Tolls, Tariff, Facilities & Procedures Committee

Resolution

T2014-01: Revenue Requirement Settlement Discussions

Resolution

The Tolls, Tariff, Facilities & Procedures Committee ("TTFP") agrees to the provisions of the NGTL 2015 Revenue Requirement Settlement (the "Settlement"), as attached.

Background

On February 11, 2014, the TTFP adopted Issue T2014-01. In order to ensure that discussions were inclusive of all interested and potentially affected parties, NGTL sent a letter to all NGTL System customers, TTFP members and additional stakeholders inviting them to participate in the discussions and negotiations.

A task force of the TTFP was established to conduct the negotiations. The first meeting of the 2015 revenue requirement task force took place on May 15, 2014 and was followed by numerous additional task force meetings. This process resulted in the Settlement.

Next Steps

NGTL will file an application with the National Energy Board ("NEB") for approval of the Settlement. This resolution and the attached Settlement will be filed in support of the application.

NOVA Gas Transmission Ltd.

2015 Revenue Requirement Settlement

OVERVIEW

This 2015 Revenue Requirement Settlement (the "**Settlement**") includes all elements of NOVA Gas Transmission Ltd.'s ("**NGTL**") annual revenue requirement for January 1, 2015 to December 31, 2015 (the "**Term**").

Rates during the Term of the Settlement will be based on the revenue requirement for 2015 and calculated in accordance with the tolling methodology in effect at the time.

1. **2015 REVENUE REQUIREMENT** (all amounts are in $000 unless otherwise indicated)

The 2015 revenue requirement is forecast to be $1,718,586 and shall be calculated based on the inclusion of the fixed cost component in Section 1(A) and the forecast flow-through cost components in Section 1(C).

(A) **Fixed Component**

(i) Operations, Maintenance, and Administrative costs ("**OM&A Costs**") for the Term shall be fixed at an amount equal to the actual 2014 OM&A Costs plus 4.5% ("**Fixed OM&A Costs**").

(B) **OM&A Cost Sharing**

(i) For any variance between the actual 2015 OM&A costs and the Fixed OM&A Costs, the portion of the variance that is:

(a) less than or equal to ±$5 million from the Fixed OM&A Costs will be shared 50% to the account of NGTL and 50% to the account of NGTL's gas transportation customers ("**Customers**");

(b) greater than ±$5 million and less than or equal to ±$10 million from the Fixed OM&A Costs will be shared 75% to the account of NGTL and 25% to the account of Customers;

(c) greater than ±$10 million from the Fixed OM&A Costs will be 100% to the account of NGTL.

(ii) Any variances that accrue to the account of Customers shall be recorded in the deferral account set out in Section 2(D)(iv) and shall be included in the 2016 revenue requirement.

(C) **Flow-Through Components**

All other components of the annual revenue requirement for the Term, including without limitation all costs set out in Sections 1(C)(i) to (xvii) and any balances in deferral accounts set out in Section 2(D) 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 recorded in the appropriate deferral account, set out in Section 2(D), and shall be included in the 2016 revenue requirement.

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

(i) **Transportation by Others (“TBO”)**

(a) Costs for existing TBO arrangements shall be included in the revenue requirement during the Term; and

(b) Costs for new TBO arrangements shall be included in the revenue requirement during the Term if such costs have been approved by the National Energy Board (“**NEB**”).

TBO cost for 2015 is forecast to be $86,334.

(ii) **Pipeline Integrity Expense**

Pipeline integrity expense for 2015 is forecast to be $184,663.

(iii) **NEB Cost Recovery**

The NEB cost recovery for 2015 is forecast to be $25,500.

(iv) **Return**

For the Term, NGTL will have a deemed equity/debt ratio of 40%/60% and a return on equity of 10.1%. Return on equity for 2015 is forecast to be $252,015. Return on debt for 2015 is forecast to be $205,230.

(v) **Income Taxes**

For 2015, income tax expense is forecast to be $42,108.

(vi) **Depreciation**

Depreciation expense shall be calculated using the rates for each asset class as provided in Appendix 1.

For 2015, the forecast composite depreciation rate that results from the rates for the asset classes set out in Appendix 1 is 3.16% and the forecast expense is $364,393.

(vii) **Regulatory Proceeding Costs**

The regulatory proceeding costs for 2015 are forecast to be $250.

(viii) **Emissions Compliance Costs**

Emissions compliance costs for 2015 are forecast to be $12,500.

(ix) **Municipal and Other Taxes**

Municipal and other taxes for 2015 are forecast to be $130,480.

(x) **Regulatory Amortizations**

Deferral Account balances from the preceding year will be included in the revenue requirement. The total deferred balance from 2014 is forecast to be an over-collection of $7,227 to be a credit in the 2015 revenue requirement.

(xi) **Compressor Repair Expense**

Compressor repair expense for 2015 is forecast to be $2,625. Other costs related to major and minor compressor repair and overhaul will be included in rate base.

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

The Pension and OPEB Actuarial Loss Amortization for 2015 is forecast to be $7,958.

(xiii) **Uninsured Losses**

Uninsured losses for 2015 are forecast to be $2,000.

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

The foreign exchange amortization amount for 2015 is forecast to be a $901 credit in the 2015 revenue requirement.

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

Foreign exchange on interest payments for 2015 is forecast to be a $5,310 credit in the 2015 revenue requirement.

(xvi) **CO_2 Management Service Costs**

CO_2 Management Service costs for 2015 are forecast to be $252.

(xvii) **Integrated NGTL System Costs**

Pursuant to the Integration Agreement between NGTL and ATCO Gas and Pipelines Ltd. ("**ATCO Pipelines**"), NGTL will include ATCO Pipelines' Alberta Utilities Commission approved annual revenue requirement in NGTL's annual revenue requirement. Integration costs for 2015 are forecast to be $192,642.

2. OTHER PROVISIONS

(A) Settlement Package

The parties agree that regulatory 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 do not set any precedent and does not prejudice any party in any position it may take regarding the matters addressed in this Settlement in other proceedings or forums.

(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 regulatory authorities and may disclose the terms and conditions of this Settlement as it determines necessary in a news release or other public reporting.

(C) 2016 Interim Rates

NGTL shall calculate interim rates, tolls, and charges for 2016 based on the forecast revenue requirement or the approved 2015 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, 2015, the interim rates, tolls, and charges to be effective January 1, 2016 will be provided to interested parties and filed with the NEB for approval.

(D) Deferral Accounts

NGTL will use the following deferral accounts for 2015:

(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 2015 year's rates, including all variances related to all Firm Transportation services; and

(b) Variances in revenues resulting from actual Interruptible Transportation Services revenue differing from the forecast of Interruptible Transportation Services revenue used in establishing the 2015 rates, including all variances from interruptible receipt and interruptible delivery revenues net of Alternate Access, Facilities Connection Service, Pressure/Temperature Service and Other Services, and ATCO Pipeline Franchise Fees.

(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 2015. 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 with the exception of costs related to the CO_2 Management Service.

(iv) **Fixed OM&A Deferral Account**

The Fixed OM&A Deferral Account will be utilized to capture any variances to Customers' account pursuant to Section 1(B) and shall be applied to NGTL's 2016 revenue requirement.

(E) **Accounting Matters**

(i) Support services costs not directly charged to capital projects will be capitalized. TransCanada PipeLines Limited's support services recovery rate for 2015 is forecast to be 30%.

(ii) Allowance for Funds Used During Construction ("**AFUDC**") and carrying charges will be calculated using the NGTL System weighted average cost of capital based on a deemed debt/equity ratio of 60%/40% and a return on equity of 10.1%.

(F) **Surveillance Reporting**

(i) NGTL will seek exemption from the Toll Information Regulations, to allow it to file surveillance reports on an annual basis for the Term. Surveillance reports will be filed no later than 60 days following December 31, 2015.

(ii) Notwithstanding Section 2(F)(i), NGTL will file with the NEB, on a quarterly basis, schedules in the same format as schedules 3.0 and 3.1 in the NEB Quarterly Surveillance Report.

(G) **Tolls, Tariff, Facilities, and Procedures Committee ("TTFP") Reporting**

(i) On or before March 31, 2016, NGTL will provide Supplemental Schedules to the TTFP as provided proforma in Appendix 2 (the "**Supplemental Schedules**").

(ii) On or before March 31, 2016, NGTL will provide an update to the TTFP on the 2015 pipeline integrity and compressor repair and overhaul activities and costs.

(iii) During the Term, NGTL will provide the TTFP with variance updates for Annual Plan (as defined in NGTL's Gas Transportation Tariff) projects forecast to be in excess of $50 million.

(iv) NGTL will file with the NEB the Supplemental Schedules and any updates related to items referred to in Sections 2(G)(ii) and (iii) by March 31, 2016.

(v) NGTL will provide the TTFP with quarterly reporting of 2015 actual costs in the format of the Supplemental Schedules with additional OM&A cost schedules. For each quarter of 2015, NGTL will provide the TTFP with explanations of material year-to-date variances between 2014 and 2015 actuals by line item on Schedule 1.0 of the Supplemental Schedules and on the summary-level OM&A cost schedule. NGTL will advance discussions with the TTFP regarding the future exchange of information.

(vi) 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.

(H) **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.

(I) **Audit**

The TTFP may conduct an independent audit of this Settlement and will use reasonable efforts to complete it prior to July 1, 2016. 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.

Appendix 1
SCHEDULE OF 2015 DEPRECIATION RATES

CATEGORY	ACCOUNT	DESCRIPTION	LATERAL SEGMENT DEPRECIATION RATE (%)	MAINLINE SEGMENT DEPRECIATION RATE (%)	COMPOSITE DEPRECIATION RATE (%)
Meter Stations					
	461.10	LAND RIGHTS	3.54%	2.63%	2.90%
	463.00	BUILDINGS	4.26%	3.51%	3.74%
	463.10/463.20	SITE	4.99%	4.34%	4.53%
	467.00	AUTOMATION	6.61%	5.46%	5.80%
	467.10	INSTRUMENTATION	9.01%	7.31%	7.82%
	467.20	PIPING	5.81%	4.65%	5.00%
	467.30	ELECTRICAL SYSTEM	4.59%	3.56%	3.87%
Compressor Stations					
	461.20	LAND RIGHTS	7.54%	3.82%	3.97%
	462.00	BUILDINGS	4.86%	2.51%	2.61%
	462.10	SITE	5.57%	2.91%	3.03%
	466.10	COMPRESSOR UNIT	10.21%	4.17%	4.38%
	466.20	PIPING	7.55%	3.63%	3.79%
	466.30	INSTRUMENTATION	16.82%	5.85%	6.31%
	466.40	ELECTRICAL SYSTEM	4.66%	2.23%	2.33%
	466.50	AUTOMATION	7.05%	3.75%	3.89%
	466.90	COMPRESSOR OVERHAUL	7.39%	7.39%	7.39%
Pipelines					
	461.00	LAND RIGHTS	1.38%	1.60%	1.57%
	465.10	PIPE	2.89%	2.57%	2.61%
	465.20	VALVES	2.93%	2.31%	2.40%
	468.00	COMMUNICATION STRUCT. & EQUIP.	6.70%	6.70%	6.70%
General Plant					
	482.10	BUILDINGS			3.52%
	483.10	OFFICE FURNITURE			7.60%
	483.20	OFFICE EQUIPMENT			6.70%
	483.40	COMPUTER HARDWARE			10.41%
	483.60	COMPUTER SOFTWARE			12.86%
	484.10	VEHICLES AND TRAILERS			7.61%
	485.00	HEAVY WORK EQUIPMENT			3.75%
	486.00	TOOLS AND WORK EQUIPMENT			1.89%
	488.00	MISCELLANEOUS EQUIPMENT			4.95%
	482.00	LEASEHOLD IMPROVEMENTS			10.84%
	482.20	TC NEW TOWER			4.37%

Appendix 2

NOVA GAS TRANSMISSION LTD.

NGTL SYSTEM
2015 REVENUE REQUIREMENT SETTLEMENT

SUPPLEMENTAL SCHEDULES

FOR THE YEAR ENDED DECEMBER 31, 2015

NOVA GAS TRANSMISSION LTD.

NGTL SYSTEM
2015 REVENUE REQUIREMENT SETTLEMENT

SUPPLEMENTAL SCHEDULES

FOR THE YEAR ENDED DECEMBER 31, 2015

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NOVA Gas Transmission Ltd. - NGTL System

2015 Revenue Requirement Settlement
Supplemental Schedules
Schedule 1.0

REVENUE REQUIREMENT SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 2015
($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 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	Subtotal	
19	Integration Costs	
20	Total Revenue Reqirement	

AVERAGE RATE BASE SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 2015
($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, 2015
($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						

WEIGHTED AVERAGE COST OF LONG-TERM DEBT OUTSTANDING

FOR THE YEAR ENDED DECEMBER 31, 2015

($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	12.20 % Series 20							
2	12.20 % Series 21							
3	9.9% Series 23							
4	7 7/8% U.S. $200MM							
5	7.7% U.S. $200MM							
	Medium Term Notes							
6	8.90% MTN #7							
7	8.90% MTN #8							
8	8 7/8% MTN #9							
9	8.46% MTN #11							
10	8.90% MTN #12							
11	8 7/8% MTN #13							
12	7.00% $100MM MTN #17							
13	7.00% $50MM MTN #18							
14	6.59% $20MM MTN #20							
15	6.59% $2.5MM MTN #21							
16	6.59% $10MM MTN #22							
17	6.59% $20MM MTN #23							
18	6.59% $25MM MTN #29							
19	6.30% $100MM MTN#31							
20	5.10% $300MM Note Payable to TransCanada							
22	8.05% $400MM Note Payable to TransCanada							
23	4.55% $250MM Note Payable to TransCanada							
23	4.55% $300MM Note Payable to TransCanada							
24	3.65% $200MM Note Payable to TransCanada							
25	3.69% $450MM Note Payable to TransCanada							
26	7.50% U.S. $32.5MM							
27	**Total Interest**							
28	Weighted Average (Schedule 3.2.4)							
29	Amortization of Issue Costs (Schedule 3.3.4)							
30	**Total Cost of Long Term Debt Outstanding**							
31	**Financing Cost Rate**							

[1] The effective interest rate on Series 20 and Series 21 debentures have both been reduced by 88 basis points. This adjustment has been made since Alberta Public Utilities Board order E92086.

WEIGHTED LONG-TERM DEBT OUTSTANDING

FOR THE YEAR ENDED DECEMBER 31, 2015

($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	12.20 % Series 20														
2	12.20 % Series 21														
3	9.9% Series 23														
4	7 7/8% U.S. $200MM														
5	7.70% U.S. $200MM														
	Medium Term Notes														
6	8.90% MTN #7														
7	8.90% MTN #8														
8	8 7/8% MTN #9														
9	8.46% MTN #11														
10	8.90% MTN #12														
11	8 7/8% MTN #13														
12	7.00% $100MM MTN #17														
13	7.00% $50MM MTN #18														
14	6.59% $20MM MTN #20														
15	6.59% $2.5MM MTN #21														
16	6.59% $10MM MTN #22														
17	6.59% $20MM MTN #23														
18	6.59% $25MM MTN #29														
19	6.30% $100MM MTN#31														
20	5.10% $300MM Note Payable to TransCanada														
21	8.05% $400MM Note Payable to TransCanada														
21	4.55% $250MM Note Payable to TransCanada														
22	4.55% $300MM Note Payable to TransCanada														
22	3.65% $200MM Note Payable to TransCanada														
23	3.69% $450MM Note Payable to TransCanada														
23	7.50% U.S. $32.5MM														
24	**Total**														

AMORTIZATION OF LONG-TERM DEBT ISSUE EXPENSE

FOR THE YEAR ENDED DECEMBER 31, 2015

($000)

LINE NO.	DESCRIPTION	MATURITY YEAR	TOTAL ISSUE COSTS	UNAMORTIZED BALANCE DEC. 31, 2012	LESS: AMORTIZATION	UNAMORTIZED BALANCE DEC. 31, 2013
	(a)	(b)	(c)	(d)	(e)	(f)
	Debentures					
1	12.20% Series 21					
2	9.90% Series 23					
3	7.875% U.S. $200MM					
4	7.70% U.S. $200MM					
	Medium Term Notes					
5	8.9% MTN #7 and #8					
6	8.875% MTN #9 and 13					
7	8.46% MTN #11					
8	7.00% $100MM MTN #17					
9	6.59% $20MM MTN #20					
10	6.59% $2.5MM MTN #21					
11	6.59% $10MM MTN #22					
12	6.59% $20MM MTN #23					
13	6.59% $25MM MTN #29					
14	6.30% $100MM MTN#31					
15	5.10% $300MM Note Payable to TransCanada					
16	8.05% $400MM Note Payable to TransCanada					
17	4.55% $250MM Note Payable to TransCanada					
18	4.55% $300MM Note Payable to TransCanada					
19	3.65% $200MM Note Payable to TransCanada					
20	3.69% $450MM Note Payable to TransCanada					
21	7.50% U.S. $32.5MM					
22	**Total**					

SCHEDULE OF FLOW-THROUGH INCOME TAXES

FOR THE YEAR ENDED DECEMBER 31, 2015
($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	Capitalized Repair & Overhaul Costs	4.0.1	
10	Interest AFUDC		
11	Issue Costs		
12	Site Remediation Costs	4.0.1	
13	Sub-total		
14	Total Taxable Amount		
15	Taxes thereon (Tax Rate / (1-Tax Rate))		
16	Utility Income Tax Requirement		

SCHEDULE OF CAPITAL COST ALLOWANCE
FOR THE YEAR ENDED DECEMBER 31, 2015
($000'S)

LINE NO.	CLASS	UNDEPRECIATED CAPITAL COST OPENING BALANCE	ADDITIONS (NET)	BALANCE BEFORE CLAIM	MAXIMUM CCA	CLOSING BALANCE
	(a)	(b)	(c)	(d)	(e)	(f)
1	Class 1 - Full (4%)					
2	- Half Year					
3	Class 2 - Full (6%)					
4	Class 3 - Full (5%)					
5	- Half Year					
6	Class 6 - (10%)					
7	Class 7 - Full (15%)					
8	- Half Year					
9	Class 8 - Full (20%)					
10	- Half Year					
11	Class 10 - Full (30%)					
12	- Half Year					
13	Class 10a - Full (45%)					
14	Class 10b - Full (55%)					
15	- Half Year					
16	Class 12 - Full (100%)					
17	- Half Year					
18	Class 13 - Full (S/L)					
19	- Half Year					
20	Class 17 - Full (S/L)					
21	Class 49 - Full (8%)					
22	- Half Year					
23	TOTAL					

CAPITAL COST ALLOWANCE RECONCILIATION
($000's)

LINE NO.	PARTICULARS		CLOSING BALANCE
1	Transfers to GPIS (including Overhead, excluding AFUDC)		
2	Regulated General Plant Additions in 2015		
	Adjustments		
3	Compressor Overhaul Capitalized		
4	Net Proceeds - Retirements		
5	Site Remediation & Environmental costs		
6	Total Adjustments		
7	Capital Cost Allowance Additions per Line 23 above		

INCOME TAX EXPENSE SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2015
($000'S)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
	CALCULATION OF ELIGIBLE CAPITAL EXPENSES	
1	Unamortized Balance at January 1, 2015	
2	Additions - Land Rights (@75%)	
3	Balance at December 31, 2015	
4	Amount Available for Tax Deduction at 7% of Line 3	
5	Unamortized Balance at January 1, 2016	

DEPRECIATION

FOR THE YEAR ENDED DECEMBER 31, 2015
($000 unless otherwise noted)

LINE NO.	DESCRIPTION	ACTUAL 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, 2015
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
1	Foothills Pipe Lines	
2	TransCanada Pipeline Ventures	
3	Other	
4	Total Transportation by Others	

FOREIGN EXCHANGE ON INTEREST PAYMENTS

FOR THE YEAR ENDED DECEMBER 31, 2015
($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	7.50% MTN #5							
6	7.875% U.S. $200 mm							
7	7.70% U.S. $50 mm							
8	7.70% U.S. $150 mm							
9	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.

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT

FOR THE YEAR ENDED DECEMBER 31, 2015
($000)

LINE NO.	DESCRIPTION	MATURITY DATE	AMOUNT (US$)	HISTORICAL EXCHANGE RATE	DEC 31, 2014 EXCHANGE RATE	CURRENT YEAR LOSS/(GAIN)
	(a)	(b)	(c)	(d)	(e)	(f)
1	7.875% US$200MM					
2	7.70% US$150MM Note Payable to TCPL					
3	7.70% US$50MM Note Payable to TCPL					
4	7.50% Medium Term Note - US$32.5MM					
5						
6	Prefunded / (Unfunded) Foreign Exchange on Long Term Debt Balance at January 1, 2015					
7	**Total**					
8	Annual Foreign Exchange Amortization Amount (Line 6 divided by 14)[1]					

[1] Represents the number of years remaining until the last USD debt instrument matures.

GPIS and GPUC CONTINUITY SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 2015
($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	