Tolls, Tariff, Facilities & Procedures Committee

Resolution

T2015-02: Revenue Requirement Settlement Discussions

Resolution

The Tolls, Tariff, Facilities & Procedures Committee ("TTFP") agrees to the provisions of the 2016-2017 Revenue Requirement Settlement (the "Settlement"), as attached.

Background

On April 14, 2015, the TTFP adopted Issue T2015-02. In order to ensure that the 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 revenue requirement task force took place on July 17, 2015 and was followed by additional task force meetings. The Settlement resulted from this process.

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.

2016-2017 Revenue Requirement Settlement

OVERVIEW

This 2016-2017 Revenue Requirement Settlement (the "**Settlement**") includes all elements of NOVA Gas Transmission Ltd.'s ("**NGTL**") annual revenue requirement for each calendar year during the period from January 1, 2016 to December 31, 2017 (the "**Term**").

Rates during the Term of the Settlement will be based on the revenue requirement for 2016 and 2017 (as applicable) and calculated in accordance with the tolling methodology in effect at the time.

1. **2016 and 2017 REVENUE REQUIREMENTS** (all amounts are in $000 unless otherwise indicated)

The 2016 revenue requirement is forecast to be $1,857,351. The annual revenue requirements for 2016 and 2017 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 each year of the Term shall be fixed at ("**Fixed OM&A Costs**"):

2016: $222.5 million

2017: $222.5 million

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

(i) For each year of the Term, for any variance between the actual OM&A Costs and the applicable 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 for each calendar year of the Term shall be recorded in the deferral account set out in Section 2(D)(iv) and shall be included in the revenue requirement for the following calendar year.

(C) **Flow-Through Components**

All other components of the annual revenue requirement for each calendar year of the Term, including without limitation all costs set out in Sections 1(C)(i) to (xviii) and any balances in deferral accounts set out in Section 2(D) for the previous calendar year, shall be flow-through costs (the "**Flow-Through Costs**"). Any variance between the actual and forecast Flow-Through Costs and revenues for each calendar year shall be recorded in the appropriate deferral account, set out in Section 2(D), and shall be included in the revenue requirement for the following calendar year.

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 for each calendar year during the Term; and

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

TBO cost for 2016 is forecast to be $85,262.

(ii) **Pipeline Integrity Expense**

Pipeline integrity expense for 2016 is forecast to be $206,841.

(iii) **NEB Cost Recovery**

The NEB cost recovery for 2016 is forecast to be $19,000.

(iv) **Return**

For the Term, NGTL will have a deemed equity/debt ratio of 40%/60% and a return on equity of 10.1% per year. Return on equity for 2016 is forecast to be $275,405. Return on debt for 2016 is forecast to be $198,374.

(v) **Income Taxes**

For 2016, income tax expense is forecast to be $41,499.

(vi) **Depreciation**

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

For both 2016 and 2017, the forecast composite depreciation rate that results from the rates for the asset classes set out in Appendix 1 is 3.16% for the year. For 2016, Depreciation expense is forecast to be $392,679.

(vii) **Regulatory Proceeding Costs**

The regulatory proceeding costs for 2016 are forecast to be $785.

(viii) **Emissions Compliance Costs**

Emissions compliance costs for 2016 are forecast to be $21,800.

(ix) **Municipal and Other Taxes**

Municipal and other taxes for 2016 are forecast to be $130,000.

(x) **Regulatory Amortizations**

The annual revenue requirement for 2016 and 2017 shall include Deferral Account balances from the preceding calendar year. The total deferred balance from 2015 is forecast to be an under-collection of $38,420, to be a charge in the 2016 revenue requirement.

(xi) **Compressor Repair Expense**

Compressor repair expense for 2016 is forecast to be $2,862. Capital 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 2016 is forecast to be $15,387.

(xiii) **Uninsured Losses**

Uninsured losses for 2016 are forecast to be $2,000.

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

The foreign exchange amortization amount for 2016 is forecast to be a $901 credit in the 2016 revenue requirement.

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

Foreign exchange on interest payments for 2016 is forecast to be a $610 credit in the 2016 revenue requirement.

(xvi) **CO_2 Management Service Costs**

CO_2 Management Service costs for 2016 are forecast to be $156.

(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 for each of 2016 and 2017 in NGTL’s annual revenue requirement for each of 2016 and 2017, respectively. Integration costs for 2016 are forecast to be $205,893.

(xviii) **Severance Costs**

For the Term of the Settlement, any Severance Costs allocated to NGTL that are incurred during the Term will be treated as flow through. There is no forecast for Severance Costs for 2016.

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) **2017 and 2018 Interim Rates**

NGTL shall calculate interim rates, tolls, and charges based on the forecast revenue requirement or the approved previous year’s 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 to be effective January 1 of 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 each of 2016 and 2017, and the balance shall be applied to NGTL’s revenue requirement for 2017 and 2018, respectively:

(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 in a calendar year used in establishing the applicable 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 in a calendar year 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, 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 for each calendar year in the Term. 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 in a calendar year 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) for each of 2016 and 2017 and shall be applied to NGTL's revenue requirement for 2017 and 2018, respectively.

(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 2016 is forecast to be 41%.

(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% per year.

(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 of each year of the Term.

(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.

(iii) For the purpose of annual 2017 Surveillance Reporting, the actual 2016 level for each flow through cost will be reported as the 2017 forecast amount.

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

(i) On or before March 31, 2017 (for 2016) and on or before March 31, 2018 (for 2017), NGTL will provide Supplemental Schedules to the TTFP as provided proforma in Appendix 2 (the "**Supplemental Schedules**").

(ii) On or before March 31, 2017, NGTL will provide an update to the TTFP on the 2016 pipeline integrity and compressor repair and overhaul activities and costs. On or before March 31, 2018, NGTL will provide an update to the TTFP on the 2017 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 $25 million. NGTL will advance discussions with the TTFP regarding capital cost reporting, with changes agreed upon by NGTL and the TTFP applying during the Term.

(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, 2017 (for 2016) and March 31, 2018 (for 2017).

(v) NGTL will provide the TTFP with quarterly reporting of 2016 and 2017 actual costs in the format of the Supplemental Schedules with additional OM&A cost schedule information consistent with 2015 settlement reporting. For each quarter of 2016 and 2017, NGTL will provide the TTFP with explanations of material year-to-date variances between actuals for the previous calendar year and the applicable calendar year by line item on Schedule 1.0 of the Supplemental Schedules and on the summary-level OM&A cost schedule.

(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, 2018. 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 2016 and 2017 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

2016 - 2017 REVENUE REQUIREMENT SETTLEMENT

SUPPLEMENTAL SCHEDULES

FOR THE YEARS ENDED DECEMBER 31, 2016 & 2017

NOVA GAS TRANSMISSION LTD.

NGTL SYSTEM
2016 - 2017 REVENUE REQUIREMENT SETTLEMENT

SUPPLEMENTAL SCHEDULES

FOR THE YEARS ENDED DECEMBER 31, 2016 & 2017

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REVENUE REQUIREMENT SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 2016
AND THE YEAR ENDED DECEMBER 31, 2017
($000)

LINE NO.	DESCRIPTION	2016 ACTUAL	2017 ACTUAL
	(a)	(b)	(c)
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	Severance Costs		
15	Uninsured Losses		
16	Annual Foreign Exchange Amortization Amount		
17	Foreign Exchange on Interest Payments		
18	CO_2 Management Service Costs		
19	Subtotal		
20	Integration Costs		
21	Total Revenue Reqirement		

AVERAGE RATE BASE SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 2016
AND THE YEAR ENDED DECEMBER 31, 2017
($000)

LINE NO.	DESCRIPTION	2016 ACTUAL	2017 ACTUAL
	(a)	(b)	(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, 2016
($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, 2016

($000)

LINE NO.	DESCRIPTION	MATURITY	INTEREST RATE	PRINCIPAL OUTSTANDING	DAYS OUTSTANDING	TOTAL INTEREST
	(a)		(b)	(c)	(d)	(e)
	Debentures					
1	12.20% $100MMSeries 20					[(1)]
2	12.20% $125MM Series 21					[(1)]
3	9.90% $100MM Series 23					
4	7.875% US$200MM					
5	7.70% US$200MM					
	Medium Term Notes					
6	8.90% $33MM MTN #7					
7	8.90% $39MM MTN #8					
8	8.875% $30MM MTN #9					
9	8.46% $45MM MTN #11					
10	8.90% $15MM MTN #12					
11	8.875% $15MM 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					
22	4.55% $250MM Note Payable to TransCanada					
23	3.65% $200MM Note Payable to TransCanada					
24	4.55% $300MM Note Payable to TransCanada					
25	3.69% $450MM Note Payable to TransCanada					
26	3.30% $750MM Note Payable to TransCanada					
27	4.55% $400MM Note Payable to TransCanada					
28	7.50% US$32.5MM					
29	**Total Interest**					
30	Weighted Average					
31	Amortization of Issue Costs					
32	**Total Cost of Long-Term Debt Outstanding**					
33	**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.

AVERAGE CAPITALIZATION AND OVERALL RATE OF RETURN
FOR THE YEAR ENDED DECEMBER 31, 2017
($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.

2016 - 2017 Revenue Requirement Settlement

Supplemental Schedules

Schedule 3.1.1

WEIGHTED AVERAGE COST OF LONG-TERM DEBT OUTSTANDING

FOR THE YEAR ENDED DECEMBER 31, 2017

($000)

LINE NO.	DESCRIPTION	MATURITY	INTEREST RATE	PRINCIPAL OUTSTANDING	DAYS OUTSTANDING	TOTAL INTEREST
	(a)		(b)	(c)	(d)	(e)
	Debentures					
1	9.90% $100MM Series 23					
2	7.875% US$200MM					
3	7.70% US$200MM					
	Medium Term Notes					
4	8.90% $33MM MTN #7					
5	8.90% $39MM MTN #8					
6	8.875% $30MM MTN #9					
7	8.46% $45MM MTN #11					
8	8.90% $15MM MTN #12					
9	8.875% $15MM MTN #13					
10	7.00% $100MM MTN #17					
11	7.00% $50MM MTN #18					
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	5.10% $300MM Note Payable to TransCanada					
19	8.05% $400MM Note Payable to TransCanada					
20	4.55% $250MM Note Payable to TransCanada					
21	3.65% $200MM Note Payable to TransCanada					
22	4.55% $300MM Note Payable to TransCanada					
23	3.69% $450MM Note Payable to TransCanada					
24	3.30% $750MM Note Payable to TransCanada					
25	4.55% $400MM Note Payable to TransCanada					
26	7.50% US$32.5MM					
27	**Total Interest**					
28	Weighted Average					
29	Amortization of Issue Costs					
30	**Total Cost of Long-Term Debt Outstanding**					
31	**Financing Cost Rate**					

SCHEDULE OF FLOW-THROUGH INCOME TAXES

FOR THE YEAR ENDED DECEMBER 31, 2016
AND THE YEAR ENDED DECEMBER 31, 2017
($000)

LINE NO.	DESCRIPTION	SCH. REF.	2016 ACTUAL	2017 ACTUAL
	(a)	(b)	(c)	(d)
1	Return on Equity	3.0		
	Add:			
2	Depreciation	5.0		
3	Non-allowed Amortization of Debt Discount & Expense			
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, 2016

($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 2016		
	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, 2016
($000'S)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
	CALCULATION OF ELIGIBLE CAPITAL EXPENSES	
1	Unamortized Balance at January 1, 2016	
2	Additions - Land Rights (@75%)	
3	Balance at December 31, 2016	
4	Amount Available for Tax Deduction at 7% of Line 3	
5	Unamortized Balance at January 1, 2017	

SCHEDULE OF CAPITAL COST ALLOWANCE
FOR THE YEAR ENDED DECEMBER 31, 2017
($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 2017	
	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, 2017
($000'S)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
	CALCULATION OF ELIGIBLE CAPITAL EXPENSES	
1	Unamortized Balance at January 1, 2017	
2	Additions - Land Rights (@75%)	
3	Balance at December 31, 2017	
4	Amount Available for Tax Deduction at 7% of Line 3	
5	Unamortized Balance at January 1, 2018	

DEPRECIATION

FOR THE YEAR ENDED DECEMBER 31, 2016
AND THE YEAR ENDED DECEMBER 31, 2017
($000 unless otherwise noted)

LINE		2016 ACTUAL		2017 ACTUAL	
NO.	DESCRIPTION	RATE	EXPENSE	RATE	EXPENSE
	(a)	(b)	(c)	(d)	(e)
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, 2016
AND THE YEAR ENDED DECEMBER 31, 2017
($000)

LINE NO.	DESCRIPTION	2016 ACTUAL	2017 ACTUAL
	(a)	(b)	(c)
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, 2016
($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.

FOREIGN EXCHANGE ON INTEREST PAYMENTS

FOR THE YEAR ENDED DECEMBER 31, 2017
($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, 2016
($000)

LINE NO.	DESCRIPTION	MATURITY DATE	AMOUNT (US$)	HISTORICAL EXCHANGE RATE	DEC 31, 2015 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, 2016					
7	**Total**					
8	Annual Foreign Exchange Amortization Amount (Line 6 divided by 13) [1]					

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

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT

FOR THE YEAR ENDED DECEMBER 31, 2017
($000)

LINE NO.	DESCRIPTION	MATURITY DATE	AMOUNT (US$)	HISTORICAL EXCHANGE RATE	DEC 31, 2016 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, 2017					
7	**Total**					
8	Annual Foreign Exchange Amortization Amount (Line 6 divided by 12) [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, 2016
AND THE YEAR ENDED DECEMBER 31, 2017
($000)

LINE NO.	DESCRIPTION	2016 ACTUAL	2017 ACTUAL
	(a)	(b)	(c)
	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		