allocation process is to associate asset and operating costs with the various utility service functions. There are four functions generally accepted as necessary to obtain and move gas to market: purchase and production of gas, storage, transmission, and distribution.

2. Classification: The second step, categorizes functionalized asset and operating costs into classifications according to cost incurrence. The three main classifications are demand-related, commodity-related, and customer-related. Demand-related costs, also known as capacity-related costs are costs that vary with peak day usage of the system. Commodity-related costs are costs that are typically variable in nature and vary with the level of gas consumed. Customer-related costs are costs that are incurred by virtue of a customer taking service and do not vary with either peak day demand or consumption.

3. Allocation: The final step in the cost allocation process attributes the three types of costs classified above. Allocation factors that reflect the underlying cause of cost incurrence are used in the allocation process. For example, demand-related costs are allocated using the peak day demands of each rate class. Commodity-related costs are allocated based on rate class consumption. Customer-related costs are allocated based on the number of customers in a rate class.

A complete description of the cost allocation methodology is provided at Exhibit G3, Tab 1.

In conducting its analysis and preparing this evidence, Union has used the Board's previously approved cost allocation methodologies, subject to the removal of the unregulated business and the proposals outlined in the following sections.

1/ System Integrity

2/ Tecumseh Metering Assets

3/ Oil Springs East Assets

4/ New Ex-Franchise Transportation Services

5/ Other Proposed Changes

1/ System Integrity

As per the Board's Decision in NGEIR (EB-2005-0551), the 100 PJ of storage space reserved for in-franchise demands includes the space reserved for system integrity. The system integrity space costs are included in the cost allocation study and allocated to utility rate classes and the

Excess Utility Storage Space category. The Excess Utility Storage category includes the system integrity space costs for short-term storage and non-utility storage operations. Union has used the Board-approved methodology to allocate system integrity costs, subject to the proposal for storage pool hysteresis, which is described below.

Based on Union's proposed changes to system integrity components, as described in Exhibit D1, Tab 9, Union proposes to allocate system integrity costs for hysteresis based on the filled and empty system integrity space requirements. Union requires 6.0 PJ of filled space to meet winter operational requirements resulting from system upsets, imbalances and forecast variances. Of the 6.0 PJ filled space, Union requires 1.2 PJ for storage operating constraints (hysteresis). Union also requires 3.5 PJ of empty space on November 1st to manage late season injection demands, of which 0.7 PJ of empty space is reserved to manage storage operating constraints (hysteresis).

Consistent with the Board-approved methodology, Union proposes that the filled space costs continue to be allocated on the basis of storage space requirements. For purposes of determining storage pool hysteresis requirements, Union calculates a revised storage space requirement which includes total working storage capacity less non-utility third party storage space and system integrity space reserved for the Hagar LNG facility and storage hysteresis. The system integrity storage space allocation of hysteresis is provided in Table 1.

Union requires empty system integrity space on November 1st to manage late season injection demands. The space is specifically held in reserve to manage the difference between in-franchise supplies and demands. Empty system integrity space is not required for short-term and long-term non-utility storage contracts as these contracts have little to no firm injection rights during October and November. Accordingly, Union proposes to allocate the empty system integrity space costs reserved for hysteresis based on the revised storage space excluding short-term and long-term non-utility storage space. The system integrity storage space allocation of hysteresis is provided in Table 1.

The allocation of system integrity costs is provided at Exhibit G3, Tab 5, Schedule 23, pp. 5-6. The impact of the change to rate classes is provided at Appendix B.

Table 1

System Integrity Storage Space Allocation of Hysteresis

Line No.	Storage Space Component (PJ)	Excess Utility Storage Space In-Franchise (a)	Short-Term (b)	Long-Term (c)	Total (a+b+c = d)
1	In-franchise Storage Space	77.5			77.5
2	Short-Term and Long-Term Storage Space[1]		13.0	66.5	79.5
3	System Integrity Space [2]	6.6	0.1	0.3	6.9
4	Revised Storage Space (Lines 1 + 2 + 3)	84.1	13.0	66.8	163.9
5	Allocation of Filled Space of Hysteresis [3]	0.6	0.1	0.5	1.2
6	Revised Storage Space less Short-Term and Long-Term Storage Space (Lines 1 + 3)	84.1	0.1	0.3	84.4
7	Allocation of Empty Space of Hysteresis [4]	0.7	0.0	0.0	0.7

(1) Storage Space includes total working storage capacity less non-utility third party storage space.

(2) System integrity space excludes space reserved for the Hagar LNG facility and storage hysteresis (9.5 PJ less 2.6 PJ).

(3) System Integrity Space required for filled hysteresis space is allocated based on the revised storage space (Line 4).

(4) System Integrity Space required for empty hysteresis space is allocated based on the revised storage space less short-term and long-term storage space (Line 6).

2/ TECUMSEH METERING ASSETS

Union proposes to change the classification and allocation of costs associated with Tecumseh metering assets.

In Union's Board-approved 2007 cost allocation study, certain Tecumseh metering assets at the Dawn facility were reflected as transmission assets in Union's plant accounting records. These metering assets were directly assigned to the Dawn Station transmission function and the Dawn

Station Customer classification. The costs were then allocated to the M12 rate class based on Tecumseh metering demands.

Based on a review of the Tecumseh metering assets, Union updated the plant accounting records to move the assets from transmission to underground storage. However, as the Tecumseh metering assets continue to provide transmission service, Union direct assigned the Tecumseh metering assets to the Dawn Station transmission function. Similar to other underground storage assets functionalized to Dawn Station, Union proposes to classify the costs to Demand and allocate the costs to rate classes based on the design day demands of Dawn compression. Union also proposes to eliminate the Dawn Station Customer classification, as the Tecumseh metering costs were the only costs previously allocated to this functional classification.

The impact of the change to rate classes is provided at Appendix B. A description of the underground storage asset re-classifications to the transmission function is provided at Exhibit G3, Schedule 1.

3/ OIL SPRINGS EAST ASSETS

Union proposes to change the functionalization, classification and allocation of costs associated with Oil Springs East assets.

In Union's Board-approved 2007 cost allocation study, Union directly assigned the structure and improvements and measuring and regulating equipment plant costs associated with the Oil

Springs East storage pool to the Dawn Trafalgar Easterly transmission function. This re-classification from underground storage to transmission was based on the use of the assets, which previously served Union North transmission needs. Union also classified the costs to the Dawn Trafalgar Easterly Oil Springs East Metering classification, and allocated costs to rate classes based on design day demands on the Dawn Parkway transmission system.

Union's review of Oil Springs East storage pool assets has determined that these assets now provide both storage and transmission services to customers. Accordingly, Union proposes to eliminate the direct assignment of Oil Springs East assets to the Dawn Trafalgar Easterly transmission function and functionalize these assets between storage and transmission. This approach is consistent with the treatment of other underground storage assets at the Dawn facility that provide both storage and transmission services. Given Union's proposal to eliminate the direct assignment of Oil Springs East assets, Union also proposes to eliminate the transmission classification of Dawn Trafalgar Easterly Transmission for Oil Springs East metering. The impact of the change is provided at Appendix B.

4/ New Ex-Franchise Transportation Services

Since Union's Board-approved 2007 cost allocation study was completed, several new ex-franchise transportation services have been developed by Union and approved by the Board. Specifically, Union has developed the C1 Dawn to Dawn-TCPL and C1 Dawn to Dawn-Vector firm transportation services, as well as the M12 firm all day (F24-T) transportation service. Union proposes to include the costs associated with these new transportation services in its 2013

cost allocation study. A description of the cost allocation methodology proposed for each of the new transportation services is provided below.

i) Dawn to Dawn-TCPL

The C1 Dawn to Dawn-TCPL firm transportation service was developed to meet TransCanada Pipelines Limited (TCPL) need for a firm transportation service within the Dawn yard from Dawn to the Dawn-TCPL interconnect. Union's transmission system had the ability to accommodate requests for transportation on this path on an interruptible basis but required new facilities to offer the transportation service on a firm basis. This service was approved in EB-2010-0207.

The costs of the Dawn to Dawn-TCPL firm transportation service include measuring and regulating assets, compressor fuel and UFG. Union proposes to directly assign the measuring and regulating gross plant, accumulated depreciation, and depreciation expense to the Dawn Station Demand classification and then to the C1 rate class. Similarly, the compressor fuel and UFG costs associated with the Dawn to Dawn-TCPL firm transportation service are also directly assigned to the C1 rate class.

This cost allocation approach is appropriate as it will ensure that the costs associated with the provision of the Dawn to Dawn-TCPL firm transportation service are assigned to the C1 rate

class and recovered in rates from customers utilizing the Dawn to Dawn-TCPL firm transportation service.

ii) Dawn to Dawn-Vector

The C1 Dawn to Dawn-Vector firm transportation service was developed to meet Greenfield Energy Centre LP's need for a firm transportation service within the Dawn yard from Dawn to the Dawn-Vector interconnect. This service was approved in EB-2007-0613.

The costs of the Dawn to Dawn-Vector firm transportation service include the costs associated with compressor fuel and UFG. Consistent with Union's proposal for the Dawn to Dawn-TCPL transportation service, Union proposes to directly assign the compressor fuel and UFG costs to the C1 rate class.

This cost allocation approach is appropriate as it will ensure that the costs associated with the provision of the Dawn to Dawn-Vector firm transportation service are assigned to the C1 rate class and recovered in rates from customers utilizing the Dawn to Dawn-Vector firm transportation service.

iii) M12 Firm All Day (F24-T)

As part of the NGEIR proceeding (EB-2005-0551), Union developed an enhanced M12 F24-T transportation service that provides additional nomination windows and firm all day transportation capacity to power generators and other customers.

The costs for the M12 F24-T transportation service include employee salaries and benefits and compressor maintenance costs. Union proposes to directly assign the employee salaries and benefits and compressor maintenance costs to the Dawn Trafalgar Easterly Transmission function and then to the M12 rate class.

This cost allocation approach is appropriate as it will ensure that the costs associated with the provision of the M12 F24-T transportation service are assigned to the M12 rate class and recovered in rates from customers utilizing the M12 F24-T transportation service.

5/ OTHER PROPOSED CHANGES

Union is proposing additional cost allocation methodology changes to better reflect cost causation and further harmonize the cost allocation methodologies used for Union North and Union South.

Specifically, Union is proposing the following changes: i) the allocation of Union North distribution customer stations plant, ii) the allocation of distribution maintenance for meter and

regulator repairs, iii) the allocation of distribution maintenance related to equipment on customer premises, and iv) the classification and allocation of general plant Purchase Production costs.

*i) **Union North Distribution Customer Stations Plant***

Union currently allocates Union North customer station costs to Union North in-franchise rate classes in proportion to average number of customers excluding the small volume general service Rate 01 rate class. The customer stations however, are constructed for customers that have hourly consumption in excess of 320 m^3. Assuming a typical industrial customer load factor of 40 percent and 20 hours of flow per day, the annual consumption for customers with a customer station would be a minimum of 934,400 m^3. Based on the 2010 actual volumes, no Rate 01 customers and only a small percentage of Rate 10 customers consume 934,400 m^3 or more per year.

All other medium and large volume customers require a total maximum daily requirement of 14,000 m^3 or more to be eligible for the respective firm contract rate classes (Rate 20 and Rate 100). Based on peak hourly flow equal to $1/20^{th}$ of the maximum daily quantity of 14,000 m^3 or more, the approximate hourly consumption for the firm contract rate classes is 700 m^3. Accordingly, Rate 20 and Rate 100 customers exceed the hourly customer station requirement of 320 m^3.

Union proposes to continue to allocate customer station costs based on the average number of customers, excluding the Rate 01 rate class and Rate 10 customers that do not meet the annual consumption threshold of 934,400 m^3. The impact of the change is provided at Appendix B.

ii) Distribution Maintenance– Meter and Regulator Repairs

Union currently classifies Union South distribution maintenance costs for meter and regulator repair to Distribution Customer and allocates the costs to the M2 rate class. For Union North, distribution maintenance costs for meter and regulator repair are classified to Distribution Demand and allocated to rate classes in proportion to the allocation of distribution meter and regulator gross plant.

Based on a review of its operating practices, Union has determined that there are minimal maintenance costs associated with residential meters because it is more economical to replace small residential meters than perform repairs. To reflect Union's operating practices and harmonize cost allocation between Union North and Union South, Union proposes to align the Union North and Union South distribution maintenance meter and regulator repair cost methodology.

Accordingly, Union proposes to classify and allocate both Union North and Union South distribution maintenance costs for meter and regulator repair in proportion to the distribution

meter and regulator gross plant cost allocation, excluding the M1 and Rate 01 rate classes. The impact of the change is provided at Appendix B.

iii) Distribution Maintenance– Equipment on Customer Premises

Union currently allocates Union South distribution maintenance costs for equipment on customer premises to M1 and M2 customers based on service call time. Union North distribution maintenance costs for equipment on customer premises are allocated to rate classes based on a historic allocator.

The maintenance of equipment on customer premises costs are primarily related to customer station maintenance. To more accurately reflect costs and to harmonize the approach between Union North and Union South, Union proposes to allocate both the Union North and Union South equipment on customer premises distribution maintenance costs to rate classes in proportion to the allocation of customer station gross plant. The impact of the change is provided at Appendix B.

iv) Purchase Production General Plant

Union currently functionalizes general plant costs in proportion to the functionalization of rate base and O&M costs. However, general plant costs are functionalized to the Purchase Production function based on O&M costs only since there are no other plants costs functionalized to Purchase Production. The Purchase Production general plant costs are

classified to Purchase Production Other and allocated to Union South in-franchise customers in proportion to delivery volumes, excluding the T1 and T3 rate classes.

Union proposes to classify general plant costs to both the Purchase Production System and Purchase Production Other classifications in proportion to the components of Purchase Production System and Other O&M. Union also proposes to allocate general plant costs to rate classes in proportion to the components of Purchase Production System and Other O&M. This methodology change will ensure general plant costs that are functionalized to purchase production are classified and allocated to rate classes on the same basis. The impact of the change is provided at Appendix B.

UNION GAS
Proposed Methodology Changes

Cost Element	Account Code	Approved Allocator (s)	Approved Factor Definitions EB-2005-0520	Proposed Allocator (s)	Proposed Methodology EB-2011-0210
1/ System Integrity					
Allocation *Storage Excluding Dehydration System Integrity* Underground Storage Plant, Gas in Storage Working Capital, Accumulated Deferred Taxes, Underground Storage O&M, General Operations & Engineering	Various	SYSINTEGRITY	Allocate System Integrity costs to rate classes in proportion to allocated system integrity inventory.	SYSINTEGRITY	Use same methodology for all integrity space components except for hysteresis. Allocate filled hysteresis space on revised storage space and empty hysteresis space on revised storage space less short-term and long-term storage space.
2/ Tecumseh Metering Assets					
Functionalization Transmission - Measuring and Regulating	467	TRANSM&R	Directly assign the plant costs of specific transmission measuring and regulating equipment to the Dawn-Trafalgar Easterly and Ojibway / St. Clair transportation systems and to Dawn Station in proportion to specifically assigned assets.	STORM&R	Remove transmission direct assignment to Dawn Station. Plant assets moved to Underground Storage M&R (account code 457) and directly assigned to Dawn Station to match plant accounting records.
Classification Transmission - Measuring and Regulating	467	THIRD	Classify costs to the third column of classification identified for a particular function. Classification - Dawn Station Customer.	FIRST	Remove Dawn Station Customer Classification. Plant assets moved to Underground Storage M&R (account code 457) and classified to Dawn Station Demand.
Allocation *Transmission Dawn Station Customer* Transmission - Measuring and Regulating, Working Capital, Income and Property Tax	Various	TECUMSEHDEMAND	Allocate costs in proportion to Tecumseh metering demand.	DAWNCOMP	Remove Tecumseh demands. Plant assets moved to Underground Storage M&R (account code 457) and allocated to rate classes based on DAWNCOMP.
3/ Oil Springs East Storage Pool					
Functionalization Storage - Structures & Improvements	452	S&IRECLASS S&IRECLAD	Directly assign the plant costs and accumulated depreciation of reclassified underground structures and improvements at Dawn Station that relate to the Dawn Trafalgar Easterly transmission system.	COMPRECL-PT	Remove OSE plant costs from direct assignment to Transmission and functionalize them between storage and transmission based on horsepower allocation.
Storage - Measuring and Regulating	457	M&RRECLASS M&RRECLAD	Directly assign the plant costs and accumulated depreciation of reclassified underground Storage measuring and regulating at Dawn Station that relate to the Dawn Trafalgar Easterly transmission system.	M&RRECL-PT	Remove OSE plant costs from direct assignment to Transmission and functionalized them between storage and transmission based on Dawn M&R activity.

UNION GAS
Proposed Methodology Changes

Cost Element	Account Code	Approved Allocator (s)	Approved Factor Definitions EB-2005-0520	Proposed Allocator (s)	Proposed Methodology EB-2011-0210
Classification					
Storage - Structures & Improvements	452	OSES&I OSES&IAD	Directly assign plant costs and accumulated depreciation of structures and improvements related to Oil Springs East to Dawn OSE Metering classification.	Various	Remove direct assignment to the Dawn Trafalgar Easterly Oil Springs East Classification. Classify costs based on various classifications by function.
Storage - Measuring and Regulating	467	OSEM&R OSEM&RAD	Direct assign the plant costs and accumulated depreciation of measuring and regulating equipment related to Oil Springs East to Dawn OSE Metering classification.	Various	Remove direct assignment to the Dawn Trafalgar Easterly Oil Springs East Classification. Classify costs based on various classifications by function.
Allocation					
Dawn-Trafalgar Easterly Oil Springs East Metering					
Underground Storage - Structures and Improvements, Measuring and Regulating, General Plant, Working Capital, Income and Property Tax	Various	DTTRANS INDIR_I&II_OSE DAWNEASTBASE-2 DAWNEASTPROTAX-2	Allocate Dawn-Trafalgar Easterly Demand costs based on firm design day demand. Allocate indirect costs based on internal general plant, working capital, income and property tax allocators.	Various	Allocate costs based on the allocators within the respective storage and transmission function.
4/ New Ex-franchise Services					
1/ Dawn to Dawn-TCPL Service					
Functionalization					
Underground Storage - Other	459	Not applicable	Not applicable	STOROTHER STOROTHERAD	Directly assign the gross plant costs and accumulated depreciation of the Dawn-TCPL measuring and regulating equipment to Dawn Station.
Underground Storage - Compressor Fuel		Not applicable	Not applicable	STORAGEFUEL	Directly assign the Dawn to Dawn-TCPL fuel to Dawn Station.
Cost of Gas - UFG		Not applicable	Not applicable	UFGFUNCT	Functionalize the costs of unaccounted-for-gas to purchase production in proportion to volumes.
Classification					
Underground Storage - Other	459	Not applicable	Not applicable	FIRST	Classify account dollars to the first column of Classification identified for a particular function. Classification - Dawn Station Demand.
Underground Storage - Compressor Fuel		Not applicable	Not applicable	SECOND	Classify account dollars to the first column of Classification identified for a particular function. Classification - Dawn Station Commodity.
Cost of Gas - UFG		Not applicable	Not applicable	SECOND	Classify account dollars to the first column of Classification identified for a particular function. Classification - Purchase Production Other Supply Commodity.

UNION GAS
Proposed Methodology Changes

Cost Element	Account Code	Approved Allocator (s)	Approved Factor Definitions EB-2005-0520	Proposed Allocator (s)	Proposed Methodology EB-2011-0210
Allocation					
Dawn Station Demand					
Underground Storage - Other	459	Not applicable	Not applicable	DAWNTCPL-M&R DAWNTCPL-ADM&R	Directly assign the gross plant costs and accumulated depreciation of the Dawn-TCPL measuring and regulating equipment to the C1 rate class.
Dawn Station Commodity					
Underground Storage - Compressor Fuel		Not applicable	Not applicable	DAWNSTORFUEL	Directly allocate the Dawn to Dawn-TCPL fuel to the C1 firm rate class in proportion to volumes.
Purchase Production Other Supply Commodity					
Cost of Gas - UFG		Not applicable	Not applicable	UFGALLO	Directly assign the Dawn to Dawn-TCPL fuel to the C1 firm rate class.
II/ Dawn to Dawn-Vector Service					
Functionalization					
Underground Storage - Compressor Fuel		Not applicable	Not applicable	STORAGEFUEL	Directly assign the Dawn to Dawn-Vector fuel to Dawn Station.
Cost of Gas - UFG		Not applicable	Not applicable	UFGFUNCT	Functionalize the costs of unaccounted-for-gas to purchase production in proportion to volumes.
Classification					
Underground Storage - Compressor Fuel		Not applicable	Not applicable	SECOND	Classify account dollars to the first column of Classification identified for a particular function. Classification - Dawn Station Commodity.
Cost of Gas - UFG		Not applicable	Not applicable	SECOND	Classify account dollars to the first column of Classification identified for a particular function. Classification - Purchase Production Other Supply Commodity.
Allocation					
Dawn Station Commodity					
Underground Storage - Compressor Fuel		Not applicable	Not applicable	DAWNSTORFUEL	Directly allocate the Dawn to Dawn-Vector fuel to the C1 firm rate class in proportion to volumes.
Purchase Production Other Supply Commodity					
Cost of Gas - UFG		Not applicable	Not applicable	UFGALLO	Directly assign the Dawn to Dawn-Vector fuel to the C1 firm rate class.

UNION GAS
Proposed Methodology Changes

Cost Element	Account Code	Approved Allocator (s)	Approved Factor Definitions EB-2005-0520	Proposed Allocator (s)	Proposed Methodology EB-2011-0210
III/ M12 F24-T Service					
Functionalization					
General Operating and Engineering - System Operation & Engineering	685	Not applicable	Not applicable	GS/AOP/F24-T	Directly assign general operating costs associated with the M12 F24-T service to the Dawn Trafalgar Easterly transmission function.
Administrative and General Expenses - Employee Benefits	725	Not applicable	Not applicable	GS/F24T-BENEFITS	Directly assign general operating employee benefit costs associated with the M12 F24-T service to the Dawn Trafalgar Easterly transmission function.
Classification					
General Operating and Engineering - System Operation & Engineering	685	Not applicable	Not applicable	F24-T - GENOPS	Directly assign general operating costs associated with the M12 F24-T service to the Dawn Trafalgar Easterly Demand classification.
Administrative and General Expenses - Employee Benefits	725	Not applicable	Not applicable	F24T-BENEFITS	Directly assign general operating employee benefit costs associated with the M12 F24-T service to the Dawn-Trafalgar Easterly Demand classification.
Allocation					
Dawn-Trafalgar Easterly Demand					
General Operating and Engineering - System Operation & Engineering	685	Not applicable	Not applicable	F24T -GENOPS	Directly assign general operating costs associated with the M12 F24-T service to the M12 rate class.
Administrative and General Expenses - Employee Benefits	725	Not applicable	Not applicable	F24T-BENEFITS	Directly assign general operating employee benefit costs associated with the M12 F24-T service to the M12 rate class.
Transmission - Compressor - Maintenance	866	Not applicable	Not applicable	F24T-COMPMAINT	Directly assign compressor maintenance costs associated with the M12 F24-T service to the M12 rate class.
5/ Other Proposed Changes					
I/ Distribution North Customer Stations					
Allocation					
Distribution Customer					
North Distribution Customer Stations	474	N_ACEXRES	Allocate costs in proportion to average number of customers in Northern and Eatern Operations area excluding residential customers.	N_CUSTSTATIONS	Allocate costs in proportion to average number of customers in Northern and Eatern Operations area excluding customers that consume less than 934,400 m^3/year.

UNION GAS
Proposed Methodology Changes

Cost Element	Account Code	Approved Allocator (s)	Approved Factor Definitions EB-2005-0520	Proposed Allocator (s)	Proposed Methodology EB-2011-0210
II/ Distribution Maintenance - Meter and Regulator Repairs					
Classification					
North Distribution Maintenance - Meter and Regulator Repairs	878	DISTM&R	Classifies costs in proportion to Distribution M&R plant.	N_DISTM&R	Classify costs in proportion to Distribution Meters & Regulators gross plant in the Northern and Eastern Operations area.
Allocation					
Distribution Customer					
South Distribution Maintenance - Meter and Regulator Repairs	878	REPAIRCOSTS	Allocate costs of repairs at customers' premises as budgeted.	S_CUSTM&RXRES	Allocate costs in proportion to Distribution Customer Meters and Regulators gross plant for the Southern operations area, excluding the M1 rate class.
North Distribution Maintenance - Meter and Regulator Repairs	878	DEMM&R	Allocates costs in proportion to Distribution Demand M&R plant.	N_CUSTM&RXRES N_DEMM&RXRES	Allocate costs in proportion to Distribution Customer and Demand Meters and Regulators gross plant for the Northern and Eastern Operations area, excluding the Rate 01 rate class.
III/ Distribution Maintenance - Equipment on Customer Premises					
Allocation					
Distribution Customer					
South Distribution Maintenance - Equipment on Customer Premises	873	S_SERVICECALLTIME	Allocate costs to the Southern operations area in proportion to service call time.	STATIONREPLCOSTS	Allocate costs in proportion to customer stations gross plant, which is allocated based on distribution station replacement costs.
North Distribution Maintenance - Equipment on Customer Premises	873	APPLIANCERENT	Allocate costs in proportion to Appliance Rentals.	N_CUSTSTATIONS	Allocate costs in proportion to customer station gross plant, which is allocated in proportion to the average number of customers in Northern and Eatern Operations area excluding customers that consume less than 934,400 m^3 per year.
IV/ Purchase Production General Plant					
Classification					
General Plant	Various	SECOND	Classify account dollars to the second column of Classification identified for a particular function. Classification - Purchase Production Other	INDIR_I&II_PROD	Classify costs based on an equal weighting between Purchase Production rate base and O&M.
Allocation					
Purchase Production Other					
General Plant	Various	S_INFRXT	Allocate costs in proportion to delivery volumes for in-franchise customers in the Southern Operations area excluding T-service.	INDIR_I&II_PROD	Allocate costs based on an equal weighting of Purchase Production Other rate base.
Purchase Production System					
General Plant	Various	Not applicable	Not applicable	SUPPLYVOL	Allocate costs in proportion to in-franchise system supply volumes.

UNION GAS LIMITED
Revenue Requirement Impacts

Line No.	Particulars ($000's)	Cost Type	Revenue Requirement Total	Gen. Service Small Volume M1	Gen. Service Large Volume M2	Firm Contract M4	Interruptible Contract-Firm M5	Interruptible Contract-Interruptible M5	Special Large Volume Contract - Firm M7	Special Large Volume Contract - Interruptible M7	Large Wholesale Service M9	Small Wholesale Service M10	Storage & Transportation Service - Firm T1	Storage & Transportation Service - Interruptible T1	Wholesale Storage & Transportation Service T3
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	System Integrity Hysterisis	Allocator	0	60	21	3	0	4	1	0	1	0	19	0	5
2	Tecumseh Metering Assets	Rate Base	0	131	44	14	0	0	5	0	2	0	101	0	11
3	Oil Springs East Storage Pool	Rate Base	0	27	9	2	0	0	1	0	0	0	16	0	2
4	Distribution Maintenance - Meter and Regulator Repairs	O&M	0	(5)	(434)	65	1	71	28	4	5	1	188	45	19
5	Distribution Maintenance - Equipment on Customer Premises	O&M	0	(324)	92	35	1	39	15	2	3	0	102	24	10
6	Purchase Production General Plant	Rate Base	0	(169)	(91)	(16)	14	(41)	(28)	0	(11)	0	41	14	2
7	Distribution North Customer Stations	Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0
8	**Revenue Requirement Change**[1]		**0**	**(279)**	**(358)**	**103**	**15**	**74**	**22**	**7**	**(1)**	**2**	**467**	**83**	**51**

(1) A positive value represents an increase to the revenue requirement based on the proposed methodology.

UNION GAS LIMITED
Revenue Requirement Impacts

Line No.	Particulars ($000's)	Cost Type	Excess Utility Storage Space	Firm Transportation Service C1	Interruptible Trans. Service & Exchanges C1	Dawn-Trafalgar Transport Service M12	Local Production Transportation Service M13	Storage Transportation Service M16	Small Volume General Firm Service R01	Large Volume General Firm Service R10	Medium Volume Firm Service R20	Large Volume High Load Factor Firm Service R100	Large Volume Interruptible Service R25
			(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
1	System Integrity Hysterisis	Allocator	(146)	0	1	4	0	0	20	5	1	0	0
2	Tecumseh Metering Assets	Rate Base	0	(0)	0	(306)	(1)	(0)	(2)	(1)	(0)	(0)	0
3	Oil Springs East Storage Pool	Rate Base	7	1	0	(77)	0	0	8	2	1	0	0
4	Distribution Maintenance - Meter and Regulator Repairs	O&M	-	-	-	-	-	-	(27)	45	(4)	(14)	12
5	Distribution Maintenance - Equipment on Customer Premises	O&M	-	-	-	-	-	-	(1,493)	286	532	152	523
6	Purchase Production General Plant	Rate Base	0	0	0	0	0	0	166	30	48	14	27
7	Distribution North Customer Stations	Rate Base	0	0	0	0	0	0	0	(2,169)	955	274	940
8	**Revenue Requirement Change**[1]		**(138)**	**1**	**1**	**(379)**	**(1)**	**0**	**(1,329)**	**(1,802)**	**1,533**	**427**	**1,502**

(1) A positive value represents an increase to the revenue requirement based on the proposed methodology.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit G1, Tab 1, Appendix B

a) Please explain the basis of the proposed change to the allocation of Union North Distribution Customer Stations Plant.

b) In particular, please explain why Rate M1 is allocated more costs.

Response:

a) The basis for the proposed change to the allocation of Union North Distribution Customer Stations Plant is to better reflect cost causality.

Union's Board-approved allocation of Union North Distribution Customer Stations Plant costs is based on the average number of customers in each rate class, excluding Rate 01. The current approved methodology would allocate 94 percent of these costs to Rate 10 customers, based on the 2013 average number of customers.

However, a customer station is a station that is constructed for customers that have hourly consumption in excess of 320 m^3. Assuming a typical industrial customer load factor of 40 percent and 20 hours of flow per day, the annual consumption for customers with a customer station would be a minimum of 934,400 m^3. Only a small percentage of Rate 10 customers consume 934,400 m^3 or more per year.

Accordingly, Union is proposing to allocate Union North Distribution Customer Stations Plant based on the average number of customers in each rate class, excluding Rate 01 and excluding the Rate 10 customers that do not consume 934,400 m^3 or more per year. As all Rate 20 and Rate 100 customers exceed the hourly customer station requirement of 320 m^3, all customers in these rate classes are included in the allocation.

b) Union's proposed methodology change to the allocation of Union North Distribution Customer Stations Plant does not result in an increase in costs allocated to Rate M1. Please see the response at J.G-5-2-1 and the updated version of Exhibit G1, Tab 1, Appendix B at J.G.1-3-1 Attachment 2.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Ref: Exhibit G1, Tab 1, Pages 11-15

Union seeks to change the methodology for allocating Union North customer station costs. Union defines a customer station as one having an hourly consumption in excess of 320 m^3/h. Union proposes to use a threshold annual consumption of 934,400 m^3/year (based on annual consumption of 320 m^3/h X 20 h/d X 365 X 0.40 LF) as the criteria to determine whether a customer station has been constructed for the customer for the purposes of allocating customer station costs to various rate classes in Union North. Union concludes that no Rate 1 customers and a small percentage of Rate 10 customers consume more than 934,400 m^3/year.

a) Please confirm that customer stations incorporate the use of meters and regulators on customer premises to measure and reduce the pressure being delivered to the customers.

b) Please confirm that this cost item relates to the capital cost of the equipment. If not confirmed, explain.

c) Please confirm that the design criteria Union uses to size and install meters and regulators for individual customer loads is the maximum peak hourly load and not the estimated annual consumption. If not confirmed, explain.

d) If two customer stations are constructed to meet the same peak hourly demand, and have similar equipment installed and one consumes more than 934,400 m^3/year and one consumes less than 934,400 m^3/year, please confirm that the customer station with the lower annual consumption would not attract the same customer station costs.

e) Please identify the number of customer meter stations in Union North in each rate class that have a design hourly load in excess of 320 m^3/h.

f) Please provide the total customer station costs for the North by rate category as proposed by Union for 2013 based on annual consumption of 934,400 m^3/year.

g) Please recalculate the customer station costs allocated by rate class if they were allocated on the basis of hourly load in excess of 320 m^3/h.

Response:

a) Confirmed.

b) Confirmed.

c) Confirmed. Maximum peak hourly load and customer delivery pressure are used as design criteria.

d) Union is proposing to allocate Union North Distribution Customer Stations Plant costs based on the average number of customers in each rate class, excluding Rate 01 and excluding the Rate 10 customers that do not consume 934,400 m^3 or more per year.

A Rate 10 customer with a customer station designed to meet an hourly demand of 320 m^3 that does not exceed an annual consumption of 934,400 m^3 is not included in the allocator described in the paragraph above. However, the customer station plant costs allocated to Rate 10 are recovered from all Rate 10 customers in Union's proposed delivery rates.

e) There are 468 Union North customer stations that exceed the design capacity of 320 m^3. The breakdown by rate class is provided in Attachment 1, column (a).

f) Please see Attachment 2.

g) Please see Attachment 1.

Allocation Change of Customer Stations Plant Based on Number of Stations

Line No.	Particulars ($000's)	Number of Customer Stations > 320 m^3/hr[1]	Allocated Union North Customer Stations Costs		
			Customer Stations Gross Plant	Accumulated Depreciation	Customer Stations Net Plant
		(a)	(b)	(c)	(d) = (b - c)
1	R01	0	0	0	0
2	R10	337	21,578	8,661	12,916
3	R20	100	6,403	2,570	3,833
4	R100	29	1,857	745	1,111
5	R25[2]	2	128	51	77
6	Total	468	29,965	12,028	17,937

Notes:

1 The number of stations in a rate class is based on the current customer rate classes and has not been updated to reflect changes to the forecasted number of customers.

2 The number of Rate 25 customers is based on the the actual number of customers that only have a Rate 25 service. No adjustment has been made to reflect the actual number of customers who have a companion Rate 25 service.

Proposed Allocation of Union North Customer Stations Plant

Line No.	Particulars ($000's)	Proposed Allocation N_CUSTSTATIONS	Allocated Union North Customer Stations Costs		
			Customer Stations Gross Plant	Accumulated Depreciation	Customer Stations Net Plant
		(a)	(b)	(c)	(d) = (b - c)
1	R01	0	0	0	0
2	R10	37	6,223	2,498	3,725
3	R20	62	10,456	4,197	6,259
4	R100	18	2,999	1,204	1,795
5	R25	61	10,287	4,129	6,158
6	Total	178	29,965	12,028	17,937

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit G1, Tab 1, Page 14 5(iii)

a) Why has Union decided that for maintenance of equipment on customer premises the costs are primarily related to customer station maintenance and a time based allocation is no longer appropriate?

b) Please provide details -amount of costs before and after the change.

c) Reconcile to Appendix B.

Response:

a) The internal work orders mapped to Distribution Maintenance - Equipment on Customer Premises primarily relate to customer station maintenance. The Board-approved cost allocation methodology allocates equipment on customer premises maintenance costs to general service customers in Union South based on service call time and general service customers in Union North based on a historic allocator. There are no maintenance costs related to equipment on customer premises allocated to contract rate customers, despite contract rate customers having customer stations requiring maintenance.

   Union is proposing to allocate these maintenance costs to both general service and contract rate customers in Union South and Union North in proportion to the allocation of customer stations plant. An allocation of maintenance costs based on the allocation of customer stations plant better reflects cost incurrence than a time-based allocation.

b) Please see Attachment 1.

c) Please see Attachment 1 (column c) and J.G-1-3-1 Attachment 1. J.G-1-3-1 includes the updated Revenue Requirement Impact to reflect the cost allocation study filed on March 27, 2012.

Revenue Requirement for Distribution Maintenance Equipment on Customer Premises by Rate Class

Line No.	Particulars ($000's)	Board-Approved Allocation Equipment on Customer Premises (a)	Proposed Allocation Equipment on Customer Premises (b)	Difference (c) = (b - a)
1	M1	3,386	3,063	(323)
2	M2	77	169	92
3	M4 Firm	0	35	35
4	M5 Firm	0	1	1
5	M5 Interruptible	0	39	39
6	M7 Firm	0	15	15
7	M7 Interruptible	0	2	2
8	M9	0	3	3
9	M10	0	0	0
10	T1 Firm	0	101	101
11	T1 Interruptible	0	24	24
12	T3	0	10	10
13	R01	1,488	0	(1,488)
14	R10	30	315	285
15	R20	0	530	530
16	R100	0	152	152
17	R25	0	521	521
18	Total	4,981	4,981	0

Ontario Energy Board



E.B.R.O. 493/494

IN THE MATTER OF THE
ONTARIO ENERGY BOARD ACT

AND

IN THE MATTER OF APPLICATIONS BY

CENTRA GAS ONTARIO INC.

AND

UNION GAS LIMITED

FOR RATES

DECISION WITH REASONS - Volume I

March 20, 1997

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9.2 DIRECT ASSIGNMENT OF GAS SUPPLY ADMINISTRATION COSTS

9.2.1 Union proposed to directly assign the incremental costs associated with the administration related to each gas supply alternative (buy-sell, T-service, bundled-T and system supply) to its rate classes. A total of $1,533,527 is associated with Union's gas supply administration exclusive of direct purchases. A total of $589,984 is associated with administering direct purchase agreements in the regular rate as well as industrial markets. Included in the system supply related costs is the gas supply commodity portion of the allowance for uncollectible accounts.

ADR Settlement Agreement

9.2.2 The following parties participated in the discussion of this issue: Kitchener, Schools, Terra, Nova, ONA, Board Staff, CAC, ECNG, NRG, IGUA, OCAP and Universities. The parties agreed that the Company's evidence on this subject should be accepted.

Board Finding

9.2.3 The Board accepts the Company's proposed assignment of gas supply administration costs for 1997 with the exception of the review of the allocation of the allowance for uncollectible accounts to the M9 rate class which is addressed later in this Chapter.

9.3 S&T: UNION M12 COST ALLOCATION

Background

9.3.1 Union's Rate M12 is the rate charged to cross-franchise shippers for firm long-term services related to transportation of gas on the Dawn-Trafalgar System.

9.3.2 In its E.B.R.O. 486 Decision the Board directed Union to prepare an M12 cost allocation study to ensure that there is no cross subsidy among rate classes which use the Dawn-Trafalgar System (including storage) and to present this study in its

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next main rates case. In October, 1995 R.J. Rudden Associates Inc ("RJRA") was retained by Union to undertake a review of the existing methodology based on the Company's rate design evidence presented in E.B.R.O. 486.

9.3.3 RJRA's report examined the following aspects of the Dawn-Trafalgar System:

- the operational characteristics and services offered;
- Union's overall cost study structure and framework;
- Union's principles and methods for functionalization, classification and allocation of costs:
- the derivation of Union's allocation factors;
- application of cost study results; and
- cross subsidization and rate design issues.

9.3.4 RJRA's overall assessment was that:

> *"the conceptual underpinnings and resulting methodologies upon which Union's cost allocation study is based are well conceived, thorough and reasonable: however the presentation of the cost study ... fails by not providing sufficient detail to allow an outside party to understand, trace and verify the study's underlying assumptions and computational process".*

9.3.5 In an attempt to remedy this deficiency, Union filed supplementary evidence to aid parties to the proceeding in completing independent reviews of the cost allocation and rate design of services offered on the Dawn-Trafalgar System.

9.3.6 The RJRA report did not recommend any changes to Union's current cost allocation for S&T services or the ex-franchise (M12) allocation of costs of the Dawn-Trafalgar System.

ADR Settlement Agreement

9.3.7 The parties to the ADR settlement process failed to reach a consensus on the following specific issues:

- mileage based cost allocations;

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- treatment of east end deliveries; and
- allocation of Dawn Compressor Station carrying costs.

Intervenor Evidence

9.3.8 TCPL and Consumers' Gas, both large ex-franchise users of the Dawn-Trafalgar System, filed evidence and presented expert witnesses who disagreed with certain aspects of Union's Dawn-Trafalgar System cost allocation and rate design methodology for M12 customers.

9.3.9 TCPL's areas of disagreement with Union's cost allocation study and its endorsement by RJRA, were the allocation of mileage credits related to *east end deliveries* to in-franchise customers and the method of *allocation of Dawn Compressor Station costs* to the S&T services provided by Union.

9.3.10 Consumers' Gas' areas of disagreement were *mileage based cost allocation*, the treatment of *east end deliveries* and the *design day forecast demand* for in-franchise and ex-franchise customers.

9.4 MILEAGE BASED COST ALLOCATION AND TREATMENT OF EAST END DELIVERIES

9.4.1 Union's evidence was that the Dawn-Trafalgar System is a bi-directional, multi-functional, integrated pipeline system. The system has a 1997 peak capacity requirement of 131,977 10^3m^3/day (plus fuel). The actual design capacity is 129,997 10^3m^3/day and the balance is met by Winter Peaking Service ("WPS") deliveries from TCPL at Parkway. Approximately 94,584 10^3m^3/day of contracted M12 volumes and 37,393 10^3m^3/day of in-franchise volumes (less 1,980 10^3m^3 of WPS) are transported easterly from Dawn with the balance of the in-franchise deliveries being delivered in part by a swap of east end deliveries with M12 volumes flowing from Dawn (14,122 10^3m^3/day).

9.4.2 With regard to *mileage based cost allocation* Union's evidence was that its cost study allocates costs of transportation on the Dawn-Trafalgar System based on a "commodity-kilometer" cost allocation factor using the principle that the system

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costs are mileage sensitive. Union's staff and outside experts contended that allocating costs based on the peak design day demand weighted by the distance that demand volumes travel from Dawn, provides the best match between cost causality and tolls.

9.4.3 RJRA's expert supported Union's methodology and cited the following reasons why *mileage based cost allocation* rather than a "postage stamp" allocation, i.e. without regard to distance of haul, was appropriate for the allocation of transportation costs on the Dawn-Trafalgar System:

- the system has a distinct west-east orientation; i.e. at peak design day conditions gas flows from west to east are much greater than at other times of the year;
- there is a need to transport M12 shippers' volumes over much greater distances than volumes for Union's in-franchise customers; and
- the location of users' demands is such that increasing the distance the gas travels increases the facilities required and hence the level of costs per unit of gas transported.

9.4.4 Consumers' Gas retained Energy Group Inc. to examine Union's mileage based cost allocation and the treatment of east end deliveries. Its expert concluded that there was no proper basis for the *mileage based cost allocation*. He advocated, given the design and operation of the Dawn Trafalgar System and its characteristics compared to other integrated systems, that costs should be allocated on a postage stamp basis. He also concluded that costs should be allocated to all Dawn-Trafalgar delivery requirements, including east end deliveries, as if they originated at Dawn, consistent with the integrated nature of the system and the physical flow of gas on the peak winter design day.

9.4.5 With regard to *east end deliveries*, Union's evidence was that at design day conditions (131,977 10^3m^3/day plus fuel) the flow is totally west-east with 115,875 10^3m^3 of the peak demand being met by the design capacity of the system and the balance, (approximately 16,000 10^3m^3) by Union contracting for TCPL WPS

(1,980 10^3m^3), through arrangements with certain in-franchise buy/sell and T-service shippers to have their gas delivered at Parkway and other east end delivery points, and through Union's own in-franchise system gas deliveries (14,122 10^3m^3). These volumes are exchanged with volumes flowing from Dawn to allow the total demand from both in-franchise and ex-franchise (M12) customers to be met.

9.4.6 Union allocates transportation costs to its in-franchise customers as if the east end volumes are delivered at 'Parkway' (actually five east end delivery points) and then transported west for delivery to its in-franchise delivery points. Therefore only a small portion of transportation costs is allocated to these volumes, compared to what the transportation cost allocation would be if the volumes had moved from Dawn. The balance of the in-franchise volumes are in fact transported from Dawn.

9.4.7 Union allocates transportation costs to its ex-franchise customers based on delivery of their total volume at Dawn and transportation easterly to the east end delivery points specified in their contracts.

9.4.8 The issue related to *east end deliveries* is that Union deems that a volume of gas equivalent to the east end deliveries, enters the system at Dawn and moves to three east end delivery points for redelivery to in-franchise customers and not to the ex-franchise customers. The lower transportation costs allocated to the *east end deliveries* for in-franchise customers result in mileage credits for the east end deliveries, which are streamed to the in-franchise customers. The Delivery Commitment Credit (DCC), Obligated Demand Premium (ODP) costs and TCPL demand charges associated with the east end delivery volumes are charged to the account of in-franchise customers only.

9.4.9 Both the east end delivery volumes (14,122 10^3m^3) and WPS volumes (1,980 10^3m^3) are functionalized as capacity (transmission) related and are not commodity related.

9.4.10 Union noted that the *east end deliveries* are a fundamental part of the peak design of the Dawn-Trafalgar System which allows the design capacity of the system to

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be smaller than otherwise required if all volumes had to move from Dawn under peak design day conditions. This reduction in capacity and facilities benefits all users of the Dawn-Trafalgar System, including ex-franchise shippers (Rate M12) and in-franchise customers, in the form of lower rates.

9.4.11 TCPL retained Tibor Haynal and Associates and Thomas R. Hughes & Associates to present evidence in support of its proposals for alternative cost allocations. In the opinion of TCPL's experts, the purpose of east end deliveries is to provide for delivery point flexibility, for example at either Dawn or Parkway and in view of this flexibility, such deliveries should be treated as gas supply (commodity) related rather than transmission (capacity) related. Union's current allocation of costs does not, in TCPL's experts' view, properly reflect the principle that cost responsibility tracks cost causation. As a result, Union has over-allocated costs to the ex-franchise (M12) customers by departing from the physical operation of the system and deeming that east end deliveries, which carry no Dawn-Trafalgar System cost, are flowing only to in-franchise customers; they are in fact swapped with M12 shippers' volumes and actually flow eastward from Parkway as part of M12 contract volumes.

9.4.12 TCPL's witnesses stated that, in their opinion, Union's cost study should be amended to allocate the savings resulting from east end deliveries to both the in-franchise and to the ex-franchise (M12) customers who make the exchange of east end delivery volumes possible. According to TCPL, if its proposals were accepted, $15.955 million of costs would be reclassified as transmission related.

Positions of the Parties

9.4.13 Union submitted that it uses direct deliveries of gas to the east end of its system to reduce the size of the facilities to serve all customers and that Union is able to rely on those deliveries for the purposes of designing the system because of the contractual arrangements which it and its direct purchase customers have with TCPL. Union submitted that both TCPL and Consumers' Gas' witnesses had conceded that the volumes involved in east end deliveries are, for the purposes of design of the system, properly treated as being delivered to the east end of the system.

9.4.14 Union's position was that it has contracted for the delivery of in-franchise gas supplies to the east end and that it is neither fair nor reasonable to suggest that Union's customers should also be allocated the costs of the Dawn-Trafalgar System to transport an equivalent volume from Dawn to Parkway.

9.4.15 TCPL submitted that the commodity-kilometer allocation units used for apportioning Dawn-Trafalgar System costs between in-franchise and ex-franchise customers should track system design and operations. This would require that east end deliveries be viewed as a part of the peak design winter day and allocated to the benefit of both groups of customers.

9.4.16 In support of its position TCPL submitted that:

- Union's cost allocation methodology is not based on actual system design and operation since there are no physical deliveries to in-franchise customers from Parkway on the peak design winter day;
- Union's operating characteristics are not unique; many U.S. LDC's operate integrated systems which provide service to both intrastate and interstate shippers;
- Union's DCC, ODP and TCPL demand charge expenditures are gas supply functions and should not be treated as transmission capacity related; and
- the RJRA report does not support Union's east end delivery cost allocations in that it supports distance based tolling on the Dawn Trafalgar system, but does not apply this methodology to the in-franchise volumes on the peak design winter day.

9.4.17 In conclusion, TCPL submitted that the Board should not perpetuate the subsidy arising from misallocation of Dawn-Trafalgar System transmission costs which, by TCPL's calculation, results in Ontario ratepayers overpaying for transportation of gas by $14.1 million. The Board should order Union to allocate Dawn-Trafalgar System transmission costs based on measuring the flows from Dawn, their actual point of origin, on the peak winter design day.

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9.4.18 Consumers' Gas submitted that although a unit cost study had not been done, there were certain characteristics of the Dawn-Trafalgar System which supported a change to a postage stamp cost allocation:

- no other North American pipeline of a comparable length uses mileage based cost allocation and mileage based allocation is usual only for pipelines with a length of over 300-500 miles (480-800 kilometers);.
- bi-directional pipelines do not use mileage for cost allocation purposes; and
- pipelines with mileage based cost allocation "telescope" with distance in that the number of loop lines decreases as distance increases; so regulators apply mileage based cost allocation to ensure that the upstream capacity cost is also allocated to downstream customers who also benefit from the upstream capacity. The Dawn-Trafalgar System does not 'telescope' and is most heavily looped in the centre.

9.4.19 Consumers' Gas submitted that elimination of mileage from the cost allocation factor would put in-franchise and ex-franchise customers on the same basis and that Union had admitted that, in essence, in-franchise customers were currently all paying as if their deliveries were all made at a point near London which is equivalent to a postage stamp rate. Adopting Consumers' Gas' proposal would also eliminate the dispute over the allocation of the mileage credits associated with east end deliveries.

9.4.20 The cost rebalancing advocated by Consumers' Gas would shift $19.3 million in costs to Union's in-franchise customers. Although this is a very significant cost shift, Consumers' Gas submitted that Ontario customers would benefit in two ways. The in-franchise customers of Consumers' Gas and Centra would benefit from cost savings resulting from lower M12 rates. All in-franchise customers of Union, Centra and Consumers' Gas would benefit from the TCPL cost savings that would result. If the Board felt the rate impact of levelling the playing field was too large, the change could be phased in over two years.

9.4.21 Consumers' Gas supported TCPL's position that, absent adoption of a postage stamp cost allocation, east end delivery mileage credits should be allocated to all customers. It also argued that the DCC and ODP and TCPL demand charges were

gas supply related and as such should continue to be allocated entirely to in-franchise customers.

9.4.22 CAC and OCAP supported Union's current S&T cost allocation methodology, including the M12 cost allocation, and submitted that the Board should reject the alternatives proposed by Consumers' Gas and TCPL.

9.4.23 In IGUA's submission the existing transmission system and facilities paid for by in-franchise customers upstream of Parkway operate to produce the equivalent of a stand-alone west-east system with no upstream facilities at Parkway. It argued that since a primary purpose of the west-east transmission system is to carry M12 demands from Dawn to Parkway, it is fair and reasonable to allocate the costs in the manner Union proposes.

9.4.24 IGUA submitted that the costs of the transmission facilities upstream of Parkway, which are used to provide east end deliveries to M12 customers during peak periods, together with the costs of the Dawn-Trafalgar System which are allocated to in-franchise customers comprise, in total, a reasonable share of the total costs incurred to support the transmission capacity which Union uses to provide in-franchise customers with distribution services. Accordingly, Union's allocation of costs between in-franchise and ex-franchise customers based on a distance-weighted demand ought to continue to be approved.

9.4.25 Board Staff submitted that although Consumers' Gas experts' criteria for the application of postage stamp rates are in general appropriate, these criteria do not recognize the inescapable truth that the Dawn-Trafalgar System is primarily designed to store gas for winter consumption and deliver that gas on design day to various take off points on the pipeline system. Therefore on design day it operates to deliver gas in a single direction - from Dawn easterly.

9.4.26 Board Staff submitted that the other criteria for using postage stamp rates which had been suggested by Consumers' Gas' experts, were inappropriate for application to the Dawn-Trafalgar System, and that the existence of large storage pools at one end of the system may have a significant impact on how the system is configured.

Board Staff therefore did not support the use of postage stamp rates for the Dawn-Trafalgar System.

9.4.27 Board Staff also submitted that Union's calculation and allocation of the benefits of east end deliveries is appropriate and consistent with its mileage based cost allocation.

9.4.28 In Board Staff's submission, the counter arguments of TCPL's and Consumers' Gas' experts failed in three ways:

- the costs of the east end deliveries, including premiums are paid for by the in-franchise customers to obtain gas deliveries for their use;
- the ex-franchise customers deliver their gas at Dawn for transportation to points east on design day; and
- if there were no ex-franchise demands to be met, east end delivered gas would flow westward to serve the in-franchise customers of Union.

Board Findings

Storage and Transportation Cost Allocation Study

9.4.29 The Board finds that in general, the review of the Company's cost allocation study was useful and that the recommendations made by RJRA to improve the transparency of the methodology are helpful and worthy of expeditious implementation by Union.

9.4.30 In its subsequent Findings, the Board has noted several areas which require further review in light of the evidence in this case, but these should not be considered as a reason to delay the implementation of the RJRA's recommendations.

Mileage Based Cost Allocations

9.4.31 The Board is satisfied that Union's cost allocation study properly reflects the peak winter design day. The unchallenged evidence is that at design conditions the system operates as a unidirectional west-east transmission pipeline. The fact that

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the pipeline is multi-functional and operates as a bi-directional integrated pipeline at other times, does not change the fact that on design day, both in-franchise and ex-franchise gas is flowing easterly and that it requires considerable upstream capacity and additional compression to provide delivery service to the M12 customers at Parkway and other east end delivery points specified in their contracts.

9.4.32 The Board accordingly continues to find Union's methodology based on a commodity-kilometer allocation factor, appropriate for allocating the costs of the Dawn-Trafalgar System.

Treatment of East End Deliveries

9.4.33 The Board accepts Union's position that east end deliveries and WPS are an integral part of the peak day design of the Dawn-Trafalgar System and therefore are appropriately classified as transmission-related costs rather, than as TCPL and Consumers' Gas have suggested, commodity-related costs.

9.4.34 In the Board's view, the issue raised by TCPL and Consumers' Gas is not whether the M12 shippers are paying too much for the service they receive, but rather whether they should receive an additional benefit from the east end mileage credits because the existence of their volumes moving from Dawn allows the in-franchise customers to be served by swapping these volumes with the east end deliveries.

9.4.35 The Board believes that the evidence in this case indicates that as long as the Dawn-Trafalgar System is an integral part of the utility plant needed to serve its in-franchise customers, the current allocation of the east end mileage credits is appropriate. First, the east end volumes are owned by Union and its in-franchise customers who pay the TCPL delivery tolls. Second, Union pays the DCC and ODP on these volumes, as for all peak deliveries to ensure delivery, and also arranges its nominations to ensure peak day east end delivery of the volumes. The Board finds it persuasive from a cost/benefit matching point of view that the DCC, ODP and TCPL tolls are paid only by in-franchise customers.

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9.4.36 The Board finds that the streaming of the benefits of east end deliveries to in-franchise customers is reasonable, given that the in-franchise customers pay all the costs associated with the delivery of these volumes to the east end and then pay a mileage based charge for a deemed westerly delivery. In the Board's view it would not be just and reasonable for the in-franchise customers to pay any portion of the costs to move equivalent volumes from Dawn.

9.4.37 The Board finds that the fact that at design conditions, delivery of east end volumes (14,122 10^3m^3) to in-franchise customers requires a swap with volumes being transported from Dawn for M12 customers is insufficient reason for the M12 shippers to share in the east end mileage credits and hence pay lower net tolls for the delivery of their contract volumes to their contracted east end delivery points. The M12 customers receive what they pay for: delivery of their total design day contract demand from Dawn to Parkway, or other east end delivery points as specified in their contracts. The costs allocated by Union to the M12 rate class are, in the Board's view, appropriate.

9.4.38 The Board notes that both M12 shippers and Union's in-franchise customers benefit from east end deliveries by the fact that the design capacity of the system is smaller by 16,000 10^3m^3/day and the associated utility plant rate base is significantly reduced.

9.4.39 For the purposes of setting 1997 test year rates, the Board finds Union's current treatment of east end deliveries and the allocation of costs to the M12 rate class to be just and reasonable.

9.5 ALLOCATION OF DAWN COMPRESSOR STATION CARRYING COSTS

9.5.1 Union's evidence with regard to classification of Dawn Compressor Station carrying costs, was that the Dawn Compressor Station provides peak design day service for storage injection and withdrawals and for easterly transmission of ex-franchise deliveries received at Dawn. The Station has six compressors (A,C,D,E,F,G,) with a total installed power at ISO conditions of 114.16 MW and one backup unit (B) with a rating of 19.91 MW. For cost allocation purposes Union bases the functionalization of investment carrying costs to transmission on

the proportion of the total installed power that is required to raise the gas delivered at Dawn by TCPL and other cross-franchise shippers from the minimum receipt pressure of 700 psi to the pressure of 895 psi required for entry into the Dawn-Trafalgar System.

9.5.2 According to Union's methodology, which assumes that the total capacity is required for both storage and transmission services, 59.2% of the total test year carrying costs of $35.261 million is classified as transmission related and 40.8% as storage related.

9.5.3 TCPL's witnesses provided an alternative calculation which assumed that under peak design conditions, only part of the delivery capacity of compressors A and G (66,035 10^3m^3/day) was utilized to provide compression of cross franchise volumes (31,419 10^3m^3/day). The corresponding power requirement is 16.96 MW out of the total installed compression of 134.07 MW at the Dawn Station (including backup compressor B). This calculation results in a revised allocation of Dawn Compressor Station costs, 14.5 % to transmission and 85.5 % to storage. The result would be a cost shift of $7.035 million from ex-franchise transportation customers to storage customers.

9.5.4 Consumers' Gas provided evidence that its S&T contract with Union requires that volumes from the Tecumseh Gas storage pools also have to be delivered to the inlet of the Dawn Compressor Station at a minimum pressure of 700 psi and are then compressed to 895 psi for entry into the Dawn-Trafalgar System. Thus, the service provided to Consumers' Gas is identical to the service provided to cross-franchise transportation customers such as TCPL and Sithe Energies Inc. and accordingly, should be functionalized as transmission.

Positions of the Parties

9.5.5 Union argued that its allocation of Dawn Compressor Station investment carrying costs was appropriate since, if there were no storage facilities, Union would require compression facilities sufficient to raise the volume of all deliveries at Dawn to 895 psi. TCPL's proposal would also require a breakdown of the cost of each compressor unit and allocation to either transmission or storage whereas, in

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fact, all units are used interchangeably for both services. Union submitted that TCPL's calculations were based on a false premise and that Union's current methodology better reflects the realities and cost causality.

9.5.6 TCPL submitted that there is no rationale supporting Union's assumption that the power required for raising the pressure of storage gas from 700 psi to 895 psi is transmission related. In TCPL's view the allocation of Dawn Compressor Station carrying costs to transmission should be based on a factor of 14.5%. It also argued that Union's calculation of 59.2% is unsupported, is not based on cost causation and results in unjust and unreasonable M12 transportation rates. TCPL argued that the main purpose of the Dawn Compressor Station is to provide storage services; thus it is not part of the Dawn-Trafalgar System and therefore only a small percentage of the compressor power at Dawn is needed and used for transmission services during the Peak Design Day.

9.5.7 TCPL acknowledged that based on Consumers' Gas' evidence regarding the service provided to Tecumseh Gas Storage volumes, there is some basis for a treatment which is similar to that applied to volumes which arrive from the Great Lakes Pipeline, which require the same increase in pressure. If the Board concluded that those volumes are also transmission, instead of storage related, then TCPL calculated that the allocation factor for transmission would be 35.4%.

9.5.8 TCPL submitted that the Board should order Union to allocate 14.5% of Dawn Compressor Station carrying costs to transmission; alternatively, it argued that if the Board determines that Consumers' Gas' volumes are transmission related, 35.4% of the carrying costs should be allocated to transmission.

9.5.9 IGUA submitted that Union's methodology for allocating Dawn Compressor Station carrying costs better reflects realities and cost causality than TCPL's proposal. Any of the compressors can be used for transmission activity and are interchangeable, so that TCPL's analysis based on the assumption that only two compressors are used for transmission service is, as Union argued, a false premise.

9.5.10 Board Staff submitted that the allocation of Dawn Compressor Station investment carrying costs should be reviewed. The costs of the Dawn plant should reflect its

use. If, as TCPL suggests, the compression required to raise gas from 700 psi to 895 psi is lower than the 59% of total compression currently allocated, it should be changed. Staff submitted that transmission customers should be allocated the cost of raising their gas to the outlet pressure and storage customers should be allocated the cost to withdraw their gas from storage and raise it to the outlet pressure on the Dawn-Trafalgar System.

Board Findings

9.5.11 The Board finds merit in TCPL's evidence and argument that the investment carrying costs of providing transmission related service at the Dawn Compressor Station are less than the 59% of the carrying costs of the Station which are currently allocated to this service by Union.

9.5.12 However the Board has an insufficient evidentiary basis upon which to find a more appropriate allocation, since TCPL's evidence supporting its proposed change to the allocation of compression costs, in the Board's view, is an incomplete analysis based on a challenged assumption that only part use of two compressors is required to provide transmission related service. This is not a criticism of TCPL's experts, but rather reflects deficiencies in the information upon which they had to rely.

9.5.13 The Board directs Union to examine this area more closely and in the next rates case, define in clear terms the exact design day compression services for storage and transmission services including those for Tecumseh Gas Storage, which it provides at Dawn, and to propose the appropriate adjustment to allocation of the associated carrying costs to each.

9.5.14 It appears to the Board that transmission compression service is relatively easy to define and cost, so it may be appropriate that once this is done, the balance of the installed compression costs should simply be allocated to storage compression service. The Board expects Union to allocate back up compression capacity to each service on a reasonable basis, such as the loss of one unit if specific units are allocated to each service, or alternatively proportioned to the compression requirement of each service.

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9.5.15 For the purposes of setting 1997 test year rates the Board accepts Union's current allocation of Dawn Compressor Station investment carrying costs.

9.6 ALLOCATION FACTORS FOR DEMAND RELATED COSTS

9.6.1 Union's cost allocation is based on the aggregate contract demands of its M12 customers and the test year winter design day forecast peak demand of its in-franchise customers. The M12 customers are subject to overrun charges if their contract demand is exceeded whereas the in-franchise customers are not.

9.6.2 Consumers' Gas' witnesses disagreed with the different treatment of the design day peak demand for different customer classes and stated that a further concern is that Union is able to utilize the overruns of in-franchise customers to earn additional distribution margins. To correct this situation Consumers' Gas' witnesses proposed that a "ratchet provision" be applied to the in-franchise forecast peak demand. This would lock in the in-franchise demand based on a long-term forecast, in a similar manner to the way the M12 contract demand is derived. The provision should also apply to the forecast storage demand used for the allocation of storage costs.

Positions of the Parties

9.6.3 Consumers' Gas submitted that the different treatment of the two customer groups is unfair *per se*. Furthermore, it argued that the unfairness transcends the cost allocation process when overruns are taken into account. Consumers' Gas argued that its proposal for a "ratchet provision" applied to in-franchise design demand would introduce a much needed element of fairness, and at the same time would not impose overrun charges on in-franchise customers.

9.6.4 Board Staff, while subscribing to the case made by Consumers' Gas for equal treatment of in-franchise and ex-franchise customers, submitted that it is unclear from the evidence whether "there is a potential for a benefit to flow back to in-franchise customers because of the way Union is calculating the demand allocation factor. If Union is not properly reflecting its forecast of in-franchise demand and allowing its in-franchise customers to constantly overrun the system,

then the factor should be changed." In Board Staff's view additional information and quantification of any benefit would be required before a change is made. There may be significant risks that the in-franchise customer assumes as a captive customer of the system.

9.6.5 Union, in reply, submitted that Consumers' Gas' analysis fails to recognize that in-franchise demand beyond design levels is supplied by additional east end deliveries and does not use Dawn-Trafalgar System transmission capacity. Consumers' Gas' proposal is also designed to ensure that if in-franchise demand goes below design levels there will be no increase in costs allocated to ex-franchise customers. Union submitted that this latter problem has not occurred and, no doubt should it do so, there would be further proceedings to determine the appropriate cost allocation and rate design responses.

Board Finding

9.6.6 The Board finds that there is an insufficient evidentiary basis to change the current allocation factors and, for the purposes of setting 1997 test year rates, accepts Union's current approach.

9.7 ALLOCATION OF STORAGE REVENUES

9.7.1 Union's storage operations include 16 gas storage pools with a 1997 working capacity of 3.536 10^6m^3. Of this available space 2.198 10^6m^3 is used to meet in-franchise requirement and 1.338 10^6m^3 is contracted to ex-franchise customers.

9.7.2 Union also provides other services including both peak and off-peak storage services (gas loans, exchanges and parking) under the C1 rate.

9.7.3 For the 1997 test year Union's forecast of C1 Storage volumes and revenues was:

Peak Storage	560,894 10^3m^3; $3.974 million
Off-Peak Storage	1,071,468 10^3m^3; $1.898 million

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Union allocates the forecast $5.872 million revenues from these services to the in-franchise customers.

9.7.4 Unforecast revenues from peak storage sales and exchanges are collected in the C1 Storage Revenue Deferral Account No. 179-39 for future disposition by the Board. This account captures revenue from the following services: C1 Peak Storage; C1 Firm short-term deliverability; and M12 Interruptible Storage Deliverability. There is no deferral account for unforecast off-peak storage.

9.7.5 Consumers' Gas disputed the allocation of C1 peak storage revenues to in-franchise customers only, on the basis that the total available storage space rather than just the in-franchise space makes such sales possible.

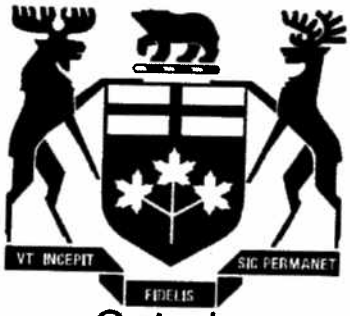
9.7.6 Union's evidence was that because M12 customers had contracted for a certain level of storage space, Union could not then sell off that space to the C1 peak storage market. With respect to off-peak storage, Union stated that M12 customers use their entire storage space and Union cannot therefore use that space to sell as off-peak storage.

9.7.7 Consumers' Gas' experts stated that in their opinion, unforecast C1 peak and off-peak storage revenues should be allocated to both in-franchise and ex-franchise storage customers since the latter pay for storage on the same basis as the in-franchise customers, and it is the total storage capacity which is used to generate the revenues. They pointed out that unforecast C1 transportation revenues are allocated to all customers. They also stated that apart from times when M12 storage space was full, it could be sold to the off-peak storage market.

Positions Of the Parties

9.7.8 All parties to the ADR Settlement Agreement, except Consumers' Gas, reached consensus that the disposition of the balance in the C1 Storage Revenue Deferral Account No. 179-39 should be based on a 90/10 split between in-franchise customers and the shareholder in both 1996 and 1997.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **11**

DATE: **July 27, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

You are not suggesting any sort of adjustment for that, are you?

MR. ROSENKRANZ: I am not suggesting any sort of allocation of costs or margins from a pool of transactions.

I think that in order to protect ratepayers, the assets themselves should be identified and it should be noted at the time the transaction is made whether that is being made from the utility space or non-utility space.

MR. SMITH: Okay, that is helpful. Thank you. Can I ask you -- I had given to your counsel, and I think you have a copy, a compendium, and I believe Board Staff should have a copy. If I could just have that marked as an exhibit?

MR. MILLAR: Mr. Smith, can you show me which...

MR. SMITH: It says "Union Gas Limited Cross-Examination Compendium for Mr. John Rosenkranz".

MR. MILLAR: Yes, we have it. Thank you. K11.3.

EXHIBIT NO. K11.3: UNION GAS LIMITED CROSS-EXAMINATION COMPENDIUM FOR MR. JOHN ROSENKRANZ.

MS. HARE: Mr. Millar, I don't think we have that.

MR. MILLAR: Yes. I will bring it up.

[Mr. Millar distributes compendium to Board Panel]

MR. SMITH: Mr. Rosenkranz, just a couple of -- one preliminary matter. Can I ask you to turn in the compendium to page 21? Yes, page 21.

So you will see here the cover page for Union's RP-2003-0063 case, which was Union's 2004 cost of service proceeding. Do you have that?

MR. ROSENKRANZ: Yes, I do. Thank you.

MR. SMITH: If you turn over the page to page 22, this is an excerpt of the decision. I just wanted to put the point of principle to you.

You will see at page 176 in the third paragraph the Board indicates:

> "The revenue requirement established by the Board in rates cases such as the present case represents the system's overall financial burden. In order for rates to be just and reasonable, which is the statutory requirement, each rate class should bear a proportion of that burden roughly coincident with the cost incurred by the system operator, in this case Union Gas, in providing the necessary infrastructure and services to arrange for, store and transport the commodity to that rate class's members."

Do you see that?

MR. ROSENKRANZ: Yes, I see it.

MR. SMITH: I take it you agree with that?

MR. ROSENKRANZ: I certainly agree that cost allocation should be done in conformance with basic cost causation principles, and that is what this appears to say.

MR. SMITH: And if I can ask you to turn to your report, sir, at page 1, dealing with Parkway station costs. Have you got that?

MR. ROSENKRANZ: Yes, I do.

MR. SMITH: You say at the beginning of line 15 that:

"In Union's cost allocation study, the costs of transporting gas on the Dawn-Parkway transmission system are divided into two categories: (1) the cost of the compressors needed to move gas from the Dawn Hub into the Dawn-Parkway system."

And those are Dawn station costs; correct?

MR. ROSENKRANZ: Correct.

MR. SMITH: And then all remaining costs, which are Dawn Trafalgar Easterly costs; correct?

MR. ROSENKRANZ: Correct.

MR. SMITH: Those are allocated using the DT trans allocator?

MR. ROSENKRANZ: Correct, which is the commodity distance-based.

MR. SMITH: Right. It is the distance weighted commodity allocator; correct?

MR. ROSENKRANZ: Thank you. You said it better than I did.

MR. SMITH: Now, you go on to say:

"Dawn-Trafalgar Easterly costs include Union's transmission pipelines, the compressors at Lobo, Bright, and Parkway, and the metering facilities at Kirkwall and Parkway."

Do you see that?

MR. ROSENKRANZ: Yes.

MR. SMITH: You then go on to say:

"Parkway Station costs are allocated to rate classes based on design day demand..."

And I think that is a mistake. I think you mean Dawn station costs are allocated to rate classes based on design day demand:

> "... while Dawn-Trafalgar Easterly costs are allocated using a distance-based 'commodity-kilometres' methodology."

MR. ROSENKRANZ: You are absolutely correct. That should say Dawn station costs, not Parkway station costs.

MR. SMITH: Okay. Now, if I can ask you to turn back to the compendium, I have, beginning at page 1, an excerpt from the EBRO-493/494 decision.

Do you see that? That was a very long decision; that is why it is an excerpt.

Have you got the decision, sir?

MR. ROSENKRANZ: Yes, I have it in front of me.

MR. SMITH: And this -- there are a few things that are interesting about this case, but this was, I believe, the first application by Centra and Union, as they had recently become a combined entity at that time.

But if I can ask you to turn to page 2 -- or page 3, my apologies.

MR. ROSENKRANZ: Yes, I have it.

MR. SMITH: You see "Union M12 cost allocation"? Have you got that?

MR. ROSENKRANZ: Yes.

MR. SMITH: And then if we look over a number of pages, you will see over on page -- I believe it should be page 16 -- page 14, I'm sorry, under the heading

"Allocation of Dawn compressor station carrying costs" -- do you see that?

MR. ROSENKRANZ: You're at the bottom of page 14?

MR. SMITH: Page 14, heading 9.5, "Allocation of Dawn compressor station carrying costs."

MR. ROSENKRANZ: Yes, I see it now.

MR. SMITH: Okay. Were you aware of this decision when you provided your report?

MR. ROSENKRANZ: No, I have not reviewed this decision.

MR. SMITH: Okay. And I take it that means both before you filed your evidence and subsequently, you haven't reviewed this decision?

MR. ROSENKRANZ: Until first thing this morning when I got an e-mail with your compendium. That's the first time I had a chance to look at this decision.

MR. SMITH: Okay. Well, I provided the compendium to your counsel last night, but we will go slowly through it, then.

Looking back at page 3, beginning at section 9.3, the Board begins a review of the M12 cost allocation methodology.

And it is fairly apparent when you look through the portion of this -- this portion of the decision, going all the way from page -- paragraph that we started at, 9.3.1, all the way through to section 9.5, that there was considerable controversy about the cost allocation method that Union was proposing in relation to the M12 rate class.

Can we agree on that?

MR. ROSENKRANZ: I understood from reading this that there certainly were -- there was a controversy. That makes sense.

MR. SMITH: And M12 shippers at that time, most notably Enbridge and TCPL, were taking the position that they were bearing a disproportionate share of Dawn-Parkway costs; fair?

MR. ROSENKRANZ: I suspect that is what they were arguing. Again, I haven't spent much time with this.

MR. SMITH: Well, if we go over to 9.4.13, "Position of the parties," it starts with Union, and then halfway through that paragraph, you will see that there were both TCPL and Consumers Gas witnesses who testified.

And then there were rather large adjustments that were sought by both TCPL and Consumers. Indeed, at paragraph 9.4.20 -- which I think is at page 8 of the compendium -- sorry, page 10. I numbered mine myself. I made a big mistake.

You will see that Consumers at that point was looking to shift $19.3 million to Union's in-franchise customers.

Do you see that?

MR. ROSENKRANZ: Yes. And my understanding from reading this is that that was based on a position that the mileage-based rates should be replaced with a postage-based rate.

MR. SMITH: That's right. They didn't like the distance-weighted demand allocation.

MR. ROSENKRANZ: That appears to be the basic issue.

MR. SMITH: Right.

MR. ROSENKRANZ: Okay.

MR. SMITH: And if you can continue over with 9.5, there was also some controversy in relation to the methodology used to allocate Dawn compressor station carrying costs, and the Board made certain findings in relation to that. And you will see those all the way over at page 19, paragraph 9.6.6, where the Board ultimately accepts Union's approach. Do you see that, sir?

MR. ROSENKRANZ: I will say that what you sent out last night was truncated. That last section wasn't included in that package, but when I read it just now, it appears that the issue was only with respect to the allocation of Dawn compressor costs between storage and transmission, and that it appears that the Board directed that there be more study of that, yes.

That was my read of it.

MR. SMITH: No, no. That is absolutely fair. Just a couple of additional questions in relation to this.

Are you aware, sir, that the allocation of Dawn-Trafalgar easterly costs and the Dawn-Parkway system has remained the same since this decision by the Board in 1997? Were you aware of that?

MR. ROSENKRANZ: I can't confirm that, because I did not go back and research in terms of exactly what the allocation -- I would accept that that is probably the case, that this has been a longstanding cost allocation

methodology that's been used for the Dawn-Trafalgar facility costs.

MR. SMITH: Just so that we can put some numbers on it, can we agree that of the Dawn-Trafalgar easterly costs, in-franchise ratepayers pay approximately 16 percent of those costs?

MR. ROSENKRANZ: Based on the initial application Union has made, yes, that's what I calculated, as well.

MR. SMITH: And the balance, the 84 percent of Dawn-Trafalgar easterly costs are paid for by ex-franchise ratepayers?

MR. ROSENKRANZ: I would be a little careful there. The remaining is paid by M12 shippers, and the M12 shippers does include in-franchise customers that use M12 service in order to satisfy their Parkway delivery obligation.

It is also used by power generators under the billing contract demand option, to move their receipt point to Dawn.

So you cannot -- you can't make the -- you can't make the conclusion that all costs that go to M12 shippers are going to ex-franchise customers. There are some in-franchise customers, as well.

MR. SMITH: Right, and we will come to that in a minute.

Now, if we look back at the 493/494 decision, a couple of propositions from that decision I would like to put to you.

If you turn to paragraph 9.4.10, which should be at

the bottom of page 7?

MR. ROSENKRANZ: Yes, I have that. Thank you.

MR. SMITH: What is indicated in the decision is Union noted that east end deliveries -- and that is the Parkway obligation, correct? It is the obligation to deliver gas at Parkway?

MR. ROSENKRANZ: That was my interpretation, yes.

MR. SMITH:

> "Union noted that the east end deliveries are a fundamental part of the peak design of the Dawn-Trafalgar system, which allows the design capacity of the system to be smaller than otherwise required if all volumes had to move from Dawn under peak design day conditions. This reduction in capacity and facilities benefits all users of the Dawn-Trafalgar system, including ex-franchise shippers (Rate M12) and in-franchise customers in the form of lower rates."

And I take it you agree with that, as well?

MR. ROSENKRANZ: I agree that the Parkway delivery obligation does reduce the need to build facilities from west to east on the Dawn-Trafalgar system, yes.

MR. SMITH: And if we continue in the decision, sir, if you go over to the Board's findings on page 12 under heading paragraph 9.4.13, do you see that at the very bottom?

MR. ROSENKRANZ: Okay, yes.

MS. TAYLOR: Sorry, just for the record --

MR. SMITH: Sorry, 9.4.31, yes.

MR. ROSENKRANZ: Three-one.

MR. SMITH: Yes, my mistake. Do you have that?

> "The Board is satisfied that Union's cost allocation study properly reflects the peak winter design day. The unchallenged evidence is that at design conditions, the system operates as an unidirectional west-east transmission pipeline."

Pausing there, I take it you agree that at design condition, the system operates as a unidirectional west-east transmission pipeline?

MR. ROSENKRANZ: That is my understanding of the system design; correct.

MR. SMITH: Continuing:

> "The fact that the pipeline is multi-functional and operates as a bidirectional integrated pipeline at other times does not change the fact that on design day, both in-franchise and ex-franchise gas is flowing easterly and that it requires considerable upstream capacity and additional compression to provide delivery service to the M12 customers at Parkway and other..."

Pausing there, and as you recognized, sir, M12 customers can include capacity for in-franchise customers:

> "...and other east end delivery points specified in their contracts."

Do you see that?

MR. ROSENKRANZ: Yes, I see it. I am just --

MR. SMITH: Take a moment to read it.

MR. ROSENKRANZ: Thank you.

MR. ROSENKRANZ: Okay, I think I've got it.

MR. SMITH: I take it you agree with this passage by the Board?

MR. ROSENKRANZ: Yes, I think it makes sense.

MR. SMITH: We touched on this before, sir, but you are aware, obviously, that Union holds TCPL capacity from Parkway to various easterly and northerly and westerly delivery points to meet peak demand from Parkway?

MR. ROSENKRANZ: I believe that -- I believe that there is some Parkway TCPL capacity to easterly points, yes. I am not sure how much. I didn't go into that.

MS. TAYLOR: Mr. Smith, just before we continue, I would like to go back to the second-last question that you asked Mr. Rosenkranz about the paragraph at 9.4.31.

MR. SMITH: Yes.

MS. TAYLOR: So is he confirming to you that the system continues to operate on a peak day in a west to east flow today versus at the time of this decision, being 1997?

MR. SMITH: Yes. And I took from his answer - and maybe if you disagree, Mr. Rosenkranz, you can tell me - that both in-franchise and ex-franchise gas is flowing easterly and that it requires considerable upstream capacity and additional compression to provide delivery service to the M12 customers at Parkway and other east end

delivery points in their contracts.

Do you agree with that?

MR. ROSENKRANZ: I agree that the design is based on west to east and continues to be today. I agree that there is -- the Dawn-Trafalgar system, the pipeline itself, is required to get gas to Parkway for customers that have downstream -- have rights to deliver gas either to Enbridge or to TCPL at Parkway.

MR. SMITH: Thank you. Mr. MacIntosh asked you a few questions. I just want to pick up on something that he asked you about the costs that would go to Enbridge.

And you will recall, of the 1.6 million that you had estimated, that half of that, roughly, would go to Enbridge customers, assuming those costs are passed on?

MR. ROSENKRANZ: Assuming the costs are passed on. Assuming they're not doing other things with the capacity to mitigate those costs, but, yes, assuming that -- that would be Enbridge Gas Distribution as an entity. That would be the additional cost of their M12 service, in rough terms.

MR. SMITH: And -- well, it's not an issue in this proceeding, as we've talked about. On Parkway, Parkway West, you identified a number. I can't recall, but it was in the neighbourhood of $3 or $3.3 million; is that correct?

MR. ROSENKRANZ: When you add what Union had indicated to be the -- I'm not even sure it was a full first year cost of service of Parkway West. I added that to the --

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Ex. B1/T5/p.8, lines 19-20:

"The operation of Union's Dawn-Parkway system continues to rely on firm deliveries to Union at Parkway."

a) Please explain fully how the operation of Union's Dawn-Parkway system relies on firm deliveries to Union at Parkway.

b) Please provide the volume of deliveries to Parkway that Union will require, by rate class, in each of 2012 and 2013.

c) Please quantify, by volume, the extent to which Union relies on Parkway deliveries to service in-franchise customers, and the extent to which Union relies on Parkway deliveries to serve ex-franchise customers.

d) What is the value to Union's customers, in each of 2012 and 2013, of the cost savings associated with Parkway obligated firm deliveries? Please disaggregate this value as between in-franchise and ex-franchise customers.

e) Please provide the volume of deliveries to Parkway that Union will require, by rate class, from or on behalf of customers located;

   i. West of Parkway but east of Dawn.

   ii. West of Dawn.

f) What is the current cost of transporting gas from Dawn to Parkway?

g) What is the current cost differential for buying gas delivered at Parkway versus buying gas delivered at Dawn?

Response:

a) Union relies on obligated Parkway deliveries (firm deliveries) in designing the Dawn-Parkway transmission system. These volumes, which are required to land at Parkway, plus the physical capacity of the Dawn-Parkway facilities, equal the total capacity of the Dawn-Parkway system. As a result of these deliveries the Dawn-Parkway transmission system is

smaller than would otherwise be necessary to meet design day demand requirements. This translates into lower rates for all in-franchise customers in Union's system.

Winter 2013/2014 obligated (firm) deliveries at Parkway are 639,088 GJ/day. Removing the Parkway delivery obligation would result in increased transport requirements on the Dawn-Parkway system. A Dawn-Parkway transport increase of this size would require significant facilities expansion which would result in increased Dawn-Parkway costs to all customers.

b) Please see Attachment 1 for the volume of deliveries to Parkway for 2012 and 2013.

Union does not track deliveries by rate class for South Sales Service. Union's bundled direct purchase contracts are not rate class specific. These contracts have a mix of general service and contract rate accounts attached to each contract. As a result, Parkway deliveries by rate class are not available. However, Union can provide a breakout of bundled direct purchase contract deliveries between those that are 100% general service and those that have a contract rate account attached.

c) The volume of Parkway Obligated Deliveries for Winter 2012/13 and 2013/14 are shown below. Union relies upon these volumes to serve in-franchise customers on design day.
Winter Parkway Obligated Deliveries (GJ/d)

Winter	Parkway Obligated Deliveries (GJ/d)
2012 / 2013	654,370
2013 / 2014	639,088

The Parkway Obligated Deliveries are made by in-franchise direct purchase customers and by Union on behalf of sales service customers to reduce transport requirements on the Dawn-Parkway system. Due to the net flow of gas from Dawn to Parkway, physical Obligated Delivery molecules are consumed downstream of Parkway by a combination of in-franchise and ex-franchise customers.

d) Removal of obligated deliveries at Parkway (639,088 GJ/day) would require the replacement volumes to be sourced from Dawn and shipped on the Dawn-Parkway system. The estimated capital cost of the expansion required to meet incremental Dawn send-out and Dawn-Parkway transport is between $250 million and $500 million. The removal of east end deliveries at Parkway will increase the volume of gas compressed at Parkway, and may impact the capacity of TCPL's system.

The facilities required vary depending on the amount of available capacity and future growth of the Dawn-Parkway demands. If sufficient Dawn-Parkway capacity were available to permanently eliminate the Parkway obligation there would be no change in rate base. In-

franchise rates would, however, increase to reflect the increased use of the Dawn-Parkway system by in-franchise customers.

The approximate revenue requirement associated with expanding the Dawn-Parkway system is $30 million ($22 million to in-franchise rate classes) to $60 million ($33 million to in-franchise rate classes).

e) i. – ii. Please see the response to b) above.
Union does not track Parkway deliveries by customer location for South Sales Service, South Bundled –T, General Service and Unbundled services.

f) The cost to transport gas on the Union system from Dawn to Parkway is the M12 toll which can be found on Union's website at the following link:

http://www.uniongas.com/storagetransportation/services/currentm12ratesfuel.asp

The current 100% Load Factor rate is $.076 CDN/GJ/day plus the applicable fuel.

g) The cost differential between buying gas at Parkway vs. buying gas at Dawn changes constantly due to changing market conditions. Since the beginning of 2011 the average monthly differential has been as high as $0.14 US/mmbtu (Feb 2011). The current differential (monthly average up to April 10, 2012) is $0.06 US/mmbtu. All numbers are based on the daily Dawn-Parkway Physical Trading Spread as reported by NGX.

Schedule 1

Parkway Deliveries by Service Type/Rate Class

Line No.	Volumes in: GJ's	Annualized 2012 (a)	Annualized 2013 (b)	2012 East of Dawn (c)	2012 West of Dawn (d)	2013 East of Dawn (e)	2013 West of Dawn (f)
1	Total South Sales Service	32,954,215	33,042,355				
2	Total South Bundled T - General Service	27,834,900	26,911,085				
3	Total South Bundled T - Contract	35,301,517	34,230,771	20,642,387	14,659,130	19,757,061	14,473,710
4	Total T-1	78,449,085	79,179,450	27,707,880	50,741,205	28,326,920	50,852,530
5	Total T-3	11,708,835	11,708,835	11,708,835	-	11,708,835	-
6	Unbundled	5,589,245	5,592,530				
7	Total Parkway Deliveries	191,837,796	190,665,026	60,059,102	65,400,335	59,792,816	65,326,240

EB-2005-0551

UNION GAS LIMITED

SETTLEMENT AGREEMENT

June 13, 2006

1 RATES FOR GAS-FIRED GENERATORS (AND OTHER QUALIFIED CUSTOMERS)

Should the Board order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers)? If the Board does order new rates, should that order contain the following requirements:

1.1 MORE FREQUENT NOMINATION WINDOWS FOR DISTRIBUTION, STORAGE AND TRANSPORTATION THAT CORRESPOND WITH THE NOMINATIONS OF UPSTREAM PIPELINES THAT CONNECT TO THE ONTARIO GAS SYSTEM.

(Partial Settlement with the exception of Union's proposal that F24-S, UPBS and DPBS be priced at market based rates. The parties agree that the issue of market based storage pricing is within the ambit of Issue No. 2 (storage regulation) and accordingly beyond the scope of this settlement. TCPL and Energy Probe oppose Union offering new F24-T service first to 2007 transportation expansion shippers.)

The parties accept Union's proposal to develop four (4) new ex-franchise services (recognizing that it is Union's position that development of F24-S, UPBS and DPBS is contingent on the resolution of the storage pricing issue): F24T, F24S, UPBS and DPBS as described in its evidence subject to the following modifications:

- Three additional nomination windows will be provided. The additional nomination windows have nomination deadlines of 12:00, 18:00, and 07:00 with effective times of 14:00, 20:00, and 09:00 respectively. The complete nomination schedule has been attached as Appendix A. The additional nomination windows will provide more flexibility to customers such as power generators and can be provided without the implementation of hourly balancing agreements with upstream and downstream pipelines. The additional nomination windows apply to the receipt of gas from Enbridge, TCPL and Vector and to the delivery of gas to TCPL at Kirkwall and Parkway, all subject to their ability to confirm nominations.
- Union agrees to make the additional nomination windows available to U7 storage, U7 delivery services, and U7 receipts for new customers with loads greater than 1,200,000 m*3 per day.
- Union agrees to make the additional nomination windows available to T1 receipts for new customers with non obigated deliveries and loads greater than 1,200,000 m*3 per day.
- The U7 and T1 rate schedules will be modified to incorporate charges associated with making additional nomination windows available to those customers who elect to take the service. These charges will be cost-based, and will take into account the common IT capital costs and the costs associated with additional staffing associated with making additional nomination windows available for F24-T. The changes to the U7 and T1 rate schedules will be similar to the changes made to the M12 rate schedule to incorporate F24-T.

- Union agrees that it will evaluate the possibility of extending the additional nomination windows and reservation of capacity found in F24-T to the following transportation services:

  i) C1 between Ojibway and Dawn
  ii) C1 between Bluewater and Dawn
  iii) C1 between St. Clair and Dawn
  iv) C1 between Parkway and Kirkwall
  v) C1 transport within the Dawn yard (e.g. between Union Dawn and Vector Dawn)

  Union agrees to provide APPrO and other settlement conference participants with a summary of its findings no later than December 31, 2006.

- Customers may request that nomination changes become effective sooner and Union will use reasonable efforts to accommodate these requests, it being recognized that at the present time and for the foreseeable future Union does not expect to be able to make nomination changes effective sooner than two hours after the nomination.
- Union will also make reasonable efforts to allow large customers (with loads greater than 1,200,000 m3 per day) to take gas prior to a scheduled nomination. The customer will make a request for such service directly to Union's Gas Control Department, and Union will permit such early start-up provided it has no adverse impact on Union's system. Depending on the customer's location, the customer may need approval of Enbridge and TCPL's Gas Control Departments as well.
- The proposed UPBS will allow customers to deliver supply at even hourly flow rates to consume at accelerated flow rates over 4 to16 hours. The parties recognize that higher consumption flow rates will require higher levels of storage deliverability.

- Power generators that subscribe for U7 or T1 services and ex-franchise power generators that subscribe for F24-T, F24-S, UPBS, and DPBS services will provide the utility with a day ahead non-binding hourly gas consumption forecast and will use reasonable efforts to communicate changes from that forecast to assist Union in managing its system.
- Union, Enbridge and APPrO agree to convene an Industry Task Force and will invite all service providers interconnecting with Union and other parties that have expressed an interest. The purpose of the Industry Task Force is to investigate and develop, where feasible, appropriate arrangements for services that would enable Union to accept nomination changes each hour throughout the day (on a firm/reserved capacity basis) with changes becoming effective two hours later. The Industry Task Force will hold its first two meetings no later than September 30, 2006. Union, Enbridge and APPrO agree to work co-operatively and diligently to investigate and develop, where feasible, appropriate arrangements.
- Parties agree that once sufficient operating experience has been gained and in any event no later than March 31, 2009, interested customer groups and Union will convene to evaluate and discuss the experience and success of the services offered as a result of this proceeding. At that time, any party may propose further modifications to the rate schedules.

The parties accept Union's evidence that:

- To maximize the effectiveness of Union offering additional nomination windows, other pipeline operators, storage operators, marketers and producers will need to be able to manage and offer the same nomination windows and be able to confirm nominations on the same two hour schedule.

- F24-T will only be developed if there is 250,000 GJ/day or greater of customer demand (the level of demand used to determine the cost based F24-T rate). The parties are of the view that 250,000 GJ/day of demand is a realistic threshold. Union will offer the new F24-T service first to 2007 transportation expansion customers. Union will then hold an open season to determine if any other customers are interested in the service.
- The availability of F24-S, UPBS and DPBS is dependent upon Union's ability to develop assets to provide incremental storage deliverability.
- There will only be 500,000 GJ/day of F24-T available initially as a result of the 2006 and 2007 expansions of the Dawn-Trafalgar system. This capacity will not be available until the 2007 expansion of the Dawn-Trafalgar system is in service on November 1, 2007. Additional F24-T may become available as a result of future expansion of the Dawn-Trafalgar system and will be made available through an open season process.
- Union requires 12 months to develop the new IT systems required to implement F24-T, F24-S, UPBS and DPBS following a Board Decision and sufficient customer interest to develop the services. Upon the Board accepting this Settlement Agreement, Union will proceed immediately to contact 2007 expansion customers to ascertain their interest in subscribing to the F24-T service and if remaining capacity is available then hold an open season to determine if other existing M12 shippers are interested in the residual capacity. Union expects the open season process to be completed by 30 days after a Board Decision. Union will require approximately 24 months to build additional storage deliverability to provide new incremental high deliverability F24-S, UPBS and DPBS (recognizing that it is Union's position that development of F24-S, UPBS and DPBS are contingent on the resolution of the storage pricing issue).

- IT capital costs and the costs associated with additional staffing required to implement F24-T, F24-S, UPBS and DPBS will be recovered from the customers who elect the new services.

The settlement of this issue has no identifiable adverse impacts on existing customers.

The following parties agree with the settlement of this issue: APPrO, CCC, CME, IGUA, LMPA, LIEN, SEC, CCK, VECC, WPSPG, Sithe, TransCanada Energy, Portlands

The following parties take no position on this issue: Aegent

Evidence References:

1. Union Evidence - A/T4, D/T1 p.6-11 & p.15-18
2. Union Undertakings - UGL 12, UGL 28, UGL 23A, UGL 23B
3. Intervenor Evidence - APPrO May 1/06, TCPL Issue I (Section 2.2) & Appendix IB May 1/06, IGUA-AMPCO May 1/06
4. Intervenor Undertakings - APPrO 1, APPrO 2, APPrO 3, APPrO 7, TCPL 1, TCPL 2&3

1.2 FIRM HIGH DELIVERABILITY SERVICE FROM STORAGE WITH CUSTOMER OPTIONS FOR 1.2%, 5% AND 10% DELIVERABILITY.

(Complete Settlement with the exception of Union's proposal to price firm deliverability greater than 1.2% at market based rates. The parties agree that the issue of market based storage pricing is within the ambit of Issue No. 2 (storage regulation) and accordingly beyond the scope of this settlement.)

The parties agree that new T1 and U7 customers with non-obligated supply shall be entitled to contract for T1 and U7 storage service with firm storage deliverability up to 24 times the customer's peak hourly consumption and storage space up to 24 times the customer's peak

UNION GAS LIMITED
Calculation of Firm All Day (F24-T) Transportation Service Charges
Effective January 1, 2013

Line No.	Particulars	($ 000's)
	Cost of Service	
1	Operating & Maintenance Costs (1)	647
2	Depreciation Expense	-
3	Return, Income and Capital Taxes	-
4	Total Cost of Service	647
5	Demand (GJ/day)	356,500
6	Demand Rate ($/GJ) ((line 4 * 1000) / (line 5 *12))	0.151
7	Demand Rate Commoditized ($/GJ) (line 6 *12 /365)	0.005
8	Demand Rate ($/$10^3m^3$) (line 6 * 37.75)	5.709

Notes:
(1) Assumes 6 staff at an average annual salary and benefits of $124,487 each, $300,000 personnel overtime STO and $100,000 additional compressor maintenance, less the F24-T O&M reductions of $500,000 as per Settlement Agreement, Appendix B, Schedule 2, note 2.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **8**

DATE: **July 24, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

plant additions for, you know, a replacement maintenance project between utility and non-utility being updated to reflect non-utility plant additions for expansion projects similar to the plant J replacement of plant A?

MS. VIENNEAU: The storage allocations that we used in the 2013 rate case were not updated to reflect the expansion.

Any expansion that was 100 percent unregulated has gone to the unregulated operation.

There have been a couple of pools that have had 100 percent unregulation, or had had a project that has had 100 percent unregulated work completed at it in the intervening years.

That allocation wasn't updated for the 2013 rate case, but when we looked at that now and have gone back and reviewed, there has been an immaterial impact to what would have been allocated regulated versus unregulated.

MR. QUINN: Okay. Could you define "immaterial"?

MS. VIENNEAU: In 2012 the impact is approximately $50,000, and in 2013 the impact is approximately $25,000.

MR. QUINN: And is that on the basis of space and deliverability?

MS. VIENNEAU: It is on the basis similar to what is outlined in JT1.41, where we've done the original allocation based on the approved methodology by the Board, layering in the incremental cost of the additional storage capacity, which provides you with a new blended rate for the facility.

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

Pool Name	Section 1 2013 Filed Unreg	Reg	Total	Section 2 Plant Accounting Update 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.

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")
Supplemental Questions

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.

Appendix A

Summary of In-Franchise Rate Proposals

Rate Design Proposals	Current Approved	Proposed
Contract Service **Effective January 1, 2013**		
1. Rate 77	N/A	Eliminate Rate Schedule effective January 1, 2013
2. Rate 20 and Rate 100 Unbundled Services	N/A	Eliminate Contract Unbundled Service offerings effective January 1, 2013
3. Rate U5, Rate U7 and Rate U9	N/A	Eliminate Contract Rate Schedules effective January 1, 2013
Contract Service - Semi-Unbundled **Rate T1 Redesign** **Effective January 1, 2013**		
4. Proposed Rate T1	• Qualifying Annual Volume of 5,000,000 m^3 • Two Firm Contract Demand blocks: First 140,870 m^3/day All Over 140,870 m^3/day • Two Firm Commodity blocks: First 2,360,653 m^3 All Over 2,360,653 m^3	• Qualifying Annual Volume of 2,500,000 m^3; • Firm daily Contract Demand up to 140,870 m^3/day • Two Firm Contract Demand blocks: First 28,150 m^3/day, Next 112,720 m^3/day • Single block Firm Commodity rate
5. Proposed Rate T2	• Qualifying Annual Volume of 5,000,000 m^3 • Two Firm Contract Demand blocks: First 140,870 m^3/day All Over 140,870 m^3/day • Two Firm Commodity blocks: First 2,360,653 m^3 All Over 2,360,653 m^3	• Firm daily Contract Demand greater than 140,870 m^3/day • Two Firm Contract Demand blocks: First 140,870 m^3/day, All Over 140,870 m^3/day • Single block Firm Commodity rate
General Service **Effective January 1, 2014**		
1. (a) Annual volume breakpoint between Small & Large Volume rate classes	Annual Volume Breakpoint of 50,000 m^3	Annual Volume Breakpoint of 5,000 m^3
(b) Harmonize the Rate 01 delivery commodity blocking structure with the current approved blocking structure for Rate M1	First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	First 100 m^3 Next 150 m^3 All Over 250 m^3
(c) Harmonize the Rate 10 delivery commodity blocking structure with the current approved blocking structure for Rate M2	First 1,000 m^3 Next 9,000 m^3 Next 20,000 m^3 Next 70,000 m^3 All Over 100,000 m^3	First 1,000 m^3 Next 6,000 m^3 Next 13,000 m^3 All Over 20,000 m^3
Contract Service - Bundled **Effective January 1, 2014**		
2. Lower Union South Bundled Mid-Market Contract rate class eligibility for Rates M4 & M5A	• Contract Demand of 4,800 to 140,870 m^3/day • Minimum Annual Volume of 700,000 m^3 • Rate M4 load factor of at least 40%	• Contract Demand of 2,400 to 60,000 m^3/day • Minimum Annual Volume of 350,000 m^3 • Rate M4 load factor of at least 40%
3. Introduction of a Rate M4 Interruptible Service Offering	Firm Contract Service only	Firm Contract Service with Interruptible Option
4. Lower Union South Bundled Large Volume Contract rate class eligibility for Rate M7	• Combined Firm, Interruptible, and Seasonal Contract Demand of at least 140,870 m^3/day • Annual volume of at least 28,327,840 m^3	• Contract Demand of at least 60,000 m^3/day

PREFILED EVIDENCE OF

GREG TETREAULT, MANAGER, RATES AND PRICING

HAROLD PANKRAC, TEAM LEADER, RATES AND PRICING

This evidence will address the following rate related matters:

1/ Revenue Deficiency Restatement

2/ Recovery of the 2013 Revenue Deficiency

3/ S&T Transactional Services Revenue

4/ Rate Design Considerations

5/ In-Franchise Rate Design Proposals

a) Rate Review Guidelines

b) General Service Rates

c) Union South Bundled Contract Rate Eligibility

d) Rate M4 Interruptible Service Offering

e) Rate T1 Redesign

f) Customer Charges in Contract Rates

g) Elimination of Wholesale Transportation Service Rate 77

h) Elimination of Contract Rate Unbundled Service Offerings

6/ Ex-Franchise Rates

a) Response to the M12-X and C1 Kirkwall to Dawn and M12 and C1 Kirkwall to Parkway Directives

b) C1 Dawn to Dawn-Vector Fuel Ratios

7/ Other Rate Schedule Changes

a) In-Franchise Rate Schedules

b) Ex-Franchise Rate Schedules

1/ REVENUE DEFICIENCY RESTATEMENT

Union has restated its revenue deficiency to reflect revenue and cost revisions not captured in Union's Phase I Settlement Agreement filed on June 28, 2012. As shown at Settlement Agreement, Appendix B, Schedule 1, line 10, Union's revenue deficiency was $56.580 million. Union's restated revenue deficiency is $54.524 million, a decrease of $2.056 million. Table 1 summarizes the Phase II revenue deficiency restatements.

Table 1

Restatement of Union's 2013 Revenue Deficiency/(Sufficiency)

Line No.	Particulars	($ millions)
	Phase I Revenue Deficiency	
1	Total Deficiency	55.810
2	Shareholder Portion of Storage Margin	0.770
3	Adjusted Deficiency	56.580
	Phase II Revenue Deficiency	
4	Deficiency Per Phase I	56.580
5	Compressor Fuel Budget Adjustment	0.300
6	Update to Non-Utility Cross Charge	(0.196)
7	C1 Union Supplied Fuel Revenue Adjustment	(0.103)
8	Heritage Pool M16 Transmission Charge	(0.057)
9	C1 St. Clair to Dawn Revenue Adjustment	(2.000)
10	Updated Deficiency	54.524

The adjustments to the Phase I revenue deficiency are described below.

Compressor Fuel Budget

Union has updated its compressor fuel budget to account for M12 transportation activity that was not included in the compressor fuel budget. As a result of this increase in compressor fuel costs, Union's revenue deficiency has increased by $0.300 million.

C1 St. Clair to Dawn Revenue

The C1 transportation revenue forecast for St. Clair to Dawn transportation provided at Exhibit H3, Tab 1, Schedule 2, page 11, line 3, column b) has been updated to include an additional $2.000 million. The increase in C1 transportation revenue results in a decrease of $2.000 million to Union's revenue deficiency.

2/ RECOVERY OF THE 2013 REVENUE DEFICIENCY

Union's proposed recovery of the 2013 revenue deficiency is provided at Exhibit H3, Tab 1, Schedule 1. Union proposes to increase in-franchise delivery and gas supply transportation rates to recover a deficiency of $58.491 million, and increase ex-franchise transportation rates to recover a deficiency of $1.467 million. Union also proposes to decrease the Gas Supply Administration Charge by $3.990 million, resulting in a net deficiency of $55.968 million for recovery.

In addition, there is a Gas Supply Commodity sufficiency of $1.765 million, which Union is not proposing to recover as part of this proceeding. Union will continue to process Gas Supply Commodity-related rate adjustments through the Board-approved QRAM process.

Finally, there is a non-utility system integrity cost deficiency of $0.321 million, which Union is not proposing to recover from ratepayers. The non-utility system integrity costs are recovered from the non-utility business, not ratepayers.

The rate adjustments in total recover the restated revenue deficiency of $54.524 million. Table 4 provides the proposed recovery of the 2013 revenue deficiency.

Table 4

Recovery of Union's 2013 Revenue Deficiency/(Sufficiency)

Line No.	Particulars	($ millions)
1	In-franchise Delivery and Gas Supply Transportation-related Revenue Deficiency	58.491
2	Ex-franchise Transportation-related Revenue Deficiency	1.467
3	Gas Supply Administration Charge-related Sufficiency	(3.990)
4	Total Deficiency for Recovery	55.968
5	Gas Supply Commodity-related Sufficiency	(1.765)
6	Non-utility System Integrity Costs Deficiency	0.321
7	Restated Phase II Revenue Deficiency	54.524

Union proposes to increase delivery and gas supply transportation rates in Union North to recover $33.335 million of the total in-franchise delivery and gas supply transportation related deficiency of $58.491 million. The in-franchise delivery and gas supply transportation deficiency in Union North is primarily driven by cost increases related to return, depreciation expense and O&M expenses, offset by increases to delivery revenue. For a residential

customer consuming 2,200 m^3 per year this represents an annual increase of approximately $65.

Union proposes to increase in-franchise delivery rates in Union South to recover $25.155 million of the total in-franchise delivery and gas supply transportation related revenue deficiency of $58.491 million. The in-franchise delivery deficiency in Union South is primarily driven by cost increases related to return, depreciation expense and O&M expenses, offset by increases to delivery revenue. For a residential customer consuming 2,200 m^3 per year this represents an annual increase of approximately $13.

As indicated above, the proposed recoveries of the 2013 revenue requirement by rate class are provided at Exhibit H3, Tab 1, Schedule 1. Exhibit H3, Tab 1, Schedule 1 also provides the 2007 Board-approved and 2013 revenue to cost ratios. Exhibit H3, Tab 1, Schedule 2 provides detailed in-franchise and ex-franchise rates. The percentage change in average unit prices is provided at Exhibit H3, Tab 1, Schedule 3.

3/ S&T TRANSACTIONAL SERVICES REVENUE

Union has included the ratepayer portion of forecast S&T transactional service revenue in the revenue stream for ratemaking purposes in 2013. To reflect the results of the 2013 cost allocation study, Union proposes to include S&T transactional services revenue of $23.903 million in in-franchise rates. The S&T transactional services revenue restated to reflect 2013 costs is provided at Exhibit H3, Tab 10, Schedule 1.

4/ RATE DESIGN CONSIDERATIONS

When designing 2013 proposed rates for Union North and Union South, the following factors (in no particular order) have been taken into consideration:

a) The revenue deficiency for the company as a whole;

b) The relative rate changes of other rate classes;

c) The allocated cost of service;

d) The level of current rates and the magnitude of the proposed change;

e) The potential impact on customers;

f) The level of contribution to fixed cost recovery;

g) Customer expectations with respect to rate stability and predictability; and

h) Equivalency of comparable service options.

The revenue to cost ratios resulting from Union's 2013 rate design proposals have been filed at Exhibit H3, Tab 1, Schedule 1. For purposes of comparison, Union has also provided the EB-2005-0520 revenue to cost ratios approved by the Board for 2007 in column (j) of Exhibit H3, Tab 1, Schedule 1. The revenue to cost ratios reflect Union's application of accepted rate design principles and as noted above, are underpinned by the cost allocation study filed at Exhibit G3, Tab 1 through Tab 5. The 2013 proposed revenue to cost ratios are within an acceptable range and are generally consistent with those approved by the Board in EB-2005-0520.

5/ IN-FRANCHISE RATE DESIGN PROPOSALS

a) RATE REVIEW GUIDELINES

In reviewing in-franchise rates and service offerings, Union has defined a number of key guidelines to determine appropriate rate class boundaries and rate structures:

i. Common profiles within rate classes – Rate class groupings should exhibit sufficiently similar profiles with regards to average and peak use, seasonal usage and annual volume.

ii. Sufficient rate class size – Each rate class should be sufficiently large enough to produce meaningful average costing/pricing to ensure ongoing rate stability within the rate class (i.e. rates and costs that are stable and predictable).

iii. Sufficient differentiation among rate groupings – Proposed rate groupings must be examined to determine if they are materially different from other groupings with regards to the criteria developed in item (i). Sufficient differentiation is necessary to avoid an unnecessary number of rate classes, minimize undue rate class switching and to reduce the number of customers with similar operating profiles in different rate classes.

iv. Sufficient interest and reasonable prospect of use – Union continues to assess the appropriateness of its rates and service offerings based on customer interest and use

(or lack thereof) in order to avoid hypothetical rate designs in the absence of a proven market. The design of rates should be driven by a demonstrated need and provide customers some assurance that workable services will be offered on a sustained basis.

v. Rate harmonization – Where appropriate, Union will consider common rate structures, but not necessarily common rate levels, in accordance with the Board's EBO 195 Report (Application to Amalgamate Union Gas and Centra, Section 2.5 Rates).

b) GENERAL SERVICE RATES

Union is proposing two rate design changes in its General Service market. The first proposed change is to lower the annual volume breakpoint between the Rate 01 and Rate 10 rate classes in Union North and the Rate M1 and Rate M2 rate classes in Union South from 50,000 m^3 to 5,000 m^3. The second proposed change is to harmonize the rate block structures in the small volume General Service rate classes (Rate 01 and Rate M1) and in the large volume General Service rate classes (Rate 10 and Rate M2).

Union proposes to implement the annual volume breakpoint and rate block structure harmonization to General Service rate classes on a revenue neutral basis effective January 1, 2014. Each of the proposed changes is described below.

Lowering the Annual Volume Breakpoint

The current annual volume breakpoint between small volume General Service rate classes (Rate 01 and Rate M1) and large volume General Service rate classes (Rate 10 and Rate M2) is 50,000 m^3.

The annual volume breakpoint of 50,000 m^3 was first approved for small volume General Service Rate 01 by the Board in E.B.R.O 411-III/E.B.R.O. 430-II Decision with Reasons, dated May 20, 1988. Based on the Customer Reclassification Study for ICG Utilities (Ontario) Ltd, the Board approved the current Rate 01 rate class, which previously applied strictly to residential customers, to include residential, small commercial, and small industrial customers in Union North.

In EB-2005-0520 (Union's 2007 rate case), the Board approved the use of the annual volume breakpoint of 50,000 m^3 to split the General Service Rate M2 rate class into small volume Rate M1 and large volume Rate M2 in Union South. Using an annual volume breakpoint of 50,000 m^3 to split the rate class recognized that a small volume residential customer does not incur the same level of customer-related costs as a large volume industrial customer.

Union is proposing to lower the annual volume breakpoint between small volume General Service rate classes (Rate 01 and Rate M1) and large volume General Service rate classes (Rate 10 and Rate M2) to 5,000 m^3 from 50,000 m^3 to improve the rate class composition of Rate 01 and M1 and achieve more homogeneous rate classes. Union's proposal will also improve the

rate class size in Rate 10 and Rate M2, which will ensure viable large volume General Service rate classes and improve rate stability.

Rate Class Homogeneity

The small volume General Service rate classes (Rate 01 and Rate M1) display a lack of homogeneity at the current annual volume breakpoint of 50,000 m^3. Union proposes to improve the homogeneity of these rate classes by lowering the annual volume breakpoint to 5,000 m^3.

As shown at Table 5, line 16, at the current annual volume breakpoint of 50,000 m^3 for Rate M1, the class average use per customer is 2,700 m^3. However, within the residential, commercial and industrial markets there are significant differences in average use per customer.

The residential market average use per customer at the 50,000 m^3 breakpoint is 2,258 m^3, which is similar to the class average of 2,700 m^3. The commercial and industrial market average use per customer are 7,650 m^3 and 12,966 m^3 respectively, which differ significantly from the class average use.

Table 5

Union South - General Service Rate Class Profiles
Annual Volume Breakpoint Analysis using 2010 Actuals

Line No	Annual Volume Breakpoint	Rate M1 Annual Volume (m^3) (a)	Rate M1 Number of Meters (b)	Rate M1 Average Use per Customer (m^3) (c) = (a/b)	Rate M2 Annual Volume (m^3) (d)	Rate M2 Number of Meters (e)	Rate M2 Average Use per Customer (m^3) (f) = (d/e)
	2,500 m^3						
1	Residential	1,073,442,283	619,856	1,732	997,338,294	295,369	3,377
2	Commercial	30,624,470	25,579	1,197	1,237,704,163	52,917	23,390
3	Industrial	930,477	752	1,237	310,881,622	4,339	71,648
4	Total	1,104,997,230	646,187	1,710	2,545,924,079	352,625	7,220
	5,000 m^3						
5	Residential	1,949,672,659	898,064	2,171	121,107,917	17,161	7,057
6	Commercial	90,773,709	42,241	2,149	1,177,554,925	36,255	32,480
7	Industrial	3,437,553	1,432	2,401	308,374,546	3,659	84,278
8	Total	2,043,883,921	941,737	2,170	1,607,037,388	57,075	28,157
	20,000 m^3						
9	Residential	2,061,185,940	915,011	2,253	9,594,636	214	44,835
10	Commercial	324,435,758	65,832	4,928	943,892,876	12,664	74,534
11	Industrial	20,838,044	3,021	6,898	290,974,055	2,070	140,567
12	Total	2,406,459,741	983,864	2,446	1,244,461,567	14,948	83,253
	50,000 m^3						
13	Residential	2,066,157,260	915,184	2,258	4,623,316	41	112,764
14	Commercial	561,651,565	73,418	7,650	706,677,068	5,078	139,164
15	Industrial	51,749,801	3,982	12,996	260,062,298	1,109	234,502
16	Total	2,679,558,627	992,584	2,700	971,362,682	6,228	155,967
	80,000 m^3						
17	Residential	2,067,536,745	915,206	2,259	3,243,831	19	170,728
18	Commercial	698,927,422	75,604	9,245	569,401,212	2,892	196,888
19	Industrial	71,464,633	4,296	16,635	240,347,466	795	302,324
20	Total	2,837,928,799	995,106	2,852	812,992,509	3,706	219,372

As shown at Table 5, line 8, at the proposed annual volume breakpoint of 5,000 m^3 for Rate M1, the class average use per customer is 2,170 m^3. The residential, commercial and industrial markets all exhibit average uses per customer that are similar in magnitude to the Rate M1

class average use shown at Table 5, line 8. This demonstrates that the annual volume breakpoint of 5,000 m^3 best achieves a homogeneous grouping of customers in Rate M1.

A similar improvement in rate class homogeneity in Rate 01 is also achieved. As shown at Table 6, line 16, at the current annual volume breakpoint of 50,000 m^3 for Rate 01, the class average use per customer is 2,797 m^3. However, within the Rate 01 residential, commercial and industrial markets there are significant differences in average use per customer.

The residential market average use per customer is 2,250 m^3, is similar in magnitude to the rate class average of 2,797 m^3. The commercial and industrial market average use per customer, however, are 8,413 m^3 and 27,318 m^3 respectively, which differs significantly from the rate class average use.

Table 6

Union North - General Service Rate Class Profiles
Annual Volume Breakpoint Analysis using 2010 Actuals

Line No	Annual Volume Breakpoint	Rate 01 Annual Volume (m^3) (a)	Rate 01 Number of Meters (b)	Rate 01 Average Use per Customer (m^3) (c) = (a/b)	Rate 10 Annual Volume (m^3) (d)	Rate 10 Number of Meters (e)	Rate 10 Average Use per Customer (m^3) (f) = (d/e)
	2,500 m^3						
1	Residential	321,514,442	186,202	1,727	292,983,236	86,765	3,377
2	Commercial	9,594,021	7,662	1,252	415,381,609	20,370	20,392
3	Industrial	1,425	5	285	42,876,633	140	306,262
4	Total	331,109,888	193,869	1,708	751,241,478	107,275	7,003
	5,000 m^3						
5	Residential	578,531,026	267,742	2,161	35,966,652	5,225	6,884
6	Commercial	30,835,838	13,498	2,284	394,139,792	14,534	27,118
7	Industrial	4,456	6	743	42,873,602	139	308,443
8	Total	609,371,320	281,246	2,167	472,980,046	19,898	23,770
	20,000 m^3						
9	Residential	612,892,618	272,913	2,246	1,605,060	54	29,723
10	Commercial	130,045,789	23,394	5,559	294,929,842	4,638	63,590
11	Industrial	61,526	10	6,153	42,816,533	135	317,160
12	Total	742,999,932	296,317	2,507	339,351,434	4,827	70,303
	50,000 m^3						
13	Residential	614,276,579	272,963	2,250	221,100	4	55,275
14	Commercial	222,217,874	26,413	8,413	202,757,756	1,619	125,236
15	Industrial	901,507	33	27,318	41,976,551	112	374,791
16	Total	837,395,960	299,409	2,797	244,955,407	1,735	141,185
	80,000 m^3						
17	Residential	614,497,678	272,967	2,251	0	0	0
18	Commercial	270,391,583	27,188	9,945	154,584,047	844	183,156
19	Industrial	2,415,034	56	43,126	40,463,025	89	454,641
20	Total	887,304,295	300,211	2,956	195,047,071	933	209,054

As shown at Table 6, line 8, at the proposed annual volume breakpoint of 5,000 m^3 for Rate 01, the class average use per customer is 2,167 m^3. The residential and commercial markets exhibit average uses per customer that are similar to the Rate 01 class average use shown at Table 6, line 8.

Union notes that the industrial customers' average use per customer is only 743 m^3. In Union's view, the level of the average use for industrial customers has no material impact on the improved homogeneity of the new Rate 01 rate class as there are only six customers identified as industrial.

Rate Class Size

By lowering the annual volume breakpoint from 50,000 m^3 to 5,000 m^3, Union is also able to improve the rate class size and composition of large volume General Service rate classes (Rate M2 and Rate 10).

As shown at Table 5, line 16, at an annual volume breakpoint of 50,000 m^3, the current Rate M2 rate class is comprised of 6,228 customers. Of the 6,228 customers in the current Rate M2, 81% (or 5,078) are commercial customers. The remaining customers in the current Rate M2 are predominantly industrial customers.

Lowering the annual volume breakpoint to 5,000 m^3 results in an increase in customers in the Rate M2 rate class to 57,075 customers. Of the 57,075 customers in proposed Rate M2, 64% (or 36,255) are commercial customers. Residential customers in proposed Rate M2 represent 30% (or 17,161) and industrial customers represent the remaining 6%.

A similar improvement in rate class size and composition is also achieved in Rate 10.

As shown at Table 6, Line 16, at an annual volume breakpoint of 50,000 m^3, the current Rate 10 rate class is comprised of 1,735 customers. Of the 1,735 customers in current Rate 10, 93% (or 1,619) are commercial customers. The remaining customers in current Rate 10 are predominantly industrial customers.

Lowering the annual volume breakpoint to 5,000 m^3 results in an increase in customers in the Rate 10 rate class to 19,898 customers. Of the 19,898 customers in proposed Rate 10, 73% (or 14,534) are commercial customers. Residential customers in proposed Rate 10 represent 26% (or 5,225) with industrial customers representing the remaining 1%.

The increase in rate class size in the Rate 10 and Rate M2 is consistent with Union's rate review guidelines and will ensure viable large volume General Service rate classes with improved rate class composition. The increase in rate class size will allow for more meaningful average pricing and rate stability in these rate classes.

Harmonization of Rate Block Structures

As indicated above, Union is proposing to harmonize the rate block structures in the small volume General Service rate classes (Rate 01 and M1) and in the large volume General Service rate classes (Rate 10 and Rate M2). Union proposes to utilize the current Board-approved rate block structures for Rate M1 and Rate M2 in Union South for Rate 01 and Rate 10 in Union North respectively. Union proposes to implement the volume breakpoint and rate block structure harmonization to General Service rate classes on a revenue neutral basis effective

January 1, 2014.

The current approved rate block structure of Rate M1 is provided at Table 7.

Table 7

Rate M1
Current Appoved Rate Block Structure

Particulars	Annual Volume Breakpoint of 50,000 m^3
Rate M1	First 100 m^3
	Next 150 m^3
	All Over 250 m^3

The first delivery block volume of 100 m^3 is intended to capture base load consumption. The second block, the next 150 m^3, accommodates the consumption of the average customer. The final block, all over 250 m^3, accommodates customers with higher volume and is priced to ensure a smooth transition between small volume and large volume General Service rates.

The current approved rate block structure for Rate M2 is provided at Table 8.

Table 8

Rate M2
Current Appoved Rate Block Structure

Particulars	Annual Volume Breakpoint of 50,000 m^3
Rate M2	First 1,000 m^3
	Next 6,000 m^3
	Next 13,000 m^3
	All Over 20,000 m^3

The first block volume of 1,000 m^3 is intended to capture base load consumption. The second block and third block, the next 6,000 m^3 and 13,000 m^3, accommodates the consumption of most commercial/industrial customers. The final block, all over 20,000 m^3, accommodates customers with higher volume and is priced to ensure the smooth transition between large volume General Service and contract rates.

Proposed General Service Pricing and Bill Impacts

Union's proposed 2013 and 2014 pricing and rate blocking structures for small volume General Service rate classes Rate 01 and Rate M1 and large volume General Service rate classes Rate 10 and Rate M2 are provided at Tables 9 and 10.

Table 9

Small Volume General Service
Rate Structure Harmonization and Proposed Pricing

Particulars	2013 Rate Structure - Annual Volume Breakpoint of 50,000 m^3	2013 Proposed Rates (cents/m^3)	2014 Proposed Rate Structure - Annual Volume Breakpoint of 5,000 m^3	2014 Proposed Rates (cents/m^3)
Rate 01	Monthly Charge	$ 21.00	Monthly Charge	$ 21.00
	First 100 m^3	9.7156	First 100 m^3	9.6122
	Next 200 m^3	9.1911	Next 150 m^3	9.2420
	Next 200 m^3	8.8184	All Over 250 m^3	8.7256
	Next 500 m^3	8.4764		
	Over 1,000 m^3	8.1939		
Rate M1	Monthly Charge	$ 21.00	Monthly Charge	$ 21.00
	First 100 m^3	4.0938	First 100 m^3	4.2635
	Next 150 m^3	3.8873	Next 150 m^3	3.9188
	All Over 250 m^3	3.3988	All Over 250 m^3	3.4122

Table 10

Large Volume General Service
Rate Structure Harmonization and Proposed Pricing

Particulars	2013 Rate Structure - Annual Volume Breakpoint of 50,000 m^3	2013 Proposed Rates (cents/m^3)	2014 Proposed Rate Structure - Annual Volume Breakpoint of 5,000 m^3	2014 Proposed Rates (cents/m^3)
Rate 10				
	Monthly Charge	$ 70.00	Monthly Charge	$ 35.00
	First 1,000 m^3	7.5628	First 1,000 m^3	6.7117
	Next 9,000 m^3	6.1492	Next 6,000 m^3	6.6340
	Next 20,000 m^3	5.3430	Next 13,000 m^3	5.9873
	Next 70,000 m^3	4.8269	All Over 20,000 m^3	4.9660
	Over 100,000 m^3	2.8717		
Rate M2				
	Monthly Charge	$ 70.00	Monthly Charge	$ 35.00
	First 1,000 m^3	4.1184	First 1,000 m^3	3.3112
	Next 6,000 m^3	4.0421	Next 6,000 m^3	3.2234
	Next 13,000 m^3	3.8147	Next 13,000 m^3	3.1256
	All Over 20,000 m^3	3.5418	All Over 20,000 m^3	3.0517

In Rate 01 and Rate M1, Union proposes to maintain the current approved monthly customer charge of $21 per month. The remaining customer-related costs and all demand and commodity-related costs will continue to be recovered in volumetric delivery rates.

In Rate 10 and Rate M2, Union proposes to decrease the monthly customer charge to $35 per month from the current approved monthly customer charge of $70 per month. Union is

proposing to decrease the monthly customer charge to recognize that the redesigned Rate 10 and Rate M2 rate classes will have significantly more customers than the current Rate 10 and Rate M2 rate classes. A monthly customer charge of $70, when applied to the increased number of customers, results in a significant over-recovery of allocated customer-related costs.

The proposed monthly customer charge of $35 is more reflective of the composition of the new Rate 10 and Rate M2 rate classes, which have lower average use per customer than at the 50,000 m^3 annual volume breakpoint. The lower monthly customer charge also helps mitigate rate impacts for smaller customers migrating to the new Rate 10 and Rate M2 rate classes. The remaining customer-related costs and all demand and commodity-related costs will continue to be recovered in volumetric delivery rates.

The bill impacts associated with Union's proposal to lower the annual volume breakpoint and harmonize the rate block structures between small and large volume General Service rate classes are provided at Table 11 for Union North and Table 12 for Union South.

Table 11

Union North
Annual General Service Delivery Bll Impacts of
2014 Rate Proposals

Line No.	Annual Volume (m^3/year)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate 01 ($)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate 10 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate 01 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate 10 ($)	Annual Bill Impacts ($)	Annual Bill Impacts (%)
1	1,800	422.31		421.12		(1.19)	-0.3%
2	2,200	458.73		457.04		(1.69)	-0.4%
3	2,600	494.80		492.79		(2.01)	-0.4%
4	3,000	530.67		528.39		(2.28)	-0.4%
5	5,000	705.54		705.23		(0.31)	0.0%
6	7,000	876.55			889.80	13.25	1.5%
7	10,000	1,128.39			1,090.00	(38.39)	-3.4%
8	20,000	1,957.51			1,755.24	(202.27)	-10.3%
9	30,000	2,780.82			2,419.31	(361.50)	-13.0%
10	50,000	4,422.82			3,743.64	(679.18)	-15.4%
11	80,000		5,899.52		5,626.55	(272.97)	-4.6%
12	100,000		7,037.89		6,863.64	(174.24)	-2.5%
13	200,000		12,571.60		12,626.80	55.19	0.4%
14	300,000		17,752.05		17,917.17	165.12	0.9%
15	500,000		27,715.09		28,150.63	435.54	1.6%

Table 12

Union South
Annual General Service Delivery Bll Impacts of
2014 Rate Proposals

Line No.	Annual Volume (m^3/year)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate M1 ($)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate M2 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate M1 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate M2 ($)	Annual Bill Impacts ($)	Annual Bill Impacts (%)
1	1,800	323.12		324.97		1.85	0.6%
2	2,200	337.57		339.58		2.01	0.6%
3	2,600	351.94		354.09		2.14	0.6%
4	3,000	366.20		368.47		2.27	0.6%
5	5,000	436.44		439.21		2.77	0.6%
6	7,000	505.38			651.36	145.98	28.9%
7	10,000	608.53			749.11	140.58	23.1%
8	20,000	948.89			1,073.28	124.39	13.1%
9	30,000	1,288.78			1,396.41	107.64	8.4%
10	50,000	1,968.54			2,038.38	69.85	3.5%
11	80,000		4,031.07		2,987.00	(1,044.07)	-25.9%
12	100,000		4,804.38		3,616.58	(1,187.80)	-24.7%
13	200,000		8,521.82		6,720.25	(1,801.58)	-21.1%
14	300,000		12,148.30		9,797.39	(2,350.91)	-19.4%
15	500,000		19,308.57		15,922.58	(3,385.98)	-17.5%

c) Union South Bundled Contract Rate Eligibility

Union is proposing to lower the eligibility criteria for the mid-market bundled contract rate class (Rate M4 or Rate M5A) and the large market bundled contract rate class (Rate M7) in Union South. Union proposes to implement the bundled contract rate class eligibility changes effective January 1, 2014.

d) Rate M4 Interruptible Service Offering

Union is proposing to enhance the current Rate M4 firm service by adding an interruptible service offering to the Rate M4 rate schedule. Union's proposal to introduce an interruptible service offering to firm Rate M4 mirrors the optional, firm base service currently available to interruptible customers taking service under Rate M5A. The introduction of this interruptible service offering to Rate M4 ensures all contract rate customers in Union South for which Union provides the burner-tip service (Rates M4, M5A, M7 and T1) have both firm and interruptible service offerings.

The eligibility criteria for the proposed Rate M4 interruptible service will be an interruptible daily contracted demand of at least 2,400 m^3 and a minimum annual interruptible volume of 350,000 m^3. The structure and pricing of the proposed Rate M4 interruptible service matches the Rate M5A interruptible service.

e) Rate T1 Redesign

Union is proposing to split current Rate T1 into two rate classes with distinct rate structures; a new Rate T1 mid-market service and a new Rate T2 large market service. If approved by the Board, Union proposes to implement the new rate classes, eligibility changes and rate structures, on a revenue neutral basis, effective January 1, 2013.

Current Rate Design

The Rate T1 rate schedule is applicable to customers with combined firm and interruptible annual consumption of 5,000,000 m^3 or more. Customers can contract for 100% firm, 100% interruptible or combined firm and interruptible transportation service. Interruptible transportation rates are customer specific and are negotiated within a Board-approved range. Union is not proposing any rate design changes to the rates it charges for interruptible services.

The current rate design for firm transportation service was approved by the Board in RP-2003-0063. In RP-2003-0063, the Board approved Union's proposal to introduce a two demand, two commodity block rate structure for Rate T1 firm transportation service. This rate design was proposed by Union to better align cost incurrence with cost recovery and to reduce intra-class cross subsidization of small customers by large customers.

Proposed 2013 rates designed using the current approved rate structure for firm Rate T1 transportation service are provided at Table 13.

Table 13

2013 Proposed Rate T1 with no Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116
Fuel Ratio	Transportation	0.237%

Union is not proposing any changes to the rate design for storage service provided under the Rate T1 rate schedule. Storage service is an optional service available at cost-based rates for space up to the amount determined by applying the aggregate excess methodology or 15 times the customer's daily contract quantity ("DCQ"). Rate T1 customers may also contract for cost-based deliverability at the greater of DCQ or CD minus DCQ. The current method for allocating cost-based storage to T1 customers was approved in EB-2007-0725.

Rationale for Splitting the Current T1 Rate Class

Union is proposing to split current Rate T1 into two rate classes to better align cost incurrence and cost recovery by recognizing the differences in distribution demand and distribution customer-related costs between small Rate T1 and large Rate T1 customers. The proposed split also addresses the significant diversity in daily contracted demand and firm annual consumption that exists between small and large customers within the current Rate T1 rate class.

Customers Served Directly Off Transmission Main

Under the current cost allocation method used to allocate distribution demand-related costs, rate classes with customers served directly off transmission main are allocated less distribution demand-related costs than rate classes with fewer customers served directly off transmission main. The proportion of customers in a rate class served off transmission main has an impact on the overall level of distribution demand-related costs allocated to a rate class.

As customers served directly off transmission main are generally larger in terms of daily contracted demand and annual consumption than those customers served off distribution main, an intra-class subsidy of small customers (CD's less than 140,870 m^3/day) by large customers exists. The current two block demand rate design for Rate T1 firm transportation service only partially recognizes the costing differences within the Rate T1 class. In the current Rate T1 rate class, 20 of 59 customers (or 34%) are served directly off transmission main, while the remaining 39 customers (66%) are served off distribution main.

Mains and Services Replacement Costs

Mains and services classified to distribution customer are allocated to rate classes using service replacement costs. The allocation of service replacement costs to Rate T1 is determined by estimating the cost of replacing the service based on service length, size and type of pipe. When preparing the 2013 cost allocation study, Union updated the service replacement cost information used to determine its service replacement cost allocator. The allocation of service replacement costs to the current Rate T1 rate class has increased, primarily as a result of the service replacement costs associated with large Rate T1 customers. This is the case because, generally, the service replacement costs for large Rate T1 customers are greater than the service replacement costs for small Rate T1 customers due to the services being of greater size and length.

By proposing to split the current Rate T1 rate class, Union is able to address the intra-class subsidy of large Rate T1 customers by small Rate T1 customers by setting monthly customer charges that are more reflective of the level of customer-related costs for each of the new semi-unbundled rate classes.

Non-homogeneous Rate Class Characteristics

As shown at Table 14, the current Rate T1 rate class is comprised of a diverse group of customers with significantly different load profiles.

Table 14

Load Profile - Current Rate T1 Customers

Particulars		2013 Rate T1 Customers
Number of Customers		59
Firm Contracted Demand (m^3/day)	MIN	9,300
	MAX	2,755,000
	AVG	343,191
	MED	67,800
Annual Firm Volume (m^3)	MIN	4,640,210
	MAX	836,320,120
	AVG	78,383,593
	MED	13,628,490
Customers served directly off transmission (Percent of class)		20 (34%)

Of the 59 customers forecasted in current Rate T1 for 2013, there is significant diversity in firm daily contracted demands. The smallest Rate T1 customer has a firm daily contracted demand of 9,300 m^3, while the largest Rate T1 customer has a firm daily contracted demand of 2,755,000 m^3 (296 times the size of the smallest Rate T1 customer). The average firm daily contracted demand is approximately 343,000 m^3.

This diversity within Rate T1 is also exhibited when examining firm annual consumption for small and large Rate T1 customers. The smallest Rate T1 customer has firm annual consumption of approximately 4,600,000 m^3, while the largest Rate T1 customer has firm

annual consumption of 836,000,000 m^3 (181 times the consumption of the smallest Rate T1 customer). The average firm annual consumption is approximately 78,000,000 m^3.

Union's proposal to split current Rate T1 will result in a more homogeneous group of customers in both the new Rate T1 and Rate T2 rate classes.

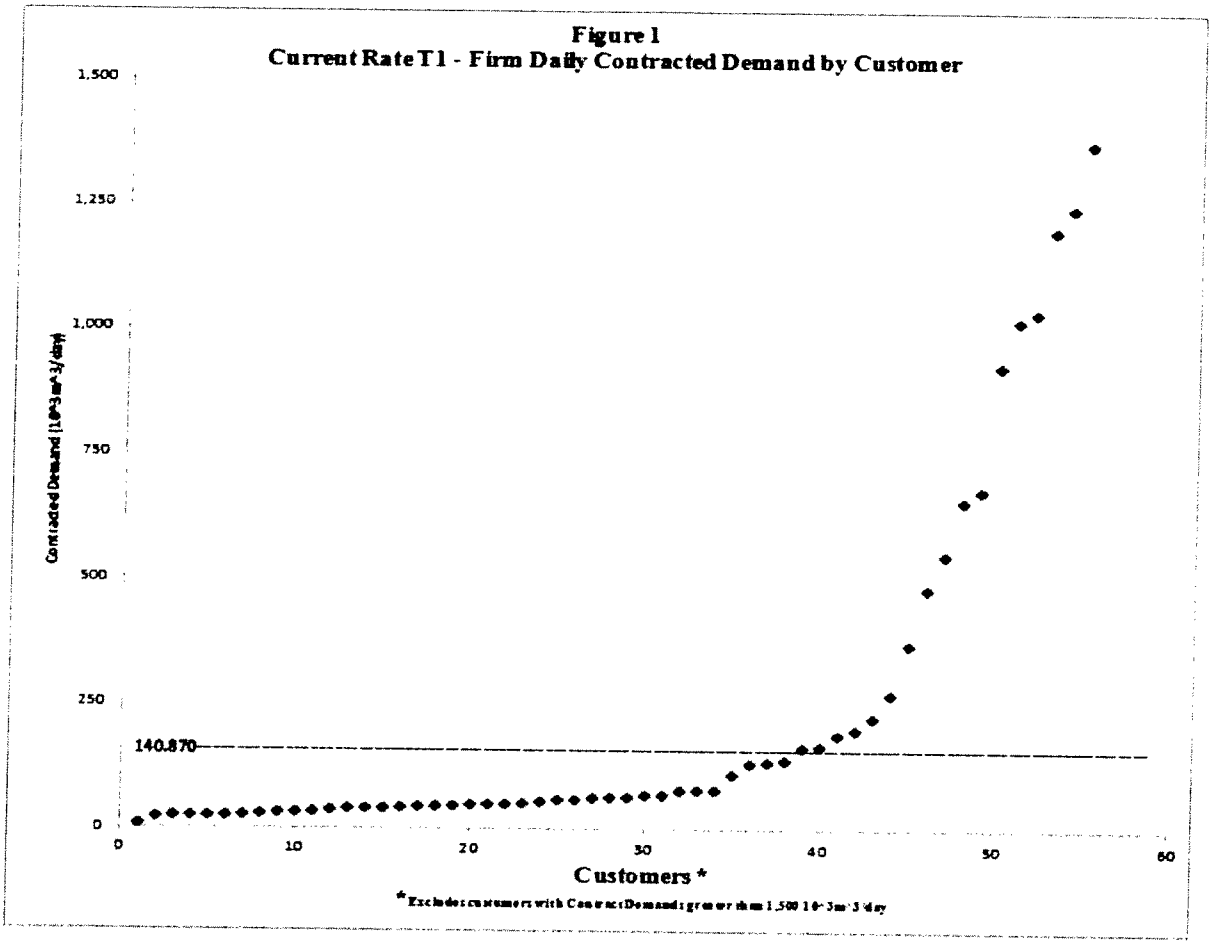
Proposed Rate T1/Rate T2 Eligibility

As indicated above, to qualify for the current Rate T1 service, a customer must have combined firm and interruptible annual consumption of 5,000,000 m^3 or more. For the new Rate T1 mid-market service, Union is proposing a minimum annual volume of 2,500,000 m^3. Further, Union is proposing that the daily firm contracted demand for the new Rate T1 not exceed 140,870 m^3.

The new Rate T2 large market service will be available to customers with a minimum firm daily contracted demand of 140,870 m^3. Union is not proposing any minimum annual volume requirement as a condition for qualifying for new Rate T2.

The proposed firm contracted demand breakpoint between mid-market Rate T1 and large market Rate T2 is derived using the scatter diagram plotting firm daily contracted demands provided at Figure 1.

Figure 1
Current Rate T1 - Firm Daily Contracted Demand by Customer



1 Union's proposal to split the current Rate T1 into two rate classes will result in improved rate
2 class composition in both Rate T1 and Rate T2. Specifically, both proposed Rate T1 and Rate
3 T2 will be comprised of more homogeneous customers in terms of firm contracted demands
4 and firm annual consumption. The proposed split of current Rate T1 will also recognize cost
5 differences within the current Rate T1 rate class associated with the allocation of distribution
6 demand-related and distribution customer-related costs. Table 15 shows the load

characteristics after the proposed split of the current Rate T1. For comparison purposes, Table 15 also includes the load characteristics of the current Rate T1 provided at Table 14.

Table 15

Load Profile - Current Rate T1 Customers
with Rate T1 Redesign

Particulars		2013 Rate T1 without Redesign	Rate T1 Redesign	
			Proposed Rate T1	Proposed Rate T2
Number of Customers		59	39	20
Firm Contracted Demand (m^3/day)	MIN	9,300	9,300	165,000
	MAX	2,755,000	140,000	2,755,000
	AVG	343,191	55,812	889,212
	MED	67,800	48,750	669,000
Annual Firm Volume (m^3)	MIN	4,640,210	4,640,210	22,590,890
	MAX	836,320,120	42,600,000	836,320,120
	AVG	78,383,593	12,795,770	199,721,065
	MED	13,628,490	10,726,120	146,616,000
Customers served directly off transmission (Percent of class)		20 (34%)	6 (15%)	14 (70%)

The rate structures and proposed pricing for the new Rate T1 and new Rate T2 rate classes are described below.

Rate T1 Rate Design and Pricing

Union is proposing that the rate structure of the new Rate T1 consist of a monthly customer charge, a two block monthly demand charge and a single block commodity charge. Table 16 provides a comparison of Rate T1 before rate redesign and proposed new Rate T1 rate structures and proposed rates.

Table 16

Comparison of 2013 Proposed Rate T1 with no Redesign
and 2013 Proposed Rate T1 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T1 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83	Charge per Re-delivery point	$2,001.29
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 28,150 m^3 Next 112,720 m^3	31.5395 23.2744
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0715
Fuel Ratio	Transportation	0.237%	Transportation	0.256%

The proposed monthly customer charge of $2,001.29 is cost-based and fully recovers all of the customer-related costs applicable to the new Rate T1. The two block demand charge recovers approximately 82% of new Rate T1 demand-related transportation costs. The remainder of

new Rate T1 demand-related transportation costs are recovered through the Rate T1 storage-related sufficiency. The single commodity charge recovers all the variable transportation costs.

The two block demand and single block commodity rate structure for firm service in new Rate T1 is based on the comparable Rate M4 firm service, which also has a daily contracted demand breakpoint of 28,150 m^3. This approach results in consistency between mid-market bundled and mid-market semi-unbundled service offerings.

As indicated above, Union is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. However, given that Union is proposing a maximum firm daily contracted demand of 140,870 m^3 in the new Rate T1, the new Rate T1 rate schedule will exclude the storage space, storage injection/withdrawal rights and transportation service provisions that are only applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day.

The derivation of the Rate T1 monthly customer charge, demand charges and commodity charge are provided at Exhibit H3, Tab 11, Schedule 1.

Delivery bill impacts for typical proposed Rate T1 customers are provided at Table 17.

Table 17

Calculation of 2013 Estimated Bill Impacts with and without Rate T1 Redesign

Particulars ($'s)		Transportation Bill at 2013 Rates No Redesign (a)	Transportation Bill at 2013 Rates With Redesign (b)	Estimated Bill Impacts (c) = ((b-a)/a)
Small Customer - Rate T1				
Contracted Demand (m^3/day)	25,750			
Load Factor	80%			
Annual Volume (m^3)	7,537,000			
Demand Bill		55,220	97,457	
Commodity Bill		1,750	5,392	
Customer Charge		79,210	24,015	
Total Annual Bill		136,180	126,864	-6.8%
Average Customer - Rate T1				
Contracted Demand (m^3/day)	48,750			
Load Factor	65%			
Annual Volume (m^3)	11,565,938			
Demand Bill		104,542	164,075	
Commodity Bill		2,686	8,274	
Customer Charge		79,210	24,015	
Total Annual Bill		186,438	196,364	5.3%
Large Customer - Rate T1				
Contracted Demand (m^3/day)	133,000			
Load Factor	53%			
Annual Volume (m^3)	25,624,080			
Demand Bill		285,213	399,379	
Commodity Bill		5,759	18,330	
Customer Charge		79,210	24,015	
Total Annual Bill		370,182	441,725	19.3%

New Rate T2 Rate Design and Pricing

Union is proposing that the rate structure of the new Rate T2 consist of a monthly customer charge, two block monthly demand charge and a single block commodity charge. Table 18 provides a comparison of Rate T1 before rate redesign and proposed new Rate T2 rate structures and proposed rates.

Table 18

Comparison of 2013 Proposed Rate T1 with no Redesign
and 2013 Proposed Rate T2 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T2 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83	Charge per Re-delivery point	$6,000.00
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 140,870 m^3 All Over 140,870 m^3	21.7032 11.3232
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0081
Fuel Ratio	Transportation	0.237%	Transportation	0.234%

The proposed monthly customer charge for the new Rate T2 rate class has been set at $6,000. At this level, the proposed monthly customer charge recovers approximately 50% of the customer-related costs attributable to the new Rate T2. Union is proposing to set the monthly

customer charge at $6,000 to ensure a smooth rate continuum between Rate T1 and Rate T2 at the daily contracted demand breakpoint of 140,870 m^3. The balance of the customer-related costs not recovered in the Rate T2 monthly customer charge are recovered in the first block demand charge, which is common to all Rate T2 customers. The revenue to cost ratio for new Rate T2 is consistent with the revenue to cost ratio for Rate T1 before rate redesign.

The two block demand rate structure for the new Rate T2 is based on a daily contracted demand breakpoint of 140,870 m^3. This is the same daily contracted demand as the current Rate T1 structure. The two block demand charge also recovers all the demand-related transportation costs. The single commodity charge recovers all the variable transportation costs.

As indicated above. Union is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. The proposed 2013 Rate T2 rate schedule, which is provided at Exhibit H3, Tab 3, Schedule 2, will include all the current Board-approved storage space and storage injection/withdrawal rights per the current approved Rate T1 rate schedule. Also, the transportation service provisions that are applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day are included in the proposed T2 rate schedule.

The derivation of the Rate T2 monthly customer charge, demand charges and commodity charge are provided at Exhibit H3, Tab 11, Schedule 1.

Delivery bill impacts for typical proposed Rate T2 customers are provided at Table 19.

Table 19

Calculation of 2013 Estimated Bill Impacts with and without Rate T1 Redesign

Particulars ($'s)		Transportation Bill at 2013 Rates No Redesign (a)	Transportation Bill at 2013 Rates With Redesign (b)	Estimated Bill Impacts (c) = ((b-a)/a)
Small Customer - Rate T2				
Contracted Demand (m^3/day)	190,000			
Load Factor	85%			
Annual Volume (m^3)	59,256,000			
Demand Bill		374,082	433,637	
Commodity Bill		10,152	4,808	
Customer Charge		79,210	72,000	
Total Annual Bill		463,445	510,445	10.1%
Average Customer - Rate T2				
Contracted Demand (m^3/day)	669,000			
Load Factor	81%			
Annual Volume (m^3)	197,789,850			
Demand Bill		1,075,988	1,084,495	
Commodity Bill		26,160	16,049	
Customer Charge		79,210	72,000	
Total Annual Bill		1,181,358	1,172,543	-0.7%
Large Customer - Rate T2				
Contracted Demand (m^3/day)	1,200,000			
Load Factor	84%			
Annual Volume (m^3)	370,089,000			
Demand Bill		1,854,092	1,806,009	
Commodity Bill		46,069	30,029	
Customer Charge		79,210	72,000	
Total Annual Bill		1,979,371	1,908,039	-3.6%

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit H1, Tab 1, page 14

The evidence states that the proposed revenue to cost ratios are within an acceptable range and are generally consistent with those previously approved by the Board. Please identify what Union views as an "acceptable range". What, from Union's perspective, would not be an acceptable revenue to cost ratio?

Response:

Revenue-to-cost ratios are the outcome, not an input, of the application of Union's Rate Design Considerations described at Exhibit H1, Tab 1, Updated, page 11. As a final check on its rate design, Union reviews the resulting revenue-to-cost ratios for reasonableness. Acceptable revenue-to-cost ratios must:

1. satisfy rate design principles set forth in evidence, and
2. bear a reasonable relationship to previously approved revenue-to-cost ratios.

When setting 2013 rates, revenue-to-cost ratios also reflect the application of $20.852 million in S&T transactional credits to in-franchise rates with the resulting revenue-to-cost ratio for all in-franchise delivery services of 95.3%.

Acceptable revenue-to-cost ratios guidelines will usually include:

1. Firm in-franchise general services (Rate 01, Rate 10, Rate M1 & Rate M2) close to unity.
2. Large firm in-franchise contract services (Rate T1, Rate T3 and Rate 100) close to unity.
3. Other in-franchise firm services between (1) and (2) above will vary due to firm rate continuum considerations. A revenue-to-cost ratio approximating 80% or more is generally realized.
4. Rate M12 firm transportation service close to unity.
5. Interruptible in-franchise service pricing is set in relative relationship to firm services, with the resulting revenue-to-cost ratios showing greater deviation from unity.

Rate designs not meeting the above criteria would be considered unacceptable.

UNION GAS LIMITED
Revenue Deficiency Recovery
Effective January 1, 2013

Line No	Particulars	Before Recovery: Current Approved Revenue (1) ($000's) (a)	Before Recovery: Current Approved Rates (2) (cents/m³) (b)	Before Recovery: Revenue (Deficiency) / Sufficiency ($000's) (c) = (a -d)	Proposed Revenue Requirement (3) ($000's) (d)	After Recovery: Revenue (Deficiency) / Sufficiency ($000's) (e) = (f - d)	After Recovery: Proposed Revenue (4) ($000's) (f)	After Recovery: Proposed Rates (5) (cents/m³) (g)	After Recovery: Revenue to Cost Ratios (h) = (f / d)	After Recovery: Rate Change (%) (i) = (g - b) / (b)	EB-2005-0520 Approved Revenue to Cost Ratios (j)
	North Delivery										
1	R01	137,746	16.0994	(24,605)	162,351	(4,040)	158,311	18.5030	0.975	14.9%	0.976
2	R10	16,637	5.2906	(2,524)	19,161	(17)	19,144	6.0531	0.999	15.1%	1.056
3	R20	9,721	1.5476	(8,600)	18,322	(5,361)	12,961	2.0833	0.707	33.3%	0.587
4	R25	2,337	1.8052	(4,368)	6,705	(3,717)	2,988	2.3077	0.446	27.8%	0.487
5	R100	12,656	0.6678	(3,686)	16,326	0	16,326	0.8613	1.000	29.0%	0.885
6	Total North Delivery	179,100		(43,785)	222,885	(13,135)	209,730		0.941	17.1%	0.939
7	Total Recovery of North Delivery Deficiency (col. f - a)						30,630				
	South Delivery & Storage										
8	M1	379,511	13.2224	(16,512)	396,023	1,136	397,160	13.8075	1.000	4.4%	0.972
9	M2	44,036	4.6078	(8,804)	52,840	(3,160)	49,680	5.1931	0.940	12.7%	0.972
10	M4	10,841	2.8157	(5,087)	15,927	(3,154)	12,773	3.3177	0.802	17.8%	0.783
11	M5A	8,674	1.8666	(7,406)	16,280	(4,131)	12,149	2.2818	0.746	36.9%	0.824
12	M7	3,951	2.8652	(1,340)	5,291	(1,215)	4,076	2.7701	0.770	3.2%	0.897
13	M9	819	1.3486	48	771	(3)	768	1.2639	0.996	-6.3%	0.948
14	M10	5	2.5245	(71)	75	(71)	6	2.9185	0.073	15.6%	0.131
15	T1	57,783	1.1187	3,511	54,272	0	54,272	1.0508	1.000	-6.1%	0.973
16	T3	4,571	1.8782	(271)	4,843	(180)	4,662	1.7997	0.963	2.0%	0.943
17	Total South Delivery & Storage	510,391		(35,932)	546,323	(10,778)	536,547		0.980	4.9%	0.858
18	Total Recovery of South Delivery & Storage Deficiency (col. f - a)						25,155				
19	Total In-Franchise Delivery (line 6 + line 17)	689,491		(79,697)	769,188	(23,913)	745,277		0.969	8.1%	0.953

Notes:
(1) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (b).
(2) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (c).
(3) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (e).
(4) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (g).
(5) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (h).

UNION GAS LIMITED
Revenue Deficiency Recovery
Effective January 1, 2013

Line No	Particulars	Before Recovery: Current Approved Revenue (1) ($000's) (a)	Current Approved Rates (2) (cents/m³) (b)	Revenue (Deficiency) / Sufficiency ($000's) (c) = (a -d)	Proposed Revenue Requirement (3) ($000's) (d)	After Recovery: Revenue (Deficiency) / Sufficiency ($000's) (e) = (f - d)	Proposed Revenue (4) ($000's) (f)	Proposed Rates (5) (cents/m³) (g)	Revenue to Cost Ratios (h) = (f / d)	Rate Change (%) (i) = (g - b) / (b)	EB-2005-0520 Approved Revenue to Cost Ratios (j)
	North Transportation & Storage										
1	R01	68,509	8.0071	(2,902)	71,411	-	71,411	8.3483	1.000	4.2%	1.000
2	R10	22,677	7.1700	(517)	23,194	-	23,194	7.3337	1.000	2.3%	1.000
3	R20	8,815	7.2291	1,078	7,738	-	7,738	6.3446	1.000	-12.2%	1.000
4	R25	1,665	3.9299	(433)	2,118	-	2,118	4.9352	1.000	25.7%	1.000
5	R100	197	-	79	118	10	129	-	1.088		0.701
6	Total North Transportation & Storage	101,862		(2,686)	104,577	10	104,588		1.000	2.7%	0.991
7	Total Recovery of North Transport & Storage Deficiency (col. f -a)						2,705				
8	Total In-Franchise (page 1, line 19 + line 6)	791,374		(82,392)	873,766	(23,903)	849,886		0.973	7.4%	0.956
9	Total Recovery of In-Franchise Deficiency (col. f - a)						58,490				
	Ex-Franchise										
10	M12	161,163		(4,228)	165,389	(2,604)	162,785		0.984	1.0%	0.984
11	M13	373		158	215	209	423		1.971	13.5%	1.470
12	M16	748		286	462	297	759		1.643	1.5%	1.356
13	C1	40,666		26,415	14,263	26,198	40,482		2.834	-0.5%	2.610
14	Total Ex-Franchise	202,962		22,633	180,349	24,100	204,449		1.134	0.7%	1.177
15	Total Recovery of Ex-Franchise Deficiency (col. f - a)						1,467				
16	Total Delivery, Transportation & Storage (line 6 + line 14)	994,355		(59,760)	1,054,115	198 (6)	1,054,313		1.000	8.0%	1.004
17	Total In-Franchise Commodity / Admin	610,495		5,754	604,742	1,785	606,506		1.003	-0.7%	-
18	Total Recovery of Commodity / Admin Sufficiency (col. f - a)						(3,980)				
19	Total Union Gas (line 16 + line 17)	1,604,851		(54,006)	1,658,857	1,981	1,660,819		1.001	3.5%	1.002

Notes:
(1) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (b).
(2) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (c).
(3) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (d).
(4) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (e).
(5) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (f).
(6) Includes Phase I sharing of short-term storage margin of $0.770 million and Phase II update of a $0.196 million decrease; Heritage Pool sufficiency of $0.057 million; and the exclusion of $0.32 l million of System Integrity costs related to Union's non-utility storage space per Settlement Agreement.

UNION GAS LIMITED
Southern Operations Area
Ex-Franchise Customers
Effective January 1, 2013

Line No	Particulars	Billing Units	2013 Forecast Usage (a)	Current Approved Revenue ($000's) (1) (b)	Current Approved Rates (2), (4) ($/10³m³) (c)	Revenue (Deficiency) / Sufficiency ($000's) (d) = (b - e)	Proposed 2013 Revenue Requirement (3) ($000's) (e)	Revenue (Deficiency) / Sufficiency ($000's) (f)	Revenue ($000's) (g) = (e + f)	Rates ($/10³m³) (h) = (g / a)	Revenue to Cost Ratios (i) = (g / e)	Rate Change % (j) = (g - b) / (b)
	M12 Transportation Service											
	Demand:											
	Dawn to Kirkwall											
1	- 12 months	10³m³/d/mo	11,108	11,167 (5)	74.934	(7,679)	18,847	(706)	11,720	78.641		
2	- 10 months	10³m³/d/mo	8,068	6,046	74.934	6,046			6,345	78.641		
3	- 2 months	10³m³/d/mo	486	73	74.934	73			77	78.641		
4	- F24-T - 12 months	10³m³/d/mo	1,311	410	26.048	320			90	5.709		
	Dawn to Parkway						90	-				
5	- 12 months	10³m³/d/mo	85,458	96,869 (5)	88.033	(11,673)	110,542	(4,234)	104,688	93.214		
6	- 10 months	10³m³/d/mo	1,722	1,516	88.033	1,516			1,605	93.214		
7	- 3 months	10³m³/d/mo	53	14	88.033	14			15	93.214		
8	- F24-T - 12 months	10³m³/d/mo	8,132	2,542	26.048	1,985			557	5.709		
	M12-X Easterly (between Dawn, Kirkwall and Parkway)						557	-				
9	- 12 months	10³m³/d/mo	10,358	10,942	88.033	(1,105)	12,048	(461)	11,586	93.214		
	M12-X Easterly (between Dawn, Kirkwall and Parkway)											
10	- 12 months	10³m³/d/mo	10,358	2,557	20.574	2,557	-	2,821	2,821	22.699		
	Kirkwall to Parkway											
11	- 12 months	10³m³/d/mo	2,344	364	13.062 (6)	(208)	569	(24)	410	14.574		
12	- 2 months	10³m³/d/mo	4,629	109	13.062 (6)	109			135	14.574		
	Commodity:											
13	Easterly - Providing Own Fuel	10³m³	18,688,739	26,454		3,767	22,687	(0)	22,687			
	Westerly - Providing Own Fuel	10³m³										
14	Parkway to Kirkwall/Dawn		23,986	15		4	12	0	12			
15	Kirkwall to Dawn		133,279	86		46	38	0	38			
16	Total Rate M12		18,846,004	161,163		(4,226)	165,389	(2,605)	162,785		0.984	1.0%

Notes:
(1) EB-2011-0210, Exhibit C3, Tab 4, Schedule 1.
(2) EB-2010-0359, Appendix A, Pages 13-15 effective January 1, 2011.
(3) EB-2011-0210, Exhibit G3, Tab 2, Schedules 2-21.
(4) The conversion factor used to convert to $/GJ as found in the rate schedules is 37.75 GJ per 10³m³.
(5) M12 demand revenues for Dawn to Kirkwall and Dawn to Parkway also include F24-T demands.
(6) Decision and Order, EB-2011-0257.

UNION GAS LIMITED
Southern Operations Area
Ex-Franchise Customers (7)
Effective January 1, 2013

Line No.	Particulars	Billing Units	2013 Forecast Usage (a)	Current Approved			Proposed 2013					
				Revenue ($000's) (1) (b)	Rates (2), (4) ($/10³m³) (c)	Revenue (Deficiency) / Sufficiency ($000's) (d) = (b - e)	Revenue Requirement (3) ($000's) (e)	Revenue (Deficiency) / Sufficiency ($000's) (f)	Revenue ($000's) (g) = (e + f)	Rates ($/10³m³) (h) = (g / a)	Revenue to Cost Ratios (i) = (g / e)	Rate Change % (j) = (g - b) / (b)
	C1 Cross Franchise Transportation Service											
	Transportation Service:											
	Demand:											
1	Parkway to Dawn/Kirkwall											
2	- 12 months	10^3m^3/mo	9,202	2,272	20.574	2,272	-	2,605	2,507	22.699		
3	- 3 months	10^3m^3/mo	1,440	89	20.574	89			98	22.699		
	Kirkwall to Dawn	10^3m^3/mo	0	-	44.394			-		40.032		
4	Dawn to Parkway											
5	- 12 months	10^3m^3/mo	187	413	88.033	377	35	377	413	93.214		
	Kirkwall to Parkway	10^3m^3/mo			13.062 (6)	-				14.574		
	Firm Commodity											
	Easterly											
	Union Providing Fuel											
6	Dawn to Parkway (TCPL)	10^3m^3	64,193	103		20	83	2	85			
	Providing Own Fuel											
	Westerly - Providing Own Fuel											
7	Parkway to Kirkwall	10^3m^3	0	-		-		-				
8	Parkway to Dawn	10^3m^3	105,702	68		15	53	(1)	52			
9	Total Rate C1 (Dawn-Trafalgar only)		169,825	2,944		2,774	170	2,983	3,154		18.51%	7.1%
10	Total Ex-Franchise M12 & C1			164,197		(1,457)	168,459	336	165,938		1.002	1.1%

Notes:
(1) EB-2011-0210, Exhibit C3, Tab 4, Schedule 1.
(2) EB-2010-0359, Appendix A, Pages 13-15 effective January 1, 2011.
(3) EB-2011-0210, Exhibit G3, Tab 2, Schedules 2-21.
(4) The conversion factor used to convert to $/GJ as found in the rate schedules is 37.75 GJ per 10^3m^3.
(5) C1 St Clair to Dawn revenue adjustment of $2.000 million
(6) Decision and Order, EB-2011-0257
(7) Grey shading represents all the changes when compared to Exhibit H3, Tab 1, Schedule 2, page 11, Updated: 2012-07-13

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

With respect to the table contained in Exhibit J.H-1-15-1:

a) Please explain why the average unit cost to distribute gas to higher volume general service customers is in all cases higher than the average unit cost to distribute gas to lower volume general service customers.

b) Please identify and quantify all diseconomies of scale affecting the cost to distribute gas to higher volume general service customers.

c) Please explain why the average volumetric rate for M2 customers is in all cases higher than the average volumetric rate for M1 customers. Please explain the cost drivers causing this result.

d) Please prepare a table in this format performing the same calculations for Rates 01 and 10. Please explain why the same pattern of higher unit rates for higher volume customers (both overall unit rate and average volumetric rate) does not apply to these rate classes in the same way as M1 and M2. Please identify and quantify the costs that cause this different result.

Response:

Please see Attachments 1-4.

The relationship of the average unit cost to distribute gas to higher volume general service customers when compared to lower volume general service customers is affected by:

a. the effect of the monthly charge increases in the small volume general service rates during the incentive regulation period,
b. cost differences by rate class, and
c. rate design differences arising due to the rate class composition.

The attachments identify the impact of these changes on volumetric rates.

i. Attachment 1 shows the appropriate annual rate comparison using an annual volume breakpoint of 50,000 m^3 at 2013 proposed rates.

ii. Attachment 2 details the 2013 fixed costs by rate class recovered in volumetric rates.

iii. Attachment 3 shows the appropriate annual rate comparison using an annual volume breakpoint of 5,000 m^3 at 2014 proposed rates.

iv. Attachment 4 details the 2014 fixed costs by rate class recovered in volumetric rates.

Effect of the Monthly Charge Increases during the IR period

During the incentive regulation period, annual increases of $1 per month in the monthly charge, from $16 in 2007 to $21 in 2012, for each of Rates M1 and Rate 01, were offset by reductions in volumetric rates for these rate classes on a revenue neutral basis.

During this same period there were no similar increases in monthly charges or corresponding reductions in volumetric rates of the large volume general service classes. Consequently the smooth rate continuum, with relatively small price differentials at the annual volume breakpoint in 2008 rates, was eroded. Attachment 1 shows the impact of this change from 2008 to 2012 at lines 1-4.

Cost differences between Small Volume and Large Volume General Service Rate Classes

Rate M1 small volume general service costs are primarily customer-related. With about 95% of the customer-related costs recovered by the monthly charge of $21, only 5% of customer-related costs (or $15.258 million) and 100% of the demand-related costs ($102.204 million) are shifted to volumetric rates yielding an average volumetric rate of 4.0836 cents/m^3 to recover fixed costs shown at Attachment 2, line 9, column (a).

Rate M2 large volume general services cost are primarily demand-related costs. With about 63% of the customer-related costs recovered by the monthly charge of $70, about 37% (or $3.290 million) of customer-related costs and 100% of the demand-related costs ($34.915 million) are shifted to volumetric rates yielding an average volumetric rate of 3.9936 cents/m^3 shown at Attachment 2, line 9, column (b) . Large volume general service rate classes recover significant fixed costs in volumetric rates. This results in unit cost shifts to volumetric rates that are almost identical for Rate M1 and Rate M2.

Attachment 2 also shows the comparable analysis for Union North. In the case of Union North more of the customer-related costs are shifted to volumetric rates for Rate 01 resulting in an average volumetric rate of 9.8611 cents/m^3 shown at Attachment 2, line 9, column (c). For Rate 10, the average volumetric rate of 5.5412 cents/m^3 is shifted to volumetric rates shown at Attachment 2, line 9, column (d). At an annual volume of 50,000 m^3, Rate 10 compares favourably with Rate 01.

Rate design differences arising due to the rate class composition

The rate setting process for each of these classes, as they are currently constituted, is impacted by the number of customers and annual volumes for each rate class. Small volume rate classes have a large number of customers and significant annual volume. By comparison, large volume general service rate classes are comparatively small in the number of customers and annual volumes.

Comparison of 2013 and 2014

With the proposed 2014 reduction in the annual volume breakpoint from 50,000 m^3 to 5,000 m^3, the rate class composition changes. The proposed reduction in monthly customer charge from $70/month to $35/month will recover most of the customer-related costs of the large volume Rate M2 and Rate 10 in the monthly charge. With less fixed costs shifted to volumetric rates, the volumetric rates for each of Rate 10 and Rate M2 are lower. Attachment 4 shows the same calculation for 2014 as Attachment 2 does for 2013.

With the lower volume threshold for the large volume rates, the effect of setting the monthly customer charge at $35 for a customer consuming 5,000 m^3 or more, results in a commodity equivalent monthly charge of 8.4000 cents/m^3 shown at Attachment 4, line 12, column (b) and (d). For a small volume customer at 5,000 m^3, the comparable commodity equivalent to the monthly charge of $21 is 5.0400 cents/$m^3$ shown at Attachment 4, line 12, column (a) and (c). The effect of this 3 cents/m^3 differential between monthly charges in the small volume and large volume general service rate results in:

1. Minimum bill impacts for Union North customers, now eligible for new Rate 10.

2. Rate increases for Union South customers, now eligible for new Rate M2, that diminish as volume increases. Customers in the new Rate M2 rate class at the lower end of the monthly usage scale will see an increase in their monthly bills, mainly due to the increase in the monthly charge occurring at 5,000 m^3. Most customers at the higher end of the usage range will see reduced bills.

Rate Analysis based on an Annual Volume of 50,000 m^3
and an Annual Volume Breakpoint of 50,000 m^3 per year
(cents/m^3)

Line No.	Particulars	Small Volume General Service: Average Annual Fixed Rate (1) (a)	Small Volume General Service: Average Annual Volumetric Rate (b)	Small Volume General Service: Total Annual Average Rate (c)	Particulars	Large Volume General Service: Average Annual Fixed Rate (2) (d)	Large Volume General Service: Average Annual Volumetric Rate (e)	Large Volume General Service: Total Annual Average Rate (f)	Difference by Rate Component: Average Annual Fixed Rate (g) = (d-a)	Difference by Rate Component: Average Annual Volumetric Rate (h) = (e-b)	Difference by Rate Component: Total Annual Average Rate (i) = (f-c)
	2008				2008						
1	Rate M1	0.4080	4.1418	4.5498	Rate M2	1.6800	3.6070	5.2870	1.2720	(0.5348)	0.7372
2	Rate 01	0.4080	7.3849	7.7929	Rate 10	1.6800	6.2640	7.9440	1.2720	(1.1209)	0.1511
	2012				2012						
3	Rate M1	0.5040	2.9215	3.4255	Rate M2	1.6800	3.6691	5.3491	1.1760	0.7476	1.9236
4	Rate 01	0.5040	6.2151	6.7191	Rate 10	1.6800	5.1042	6.7842	1.1760	(1.1110)	0.0650
	2013				2013						
5	Rate M1	0.5040	3.6869	4.1909	Rate M2	1.6800	4.1503	5.8303	1.1760	0.4633	1.6393
6	Rate 01	0.5040	8.7898	9.2938	Rate 10	1.6800	6.5139	8.1939	1.1760	(2.2758)	(1.0998)

Notes:
(1) The volumetric equivalent of the fixed rate for Rate M1 and Rate 01 is based on a Monthly Customer Charge of $17 in 2008 and $21 in 2012 and 2013.
(2) The volumetric equivalent of the fixed rate for Rate M2 and Rate 10 is based on a Monthly Customer Charge of $70 for each of 2008, 2012 and 2013.

Analysis of Fixed Cost Recovery in 2013 Monthly Charges and Volumetric Rates
based on 2013 General Service Rate Class Billing Units and an Annual Volume Breakpoint of 50,000 m^3

Line No.	Particulars ($000's)	Union South		Union North	
		Rate M1	Rate M2	Rate 01	Rate 10
		(a)	(b)	(c)	(d)
	Recovery of Fixed Costs in Volumetric Rates				
1	Customer -Related Costs				
2	Monthly Charge Revenue	282,101	8,992	117,795	3,770
3	Customer-related costs less monthly charge revenue (line 1 - line 2)	266,843	5,702	80,490	1,720
4	Proportion recovered in monthly charge	15,258	3,290	37,305	2,050
5	Proportion recovered in volumetric rates	95%	63%	68%	46%
		5%	37%	32%	54%
6	Demand-Related Costs	102,204	34,915	47,066	15,475
7	Amount Shifted to Volumetric Rates (line 3 + line 6)	117,462	38,205	84,371	17,525
8	Annual Volume - 2013 Forecast (10^3m^3)	2,876,411	956,651	855,598	316,269
9	Average Volumetric Rate to Recover Fixed Costs (line 7 / line 8)	4.0836	3.9936	9.8611	5.5412
	Volume Equivalent Rate for Monthly Charge				
10	Monthly Customer Charge ($)	21.00	70.00	21.00	70.00
11	Annual Customer Charge Revenue ($) (line 10 x 12 months)	252.00	840.00	252.00	840.00
12	Equivalent Volumetric Charge at 50,000 m^3 (cents/m^3)	0.5040	1.6800	0.5040	1.6800

Rate Analysis at Annual Volume of 5,000 m³
Using 2014 Proposed Rates and Annual Volume Breakpoint of 5,000 m³
(cents/m³)

Line No.	Particulars	Small Volume General Service			Particulars	Large Volume General Service			Difference by Rate Component		
		Average Annual Fixed Rate (1)	Average Annual Volumetric Rate	Total Annual Average Rate		Average Annual Fixed Rate (2)	Average Annual Volumetric Rate	Total Annual Average Rate	Average Annual Fixed Rate	Average Annual Volumetric Rate	Total Annual Average Rate
	2014	(a)	(b)	(c)		(d)	(e)	(f)	(g) = (d-a)	(h) = (e-b)	(i) = (f-c)
1	Rate M1	5.0400	3.9868	9.0268	Rate M2	8.4000	3.5412	11.9412	3.3600	(0.4456)	2.9144
2	Rate 01	5.0400	9.4882	14.5282	Rate 10	8.4000	7.0322	15.4322	3.3600	(2.4560)	0.9040

Notes:
(1) The volumetric equivalent of the fixed rate for Rate M1 and Rate 01 is based on a Monthly Customer Charge of $21 in 2014.
(2) The volumetric equivalent of the fixed rate for Rate M2 and Rate 10 is based on a Monthly Customer Charge of $35 in 2014.

Analysis of Fixed Cost Recovery in 2014 Monthly Charges and Volumetric Rates
based on 2014 General Service Rate Class Billing Units and an Annual Volume Breakpoint of 5,000 m^3

Line No.	Particulars ($000's)	Union South		Union North	
		Rate M1	Rate M2	Rate 01	Rate 10
		(a)	(b)	(c)	(d)
	Recovery of Fixed Costs in Volumetric Rates				
1	Customer -Related Costs	269,086	22,006	111,039	10,527
2	Monthly Charge Revenue	253,207	25,577	75,654	8,921
3	Customer-related costs less monthly charge revenue (line 1 - line 2)	15,879	(3,571)	35,385	1,606
4	Proportion recovered in monthly charge (line 2 / line 1)	94%	116%	68%	85%
5	Proportion recovered in volumetric rates (line 3 / line 1)	6%	-16%	32%	15%
6	Demand-Related Costs	76,763	60,356	35,211	27,330
7	Amount Shifted to Volumetric Rates (line 3 + line 6)	92,642	56,785	70,596	28,936
8	Annual Volume - 2013 Forecast (10^3m^3)	2,145,851	1,687,211	659,769	512,098
9	Average Volumetric Rate to Recover Fixed Costs (cents/m^3) (line 7 / line 8)	4.3173	3.3656	10.7001	5.6505
	Volume Equivalent Rate for Monthly Charge				
10	Monthly Customer Charge ($)	21.00	35.00	21.00	35.00
11	Annual Customer Charge Revenue ($) (line 10 x 12 months)	252.00	420.00	252.00	420.00
12	Equivalent Volumetric Charge at 50,000 m^3 (cents/m^3)	5.0400	8.4000	5.0400	8.4000

EB-2011-0210
Undertaking J12.5
Attachment 1

Table 11

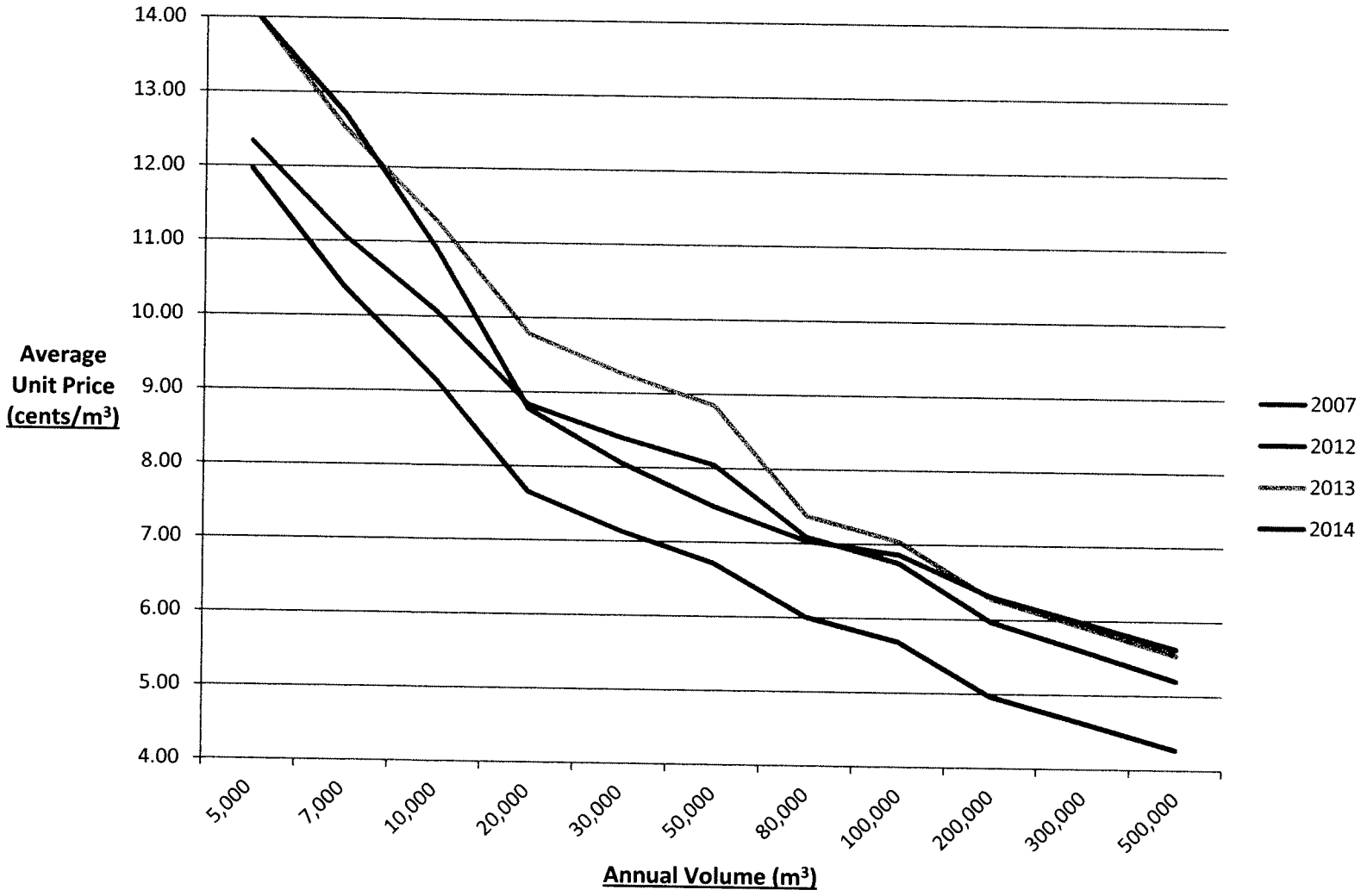
Union North
Annual General Service Delivery Bill Impacts of
2014 Rate Proposals

Line No.	Annual Volume (m^3/year)	2007 Approved (1) - Annual Volume Breakpoint of 50,000 m^3 Rate 01 ($)	2007 Approved (1) - Annual Volume Breakpoint of 50,000 m^3 Rate 10 ($)	2012 Approved (2) - Annual Volume Breakpoint of 50,000 m^3 Rate 01 ($)	2012 Approved (2) - Annual Volume Breakpoint of 50,000 m^3 Rate 10 ($)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate 01 ($)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate 10 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate 01 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate 10 ($)	Annual Bill Impacts ($)	Annual Bill Impacts (%)	Average Unit Price (cents/m^3) 2007 Approved	2012 Approved	2013 Proposed	2014 Proposed
1	1,800	353.03		383.49		422.31		421.12		(1.19)	-0.3%	19.6128	21.3050	23.4615	23.3954
2	2,200	387.22		411.33		458.73		457.04		(1.69)	-0.4%	17.6009	18.6968	20.8514	20.7746
3	2,600	420.96		438.84		494.80		492.79		(2.01)	-0.4%	16.1908	16.8785	19.0309	18.9536
4	3,000	454.48		466.13		530.67		528.39		(2.28)	-0.4%	15.1493	15.5377	17.6891	17.6131
5	5,000	616.94		598.23		705.54		705.23		(0.31)	0.0%	12.3388	11.9646	14.1108	14.1045
(3) 6	5,001	617.02		598.31		705.63		755.65		50.03	7.1%	12.3379	11.9638	14.1097	15.1100
7	7,000	775.03		726.61		876.55		889.80		13.25	1.5%	11.0719	10.3801	12.5221	12.7114
8	10,000	1,006.75		914.59		1,128.39		1,090.00		(38.39)	-3.4%	10.0675	9.1459	11.2839	10.9000
9	20,000	1,767.32		1,531.22		1,957.51		1,755.24		(202.27)	-10.3%	8.8366	7.6561	9.7875	8.7762
10	30,000	2,521.27		2,142.17		2,780.82		2,419.31		(361.50)	-13.0%	8.4042	7.1406	9.2694	8.0644
11	50,000	4,023.82		3,359.60		4,422.82		3,743.64		(679.18)	-15.4%	8.0476	6.7192	8.8456	7.4873
(3) 12	50,001		3,947.43		3,392.17		4,084.32		3,743.70	(340.62)	-8.3%	7.8947	6.7842	8.1685	7.4873
13	80,000		5,672.32		4,805.71		5,899.52		5,626.55	(272.97)	-4.6%	7.0904	6.0071	7.3744	7.0332
14	100,000		6,746.03		5,683.78		7,037.89		6,863.64	(174.24)	-2.5%	6.7460	5.6838	7.0379	6.8636
15	200,000		11,946.45		9,932.35		12,571.60		12,626.80	55.19	0.4%	5.9732	4.9662	6.2858	6.3134
16	300,000		16,771.53		13,864.38		17,752.05		17,917.17	165.12	0.9%	5.5905	4.6215	5.9173	5.9724
17	500,000		25,999.03		21,371.97		27,715.09		28,150.63	435.54	1.6%	5.1998	4.2744	5.5430	5.6301

Notes:

(1) Calculated using January 2007 QRAM rates as approved by the Board in EB-2006-0502. Includes monthly customer charge and delivery commodity portions only.
(2) Calculated using January 2012 QRAM rates as approved by the Board in EB-2011-0382. Includes monthly customer charge and delivery commodity portions only.
(3) Consistent with Union's response in JT2.24 (based on March filing), updated for the Settlement Conference filing.

Union North - Rate 01 & Rate 10
General Service Rate Continuity



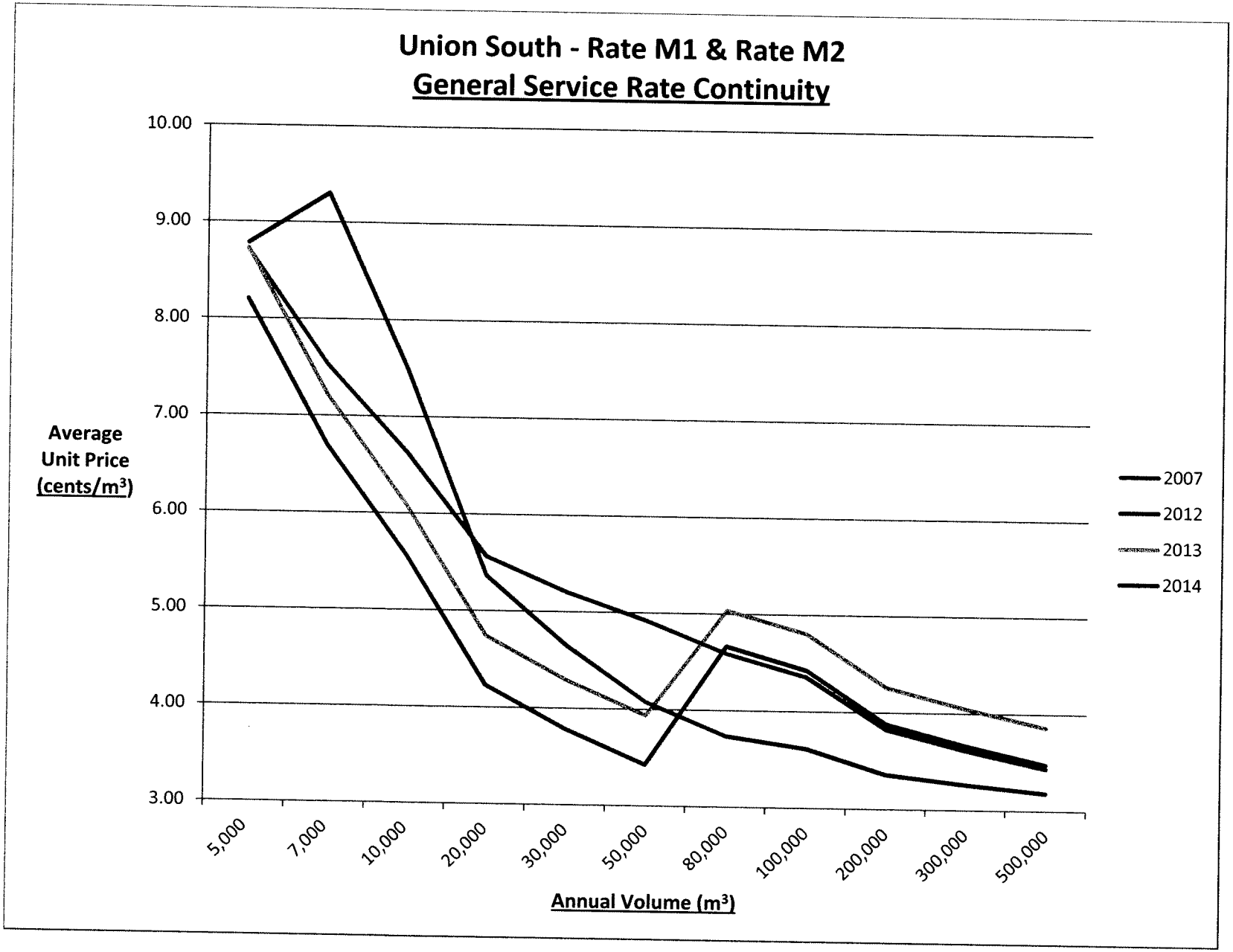
EB-2011-0210
Undertaking J12.5
Attachment 2

Table 12

Union South
Annual General Service Delivery Bill Impacts of
2014 Rate Proposals

Line No.	Annual Volume (m^3/year)	2007 Approved (1) - Annual Volume Breakpoint of 50,000 m^3 Rate M1 ($)	2007 Approved (1) - Annual Volume Breakpoint of 50,000 m^3 Rate M2 ($)	2012 Approved (2) - Annual Volume Breakpoint of 50,000 m^3 Rate M1 ($)	2012 Approved (2) - Annual Volume Breakpoint of 50,000 m^3 Rate M2 ($)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate M1 ($)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate M2 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate M1 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate M2 ($)	Annual Bill Impacts ($)	Annual Bill Impacts (%)	Average Unit Price (cents/m^3) 2007 Approved	2012 Approved	2013 Proposed	2014 Proposed
1	1,800	286.23		313.37		323.12		324.97		1.85	0.6%	15.9017	17.4094	17.9511	18.0538
2	2,200	305.35		325.75		337.57		339.58		2.01	0.6%	13.8795	14.8068	15.3443	15.4356
3	2,600	324.35		338.01		351.94		354.09		2.14	0.6%	12.4750	13.0004	13.5363	13.6187
4	3,000	343.20		350.20		366.20		368.47		2.27	0.6%	11.4400	11.6733	12.2068	12.2824
5	5,000	436.01		410.12		436.44		439.21		2.77	0.6%	8.7202	8.2024	8.7287	8.7842
(3) 6	5,001	436.06		410.14		436.47		585.59		149.12	34.2%	8.7195	8.2012	8.7277	11.7095
7	7,000	527.08		468.81		505.38		651.36		145.98	28.9%	7.5297	6.6973	7.2197	9.3052
8	10,000	663.32		556.60		608.53		749.11		140.58	23.1%	6.6332	5.5660	6.0853	7.4911
9	20,000	1,112.79		845.99		948.89		1,073.28		124.39	13.1%	5.5640	4.2300	4.7445	5.3664
10	30,000	1,561.60		1,134.90		1,288.78		1,396.41		107.64	8.4%	5.2053	3.7830	4.2959	4.6547
11	50,000	2,459.22		1,712.75		1,968.54		2,038.38		69.85	3.5%	4.9184	3.4255	3.9371	4.0768
(3) 12	50,001		2,635.38		2,674.62		2,861.41		2,038.41	(822.99)	-28.8%	5.2707	5.3491	5.7227	4.0767
13	80,000		3,672.90		3,730.75		4,031.07		2,987.00	(1,044.07)	-25.9%	4.5911	4.6634	5.0388	3.7337
14	100,000		4,358.64		4,428.16		4,804.38		3,616.58	(1,187.80)	-24.7%	4.3586	4.4282	4.8044	3.6166
15	200,000		7,650.33		7,761.05		8,521.82		6,720.25	(1,801.58)	-21.1%	3.8252	3.8805	4.2609	3.3601
16	300,000		10,858.44		10,999.89		12,148.30		9,797.39	(2,350.91)	-19.4%	3.6195	3.6666	4.0494	3.2658
17	500,000		17,189.49		17,381.76		19,308.57		15,922.58	(3,385.98)	-17.5%	3.4379	3.4764	3.8617	3.1845

Notes:
(1) Calculated using Approved Rate M1 & Rate M2 rates as per EB-2005-0520, Rate Order, Working Papers, Schedule 21. Includes monthly customer charge and delivery commodity portions only.
(2) Calculated using January 2012 QRAM rates as approved by the Board in EB-2011-0382. Includes monthly customer charge and delivery commodity portions only.
(3) Consistent with Union's response in JT2.24 (based on March filing), updated for the Settlement Conference filing.


Union South - Rate M1 & Rate M2
General Service Rate Continuity
Average Unit Price (cents/m³)
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
5,000
7,000
10,000
20,000
30,000
50,000
80,000
100,000
200,000
300,000
500,000
Annual Volume (m³)
2007
2012
2013
2014

UNION GAS LIMITED
Southern Operations Area
In-Franchise Customers
Effective January 1, 2013

Line No	Particulars	Billing Units	2013 Forecast Usage (1) (a)	Current Approved Revenue ($000's) (b)	Current Approved Rates (2) (cents / m^3) (c)	Revenue (Deficiency) / Sufficiency ($000's) (d) = (b - e)	Proposed 2013 Revenue Requirement (3) ($000's) (e)	Proposed 2013 Revenue (Deficiency) / Sufficiency ($000's) (f)	Proposed 2013 Revenue ($000's) (g) = (e + f)	Proposed 2013 Rates (cents / m^3) (h) = (g / a)	Proposed 2013 Revenue to Cost Ratios (i) = (g / e)	Proposed 2013 Rate Change (%) (j) = (h - c) / (c)
	Rate T1 - Storage and Transportation Rate											
	Storage ($/GJ)											
	Demand:											
	Firm injection / withdrawal											
1	Union provides deliverability inventory	GJ/d/mo.	2,009,280	3,078	1.532	171	2,908	412	3,319	1.652		
2	Customer provides deliverability inventory	GJ/d/mo.	1,503,356	1,527	1.016	85	1,443	436	1,879	1.250		
3	Incremental firm injection right	GJ/d/mo.	-	-	1.016	-	-	-	-	1.250		
4	Interruptible	GJ/d/mo.	477,948	486	1.016	486	-	597	597	1.250		
5	Space	GJ/d/mo.	129,041,736	1,290	0.010	(240)	1,530	7	1,537	0.012		
6	Commodity (Customer Provides)	GJ	10,620,082	74	0.007	(3)	78	2	79	0.007		
7	Commodity (Union Provides)	GJ	-	-	0.039	-	-	-	-	0.027		
8	Customer supplied fuel	GJ	63,503	341	-	135	206	-	206	-		
	Transportation (cents/ m^3)											
	Demand											
9	First 140,870 m^3	10^3m^3/d/mo.	71,774	13,701	19.0898	314	13,387	(561)	12,826	17.8705		
10	All Over 140,870 m^3	10^3m^3/d/mo.	167,088	21,796	13.0445	500	21,296	(892)	20,404	12.2113		
	Commodity											
	Firm											
11	First 2,360,653 m^3	10^3m^3	1,241,155	2,278	0.1835	1,989	288	-	288	0.0232		
12	All Over 2,360,653 m^3	10^3m^3	3,502,055	3,197	0.0913	2,793	405	-	405	0.0116		
13	Interruptible	10^3m^3	421,771	2,959	0.7014	(1,348)	4,306	-	4,306	1.0210		
14	Monthly Charge	Meter/mo.	972	1,745	$1,795.31	(4,671)	6,416	-	6,416	$6,600.83	1.000	
15	Customer supplied fuel	10^3m^3	26,210	5,310	202.610	3,301	2,009	-	2,009	-		
16	Total Rate T1		5,164,982	57,783	1.1187	3,511	54,272	0	54,272	1.0508	1.000	-6.1%
	Rate T3 - Storage and Transportation Rate											
	Storage ($/GJ)											
	Demand											
	Firm injection / withdrawal											
17	Union provides deliverability inventory	GJ/d/mo.	-	-	1.532	-	-	-	-	1.652		
18	Customer provides deliverability inventory	GJ/d/mo.	679,320	690	1.016	(156)	846	3	849	1.250		
19	Incremental firm injection right	GJ/d/mo.	-	-	1.016	-	-	-	-	1.250		
20	Interruptible	GJ/d/mo.	-	-	1.016	-	-	-	-	1.250		
21	Space	GJ/d/mo.	36,614,256	366	0.010	(70)	436	(0)	436	0.012		
22	Commodity (Customer Provides)	GJ	4,459,672	31	0.007	(2)	33	1	33	0.007		
23	Commodity (Union Provides)	GJ	-	-	0.039	-	-	-	-	0.027		
24	Customer supplied fuel	GJ	26,668	143	-	57	87	-	87	-		
	Transportation (cents/ m^3)											
25	Demand	10^3m^3/d/mo.	28,200	2,544	9.0218	(461)	3,005	(183)	2,822	10.0067		
26	Commodity	10^3m^3	272,712	186	0.0682	156	30	-	30	0.0110		
27	Monthly Charge	Meter/mo.	12	211	$17,567.33	(49)	260	-	260	$21,660.91	1.000	
28	Customer supplied fuel	10^3m^3	1,972	399	202.610	254	146	-	146	-		
29	Total Rate T3		272,712	4,571	1.6762	(271)	4,843	(180)	4,662	1.7097	0.963	2.0%

Notes:
(1) EB-2011-0210, Exhibit C3, Tab 2, Schedule 1, Column (b).
(2) EB-2010-0359, Appendix A effective January 1, 2011 (Excludes Price Adjustments).
(3) EB-2011-0210, Exhibit G3, Tab 2, Schedules 2-21, excludes Other Revenue.

UNION GAS LIMITED

Undertaking of Mr. Tetreault
To Mr. Wolnik

Please explain what other measures, by order of priority, could be used to reach 10 percent threshold, if the four mitigation tools were insufficient.

The Board's guidance to electricity distributors regarding rate mitigation contemplates a mitigation plan where a customer class or group **total** bill increase exceeds 10%. There is no comparable guidance provided to gas distributors. Union's proposed deficiency and the associated total bill impacts for each rate class fall below the 10% threshold. Please see Attachment 1.

Union does not consider mitigation to be necessary. If mitigation were ordered by the Board, any one of the mitigation measures included in Exhibit J.H-1-1-2 would keep the total bill impact below 10%.

Notwithstanding the fact that the total bill impacts provided in Attachment 1 do not exceed 10% for any in-franchise rate class, Union has provided Attachment 2. Attachment 2 provides the delivery rate impact associated with the expected reduction in return on equity ("ROE") from 9.58% to 9.10%, the impact of an alternative allocation of the distribution-related rate base reduction agreed to at Issue 1.4 of the EB-2011-0210, Settlement Agreement ("Settlement") and the mitigation measures discussed at Exhibit J.H-1-1-2.

ROE Reduction 9.58% to 9.10%

Based on the June 2012 Consensus of 2012 actual and forecast bond yields, the Board's formula produces an ROE of 9.10%. The ROE included in the revenue requirement underpinning delivery rate impacts provided at Exhibit H1, Tab 1, Schedule 1, revised for the Settlement is 9.58%. Before considering the impact of mitigation measures on delivery rates it is appropriate to adjust for the reduced ROE. The revenue requirement impact of going from 9.58% to 9.10% is approximately $8.6 million.

FT-RAM Revenue

At Exhibit J.C-4-7-9, Union indicated that if TCPL's RAM program is not eliminated on November 1, 2012, Union's 2013 revenue forecast attributable to FT-RAM would be $11.6 million. In preparing Attachment 2, Union has reduced delivery rates by $11.6 million to reflect the continuation of TCPL's RAM program beyond November 1, 2012.

Should the Board order the inclusion of FT-RAM revenue in delivery rates, Union would require deferral account protection, including the attributes as described at Transcript Volume 7 pp. 35-37, against the risk of elimination of the RAM program.

Alternative Allocation of Distribution-Related Rate Base Adjustment

At Issue 1.4 of the Settlement, parties agreed to reduce distribution-related rate base by $12 million. The effect of the reduction was a revenue requirement reduction of approximately $1.7 million.

To implement the distribution-related rate base reduction, Union reduced distribution mains, the largest distribution-related plant type. In cross-examination, parties requested that Union consider an alternative method for incorporating the distribution-related rate base adjustment and provide the impact of that alternative.

For the purposes of preparing Attachment 2, rather than attributing the rate base adjustment to distribution mains, Union allocated the adjustment using total distribution rate base. The impact of the alternative allocation is provided at column (h) of Attachment 2.

Phase In of Increase in Common Equity Ratio

For the purposes of preparing Attachment 2, Union was asked to assume that its proposal to increase its common equity ratio from 36% to 40% would be phased in over four years starting in 2013. Phasing in the increase in common equity thickness over four years reduces the 2013 revenue deficiency by approximately $11.1 million.

Phase In of the 20-Year Declining Trend Weather Methodology

As described in J.H-1-1-2 part c) Union's proposal to change its weather normalization method from the current 55:45 method to 100% 20-year declining trend increases its revenue deficiency by approximately $7 million. For the purposes of preparing Attachment 2, Union was asked to assume that the change in the weather normalization method would be implemented over five years starting in 2013. Phasing in the weather normalization method over five years reduces the 2013 revenue deficiency by approximately $5.8 million.

Adjustments to Revenue to Cost Ratios and Other Mitigation Methods

The mitigation measures above were sufficient to reduce the delivery rate impacts below 10%. Accordingly, there were no additional amounts to be deferred for future recovery and no need to adjust revenue to cost ratios. Union's view is that no further adjustments should be made to the revenue to cost ratios between North and South unless the Board was to set a longer term direction for Union to harmonize rate levels as well as rate structures between North and South customers.

Union North
Calculation of Annual Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Current Approved Bill ($) (a)	Current Approved Unit Rate (cents/m³) (b)	2013 Proposed Bill ($) (c)	2013 Proposed Unit Rate (cents/m³) (d)	Impact Unit Rate (cents/m³) (e) = (d-b)	Impact Bill ($) (f) = (c-a)	Impact Bill (%) (g) = (f/a)	Volumes Used for Rate Calcs
1	Small Rate 01								
2	Delivery Charges	404	18.3500	459	20.8509	2.5009	55	13.6%	2,200
3	Gas Supply Charges	469	21.3359	480	21.7968	0.4609	10	2.2%	2,200
	Total Bill	873	39.6859	938	42.6477	2.9618	65	7.5%	2,200
4	Small Rate 10								
5	Delivery Charges	4,224	7.0394	4,699	7.8320	0.7925	476	11.3%	60,000
6	Gas Supply Charges	12,188	20.3141	12,334	20.5563	0.2422	145	1.2%	60,000
	Total Bill	16,412	27.3535	17,033	28.3883	1.0348	621	3.8%	60,000
7	Large Rate 10								
8	Delivery Charges	13,228	5.2912	15,209	6.0837	0.7926	1,981	15.0%	250,000
9	Gas Supply Charges	50,785	20.3141	51,391	20.5564	0.2423	606	1.2%	250,000
	Total Bill	64,013	25.6053	66,600	26.6401	1.0348	2,587	4.0%	250,000
10	Small Rate 20								
11	Delivery Charges	54,251	1.8084	71,780	2.3927	0.5843	17,529	32.3%	3,000,000
12	Gas Supply Charges	605,494	20.1831	595,032	19.8344	(0.3488)	(10,463)	-1.7%	3,000,000
	Total Bill	659,745	21.9915	666,811	22.2270	0.2355	7,066	1.1%	3,000,000
13	Large Rate 20								
14	Delivery Charges	204,868	1.3658	271,339	1.8089	0.4431	66,471	32.4%	15,000,000
15	Gas Supply Charges	2,865,317	19.1021	2,818,008	18.7867	(0.3154)	(47,308)	-1.7%	15,000,000
	Total Bill	3,070,185	20.4679	3,089,348	20.5957	0.1278	19,163	0.6%	15,000,000
	Average Rate 25								
16	Delivery Charges	33,278	1.7988	42,569	2.3010	0.5022	9,291	27.9%	1,850,000
17	Gas Supply Charges	326,112	17.6277	344,766	18.6360	1.0083	18,654	5.7%	1,850,000
18	Total Bill	359,391	19.4265	387,335	20.9370	1.5105	27,945	7.8%	1,850,000
	Small Rate 100								
19	Delivery Charges	207,338	0.7679	272,804	1.0104	0.2425	65,466	31.6%	27,000,000
20	Gas Supply Charges	5,508,162	20.4006	5,481,147	20.3005	(0.1001)	(27,015)	-0.5%	27,000,000
21	Total Bill	5,715,500	21.1685	5,753,951	21.3109	0.1424	38,451	0.7%	27,000,000
	Large Rate 100								
22	Delivery Charges	1,713,524	0.7140	2,208,728	0.9203	0.2063	495,204	28.9%	240,000,000
23	Gas Supply Charges	48,118,849	20.0495	47,877,126	19.9488	(0.1007)	(241,724)	-0.5%	240,000,000
24	Total Bill	49,832,373	20.7635	50,085,853	20.8691	0.1056	253,480	0.5%	240,000,000

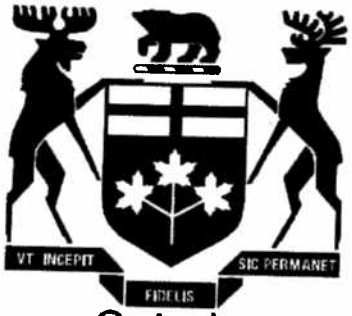
Union South
Calculation of Annual Bill Impacts for Typical Small and Large Customers

	Small Rate M1								
25	Delivery Charges	340	15.4464	355	16.1350	0.6886	15	4.5%	2,200
26	Gas Supply Charges	392	17.8227	390	17.7073	(0.1155)	(3)	-0.6%	2,200
27	Total Bill	732	33.2691	745	33.8423	0.5732	13	1.7%	2,200
	Small Rate M2								
28	Delivery Charges	3,387	5.6453	3,738	6.2306	0.5853	351	10.4%	60,000
29	Gas Supply Charges	10,694	17.8227	10,624	17.7070	(0.1157)	(69)	-0.6%	60,000
30	Total Bill	14,081	23.4680	14,363	23.9376	0.4696	282	2.0%	60,000
	Large Rate M2								
31	Delivery Charges	10,906	4.3623	12,369	4.9476	0.5853	1,463	13.4%	250,000
32	Gas Supply Charges	44,557	17.8227	44,268	17.7070	(0.1157)	(289)	-0.6%	250,000
33	Total Bill	55,463	22.1850	56,637	22.6547	0.4696	1,174	2.1%	250,000
	Small Rate M4								
34	Delivery Charges	33,628	3.8432	38,172	4.3626	0.5193	4,544	13.5%	875,000
35	Gas Supply Charges	155,949	17.8227	154,936	17.7070	(0.1157)	(1,012)	-0.6%	875,000
36	Total Bill	189,577	21.6659	193,109	22.0696	0.4036	3,532	1.9%	875,000
	Large Rate M4								
37	Delivery Charges	237,903	1.9825	291,342	2.4278	0.4453	53,439	22.5%	12,000,000
38	Gas Supply Charges	2,138,724	17.8227	2,124,840	17.7070	(0.1157)	(13,884)	-0.6%	12,000,000
39	Total Bill	2,376,627	19.8052	2,416,182	20.1348	0.3296	39,555	1.7%	12,000,000
	Small Rate M5								
40	Delivery Charges	20,602	2.4972	27,525	3.3363	0.8392	6,923	33.6%	825,000
41	Gas Supply Charges	147,037	17.8227	146,083	17.7070	(0.1157)	(955)	-0.6%	825,000
42	Total Bill	167,639	20.3199	173,608	21.0433	0.7235	5,969	3.6%	825,000
	Large Rate M5								
43	Delivery Charges	102,925	1.5835	141,680	2.1797	0.5962	38,754	37.7%	6,500,000
44	Gas Supply Charges	1,158,476	17.8227	1,150,955	17.7070	(0.1157)	(7,521)	-0.6%	6,500,000
45	Total Bill	1,261,401	19.4062	1,292,635	19.8867	0.4805	31,234	2.5%	6,500,000
	Small Rate M7								
46	Delivery Charges	579,244	1.6090	611,959	1.6999	0.0909	32,715	5.6%	36,000,000
47	Gas Supply Charges	6,416,172	17.8227	6,374,520	17.7070	(0.1157)	(41,652)	-0.6%	36,000,000
48	Total Bill	6,995,416	19.4317	6,986,479	19.4069	(0.0248)	(8,937)	-0.1%	36,000,000
	Large Rate M7								
49	Delivery Charges	2,298,408	4.4200	2,337,963	4.4961	0.0761	39,556	1.7%	52,000,000
50	Gas Supply Charges	9,267,804	17.8227	9,207,640	17.7070	(0.1157)	(60,164)	-0.6%	52,000,000
51	Total Bill	11,566,212	22.2427	11,545,603	22.2031	(0.0396)	(20,608)	-0.2%	52,000,000
	Small Rate M9								
52	Delivery Charges	130,944	1.8841	124,832	1.7962	(0.0879)	-6,112	-4.7%	6,950,000
53	Gas Supply Charges	1,238,678	17.8227	1,230,637	17.7070	(0.1157)	(8,041)	-0.6%	6,950,000
54	Total Bill	1,369,622	19.7068	1,355,469	19.5032	(0.2036)	(14,153)	-1.0%	6,950,000
	Large Rate M9								
55	Delivery Charges	388,775	1.9267	370,961	1.8384	(0.0883)	-17,815	-4.6%	20,178,000
56	Gas Supply Charges	3,596,264	17.8227	3,572,918	17.7070	(0.1157)	(23,346)	-0.6%	20,178,000
57	Total Bill	3,985,040	19.7494	3,943,879	19.5454	(0.2040)	(41,160)	-1.0%	20,178,000
	Small Rate T1								
58	Delivery Charges	94,362	1.2520	126,861	1.6832	0.4312	32,500	34.4%	7,537,000
59	Gas Supply Charges	1,343,297	17.8227	1,334,577	17.7070	(0.1157)	(8,720)	-0.6%	7,537,000
60	Total Bill	1,437,658	19.0747	1,461,438	19.3902	0.3155	23,780	1.7%	7,537,000
	Average Rate T1								
61	Delivery Charges	154,443	1.3353	196,360	1.6977	0.3624	41,917	27.1%	11,565,938
62	Gas Supply Charges	2,061,362	17.8227	2,047,981	17.7070	(0.1157)	(13,382)	-0.6%	11,565,938
63	Total Bill	2,215,805	19.1580	2,244,341	19.4047	0.2467	28,536	1.3%	11,565,938
	Large Rate T1								
64	Delivery Charges	373,237	1.4566	441,716	1.7238	0.2672	68,479	18.3%	25,624,080
65	Gas Supply Charges	4,566,903	17.8227	4,537,256	17.7070	(0.1157)	(29,647)	-0.6%	25,624,080
66	Total Bill	4,940,140	19.2793	4,978,971	19.4308	0.1515	38,831	0.8%	25,624,080
	Small Rate T2								
67	Delivery Charges	501,369	0.8461	510,436	0.8614	0.0153	9,067	1.8%	59,256,000
68	Gas Supply Charges	10,561,019	17.8227	10,492,460	17.7070	(0.1157)	(68,559)	-0.6%	59,256,000
69	Total Bill	11,062,389	18.6688	11,002,896	18.5684	(0.1004)	(59,492)	-0.5%	59,256,000
	Average Rate T2								
70	Delivery Charges	1,377,649	0.6965	1,172,515	0.5928	(0.1037)	-205,134	-14.9%	197,789,850
71	Gas Supply Charges	35,251,492	17.8227	35,022,649	17.7070	(0.1157)	(228,843)	-0.6%	197,789,850
72	Total Bill	36,629,140	18.5192	36,195,164	18.2998	(0.2194)	(433,976)	-1.2%	197,789,850
	Large Rate T2								
73	Delivery Charges	2,366,153	0.6393	1,907,986	0.5155	(0.1238)	-458,168	-19.4%	370,089,000
74	Gas Supply Charges	65,959,852	17.8227	65,531,659	17.7070	(0.1157)	(428,193)	-0.6%	370,089,000
75	Total Bill	68,326,006	18.4620	67,439,645	18.2225	(0.2395)	(886,361)	-1.3%	370,089,000
	Large Rate T3								
76	Delivery Charges	2,940,945	1.0784	3,111,819	1.1411	0.0627	170,873	5.8%	272,712,000
77	Gas Supply Charges	48,604,642	17.8227	48,289,114	17.7070	(0.1157)	(315,528)	-0.6%	272,712,000
78	Total Bill	51,545,587	18.9011	51,400,932	18.8481	(0.0530)	(144,654)	-0.3%	272,712,000

Union Gas Limited
2013 Cost of Service - Rate Impacts of Potential Rate Mitigation Measures

Line No.	Particulars	Per Settlement Filing: Current Approved Revenue ($000's) (a)	Per Settlement Filing: Proposed Revenue ($000's) (b)	Per Settlement Filing: Proposed Rate Change (%) (c) = (b/a)	Reduction in ROE: Impact ($000's) (d)	Reduction in ROE: Impact (%) (e) = (d/a)	FT RAM Revenue: Impact ($000's) (f)	FT RAM Revenue: Impact (%) (g) = (f/a)	Distribution Rate Base Alternative: Impact ($000's) (h)	Distribution Rate Base Alternative: Impact (%) (i) = (h/a)	Common Equity Thickness Phase-In: Impact ($000's) (j)	Common Equity Thickness Phase-In: Impact (%) (k) = (j/a)	20-Year Declining Trend Weather Phase-In: Impact ($000's) (l)	20-Year Declining Trend Weather Phase-In: Impact (%) (m) = (l/a)	Rate Mitigation: Proposed Revenue ($000's) (n) = (b+d+f+h+j+l)	Rate Mitigation: Proposed Rate Change (%) (o) = (n/a)
	North Delivery															
1	Rate 01	137,746	158,311	14.9%	(1,341)	-1.0%	(3,797)	-2.8%	(31)	0.0%	(1,730)	-1.3%	(1,905)	-1.4%	149,507	8.5%
2	Rate 10	16,637	19,144	15.1%	(160)	-1.0%	(437)	-2.6%	17	0.1%	(206)	-1.2%	(299)	-1.8%	18,058	8.5%
3	Rate 20	9,721	12,961	33.3%	(159)	-1.6%	(1,987)	-20.4%	(58)	-0.6%	(205)	-2.1%	-	0.0%	10,552	8.5%
4	Rate 25	2,337	2,988	27.8%	(57)	-2.4%	(301)	-12.9%	(20)	-0.8%	(74)	-3.2%	-	0.0%	2,537	8.5%
5	Rate 100	12,658	16,326	29.0%	(131)	-1.0%	(2,238)	-17.7%	(50)	-0.4%	(169)	-1.3%	-	0.0%	13,738	8.5%
6	Total North Delivery	179,100	209,730	17.1%	(1,848)	-1.0%	(8,760)	-4.9%	(141)	-0.1%	(2,385)	-1.3%	(2,205)	-1.2%	194,392	8.5%
	South Delivery & Storage															
7	Rate M1	379,511	397,160	4.4%	(3,337)	-0.9%	-	0.0%	(18)	0.0%	(4,307)	-1.1%	(2,784)	-0.7%	386,714	1.9%
8	Rate M2	44,036	49,680	12.7%	(506)	-1.1%	-	0.0%	76	0.2%	(653)	-1.5%	(767)	-1.7%	47,831	8.6%
9	Rate M4	10,841	12,773	17.8%	(125)	-1.2%	(625)	-5.8%	23	0.2%	(162)	-1.5%	-	0.0%	11,884	9.6%
10	Rate M5	8,874	12,149	36.9%	(107)	-1.2%	(2,215)	-25.0%	32	0.4%	(138)	-1.6%	-	0.0%	9,722	9.6%
11	Rate M7	3,951	4,076	3.2%	(44)	-1.1%	-	0.0%	4	0.1%	(57)	-1.4%	-	0.0%	3,980	0.7%
12	Rate M9	819	768	-6.3%	(8)	-1.0%	-	0.0%	(0)	0.0%	(11)	-1.3%	-	0.0%	749	-8.6%
13	Rate M10	5	6	15.6%	(0)	-6.7%	-	0.0%	(0)	-0.4%	(0)	-8.6%	-	0.0%	5	-0.1%
14	Rate T1	57,783	54,272	-6.1%	(474)	-0.8%	-	0.0%	25	0.0%	(611)	-1.1%	-	0.0%	53,212	-7.9%
15	Rate T3	4,571	4,662	2.0%	(51)	-1.1%	-	0.0%	(0)	0.0%	(66)	-1.4%	-	0.0%	4,545	-0.6%
16	Total South Delivery & Storage	510,391	535,546	4.9%	(4,652)	-0.9%	(2,840)	-0.6%	142	0.0%	(6,004)	-1.2%	(3,551)	-0.7%	518,641	1.6%
17	Total In-Franchise Delivery	689,491	745,276	8.1%	(6,499)	-0.9%	(11,600)	-1.7%	0	0.0%	(8,388)	-1.2%	(5,755)	-0.8%	713,033	3.4%
	North Transportation & Storage															
18	Rate 01	68,509	71,411	4.2%	(183)	-0.3%	-	0.0%	-	0.0%	(236)	-0.3%	-	0.0%	70,991	3.6%
19	Rate 10	22,677	23,194	2.3%	(55)	-0.2%	-	0.0%	-	0.0%	(71)	-0.3%	-	0.0%	23,068	1.7%
20	Rate 20	8,815	7,736	-12.2%	(15)	-0.2%	-	0.0%	-	0.0%	(19)	-0.2%	-	0.0%	7,702	-12.6%
21	Rate 25	1,685	2,118	25.7%	(0)	0.0%	-	0.0%	-	0.0%	(0)	0.0%	-	0.0%	2,117	25.7% (1)
22	Rate 100	197	129	-34.7%	(1)	-0.6%	-	0.0%	-	0.0%	(1)	-0.7%	-	0.0%	126	-36.0%
23	Total North Transport & Storage	101,882	104,588	2.7%	(255)	-0.3%	-	0.0%	-	0.0%	(329)	-0.3%	-	0.0%	104,004	2.1%
24	Total In-Franchise	791,374	849,864	7.4%	(6,754)	-0.9%	(11,600)	-1.5%	0	0.0%	(8,717)	-1.1%	(5,755)	-0.7%	817,037	3.2%
	Ex-Franchise (2)															
25	Rate M12	161,163	162,785	1.0%	(1,774)	-1.1%	-	0.0%	-	0.0%	(2,289)	-1.4%	-	0.0%	158,722	-1.5%
26	Rate M13	373	423	13.5%	(1)	-0.3%	-	0.0%	-	0.0%	(2)	-0.4%	-	0.0%	420	12.7%
27	Rate M16	748	759	1.5%	(2)	-0.3%	-	0.0%	-	0.0%	(3)	-0.4%	-	0.0%	754	0.8%
28	Rate C1	40,698	40,482	-0.5%	(69)	-0.2%	-	0.0%	-	0.0%	(89)	-0.2%	-	0.0%	40,324	-0.9%
29	Total Ex-Franchise	202,982	204,449	0.7%	(1,846)	-0.9%	-	0.0%	-	0.0%	(2,383)	-1.2%	-	0.0%	200,220	-1.4%
30	Total Union Gas	994,355	1,054,313	6.0%	(8,600)	-0.9%	(11,600)	-1.2%	0	0.0%	(11,100)	-1.1%	(5,755)	-0.6%	1,017,258	2.3%

Notes:
(1) Rate changes in Rate 25 Transportation mainly reflect gas cost pass-through items.
(2) Union is not proposing any rate mitigation measures in the Ex-franchise market.



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **12**

DATE: **July 30, 2012**

BEFORE:

Marika Hare	**Presiding Member**
Paul Sommerville	**Member**
Karen Taylor	**Member**

Now, I believe you discussed this last week with Mr. Shepherd. So am I correct that these costs are costs that vary with annual volumes and the demand or capacity-related costs?

MR. PANKRAC: That's correct.

MR. AIKEN: Okay. And you're proposing -- excuse me. You're proposing to allocate these costs based on annual volumes?

MR. PANKRAC: That's right.

MR. AIKEN: Now, earlier today you indicated that demand- or capacity-related costs are generally allocated on peak demand. So my question is: Why are you proposing to use annual volumes for your breakpoint proposal?

MR. PANKRAC: Because at the end of the day, I have a rate design in these classes. I don't have a daily meter. So I'm not able to build demand for those customers, because the cost of putting daily meters in, for us, would be simply ridiculous.

So in my rate design I have two things. I have a monthly customer charge and I have a volumetric charge. And so given constraint, the constraint of not having daily metering on these accounts, then my approach says I need to address what the customer charge level would be, and I need to address what the balance of the costs, be they demand-related or volume-related, are in a volumetric rate.

MR. AIKEN: Well, how do you allocate -- or how did you determine what the peak demand is for residential, commercial, and industrial customers under the current M1

and M2 breakdown?

MR. TETREAULT: Sorry, under current cost allocation, we receive the demands in aggregate for M1/M2, and for Rate 1/Rate 10, and allocate those demands to rate class based on volume, which is consistent with the methodology that we're -- that we're discussing on page 17. It is entirely the same approach.

MR. AIKEN: Sorry, I thought you just said you allocate them based on volume, but earlier today you indicated you allocate the peak day related costs -- or, sorry, the demand-related costs based on peak day, not on annual volumes.

MR. TETREAULT: As a general cost allocation principle, that's true. However, Union does not have a general service forecast on that basis. What we have are demands in aggregate for the two general service classes in the north and the two general service classes in the south.

And the current cost allocation to split those demands, because we don't have it by rate classes, is to do so on the combined annual volume of the two classes in each operating area.

So the approach we're taking here for 2014 is consistent with that approach.

MR. AIKEN: So I take it from that that you have no relative weights for peak demand, for residential versus commercial versus industrial? In other words, an industrial peak demand, in your cost allocation, is the same as a residential peak demand?

MR. TETREAULT: We have total demand for the two general service class combined in each operating area, yes.

MR. AIKEN: Now, how is that different than what you have or don't have for customer-related costs? Do you keep accounting records so that you can distinguish, for example, an M1 industrial versus an M1 commercial versus an M1 residential?

MS. STEVENSON: In 2013, we do have the residential-commercial-industrial forecasts that we use in certain allocators.

MR. AIKEN: But my question was: Do you have the plant accounting, for example, that you know that, Here's the meter costs, the service costs, the regulator costs for Rate 1 residential, and then you have a separate line item for Rate 1 industrial? Do your accounting levels go to that level of detail?

MS. STEVENSON: I believe that some of those records are available, but I'd have to check with our plant accounting records to see what level of detail is available for each different type of cost.

MR. AIKEN: Now, do you know what the approximate breakdown of the total other delivery-related costs of 62-1/2 million in the north and 135.6 million in the south, shown on page 7 of the SEC compendium, are demand-related?

Earlier you said the lion's share are demand related. So I'm asking to quantify the size of the lion.

MR. PANKRAC: Yes, and that is what we have in the J1. -- I believe it's J1.14.2. We do know what the fixed costs