Tolls, Tariff, Facilities & Procedures Committee

Resolution

T2009-05: 2010 - 2012 Revenue Requirement

Resolution

The Tolls, Tariff, Facilities & Procedures Committee ("TTFP") agrees to the Alberta System 2010-2012 Revenue Requirement Settlement (the "Settlement") as attached.

Background

On October 27, 2009, the TTFP adopted Issue T2009-05. In order to ensure that the discussions were inclusive of all interested and potentially affected parties, NGTL sent a letter to all Alberta System customers inviting them to participate in the negotiations.

A task force of the TTFP was established to conduct the negotiations. The first meeting of the 2010+ Revenue Requirement Task Force took place on December 15, 2009 and was followed by five additional meetings, resulting in the attached Settlement.

Next Steps

TransCanada will file this Resolution with the National Energy Board ("NEB") for approval.

Adopted by TTFP: June 8, 2010

NOVA Gas Transmission Ltd.
2010-2012 Revenue Requirement Settlement (the "Settlement")

OVERVIEW

This Settlement includes all elements of NOVA Gas Transmission Ltd.'s ("NGTL") revenue requirement but does not extend to any rate design, accountability, services, or competitive issues.

Rates during the term will be based on the revenue requirement for that year and calculated in accordance with the methodology in effect at the time.

1. REVENUE REQUIREMENT FOR EACH YEAR OF THE TERM

The revenue requirement for the period commencing January 1, 2010 to and including December 31, 2012, (the "Term") shall be calculated based on the inclusion of a fixed cost component and a forecast of flow-through costs. For all flow-through costs, any variance between actual and forecast costs for each year of the Term shall be included in the appropriate deferral account and included in the following year's revenue requirement.

(A) Fixed Component

(i) **Operations, Maintenance, and Administrative Costs ("OM&A")**

OM&A costs for each year of the Term shall be fixed at:

2010 - $173,500,000
2011 - $173,500,000
2012 - $173,500,000

(B) Flow-Through Components

All other costs for the Term including without limitation, all costs set out in 1(B)(i) to (xvii) and any balances in Deferral Accounts for the previous year, shall be flow-through costs (the "Flow-Through Costs"). Any variance between the actual and forecast Flow-Through Costs and revenues shall be included in the appropriate Deferral Account as defined in section 2(D) to be included in the revenue requirement for the following year.

Flow-Through Costs shall include, but not be limited to, the following:

(i) **Return**

For each year of the Term, NGTL will have a deemed equity/debt ratio of 40%/60% and a return on equity of 9.7%. Return on equity for 2010 is forecast to be $189,354,000. Return on debt for 2010 is forecast to be $212,779,000.

(ii) **Depreciation**

Depreciation expense shall be calculated using the rates for each asset class as provided in Appendix 1. Acceptance of these depreciation rates is without prejudice to any position that may be taken in any future forum and does not set a precedent with regard to future treatment of depreciation expense.

For 2010, the resulting forecast composite depreciation rate is 2.85% and the forecast expense is $252,772,000.

(iii) **Income Taxes**

For 2010, income tax expense is forecast to be $68,783,000.

(iv) **Foreign Exchange on Interest Payments**

Foreign exchange on interest payments for 2010 is forecast to be ($7,359,000).

(v) **Municipal and Other Taxes**

Municipal and other taxes for 2010 are forecast to be $117,510,000.

(vi) **Uninsured Losses**

Uninsured losses for each year of the Term are forecast to be $2,000,000.

(vii) **Transportation by Others ("TBO") Costs**

TBO costs for 2010 are forecast to be $77,828,000. Any costs for new TBO arrangements, such TBO arrangements having been approved by the National Energy Board ("NEB"), shall be added to the actual TBO costs for the appropriate year. TBO costs related to an extension of Alberta System service to pipelines downstream of Empress, McNeill, or Alberta/BC are an off-ramp as provided in section 2(I) of this Settlement.

(viii) **Emissions Compliance Costs**

Emissions compliance costs for 2010 are forecast to be $0.

(ix) **Regulatory Proceeding Costs**

The regulatory proceeding costs for 2010 are forecast to be $425,000.

(x) **NEB Cost Recovery**

The NEB cost recovery for 2010 is forecast to be $11,600,000.

(xi) **Pipeline Integrity Expense**

Pipeline integrity expense for 2010 is forecast to be $44,221,000.

(xii) **Compressor Repair and Overhaul Expense**

Compressor repair and overhaul expense for 2010 is forecast to be $5,533,000. Other costs related to major and minor compressor repair and overhaul will be included in rate base.

(xiii) **Annual Foreign Exchange Amortization Amount**

The foreign exchange amortization amount for 2010 is forecast to be $1,604,000.

(xiv) **CO_2 Management Service Costs**

CO_2 Management Service costs for 2010 are forecast to be $408,000.

(xv) **Pension and Other Post Employment Benefits ("OPEB") Actuarial Loss Amortization**

The Pension and OPEB Actuarial Loss Amortization for 2010 is forecast to be $1,500,000. Effective 2011, this amount will be determined as per section 2(E)(iii).

(xvi) **Regulatory Amortizations**

Deferral Account balances from the preceding year will be included in the revenue requirement. The total deferred balance from 2009 is an under-collection of $31,116,000 to be included in the 2010 revenue requirement.

(xvii) **Integrated Alberta System Costs**

Subject to the required regulatory approvals, effective upon commercial implementation of the Integration Agreement, NGTL will include ATCO Pipelines' Alberta Utilities Commission approved revenue requirement in the revenue requirement for the Alberta System.

2. OTHER PROVISIONS

(A) Settlement Package

The parties agree that approval of this Settlement in its entirety as a package is a requirement for the Settlement to be binding on any party. The terms and conditions of this Settlement set no precedent nor shall they prejudice any position any party may take regarding the matters addressed in this Settlement in other proceedings or forums at any time.

(B) Confidentiality

All information exchanged in this Settlement process is confidential and is provided on a without prejudice basis. NGTL shall be entitled to file this Settlement with the appropriate regulatory authorities and may disclose the terms and conditions of this Settlement as it determines necessary in a press release.

(C) 2011, 2012, and 2013 Interim Rates

NGTL shall calculate interim rates, tolls, and charges based on the forecast revenue requirement or the previous year's approved revenue requirement, a forecast of firm transportation contract demand quantity and throughput, and the approved rate design in place at the time. On or before December 1 of each year, the interim rates, tolls, and charges for the following year will be provided to interested parties and filed with the NEB for approval.

(D) Deferral Accounts

NGTL will use the following deferral accounts for 2010, 2011, and 2012:

(i) Revenue Deferral Account

The Revenue Deferral Account will be used to capture:

a) Variances in revenue resulting from actual Firm Transportation Contract Demand revenue differing from the forecast of Firm Transportation Contract Demand revenue used in establishing the applicable year's rates, including all variances related to all Firm Transportation services.

b) Variances in revenues resulting from actual Interruptible Transportation Services revenue differing from the forecast of Interruptible Transportation Services revenue used in establishing the applicable year's rates, including all variances from interruptible receipt and interruptible delivery revenues net of Alternate Access, Facilities Connection Service, Pressure/Temperature Service and Other Services.

(ii) CO_2 Management Service Deferral Account

The CO_2 Management Service Deferral Account will be utilized to capture the variances between forecast and actual revenue and forecast and actual costs attributable to the CO_2 Management service in the applicable year. Any incentive earned by NGTL under the provisions of the CO_2 incentive mechanism will also be recorded in this account.

(iii) Flow-Through Costs Deferral Account

The Flow-Through Costs Deferral Account will be utilized to capture the variances between forecast and actual costs for all flow-through cost components of the revenue requirement including variances due to the implementation of IFRS, with the exception of costs related to the CO_2 Management Service.

(E) Accounting Matters

(i) Support services costs not directly charged to capital projects will be capitalized. TransCanada's support services recovery rate for 2010 is forecast to be 35%.

(ii) During the Term, any revenue requirement variances related to International Financial Reporting Standards ("IFRS") accounting changes will be treated as Flow-Through Costs and will be recorded in the Flow-Through Costs Deferral Account.

(iii) Due to the adoption of IFRS, the Unamortized Pension and OPEB Actuarial Loss of $94 million as of December 31, 2009 will be amortized over 20 years on a fixed straight-line basis. Commencing in 2011, the Pension and OPEB Actuarial Loss Amortization included in the revenue requirement will be $4,700,000. To the extent that amounts collected in rates differ from NGTL cash funding of its pension plans, the difference will be included in rate base.

(iv) Allowance for Funds Used During Construction ("AFUDC") and carrying charges will be calculated in a manner consistent with TransCanada's other NEB regulated pipelines such that AFUDC and carrying charges will be compounded at the weighted average cost of capital.

(F) Reporting

(i) NGTL will seek exemption from the Toll Information Regulations, such that NGTL will only file surveillance reports on an annual basis for each twelve month period ending December 31.

(ii) On or before March 31 of the applicable year, NGTL will provide Supplemental Schedules to the Tolls, Tariff, Facilities, and Procedures Committee ("TTFP") as provided proforma in Appendix 2 (the "Supplemental Schedules").

(iii) During the Term, NGTL will provide annual updates to the TTFP on the Pipeline Integrity and Compressor Repair and Overhaul programs' activities and costs.

(iv) During the Term, NGTL will provide annual updates to the TTFP of the ATCO Integration one-time OM&A expense and capital costs.

(v) During the Term, NGTL will provide annual variance updates to the TTFP for facility projects forecast to be in excess of $50 million.

(i) Upon commencement of negotiations toward a settlement regarding the revenue requirement after the Term, NGTL will provide Supplemental Schedules for the base year, test year, and forecast years. In addition, NGTL will provide Full Time Equivalent ("FTE") and OM&A breakdown by company for the Canadian pipelines for the base year, test year, and forecast years.

(G) Regulatory or Legislative Changes

Any cost variances due to any regulatory or legislative changes that were not known of or otherwise reasonably foreseeable to be incurred during the Term shall be treated as Flow-Through Costs.

(H) Audit

The TTFP may conduct an independent audit of this Settlement and will use reasonable efforts to complete it prior to July 1, 2013. The audit will verify compliance by NGTL with the terms of this Settlement and verify the validity of the information provided in the reporting packages. Subject to the execution of an acceptable confidentiality agreement by the auditor, NGTL will provide reasonable access to all necessary source data. The costs and expenses for the audit will be paid by NGTL and added to NGTL's revenue requirement for the subsequent year.

(I) Settlement Off-Ramp

If NGTL and/or its affiliates file an application with the NEB for an extension of Alberta System service on pipelines downstream of Empress, McNeill, or Alberta/BC during the Term of the Settlement, two or more of the following parties;

- Canadian Association of Petroleum Producers
- Industrial Gas Consumers Association of Alberta
- Western Export Group
- Utilities Consumer Advocate

may provide notice to the TTFP to terminate the Settlement effective on a date to be determined by the parties giving notice but, in any case, a date no earlier than 90 days following the provision of the notice and no later than the date of the implementation of the extension of the Alberta System (the "Termination Date").

NGTL will advise the NEB that the Settlement has been terminated as of the Termination Date for the remainder of the Term of the Settlement and will request that the NEB place NGTL on interim rates effective the Termination Date. All parties are then free to act as they deem appropriate.

SCHEDULE OF DEPRECIATION RATES

CATEGORY	ACCOUNT	DESCRIPTION	DEPRECIATION RATE %
(a)	(b)	(c)	(d)
Meter Stations			
	4611	Land Rights	1.97
	4630	Buildings	2.54
	4631/4632	Site	3.61
	4670	Automation	4.23
	4671	Intrumentation	3.69
	4672	Piping	2.79
	4673	Electric System	2.38
Compressor Stations			
	4612	Land Rights	3.45
	4620	Buildings	4.86
	4621	Site	6.25
	4661	Compressor Unit	3.05
	4662	Piping	4.60
	4663	Instrumentation	4.11
	4664	Electric System	3.90
	4665	Control System	4.28
	4669	Compressor Overhauls	7.69
Pipelines			
	4610	Land Rights	1.45
	4651	Pipe	2.24
	4652	Valve Assemblies	2.30
General Plant			
	4010	Intangible Assets	3.82
	4680	Communication Equipment	5.02
	4821	Buildings	10.84
	4831	Office Furniture	6.67
	4832	Office Equipment	0.00
	4834	Computer Hardware	27.21
	4836	Computer Software	28.16
	4841	Vehicles and Trailers	0.00
	4850	Heavy Work Equipment	0.00
	4860	Tools and Work Equipment	2.03
	4880	Miscellaneous Equipment	5.00

NOVA GAS TRANSMISSION LTD.

ALBERTA SYSTEM
2010 - 2012 REVENUE REQUIREMENT SETTLEMENT

PROFORMA ANNUAL REPORTING PACKAGE

FOR THE YEAR ENDED DECEMBER 31, 2010

NOVA GAS TRANSMISSION LTD.

ALBERTA SYSTEM
2010 - 2012 REVENUE REQUIREMENT SETTLEMENT

PROFORMA ANNUAL REPORTING PACKAGE

FOR THE YEAR ENDED DECEMBER 31, 2010

INDEX

REVENUE REQUIREMENT SUMMARY
FOR THE YEAR ENDED DECEMBER 31, 2010
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
1	Transportation by Others	
2	Pipeline Integrity Expense	
3	NEB Cost Recovery	
4	Return	
5	Income Taxes	
6	Depreciation	
7	Regulatory Proceeding Costs	
8	Emissions Compliance Costs	
9	Municipal and Other Taxes	
10	Regulatory Amortizations	
11	Compressor Repair and Overhaul Expense	
12	Operations, Maintenance and Administrative Costs	
13	Pension and Other Post Employment Benefits Actuarial Loss Amortization	
14	Uninsured Losses	
15	Annual Foreign Exchange Amortization Amount	
16	Foreign Exchange on Interest Payments	
17	CO_2 Management Service Costs	
18	Revenue Requirement	
19	Integrated Alberta System Costs	
20	Total Revenue Reqirement	

AVERAGE RATE BASE SUMMARY
FOR THE YEAR ENDED DECEMBER 31, 2010
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
	Utility Investment	
1	Gross Plant	
2	Accumulated Depreciation	
3	Net Plant	
	Working Capital	
4	Cash	
5	Materials and Supplies	
6	Transmission Linepack	
7	Total Working Capital	
	Deferred Costs	
8	Prefunded / (Unfunded) Foreign Exchange on Long-term Debt	
9	Debt Discount & Expense	
10	Prefunded / (Unfunded) Pension and OPEB Liability	
11	Operating and Debt Service Deferrals	
12	Total Deferred Costs	
13	Total Rate Base	
14	GPUC	
15	Total Investment Base	

AVERAGE CAPITALIZATION AND OVERALL RATE OF RETURN
FOR THE YEAR ENDED DECEMBER 31, 2010
($000)

LINE NO.	DESCRIPTION	SCH. REF.	AMOUNT ($000)	RATIO %	COST RATE %	COST COMPONENT %	COST AMOUNT $
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Debt - Funded	3.0.1					
2	Debt - Unfunded / (Prefunded)						
3	Total Debt						
4	Common Equity						
5	Total Capitalization and Rate of Return						
6	Rate Base						
7	GPUC						
8	Total Capitalization						

NOVA Gas Transmission Ltd. - Alberta System

2010 - 2012 Revenue Requirment Settlement

Proforma Annual Reporting Package

Schedule 3.0.1

WEIGHTED AVERAGE COST OF LONG-TERM DEBT OUTSTANDING

FOR THE YEAR ENDED DECEMBER 31, 2010

($000)

LINE NO.	DESCRIPTION	INTEREST RATE %	PRINCIPAL OUTSTANDING	DAYS OUTSTANDING	TOTAL NGTL INTEREST	DISALLOWED INTEREST [1] %	DISALLOWED INTEREST [1]	ADJUSTED INTEREST
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Debentures							
1	11.2% Series 18							
2	11.2% Series 18							
3	12 5/8% Series 19							
4	12.20 % Series 20							
5	12.20 % Series 21							
6	9.9% Series 23							
7	8 1/2% U.S. $175MM							
8	8 1/2% U.S. $175MM							
9	7 7/8% U.S. $200MM							
10	7.7% U.S. $200MM							
	Medium Term Notes							
11	8.90% MTN #7							
12	8.90% MTN #8							
13	8 7/8% MTN #9							
14	8.46% MTN #11							
15	8.90% MTN #12							
16	8 7/8% MTN #13							
17	7.00% $100MM MTN #17							
18	7.00% $50MM MTN #18							
19	6.59% $20MM MTN #20							
20	6.59% $2.5MM MTN #21							
21	6.59% $10MM MTN #22							
22	6.59% $20MM MTN #23							
23	6.59% $25MM MTN #29							
24	6.30% $100MM MTN#31							
25	7.52% $300MM Note Payable to TransCanada							
26	5.10% $300MM Note Payable to TransCanada							
27	5.05% $500MM Note Payable to TransCanada							
28	8.05% $400MM Note Payable to TransCanada							
29	7.50% US$32.5MM							
30	**Total Interest**							
31	Weighted Average (Schedule 3.0.2)							
32	Amortization of Issue Costs (Schedule 3.0.3)							
33	**Total Cost of Long Term Debt Outstanding**							
34	**Financing Cost Rate**							

[1] The effective interest rate on Series 19, Series 20 and Series 21 debentures has been reduced by 44 basis points (bp), 88 bp and 88 bp respectively, in accordance with PUB order E92086.

WEIGHTED LONG-TERM DEBT OUTSTANDING

FOR THE YEAR ENDED DECEMBER 31, 2010

($000,000)

LINE NO.	DESCRIPTION	Jan 1	Jan 31	Feb 28	Mar 31	Apr 30	May 31	June 30	July 31	Aug 31	Sep 30	Oct 31	Nov 30	Dec 31	13 MONTH AVERAGE
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Debentures														
1	11.2% Series 18														
2	12 5/8% Series 19														
3	12.20 % Series 20														
4	12.20 % Series 21														
5	9.9% Series 23														
6	8 1/2% U.S. $175 MM														
7	7 7/8% U.S. $200 MM														
8	7.70% US$200 MM														
	Medium Term Notes														
9	8.90% MTN #7														
10	8.90% MTN #8														
11	8 7/8% MTN #9														
12	8.46% MTN #11														
13	8.90% MTN #12														
14	8 7/8% MTN #13														
15	7.00% $100MM MTN #17														
16	7.00% $50MM MTN #18														
17	6.59% $20MM MTN #20														
18	6.59% $2.5MM MTN #21														
19	6.59% $10MM MTN #22														
20	6.59% $20MM MTN #23														
21	6.59% $25MM MTN #29														
22	6.30% $100MM MTN#31														
23	7.52% $300MM Note Payable to TransCanada														
24	5.10% $300MM Note Payable to TransCanada														
25	5.05% $500MM Note Payable to TransCanada														
26	8.05% $400MM Note Payable to TransCanada														
27	7.50% US$32.5 MM														
28	**Total**														

AMORTIZATION OF LONG-TERM DEBT ISSUE EXPENSE

FOR THE YEAR ENDED DECEMBER 31, 2010

($000)

LINE NO.	DESCRIPTION	MATURITY YEAR	TOTAL ISSUE COSTS	UNAMORTIZED BALANCE DEC. 31, 2009	LESS: AMORTIZATION	UNAMORTIZED BALANCE DEC. 31, 2010
	(a)	(b)	(c)	(d)	(e)	(f)
	Debentures					
1	11.20% Series 18					
2	12.625% Series 19					
3	12.20% Series 21					
4	9.90% Series 23					
5	8.50% US$175MM					
6	7.875% US$200MM					
7	7.70% US$200MM					
	Medium Term Notes					
8	8.9% MTN #7 and #8					
9	8.875% MTN #9 and 13					
10	8.46% MTN #11					
11	7.00% $100MM MTN #17					
12	6.59% $20MM MTN #20					
13	6.59% $2.5MM MTN #21					
14	6.59% $10MM MTN #22					
15	6.59% $20MM MTN #23					
16	6.59% $25MM MTN #29					
17	6.30% $100MM MTN#31					
18	7.52% $300MM Note Payable to TransCanada					
19	5.10% $300MM Note Payable to TransCanada					
20	5.05% $500MM Note Payable to TransCanada					
21	8.05% $400MM Note Payable to TransCanada					
22	7.50% US$32.5 MM					
23	**Total**					

SCHEDULE OF FLOW-THROUGH INCOME TAXES
FOR THE YEAR ENDED DECEMBER 31, 2010
($000)

LINE NO.	DESCRIPTION	SCH. REF.	ACTUAL
	(a)	(b)	(c)
1	Return on Equity	3.0	
	Add:		
2	Depreciation	5.0	
3	Non-allowed Amortization of Debt Discount & Expense	3.0.3	
4	Annual Foreign Exchange Amortization Amount	8.0	
5	Non-allowed Meals and Entertainment		
6	Sub-total		
	Deduct:		
7	Capital Cost Allowance	4.0.1	
8	Cumulative Eligible Capital	4.0.1	
9	Interest AFUDC		
10	Issue Costs		
11	Site Remediation Costs		
12	Sub-total		
13	Total Taxable Amount		
14	Taxes thereon (Tax Rate / (1-Tax Rate))		
15	Utility Income Tax Requirement		

NOVA Gas Transmission Ltd. - Alberta System

2010 - 2012 Revenue Requirment Settlement
Proforma Annual Reporting Package
Schedule 4.0.1

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDED DECEMBER 31, 2010
($000 unless otherwise noted)

CCA CLASS	UCC OPENING BALANCE	ADJUSTED OPENING BALANCE	ADDITIONS AND REMOVAL	SALVAGE	CURRENT YEAR NET ADDS	UCC BEFORE 1/2 YEAR EXCLUSION	1/2 YEAR RULE ADDS EXCLUDED	UCC ELIGIBLE FOR CCA	MAX RATE	CAPITAL COST ALLOWANCE	UNDEP CAPITAL COST
01											
02											
03											
06											
07											
08											
09											
10											
10A											
10B											
12											
13											
17											
49											

In-Service Additions	**Total**	
	AFUDC	
	CEC (Land Right)	
	Land	
	Removal	
	Straight Deduct	

CUMMULATIVE ELIGIBLE CAPITAL
FOR THE YEAR ENDED DECEMBER 31, 2010
($000 unless otherwise noted)

CEC	OPENING BALANCE	ADJUSTMENT TO OPENING BALANCE	COST OF ADDITIONS	EXCLUDE 25 % OF ADDITIONS	ELIGIBLE BALANCE	RATE	CEC DEDUCTION	CLOSING BALANCE

DEPRECIATION
FOR THE YEAR ENDED DECEMBER 31, 2010
($000 unless otherwise noted)

LINE NO.	DESCRIPTION	RATE	ACTUAL EXPENSE
	(a)	(b)	(c)
1	Intangible Plant		
2	Land Rights		
3	Mains		
4	Compressor		
5	Measuring and Regulating		
6	CO_2 Service		
7	Communication Equipment - Transmission		
8	Structures & Improvements		
9	Furniture & Equip - General		
10	Furniture & Equip - Computers		
11	Vehicles		
12	Heavy Work Equipment		
13	Tools & Work Equipment		
14	Communication Equipment - General		
15	Total Depreciation Expense		

TRANSPORTATION BY OTHERS
FOR THE YEAR ENDED DECEMBER 31, 2010
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
1	Foothills Pipe Lines	
2	TransCanada Pipeline Ventures	
3	ATCO East Edmonton	
4	ATCO Grand Cache	
5	Total Transportation by Others	

FOREIGN EXCHANGE ON INTEREST PAYMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010
($000s)

LINE NO.	DESCRIPTION	DEBT ISSUE (US$)	INTEREST RATE	DATE OF INTEREST PAYMENT	INTEREST PAYMENTS (US$)	HISTORICAL EXCHANGE RATE [1]	FORECAST EXCHANGE RATE	FORECAST (GAIN) / LOSS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	7.50% MTN #5							
2	7.875% U.S. $200 mm							
3	7.70% U.S. $50 mm							
4	7.70% U.S. $150 mm							
5	8.50% U.S. $175 mm (Swap - 8.5% Fixed) [2]							
6	7.50% MTN #5							
7	7.875% U.S. $200 mm							
8	7.70% U.S. $50 mm							
9	7.70% U.S. $150 mm							
10	8.50% U.S. $175 mm (Swap - 8.5% Fixed) [2]							
11	Total foreign exchange (gain) / loss on interest payments							

[1] Historical exchange rates pertain to the original financing when a maturing issue(s) is rolled into a new issue.
[2] US$ 37 million of the 8.5% US$ 175 million debt instrument has been swapped to CDN$.

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT

FOR THE YEAR ENDED DECEMBER 31, 2010

($000)

LINE NO.	DESCRIPTION	MATURITY DATE	AMOUNT (US$)	HISTORICAL EXCHANGE RATE	DEC 31, 2009 EXCHANGE RATE	CURRENT YEAR LOSS/(GAIN)
	(a)	(b)	(c)	(d)	(e)	(f)
1	8.50% US$175MM [1]					
2	7.875% US$200MM					
3	7.70% US$150MM Note Payable to TCPL					
4	7.70% US$50MM Note Payable to TCPL					
5	7.50% Medium Term Note - US$32.5MM					
6						
7	Prefunded / (Unfunded) Foreign Exchange on Long Term Debt Balance at January 1, 2010					
8	**Total**					
9	Annual Foreign Exchange Amortization Amount (Line 7 divided by 19)					

[1] US$ 37 million of the 8.5% US$ 175 million debt instrument has been swapped to CDN$.

GPIS and GPUC CONTINUITY SUMMARY
FOR THE YEAR ENDED DECEMBER 31, 2010
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
	Gas Plant In Service	
1	Opening Gas Plant In Service	
2	GPIS Transfers	
3	General Plant Additions	
4	Retirements	
5	Closing Gas Plant In Service	
6	Opening Accumulated Depreciation	
7	Depreciation Expense	
8	Retirements	
9	Closing Accumulated Depreciation	
10	Retirements In Progress	
11	Closing Net Gas Plant In Service	
	Gas Plant Under Construction	
12	Opening Gas Plant Under Construction	
13	Capital Expenditures	
14	AFUDC	
15	GPIS Transfers	
16	Closing Gas Plant Under Construction	